Columbia Gas of Massachusetts
A NiSource Company

Mark Kempic
President and COO

4 Technology Drive, Suite 250
Westborough, MA 01581
(508) 836-7320
Cellular: (412) 719-7714
mkempic@nisource.com

March 31, 2020

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: Bay State Gas Company d/b/a Columbia Gas of Massachusetts - Annual Return for Year Ending 12-31-19

Dear Secretary Marini:

Enclosed is the Annual Return of Bay State Gas Company d/b/a Columbia Gas of Massachusetts ("Company") for the year ending December 31, 2019. The Company's Annual Return is submitted pursuant to G.L. c. 164, § 83 and the Memorandum issued by the Department of Public Utilities ("Department") on August 18, 2011, as clarified on February 14, 2014 and January 21, 2020. The Annual Return includes the signed Statement of Operating Revenues required by the Memorandum.

Please note that the Company has excluded section R2 from the Annual Return because the computation cannot be performed at this time. Section R2 relates to the return on equity for 2019 operations. The data needed for the computation is not yet entirely available and the data is anomalistic due to the ongoing impacts of the Merrimack Valley event.

Pursuant to 220 C.M.R. § 79.01, the Company has enclosed copies of the most recent Integrated Annual Report to Stockholders of NiSource Inc. (for CY 2018) and the NiSource Inc. Form 10-K, submitted to the Securities Exchange Commission on February 28, 2020.[1]

If you have any questions with respect to this filing, please contact me. Thank you for your attention to this matter.

Sincerely,

Mark Kempic

Mark Kempic

cc: George Yiankos, Director, Natural Gas Division
Rebecca Tepper, Esq., Office of the Attorney General

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1 Bay State Gas Company d/b/a Columbia Gas of Massachusetts does not issue or file independent reports with stockholders.

GAS COMPANIES

The Commonwealth of Massachusetts

RETURN

OF THE

BAY STATE GAS COMPANY d/b/a COLUMBIA GAS OF MASSACHUSETTS

TO THE

DEPARTMENT OF PUBLIC UTILITIES

OF MASSACHUSETTS

FOR THE YEAR ENDED DECEMBER 31,

2019

DEPARTMENT OF PUBLIC UTILITIES

This statement is filed in accordance with Chapter 164, Section 84A

CONDENSED FINANCIAL RETURN

FOR YEAR ENDED DECEMBER 31, 2019

FULL NAME OF COMPANY Bay State Gas Company d/b/a Columbia Gas of Massachusetts

LOCATION OF PRINCIPAL BUSINESS OFFICE 4 Technology Drive, Suite 250, Westborough MA, 01581

STATEMENT OF INCOME FOR THE YEAR

Item	Current Year	Increase or (Decrease) from Preceding Year
OPERATING INCOME		
Operating Revenues...	573,128,555	(12,749,424)
Operating Expenses..		
Operation Expense...	486,655,852	3,999,875
Maintenance Expense...	(322,700,921)	(1,164,087,337)
Depreciation Expense...	52,822,219	6,509,730
Amortization of Utility Plant......................................	14,629,776	120,942
Amortization of Property Losses...	0	0
Amortization of Investment Tax Credit................................	0	0
Taxes other than Income Taxes..	49,498,064	19,832,154
Income Taxes...	71,392,447	73,943,034
Provisions for Deferred Federal Income Taxes......................................	113,990,955	48,142,549
Federal Income Taxes Deferred In Prior Years..............................	(133,567,116)	165,371,004
Total Operating Expenses...	332,721,276	(846,168,049)
Net Operating Revenues...	240,407,279	833,418,624
Income from Utility Plant Leased to Others.....................................	0	0
Other Utility Operating Income..	0	0
Total Utility Operating Income..	240,407,279	833,418,624
OTHER INCOME		
Income (Loss) from Mdse. Jobbing & Contract Work - After Taxes	0	0
Income from Nonutility Operations - After Taxes	0	0
Nonoperating Rental Income - After Taxes	0	0
Interest and Dividend Income - After Taxes	1,804,234	196,491
Miscellaneous Nonoperating Income + Earnings of Subsidiaries - After Taxes	(149,299,974)	(152,753,466)
Total Other Income..	(147,495,740)	(152,556,975)
Total Income..	92,911,539	680,861,649
MISCELLANEOUS INCOME DEDUCTIONS		
Miscellaneous Amortization...	0	0
Other Income Deductions - After Taxes	53,490,874	53,166,444
Total Income Deductions..	53,490,874	53,166,444
Income Before Interest Charges..	39,420,665	627,695,205
INTEREST CHARGES		
Interest on Long-Term Debt...	2,521,000	0
Amortization of Debt Discount and Expense...	329,616	0
Amortization of Premium on Debt-Credit....................................	0	0
Interest on Debt to Associated Companies..	39,963,044	20,887,922
Other Interest Expense...	644,737	33,463
Interest Charged to Construction-Credit...	(491,532)	(203,302)
Total Interest Charges..	42,966,865	20,718,083
Net Income..	(3,546,200)	606,977,122

Note The financial information presented herein contains restoration costs associated with the Merrimack Valley event that occurred on September 13, 2019.

BALANCE SHEET

Title of Account	Balance End of Year	Title of Account	Balance End of Year
UTILITY PLANT		PROPRIETARY CAPITAL	
Utility Plant........................	$ 2,515,218,676	CAPITAL STOCK	
OTHER PROPERTY AND INVESTMENTS		Common Stock Issued....................	$ 100
		Preferred Stock Issued....................	0
Nonutility Property..........................	226,850	Capital Stock Subscribed.....................	0
Investment in Associated Companies......	0	Premium on Capital Stock..................	411,771,866
Other Investments.........................	25,000	Total....................................	411,771,966
Special Funds.........................	2,124,338	SURPLUS	
Total Other Property and Investments	2,376,188	Other Paid-In Capital...........................	184,597,121
CURRENT AND ACCRUED ASSETS		OCI Deficit………………………………..	0
Cash................................	2,183,470	Earned Surplus	(489,258,006)
Special Deposits............................	0	Total.......................................	(304,660,885)
Working Funds.............................	1,200	Total Proprietary Capital......................	107,111,081
Temporary Cash Investments........	0	LONG-TERM DEBT	
Notes and Accounts Receivable............	87,350,956	Bonds................................	0
Receivables from Associated Co........	587,274	Capital-Lease Obligations......................	56,156,828
Materials and Supplies..................	18,276,874	Other Long-Term Debt.........................	349,400,000
Prepayments...........................	6,861,615	Total Long-Term Debt	405,556,828
Interest and Dividends Receivable..........	0	CURRENT AND ACCRUED LIABILITIES	
Rents Receivable.........................	0		
Accrued Utility Revenues.....................	46,692,212	Notes Payable.........................	0
Miscellaneous Current and Accrued Assets	0	Accounts Payable................................	53,440,751
Def. Fuel Costs.....................	2,352,539	Payables to Associated Companies..........	752,605,249
Total Current and Accrued Assets.......	164,306,140	Customer Deposits..............................	3,257,178
DEFERRED DEBITS		Taxes Accrued.................................	35,968,631
Unamortized Debt Discount Expense	1,984,666	Interest Accrued...........................	875,444
Extraordinary Property Losses.............	0	Dividends Declared...........................	0
Preliminary Survey and Investigation		Fuel Purchase Commitments............	0
Charges...........................	1,767,217	Capital Leases	3,028,817
Clearing Accounts....................	0	Tax Collections Payable......................	652,154
Temporary Facilities........................	0	Misc. Current and Accrued Liabilities......	251,771,500
Miscellaneous Deferred Debits...............	145,015,574	Total Current and Accrued Liabilities.......	1,101,599,724
Total Deferred Debits..........................	148,767,457	DEFERRED CREDITS	
CAPITAL STOCK DISCOUNT AND EXPENSE		Unamortized Premium on Debt.........	0
		Customer Advances for Construction......	6,905
Discount on Capital Stock..............	0	Other Deferred Credits.................	152,815,087
Capital Stock Expense....................	0	Total Deferred Credits........................	152,821,992
Total Capital Stock Discount and Exp.	0	RESERVES	
REACQUIRED SECURITIES		Reserves for Depreciation.....................	596,095,829
Reacquired Capital Stock.........	0	Reserves for Amortization.................	460,331,193
Reacquired Bonds.........................	0	Reserves for Uncollectible Accounts......	6,176,595
Total Reacquired Securities................	0	Operating Reserves..............................	13,956,194
Total Assets and Other Debits..................	$ 2,830,668,461	Reserve for Depreciation and Amortization of Nonutility Property............	192,134
		Reserves for Deferred Federal Income Taxes.....................................	(21,815,884)
		Total Reserves...........................	1,054,936,061
		CONTRIBUTIONS IN AID OF CONSTRUCTION	
		Contributions in Aid of Construction.......	8,642,775
		Total Liabilities and Other Credits.......	$ 2,830,668,461

STATEMENT OF EARNED SURPLUS

	Amount for Year	Increase or (Decrease) from Preceding Year
Unappropriated Earned Surplus (at beginning of period)	$ (485,711,806)	$ (610,523,323)
Balance Transferred from Income..	(3,546,200)	606,977,123
Miscellaneous Credits to Surplus……………..	0	0
Miscellaneous Credits to Surplus……………..	0	0
Miscellaneous Credits to Surplus……………..	0	0
Miscellaneous Credits to Surplus……………..	0	0
Miscellaneous Credits to Surplus…………….	0	0
Miscellaneous Credits to Surplus……………..	0	0
Net Additions to Earned Surplus...	(3,546,200)	606,977,123
Dividends Declared-Preferred Stock..	0	0
Appropriations of Surplus.for Common Stock Rights....................................…	0	0
Dividends Declared-Common Stock..		0
Unappropriated Earned Surplus (at end of period).....................................	$ (489,258,006)	$ (3,546,200)

ELECTRIC OPERATING REVENUES

Account	Operating Revenues	
	Amount for Year	Increase or (Decrease) from Preceding Year
SALES OF ELECTRICITY	$	$
Residential Sales...		
Commercial and Industrial Sales..		
Small (or Commercial)...		
Large (or Industrial)..		
Public Street and Highway Lighting.....................................		
Other Sales to Public Authorities..		
Sales to Railroad and Railways..		
Interdepartmental Sales..		
Miscellaneous Electric Sales..		
Total Sales to Ultimate Consumers...		
Sales for Resale...		
Total Sales of Electricity...		
OTHER OPERATING REVENUES		
Forfeited Discounts...		
Miscellaneous Service Revenues...		
Sales of Water and Water Power...		
Rent from Electric Property...		
Interdepartmental Rents...		
Other Electric Revenues...		
Total Other Operating Revenues..		
Total Electric Operating Revenues..		

SUMMARY OF ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Functional Classification	Operation	Maintenance	Total
	$	$	$
Power Production Expenses..			
Electric Generation			
Steam Power...			
Nuclear Power..			
Hydraulic Power..			
Other Power....................................			
Other Power Supply Expenses................................			
Total Power Production Expenses.........................			
Transmission Expenses...			
Distribution Expenses......................................			
Customer Accounts Expenses..........................			
Sales Expenses...................................			
Administrative and General Expenses....................			
Total Electric Operation and Maintenance Expenses.			

GAS OPERATING REVENUES

ACCOUNT	Operating Revenues	
	Amount for Year	Increase or (Decrease) from Preceding Year
SALES OF GAS		
Residential Sales..	$ 368,531,000	$ (15,543,175)
Commercial and Industrial Sales...		
Commercial & Industrial..	109,873,519	(8,872,068)
Interruptible..	0	0
Other Sales to Public Authorities...	0	0
Interdepartmental Sales...	0	0
Unbilled Gas Sales..	(2,197,000)	2,859,100
Total Sales to Ultimate Consumers..	476,207,519	(21,556,143)
Sales for Resale..	1,041,675	(1,774,624)
Total Sales of Gas..	477,249,194	(23,330,767)
OTHER OPERATING REVENUES		
Residential Transportation....................................	535,116	(303,323)
Forfeited Discounts-Late Payment Charges............................	575,083	113,944
Miscellaneous Service Revenues...	0	0
Revenues from Transportation of Gas to Others....................	51,060,019	3,607,284
Sales of Products Extracted from Natural Gas.......................	0	0
Revenues from Natural Gas Processed by Others.................	0	0
Rent from Gas Property...	140,396	6,732
Interdepartmental Rents...	0	0
Other Gas Revenues...	43,568,747	7,156,706
Total Other Operating Revenues..	95,879,361	10,581,343
Total Gas Operating Revenues...	$ 573,128,555	$ (12,749,424)

SUMMARY OF GAS OPERATIONS AND MAINTENANCE EXPENSES

Functional Classification	Operation	Maintenance	Total
Steam Production..			
Manufactured Gas Production.......................................	$ 11,784,712	$ 407,023	$ 12,191,735
Other Gas Supply Expenses..	204,868,802	0	204,868,802
Total Production Expenses..	216,653,514	407,023	217,060,537
Local Storage Expenses...	0	0	0
Transmission and Distribution Expense.........................	45,596,500	(329,895,872)	(284,299,372)
Customer Accounts Expense..	73,553,220	0	73,553,220
Sales Expense...	248,827	0	248,827
Administrative and General Expenses............................	150,603,791	6,787,928	157,391,719
Total Gas Operation and Maintenance Expenses............	$ 486,655,852	$ (322,700,921)	$ 163,954,931

March 23, 2020, I hereby certify that the foregoing statements are full, just and true to the best of my knowledge and belief. This statement is signed under the penalties of perjury.

Joseph W. [signature]
Controller

Commonwealth of Massachusetts
Department of Public Utilities
One South Street
Boston, MA 02110

STATEMENT OF OPERATING REVENUES

YEAR 2019

Name of Company	Bay State Gas Company
D/B/A	Columbia Gas of Massachusetts
Address	4 Technology Drive, Suite 250, Westborough, MA 01581-1791

		Location on Annual Return
Massachusetts Operating Revenues (Intrastate)	$ 572,741,577	C1, C4, 10, 43
Other Revenues (outside Massachusetts)	$ 386,978	C4, 43, 48
Total Revenues	$ 573,128,555	C1, C4, 10, 43

I hereby certify under the penalties of perjury that the foregoing statement is true to the best of my knowledge and belief.

Signature Mark Kempic
Name Mark Kempic
Title President & Director

The purpose of this statement is to provide the Department of Public Utilities with the amount of intrastate operating revenues for the annual assessment made pursuant to G.L. c. 25, § 18.

If invoices or correspondence are to be addressed to a particular individual or department of the Company, please provide the name, title, and address below.

Name Mark Kempic
Title President & Director
Address Columbia Gas of Massachusetts
4 Technology Drive, Suite 250
Westborough, MA 01581-1791

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Receivables from Associated Companies	23	
Materials and Supplies	24	
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Extraordinary Property Losses	27	N/A
Miscellaneous Deferred Debits	27	
Discount on Capital Stock	28	N/A
Capital Stock Expense	28	N/A
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Other Paid-In Capital	30	
Long-Term Debt	31	
Notes Payable	32	N/A
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Summary of Electric Operation and Maintenance Expenses	42	N/A
Gas Operating Revenues	43	
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Other Utility Operating Income	50	N/A
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GENERAL INFORMATION

PRINCIPAL AND SALARIED OFFICERS *

Titles	Names	Addresses	Annual Salaries
President	Mark Kempic	4 Technology Drive, Westborough, MA	$ 300,000
Vice President & General Manager	Martin G. Poulin	4 Technology Drive, Westborough, MA	192,000
Vice President & Treasurer	Randy G. Hulen	801 E. 86th Ave., Merrillville, IN	30,769
Vice President, Chief Accounting Officer, & Controller	Joseph W. Mulpas	290 W. Nationwide Blvd., Columbus OH	37,795

DIRECTORS *

Names	Addresses	Fees Paid During Year (E)
Mark Kempic	4 Technology Drive, Westborough, MA	No fees paid
Martin G. Poulin	4 Technology Drive, Westborough, MA	No fees paid

(E) Included, where applicable, annual retainer paid to Directors who are not salaried officers of Company or subsidiary. Directors' meeting attendance fees, annual committee fees and committee meeting attendance fees.

* By General Laws, Chapter 164 , Section 83, the Return must contain a "list of the names of all their salaried officers and the amount of the salary paid to each," and by Section 77, the department is required to include in its annual report "the names and addresses of the principal officers and of the directors."

GENERAL INFORMATION - Continued

1. Corporate name of company making this report:
   Bay State Gas Company

2. Date of organization:
   See Note 1

3. Date of incorporation:
   November 10, 1998 as Acquisition Gas Company, Inc.

4. Give location (including street and number) of principal business office:
   4 Technology Drive, Suite 250, Westborough, Massachusetts 01581

5. Total number of stockholders: One - NiSource Inc., 801 East 86th Avenue, Merrillville, IN 46410

6. Number of stockholders in Massachusetts: None

7. Amount of stock held in Massachusetts:	No. of shares,	0	Common	$0
	No. of shares,	0	$50 Pfd.	$0
	No. of shares,	0	$100 Pfd.	$0
8. Capital stock issued prior to June 5,1894:	No. of shares,	N/A		
9. Capital stock issued with approval of Board	No. of shares,	100	Common	$100
of Gas and Electric Light Commissioners or	No. of shares,	0	$100 Pfd.	$0
Department of Public Utilities since June 5, 1894	No. of shares,	0	$50 Pfd.	$0
Total 100 Common Shares, par value, $1.00, outstanding at December 31, 2019				$100
0 Pfd., par value, $100				$0
0 Pfd., par value, $ 50				$0

10. In connection with the Company's Common Stock Issuance:

DTE #98-31

In connection with the Company's Merger with NiSource Inc. 100 Shares of Common Stock, $ 1.00 Par Value, were Issued, as approved in DTE #98-31, dated November 5, 1998.

11. Management Fees and Expenses during the Year.

List all individuals, corporations or concerns with whom the company has any contract or agreement covering management or supervision of its affairs, such as accounting, financing, engineering, construction, purchasing, operation, etc., & show the total amount paid to each for the year.

Year 2019	Gross Dollars Billed to Columbia Gas of Massachusetts	Portion of Billed Charged to Balance Sheet or Non-Utility Expense
Management Fee - NiSource Corporate Services Co.	36,361,792	16,151,023

GENERAL INFORMATION - Continued

12. Describe briefly all the important physical changes in the property during the last fiscal period including additions, alterations or improvements to the works or physical property retired.

ADDITIONS - MAJOR
Gas Mains
Gas Services

RETIREMENTS - MAJOR
Gas Services
Gas Mains

Note 1

On November 10, 1998, Acquistion Gas Company, Inc. was formed as a subsidiary of NiSource, Inc. On February 12, 1999, (Old) Bay State Gas Company was merged into Acquisition Gas Company, Inc. Old Bay State Gas Company was dissolved and Acquistion Gas Company changed its name to Bay State Gas Company.

Note 2

In connection with the Greater Lawrence Incident, which occurred on September 13, 2018, the Company, in cooperation with the Massachusetts Governor's Office, replaced the entire affected 45-mile cast iron and bare steel pipeline system that delivers gas to approximately 7,500 gas meters, the majority of which serve residences and of which approximately 700 serve businesses impacted in the Greater Lawrence Incident. This system was replaced with plastic distribution mains and service lines, as well as enhanced safety features such as pressure regulation and excess flow valves at each premise. We incurred approximately $91 million of capital spend for the pipeline replacement during 2019. This included $88 million for Gas Mains and $3 million for Gas Services; there was substantially no gross book value of plant retired for Gas Mains or for Gas Services in 2019. The total investment in the pipeline replacement work was $258 million, which includes $167 million incurred in 2018.

Annual report of ....Columbia Gas of Massachusetts.....................Year ended December 31, 2019

GENERAL INFORMATION - Continued

Names of the cities or towns in which the company supplies GAS, with the number of customers' meters in each place.		Names of the cities or towns in which the company supplies GAS, with the number of customers' meters in each place.	
City or Town	Number of Customers' Meters, December 31, 2019	City or Town	Number of Customers' Meters, December 31, 2019
Abington	222	Medfield	2,931
Agawam	8,089	Medway	2,626
Andover	8,842	Mendon	39
Attleboro	8,899	Methuen	14,304
Avon	1,118	Middleborough	58
Bellingham	2,202	Millis	1,321
Berkley	86	Monson	218
Bridgewater	4,283	Norfolk	509
Brockton	22,231	North Andover	6,545
Canton	6,759	Northampton	8,932
Chicopee	14,167	Norton	4,329
Dighton	810	Norwell	1,967
Dover	87	Palmer	253
Duxbury	3,594	Pembroke	4,248
East Bridgewater	2,517	Plympton	173
East Longmeadow	4,936	Randolph	7,925
Easthampton	3,791	Raynham	2,050
Easton	4,878	Rehoboth	157
Foxborough	5,018	Scituate	5,597
Franklin	8,482	Seekonk	3,043
Granby	274	Sharon	4,756
Halifax	843	South Hadley	4,267
Hampden	853	Southwick	780
Hanover	3,350	Springfield	41,070
Hanson	2,400	Stoughton	8,108
Haverhill	10	Swansea	29
Holbrook	2,240	Taunton	14,306
Lakeville	663	Walpole	6,220
Lawrence	21,532	West Bridgewater	1,717
Longmeadow	5,150	West Springfield	9,029
Ludlow	4,885	Wilbraham	3,133
Mansfield	5,549	Wrentham	2,061
Marshfield	8,009		
	166,769		162,701
		* TOTAL	329,470

* Total represents active meters at December 31, 2019

COMPARATIVE BALANCE SHEET Assets and Other Debits

Line No.	Title of Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Increase or (Decrease) (d)
1	UTILITY PLANT			
2	Utility Plant (101-107) P.13	2,317,003,817	2,515,218,676	198,214,859
3	OTHER PROPERTY AND INVESTMENTS			
4	Nonutility Property (121) P.19...	226,850	226,850	0
5	Investment in Associated Companies (123) P.20.........................	0	0	0
6	Other Investments (124) P.20...	25,000	25,000	0
7	Special Funds (125,126,127,128) P.21.....................................	0	2,124,338	2,124,338
8	Total Other Property and Investments.....................................	251,850	2,376,188	2,124,338
9	CURRENT AND ACCRUED ASSETS			
10	Cash (131)...	4,717,808	2,183,470	(2,534,338)
11	Special Deposits (132,133,134) P.21....................................	0	0	0
12	Working Funds (135)..	1,200	1,200	0
13	Temporary Cash Investments (136) P.20.....................................	0	0	0
14	Notes and Accounts Receivable (141,142,143) P.22.......................	231,414,516	87,350,956	(144,063,560)
15	Receivables from Assoc. Companies (145,146) P.23........................	603,477	587,274	(16,203)
16	Materials and Supplies (151-159,163) P.24.............................	19,377,074	18,276,874	(1,100,200)
17	Prepayments (165)..	6,356,117	6,861,615	505,498
18	Interest and Dividends Receivable (171).......................................	0	0	0
19	Rents Receivable (172)..	0	0	0
20	Accrued Utility Revenues (173)..	48,604,097	46,692,212	(1,911,885)
21	Miscellaneous Current and Accrued Assets (174)	0	0	0
22	Def. Fuel Costs (175)...	12,177,636	2,352,539	(9,825,097)
23	Total Current and Accrued Assets.......................................	323,251,925	164,306,140	(158,945,785)
24	DEFERRED DEBITS			
25	Unamortized Debt Discount and Expense (181) P.26....................	2,249,855	1,984,666	(265,189)
26	Extraordinary Property Losses (182) P.27..............................	0	0	0
27	Preliminary Survey and Investigation Charges (183)...................	997,394	1,767,217	769,823
28	Clearing Accounts (184)...	0	0	0
29	Temporary Facilities (185)..	0	0	0
30	Miscellaneous Deferred Debits (186)...P.27.......................	139,914,411	145,015,574	5,101,163
31	Total Deferred Debits..	143,161,660	148,767,457	5,605,797
32	CAPITAL STOCK DISCOUNT AND EXPENSE			
33	Discount on Capital Stock (191) P.28......................................	0	0	0
34	Capital Stock Expense (192) P.28..	0	0	0
35	Total Capital Stock Discount and Expense........................	0	0	0
36	REACQUIRED SECURITIES			
37	Reacquired Capital Stock (196).......................................	0	0	0
38	Reacquired Bonds (197)..	0	0	0
39	Total Reacquired Securities...	0	0	0
40	Total Assets and Other Debits....................................	2,783,669,252	2,830,668,461	46,999,209

COMPARATIVE BALANCE SHEET Liabilities and Other Credits

Line No.	Title of Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Increase or (Decrease) (d)
1	PROPRIETARY CAPITAL			
2	CAPITAL STOCK			
3	Common Stock Issued (201) P.29.....................................	100	100	0
4	Preferred Stock Issued (204) P.29..	0	0	0
5	Capital Stock Subscribed (202,205)..	0	0	0
6	Premium on Capital Stock (207) P.29.................................	411,771,866	411,771,866	0
7	Total..	411,771,966	411,771,966	0
8	SURPLUS			
9	Other Paid-In Capital (208-211) P. 30...............................	69,597,121	184,597,121	115,000,000
10	OCI Deficit ……………………………………………	0	0	0
11	Earned Surplus (215,216) P. 12...	(485,711,806)	(489,258,006)	(3,546,200)
12	Total..	(416,114,685)	(304,660,885)	111,453,800
13	Total Proprietary Capital......................................	(4,342,719)	107,111,081	111,453,800
14	LONG TERM DEBT			
15	Bonds (221) P.31...	0	0	0
16	Capital Lease Obligations	44,245,679	56,156,828	11,911,149
17	Other Long-Term Debt (224) P.31...................................	384,400,000	349,400,000	(35,000,000)
18	Total Long-Term Debt...	428,645,679	405,556,828	(23,088,851)
19	CURRENT AND ACCRUED LIABILITIES			
20	Notes Payable (231) P.32...	0	0	0
21	Accounts Payable (232)..	249,910,661	53,440,751	(196,469,910)
22	Payables to Associated Companies (233,234) P.32.........................	968,794,054	752,605,249	(216,188,805)
23	Customer Deposits (235)..	2,997,316	3,257,178	259,862
24	Taxes Accrued (236)..	3,146,101	35,968,631	32,822,530
25	Interest Accrued (237)...................................	844,877	875,444	30,567
26	Dividends Declared (238)...	0	0	0
27	Fuel Purchase Commitments............................	0	0	0
28	Capital Leases (240)..	1,453,087	3,028,817	1,575,730
29	Tax Collections Payable (241)..	749,993	652,154	(97,839)
30	Misc. Current and Accrued Liabilities (242) P.33..................	140,060,624	251,771,500	111,710,876
31	Total Current and Accrued Liabilities..	1,367,956,713	1,101,599,724	(266,356,989)
32	DEFERRED CREDITS			
33	Unamortized Premium on Debt (251) P.26.................................	0	0	0
34	Customer Advances for Construction (252)	7,296	6,905	(391)
35	Other Deferred Credits (253) P.33..................................	165,602,151	152,815,087	(12,787,064)
36	Total Deferred Credits..	165,609,447	152,821,992	(12,787,455)
37	RESERVES			
38	Reserves for Depreciation (254-256) P.13.......................................	558,529,471	596,095,829	37,566,358
39	Reserves for Amortization (257-259) P.13............................	237,290,022	460,331,193	223,041,171
40	Reserve for Uncollectible Accounts (260)..........................	6,263,695	6,176,595	(87,100)
41	Operating Reserves (261-265) P.35..................................	21,259,641	13,956,194	(7,303,447)
42	Reserve for Depreciation and Amortization of			
43	Nonutility Property (266)...	192,134	192,134	0
	Reserves for Deferred Federal Income			
44	Taxes (267,268) P.36...	(5,562,555)	(21,815,884)	(16,253,329)
45	Total Reserves...	817,972,408	1,054,936,061	236,963,653
46	CONTRIBUTIONS IN AID OF CONSTRUCTION			
47	Contributions in Aid of Construction (271) P. 36.........................	7,827,724	8,642,775	815,051
48	Total Liabilities and Other Credits..................................	2,783,669,252	2,830,668,461	46,999,209

STATEMENT OF INCOME FOR THE YEAR

Line No.	Account (a)	Current Year (b)	Increase or (Decrease) from Preceding Year (c)
1	OPERATING INCOME		
2	Operating Revenues (400) P.37,43.................................	$ 573,128,555	$ (12,749,424)
3	Operating Expenses:		
4	Operation Expense (401) P.42,47....................................	486,655,852	3,999,875
5	Maintenance Expense (402) P.42,47...................................	(322,700,921)	(1,164,087,337)
6	Depreciation Expense (403) P.34................................	52,822,219	6,509,730
7	Amortization of Utility Plant (404 and 405).........................	14,629,776	120,942
8	Asset Impairment.........................	0	0
9	Amortization of Investment Tax Credit (407.2)......................	0	0
10	Taxes Other Than Income Taxes (408) P.49..........................	49,498,064	19,832,154
11	Income Taxes (409) P.49..	71,392,447	73,943,034
12	Provision for Deferred Fed. Inc. Taxes (410) P.36.................	113,990,955	48,142,549
13	Fed. Inc. Taxes Def. in Prior Yrs.-Cr. (411) P. 36.................	(133,567,116)	165,371,004
14	Total Operating Expenses.......................................	332,721,276	(846,168,049)
15	Net Operating Revenues..	240,407,279	833,418,624
16	Income from Utility Plant Leased to Others (412)-Net..............	0	0
17	Other Utility Operating Income (414) P.50..........................		
18	Total Utility Operating Income.................................	240,407,279	833,418,624
19	OTHER INCOME		
20	Income (Loss) from Mdse. Job & Contract Work (415) P. 51-After Taxes......	0	0
21	Income from Nonutility Operations (417)-After Taxes................	0	0
22	Nonoperating Rental Income (418)......................................	0	0
23	Interest and Dividend Income (419)-After Taxes.......................	1,804,234	196,491
24	Misc Nonoperating Income (421)-After Taxes and Earnings of Subsidiaries..................	(149,299,974)	(152,753,466)
25	Total Other Income...	(147,495,740)	(152,556,975)
26	Total Income...	92,911,539	680,861,649
27	MISCELLANEOUS INCOME DEDUCTIONS		
28	Miscellaneous Amortization (425)......................................	0	0
29	Other Income Deductions (426) After Taxes....................	53,490,874	53,166,444
30	Total Income Deductions......................................	53,490,874	53,166,444
31	Income Before Interest Charges..................................	39,420,665	627,695,205
32	INTEREST CHARGES		
33	Interest on Long-Term Debt (427) P.31...............................	2,521,000	0
34	Amortization of Debt Disc. & Expense (428) P.26.....................	329,616	0
35	Amortization of Prem. on Debt-Credit (429) P.26....................	0	0
36	Int. on Debt to Associated Companies (430) P.31,32................	39,963,044	20,887,922
37	Other Interest Expense (431).....................................	644,737	33,463
38	Interest Charged (Credited) to Construction-Credit (432)......................	(491,532)	(203,302)
39	Total Interest Charges..	42,966,865	20,718,083
40	Net Income..	$ (3,546,200)	$ 606,977,122
41	EARNED SURPLUS		
42	Unappropriated Earned Surplus (at beginning of period) (216)	$ (485,711,806)	$ (610,523,323)
43	Balance Transferred from Income (433).........................	(3,546,200)	606,977,123
44	Miscellaneous Debits to Surplus (434)............................	0	0
45	Miscellaneous Credits to Surplus(434)…………………	0	0
46	Miscellaneous Credits to Surplus (434).........................…	0	0
47	Miscellaneous Debits to Surplus (435)............................	0	0
48	Net Additions of Earned Surplus.......................................	(3,546,200)	606,977,123
49	Appropriations of Surplus for Common Stock Rights(436)......................................	0	0
50	Dividends Declared-Common Stock (438)..............................	0	0
51	Unappropriated Earned Surplus (at end of period) (216)............	$ (489,258,006)	$ (3,546,200)

STATEMENT OF EARNED SURPLUS (Accounts 215-216)

1. Report in this schedule an accounting for changes in appropriated and unappropriated earned surplus for the year.
2. Each credit and debit during the year should be identified as to the surplus account in which included (Accounts 433-438 inclusive) and the contra primary accounts affected shown. Minor items may be grouped by classes; however, the number of items in each group should be shown.
3. For each reservation or appropriation of earned surplus state the purpose, amount, and in the case of reservations, the reserve account credited. Explain in a footnote the basis for determining the amount reserved or appropriated and if such reservation or appropriation is to be recurrent, state the number and annual payments to be reserved or appropriated as well as the totals eventually to be accumulated.
4. Dividends should be shown for each class and series of capital stock. Show amounts of dividends per share.
5. List credits first; then debits.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
1	UNAPPROPRIATED EARNED SURPLUS (Account 216)		
2	Balance-Beginning of Year		$ (485,711,806)
3	Changes: (identify by prescribed earned surplus accounts)		
4	Net Income - Mass operations	433	(3,546,200)
5			
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19	Less: Appropriation of Earned Surplus for Common Stock Rights		
20	Appropriation of Earned Surplus for Common Stock Dividends		$ 0
21			
22			
23			
24			
25			
26			
27	Balance - end of year		$ (489,258,006)
28	APPROPRIATED EARNED SURPLUS (Account 215)		$
29	State balance and purpose of each appropriated earned surplus amount at end		
30	of year and give accounting entries for any applications of appropriated earned		
31	surplus during the year.		
32			
33			
34			
35	NONE		
36			
37			
38			
39			
40			
41			
42			
43			

SUMMARY OF UTILITY PLANT AND RESERVES FOR DEPRECIATION AND AMORTIZATION

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	(e)	(f)	Common (g)
1	UTILITY PLANT:						
2	In Service:						
3	101 Plant in Service (Classified)	$ 2,378,894,577		$ 2,378,894,577			
4	106 Completed Construction not Classified.............						
5	Total P. 18..................	2,378,894,577		2,378,894,577			
6	101.1 Leased from Others..............	48,410,000		48,410,000			
7	101.12 Right of Use Assets.........	14,798,555		14,798,555			
8	105 Held for Future Use...........						
	106 Completed Construction Not Classified…	43,674,083		43,674,083			
9	107 Construction Work in Progress..	29,441,461		29,441,461			
10	Total Utility Plant........	$ 2,515,218,676		$ 2,515,218,676			
11	DETAIL OF RESERVES FOR DEPRECIATION AND AMORTIZATION						
12	In Service:						
13	254 Depreciation P. 34...........	$ 596,095,829		$ 596,095,829			
14	257 Amortization................	460,331,193		460,331,193			
15	Total, in Service.............	$ 1,056,427,022		$ 1,056,427,022			
16	Leased to Others:						
17	255 Depreciation................						
18	258 Amortization................						
19	Total, Leased to Others........						
20	Held For Future Use:...............						
21	256 Depreciation................						
22	259 Amortization................						
23	Total, Held for Future Use.....						
24	Total Reserves for Depreciation and Amortization.............	$ 1,056,427,022		$ 1,056,427,022			

UTILITY PLANT-GAS

1. Report below the cost of utility plant in service according to prescribed accounts.
2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.
3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.
4. Reclassifications or transfers within utility plant accounts should be shown in column (f).

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance End of Year (g)
1	1. INTANGIBLE PLANT	$	$	$	$	$	$
2	301 Organization..................	4,432,919					4,432,919
3	303 Miscellaneous Intangible Plant..	462,198,684	4,055,149	1,345,724			464,908,109
4	Total Intangible Plant............	466,631,603	4,055,149	1,345,724			469,341,028
5	2. PRODUCTION PLANT						
6	Manufactured Gas Production Plant...						
7	304 Land and Land Rights	412,592					412,592
8	305 Structures and Improvements........	4,588,685		18,814			4,569,871
9	306 Boiler Plant Equipment.........						
10	307 Other Power Equipment............						
11	310 Water Gas Generating Equipment.						
12	311 Liquefied Petroleum Gas....... Equipment.....................	4,691,606					4,691,606
13	312 Oil Gas Generating Equipment...						
14	313 Generating Equipment-Other..... Processes.....................						
15	315 Catalytic Cracking Equipment...						
16	316 Other Reforming Equipment......						
17	317 Purification Equipment.........						
18	321 LNG Equipment.......................	28,218,076	90,249	925			28,307,400
19	319 Gas Mixing Equipment................						
20	320 Other Equipment.....................................						
21	Total Manufactured Gas						
22	Production Plant...................	37,910,959	90,249	19,739			37,981,469
23	3. STORAGE PLANT						
24	360 Land and Land Rights............						
25	361 Structures and Improvements..................						
26	362 Gas Holders.......................						
27	363 Other Equipment.............						
28	Total Storage Plant............						

UTILITY PLANT - GAS (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance End of Year (g)
1	4. TRANSMISSION AND DISTRIBUTION PLANT						
2	365.1 Land and Land Rights.............						
3	365.2 Rights of Way....................						
4	366 Structures and Improvements...........						
5	367 Mains.........................						
6	368 Compressor Station Equipment...						
7	369 Measuring and Regulating						
8	Station Equipment...............						
9	374 Land & Land Rights, right of Way	556,701	312,890				869,591
10	375 Structures &Improvements……..	18,513,621	394,992				18,908,613
11	376 Mains.........................	754,436,373	251,135,352	1,744,790			1,003,826,935
12	377 Compressor Station Equipment.........						
13	378 Regulator Station.................	27,122,760	559,019	250,184			27,431,595
14	379 Other Equipment.................						
15	380 Services..............................	556,327,241	71,208,387	2,005,048			625,530,580
16	381 Meters.........................	33,258,656	3,074,929	1,934,601			34,398,984
17	382 Meter Installations...................	92,623,746	5,391,251	1,452,852			96,562,145
18	383 House Regulators...........................	11,156,827	904,221	276,943			11,784,105
	385 Industrial Mea & Reg Sta Eq	33,978					33,978
19	386 Other Property on Cust's Prem.....						
20	387 Other Equipment..................						
21	Total Transmission and	1,494,029,903	332,981,041	7,664,418			1,819,346,526
22	Distribution Plant.........						
23	5. GENERAL PLANT						
24	389 Land and Land Rights......................	14,143					14,143
25	390 Structures and Improvements......						
26	391 Office Furniture and Equipment...................	5,779,572	126,875	1,872,146			4,034,301
27	392 Transportation Equipment.......................	36,454					36,454
28	393 Stores Equipment........................	78,477					78,477
29	394 Tools, Shop, and Garage Eqpt.....	9,849,065	1,428,162				11,277,227
30	395 Laboratory Equipment............................	275,546					275,546
31	396 Power Operated Equipment..............	26,896					26,896
32	397 Communication Equipment..................	29,447,546	516,053	2,365,301			27,598,298
33	398 Miscellaneous Equipment......................	241,436					241,436
34	399 Other Tangible Property...............						
35	Total General Plant..............	45,749,135	2,071,090	4,237,447			43,582,778
36	Total Gas Plant in Service.............	2,044,321,600	339,197,527	13,267,328			2,370,251,801
37	101 Contributions in Aid of Construction (offset in Account 271)	7,827,724	815,051				8,642,775
38	101.1 Utility Plant Leased From Others................	48,410,000					48,410,000
39	101.12 Right of Use Assets.........	0	14,798,555				14,798,555
39	105 Held for Future Use						
40	106 Completed Construction Not Classified…	205,006,651	(161,332,568)				43,674,083
41	107 Construction Work in Progress..........	11,437,842	18,003,619				29,441,461
42	Total Utility Plant - Gas..........	2,317,003,817	211,482,184	13,267,328			2,515,218,675

Note: Completed Construction Not Classified, Account 106, shall be classified in this schedule according to prescribed accounts, on an estimated basis if necessary, and the entries included in column (c). Also to be included in column (c) are entries for reversals of tentative distribution of prior year reported in column (c). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary

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NONUTILITY PROPERTY (ACCOUNT 121)

Give particulars of all investments of the respondent in physical property not devoted to utility operation.

Line No.	Description and Location (a)	Book Value at End of Year (b)	Revenue for the Year (c)	Expense for the Year (d)	Net Income after Tax for the Year (e)
1					
2					
3	Non-Utility Property				
4					
6	Land - Belmont Street, Brockton	$ 29,197			
7	Land - Meadow Lane, Brockton	5,519			
8		34,716	0	0	0
9					
10					
11	Other Non-Utility - 398	192,134			
12					
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51					
52					
53	TOTALS	$ 226,850	$ 0	$ 0	$ 0

INVESTMENTS (ACCOUNTS 121, 136)

Give particulars of all investments in stocks, bonds, notes, etc. held by the respondent at the end of the year.
Provide a subheading for each list thereunder the information called for.

Line No.	Description of Security Held by Respondent (a)	Amount (b)
1		
2	Other Investments:	
3	Springfield Area Development Corp.: "A" Stock, 500 Shares	2,500
4	"B" Stock, 5,500 Shares	22,500
5		
6		
7	Total Other Investments	$ 25,000
8		
9		
10		
11		
12		
13		

SPECIAL FUNDS (Accounts 125,126,127,128)

(Sinking Funds, Depreciation Fund, Amortization Fund-Federal, Other Special Funds)

Report below the balance at end of year of each special fund maintained during year. Identify each fund as to account in which included. Indicate nature of any fund included in Account 128, Other special funds.

Line No.	Name of Fund and Trustee If Any (a)	Balance End of Year (b)
1	Pension Fund - Funds Held in Trust	$ 2,124,338
2		
3		
4		
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6		
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14		
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17		
18		
19	TOTAL	$ 2,124,338

SPECIAL DEPOSITS (Accounts 132, 133, 134)

1. Report below the amount of special deposits by classes at end of year.
2. If any deposit consists of assets other than cash, give a brief description of such assets.
3. If any deposit is held by an associated company, give name of comapny.

Line No.	Description and Purpose of Deposit (a)	Balance End of Year (b)
20	Interest Special Deposits (Account 132).................................	
21	Dividend Special Deposits (Account 133).................................	
22		
23	Other Special Deposits (Account 134)	
24	(specify purpose of each other special deposit).....................	
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		NONE

NOTES RECEIVABLE (Account 141)

1. Give the particulars called for below concerning notes receivable at the end of year.
2. Give particulars of any note pledged or discounted.
3. Minor items may be grouped by classes, showing number of such items.
4. Designate any note the maker of which is a director, officer or other employee.

Line No.	Name of Maker and Purpose for Which Received (a)	Date of Issue (b)	Date of Maturity (c)	Amount End of Year (e)
1				
2	NONE			
3				
4				
5				
6				
7				
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22				

ACCOUNTS RECEIVABLE (Accounts 142, 143)

1. Give the particulars called for below concerning accounts receivable at end of year.
2. Designate any account included in Account 143 in excess of $5,000.

Line No.	Description (a)	Amount End of Year (b)
23	Customers (Account 142):	
24		
25	Gas	$ 70,480,461
26	Other Gas Utility	13,682,798
27		
28		
29		
30	Other Accounts Receivable (Account 143):	
31		
32		
33	Reimbursable Capital Projects	2,673,584
34	Insurance Reimbursables	514,113
35		
36		
37		
38		
39		
40		
41		
42		$ 87,350,956
43	Total Notes and Accounts Receivable	$ 87,350,956

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145,146)

1. Report particulars of notes and accounts receivable from associated companies at end of year.

2. Provide separate headings and totals for Account 145, Notes Receivable from Associated Companies, and 146, Accounts Receivable from Associated Companies, in addition to a total for the combined accounts.

3. For notes receivable list each note separately and state purpose for which received. Show also in column (a) date of note and date of maturity.

4. If any note was received in satisfaction of an open account, state the period covered by such open account.

5. Include in column (d) interest recorded as income during the year, including interest on accounts and notes held any time during the year.

6. Give particulars of any notes pledged or discounted, also of any collateral held as guarantee of payment of any note or account.

Line No.	Name of Company (a)	Amount End of Year (b)	Interest for Year Rate (c)	Interest for Year Amount (d)
	Accounts Receivable (Account 146)			
1	Nisource Corporate Services	$ 580,500	N/A	$ 0
2	Columbia Gas of Ohio	6,774	N/A	0
3				
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42				
43	TOTALS	$ 587,274		$ 0
44				

MATERIALS AND SUPPLIES (Accounts 151-159,163)
Summary Per Balance Sheet

Line No.	Account (a)	Amount End of Year: Electric (b)	Amount End of Year: Gas (c)
1	Fuel (Account 151) (See Schedule, Page 25)		$ 17,197,107
2	Plant Materials (Account 154)		$ 1,079,767
3			
4			
5			
6			
7			
8			
9			
10			
11			
12	Total Per Balance Sheet		$ 18,276,874

PRODUCTION FUEL AND OIL STOCKS - Included in Account 151
(Except Nuclear Materials)

1. Report below the information called for concerning production fuel and oil stocks.
2. Show quantities in tons of 2,000 lbs., gal., or Mcf., whichever unit of quantity is applicable.
3. Each kind of coal or oil should be shown separately.
4. Show gas and electric fuels separately by specific use.

			Kinds of Fuel and Oil			
			Liquid Propane		Liquefied Natural Gas	
Line No.	Item (a)	Total Cost (b)	Quantity (Gallons) (c)	Cost (d)	Quantity (MMBTU) (e)	Cost (f)
1	On Hand Beginning of Year...............	18,275,997	1,504,682	1,789,010	1,793,323	11,515,977
2						
3	Received During Year............................	11,538,651	244,653	212,302	1,264,820	6,839,481
4	TOTAL............................	29,814,648	1,749,335	2,001,312	3,058,143	18,355,458
5	Used During Year...................					
6	Retail Bottled Gas Sale					
7						
8						
9						
10						
11	Sold or Transferred......................	12,617,541	218,415	218,051	1,236,868	6,992,693
12	TOTAL DISPOSED OF	12,617,541	218,415	218,051	1,236,868	6,992,693
13	BALANCE END OF YEAR..........................	17,197,107	1,530,920	1,783,261	1,821,275	11,362,765

		Kinds of Fuel and Oil - Continued			
		Retail Propane		Natural Gas	
Line No.	Item (g)	Quantity (Gallons) (h)	Cost (i)	Quantity (MMBTU) (j)	Cost (k)
14	On Hand Beginning of Year...	0	0	1,459,383	4,971,010
15	Received During Year.......................................	0	0	1,574,801	4,486,868
16	TOTAL..	0	0	3,034,184	9,457,878
17	Used During Year...				
18	Retail Propane Sales..				
19					
20					
21					
22					
23					
24	Sold or Transferred...	0	0	1,643,128	5,406,797
25	TOTAL DISPOSED OF	0	0	1,643,128	5,406,797
26	BALANCE END OF YEAR...	0	0	1,391,056	4,051,081

UNAMORTIZED DEBT DISCOUNT AND EXPENSE AND UNAMORTIZED PREMIUM ON DEBT (Accounts 181, 251)

1. Report under separate subheadings for Unamortized Debt Discount and Expense and Unamortized Premium on Debt, particularly of discount and expense or premium applicable to each class and series of long-term debt.
2. Show premium amounts by enclosure in parentheses.
3. In column (b) show the principal amount of bonds or other long-term debt originally issued.
4. In column (c) show the discount and expense or premium with respect to the amount of bonds or other long-term debt originally issued.
5. Furnish particulars regarding the treatment of unamortized debt discount and expense or premium, redemption premiums, and redemption expenses associated with issues redeemed during the year, also, date of the Department's authorization of treatment other than as specified by the Uniform System of Accounts.
6. Set out separately and identify undisposed amounts applicable to issues which were redeemed in prior years.
7. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount or Expense, or credited to Account 429, Amortization of Premium on Debt - Credit.

Line No.	Designation of Long-Term Debt (a)	Balance at the end of the reporting year	Principal Amount of Securities to which Discount and Expenses or Premium Minus Expense,Relates (Omit Cents) (b)	Total Discount and Expense or Net Premium (Omit Cents) (c)	Amortization Period (d)	To (e)	Balance Beginning of Year (f)	Debits During Year (g)	Credits During Year (h)	Balance End of Year (i)
1	6.43% notes, due December 15, 2025	10,000,000	10,000,000	2,148,966	12/15/95	12/15/25	501,396		71,628	429,768
2	6.26% notes, due February 15, 2028	30,000,000	30,000,000	5,957,669	12/15/98	2/15/28	1,743,347		191,929	1,551,418
3	5.58% notes, due December 20, 2019	35,000,000	0	14,078	12/20/04	12/20/19	936		936	0
4	5.94% notes, due December 20, 2024	35,000,000	35,000,000	14,079	12/20/04	12/20/24	4,176		696	3,480
5	5.36% notes, due December 16, 2041	11,000,000	11,000,000	0			0		0	0
6	4.97% notes, due November 28, 2042	8,000,000	8,000,000	0			0		0	0
7	5.57% notes, due September 24, 2043	22,000,000	22,000,000	0			0		0	0
8	4.98% notes, due March 18, 2043	50,000,000	50,000,000	0			0		0	0
9	4.62% notes, due November 20, 2044	28,400,000	28,400,000	0			0		0	0
10	4.99% notes, due June 26, 2045	15,000,000	15,000,000	0			0		0	0
11	4.70% notes, due December 30, 2045	15,000,000	15,000,000	0			0		0	0
12	3.86% notes, due June 30, 2046	58,000,000	58,000,000	0			0		0	0
13	4.16% notes, due June 30, 2047	15,000,000	15,000,000	0			0		0	0
14	4.11% notes, due September 29, 2047	7,000,000	7,000,000	0			0		0	0
15	3.89% notes, due December 29, 2047	45,000,000	45,000,000	0			0		0	0
16	Acct 181 TOTALS (Credits tie to 428 account charges)						2,249,855	0	265,189	1,984,666
17	TOTALS	384,400,000	349,400,000	8,134,792						

EXTRAORDINARY PROPERTY LOSSES (Account 182)

1. Report below particulars concerning the accounting for extraordinary property losses.
2. In column (a) describe the property abandoned or extraordinary loss suffered, date of abandonment or loss, date of Department authorization of use of Account 182, and period over which amortization is being made.

Line No.	Description of Property Loss or Damage (a)	Total Amount of Loss (b)	Previously Written Off (c)	Written off During Year: Account Charged (d)	Written off During Year: Amount Amount	Balance End of Year (f)
1						
2						
3			NONE			
4						
5						
6						
7						
8						
9						
10						
11	TOTALS					

MISCELLANEOUS DEFERRED DEBITS (Account 186)

1. Report below the particulars called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized show period of amortization.
3. Minor items may be grouped by classes, showing number of such items.

Line No.	Description (a)	Balance Beginning of Year (b)	Debits (c)	Credits: Account Charged (d)	Credits: Amount (d)	Balance End of Year (f)
12	Regulatory Asset - Working Capital	281,511	1,221,755	495	1,262,673	240,593
13	Regulatory Asset - Demand Side Management	4,253,534	86,857,351	923	79,770,379	11,340,506
14	Regulatory Asset - Demand Side Management Incentive	(846,300)	0	186	1,660,759	(2,507,059)
15	Regulatory Asset - LDAC Recoveries Unbilled	(7,626,529)	57,571,638	930	59,153,840	(9,208,731)
16	Regulatory Asset - Production & Storage	1,179,558	14,781,062	495	14,182,669	1,777,951
17	Regulatory Asset - Environmental - Incurred Costs	7,511,618	5,194,614	932,186	5,199,393	7,506,839
18	Regulatory Asset - Environmental - Expected Costs	12,667,618	2,822,807	242,253	1,166,661	14,323,764
19	Regulatory Asset - Bad Debt - Gas Portion	4,152,897	10,056,480	904	9,140,801	5,068,576
20	Regulatory Asset - Debt Redemption	201,059	0	428	64,428	136,631
21	Regulatory Asset - Active Hardship Protected Accounts	4,256,566	2,283,502	142	1,292,440	5,247,628
22	Regulatory Asset - Pension Tracker	18,954,919	36,314,748	926	33,081,926	22,187,741
23	Regulatory Asset - Residential Discount	3,487,062	27,507,701	495	28,278,990	2,715,773
24	Regulatory Asset - FAS 109 Taxes	5,250,239	0	267,268	0	5,250,239
25	Regulatory Asset - Pension SFAS 158	44,291,611	445,101	926,261-265	9,745,336	34,991,376
26	Regulatory Asset - OPEB SFAS 158	16,680,260	501,241	926,261-265	4,440,708	12,740,793
27	Credit Balance Regulatory Assets Transferred	12,759,382	8,803,071	253	10,760,542	10,801,912
28	Regulatory Asset - Attorney General Consulting Fees	14,616	69,082	928	29,069	54,629
29	Regulatory Asset - Decoupling	(5,382,819)	23,314,644	495	20,332,692	(2,400,867)
30	Reg. Asset - Targeted Infrastructure Reinvestment Factor	-	760	495	760	0
31	Regulatory Asset - Deferred Depreciation Capital Lease	1,653,641	3,163,841	107	2,239,588	2,577,894
32	Regulatory Asset - Gas System Enhancement Program	14,232,745	43,250,657	495	37,207,243	20,276,159
33	Regulatory Asset - Asset Sale	152,662	0	-	0	152,662
34	Regulatory Asset - Shrewsbury Training Center	1,788,561	3,401,112	165,107	3,449,108	1,740,565
35						
36						
37	TOTALS	$ 139,914,411	$ 327,561,167		$ 322,460,005	$ 145,015,574
38						
39						
40						

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CAPITAL STOCK AND PREMIUM (Accounts 201, 204, and 207)

1. Report below the particulars called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show totals separately for common and preferred stock.
2. Entries in column (b) should represent the number of shares authorized by the Department.
3. Give particulars concerning shares of any class and series of stock authorized to be issued by the Department which have not yet been issued.
4. The designation of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State if any capital stock which has been nominally issued is nominally outstanding at end of year.
6. Give particulars of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock (a)	Number of Shares Authorized (b)	Par Value per Share (c)	Amount Authorized (d)	Outstanding per Balance Sheet * Shares (e)	Outstanding per Balance Sheet * Amount (f)	Premium at End of Year (g)
1	Common Stock	1,000	1	1,000	100	100	411,771,866
2							
3							
4							
5							
6							
7							
9							
10	In connection with the Company's merger with NiSource Inc., 100 shares of Common Stock,						
11	$1.00 Par Value were Issued, as approved in DTE #98-31, dated November 5, 1998.						
12							
13							
14							
15							
16							
17							
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19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31	TOTALS	1,000	1	1,000	100	100	411,771,866

* Total amount outstanding without reduction for amounts held by respondent.

OTHER PAID-IN CAPITAL (Accounts 208-211)

1. Report below balance at end of year and the information specified in the instructions below for respective other paid-in capital accounts. Provide a conspicuous subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet. Additional columns may be added for any account if deemed necessary. Explain the change in any account during the year and give the accounting entries effecting such change.
2. Donations received from Stockholders (Account 208) - State amount and give brief explanation of the origin and purpose of each donation.
3. Reduction in Par Value of Capital Stock (Account 209) - State amount and give brief explanation of the capital changes which gave rise to amounts reported under the caption including identification with the class and series of stock to which related.
4. Gain on Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a succinct designation of the nature of each credit and debit identified as to class and series of stock to which related.
5. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account at end year according to captions which, together with brief explanations, disclose the general nature of transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1		
2	Tax Allocation	$ 7,628,998
3	Additional Paid-In Capital Stock Compensation	(31,877)
4	Additional Paid-In Capital	177,000,000
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
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24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	$ 184,597,121

LONG TERM DEBT (Accounts 221,223-224)

Report by balance sheet accounts particulars concerning long-term debt in Accounts 221, Bonds;
223 Advances from Associated Companies; and 224, Other Long-Term Debt.

Line No.	Class and Series of Obligation (a)	Date of Issue (b)	Date of Maturity (c)	Amount Authorized (d)	Amount Actually Outstanding at End of Year (e)	Interest Provisions: Rate per Cent (f)	Interest Provisions: Dates Due (g)	Interest Accrued During Year, Charged to Income (h)	Interest Paid During Year (i)
1	6.43% notes, due December 15, 2025 (A)	12/15/95	12/15/25	10,000,000	10,000,000	6.43%	6/12-12/15	643,000	643,000
2	6.26% notes, due February 15, 2028 (A)	2/15/98	2/15/28	30,000,000	30,000,000	6.26%	2/1-8/1	1,878,000	1,878,000
3	5.58% notes, due December 20, 2019	12/21/04	12/20/19	35,000,000	0	5.58%	6/1-12/1	1,888,792	2,054,663
4	5.94% notes, due December 20, 2024	12/21/04	12/20/24	35,000,000	35,000,000	5.94%	6/1-12/1	2,079,000	2,079,000
5	5.36% notes, due December 16, 2041	12/16/11	12/16/41	11,000,000	11,000,000	5.36%	6/1-12/1	589,600	589,600
6	4.97% notes, due November 28, 2042	11/28/12	11/28/42	8,000,000	8,000,000	4.97%	6/1-12/1	397,600	397,600
7	5.57% notes, due September 24, 2043	9/24/13	9/24/43	22,000,000	22,000,000	5.57%	6/1-12/1	1,225,400	1,225,400
8	4.98% notes, due March 18, 2043	3/18/13	3/18/43	50,000,000	50,000,000	4.98%	6/1-12/1	2,490,000	2,490,000
9	4.62% notes, due November 20, 2044	11/20/14	11/20/44	28,400,000	28,400,000	4.62%	6/1-12/1	1,312,080	1,312,080
10	4.99% notes, due June 26, 2045	6/26/15	6/26/45	15,000,000	15,000,000	4.99%	6/1-12/1	748,500	748,500
11	4.70% notes, due December 30, 2045	12/30/15	12/30/45	15,000,000	15,000,000	4.70%	6/1-12/1	705,090	705,090
12	3.86% notes, due June 30, 2046	6/30/16	6/30/46	58,000,000	58,000,000	3.86%	6/1-12/1	2,237,176	2,237,176
13	4.16% notes, due June 30, 2047*	6/30/17	6/30/47	15,000,000	15,000,000	4.16%	6/1-12/1	624,165	624,165
14	4.11% notes, due September 29, 2047*	9/29/17	9/29/47	7,000,000	7,000,000	4.11%	6/1-12/1	287,861	287,861
15	3.89% notes, due December 29, 2047*	12/29/17	12/29/47	45,000,000	45,000,000	3.89%	6/1-12/1	1,750,995	1,750,995
16									
17									
18	(A) Unaffiliated debt								
19	* New Long-Term Debt								
20									
21									
22									
23	TOTALS			$ 384,400,000	$ 349,400,000			$ 18,857,259	$ 19,023,130

For issues of long-term debt made during current year state purpose for which issued, date of issue, Department authorization date and D.P.U. #.

Purpose	Issue Date	Department Authorization Date	D.P.U. #

NOTES PAYABLE (Account 231)

Report the particulars indicated concerning notes payable at end of year.

Line No.	Payee (a)	Date of Note (b)	Date of Maturity (c)	Int. Rate (d)	Balance End of Year (e)
	Notes Payable:				
1					
2					
3					
4					
5					
6					
7					
8					
13					
14					
15					
18					
19					
20					
21			TOTAL		NONE

PAYABLES TO ASSOCIATED COMPANIES (Accounts 233, 234)

Report particulars of notes and accounts payable to associated companies at end of year.

Line No.	Name of Company (a)		Amount End of Year (b)	Interest for Year Rate (c)	Interest for Year Amount (d)
22	Notes Payable (Account 233)				
23					
24					
25					
26					
27	Accounts Payable (Account 234)				
28					
29	Columbia Gas of Pennslyvania		76,081		NONE
30	Northern Indiana Public Service Company		7,501		NONE
31	Columbia Gas of Virginia		35,827		NONE
32	Nisource Corporate Services		20,529,640		NONE
33	Columbia Gas of Maryland		3,361		NONE
34	Columbia Gas of Kentucky		10,035		NONE
35	NiSource Money Pool and Interest		730,596,945	see table	23,626,785
36	NiSource		1,345,859	see page 31	
37					
38					
39	Interest Rates for Nisource Money Pool				
40	January	3.02%			
41	February	2.89%			
42	March	2.86%			
43	April	2.88%			
44	May	2.84%			
45	June	2.81%			
46	July	2.73%			
47	August	2.52%			
48	September	2.54%			
49	October	2.49%			
50	November	2.20%			
51	December	1.93%			
		TOTALS	$ 752,605,249		$ 23,626,785

Note 1: Includes accrued interest on affiliated long-term debt reported on page 31 under column (h) with rates reported under column (f)

MISCELLANEOUS CURRENT AND ACCRUED LIABILITIES (Account 242)

1. Report the amount and description of other current and accrued liabilities at end of year.
2. Minor items may be grouped under appropriate title.

Line No.	Item (a)	Amount (b)
1	Accrued Vacation	$ 6,354,863
2	Current Environmental Remediation Liabilities	1,873,435
3	Accrued Payroll	1,846,661
4	Accrued Incentives	3,648,611
5	Accrued Medical, Dental and Pharmacy Expenses	479,906
6	Accounts Receivable - Budget Plan Credit Balances	18,351,403
7	Accrued Professional Services	209,342
8	Supplier Refunds	(32,958)
10	Insurance Reserve	163,869,193
11	Pension Liability - ST Non Qualified	280,600
12	ST Accrued Equipment Repair	1,890,444
13	Accrued Fines and Penalties	53,000,000
	TOTAL	$ 251,771,500

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars called for concerning other deferred credits.
2. For any deferred credits being amortized show the period of amortization.
3. Minor items may be grouped by classes. Show number of items.

Line No.	Description of Other Deferred Credit (a)	Balance Beginning of Year (b)	Debits: Account Credited (c)	Debits: Amount (d)	Credits (e)	Balance End of Year (f)
1	Credit Balance Regulatory Asset Transfer	$ 12,759,382	186	$ 10,760,543	8,803,071	$ 10,801,912
2	ST Regulatory Liabiligy - Amort of Tax Excess	91,000		0	32,264	123,264
3	LT Environmental Remediation Liabilities	10,809,202	186	1,077,595	2,718,723	12,450,330
4	Deferred Rent	209,622	131	90,513	45,340	164,449
5	Reg Liab Curr-Inc Tax Fed/St	0		0	3,281,913	3,281,913
6	Rate Reserve	6,129,349	400	9,133,075	3,003,728	0
7	Reg Liab NC-Inc Tax Fed-St	128,394,491	267/268, 410	29,150,819	22,548,420	121,792,092
8	LT Accrued Equipment Repair	3,500,000	242	3,500,000	0	0
9	LT Regulatory Liability - Amort of Tax Excess	3,709,105	400	145,256	637,278	4,201,127
	TOTALS	$ 165,602,151		$ 53,857,801	$ 41,070,737	$ 152,815,087

RESERVE FOR DEPRECIATION OF UTILITY PLANT IN SERVICE (Account 254)

Show below the amount credited during the year to Depreciation Reserve, and the amount charged to Depreciation Reserve on account of property retired. Also the balance in the account at the end of the year.

Line No.	(a)	Electric (b)	Gas (c)	Total (d)
1	Balance at beginning of year..................................		$ 558,529,471	$ 558,529,471
2	Credits to Depreciation Reserve during year:			
3	Account 403 Depreciation....................................		52,822,219	52,822,219
3A	Allocated Vehicle Depreciation		2,522	2,522
3B	Capital Leases		2,337,939	2,337,939
	Sub-Total		55,162,680	55,162,680
4				
5				
6				
7	TOTAL CREDITS DURING YEAR............................		55,162,680	55,162,680
8	Net Charges for Plant Retired:			
9	Book Cost of Plant Retired……………………………..		21,518,234	21,518,234
10	Cost of Removal..		(3,921,912)	(3,921,912)
11	Salvage (Credit)..		0	0
12	Other			0
13	NET CHARGES DURING YEAR..............................		17,596,322	17,596,322
14	Balance December 31, 2019................................		$ 596,095,829	$ 596,095,829

METHOD OF DETERMINATION OF DEPRECIATION CHARGES

Give in detail the rule and rates, by which the respondent determined the amount charged to operating expenses and other accounts, and credited to Depreciation Reserve. Report also the depreciation taken for the year for federal income tax purposes.

Line No.		Avg Plant Balance	Average Rate	Depreciation
15				
16				
17	Production...	$ 37,531,928	0.0176	$ 661,249
18	Distribution.......................................	1,779,794,870	0.0272	48,373,228
19	General...	67,978,209	0.0557	3,787,742
20				
21	Total..	$ 1,885,305,007	0.0280	$ 52,822,219
22				
23				

DIVIDENDS DECLARED DURING THE YEAR (Accounts 437,438)

Give particulars of dividends declared on each class of stock during the year, and charged to Earned Surplus. This schedule shall include only dividends that have been declared by the Board of Directors during the fiscal year.

Line No.	Name of Security on Which Dividend was Declared (a)	Rate Per Cent Regular (b)	Rate Per Cent Extra (c)	Amount of Capital Stock On Which Dividend Was Declared (d)	Amount of Dividend (e)	Date Declared	Date Payable
24							
25							
26							
27	See Page 34A						
28							
29							
30							
31							
32							
33	TOTALS						

34
35 Dividend rates on Common Stock and Premium %.
36 Dividend rates on Common Stock, Premium, and Surplus %.

DIVIDENDS DECLARED DURING THE YEAR (Accounts 437,438)

Give particulars of dividends declared on each class of stock during the year, and charged to Earned Surplus. This schedule shall include only dividends that have been declared by the Board of Directors during the fiscal year.

Line No.	Name of Security (a)	Rate Per Share (b)	No. of Shares (c)	Par Value (d)	Amount of Dividend (e)	Date Declared (f)	Record Date (g)	Date Payable (h)
1								
2	Common Stock							
3								
4	NONE							
5								
6								
7								
8								
9								
10								
11								
12	Total Dividends				$ 0			
13								
14								

OPERATING RESERVES (Accounts 261, 262, 263, 264, 265)

1. Report below an analysis of the change during the year for each of the above-named reserves.
2. Show name of reserve and account number, balance beginning of year, credits, debits, and balance at end of year. Credit amounts should be shown in black, debit amounts enclosed by parentheses.
3. Each credit and debit amount should be described as to its general nature and the contra account debited or credited shown. Combine the amounts of monthly accounting entries of the same general nature. If respondent has more than one utility department, contra accounts debited or credited should indicate the utility department affected.
4. For Accounts 261, Property Insurance Reserve and 262, Injuries and Damages Reserve, explain the nature of the risks covered by the reserve.
5. For Account 265, Miscellaneous Operating Reserves, report separately each reserve comprising the account and explain briefly its purpose.

Line No.	Item (a)	Contra Account Debited or Credited (b)	Amount (c)
1	**Reserve for Pensions-Union and Non-Union (Account 263)**		
2	Balance Beginning of Year		$ 6,179,790
3			
4	Pension/OCI Regulatory Asset	186	(2,400,042)
5	Expense - later deferred into regulatory asset per tracker mechanism	926	(1,713)
6	Expense	926	0
7	SERP payments	131	(270,582)
8			
9	Balance End of Year - Reserve for Pensions		3,507,453
10			
11	**Reserve for Other Post Employment Benefits - Non-Union (Account 263)**		
12	Beginning Balance		13,617,037
13	Expense - later deferred into regulatory asset per tracker mechanism	926	(75,771)
14	Cash	131	(991,971)
15	OPEB Regulatory Asset/Liability	186/131	(3,570,405)
16	Balance End of Year - OPEB		8,978,890
17			
18	**Reserve for Board of Directors Retirement Plan (Account 263)**		
19	Beginning Balance		43,085
20	Adjust Reserve		0
21	Balance End of Year - BOD Retirement Plan		43,085
22			
23	**Reserve for Window Warranties (Account 265)**		
24	Beginning Balance		6,000
25	Adjust Reserve	925	(2,000)
26	Balance End of Year - Window Warranties		4,000
27			
28	**Reserve for Worker Compensation, General Liab., Auto Liab. (Account 262)**		
29	Beginning Balance		534,121
30	Expense Accruals	925	(93,063)
31	Payments Made	131	0
32	Balance End of Year - Worker Compensation, General Liab., Auto Liab.		441,058
33			
34	**Reserve for Banked Vacation (Account 265)**		
35	Beginning Balance		863,046
36	Banked Vacation	234/242	97,697
37	Balance End of Year - Banked Vacation		960,743
38			
39	**Reserve for Thrift Plan Restoration (Account 265)**		
40	Beginning Balance		16,562
41	Thrift Plan Restoration	926	4,403
42	Balance End of Year - Thrift Plan Restoration		20,965
43			
44	**Total Operating Reserves:**		$ 13,956,194

RESERVES FOR DEFERRED FEDERAL INCOME TAXES (Accounts 267, 268)

1. Report the information called for below concerning the respondent's accounting for deferred federal income taxes.
2. In the space provided furnish significant explanations, including the following:
(a) Accelerated Amortization - State for each certification number a brief description of property, total and amortizable cost of such property, date amortization for tax purposes commenced, "normal" depreciation rate used in computing deferred tax amounts.
(b) Liberalized Depreciation - State the general method or methods of liberalized depreciation being used (sum of years digits, declining balance, etc.), estimated useful lives and classes of plant to which each method is being applied. Furnish a table showing for each year, 1954 to date of this report, the annual amounts of tax deferral, the total debits thereto which have been accounted for as credits to Acccount 411, Federal Income Taxes Deferred in Prior Years - Credit or comparable account of the previous system of accounts.

Line No.	Account Subdivisions (a)		Balance Beginning of Year (b)	Changes During Year: Amounts Debited Account 410 (1) (c)	Changes During Year: Amounts Credited Account 411 (2) (d)	Changes During Year: Other (e)	Balance End of Year (f)
1	Accelerated Amortization		$	$	$		$
2	(Account 267)						
3	Electric....................................						
4	Gas..						
5	Other (Specify)................................						
6	Totals...................................						
7	Gas SFAS 109 Reserve - State		-	-	-	-	-
8	Gas SFAS 109 Reserve - Federal		-	-	-	-	-
			-	-	-	-	-
9	Gas Plant Acquistion Adjustment - State & Federal		60,296,703	-	(60,296,702)	0	1
	Liberalized Depreciation						
	(Account 268)						
10	Electric...						
11	Gas - State..................................		42,753,314	11,724,402	(234,699)	(469,398)	53,773,619
12	Gas - Federal..................................		159,294,771	23,793,835	(3,792,230)	3,792,230	183,088,606
	Other (Specify) -	Non Utility - State	-	-	-	-	
		Non Utility - Federal	-	-	-	-	
13	Totals................................		202,048,085	35,518,237	(4,026,929)	3,322,832	236,862,225
14	Gas - Other Reserves - State............................	All other	(68,231,303)	40,230,252	(29,242,025)	(3,856,945)	(61,100,021)
15	Gas - Other Reserves - Federal......................	All other	(199,676,040)	38,242,466	(40,001,460)	3,856,945	(197,578,089)
16	Totals................................		(267,907,343)	78,472,718	(69,243,485)	-	(258,678,110)
	Total (Accounts 267, 268)						
17	Electric..						
18	Gas...						
19	Other Adjustments..................................						
20			(65,859,258)	113,990,955	(73,270,414)	3,322,832	(21,815,885)
21	Totals...		(5,562,555)	113,990,955	(133,567,116)	3,322,832	(21,815,884)

Line No.	Analysis of Charges:	(d)	(f)
22	Provision for Deferred Income Taxes	40,720,541	(21,815,885)
23	Provision for Plant Acqusition Adjustment	(60,296,702)	1
24	Regulatory Asset related to State Rate Change	-	
25	Regulatory Liability related to Fed Rate Change (See Page 33)	-	
26	SFAS 109 DIT Regulatory Liabilities-Act 254 (See Page 33)	3,322,832	
27	SFAS 109 DIT Regulatory Assets-Act 186 (See Page 27)	-	
28		(16,253,329)	(21,815,884)

29 (1) Account 410, Provision for Deferred Federal Income Taxes
30 (2) Account 411, Federal Income Taxes Deferred in Prior Years- Credit

CONTRIBUTIONS IN AID OF CONSTRUCTION (Account 271)

Report below the amount of contributions in aid of construction applicable to each utility department.

Line No.	Class of Utility Service (a)	Balance Beginning of Year (b)	Debits: Account Credited (c)	Debits: Amount (d)	Credits (e)		Balance End of Year (f)
30							
31	Contributions in Aid of Construction (offset in Account 101)	7,827,724			815,051		8,642,775
32							
33							
34							
35							
36							
37							
38							
39	TOTALS	7,827,724			815,051		8,642,775

GAS OPERATING REVENUES (Account 400)

1. Report below the amount of operating revenue for the year for each prescribed account and the amount of increase or decrease over the preceding year.
2. If increases and decreases are not derived from previously reported figures explain any inconsistencies.
3. Number of customers should be reported on the basis of number of meters, plus number of flat rate accounts, except that where separate meter readings are added for billing purposes, one customer shall be counted for each group of meters so added. The average number of customers means the average of the 12 figures at the close of each month. If the customer count in the residential service classification includes customers counted more than once because of special services, such as water heating etc., indicate in a footnote the number of such duplicate customers included in the classification.
4. Unmetered sales should be included below. The details of such sales should be given in a footnote.
5. Classification of Commercial and Industrial Sales, Account 481, according to Small (or Commercial) and Large (or Industrial) may be according to the basis of classification regularly used by the respondent.

Line No.	Account (a)	Operating Revenues: Amount for Year (b)	Operating Revenues: Increase or (Decrease) from Preceding Year (c)	MMBTU Sold (1000 BTU): Amount for Year (d)	MMBTU Sold (1000 BTU): Increase or (Decrease) from Preceding Year (e)	Average Number of Customers per Month: Number for Year (f)	Average Number of Customers per Month: Increase or (Decrease) from Preceding Year (g)
1	SALES OF GAS						
2	480 Residential Sales **...........................	$ 368,531,000	$ (15,543,175)	26,502,820	(805,437)	293,438	3,740
3	481 Commercial and Industrial Sales:						
4	Commercial & Industrial **	109,873,519	(8,872,068)	10,751,515	(551,875)	25,978	127
5	Interruptible.see instr.5......................	0	0				
6	482 Other Sales to Public Authorities.............	0	0				
7	484 Interdepartmental Sales....................	0	0				
8							
9	485 Miscellaneous Gas Sales... Unbilled.........	(2,197,000)	2,859,100	422,635	1,587,717		
10							
11	Total Sales to Ultimate Consumers....	476,207,519	(21,556,143)	37,676,970	230,405	319,416	3,867
12	483 Sales for Resale............................	1,041,675	(1,774,624)	231,468	(436,194)		0
13							
14	Total Sales of Gas	477,249,194	(23,330,767)	37,908,438	(205,789)	319,416	3,867
15							
16							
17							
18	OTHER OPERATING REVENUES						
19	480 Residential Transportation**	535,116	(303,323)	73,308	(42,537)	464	(519)
20	487 Forfeited Discounts.................	575,083	113,944				
21	488 Miscellaneous Service Revenues..........	0	0				
22	489 Revenues from Trans.of Gas of Others**	51,060,019	3,607,284	20,443,731	(1,148,399)	4,997	80
23	490 Sales of Products Extracted from Natural Gas.....	0	0				
24	491 Rev. from Natural Gas Processed by Others.......	0	0				
25	493 Rent from Gas Property	140,396	6,732				
26	494 Interdepartmental Rents.....................	0	0				
27	495 Other Gas Revenues..........................	43,568,747	7,156,706				
28							
29	Total Other Operating Revenues.................	95,879,361	10,581,343				
30							
31	Total Gas Operating Revenues..............	$ 573,128,555	$ (12,749,424)	58,425,477	(1,396,725)	324,877	3,428

Line No.		Purchased Price Adjustment Clauses	Fuel Clauses
32	** Includes billed revenues from application of	232,947,731.00	100,122,451
33	Total MMBTU to which Applied..	37,557,513	54,206,464

SALES OF GAS TO ULTIMATE CONSUMERS

Report by account the MMBTUs sold, the amount derived and the number of customers under each filed schedule or contract. Contract sales and unbilled sales may be reported separately in total.

Line No.	Account No.	Schedule (a)	MMBTU (1000 BTU) (b)	Revenue (c)	Average Revenue per MMBTU ($0.0000) (d)	Number of Customers (Per Bills Rendered) July 31 (e)	December 31 (f)
1	480	R-1 Residential Non-Heating	291,014	$ 6,214,192	$ 21.3536	16,199	16,256
2	480	R-2 Residential Non-Heating Low Income	58,859	1,213,504	20.6171	2,910	2,823
3	480	R-3 Residential Heating	22,474,829	310,366,436	13.8095	236,480	241,332
4	480	R-4 Residential Heating Low Income	3,678,005	50,736,160	13.7945	36,616	35,960
5	480	R-5 Outdoor Lighting	113	708	6.2655	0	0
6							
7		Total Residential	26,502,820	368,531,000	13.9054	292,205	296,371
8							
9	481	G-40 Commercial Low Annual/High Winter	2,608,683	34,089,513	13.0677	18,209	18,531
10	481	G-41 Commercial Med Annual/High Witner	3,717,428	38,076,267	10.2426	3,347	3,418
11	481	G-50 Commercial Low Annual/Low Winter	394,733	4,381,108	11.0989	2,534	2,707
12	481	G-51 Commercial Med Annual/Low Winter	1,424,755	11,683,428	8.2003	1,336	1,342
13	481	G-42 Industrial High Annual/High Winter	1,335,957	12,356,690	9.2493	182	180
14	481	G-43 Industrial Extra High Annual/High Winter	164,383	1,397,639	8.5023	2	3
15	481	G-52 Industrial High Annual/Low Winter	677,899	4,864,726	7.1762	63	70
16	481	G-53 Industrial Extra High Annual/Low Winter	427,677	3,024,148	7.0711	11	13
17							
18		Total Commercial & Industrial	10,751,515	109,873,519	10.2194	25,684	26,264
19							
20							
21		Unbilled	422,635	(2,197,000)	-5.1983	N/A	N/A
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
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37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49		TOTAL SALES TO ULTIMATE CONSUMERS (Page 43 line 11)	37,676,970	$ 476,207,519	$ 12.6392	317,889	322,635

GAS OPERATION AND MAINTENANCE EXPENSES

1. Enter in the space provided the operation and maintenance expenses for the year.
2. If the increases and decreases are not derived from previously reported figures explain in footnote.

Line No.	Account (a)	Amount for Year (b)	Increase or (Decrease) from Preceding Year (c)
1	PRODUCTION EXPENSES		
2	MANUFACTURED GAS PRODUCTION EXPENSES		
3	STEAM PRODUCTION		
4	Operation:		
5	700 Operation Supervision and Engineering..............................		
6	701 Operation labor...		
7	702 Boiler Fuel...		
8	703 Miscellaneous steam expenses.....................................		
9	704 Steam transferred-Cr..		
10	Total operation..		
11	Maintenance:		
12	705 Maintenance supervision and engineering...........................		
13	706 Maintenance of structures and improvements..................		
14	707 Maintenance of boiler plant equipment.........................		
15	708 Maintenance of other steam production plant..........................		
16	Total Maintenance.......................................		
17	Total steam production.......................................		
18	MANUFACTURED GAS PRODUCTION		
19	Operation:		
20	710 Operation supervision and engineering...........................	$ 122,243	$ 99,480
21	Production labor and expenses:		
22	711 Steam expenses...		
23	712 Other power expenses....................................	7,152,822	(292,229)
24	715 Water gas generating expenses....................................		
25	716 Oil gas generating expenses................................		
26	717 Liquefied petroleum gas expenses............................		-
27	718 Other process production expenses........................	1,118,680	219,871
28	Gas fuels:		
29	721 Water gas generator fuel................................		
30	722 Fuel for oil gas..		
31	723 Fuel for liquefied petroleum gas process..........................		-
32	724 Other gas fuels..	1,565,361	998,345
33	Gas raw materials:		
34	726 Oil for water gas...		
35	727 Oil for oil gas...		
36	728 Liquefied petroleum gas.................................	218,051	(590,783)
37	729 Raw materials for other gas processes.....................		
38	730 Residuals expenses.......................................		
39	731 Residuals produced-Cr...................................		
40	732 Purification expenses.......................................		
41	733 Gas mixing expenses..		
42	734 Duplicate charges-Cr...		
43	735 Miscellaneous production expenses..................................	1,607,555	331,947
44	736 Rents..		
45	Total operation..	11,784,712	766,631
46	Maintenance:		
47	740 Maintenance supervision and engineering..............................	334,293	42,703
48	741 Maintenance of structures and improvements.................	16,932	(53,669)
49	742 Maintenance of production equipment.......................	55,798	(11,046)
50	Total maintenance.......................................	407,023	(22,012)
51	Total manufactured gas production....................................	$ 12,191,735	$ 744,619

GAS OPERATION AND MAINTENANCE EXPENSES-Continued

Line No.	Account (a)	Amount for Year (b)	Increase or (Decrease) from Preceding Year (c)
1	OTHER GAS SUPPLY EXPENSES		
2	Operation:		
3	804 Natural gas city gate purchases................................	$ 188,530,465	$ (63,622,507)
4	805 Other gas purchases....................................	-	3,525,349
5	806 Deferred Cost of Gas......................................	10,622,302	15,577,824
6	807 Purchased gas expenses.......................................		
7	808 Natural Gas Storage Charges................................	4,510,693	1,911,404
8	Cost of Off-System Sales....................................		
9	812 Gas used for other utility operations-Cr.............................	(262,860)	(12,568)
10	813 Other gas supply expenses..............................	1,468,202	108,308
11	Total other gas supply expenses................................	204,868,802	(42,512,190)
12	Total Production Expenses	217,060,537	(41,767,571)
13	LOCAL STORAGE EXPENSES		
14	Operation:		
15	840 Operation supervision and engineering........................		
16	841 Operation labor and expenses.....................................		
17	842 Rents..		
18	Total Operation...		
19	Maintenance:		
20	843 Maintenance supervision and engineering.............................		
21	844 Maintenance of structures and improvements......................		
22	845 Maintenance of Gas Holders...................................		
23	846 Maintenance of other equipment...........................		
24	Total Maintenance......................................		
25	Total storage expenses...................................		
26	TRANSMISSION AND DISTRIBUTION EXPENSES		
27	Operation:		
28	850 Operation supervision and engineering............................	7,828,121	3,855,865
29	851 System control and load dispatching..............................	933,792	816,188
30	852 Communication system expenses...............................	149,956	15,248
31	853 Compressor station labor and expenses..............................		
32	855 Fuel and power for compressor stations..................		
33	857 Measuring and regulating station expenses...................	846,456	229,244
34	858 Transmission and Compression of gas by others...................		
35	874 Mains and services expenses.................................	19,336,142	6,968,325
36	878 Meter and house regulator expenses.............................	5,472,771	45,728
37	879 Customer Installations expenses..............................	9,067,018	1,974,892
38	880 Other expenses...	1,809,859	150,209
39	881 Rents..	152,385	79,695
40	Total operation..	45,596,500	14,135,394
41	Maintenance:		
42	885 Maintenance supervision and engineering..........................	97,448	22,372
43	886 Maintenance of structures and improvements........................	477,001	158,913
44	887 Maintenance of mains..	(338,808,787)	(1,167,440,057)
45	888 Maintenance of compressor station equipment.........................		
46	889 Maintenance of measuring and regulating station equipment...........	840,875	(41,945)
47	892 Maintenance of services.......................................	6,104,198	2,400,151
48	893 Maintenance of meters and house regulators.......................	411,932	(122,798)
49	894 Maintenance of other equipment..........................	981,461	269,567
50	Total Maintenance...	(329,895,872)	(1,164,753,797)
51	Total Transmission and Distribution expenses.................	$ (284,299,372)	$ (1,150,618,403)

GAS OPERATION AND MAINTENANCE EXPENSES-Continued

Line No.	Account (a)	Amount for Year (b)	Increase or (Decrease) from Preceding Year (c)
1	CUSTOMER ACCOUNTS EXPENSES		
2	Operation:		
3	901 Supervision...	$ -	$ -
4	902 Meter reading expenses...	559,952	81,171
5	903 Customer records and collection expenses................	10,515,086	1,215,052
6	904 Uncollectible accounts...................................	8,322,007	1,168,956
7	905 Miscellaneous customer accounts expenses.................	54,156,175	8,476,687
8	Total customer account expenses...........................	73,553,220	10,941,866
9	SALES EXPENSES		
10	Operation:		
11	911 Supervision..	30,028	(145)
12	912 Demonstrating and selling expenses.............................	121,837	(66,718)
13	913 Advertising expenses..	96,962	(103,483)
14	916 Miscellaneous sales expenses.................................	-	-
15	Total sales expenses..	248,827	(170,346)
16	ADMINISTRATIVE AND GENERAL EXPENSES		
17	Operation:		
18	920 Administrative and general salaries..........................	24,784,546	(13,225,987)
19	921 Office supplies and expenses............................	8,021,288	2,322,123
20	922 Administrative expenses transferred-Cr.....................	-	-
21	923 Outside services employed.................................	29,585,250	1,720,840
22	924 Property Insurance...	291,806	234,386
23	925 Injuries and damages....................................	61,439,088	41,812,703
24	926 Employees pensions and benefits...................................	16,189,858	872,505
25	928 Regulatory commission expenses................................	1,185,441	(100,600)
26	929 Duplicate charges-Cr..		
27	930 Miscellaneous general expenses.............................	2,437,681	(15,220,315)
28	931 Rents..	6,668,833	2,422,865
29	Total operation..	150,603,791	20,838,520
30	Maintenance:		
31	932 Maintenance of general plant....................................	6,787,928	688,472
32	Total administrative and general expenses..................	157,391,719	21,526,992
33	Total gas operation and maintenance expenses	$ 163,954,931	$ (1,160,087,462)

SUMMARY OF GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Functional Classification (a)	Operation (b)	Maintenance (c)	Total (d)
34	Steam production.....................................			
35	Manufactured gas production..........................	$ 11,784,712	$ 407,023	$ 12,191,735
36	Other gas supply expenses.........................	204,868,802		204,868,802
37	Total production expenses.............................	216,653,514	407,023	217,060,537
38	Local storage expenses.............................			
39	Transmission and distribution expenses.............	45,596,500	(329,895,872)	(284,299,372)
40	Customer accounts expenses.........................	73,553,220		73,553,220
41	Sales expenses..	248,827		248,827
42	Administrative and general expenses.........	150,603,791	6,787,928	157,391,719
43	Total gas operation and maintenance expenses..........................	$ 486,655,852	$ (322,700,921)	$ 163,954,931

44	Ratio of operating expenses to operating revenues (carry out decimal two places, e.g.: 0.00%) Compute by dividing Revenues (Acct. 400) into the sum of Operation and Maintenance Expenses (p. 47, line 43(d), Depreciation (Acct. 403) and Amortization (Acct. 407)...............	37.82%
45	Total salaries and wages of gas department for year, including amounts charged to operating expenses, construction and other accounts.	81,653,040
46	Total number of employees of gas department at end of year, including administrative, operating, maintenance, construction and other employees (including part time employees)..........................	781

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If gas is purchased or sold at two or more different rates, the amounts of each rate should be shown in the following table.

SALES FOR RESALE (Account 483)

Line No.	Names of Companies to Which Gas is Sold (a)	Where Delivered and Where and How Measured (b)	MMBTU (1000 BTU) (c)	Rate per M.C.F. ($0.0000) (d)	Amount (e)
1					
2					
3	Spot Off System Sales	Delivered to customers, various points			
4		of delivery	231,468	$4.5003	1,041,675
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15		TOTALS	231,468	$4.5003	1,041,675
16	Portion of above total sold to companies				
17	located outside of Massachusetts:		85,989	$4.5003	386,978

SALE OF RESIDUALS (Accounts 730, 731)

State the revenues and expenses of the respondent resulting from the sale of residuals.

Line No.	Kind (a)	Revenue (b)	Inventory Cost (c)	Labor Handling Selling, Etc. (d)	(e)	Total Cost (f)	Net Revenue (g)
18							
19	None						
20							
21							
22							
23							
24							
25	TOTALS						

PURCHASED GAS (Accounts 804-806)

Line No.	Names of Companies to Which Gas is Purchased (a)	Where Received and Where and How Measured (b)	M.C.F. (1000 BTU) (c)	Rate per M.C.F. ($0.0000) (d)	Amount (e)
26					
27	See Page 48A				
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40		TOTALS			

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PURCHASED GAS (804 - 806)

Line No.	Names of Companies from Which Gas is Purchased (a)	Where Received and Where and How Measured (b)	MMBtu (1000 BTU) (c)	Rate Per MMBtu (0.0000) (d)	Amount (e)
1	Suppliers on the Tenn. Gas Pipeline	Various locations by station	41,815,391	2.8160	117,750,281
2	Suppliers on the Algonquin Gas Pipeline	orifice meter			
3	Suppliers on the Portland Natural Gas Transmission				
4	Suppliers on the Vector Pipeline				
5	Suppliers on the Texas Easterm Gas Transmission				
6	Suppliers on the Irquois Gas Transmission System				
7	Suppliers on the National Fuel Gas Supply Pipeline				
8	Suppliers on the TransCanada Pipeline				
9	Suppliers on the Union Gas Pipeline				
10	Suppliers on the Granite State Gas Transmission				
11	Suppliers on the Transcontinental Gas Pipleline				
12	(Includes various Spot Supplies)				
13					
14					
15	Demand charges paid to suppliers				108,413,748
16	and pipelines				
17					
18		**Subtotal**	41,815,391	5.4086	226,164,029
19					
20					
21	Capacity Release and Off System Sales				(37,633,564)
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38	Total		41,815,391	$ 4.5086	$ 188,530,465
39	Deferred Cost of Gas				10,622,302
40					
41					
42					
43					----------------------------
44	Subtotal - Natural gas purchases - Account 804 - 806				199,152,767
45					
46	Total				$ 199,152,767

TAXES CHARGED DURING YEAR

1. This schedule is intended to give the account distribution of total taxes charged to operations and other final accounts during the year.
2. Do not include gasoline and other sales taxes which have been charged to accounts to which the material on which the tax was levied was charged. If the actual or estimated amounts of such taxes are known, they should be shown as a footnote and designated whether estimated or actual amounts.
3. The aggregate of each kind of tax should be listed under the appropriate heading of "Federal", "State", and "Local" in such manner that the total tax for each State and for all subdivisions can readily be ascertained.
4. The accounts to which the taxes charged were distributed should be shown in columns (c) to (j). Show both the utility department and number of account charged. For taxes charged to utility plant show the number of the appropriate balance sheet plant account or subaccount.
5. For any tax which it was necessary to apportion to more than one utility department or account, state in a footnote the basis of apportioning such a tax.
6. Do not include in this schedule entries with respect to deferred income taxes, or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.

			Distribution of Taxes Charged (omit cents) (Show utility department where applicable and account charged)							
Line No.	Kind of Tax (a)	Total Taxes Charged During Year (omit cents) (b)	Electric Acct. 408, 409 (c)	Gas Acct. 408, 409 (d)	Capital,etc 107,186,254 (e)	Mdse 415 (f)	Other 417, 419, 421, 426 (g)	Gas Proc by Others 777 (h)	Purch Gas Exp 807 (i)	Rents 931 (j)
1	STATE									
2	MA Franchise (A)	456		16,254,018			(16,253,562)			
3	Income (OTHER)	466		466						
4	Unemployment (B)	338,337		338,337	-	-				
6	Sales and Use	160,693		160,693						
7	LOCAL									
8	Property	31,147,129		28,874,976		-		-	-	2,272,153
9	Motor Vehicle Excise	-		-						
10										
11	FEDERAL									
12	FICA & Medicare (B)	3,681,126		3,681,126	-	-				
13	Unemployment (B)	25,314		25,314	-	-				
14	Incentive	163,134		163,134						
15			Account 408	49,498,064						
16										
17	FEDERAL									
18	Income (A)	32,140,093	Account 409	71,392,447			(39,252,354)			
19										
20										
21										
22										
23										
24										
25										
26										
27										
28	TOTALS	67,656,748		120,890,511	-	-	(55,505,916)	-	-	2,272,153

(A) Apportioned on Earnings Basis
(B) Apportioned on Payroll Basis

INCOME FROM MERCHANDISING, JOBBING, AND CONTRACT WORK (Account 415)

Report by utility departments the revenues, costs, expenses, and net income from merchandising, jobbing and contract work during year.

Line No.	Item (a)	Electric Department (b)	Gas Department (c)	Other Utility Department (d)	Total (e)
1	Revenues:				
2	Merchandise sales, less discounts,				
3	allowance and returns....................		$		$
4	Contract work.........................				
5	Commissions...........................				
6	Other-list according to major classes.......				
7	Install.				
8					
9					
10	Total Revenues.......................				NONE
11					
12					
13	Costs and Expenses:				
14	Cost of Sales (list according to major				
15	classes of cost)............................				
16	Cost of Merchandise Sold.................				
17	Install. expenses				
18	Servicing installed appliance (net).....				
19	Storeroom expenses..............................				
20	Fleet expenses...........................				
21					
22					
23					
24					
25					
26	Miscellaneous...........................				
27	Customer Account Expenses................				
28	Administrative and general expenses.....				
29	Clerical salaries and wages................				
30	Employee Benefits & Payroll Tax.........				
31	Income Tax................................				
32	Uncollectible Accounts....................				
33	E/S Property Tax Non-Utility				
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
50	TOTAL COSTS AND EXPENSES				NONE
51	Net Profit (or Loss)		$		$ NONE

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Annual report of.......................................Columbia Gas of Massachusetts...................................Year ended December 31, 2019

**RECORD OF SENDOUT FOR THE YEAR IN MCF
BASED ON 1000 BTU PER CUBIC FOOT**

Line No.	Item		Total	January	February	March	April	May
1	Gas Made							
2	Liquid Natural	Gas	1,059,783	364,826	104,768	105,182	46,561	46,672
3	Propane Air	Gas	12,291	8,937	1,163	0	0	0
4		Gas						
5	Propane Meter	Gas	0	0	0	0	0	0
6	TOTAL.............		1,072,074	373,763	105,931	105,182	46,561	46,672
7	Off System Sales		(224,405)	(69,732)	(33,958)	(7,285)	0	0
8	Storage Activity		64,015	334,255	192,995	64,317	(142,505)	(115,440)
	TOTAL.............		(160,390)	264,523	159,038	57,032	(142,505)	(115,440)
9	Net Gas Purchase		37,613,865	6,647,078	5,718,606	5,056,006	2,843,164	1,727,898
10	End User Transportation		19,344,017	2,303,743	1,984,372	2,016,830	1,502,331	1,098,002
11	TOTAL...............		56,957,882	8,950,821	7,702,978	7,072,835	4,345,496	2,825,900
12	TOTAL MADE AND							
13	PURCHASED		57,869,566	9,589,108	7,967,946	7,235,049	4,249,552	2,757,132
14	Difference Throughput vs. Purchased Gas......		(54,136)	30,023	(20,848)	(17,485)	(45,004)	(23,897)
15	TOTAL SENDOUT..............		57,815,430	9,619,131	7,947,098	7,217,564	4,204,547	2,733,236
16	Residential Gas		26,159,948	4,879,956	4,208,159	3,716,794	1,931,074	1,029,425
17	C&I Gas		10,572,587	1,858,213	1,686,246	1,482,091	798,203	388,450
18	Interruptible Gas		0					
19	Transportation		19,953,869	2,461,654	2,204,317	2,130,921	1,527,994	1,062,347
20	Gas Used by Company....................		287,066	22,660	36,393	27,382	20,821	24,337
21	Gas Accounted for......................		56,973,470	9,222,484	8,135,115	7,357,188	4,278,092	2,504,559
22	Gas Unaccounted for.................		841,960	396,647	(188,017)	(139,624)	(73,544)	228,677
23	% Unaccounted for (0.00%).....................		1.46%	4.12%	-2.37%	-1.93%	-1.75%	8.37%

NOTE: On a monthly basis, the MCF volumes provided above represent Company recorded MMBTU quantities converted to MCF using the applicable Mcf/MMBtu BTU conversion factors as provided by upstream pipelines

Line No.	Item	Total	January	February	March	April	May
24							
25							
26	Sendout in 24 hours						
27	in MMBTU						
28	Brockton						
29	Maximum-MMBtu..........................	256,183	256,183	213,307	192,619	114,489	78,200
30	Maximum Date.................	1/21	1/21	2/1	3/6	4/1	5/14
31	Minimum-MMBtu.........................	16,307	103,374	88,119	40,965	27,550	21,088
32	Minimum Date..................................	7/20	1/24	2/5	3/30	4/19	5/26
33	Springfield						
34	Maximum-MMBtu..........................	145,797	145,797	126,051	112,120	72,265	46,694
35	Maximum Date.................	1/21	1/21	2/1	3/6	4/1	5/13
36	Minimum-MMBtu.........................	12,868	64,656	58,926	29,986	21,054	17,462
37	Minimum Date..................................	8/5	1/4	2/4	3/30	4/19	5/26
38	Lawrence						
39	Maximum-MMBtu..........................	78,346	78,346	68,599	60,694	37,082	25,230
40	Maximum Date.................	1/21	1/21	2/1	3/6	4/1	5/2
41	Minimum-MMBtu.........................	5,234	33,675	28,482	14,438	9,134	6,938
42	Minimum Date..................................	7/20	1/24	2/4	3/30	4/20	5/26

RECORD OF SENDOUT FOR THE YEAR IN MCF-CONTINUED
BASED ON 1000 BTU PER CUBIC FOOT

Line No.	Item		June	July	August	September	October	November	December
1	Gas Made								
2	Liquid Natural	Gas	48,861	54,599	55,829	54,588	54,209	57,506	66,182
3	Propane Air	Gas	0	0	0	0	0	2,191	0
4		Gas							
5	Propane Meter	Gas	0	0	0	0	0	0	0
6	TOTAL.............		48,861	54,599	55,829	54,588	54,209	59,697	66,182
7	Off System Sales		0	0	0	0	0	(73,508)	(39,922)
8	Storage Activity		(35,992)	(34,095)	(148,794)	(59,483)	2,658	36,976	(30,877)
	TOTAL.............		(35,992)	(34,095)	(148,794)	(59,483)	2,658	(36,532)	(70,799)
9	Net Gas Purchase		940,491	732,362	886,926	879,162	1,727,621	4,444,655	6,009,896
10	End User Transportation		783,957	1,802,800	1,451,491	871,187	1,253,919	2,086,855	2,188,531
11	TOTAL..............		1,724,448	2,535,162	2,338,417	1,750,348	2,981,540	6,531,510	8,198,427
12	TOTAL MADE AND								
13	PURCHASED		1,737,316	2,555,665	2,245,453	1,745,453	3,038,407	6,554,676	8,193,810
	Difference Throughput								
14	vs. Purchased Gas......		(69)	5,545	(7,604)	(22,715)	6,154	(217)	41,981
15	TOTAL SENDOUT.............		1,737,247	2,561,211	2,237,849	1,722,738	3,044,560	6,554,458	8,235,791
16	Residential Gas		420,423	514,229	519,817	660,930	1,127,990	2,928,596	4,222,555
17	C&I Gas		277,271	273,351	273,177	303,132	460,722	1,151,596	1,620,135
18	Interruptible Gas								
19	Transportation		834,934	1,852,737	1,479,475	855,403	1,228,080	2,068,439	2,247,568
20	Gas Used by Company....................		22,551	20,263	22,080	22,698	21,432	21,442	25,007
21	Gas Accounted for......................		1,555,180	2,660,579	2,294,549	1,842,163	2,838,224	6,170,074	8,115,265
22	Gas Unaccounted for.................		182,068	(99,368)	(56,700)	(119,425)	206,337	384,385	120,526
	% Unaccounted								
23	for (0.00%).....................		10.48%	-3.88%	-2.53%	-6.93%	6.78%	5.86%	1.46%
	NOTE: On a monthly basis, the MCF volumes provided above represent Company recorded MMBTU quantities converted to MCF using the applicable Mcf/MMBtu BTU conversion factors as provided by upstream pipelines								
24									
25									
26	Sendout in 24 hours								
27	in MMBTU								
28	Brockton								
29	Maximum-MMBtu..........................		32,878	22,813	24,488	33,324	59,964	167,284	205,866
30	Maximum Date.................		6/13	7/23	8/26	9/18	10/18	11/13	12/19
31	Minimum-MMBtu.........................		18,778	16,307	17,425	18,681	25,036	63,275	69,880
32	Minimum Date..................................		6/29	7/20	8/3	9/1	10/1	11/1	12/14
33	Springfield								
34	Maximum-MMBtu..........................		21,204	18,704	18,909	22,803	39,039	95,937	118,746
35	Maximum Date.................		6/3	7/24	8/25	9/19	10/27	11/13	12/19
36	Minimum-MMBtu.........................		15,832	13,929	12,868	15,889	20,087	44,031	55,891
37	Minimum Date..................................		6/8	7/20	8/5	9/1	10/1	11/1	12/14
38	Lawrence								
39	Maximum-MMBtu..........................		10,790	7,401	7,346	10,829	19,998	53,398	64,034
40	Maximum Date.................		6/13	7/1	8/5	9/18	10/27	11/13	12/19
41	Minimum-MMBtu.........................		6,274	5,234	5,886	6,113	8,173	22,024	23,024
42	Minimum Date..................................		6/29	7/20	8/17	9/28	10/1	11/5	12/14

GAS GENERATING PLANT

Line No.	General Description - Location, Size, Type, etc.		No. of Sets	24 Hour Cap. (MMBtu)
1	Liquid Propane Plant	Brockton		21,000
2	Liquefied Natural Gas Plant	Easton		44,000
3	Liquefied Natural Gas Plant	Marshfield		8,000
4	Liquid Propane Plant	W. Springfield		18,000
5	Liquid Propane Plant	Northampton		5,000
6	Liquid Propane Plant	Lawrence		14,000
7	Liquefied Natural Gas Plant	Ludlow		48,000
8	Liquefied Natural Gas Plant	Lawrence		12,500
9				
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43				
44				
45			TOTAL	170,500

Annual report of................................Columbia Gas of Massachusetts.................................Year ended December 31, 2019

TRANSMISSION AND DISTRIBUTION MAINS

Report by size, for all mains and lines, the information called for below for cast iron, welded, wrought iron, and steel mains. Sub-totals should be shown for each type.

Line No.	Diameter	Total Length in Feet at Beginning of Year	Added During Year	Taken Up During Year	Abandoned but Not Removed During Year	Total Length in Feet at End of Year
1	CAST IRON					
2	3"	211,663			4,321	207,342
3	4"	715,683			8,393	707,290
4	6"	1,034,622			6,683	1,027,939
5	8"	110,798				110,798
6	10"	59,870			37	59,833
7	12"	104,092				104,092
8	14"	6,099				6,099
9	16"	54,366				54,366
10	20"	6,375				6,375
11	24"	2,256				2,256
12						
13	Sub Total	2,305,824			19,434	2,286,390
14	STEEL					
15	Under 4"	5,171,259	496		18,592	5,153,163
16	4"	2,529,205	299		19,877	2,509,627
17	6"	3,007,893	444		12,026	2,996,311
18	8"	1,271,826	242		4,732	1,267,336
19	10"	169,070			341	168,729
20	12"	659,365	4		10	659,359
21	16"	166,922	478		513	166,887
22	20"	7,482				7,482
23	24"	3,881				3,881
24	Sub Total	12,986,903	1,963		56,091	12,932,775
25	PLASTIC					
26	Under 4"	6,241,044	273,723		2,816	6,511,951
27	4"	2,604,729	50,899		3,782	2,651,846
28	6"	1,488,925	38,727		1,268	1,526,384
29	8" or Over	680,375	28,219		49	708,545
30	Sub Total	11,015,073	391,568		7,915	11,398,726
31	TOTALS	26,307,800	393,531		83,440	26,617,891

Normal Operating Pressure - Mains and Lines Maximum 100 lb LP 6" HP 40"

Normal Operating Pressure - Services Maximum 60 lb LP 6" HP 25"

GAS DISTRIBUTION SERVICES, HOUSE GOVERNORS AND METERS

Report below the information called for concerning Distribution Services, House Governors and Meters

Line No.	Item	Gas Services	House Governors	Meters
1	Number at beginning of year.............	270,555	0	335,091
2	Additions during year:			
3	Purchased...........................	8,548		50,328
4	Installed.............................			
5	Meter adjustments..................................			(25,859)
6	Total Additions...................	8,548	0	24,469
7	Reductions during year:			
8	Retirements.........................	2,656		14,551
9	Service adjustments..................................		0	
10	Total Reductions..................	2,656	0	14,551
11	Number at End of Year.................	276,447	0	345,009
12	In Stock...			12,134
13	On Customers' Premises - Inactive..			3,349
14	On Customers' Premises - Active..			329,470
15	In Company Use..			56
16	Number at End of Year...			345,009
17	Number of Meters Tested by State Inspectors During Year…………………………..........................			33,846

House Governors are included as a component of the Gas Service.

RESIDENTIAL NON-HEATING
RESIDENTIAL RATE R-1

AVAILABILITY

Service is available under this rate at single locations for all domestic purposes, except for resale, in individual private dwellings and individual apartments including condominiums and their facilities as defined in G.L. Chapter 183A, Section 1 and DPU 86-159 dated February 6, 1987.

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - BI-MONTHLY

The Bi-Monthly rate schedule applicable to all customers being served with Company meters that do not have an installed radio-based automated meter reading device is as follows:

Customer Charge Per Two Month Period $ 24.40

Off-Peak	All therms	@	$ 0.6638 per therm
Peak	All therms	@	$ 0.6638 per therm

RATE – MONTHLY

The Monthly rate schedule applicable to all customers being served with Company meters that have an installed radio-based automated meter reading device is as follows:

Customer Charge Per One Month Period $ 12.20

Off-Peak	All therms	@	$ 0.6638 per therm
Peak	All therms	@	$ 0.6638 per therm

RESIDENTIAL NON-HEATING
RESIDENTIAL RATE R-1

MINIMUM CHARGE

The minimum charge per month shall be the applicable bi-monthly or monthly Customer Charge.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas sold under this rate.

COST OF GAS ADJUSTMENT AND LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Adjustment and Local Distribution Adjustment Clause apply to gas sold under this rate.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

SPECIAL PROVISION

Where more than one but less than four individual apartments or dwellings are served through one meter, the billings shall be calculated as though each individual dwelling or apartment were served through a separate meter by assuming the use was divided equally among them, except that one customer charge will apply. The owner of the property or his designee will be responsible for the payment of the service. Where four or more individual apartments or dwellings are served through one meter, the billings will be calculated on the appropriate Commercial and Industrial Service Rate.

RESIDENTIAL NON-HEATING
RESIDENTIAL RATE R-1

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

LOW INCOME RESIDENTIAL NON-HEATING
RESIDENTIAL RATE R-2

AVAILABILITY

Service is available under this rate at single locations for all domestic purposes, except for resale, in individual private dwellings and individual apartments to persons who verify receipt of any means-tested public-benefit program or verify eligibility for the low-income home energy assistance program or its successor program, for which eligibility does not exceed 60 percent of the median income in Massachusetts based on a household's gross income or other criteria approved by the Department.

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - BI- MONTHLY

The Bi-Monthly rate schedule applicable to all customers being served with Company meters that do not have an installed radio-based automated meter-reading device is as follows:

Customer Charge Per Two Month Period $ 24.40

Off-Peak	-	All therms	@	$ 0.6638 per therm
Peak	-	All therms	@	$ 0.6638 per therm

RATE – MONTHLY

The Monthly rate schedule applicable to all customers being served with Company meters that have an installed radio-based automated meter reading device is as follows:

Customer Charge Per One Month Period $ 12.20

Off-Peak	-	All therms	@	$ 0.6638 per therm
Peak	-	All therms	@	$ 0.6638 per therm

LOW INCOME RESIDENTIAL NON-HEATING
RESIDENTIAL RATE R-2

MINIMUM CHARGE

The minimum charge per month shall be the applicable bi-monthly or monthly Customer Charge, less the application of the Low Income Discount Adjustment provided under this rate schedule.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas sold under this rate.

COST OF GAS ADJUSTMENT AND LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Adjustment and Local Distribution Adjustment Clause apply to gas sold under this rate.

LOW INCOME DISCOUNT ADJUSTMENT

The total amount resulting from the billing of all charges under this rate schedule shall be adjusted by a discount of 25.0 percent (25.0%) pursuant to D.P.U. 12-25.

DEFINITIONS

Off-Peak Period - Defined as the period May 1st through October 31st.
Peak Period - Defined as the period November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

SPECIAL PROVISIONS

Where more than one but less than four individual apartments or dwellings is served through one meter, the billings shall be calculated as though each individual dwelling or apartment were

LOW INCOME RESIDENTIAL NON-HEATING
RESIDENTIAL RATE R-2

served through a separate meter by assuming the use was divided equally among them, except that one customer charge will apply. The owner of the property or his designee will be responsible for the payment of the service. Where four or more individual apartments or dwellings are served through one meter, the billings shall be calculated on the appropriate Commercial and Industrial Service Rate.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

RESIDENTIAL HEATING
RESIDENTIAL RATE R-3

AVAILABILITY

Service is available under this rate at single domestic locations for all purposes, except for resale, in individual private dwellings and individual apartments including condominiums and their facilities as defined in G. L. Chapter 183A, Section 1 and DPU 86-159 dated February 6, 1987 where such residences are heated exclusively by means of permanently installed space heating equipment.

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - MONTHLY

Customer Charge Per Month			$ 12.20
Off-Peak	All therms	@	$ 0.4602 per therm
Peak	All therms	@	$ 0.4602 per therm

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company’s Revenue Decoupling Adjustment Clause apply to gas sold under this rate.

COST OF GAS ADJUSTMENT AND LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Adjustment and Local Distribution Adjustment Clause apply to gas sold under this rate.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

RESIDENTIAL HEATING
RESIDENTIAL RATE R-3

PAYMENT

Bills are net and payable upon presentation.

SPECIAL PROVISION

a) Where more than one but less than four individual apartments or dwellings are served through one meter, the billings shall be calculated as though each individual dwelling or apartment were served through a separate meter by assuming the use was divided equally among them, except that one customer charge will apply. The owner of the property or his designee will be responsible for the payment of the service. Where four or more individual apartments or dwellings are served through one meter the billing shall be calculated on the appropriated Commercial and Industrial Service Rate.

b) Temporary service will be supplied, upon written application for the limited period necessary to protect and dry out unoccupied private residences under construction. Gas fired, permanently installed heating equipment of a type approved by the Company shall be the sole source of heat for the residence. The charge shall be computed in accordance with Residential Rate R-3.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

LOW INCOME RESIDENTIAL HEATING
RESIDENTIAL RATE R-4

AVAILABILITY

Service is available under this rate at single domestic locations for all purposes, except for resale, in individual private dwellings and individual apartments where such residences are heated exclusively by means of permanently attached space heating equipment to persons who verify receipt of any means-tested public-benefit program or verify eligibility for the low-income home energy assistance program or its successor program, for which eligibility does not exceed 60 percent of the median income in Massachusetts based on a household's gross income or other criteria approved by the Department..

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - MONTHLY

Customer Charge Per Month $ 12.20

Off-Peak	All therms	@	$ 0.4602 per therm
Peak	All therms	@	$ 0.4602 per therm

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge, less the application of the Low Income Discount Adjustment provided under this rate schedule.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company’s Revenue Decoupling Adjustment Clause apply to gas sold under this rate.

LOW INCOME RESIDENTIAL HEATING
RESIDENTIAL RATE R-4

COST OF GAS ADJUSTMENT AND LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Adjustment and Local Distribution Adjustment Clause apply to gas sold under this rate.

LOW INCOME DISCOUNT ADJUSTMENT

The total amount resulting from the billing of all charges under this rate schedule shall be adjusted by a discount of 25.0 percent (25.0%) pursuant to D.P.U. 12-25.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

SPECIAL PROVISIONS

Where more than one but less than four individual apartments or dwellings is served through one meter, the billings shall be calculated as though each individual dwelling or apartment were served through a separate meter by assuming the use was divided equally among them, except that one customer charge will apply. The owner of the property or his designee will be responsible for the payment of the service. Where four or more individual apartments are served through one meter the billing shall be calculated on the appropriate Commercial and Industrial Service Rate.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

COMMERCIAL AND INDUSTRIAL SERVICE
(LOW ANNUAL USE / HIGH PEAK PERIOD USE)
RATE G-40

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - MONTHLY

Customer Charge Per Month		$ 19.80	
Off-Peak	All therms	@	$0.4550 per therm
Peak	All therms	@	$0.4550 per therm

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage of less than 5,000 therms and peak period usage greater than or equal to 70 percent of annual use as determined by Company records and procedures.

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

COMMERCIAL AND INDUSTRIAL SERVICE
(LOW ANNUAL USE / HIGH PEAK PERIOD USE)
RATE G-40

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas sold under this rate.

COST OF GAS ADJUSTMENT AND LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Adjustment and Local Distribution Adjustment Clause apply to gas sold under this rate.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1^{st} through October 31^{st}.
Peak Period - Defined as the period from November 1^{st} through April 30^{th}.

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which initial period it shall automatically renew itself for like one year periods thereafter unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

COMMERCIAL AND INDUSTRIAL SERVICE
(MEDIUM ANNUAL USE / HIGH PEAK PERIOD USE)
RATE G-41

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - MONTHLY

Customer Charge Per Month			$ 78.30
Off-Peak	All therms	@	$0.2707 per therm
Peak	All therms	@	$0.2707 per therm

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage of between 5,000 therms and 39,999 therms and peak period usage greater than or equal to 70 percent of annual use as determined by Company records and procedures.

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company’s Revenue Decoupling Adjustment Clause apply to gas sold under this rate.

COMMERCIAL AND INDUSTRIAL SERVICE
(MEDIUM ANNUAL USE / HIGH PEAK PERIOD USE)
RATE G-41

COST OF GAS ADJUSTMENT AND LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Adjustment and Local Distribution Adjustment Clause apply to gas sold under this rate.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which initial period it shall automatically renew itself for like one year periods thereafter unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

COMMERCIAL AND INDUSTRIAL SERVICE
(MEDIUM ANNUAL USE / HIGH PEAK PERIOD USE)
RATE G-41

DUAL FUEL EQUIPMENT

The rates and charges applicable under this tariff for service rendered to locations with dual fuel equipment are subject to the Special Provision for Use of Dual Fuel Equipment, M.D.P.U. No. 279, which applies to any Customer with installed dual fuel equipment capable of burning gas and another fuel.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

COMMERCIAL AND INDUSTRIAL SERVICE
(HIGH ANNUAL USE / HIGH PEAK PERIOD)
RATE G-42

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - MONTHLY

Customer Charge Per Month		$ 290.00
Off-Peak	All therms	@ $0.1455 per therm
Peak	All therms	@ $0.2360 per therm

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage between 40,000 and 249,999 therms and peak period usage greater than or equal to 70 percent of annual use as determined by Company records and procedures. With the exception that customers whose annual use is greater than 249,999 therms, and if the Company has been unable to install an Automated Meter Reading Device, such customers also shall take service under this rate schedule.

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge

COMMERCIAL AND INDUSTRIAL SERVICE
(HIGH ANNUAL USE / HIGH PEAK PERIOD)
RATE G-42

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas sold under this rate.

COST OF GAS ADJUSTMENT AND LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Adjustment and Local Distribution Adjustment Clause apply to gas sold under this rate.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which initial period it shall automatically renew itself for like one year periods thereafter unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

COMMERCIAL AND INDUSTRIAL SERVICE
(HIGH ANNUAL USE / HIGH PEAK PERIOD)
RATE G-42

DUAL FUEL EQUIPMENT

The rates and charges applicable under this tariff for service rendered to locations with dual fuel equipment are subject to the Special Provision for Use of Dual Fuel Equipment, M.D.P.U. No. 279, which applies to any Customer with installed dual fuel equipment capable of burning gas and another fuel.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

COMMERCIAL AND INDUSTRIAL SERVICE
(EXTRA HIGH ANNUAL USE / HIGH PEAK PERIOD USE)
RATE G-43

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - MONTHLY

Customer Charge Per Month:		$ 1,155.90
Demand Rates:	Off-Peak	- @ $ 0.9614 per therm of maximum daily gas usage
	Peak	- @ $ 2.3034 per therm of maximum daily gas usage
Volumetric Rates:	Off-Peak	- @ $0.0525 per therm
	Peak	- @ $0.1070 per therm

CALCULATION OF DEMAND CHARGES

Demand charges shall be calculated by applying the Demand Rate to the actual measured maximum daily gas usage in the billing month.

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage of 250,000 therms or more and peak period usage greater than or equal to 70 percent of annual use as determined by Company records and procedures.

COMMERCIAL AND INDUSTRIAL SERVICE
(EXTRA HIGH ANNUAL USE / HIGH PEAK PERIOD USE)
RATE G-43

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas sold under this rate.

COST OF GAS ADJUSTMENT AND LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Adjustment and Local Distribution Adjustment Clause apply to gas sold under this rate.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which, it shall automatically renew itself for like one year periods thereafter, unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

COMMERCIAL AND INDUSTRIAL SERVICE
(EXTRA HIGH ANNUAL USE / HIGH PEAK PERIOD USE)
RATE G-43

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

SPECIAL PROVISIONS

All customers eligible for this service class must provide and maintain a phone line for use by the Company and provide the Company with reasonable access to the meter for installation and maintenance of the Automated Meter Reading device. Customers must have Automated Meter Reading devices installed in order to receive service according to this schedule. If the Company determines that Automated Meter Reading is impractical, the customer may receive service under the terms of Rate Schedule G-42.

DUAL FUEL EQUIPMENT

The rates and charges applicable under this tariff for service rendered to locations with dual fuel equipment are subject to the Special Provision for Use of Dual Fuel Equipment, M.D.P.U. No. 279, which applies to any Customer with installed dual fuel equipment capable of burning gas and another fuel.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

COMMERCIAL AND INDUSTRIAL SERVICE
(LOW ANNUAL USE / LOW PEAK PERIOD USE)
RATE G-50

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - MONTHLY

Customer Charge Per Month		$ 19.80
Off-Peak	All therms	@ $0.4337 per therm
Peak	All therms	@ $0.4337 per therm

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage of less than 5,000 therms and peak period usage less than 70 percent of annual use as determined by Company records and procedures.

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas sold under this rate.

COMMERCIAL AND INDUSTRIAL SERVICE
(LOW ANNUAL USE / LOW PEAK PERIOD USE)
RATE G-50

COST OF GAS ADJUSTMENT AND LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Adjustment and Local Distribution Adjustment Clause apply to gas sold under this rate.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which initial period it shall automatically renew itself for like one year periods thereafter unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

COMMERCIAL AND INDUSTRIAL SERVICE
(MEDIUM ANNUAL USE / LOW PEAK PERIOD USE)
RATE G-51

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - MONTHLY

Customer Charge Per Month		$78.30
Off-Peak	All therms	@ $0.1477 per therm
Peak	All therms	@ $0.2499 per therm

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage of between 5,000 and 39,999 therms and peak period usage less than 70 percent of annual use as determined by Company records and procedures.

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

COMMERCIAL AND INDUSTRIAL SERVICE
(MEDIUM ANNUAL USE / LOW PEAK PERIOD USE)
RATE G-51

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas sold under this rate.

COST OF GAS ADJUSTMENT AND LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Adjustment and Local Distribution Adjustment Clause apply to gas sold under this rate.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which initial period it shall automatically renew itself for like one year periods thereafter unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

COMMERCIAL AND INDUSTRIAL SERVICE
(MEDIUM ANNUAL USE / LOW PEAK PERIOD USE)
RATE G-51

DUAL FUEL EQUIPMENT

The rates and charges applicable under this tariff for service rendered to locations with dual fuel equipment are subject to the Special Provision for Use of Dual Fuel Equipment, M.D.P.U. No. 279, which applies to any Customer with installed dual fuel equipment capable of burning gas and another fuel.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

COMMERCIAL AND INDUSTRIAL SERVICE
(HIGH ANNUAL USE / LOW PEAK PERIOD USE)
RATE G-52

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - MONTHLY

Customer Charge Per Month		$ 290.00	
Off-Peak	All therms	@	$0.1140 per therm
Peak	All therms	@	$0.2263 per therm

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage between 40,000 and 249,999 therms and peak period usage less than 70 percent of annual use as determined by Company records and procedures. With the exception that customers whose annual use is greater than 249,999 therms, and if the Company has been unable to install an Automated Meter Reading Device, such customers also shall take service under this rate schedule.

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

COMMERCIAL AND INDUSTRIAL SERVICE
(HIGH ANNUAL USE / LOW PEAK PERIOD USE)
RATE G-52

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas sold under this rate.

COST OF GAS ADJUSTMENT AND LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Adjustment and Local Distribution Adjustment Clause apply to gas sold under this rate.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1^{st} through October 31^{st}.
Peak Period - Defined as the period from November 1^{st} through April 30^{th}.

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which initial period it shall automatically renew itself for like one year periods thereafter unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

COMMERCIAL AND INDUSTRIAL SERVICE
(HIGH ANNUAL USE / LOW PEAK PERIOD USE)
RATE G-52

DUAL FUEL EQUIPMENT

The rates and charges applicable under this tariff for service rendered to locations with dual fuel equipment are subject to the Special Provision for Use of Dual Fuel Equipment, M.D.P.U. No. 279, which applies to any Customer with installed dual fuel equipment capable of burning gas and another fuel.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

COMMERCIAL AND INDUSTRIAL SERVICE
(EXTRA HIGH ANNUAL USE / LOW PEAK PERIOD USE)
RATE G-53

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - MONTHLY

Customer Charge Per Month:			$ 1,155.90
Demand Rates:	Off-Peak	-	@ $ 0.9614 per therm of maximum daily gas usage
	Peak	-	@ $ 2.3034 per therm of maximum daily gas usage
Volumetric Rates:	Off-Peak	-	@ $ 0.0525 per therm
	Peak	-	@ $ 0.1070 per therm

CALCULATION OF DEMAND CHARGES

Demand charges shall be calculated by applying the Demand Rate to the actual measured maximum daily gas usage in the billing month.

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage of 250,000 therms or more and peak period usage less than 70 percent of annual use as determined by Company records and procedures.

COMMERCIAL AND INDUSTRIAL SERVICE
(EXTRA HIGH ANNUAL USE / LOW PEAK PERIOD USE)
RATE G-53

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas sold under this rate.

COST OF GAS ADJUSTMENT AND LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Adjustment and Local Distribution Adjustment Clause apply to gas sold under this rate.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which, it shall automatically renew itself for like one year periods thereafter, unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

COMMERCIAL AND INDUSTRIAL SERVICE
(EXTRA HIGH ANNUAL USE / LOW PEAK PERIOD USE)
RATE G-53

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

SPECIAL PROVISIONS

All customers eligible for this service class must provide and maintain a phone line for use by the Company and provide the Company with reasonable access to the meter for installation and maintenance of the Automated Meter Reading device. Customers must have Automated Meter Reading devices installed in order to receive service according to this schedule. If the Company determines that Automated Meter Reading is impractical, the customer may receive service according to Rate Schedule G-52.

DUAL FUEL EQUIPMENT

The rates and charges applicable under this tariff for service rendered to locations with dual fuel equipment are subject to the Special Provision for Use of Dual Fuel Equipment, M.D.P.U. No. 279, which applies to any Customer with installed dual fuel equipment capable of burning gas and another fuel.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

NON-HEATING FIRM TRANSPORTATION SERVICE
RESIDENTIAL RATE T-R1

AVAILABILITY

Service is available under this rate at single domestic locations throughout the territory served by the Company for transportation of supplier-owned gas used in individual private dwellings and individual apartments including condominiums and their facilities as defined in G. L. Chapter 183A, Section 1 and DPU 86-159 dated February 6, 1987.

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - BI-MONTHLY

The Bi-Monthly rate schedule applicable to all customers being served with Company meters that do not have an installed radio-based automated meter reading device is as follows:

Customer Charge Per Two Month Period			$ 24.40	
Off-Peak	-	All therms	@	$0.6638 per therm
Peak	-	All therms	@	$0.6638 per therm

RATE – MONTHLY

The Monthly rate schedule applicable to all customers being served with Company meters that have an installed radio-based automated meter reading device is as follows:

Customer Charge Per One Month Period			$ 12.20	
Off-Peak	-	All therms	@	$0.6638 per therm
Peak	-	All therms	@	$0.6638 per therm

NON-HEATING FIRM TRANSPORTATION SERVICE
RESIDENTIAL RATE T-R1

MINIMUM CHARGE

The minimum charge per month shall be the applicable bi-monthly or monthly Customer Charge.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas transported under this rate.

LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Local Distribution Adjustment Clause apply to gas transported under this rate.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

SPECIAL PROVISION

Where more than one but less than four individual apartments or dwellings are served through one meter, the billings shall be calculated as though each individual dwelling or apartment were served through a separate meter by assuming the use was divided equally among them, except that one customer charge will apply. The owner of the property or his designee will be responsible for the payment of the service. Where four or more individual apartments or dwellings are served through one meter, the billings will be calculated on the appropriate Commercial and Industrial Service Rate.

NON-HEATING FIRM TRANSPORTATION SERVICE
RESIDENTIAL RATE T-R1

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, or other arrangements between Customers and Suppliers operating pursuant to the Company's Supplier Service Agreement Terms and Conditions, are a part of this schedule.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

LOW INCOME NON-HEATING FIRM TRANSPORTATION SERVICE RESIDENTIAL RATE T-R2

AVAILABILITY

Service is available under this rate at single domestic locations throughout the territory served by the Company for transportation of supplier-owned gas used in individual private dwellings and individual apartments for all domestic purposes to persons who verify receipt of any means-tested public-benefit program or verify eligibility for the low-income home energy assistance program or its successor program, for which eligibility does not exceed 60 percent of the median income in Massachusetts based on a household's gross income or other criteria approved by the Department..

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - BI-MONTHLY

The Bi-Monthly rate schedule applicable to all customers being served with Company meters that do not have an installed radio-based automated meter reading device is as follows:

Customer Charge Per Two Month Period $ 24.40

Off-Peak	All therms	@	$0.6638 per therm
Peak	All therms	@	$0.6638 per therm

RATE – MONTHLY

The Monthly rate schedule applicable to all customers being served with Company meters that have an installed radio-based automated meter reading device is as follows:

Customer Charge Per One Month Period $ 12.20

Off-Peak	All therms	@	$0.6638 per therm
Peak	All therms	@	$0.6638 per therm

LOW INCOME NON-HEATING FIRM TRANSPORTATION SERVICE RESIDENTIAL RATE T-R2

MINIMUM CHARGE

The minimum charge per month shall be the applicable bi-monthly or monthly Customer Charge, less the application of the Low Income Discount Adjustment provided under this rate schedule.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas transported under this rate.

LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Local Distribution Adjustment Clause apply to gas transported under this rate.

LOW INCOME DISCOUNT ADJUSTMENT

The total amount resulting from the billing of all charges under this rate schedule shall be adjusted by a discount of 25.0 percent (25.0%) pursuant to D.P.U. 12-25.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

SPECIAL PROVISIONS

Where more than one but less than four individual apartments or dwellings is served through one meter, the billings shall be calculated as though each individual dwelling or apartment were served through a separate meter by assuming the use was divided equally among them, except that one customer charge will apply. The owner of the property or his designee will be

**LOW INCOME NON-HEATING FIRM TRANSPORTATION SERVICE
RESIDENTIAL RATE T-R2**

responsible for the payment of the service. Where four or more individual apartments or dwellings are served through one meter, the billings shall be calculated on the appropriate Commercial and Industrial Service Rate.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, or other arrangements between Customers and Suppliers operating pursuant to the Company's Supplier Service Agreement Terms and Conditions, are a part of this schedule.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

HEATING FIRM TRANSPORTATION SERVICE
RESIDENTIAL RATE T-R3

AVAILABILITY

Service is available under this rate at single domestic locations throughout the territory served by the Company for transportation of supplier-owned gas used in individual private dwellings and individual apartments including condominiums and their facilities as defined in G. L. Chapter 183A, Section 1 and DPU 86-159 dated February 6, 1987 where such residences are heated exclusively by means of permanently installed space heating equipment.

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - MONTHLY

Customer Charge Per Month			$ 12.20
Off-Peak	-	All therms	@ $0.4602 per therm
Peak	-	All therms	@ $0.4602 per therm

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company’s Revenue Decoupling Adjustment Clause apply to gas transported under this rate.

LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Local Distribution Adjustment Clause apply to gas transported under this rate.

HEATING FIRM TRANSPORTATION SERVICE
RESIDENTIAL RATE T-R3

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

SPECIAL PROVISION

a) Where more than one but less than four individual apartments or dwellings are served through one meter, the billings shall be calculated as though each individual dwelling or apartment were served through a separate meter by assuming the use was divided equally among them, except that one customer charge will apply. The owner of the property or his designee will be responsible for the payment of the service. Where four or more individual apartments or dwellings are served through one meter the billing shall be calculated on the appropriated Commercial and Industrial Service Rate.

b) Temporary service will be supplied, upon written application for the limited period necessary to protect and dry out unoccupied private residences under construction. Gas fired, permanently installed heating equipment of a type approved by the Company shall be the sole source of heat for the residence. The charge shall be computed in accordance with Residential Rate R-3.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, or other arrangements between Customers and Suppliers operating pursuant to the Company's Supplier Service Agreement Terms and Conditions, are a part of this schedule.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

LOW INCOME HEATING FIRM TRANSPORTATION SERVICE
RESIDENTIAL RATE T-R4

AVAILABILITY

Service is available under this rate at single domestic locations throughout the territory served by the Company to persons who verify receipt of any means-tested public-benefit program or verify eligibility for the low-income home energy assistance program or its successor program, for which eligibility does not exceed 60 percent of the median income in Massachusetts based on a household's gross income or other criteria approved by the Department, for transportation of supplier-owned gas used in individual private dwellings and individual apartments where such residences are heated exclusively by means of permanently installed space heating equipment.

CHARACTER OF SERVICE

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

RATE - MONTHLY

Customer Charge Per Month			$ 12.20
Off-Peak	All therms	@	$0.4602 per therm
Peak	All therms	@	$0.4602 per therm

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge, less the application of the Low Income Discount Adjustment provided under this rate schedule.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas transported under this rate.

LOW INCOME HEATING FIRM TRANSPORTATION SERVICE
RESIDENTIAL RATE T-R4

LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Local Distribution Adjustment Clause apply to gas transported under this rate.

LOW INCOME DISCOUNT ADJUSTMENT

The total amount resulting from the billing of all charges under this rate schedule shall be adjusted by a discount of 25.0 percent (25.0%) pursuant to D.P.U. 12-25.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

SPECIAL PROVISIONS

Where more than one but less than four individual apartments or dwellings is served through one meter, the billings shall be calculated as though each individual dwelling or apartment were served through a separate meter by assuming the use was divided equally among them, except that one customer charge will apply. The owner of the property or his designee will be responsible for the payment of the service. Where four or more individual apartments are served through one meter the billing shall be calculated on the appropriate Commercial and Industrial Service Rate, and therefore such accounts are not eligible for the Pilot Program.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, or other arrangements between Customers and Suppliers operating pursuant to the Company's Supplier Service Agreement Terms and Conditions, are a part of this schedule.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

FIRM TRANSPORTATION SERVICE
(LOW ANNUAL USE / HIGH PEAK PERIOD USE)
RATE T-40

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company for transportation of customer-owned gas used for commercial, industrial, or institutional purposes.

RATE - MONTHLY

Customer Charge Per Month			$ 19.80
Off-Peak	All therms	@	$0.4550 per therm
Peak	All therms	@	$0.4550 per therm

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage of less than 5,000 therms and peak period usage greater than or equal to 70 percent of annual use as determined by Company records and procedures.

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas throughput transported under this rate.

FIRM TRANSPORTATION SERVICE
(LOW ANNUAL USE / HIGH PEAK PERIOD USE)
RATE T-40

LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Local Distribution Adjustment Clause apply to gas throughput transported under this rate.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which initial period it shall automatically renew itself for like one year periods thereafter unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

FIRM TRANSPORTATION SERVICE
(MEDIUM ANNUAL USE / HIGH PEAK PERIOD USE)
RATE T-41

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company for transportation of customer-owned gas used for commercial, industrial, or institutional purposes.

RATE - MONTHLY

Customer Charge Per Month			$ 78.30
Off-Peak	All therms	@	$0.2707 per therm
Peak	All therms	@	$0.2707 per therm

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage of between 5,000 therms and 39,999 therms and peak period usage greater than or equal to 70 percent of annual use as determined by Company records and procedures.

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company’s Revenue Decoupling Adjustment Clause apply to gas throughput transported under this rate.

LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Local Distribution Adjustment Clause apply to gas throughput transported under this rate.

FIRM TRANSPORTATION SERVICE
(MEDIUM ANNUAL USE / HIGH PEAK PERIOD USE)
RATE T-41

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which initial period it shall automatically renew itself for like one year periods thereafter unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

DUAL FUEL EQUIPMENT

The rates and charges applicable under this tariff for service rendered to locations with dual fuel equipment are subject to the Special Provision for Use of Dual Fuel Equipment, M.D.P.U. No. 279, which applies to any Customer with installed dual fuel equipment capable of burning gas and another fuel.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

FIRM TRANSPORTATION SERVICE
(HIGH ANNUAL USE / HIGH PEAK PERIOD USE)
RATE T-42

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company for transportation of customer-owned gas used for commercial, industrial, or institutional purposes.

RATE - MONTHLY

Customer Charge Per Month			$ 290.00
Off-Peak	All therms	@	$0.1455 per therm
Peak	All therms	@	$0.2360 per therm

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage between 40,000 and 249,999 therms and peak period usage greater than or equal to 70 percent of annual use as determined by Company records and procedures.

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas throughput transported under this rate.

LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Local Distribution Adjustment Clause apply to gas throughput transported under this rate.

FIRM TRANSPORTATION SERVICE
(HIGH ANNUAL USE / HIGH PEAK PERIOD USE)
RATE T-42

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which initial period it shall automatically renew itself for like one year periods thereafter unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

DUAL FUEL EQUIPMENT

The rates and charges applicable under this tariff for service rendered to locations with dual fuel equipment are subject to the Special Provision for Use of Dual Fuel Equipment, M.D.P.U. No. 279, which applies to any Customer with installed dual fuel equipment capable of burning gas and another fuel.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

FIRM TRANSPORTATION SERVICE
(EXTRA HIGH ANNUAL USE / HIGH PEAK PERIOD USE)
RATE T-43

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company for transportation of customer-owned gas used for commercial, industrial, or institutional purposes.

RATE - MONTHLY

Customer Charge Per Month:		$1,155.90
Demand Rates:	Off-Peak	@ $ 0.9614 per therm of maximum daily gas usage
	Peak	@ $ 2.3034 per therm of maximum daily gas usage
Volumetric Rates:	Off-Peak	@ $ 0.0525 per therm
	Peak	@ $ 0.1070 per therm

CALCULATION OF DEMAND CHARGES

Demand charges shall be calculated by applying the Demand Rate to the actual measured maximum daily gas usage in the billing month.

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage of 250,000 therms or more and peak period usage greater than or equal to 70 percent of annual use as determined by Company records and procedures.

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

FIRM TRANSPORTATION SERVICE
(EXTRA HIGH ANNUAL USE / HIGH PEAK PERIOD USE)
RATE T-43

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas throughput transported under this rate.

LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Local Distribution Adjustment Clause apply to gas throughput transported under this rate.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which initial period it shall automatically renew itself for like one year periods thereafter, unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

FIRM TRANSPORTATION SERVICE
(EXTRA HIGH ANNUAL USE / HIGH PEAK PERIOD USE)
RATE T-43

SPECIAL PROVISIONS

All customers eligible for this service class must provide and maintain a phone line for use by the Company and provide the Company with reasonable access to the meter for installation and maintenance of the Automated Meter Reading device. Customers must have Automated Meter Reading devices installed in order to receive service according to this schedule.

DUAL FUEL EQUIPMENT

The rates and charges applicable under this tariff for service rendered to locations with dual fuel equipment are subject to the Special Provision for Use of Dual Fuel Equipment, M.D.P.U. No. 279, which applies to any Customer with installed dual fuel equipment capable of burning gas and another fuel.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

FIRM TRANSPORTATION SERVICE
(LOW ANNUAL USE / LOW PEAK PERID USE)
RATE T-50

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company for transportation of customer-owned gas used for commercial, industrial, or institutional purposes.

RATE - MONTHLY

Customer Charge Per Month		$ 19.80	
Off-Peak	All therms	@	$0.4337 per therm
Peak	All therms	@	$0.4337 per therm

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage of less than 5,000 therms and peak period usage less than 70 percent of annual use as determined by Company records and procedures.

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas throughput transported under this rate.

FIRM TRANSPORTATION SERVICE
(LOW ANNUAL USE / LOW PEAK PERID USE)
RATE T-50

LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Local Distribution Adjustment Clause apply to gas throughput transported under this rate.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1^{st} through October 31^{st}.
Peak Period - Defined as being the period November 1^{st} through April 30^{th}

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which initial period it shall automatically renew itself for like one year periods thereafter unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

FIRM TRANSPORTATION SERVICE
(MEDIUM ANNUAL USE / LOW PEAK PERIOD USE)
RATE T-51

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company for transportation of customer-owned gas used for commercial, industrial, or institutional purposes.

RATE - MONTHLY

Customer Charge Per Month		$ 78.30	
Off-Peak	All therms	@	$0.1477 per therm
Peak	All therms	@	$0.2499 per therm

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage of between 5,000 therms and 39,999 therms and peak period usage less than 70 percent of annual use as determined by Company records and procedures.

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company’s Revenue Decoupling Adjustment Clause apply to gas throughput transported under this rate.

LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Local Distribution Adjustment Clause apply to gas throughput transported under this rate.

FIRM TRANSPORTATION SERVICE
(MEDIUM ANNUAL USE / LOW PEAK PERIOD USE)
RATE T-51

DEFINITIONS

Off-Peak Period - Defined as the period from May 1^{st} through October 31^{st}.
Peak Period - Defined as the period from November 1^{st} through April 30^{th}.

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which initial period it shall automatically renew itself for like one year periods thereafter unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

DUAL FUEL EQUIPMENT

The rates and charges applicable under this tariff for service rendered to locations with dual fuel equipment are subject to the Special Provision for Use of Dual Fuel Equipment, M.D.P.U. No. 279, which applies to any Customer with installed dual fuel equipment capable of burning gas and another fuel.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

FIRM TRANSPORTATION SERVICE
(HIGH ANNUAL USE / LOW PEAK PERIOD USE)
RATE T-52

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company for transportation of customer-owned gas used for commercial, industrial, or institutional purposes.

RATE - MONTHLY

Customer Charge Per Month			$ 290.00
Off-Peak	All therms	@	$0.1140 per therm
Peak	All therms	@	$0.2263 per therm

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage between 40,000 and 249,999 therms and peak period usage less than 70 percent of annual use as determined by Company records and procedures.

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company’s Revenue Decoupling Adjustment Clause apply to gas throughput transported under this rate.

LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Local Distribution Adjustment Clause apply to gas throughput transported under this rate.

FIRM TRANSPORTATION SERVICE
(HIGH ANNUAL USE / LOW PEAK PERIOD USE)
RATE T-52

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which initial period it shall automatically renew itself for like one year periods thereafter unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

DUAL FUEL EQUIPMENT

The rates and charges applicable under this tariff for service rendered to locations with dual fuel equipment are subject to the Special Provision for Use of Dual Fuel Equipment, M.D.P.U. No. 279, which applies to any Customer with installed dual fuel equipment capable of burning gas and another fuel.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

FIRM TRANSPORTATION SERVICE
(EXTRA HIGH ANNUAL USE / LOW PEAK PERIOD USE)
RATE T-53

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company for transportation of customer-owned gas used for commercial, industrial, or institutional purposes.

RATE - MONTHLY

Customer Charge Per Month:			$ 1,155.90
Demand Rates:	Off-Peak	-	@ $ 0.9614 per therm of maximum daily gas usage
	Peak	-	@ $ 2.3034 per therm of maximum daily gas usage
Volumetric Rates:	Off-Peak	-	@ $ 0.0525 per therm
	Peak	-	@ $ 0.1070 per therm

CALCULATION OF DEMAND CHARGES

Demand charges shall be calculated by applying the Demand Rate to the actual measured maximum daily gas usage in the billing month.

CHARACTERISTICS OF CUSTOMER

A customer receiving service under this schedule must have annual usage of 250,000 therms or more and peak period usage less than 70 percent of annual use as determined by Company records and procedures.

MINIMUM CHARGE

The minimum charge per month shall be the monthly Customer Charge.

FIRM TRANSPORTATION SERVICE
(EXTRA HIGH ANNUAL USE / LOW PEAK PERIOD USE)
RATE T-53

REVENUE DECOUPLING ADJUSTMENT CLAUSE

The provisions of the Company's Revenue Decoupling Adjustment Clause apply to gas throughput transported under this rate.

LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

The provisions of the Company's Local Distribution Adjustment Clause apply to gas throughput transported under this rate.

DEFINITIONS

Off-Peak Period - Defined as the period from May 1st through October 31st.
Peak Period - Defined as the period from November 1st through April 30th.

PAYMENT

Bills are net and payable upon presentation.

TERM OF CONTRACT

The term of contract under this schedule shall be for an initial period of at least one year, at the expiration of which initial period it shall automatically renew itself for like one year periods thereafter, unless terminated by either party giving to the other notice in writing 30 days prior to the expiration of any contract year.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this schedule.

FIRM TRANSPORTATION SERVICE
(EXTRA HIGH ANNUAL USE / LOW PEAK PERIOD USE)
RATE T-53

SPECIAL PROVISIONS

All customers eligible for this service class must provide and maintain a phone line for use by the Company and provide the Company with reasonable access to the meter for installation and maintenance of the Automated Meter Reading device. Customers must have Automated Meter Reading devices installed in order to receive service according to this schedule.

DUAL FUEL EQUIPMENT

The rates and charges applicable under this tariff for service rendered to locations with dual fuel equipment are subject to the Special Provision for Use of Dual Fuel Equipment, M.D.P.U. No. 279, which applies to any Customer with installed dual fuel equipment capable of burning gas and another fuel.

FARM DISCOUNT

All charges under this tariff are subject to a ten percent (10%) discount for customers who are certified as eligible by the Massachusetts Department of Food and Agriculture.

EXPENDITURES FOR CERTAIN CIVIC, POLITICAL AND RELATED ACTIVITIES

(Account 426.4)

1. Report below all expenditures incurred by the respondent during the year for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation or ordinances (either with respect to the possible adoption of referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances); approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials which are accounted for as Other Income Deductions, Expenditures for Certain Civic, Political and Related Activities; Account 426.4.

2. Advertising expenditures in this Account shall be classified according to subheadings, as follows: (a) radio, television, and motion picture advertising; (b) newspaper, magazine, and pamphlet advertising; (c) letters or inserts in customers' bills; (d) inserts in reports to stockholders; (e) newspaper and magazine editorial services; and (f) other advertising.

3. Expenditures within the definition of paragraph (1), other than advertising shall be reported according to captions or descriptions, clearly indicating the nature and purpose of the activity.

4. If respondent has not incurred any expenditures contemplated by the instructions of Account 426.4, so state.

5. For reporting years which begin during the calendar year 1963 only, minor amounts may be grouped by classes if the number of items so grouped is shown.

Note: The classification of expenses as nonoperating and their inclusion in this account is for accounting purposes. It does not preclude Commission consideration of proof to the contrary for ratemaking or other purposes.

Line No.	Item (a)	Amount (b)
1	Consulting Fees	$ 168,325
2	Other Civic, Political and Related Activities	1,178
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4		
5		
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32		
33	TOTAL	$ 169,503

913. ADVERTISING EXPENSES.

Line No.	Type (a)	General Description (b)	Amount for year (c)
1			
2	Miscellaneous Advertising	Marketing brochures, advertising rebates,	$
3		newsletters and other expenses	96,962
4			
5			
6			
7			
8			
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49		TOTAL	$ 96,962

DEPOSITS AND COLLATERAL

Statement of money and the value of any collateral held as guaranty for the payment of charges pursuant to Massachusetts General Laws, Chapter 164, Section 128.

	Town		Deposit
1	Brockton Division		$ 1,857,134
2	Lawrence Division		468,004
3	Springfield Division		932,039
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49		TOTAL	$ 3,257,177

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THIS RETURN IS SIGNED UNDER THE PENALITIES OF PERJURY

Mark Kempic .... Mark Kempic, President & Director

Said directors constitute a majority of the directors of Bay State Gas Company in accordance with M.G.L.ch 164 § 83.

SIGNATURES OF THE ABOVE PARTIES AFFIXED OUTSIDE THE COMMONWEALTH OF MASSACHUSETTS MUST BE PROPERLY SWORN TO

State of Ohio)
) ***ss:***
County of Franklin)

Before me the undersigned notary public, this day, personally appeared Mark Kempic, President & Director; and made oath to the truth of the foregoing statement by him subscribed according to his best knowledge and belief.

Subscribed and sworn to before me this __________ day of March, 2020.

____
Notary Public

THIS RETURN IS SIGNED UNDER THE PENALITIES OF PERJURY

Martin G Poulin .... Martin G. Poulin, Vice President, General Manager & Director

Said directors constitute a majority of the directors of Bay State Gas Company in accordance with M.G.L.ch 164 § 83.

SIGNATURES OF THE ABOVE PARTIES AFFIXED OUTSIDE THE COMMONWEALTH OF MASSACHUSETTS MUST BE PROPERLY SWORN TO

State of Ohio)
) ***ss:***
County of Franklin)

Before me the undersigned notary public, this day, personally appeared Martin G. Poulin, Vice President, General Manager & Director; and made oath to the truth of the foregoing statement by him subscribed according to his best knowledge and belief.

Subscribed and sworn to before me this __________ day of March, 2020.

____
Notary Public

THIS RETURN IS SIGNED UNDER THE PENALITIES OF PERJURY

.... Randy G. Hulen, Vice President & Treasurer

Said directors constitute a majority of the directors of Bay State Gas Company in accordance with M.G.L.ch 164 § 83.

SIGNATURES OF THE ABOVE PARTIES AFFIXED OUTSIDE THE COMMONWEALTH OF MASSACHUSETTS MUST BE PROPERLY SWORN TO

State of Indiana)
) ***ss:***
County of Porter)

Before me the undersigned notary public, this day, personally appeared Randy G. Hulen, Vice President & Treasurer; and made oath to the truth of the foregoing statement by him subscribed according to his best knowledge and belief.

Subscribed and sworn to before me this 17 *day of March, 2020.*

KATHLEEN ANN SIMPSON
Notary Public, State of Indiana
Porter County
Commission Number NPO714576
My Commission Expires
June 21, 2026
NOTARY PUBLIC SEAL INDIANA

Notary Public

State of Indiana)
) ***ss:***
County of Porter)

Before me the undersigned notary public, this day, personally appeared and made oath to the truth of the foregoing statement by him subscribed according to his best knowledge and belief.

Subscribed and sworn to before me this ________ day of March, 2020.

Notary Public

THIS RETURN IS SIGNED UNDER THE PENALITIES OF PERJURY

Joseph W. Mulpas ....Joseph W. Mulpas, Vice President, Chief Accounting Officer, & Controller

Said directors constitute a majority of the directors of Bay State Gas Company in accordance with M.G.L.ch 164 § 83.

SIGNATURES OF THE ABOVE PARTIES AFFIXED OUTSIDE THE COMMONWEALTH OF MASSACHUSETTS MUST BE PROPERLY SWORN TO

State of Ohio)
) *ss:*
County of Franklin)

Before me the undersigned notary public, this day, personally appeared Joseph W. Mulpas, Vice President, Chief Accounting Officer, & Controller; and made oath to the truth of the foregoing statement by him subscribed according to his best knowledge and belief.

Subscribed and sworn to before me this 23 *day of March, 2020.*

Mary E Traetow
Notary Public

NOTARIAL SEAL STATE OF OHIO

Mary E Traetow
Notary Public, State of Ohio
My Commission Expires 10-27-2024

State of Ohio)
) *ss:*
County of Franklin)

Before me the undersigned notary public, this day, personally appeared ; and made oath to the truth of the foregoing statement by him subscribed according to his best knowledge and belief.

Subscribed and sworn to before me this __________ day of March, 2020.

____
Notary Public

Columbia Gas of Massachusetts
A NiSource Company

Mark Kempic
President and COO

4 Technology Drive, Suite 250
Westborough, MA 01581
(508) 836-7320
Cellular: (412) 719-7714
mkempic@nisource.com

June 24, 2020

Kerri DeYoung Phillips, Esq.
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: Bay State Gas Company d/b/a Columbia Gas of Massachusetts - Annual Return for Year Ending 12-31-19 – ROE Schedule

Dear Ms. Phillips:

On March 31, 2020, Columbia Gas of Massachusetts ("CMA" or "Company") submitted its calendar year ("CY") 2019 annual return. CMA excluded the return on equity ("ROE") schedule from the filing as it was unusual and unrepresentative. On June 9, 2020, the Department requested CMA to submit this schedule by no later than Wednesday, June 24, 2020.

Enclosed is the Company's ROE schedule for CY 2019. The resulting ROE is unusual due to the ongoing impacts of the Merrimack Valley event and the write-off of goodwill as of December 31, 2019. Also, the total Utility Operating Income is higher than normal due to the recording of insurance recoveries related to the Merrimack Valley events as credits to operations and maintenance expense. Goodwill is an intangible asset that was recorded on the Company's books as part of the purchase price allocations relating to the acquisition of Bay State Gas Company by NIPSCO Industries Inc. in 1999. Under generally accepted accounting principles, an intangible asset, such as acquisition-related goodwill, is reviewed for impairment when events or changes in circumstances indicate the fair value might be below its carrying value. During CY 2019, the remaining balance of the merger-related goodwill was written off because the year-end impairment analysis indicated the fair value of the CMA asset group was below its carrying value. The Average Equity Balance is lower than normal due to ongoing impacts of the Merrimack Valley event recorded in CY 2018 and CY 2019, the goodwill write-off and other smaller items. Collectively, these factors produced the reported ROE for CY 2019.

If you have any questions with respect to this filing, please contact me. Thank you for your attention to this matter.

Sincerely,

Mark Kempic

Mark Kempic

cc: Mark D. Marini, Secretary
Emily Luksha, Director, Rates and Revenue Requirements Division
George Yiankos, Director, Natural Gas Division
Nathan Forster, Esq., Office of the Attorney General

Columbia Gas of Massachusetts
Return on Equity
For the Twelve Months Ended December 31, 2019

Ln. No.	Item (1)			Detail (2)	Total (3)
1	**Net Utility Income Available for Common Shareholders**				
2	Total Utility Operating Income - Annual Return - Pg. 10, Ln 18				$ 240,407,279
3	Plus:				
4	Amortization of Acquisition Premium			$ 220,705,350	
5	Service Quality Penalties			-	
6	Total			$ 220,705,350	
7	Income Taxes on amortization			$ 60,296,702	
8	Net Additions to Utility Operating Income (Ln. 6 - Ln. 7)				$ 160,408,648
9	Less:				
10	Total Interest Charges - Annual Return - Pg. 10, Ln. 39			$ 42,966,865	
11	Dividends Declared - Preferred Stock			-	
12	Total			$ 42,966,865	
13	Utility Ratio (See Ln. 35 below)			99.89%	
14	Utility Interest Charges (Ln. 12 * Ln. 13)			$ 42,919,601	
15	Income taxes on difference (Ln. 12 - Ln. 14) * 0.2732			$ 12,913	
16	Net Utility Interest Charges (Ln. 14 + Ln. 15)				$ 42,932,514
17	**Net Utility Income (Ln.2 + Ln.8 - Ln. 16)**				$ 357,883,413
18	**Total Utility Common Equity**				
19	Total Proprietary Capital - Annual Return - Pg. 9, Ln. 13				
20	Balance Beginning of Year - Column (b)				$ (4,342,719)
21	Balance End of Year - Column (c)				$ 107,111,081
22	Average (Ln. 20 + Ln 21)/2				$ 51,384,181
23	Less:		**Beginning Year**	**Ending Year**	
24	Average Preferred stock - Annual Return - Pg. 9, Ln. 4				-
25	Average Unamortized Acquisition Premium net of deferred income taxes				$ 80,204,324
26	Average Investments in Subsidiary Companies-Annual Return-Pg8, Ln.5		$ -	$ -	$ -
27	Total Average Common Equity (Ln. 22 - Lns. 24, 25 and 26)				$ (28,820,143)
28	Utility Ratio (See Ln. 35 below)				99.89%
29	**Total Average Utility Common Equity (Ln. 27 * Ln. 28)**				$ (28,788,441)
30	**Return on Equity (Ln. 17/Ln. 29)**				-1243.15%
31	**Utility Ratio:**	**Total**	**Less Acquisition Premium & Invest. In Subs.**	**Net**	
32	Utility Plant - Annual Return - Pg. 8, Ln. 2	$ 2,515,218,676	$ (442,163,257)	$ 2,073,055,419	
33	Total Other Property & Investment - Annual Return - Pg 8, Ln. 8	$ 2,376,188	$ -	$ 2,376,188	
34	Total	$ 2,517,594,864		$ 2,075,431,607	
35	**Utility Ratio (Ln. 32/ Ln. 34)**				99.89%

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)**
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2019
OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)**
OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______ to ______

Commission file number 001-16189

NiSource Inc.
(Exact name of registrant as specified in its charter)

DE	35-2108964
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
801 East 86th Avenue Merrillville, IN	46410
(Address of principal executive offices)	(Zip Code)

(877) 647-5990
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	NI	NYSE
Depositary Shares, each representing a 1/1,000th ownership interest in a share of 6.50% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock, par value $0.01 per share, liquidation preference $25,000 per share and a 1/1,000th ownership interest in a share of Series B-1 Preferred Stock, par value $0.01 per share, liquidation preference $0.01 per share	NI PR B	NYSE

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).
Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definition of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12-b-2 of the Exchange Act.

Large Accelerated Filer ☑ Accelerated Filer ☐ Emerging Growth Company ☐ Non-accelerated Filer ☐ Smaller Reporting Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the registrant's common stock, par value $0.01 per share (the "Common Stock") held by non-affiliates was approximately $10,713,311,150 based upon the June 28, 2019, closing price of $28.80 on the New York Stock Exchange.

There were 382,263,348 shares of Common Stock outstanding as of February 18, 2020.

Documents Incorporated by Reference

Part III of this report incorporates by reference specific portions of the Registrant's Notice of Annual Meeting and Proxy Statement relating to the Annual Meeting of Stockholders to be held on May 19, 2020.

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DEFINED TERMS

The following is a list of abbreviations or acronyms that are used in this report:

NiSource Subsidiaries, Affiliates and Former Subsidiaries	
Columbia of Kentucky	Columbia Gas of Kentucky, Inc.
Columbia of Maryland	Columbia Gas of Maryland, Inc.
Columbia of Massachusetts	Bay State Gas Company
Columbia of Ohio	Columbia Gas of Ohio, Inc.
Columbia of Pennsylvania	Columbia Gas of Pennsylvania, Inc.
Columbia of Virginia	Columbia Gas of Virginia, Inc.
Company	NiSource Inc. and its subsidiaries, unless otherwise indicated by the context
CPG (former subsidiary)	Columbia Pipeline Group, Inc.
NIPSCO	Northern Indiana Public Service Company LLC
NiSource ("we," "us" or "our")	NiSource Inc.
NiSource Corporate Services	NiSource Corporate Services Company
Abbreviations	
ACE	Affordable clean energy
AFUDC	Allowance for funds used during construction
AMR	Automatic meter reading
AMRP	Accelerated Main Replacement Program
AMT	Alternative Minimum Tax
AOCI	Accumulated Other Comprehensive Income
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
ATM	At-the-market
Board	Board of Directors
BTA	Build-transfer agreement
CAP	Compliance Assurance Process
CCGT	Combined Cycle Gas Turbine
CCRs	Coal Combustion Residuals
CEP	Capital Expenditure Program
CERCLA	Comprehensive Environmental Response Compensation and Liability Act (also known as Superfund)
DPA	Deferred prosecution agreement
DPU	Department of Public Utilities
DSIC	Distribution System Investment Charge
DSM	Demand Side Management
ECT	Environmental Cost Tracker
EERM	Environmental Expense Recovery Mechanism
ELG	Effluent Limitation Guidelines
EPA	United States Environmental Protection Agency
EPS	Earnings per share
FAC	Fuel adjustment clause
FASB	Financial Accounting Standards Board

DEFINED TERMS

FERC	Federal Energy Regulatory Commission
FMCA	Federally Mandated Cost Adjustment
GAAP	Generally Accepted Accounting Principles
GCA	Gas cost adjustment
GCR	Gas cost recovery
GHG	Greenhouse gas
GSEP	Gas System Enhancement Program
GWh	Gigawatt hours
IRIS	Infrastructure Replacement and Improvement Surcharge
IRP	Infrastructure Replacement Program
IRS	Internal Revenue Service
IURC	Indiana Utility Regulatory Commission
LDCs	Local distribution companies
LIBOR	London inter-bank offered rate
LIFO	Last-in, first-out
MA DOR	Massachusetts Department of Revenue
Massachusetts Business	All of the assets being sold to, and liabilities being assumed by, Eversource pursuant to the Asset Purchase Agreement
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator
MMDth	Million dekatherms
MW	Megawatts
MWh	Megawatt hours
NOL	Net Operating Loss
NTSB	National Transportation Safety Board
NYMEX	The New York Mercantile Exchange
NYSE	The New York Stock Exchange
OPEB	Other Postretirement and Postemployment Benefits
PCB	Polychlorinated biphenyls
PHMSA	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration
PISCC	Post-in-service carrying charges
PPA	Power Purchase Agreement
PSC	Public Service Commission
PTC	Production Tax Credits
PUC	Public Utility Commission
PUCO	Public Utilities Commission of Ohio
RCRA	Resource Conservation and Recovery Act
ROU	Right of use
SAB	Staff accounting bulletin
SAVE	Steps to Advance Virginia's Energy Plan
Separation	The separation of our natural gas pipeline, midstream and storage business from our natural gas and electric utility business accomplished through a pro rata distribution to holders of our outstanding common stock of all the outstanding shares of common stock of CPG. The separation was completed on July 1, 2015.
SEC	Securities and Exchange Commission

DEFINED TERMS

SMRP	Safety Modification and Replacement Program
STRIDE	Strategic Infrastructure Development and Enhancement
Sugar Creek	Sugar Creek electric generating plant
TCJA	Tax Cuts and Jobs Act of 2017
TDSIC	Transmission, Distribution and Storage System Improvement Charge
U.S. Attorney's Office	U.S. Attorney's Office for the District of Massachusetts
VSCC	Virginia State Corporation Commission
WCE	Whiting Clean Energy

Note regarding forward-looking statements

This Annual Report on Form 10-K contains “forward-looking statements,” within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Investors and prospective investors should understand that many factors govern whether any forward-looking statement contained herein will be or can be realized. Any one of those factors could cause actual results to differ materially from those projected. These forward-looking statements include, but are not limited to, statements concerning our plans, strategies, objectives, expected performance, expenditures, recovery of expenditures through rates, stated on either a consolidated or segment basis, and any and all underlying assumptions and other statements that are other than statements of historical fact. All forward-looking statements are based on assumptions that management believes to be reasonable; however, there can be no assurance that actual results will not differ materially.

Factors that could cause actual results to differ materially from the projections, forecasts, estimates and expectations discussed in this Annual Report on Form 10-K include, among other things, our debt obligations; any changes to our credit rating or the credit rating of certain of our subsidiaries; our ability to execute our growth strategy; changes in general economic, capital and commodity market conditions; pension funding obligations; economic regulation and the impact of regulatory rate reviews; our ability to obtain expected financial or regulatory outcomes; our ability to adapt to, and manage costs related to, advances in technology; any changes in our assumptions regarding the financial implications of the Greater Lawrence Incident; compliance with the agreements entered into with the U.S. Attorney’s Office to settle the U.S. Attorney’s Office’s investigation relating to the Greater Lawrence Incident; the pending sale of the Columbia of Massachusetts business, including the terms and closing conditions under the Asset Purchase Agreement; potential incidents and other operating risks associated with our business; our ability to obtain sufficient insurance coverage and whether such coverage will protect us against significant losses; the outcome of legal and regulatory proceedings, investigations, incidents, claims and litigation; any damage to our reputation, including in connection with the Greater Lawrence Incident; compliance with applicable laws, regulations and tariffs; compliance with environmental laws and the costs of associated liabilities; fluctuations in demand from residential and commercial customers; economic conditions of certain industries; the success of NIPSCO's electric generation strategy; the price of energy commodities and related transportation costs; the reliability of customers and suppliers to fulfill their payment and contractual obligations; potential impairments of goodwill or definite-lived intangible assets; changes in taxation and accounting principles; the impact of an aging infrastructure; the impact of climate change; potential cyber-attacks; construction risks and natural gas costs and supply risks; extreme weather conditions; the attraction and retention of a qualified workforce; the ability of our subsidiaries to generate cash; our ability to manage new initiatives and organizational changes; the performance of third-party suppliers and service providers; changes in the method for determining LIBOR and the potential replacement of the LIBOR benchmark interest rate; and other matters set forth in Item 1A, “Risk Factors” of this report, many of which risks are beyond our control. In addition, the relative contributions to profitability by each business segment, and the assumptions underlying the forward-looking statements relating thereto, may change over time.

All forward-looking statements are expressly qualified in their entirety by the foregoing cautionary statements. We undertake no obligation to, and expressly disclaim any such obligation to, update or revise any forward-looking statements to reflect changed assumptions, the occurrence of anticipated or unanticipated events or changes to the future results over time or otherwise, except as required by law.

ITEM 1. BUSINESS

NiSource Inc.

NiSource Inc. is an energy holding company under the Public Utility Holding Company Act of 2005 whose subsidiaries are fully regulated natural gas and electric utility companies serving approximately 4.0 million customers in seven states. NiSource is the successor to an Indiana corporation organized in 1987 under the name of NIPSCO Industries, Inc., which changed its name to NiSource on April 14, 1999.

NiSource is one of the nation’s largest natural gas distribution companies, as measured by number of customers. NiSource’s principal subsidiaries include NiSource Gas Distribution Group, Inc., a natural gas distribution holding company, and NIPSCO, a gas and electric company. NiSource derives substantially all of its revenues and earnings from the operating results of these rate-regulated businesses.

On September 13, 2018, a series of fires and explosions occurred in Lawrence, Andover and North Andover, Massachusetts related to the delivery of natural gas by Columbia of Massachusetts (referred to herein as the “Greater Lawrence Incident”). The Greater Lawrence Incident resulted in one fatality and a number of injuries, damaged multiple homes and businesses, and caused the temporary evacuation of significant portions of each municipality. The Massachusetts Governor’s Office declared a state of emergency, authorizing the Massachusetts DPU to order another utility company to coordinate the restoration of utility services in Lawrence, Andover and North Andover. The incident resulted in the interruption of gas for approximately 7,500 gas meters, the majority of which served residences and approximately 700 of which served businesses, and the interruption of other utility service more broadly in the area. Columbia of Massachusetts has replaced the cast iron and bare steel gas pipeline system in the affected area and restored service to nearly all of the gas meters. Refer to Note 6, "Goodwill and Other Intangible Assets," Note 19-C. "Legal Proceedings," and E. "Other Matters," in the Notes to Consolidated Financial Statements for more information.

On February 26, 2020, NiSource and Columbia of Massachusetts (together with NiSource, “Seller”) entered into an Asset Purchase Agreement (the "Asset Purchase Agreement") with Eversource, a Massachusetts voluntary association. Upon the terms and subject to the conditions set forth in the Asset Purchase Agreement, NiSource and Columbia of Massachusetts agreed to sell to Eversource, with certain additions and exceptions: (1) substantially all of the assets of Columbia of Massachusetts and (2) all of the assets held by any of Columbia of Massachusetts’ affiliates that primarily relate to the business of storing, distributing or transporting natural gas to residential, commercial and industrial customers in Massachusetts, as conducted by Columbia of Massachusetts, and Eversource agreed to assume certain liabilities of Columbia of Massachusetts and its affiliates. The liabilities assumed by Eversource under the Asset Purchase Agreement do not include, among others, any liabilities arising out the Greater Lawrence Incident or liabilities of Columbia of Massachusetts or its affiliates pursuant to civil claims for injury of persons or damage to property to the extent such injury or damage occurs prior to the closing in connection with the Massachusetts Business. The Asset Purchase Agreement provides for a purchase price of $1,100 million in cash, subject to adjustment based on Columbia of Massachusetts’ net working capital as of the closing. The closing of the transactions contemplated by the Asset Purchase Agreement is subject to Hart-Scott-Rodino Antitrust Improvements Act of 1976 and regulatory approvals, resolution of certain proceedings before governmental bodies and other conditions. For additional information, see Note 26, “Subsequent Event,” in the Notes to Consolidated Financial Statements.

NiSource’s reportable segments are: Gas Distribution Operations and Electric Operations. The following is a summary of the business for each reporting segment. Refer to Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Note 23, "Segments of Business," in the Notes to Consolidated Financial Statements for additional information for each segment.

Gas Distribution Operations

Our natural gas distribution operations serve approximately 3.5 million customers in seven states and operate approximately 60,000 miles of pipeline located in our service areas described below. Through our wholly-owned subsidiary NiSource Gas Distribution Group, Inc., we own six distribution subsidiaries that provide natural gas to approximately 2.7 million residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, Maryland and Massachusetts. Additionally, we distribute natural gas to approximately 839,000 customers in northern Indiana through our wholly-owned subsidiary NIPSCO.

Electric Operations

We generate, transmit and distribute electricity through our subsidiary NIPSCO to approximately 476,000 customers in 20 counties in the northern part of Indiana and engage in wholesale and transmission transactions. NIPSCO owns and operates two coal-fired electric generating stations: four units at R.M. Schahfer located in Wheatfield, IN and one unit at Michigan City located in Michigan City, IN. The two operating facilities have a generating capacity of 2,080 MW. NIPSCO also owns and operates Sugar Creek, a CCGT plant located in West Terre Haute, IN with generating capacity of 571 MW, three gas-fired generating units located at NIPSCO’s coal-fired electric generating stations with a generating capacity of 186 MW and two hydroelectric generating plants with a generating capacity of 10 MW: Oakdale located at Lake Freeman in Carroll County, IN and Norway located at Lake Schahfer in White County, IN. These facilities provide for a total system operating generating capacity of 2,847 MW.

ITEM 1. BUSINESS

NISOURCE INC.

In May 2018, NIPSCO completed the retirement of two coal-burning units (Units 7 and 8) at Bailly Generating Station, located in Chesterton, IN. These units had a generating capacity of approximately 460 MW.

NIPSCO’s transmission system, with voltages from 69,000 to 765,000 volts, consists of 3,005 circuit miles. NIPSCO is interconnected with five neighboring electric utilities. During the year ended December 31, 2019, NIPSCO generated 62.4% and purchased 37.6% of its electric requirements.

NIPSCO participates in the MISO transmission service and wholesale energy market. MISO is a nonprofit organization created in compliance with FERC regulations to improve the flow of electricity in the regional marketplace and to enhance electric reliability. Additionally, MISO is responsible for managing energy markets, transmission constraints and the day-ahead, real-time, FTR and ancillary markets. NIPSCO transferred functional control of its electric transmission assets to MISO, and transmission service for NIPSCO occurs under the MISO Open Access Transmission Tariff.

Business Strategy

We focus our business strategy on our core, rate-regulated asset-based businesses with most of our operating income generated from the rate-regulated businesses. Our utilities continue to move forward on core infrastructure and environmental investment programs supported by complementary regulatory and customer initiatives across all seven states in which we operate. Our goal is to develop strategies that benefit all stakeholders as we address changing customer conservation patterns, develop more contemporary pricing structures, and embark on long-term investment programs. These strategies are intended to improve reliability and safety, enhance customer service and reduce emissions while generating sustainable returns.

In its 2018 Integrated Resource Plan submission to the IURC, NIPSCO laid out a plan to retire the R.M. Schahfer Generating Station (Units 14, 15, 17, and 18) by 2023 and Michigan City Generating Station (Unit 12) by 2028. These units represent 2,080 MW of generating capacity, equal to 72% of NIPSCO’s remaining capacity after the retirement of Bailly Units 7 and 8 in May of 2018. The current replacement plan includes renewable sources of energy, including wind, solar, and battery storage to be obtained through a combination of NIPSCO ownership and PPAs. Refer to Note 19-E, "Other Matters," in the Notes to Consolidated Financial Statements for further discussion of these plans.

Competition and Changes in the Regulatory Environment

The regulatory frameworks applicable to our operations, at both the state and federal levels, continue to evolve. These changes have had and will continue to have an impact on our operations, structure and profitability. Management continually seeks new ways to be more competitive and profitable in this environment.

The Gas Distribution Operations companies have pursued non-traditional revenue sources within the evolving natural gas marketplace. These efforts include the sale of products and services upstream of the companies’ service territory, the sale of products and services in the companies’ service territories, and gas supply cost incentive mechanisms for service to their core markets. The upstream products are made up of transactions that occur between an individual Gas Distribution Operations company and a buyer for the sales of unbundled or rebundled gas supply and capacity. The on-system services are offered by us to customers and include products such as the transportation and balancing of gas on the Gas Distribution Operations company system. The incentive mechanisms give the Gas Distribution Operations companies an opportunity to share in the savings created from such situations as gas purchase prices paid below an agreed upon benchmark and their ability to reduce pipeline capacity charges with their customers.

Increased efficiency of natural gas appliances and improvements in home building codes and standards has contributed to a long-term trend of declining average use per customer. Residential usage for the year ended December 31, 2019 decreased primarily due to warmer weather in our operating area compared to the prior year. While historically rate design at the distribution level has been structured such that a large portion of cost recovery is based upon throughput rather than in a fixed charge, operating costs are largely incurred on a fixed basis and do not fluctuate due to changes in customer usage. As a result, Gas Distribution Operations have pursued changes in rate design to more effectively match recoveries with costs incurred. Each of the states in which Gas Distribution Operations operate has different requirements regarding the procedure for establishing changes to rate design. Columbia of Ohio restructured its rate design through a base rate proceeding and has adopted a decoupled rate design which more closely links the recovery of fixed costs with fixed charges. Columbia of Massachusetts received regulatory approval of a decoupling mechanism which adjusts revenues to an approved benchmark level through a volumetric adjustment factor. Columbia of Maryland and Columbia of Virginia have regulatory approval for a revenue normalization adjustment for certain customer classes, a decoupling mechanism whereby monthly revenues that exceed or fall short of approved levels are reconciled in subsequent months. In a prior base rate proceeding, Columbia of Pennsylvania implemented a pilot residential weather normalization adjustment. Columbia of Maryland, Columbia of Virginia and Columbia of Kentucky have had approval for a weather normalization adjustment for many years. In a prior gas base rate proceeding, NIPSCO implemented a higher fixed customer charge for residential and small customer classes moving toward full straight fixed variable rate design.

Natural Gas Competition. Open access to natural gas supplies over interstate pipelines and the deregulation of the commodity price of gas has led to tremendous change in the energy markets. LDC customers and marketers can purchase gas directly from producers and marketers as an open, competitive market for gas supplies has emerged. This separation or “unbundling” of the transportation and other services offered by pipelines and LDCs allows customers to purchase the commodity independent of services provided by the pipelines and LDCs. The LDCs continue to purchase gas and recover the associated costs from their customers. Our Gas Distribution Operations’ subsidiaries are involved in programs that provide customers the opportunity to purchase their natural gas requirements from third parties and use our Gas Distribution Operations’ subsidiaries for transportation services.

Gas Distribution Operations competes with investor-owned, municipal, and cooperative electric utilities throughout its service areas as well as other regulated and unregulated natural gas intra and interstate pipelines and other alternate fuels, such as propane and fuel oil. Gas Distribution Operations continues to be a strong competitor in the energy market as a result of strong customer preference for natural gas. Competition with providers of electricity has traditionally been the strongest in the residential and commercial markets of Kentucky, southern Ohio, central Pennsylvania and western Virginia due to comparatively low electric rates. Natural gas competes with fuel oil and propane in the Massachusetts market mainly due to the installed base of fuel oil and propane-based heating which has comprised a declining percentage of the overall market over the last few years. However, fuel oil and propane are more viable in today’s oil market.

Electric Competition. Indiana electric utilities generally have exclusive service areas under Indiana regulations, and retail electric customers in Indiana do not have the ability to choose their electric supplier. NIPSCO faces non-utility competition from other energy sources, such as self-generation by large industrial customers and other distributed energy sources.

Seasonality

A significant portion of our operations are subject to seasonal fluctuations in sales. During the heating season, which is primarily from November through March, revenues from gas sales are more significant, and during the cooling season, which is primarily June through September, revenues from electric sales are more significant, than in other months.

Other Relevant Business Information

Our customer base is broadly diversified, with no single customer accounting for a significant portion of revenues.

As of December 31, 2019, we had 8,363 employees of whom 3,219 were subject to collective bargaining agreements. Collective bargaining agreements for 96 employees are set to expire within one year.

For a listing of certain subsidiaries of NiSource refer to Exhibit 21.

We electronically file various reports with the SEC, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to such reports, as well as our proxy statements for the Company's annual meetings of stockholders at *http://www.sec.gov*. Additionally, we make all SEC filings available without charge to the public on our web site at *http://www.nisource.com*.

ITEM 1A. RISK FACTORS

NISOURCE INC.

Our operations and financial results are subject to various risks and uncertainties, including those described below, that could adversely affect our business, financial condition, results of operations, cash flows, and the trading price of our common stock.

We have substantial indebtedness which could adversely affect our financial condition.

Our business is capital intensive and we rely significantly on long-term debt to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations. We had total consolidated indebtedness of $9,642.8 million outstanding as of December 31, 2019. Our substantial indebtedness could have important consequences. For example, it could:

- limit our ability to borrow additional funds or increase the cost of borrowing additional funds;
- reduce the availability of cash flow from operations to fund working capital, capital expenditures and other general corporate purposes;
- limit our flexibility in planning for, or reacting to, changes in the business and the industries in which we operate;
- lead parties with whom we do business to require additional credit support, such as letters of credit, in order for us to transact such business;
- place us at a competitive disadvantage compared to competitors that are less leveraged;
- increase vulnerability to general adverse economic and industry conditions; and
- limit our ability to execute on our growth strategy, which is dependent upon access to capital to fund our substantial infrastructure investment program.

Some of our debt obligations contain financial covenants related to debt-to-capital ratios and cross-default provisions. Our failure to comply with any of these covenants could result in an event of default, which, if not cured or waived, could result in the acceleration of outstanding debt obligations.

A drop in our credit ratings could adversely impact our cash flows, results of operation, financial condition and liquidity.

The availability and cost of credit for our businesses may be greatly affected by credit ratings. The credit rating agencies periodically review our ratings, taking into account factors such as our capital structure, earnings profile, and, in 2018 and 2019, the impacts of the TCJA and the Greater Lawrence Incident. We are committed to maintaining investment grade credit ratings; however, there is no assurance we will be able to do so in the future. Our credit ratings could be lowered or withdrawn entirely by a rating agency if, in its judgment, the circumstances warrant. Any negative rating action could adversely affect our ability to access capital at rates and on terms that are attractive. A negative rating action could also adversely impact our business relationships with suppliers and operating partners, who may be less willing to extend credit or offer us similarly favorable terms as secured in the past under such circumstances.

Certain of our subsidiaries have agreements that contain “ratings triggers” that require increased collateral in the form of cash, a letter of credit or other forms of security for new and existing transactions if the credit ratings of our or certain of our subsidiaries are dropped below investment grade. These agreements are primarily for insurance purposes and for the physical purchase or sale of gas or power. As of December 31, 2019, the collateral requirement that would be required in the event of a downgrade below the ratings trigger levels would amount to approximately $72.1 million. In addition to agreements with ratings triggers, there are other agreements that contain “adequate assurance” or “material adverse change” provisions that could necessitate additional credit support such as letters of credit and cash collateral to transact business.

If our or certain of our subsidiaries' credit ratings were downgraded, especially below investment grade, financing costs and the principal amount of borrowings would likely increase due to the additional risk of our debt and because certain counterparties may require additional credit support as described above. Such amounts may be material and could adversely affect our cash flows, results of operations and financial condition. Losing investment grade credit ratings may also result in more restrictive covenants and reduced flexibility on repayment terms in debt issuances, lower share price and greater stockholder dilution from common equity issuances, in addition to reputational damage within the investment community.

We may not be able to execute our business plan or growth strategy, including utility infrastructure investments.

Business or regulatory conditions may result in us not being able to execute our business plan or growth strategy, including identified, planned and other utility infrastructure investments. Our customer and regulatory initiatives may not achieve planned results. Utility infrastructure investments may not materialize, may cease to be achievable or economically viable and may not be successfully completed. Natural gas may cease to be viewed as an economically and environmentally attractive fuel. Certain groups and governmental entities may continue to oppose natural gas delivery and infrastructure investments because of perceived environmental impacts associated with the natural gas supply chain and end use. Energy conservation, energy efficiency, distributed generation, energy storage, policies favoring electric heat over gas heat and other factors may reduce demand for natural gas and energy. Any of these developments could adversely affect our results of operations and growth prospects. Even if our business plan and growth strategy are executed, there is still risk of, among other things, human error in maintenance, installation or operations, shortages or delays in obtaining equipment, and performance below expected levels (in addition to the other risks discussed in this section).

Adverse economic and market conditions or increases in interest rates could materially and adversely affect our results of operations, cash flows, financial condition and liquidity.

While the national economy is experiencing modest growth, we cannot predict how robust future growth will be or whether it will be sustained. Deteriorating or sluggish economic conditions in our operating jurisdictions could adversely impact our ability to maintain or grow our customer base and collect revenues from customers, which could reduce revenue growth and increase operating costs. In addition, a rising interest rate environment may lead to higher borrowing costs, which may adversely impact reported earnings, cost of capital and capital holdings. Rising interest rates and negative market or company events may also result in a decrease in the price of our shares of common stock.

We rely on access to the capital markets to finance our liquidity and long-term capital requirements, including expenditures for our utility infrastructure and to comply with future regulatory requirements, to the extent not satisfied by the cash flow generated by our operations. We have historically relied on long-term debt and on the issuance of equity securities to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations. Successful implementation of our long-term business strategies, including capital investment, is dependent upon our ability to access the capital and credit markets, including the banking and commercial paper markets, on competitive terms and rates. An economic downturn or uncertainty, market turmoil, changes in tax policy, challenges faced by financial institutions, changes in our credit ratings, or a change in investor sentiment toward us or the utilities industry generally could adversely affect our ability to raise additional capital or refinance debt. Reduced access to capital markets and/or increased borrowing costs could reduce future net income and cash flows. Refer to Note 14, “Long-Term Debt,” in the Notes to Consolidated Financial Statements for information related to outstanding long-term debt and maturities of that debt.

If any of these risks or uncertainties limit our access to the credit and capital markets or significantly increase our cost of capital, it could limit our ability to implement, or increase the costs of implementing, our business plan, which, in turn, could materially and adversely affect our results of operations, cash flows, financial condition and liquidity.

Capital market performance and other factors may decrease the value of benefit plan assets, which then could require significant additional funding and impact earnings.

The performance of the capital markets affects the value of the assets that are held in trust to satisfy future obligations under defined benefit pension and other postretirement benefit plans. We have significant obligations in these areas and hold significant assets in these trusts as noted in Note 11, "Pension and Other Postretirement Benefits," in the Notes to Consolidated Financial Statements. These assets are subject to market fluctuations and may yield uncertain returns, which fall below our projected rates of return. A decline in the market value of assets may increase the funding requirements of the obligations under the defined benefit pension and other postretirement benefit plans. Additionally, changes in interest rates affect the liabilities under these benefit plans; as interest rates decrease, the liabilities increase, which could potentially increase funding requirements. Further, the funding requirements of the obligations related to these benefits plans may increase due to changes in governmental regulations and participant demographics, including increased numbers of retirements or changes in life expectancy assumptions. In addition, lower asset returns result in increased expenses. Ultimately, significant funding requirements and increased pension or other postretirement benefit plan expense could negatively impact our results of operations and financial position.

ITEM 1A. RISK FACTORS

NISOURCE INC.

The majority of our revenues are subject to economic regulation and are exposed to the impact of regulatory rate reviews and proceedings.

Most of our revenues are subject to economic regulation at either the federal or state level. As such, the revenues generated by us are subject to regulatory review by the applicable federal or state authority. These rate reviews determine the rates charged to customers and directly impact revenues. Our financial results are dependent on frequent regulatory proceedings in order to ensure timely recovery of costs and investments. In addition to our ongoing regulatory proceedings, the recovery of the Greater Lawrence pipeline replacement capital investment will be addressed in a future regulatory proceeding as discussed in Note 19, "Other Commitments and Contingencies - E. Other Matters” in the Notes to Consolidated Financial Statements.

The outcomes of these proceedings are uncertain, potentially lengthy and could be influenced by many factors, some of which may be outside of our control, including the cost of providing service, the necessity of expenditures, the quality of service, regulatory interpretations, customer intervention, economic conditions and the political environment. Further, the rate orders are subject to appeal, which creates additional uncertainty as to the rates that will ultimately be allowed to be charged for services. Additionally, the costs of complying with current and future changes in environmental and federal pipeline safety laws and regulations are expected to be significant, and their recovery through rates will also be contingent on regulatory approval.

Failure to adapt to advances in technology and manage the related costs could make us less competitive and negatively impact our results of operations and financial condition.

A key element of our business model is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. We continue to research, plan for, and implement new technologies that produce power or reduce power consumption. These technologies include renewable energy, distributed generation, energy storage, and energy efficiency. Advances in technology and changes in laws or regulations (including subsidization) are reducing the cost of these or other alternative methods of producing power to a level that is competitive with that of most central station power electric production or result in smaller-scale, more fuel efficient, and/or more cost-effective distributed generation. This could cause power sales to decline and the value of our generating facilities to decline. New technologies may require us to make significant expenditures to remain competitive and may result in the obsolescence of certain operating assets.

In addition, customers are increasingly expecting enhanced communications regarding their electric and natural gas services, which, in some cases, may involve additional investments in technology. We also rely on technology to adequately maintain key business records.

Our future success will depend, in part, on our ability to anticipate and successfully adapt to technological changes, to offer services that meet customer demands and evolving industry standards, and to recover all, or a significant portion of, any unrecovered investment in obsolete assets. A failure by us to effectively adapt to changes in technology and manage the related costs could harm our ability to remain competitive in the marketplace for our products, services and processes and could have a material adverse impact on our results of operations and financial condition.

The Greater Lawrence Incident has materially adversely affected and may continue to materially adversely affect our financial condition, results of operations and cash flows.

In connection with the Greater Lawrence Incident, we have incurred and will incur various costs and expenses as set forth in Note 6, "Goodwill and Other Intangible Assets," Note 19, "Other Commitments and Contingencies - C. Legal Proceedings," and “- E. Other Matters" in the Notes to Consolidated Financial Statements.

We are subject to inquiries and investigations by government authorities and regulatory agencies regarding the Greater Lawrence Incident, including the Massachusetts DPU and the Massachusetts Attorney General's Office. We are cooperating with all inquiries and investigations. In addition, on February 26, 2020, the Company and Columbia of Massachusetts entered into agreements with the U.S. Attorney’s Office to resolve the U.S. Attorney’s Office’s investigation relating to the Greater Lawrence Incident, as described further below.

As more information becomes known, management's estimates and assumptions regarding the costs and expenses to be incurred and the financial impact of the Greater Lawrence Incident may change. A change in management’s estimates or assumptions could result in an adjustment that would have a material impact on our financial condition, results of operations and cash flows during the period in which such change occurred.

While we have recovered the full amount of our liability insurance coverage available under our policies, total expenses related to the incident have exceeded such amount. Expenses in excess of our liability insurance coverage have materially adversely affected and may continue to materially adversely affect our results of operations, cash flows and financial position.

ITEM 1A. RISK FACTORS

NISOURCE INC.

We may also incur additional costs associated with the Greater Lawrence Incident, beyond the amount currently anticipated, including in connection with investigations by regulators as well as civil litigation. Further, state or federal legislation may be enacted that would require us to incur additional costs by mandating various changes, including changes to our operating practice standards for natural gas distribution operations and safety. If we are unable to recover the capital cost of the gas pipeline replacement in the impacted area or we incur a material amount of other costs that we are unable to recover through rates or offset through operational or other cost savings, our financial condition, results of operations, and cash flows could be materially and adversely affected.

Further, if it is determined in other matters that we did not comply with applicable statutes, regulations, rules, tariffs, or orders in connection with the Greater Lawrence Incident or in connection with the operations or maintenance of our natural gas system, and we are ordered to pay additional amounts in customer refunds, penalties, or other amounts, our financial condition, results of operations, and cash flows could be materially and adversely affected.

Our settlement with the U.S. Attorney's Office in respect of federal charges in connection with the Greater Lawrence Incident may expose us to further penalties, liabilities and private litigation, and may impact our operations.

On February 26, 2020, the Company entered into a DPA and Columbia of Massachusetts entered into a plea agreement with the U.S. Attorney's Office to resolve the U.S. Attorney's Office's investigation relating to the Greater Lawrence Incident. Columbia of Massachusetts' plea agreement with the U.S. Attorney's Office is subject to approval by the United States District Court for the District of Massachusetts (the "Court"). If Columbia of Massachusetts' guilty plea is not accepted by the Court or is withdrawn for any reason, the U.S. Attorney's Office may, at its sole option, render the DPA null and void. See Note 19, "Other Commitments and Contingencies - C. Legal Proceedings" in the Notes to Consolidated Financial Statements. The agreements impose various compliance and remedial obligations on the Company and Columbia of Massachusetts. Failure to comply with the terms of these agreements could result in further enforcement action by the U.S. Attorney's Office, expose the Company and Columbia of Massachusetts to penalties, financial or otherwise, and subjects the Company to further private litigation, each of which could impact our operations and have a material adverse effect on our business.

The closing of the sale of the Massachusetts Business is subject to receipt of clearance and approval from various governmental entities and other closing conditions that may not be satisfied or waived, and, in order to receive such clearance, consent or approval, governmental entities may impose conditions, terms, obligations or restrictions that Eversource is not obligated to accept in order to complete the transaction.

On February 26, 2020, NiSource, Columbia of Massachusetts and Eversource entered into the Asset Purchase Agreement providing for the sale of the Massachusetts Business to Eversource. The Asset Purchase Agreement provides for various closing conditions, including (a) the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, (b) the receipt of the approval of the Massachusetts DPU (the "MDPU Approval") and (c) the final resolution or termination of all pending actions, claims and proceedings against Seller and its affiliates under the jurisdiction of the Massachusetts DPU and all future, actions, claims and proceedings against Seller and its affiliates relating to the Greater Lawrence Incident under the jurisdiction of the Massachusetts DPU.

The satisfaction of many of the closing conditions is beyond our control. We may not receive the required clearance and approvals for the transaction or the required resolution with the Massachusetts DPU, or we may not receive them in a timely manner. In addition, governmental entities could impose conditions, terms, obligations or restrictions as conditions for their approvals and as conditions to resolve certain proceedings, and these may include substantial payments by us. Moreover, Eversource is not required to agree to any conditions, terms, obligations or restrictions to obtain required clearance and approvals if such conditions, terms, obligations or restrictions would reasonably be expected to constitute a "burdensome condition" as defined in the Asset Purchase Agreement. There can be no assurance that regulators will not seek to impose conditions, terms, obligations or restrictions that would constitute burdensome conditions.

If the closing conditions are not satisfied or there is a substantial delay in obtaining the required clearance and approvals, or otherwise satisfying the closing conditions, the sale of the Massachusetts Business may not be completed, and we may lose some or all of the intended benefits of the sale.

The sale of the Massachusetts Business poses risks and challenges that could negatively impact our business, and we may not realize the expected benefits of the sale of the Massachusetts Business.

The sale of the Massachusetts Business involves separation or carve-out activities and costs and possible disputes with Eversource. Following the sale, we may have continued financial liabilities with respect to the business conducted by Columbia of Massachusetts, as we will be required to retain responsibility for, and indemnify Eversource against, certain liabilities, including liabilities for any fines arising out of the Greater Lawrence Incident and liabilities of Columbia of Massachusetts or its affiliates pursuant to civil claims for injury of persons or damage to property to the extent such injury or damage occurs prior to the closing in connection with Columbia of Massachusetts' business. It may also be difficult to determine whether a claim from a third party is our responsibility, and we may expend substantial resources trying to determine whether we or Eversource has responsibility for the claim.

If we do not realize the expected benefits of the sale of the Massachusetts Business, our consolidated financial condition, results of operations and cash flows could be negatively impacted. The sale of the Massachusetts Business may result in a dilutive impact to our future earnings if we are unable to offset the dilutive impact from the loss of revenue associated with the sale, which could have a material adverse effect on our results of operations and financial condition.

The failure to complete the transactions contemplated by the Asset Purchase Agreement within the expected time frame or at all could adversely affect our business, financial condition and results of operations and the price of our common stock.

If the sale of the Massachusetts Business is not completed by October 26, 2020 (subject to up to two automatic 45-day extensions under certain circumstances related to obtaining required regulatory approvals and resolution with the Massachusetts DPU), we or Eversource may choose not to proceed with the transaction. Completion of the transaction is subject to risks, including the risks that approval of the transaction by governmental entities will not be obtained or that certain other closing conditions will not be satisfied. A failure to complete the transaction may result in negative publicity and a negative impression of us in the investment community. Moreover, under the terms of the settlement with the U.S. Attorney's Office, we will be obligated to use reasonable best efforts to sell Columbia of Massachusetts' business, and there is no assurance that we will be able to sell such business to a third party on as favorable terms, if at all. The occurrence of any of these events, individually or in combination, could have a material adverse effect on our results of operations, financial condition or the trading price of our common stock.

Our gas distribution activities, as well as generation, transmission and distribution of electricity, involve a variety of inherent hazards and operating risks, including potential public safety risks.

Our gas distribution activities, as well as generation, transmission, and distribution of electricity, involve a variety of inherent hazards and operating risks, including, but not limited to, gas leaks and over-pressurization, downed power lines, damage to our infrastructure by third parties, outages, environmental spills, mechanical problems and other incidents, which could cause substantial financial losses, as demonstrated in part by the Greater Lawrence Incident. In addition, these hazards and risks have resulted and may in the future result in serious injury or loss of life to employees and/or the general public, significant damage to property, environmental pollution, impairment of our operations, adverse regulatory rulings and reputational harm, which in turn could lead to substantial losses for us. The location of pipeline facilities, or generation, transmission, substation and distribution facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from such incidents. As with the Greater Lawrence Incident, certain incidents have subjected and may in the future subject us to litigation or administrative or other legal proceedings from time to time, both civil and criminal, which could result in substantial monetary judgments, fines, or penalties against us, be resolved on unfavorable terms, and require us to incur significant operational expenses. The occurrence of incidents has in certain instances adversely affected and could in the future adversely affect our reputation, cash flows, financial position and/or results of operations. We maintain insurance against some, but not all, of these risks and losses.

We may be unable to obtain insurance on acceptable terms or at all. Our liability insurance coverage did not provide protection against all significant losses as a result of the Greater Lawrence Incident and may not provide protection against all significant losses in the future.

Our ability to obtain insurance, as well as the cost and coverage of such insurance, are affected by developments affecting our business; international, national, state, or local events; and the financial condition of insurers. The insurance market is experiencing a hardening environment due to reductions in commercial suppliers and the capacity they are willing to issue, increases in overall demand for capacity, and a prevalence of severe losses. NiSource has been particularly affected by the current market conditions. We have not been able to obtain liability insurance coverage at previously procured limits at rates that are acceptable to us. Insurance coverage may not continue to be available at limits, rates or terms acceptable to us. The premiums we pay for our insurance coverage have significantly increased as a result of market conditions and the accumulated loss ratio over the history of NiSource operations, and we expect that they will continue to increase as a result of market conditions. In addition, our insurance is not sufficient or effective under all circumstances and against all hazards or liabilities to which we are subject. For example, total expenses related to the Greater Lawrence Incident have exceeded the total amount of liability coverage available under our policies.

Also, certain types of damages, expenses or claimed costs, such as fines and penalties, may be excluded under the policies. In addition, insurers providing insurance to us may raise defenses to coverage under the terms and conditions of the respective insurance policies that could result in a denial of coverage or limit the amount of insurance proceeds available to us. Any losses for which we are not fully insured or that are not covered by insurance at all could materially adversely affect our results of operations, cash flows, and financial position. For example, expenses related to the Greater Lawrence Incident that we are unable to recover from liability or property insurance have materially adversely affected and may continue to materially adversely affect our results of operations. For more information regarding our insurance programs in the context of the Greater Lawrence Incident, see Note 19, "Other Commitments and Contingencies - C. Legal Proceedings," and " - E. Other Matters" in the Notes to Consolidated Financial Statements.

The outcome of legal and regulatory proceedings, investigations, inquiries, claims and litigation related to our business operations, including those related to the Greater Lawrence Incident, may have a material adverse effect on our results of operations, financial position or liquidity.

We are involved in legal and regulatory proceedings, investigations, inquiries, claims and litigation in connection with our business operations, including the Greater Lawrence Incident, the most significant of which are summarized in Note 19, “Other Commitments and Contingencies” in the Notes to Consolidated Financial Statements. Our insurance does not cover all costs and expenses that we have incurred and that we may incur in the future relating to the Greater Lawrence Incident, and may not fully cover other incidents that may occur in the future. Due to the inherent uncertainty of the outcomes of such matters, there can be no assurance that the resolution of any particular claim or proceeding would not have a material adverse effect on our results of operations, financial position or liquidity. Certain matters in connection with the Greater Lawrence Incident have had or may have a material impact as described in Note 19, "Other Commitments and Contingencies" in the Notes to Consolidated Financial Statements. If one or more of such additional or other matters were decided against us, the effects could be material to our results of operations in the period in which we would be required to record or adjust the related liability and could also be material to our cash flows in the periods that we would be required to pay such liability.

We are exposed to significant reputational risks, which make us vulnerable to a loss of cost recovery, increased litigation and negative public perception.

As a utility company, we are subject to adverse publicity focused on the reliability of our services, the speed with which we are able to respond effectively to electric outages, natural gas leaks or events and related accidents and similar interruptions caused by storm damage or other unanticipated events, as well as our own or third parties' actions or failure to act. We are also subject to adverse publicity related to actual or perceived environmental impacts. If customers, legislators, or regulators have or develop a negative opinion of us, this could result in less favorable legislative and regulatory outcomes or increased regulatory oversight, increased litigation and negative public perception. The adverse publicity and investigations we experienced as a result of the Greater Lawrence Incident may have an ongoing negative impact on the public’s perception of us. It is difficult to predict the ultimate impact of this adverse publicity. The foregoing may have continuing adverse effects on our business, results of operations, cash flow and financial condition.

Our businesses are subject to various laws, regulations and tariffs. We could be materially adversely affected if we fail to comply with such laws, regulations and tariffs or with any changes in or new interpretations of such laws, regulations and tariffs.

Our businesses are subject to various laws, regulations and tariffs, including, but not limited to, those relating to natural gas pipeline safety, employee safety, the environment and our energy infrastructure. Existing laws, regulations and tariffs may be revised or become subject to new interpretations, and new laws, regulations and tariffs may be adopted or become applicable to us and our operations. In some cases, compliance with new laws, regulations and tariffs increases our costs. If we fail to comply with laws, regulations and tariffs applicable to us or with any changes in or new interpretations of such laws, regulations or tariffs, our financial condition, results of operations, regulatory outcomes and cash flows may be materially adversely affected.

Our businesses are regulated under numerous environmental laws. The cost of compliance with these laws, and changes to or additions to, or reinterpretations of the laws, could be significant. Liability from the failure to comply with existing or changed laws could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Our businesses are subject to extensive federal, state and local environmental laws and rules that regulate, among other things, air emissions, water usage and discharges, GHG and waste products such as coal combustion residuals. Compliance with these legal obligations require us to make expenditures for installation of pollution control equipment, remediation, environmental monitoring, emissions fees, and permits at many of our facilities. These expenditures are significant, and we expect that they will continue to be significant in the future. Furthermore, if we fail to comply with environmental laws and regulations or are found to have caused damage to the environment or persons, that failure or harm may result in the assessment of civil or criminal penalties and damages against us and injunctions to remedy the failure or harm.

Existing environmental laws and regulations may be revised and new laws and regulations seeking to change environmental regulation of the energy industry may be adopted or become applicable to us, with an increased focus on both coal and natural gas in recent years. Revised or additional laws and regulations may result in significant additional expense and operating restrictions on our facilities or increased compliance costs, which may not be fully recoverable from customers through regulated rates and could, therefore, impact our financial position, financial results and cash flow. Moreover, such costs could materially affect the continued economic viability of one or more of our facilities.

An area of significant uncertainty and risk are the laws concerning emission of GHG. While we continue to reduce GHG emissions through the retirement of coal-fired electric generation, priority pipeline replacement, energy efficiency, leak detection and repair, and other programs, and expect to further reduce GHG emissions through increased use of renewable energy, GHG emissions are currently an expected aspect of the electric and natural gas business. Revised or additional future GHG legislation and/or regulation related to the generation of electricity or the extraction, production, distribution, transmission, storage and end use of natural gas could materially impact our gas supply, financial position, financial results and cash flows.

Even in instances where legal and regulatory requirements are already known or anticipated, the original cost estimates for environmental improvements, remediation of past environmental impact, or pollution reduction strategies and equipment can differ materially from the amount ultimately expended. The actual future expenditures depend on many factors, including the nature and extent of impact, the method of improvement, the cost of raw materials, contractor costs, and requirements established by environmental authorities. Changes in costs and the ability to recover under regulatory mechanisms could affect our financial position, financial results and cash flows.

A significant portion of the gas and electricity we sell is used by residential and commercial customers for heating and air conditioning. Accordingly, fluctuations in weather, gas and electricity commodity costs and economic conditions impact demand of our customers and our operating results.

Energy sales are sensitive to variations in weather. Forecasts of energy sales are based on “normal” weather, which represents a long-term historical average. Significant variations from normal weather could have, and have had, a material impact on energy sales. Additionally, residential usage, and to some degree commercial usage, is sensitive to fluctuations in commodity costs for gas and electricity, whereby usage declines with increased costs, thus affecting our financial results. Lastly, residential and commercial customers’ usage is sensitive to economic conditions and factors such as unemployment, consumption and consumer confidence. Therefore, prevailing economic conditions affecting the demand of our customers may in turn affect our financial results.

Our business operations are subject to economic conditions in certain industries.

Business operations throughout our service territories have been and may continue to be adversely affected by economic events at the national and local level where it operates. In particular, sales to large industrial customers, such as those in the steel, oil refining, industrial gas and related industries, may be impacted by economic downturns and geographic or technological shifts in production or production methods. The U.S. manufacturing industry continues to adjust to changing market conditions including international competition, increasing costs, and fluctuating demand for its products.

The implementation of NIPSCO’s electric generation strategy, including the retirement of its coal generation units, may not achieve intended results.

On October 31, 2018, NIPSCO submitted its 2018 Integrated Resource Plan with the IURC setting forth its short- and long-term electric generation plans in an effort to maintain affordability while providing reliable, flexible and cleaner sources of power. The plan evaluated demand-side and supply-side resource alternatives to reliably and cost-effectively meet NIPSCO customers' future energy requirements over the ensuing 20 years. The preferred option within the Integrated Resource Plan sets forth a schedule to retire R.M. Schahfer Generating Station (Units 14, 15, 17, and 18) in 2023 and Michigan City Generating Station (Unit 12) in 2028. The current replacement plan includes renewable sources of energy, including wind, solar, and battery storage.

As part of this plan, NIPSCO has IURC approval for the Jordan Creek PPA for 400 MW, the Indiana Crossroads BTA for 300 MW and the Rosewater BTA for 100 MW. Each is a separate facility and all MW are nameplate capacity. NIPSCO has filed a notice with the IURC of its intention not to move forward with one of its approved PPAs due to the failure to meet a condition precedent in the agreement as a result of local zoning restrictions.

ITEM 1A. RISK FACTORS

NISOURCE INC.

There are inherent risks and uncertainties in executing the Integrated Resource Plan, including changes in market conditions, regulatory approvals, environmental regulations, commodity costs and customer expectations, which may impede NIPSCO's ability to achieve the intended results. NIPSCO's future success will depend, in part, on its ability to successfully implement its long-term electric generation plans, to offer services that meet customer demands and evolving industry standards, and to recover all, or a significant portion of, any unrecovered investment in obsolete assets. NIPSCO's electric generation strategy could require significant future capital expenditures, operating costs and charges to earnings that may negatively impact our financial position, financial results and cash flows.

Fluctuations in the price of energy commodities or their related transportation costs or an inability to obtain an adequate, reliable and cost-effective fuel supply to meet customer demands may have a negative impact on our financial results.

Our electric generating fleet is dependent on coal and natural gas for fuel, and our gas distribution operations purchase and resell much of the natural gas we deliver to our customers. These energy commodities are vulnerable to price fluctuations and fluctuations in associated transportation costs. From time to time, we have also used hedging in order to offset fluctuations in commodity supply prices. We rely on regulatory recovery mechanisms in the various jurisdictions in order to fully recover the commodity costs incurred in providing service. However, while we have historically been successful in the recovery of costs related to such commodity prices, there can be no assurance that such costs will be fully recovered through rates in a timely manner.

In addition, we depend on electric transmission lines, natural gas pipelines, and other transportation facilities owned and operated by third parties to deliver the electricity and natural gas we sell to wholesale markets, supply natural gas to our gas storage and electric generation facilities, and provide retail energy services to customers. If transportation is disrupted, or if capacity is inadequate, we may be unable to sell and deliver our gas and electric services to some or all of our customers. As a result, we may be required to procure additional or alternative electricity and/or natural gas supplies at then-current market rates, which, if recovery of related costs is disallowed, could have a material adverse effect on our businesses, financial condition, cash flows, results of operations and/or prospects.

We are exposed to risk that customers will not remit payment for delivered energy or services, and that suppliers or counterparties will not perform under various financial or operating agreements.

Our extension of credit is governed by a Corporate Credit Risk Policy, involves considerable judgment by our employees and is based on an evaluation of a customer or counterparty's financial condition, credit history and other factors. We monitor our credit risk exposure by obtaining credit reports and updated financial information for customers and suppliers, and by evaluating the financial status of our banking partners and other counterparties by reference to market-based metrics such as credit default swap pricing levels, and to traditional credit ratings provided by the major credit rating agencies. Adverse economic conditions could result in an increase in defaults by customers, suppliers and counterparties.

We have significant goodwill and definite-lived intangible assets. Impairments of goodwill and definite-lived intangible assets related to Columbia of Massachusetts have resulted in significant charges to earnings for the quarter and year ended December 31, 2019. Any future impairments of other goodwill could result in a significant charge to earnings in a future period and negatively impact our compliance with certain covenants under financing agreements.

In accordance with GAAP, we test goodwill for impairment at least annually and review our definite-lived intangible assets for impairment when events or changes in circumstances indicate its fair value might be below its carrying value. Goodwill is also tested for impairment when factors, examples of which include reduced cash flow estimates, a sustained decline in stock price or market capitalization below book value, indicate that the carrying value may not be recoverable.

We are required to record a charge in our financial statements for a period in which any impairment of our goodwill or definite-lived intangible assets is determined, negatively impacting our results of operations. In connection with the preparation of our financial statements for the year ended December 31, 2019, we conducted an impairment analysis for the goodwill and definite-lived intangible assets (franchise rights) related to Columbia of Massachusetts and concluded that such goodwill and franchise rights were impaired. As a result, we recorded an impairment charge of $204.8 million for such goodwill and an impairment charge of $209.7 million for such franchise rights at December 31, 2019. For additional information, see Note 6, "Goodwill and Other Intangible Assets," in the Notes to Consolidated Financial Statements.

A significant charge in the future could impact the capitalization ratio covenant under certain financing agreements. We are subject to a financial covenant under our revolving credit facility and term loan agreement, which require us to maintain a debt to capitalization ratio that does not exceed 70%. A similar covenant in a 2005 private placement note purchase agreement requires us to maintain a debt to capitalization ratio that does not exceed 75%. As of December 31, 2019, the ratio was 61.7%.

ITEM 1A. RISK FACTORS

NiSource Inc.

Changes in taxation and the ability to quantify such changes as well as challenges to tax positions could adversely affect our financial results.

We are subject to taxation by the various taxing authorities at the federal, state and local levels where we do business. Legislation or regulation which could affect our tax burden could be enacted by any of these governmental authorities. For example, the TCJA includes numerous provisions that affect businesses, including changes to U.S. corporate tax rates, business-related exclusions, and deductions and credits. The outcome of regulatory proceedings regarding the extent to which the effect of a change in corporate tax rate will impact customers and the time period over which the impact will occur could significantly impact future earnings and cash flows. Separately, a challenge by a taxing authority, changes in taxing authorities' administrative interpretations, decisions, policies and positions, our ability to utilize tax benefits such as carryforwards or tax credits, or a deviation from other tax-related assumptions may cause actual financial results to deviate from previous estimates.

Changes in accounting principles may adversely affect our financial results.

Future changes in accounting rules and associated changes in regulatory accounting may negatively impact the way we record revenues, expenses, assets and liabilities. These changes in accounting standards may adversely affect our financial condition and results of operations.

Aging infrastructure may lead to disruptions in operations and increased capital expenditures and maintenance costs, all of which could negatively impact our financial results.

We have risks associated with aging infrastructure, including our gas infrastructure assets. These risks can be driven by threats such as, but not limited to, internal corrosion, external corrosion and stress corrosion cracking. The age of these assets may result in a need for replacement, a higher level of maintenance costs, or unscheduled outages, despite efforts by us to properly maintain or upgrade these assets through inspection, scheduled maintenance and capital investment. In addition, the nature of the information available on aging infrastructure assets, which in some cases is incomplete, may make inspections, maintenance, upgrading and replacement of the assets particularly challenging. Additionally, missing or incorrect infrastructure data may lead to (1) difficulty properly locating facilities, which can result in excavator damage and operational or emergency response issues, and (2) configuration and control risks associated with the modification of system operating pressures in connection with turning off or turning on service to customers, which can result in unintended outages or operating pressures. Also, additional maintenance and inspections are required in some instances in order to improve infrastructure information and records and address emerging regulatory or risk management requirements, which increases our costs. The failure to operate these assets as desired could result in gas leaks and other incidents and in our inability to meet firm service obligations, which could adversely impact revenues, and could also result in increased capital expenditures and maintenance costs, which, if not fully recovered from customers, could negatively impact our financial results.

The impacts of climate change, natural disasters, acts of terrorism, accidents or other catastrophic events may disrupt operations and reduce the ability to service customers.

A disruption or failure of natural gas distribution systems, or within electric generation, transmission or distribution systems, in the event of a major hurricane, tornado, terrorist attack, cyber-attack (as further detailed below), accident or other catastrophic event could cause delays in completing sales, providing services, or performing other critical functions. We have experienced disruptions in the past from hurricanes and tornadoes and other events of this nature. The occurrence of such events could adversely affect our financial position and results of operations. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. There is also a concern that climate change may exacerbate the risks to physical infrastructure. Such risks include heat stresses to power lines, storms that damage infrastructure, lake and sea level changes that affect the manner in which services are currently provided, droughts or other stresses on water used to supply services, and other extreme weather conditions. Climate change and the costs that may be associated with its impacts have the potential to affect our business in many ways, including increasing the costs we incur in providing our products and services, impacting the demand for and consumption of our products and services (due to change in both costs and weather patterns), and affecting the economic health of the regions in which we operate.

ITEM 1A. RISK FACTORS

NISOURCE INC.

A cyber-attack on any of our or certain third-party computer systems upon which we rely may adversely affect our ability to operate and could lead to a loss or misuse of confidential and proprietary information or potential liability.

We are reliant on technology to run our business, which is dependent upon financial and operational computer systems to process critical information necessary to conduct various elements of our business, including the generation, transmission and distribution of electricity, operation of our gas pipeline facilities and the recording and reporting of commercial and financial transactions to regulators, investors and other stakeholders. In addition to general information and cyber risks that all large corporations face (e.g., malware, unauthorized access attempts, phishing attacks, malicious intent by insiders and inadvertent disclosure of sensitive information), the utility industry faces evolving and increasingly complex cybersecurity risks associated with protecting sensitive and confidential customer information, electric grid infrastructure, and natural gas infrastructure. Deployment of new business technologies represents a new and large-scale opportunity for attacks on our information systems and confidential customer information, as well as on the integrity of the energy grid and the natural gas infrastructure. Increasing large-scale corporate attacks in conjunction with more sophisticated threats continue to challenge power and utility companies. Any failure of our computer systems, or those of our customers, suppliers or others with whom we do business, could materially disrupt our ability to operate our business and could result in a financial loss and possibly do harm to our reputation.

Additionally, our information systems experience ongoing, often sophisticated, cyber-attacks by a variety of sources, including foreign sources, with the apparent aim to breach our cyber-defenses. Although we attempt to maintain adequate defenses to these attacks and work through industry groups and trade associations to identify common threats and assess our countermeasures, a security breach of our information systems, or a security breach of the information systems of our customers, suppliers or others with whom we do business, could (i) impact the reliability of our generation, transmission and distribution systems and potentially negatively impact our compliance with certain mandatory reliability standards, (ii) subject us to reputational and other harm or liabilities associated with theft or inappropriate release of certain types of information such as system operating information or information, personal or otherwise, relating to our customers or employees, (iii) impact our ability to manage our businesses, and/or (iv) subject us to legal and regulatory proceedings and claims from third parties, in addition to remediation costs, any of which, in turn, could have a material adverse effect on our businesses, cash flows, financial condition, results of operations and/or prospects. Although we do maintain cyber insurance, it is possible that such insurance will not adequately cover any losses or liabilities we may incur as a result of any cybersecurity-related litigation.

Our capital projects and programs subject us to construction risks and natural gas costs and supply risks, and require numerous permits, approvals and certificates from various governmental agencies.

Our business requires substantial capital expenditures for investments in, among other things, capital improvements to our electric generating facilities, electric and natural gas distribution infrastructure, natural gas storage, and other projects, including projects for environmental compliance. We are engaged in intrastate natural gas pipeline modernization programs to maintain system integrity and enhance service reliability and flexibility. NIPSCO also is currently engaged in a number of capital projects, including environmental improvements to its electric generating stations, the construction of new transmission facilities, and new projects related to renewable energy. As we undertake these projects and programs, we may be unable to complete them on schedule or at the anticipated costs. Additionally, we may construct or purchase some of these projects and programs to capture anticipated future growth in natural gas production, which may not materialize, and may cause the construction to occur over an extended period of time.

Our existing and planned capital projects require numerous permits, approvals and certificates from federal, state, and local governmental agencies. If there is a delay in obtaining any required regulatory approvals or if we fail to obtain or maintain any required approvals or to comply with any applicable laws or regulations, we may not be able to construct or operate our facilities, we may be forced to incur additional costs, or we may be unable to recover any or all amounts invested in a project. We also may not receive the anticipated increases in revenue and cash flows resulting from such projects and programs until after their completion. Other construction risks include changes in costs of materials, equipment, commodities or labor (including changes to tariffs on materials), delays caused by construction incidents or injuries, work stoppages, shortages in qualified labor, poor initial cost estimates, unforeseen engineering issues, the ability to obtain necessary rights-of-way, easements and transmissions connections and general contractors and subcontractors not performing as required under their contracts.

To the extent that delays occur, costs become unrecoverable, or we otherwise become unable to effectively manage and complete our capital projects, our results of operations, cash flows, and financial condition may be adversely affected.

Sustained extreme weather conditions may negatively impact our operations.

We conduct our operations across a wide geographic area subject to varied and potentially extreme weather conditions, which may from time to time persist for sustained periods of time. Despite preventative maintenance efforts, persistent weather related stress on our infrastructure may reveal weaknesses in our systems not previously known to us or otherwise present various operational challenges across all business segments. Further, adverse weather may affect our ability to conduct operations in a manner that satisfies customer expectations or contractual obligations, including by causing service disruptions.

Failure to attract and retain an appropriately qualified workforce, and maintain good labor relations, could harm our results of operations.

We operate in an industry that requires many of our employees to possess unique technical skill sets. Events such as an aging workforce without appropriate replacements, the mismatch of skill sets to future needs, or the unavailability of contract resources may lead to operating challenges or increased costs. These operating challenges include lack of resources, loss of knowledge, and a lengthy time period associated with skill development. In addition, current and prospective employees may determine that they do not wish to work for us due to market, economic, employment and other conditions. Failure to hire and retain qualified employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, safety, service reliability, customer satisfaction and our results of operations could be adversely affected.

Some of our employees are subject to collective bargaining agreements. Our collective bargaining agreements are generally negotiated on an operating company basis. Any failure to reach an agreement on new labor contracts or to negotiate these labor contracts might result in strikes, boycotts or other labor disruptions. Labor disruptions, strikes or significant negotiated wage and benefit increases, whether due to union activities, employee turnover or otherwise, could have a material adverse effect on our businesses, results of operations and/or cash flows.

We are a holding company and are dependent on cash generated by our subsidiaries to meet our debt obligations and pay dividends on our stock.

We are a holding company and conduct our operations primarily through our subsidiaries, which are separate and distinct legal entities. Substantially all of our consolidated assets are held by our subsidiaries. Accordingly, our ability to meet our debt obligations or pay dividends on our common stock and preferred stock is largely dependent upon cash generated by these subsidiaries. In the event a major subsidiary is not able to pay dividends or transfer cash flows to us, our ability to service our debt obligations or pay dividends could be negatively affected.

If we cannot effectively manage new initiatives and organizational changes, we will be unable to address the opportunities and challenges presented by our strategy and the business and regulatory environment.

In order to execute on our sustainable growth strategy and enhance our culture of ongoing continuous improvement, we must effectively manage the complexity and frequency of new initiatives and organizational changes. If we are unable to make decisions quickly, assess our opportunities and risks, and implement new governance, managerial and organizational processes as needed to execute our strategy in this increasingly dynamic and competitive business and regulatory environment, our financial condition, results of operations and relationships with our business partners, regulators, customers and stockholders may be negatively impacted.

We outsource certain business functions to third-party suppliers and service providers, and substandard performance by those third parties could harm our business, reputation and results of operations.

Utilities rely on extensive networks of business partners and suppliers to support critical enterprise capabilities across their organizations. Global metrics indicate that deliveries from suppliers are slowing and that labor shortages are occurring in the energy sector. We outsource certain services to third parties in areas including construction services, information technology, materials, fleet, environmental, operational services and other areas. Outsourcing of services to third parties could expose us to inferior service quality or substandard deliverables, which may result in non-compliance (including with applicable legal requirements and industry standards), interruption of service or accidents, or reputational harm, which could negatively impact our results of operations. If any difficulties in the operations of these third-party suppliers and service providers, including their systems, were to occur, they could adversely affect our results of operations, or adversely affect our ability to work with regulators, unions, customers or employees.

Changes in the method for determining LIBOR and the potential replacement of the LIBOR benchmark interest rate could adversely affect our business, financial condition, results of operations and cash flows.

Some of our indebtedness, including borrowings under our revolving credit agreement and term loan agreement, bears interest at a variable rate based on LIBOR. From time to time, we also enter into hedging instruments to manage our exposure to fluctuations in the LIBOR benchmark interest rate. In addition, these hedging instruments, as well as hedging instruments that our subsidiaries use for hedging natural gas price and basis risk, rely on LIBOR-based rates to calculate interest accrued on certain payments that may be required to be made under these agreements, such as late payments or interest accrued if any cash collateral should be held by a counterparty. Any changes announced by regulators in the method pursuant to which the LIBOR rates are determined may result in a sudden or prolonged increase or decrease in the reported LIBOR rates. If that were to occur, the level of interest payments we incur may change.

In July 2017, the United Kingdom Financial Conduct Authority ("FCA"), which regulates LIBOR, announced that the FCA intends to stop compelling banks to submit rates for the calculation of LIBOR after 2021. It is not possible to predict the effect of these changes, other reforms or the establishment of alternative reference rates in the United Kingdom or elsewhere. In the United States, efforts to identify a set of alternative U.S. dollar reference interest rates include proposals by the Alternative Reference Rates Committee of the Federal Reserve Board and the Federal Reserve Bank of New York. The Alternative Reference Rates Committee has proposed the Secured Overnight Financing Rate ("SOFR") as its recommended alternative to LIBOR, and the Federal Reserve Bank of New York began publishing SOFR rates in April 2018. SOFR is intended to be a broad measure of the cost of borrowing cash overnight that is collateralized by U.S. Treasury securities. However, because SOFR is a broad U.S. Treasury repurchase agreement financing rate that represents overnight secured funding transactions, it differs fundamentally from LIBOR. For example, SOFR is a secured overnight rate, while LIBOR is an unsecured rate that represents interbank funding over different maturities. In addition, because SOFR is a transaction-based rate, it is backward-looking, whereas LIBOR is forward-looking. Because of these and other differences, there is no assurance that SOFR will perform in the same way as LIBOR would have performed at any time, and there is no guarantee that it is a comparable substitute for LIBOR. SOFR may fail to gain market acceptance.

In addition, although certain of our LIBOR based obligations provide for alternative methods of calculating the interest rate payable on certain of our obligations if LIBOR is not reported, which include, without limitation, requesting certain rates from major reference banks in London or New York, uncertainty as to the extent and manner of future changes may result in interest rates and/or payments that are higher than, lower than or that do not otherwise correlate over time with, the interest rates or payments that would have been made on our obligations if a LIBOR-based rate was available in its current form.

ITEM 1B. UNRESOLVED STAFF COMMENTS

NISOURCE INC.

None.

ITEM 2. PROPERTIES

Discussed below are the principal properties held by us and our subsidiaries as of December 31, 2019.

Gas Distribution Operations
Refer to Item 1, "Business - Gas Distribution Operations" of this report for further information on Gas Distribution Operations properties.

Electric Operations
Refer to Item 1, "Business - Electric Operations" of this report for further information on Electric Operations properties.

Corporate and Other Operations
We own the Southlake Complex, our 325,000 square foot headquarters building located in Merrillville, Indiana.

Character of Ownership
Our principal properties and our subsidiaries principal properties are owned free from encumbrances, subject to minor exceptions, none of which are of such a nature as to impair substantially the usefulness of such properties. Many of our subsidiary offices in various communities served are occupied under leases. All properties are subject to routine liens for taxes, assessments and undetermined charges (if any) incidental to construction. It is our practice to regularly pay such amounts, as and when due, unless contested in good faith. In general, the electric lines, gas pipelines and related facilities are located on land not owned by us or our subsidiaries, but are covered by necessary consents of various governmental authorities or by appropriate rights obtained from owners of private property. We do not, however, generally have specific easements from the owners of the property adjacent to public highways over, upon or under which our electric lines and gas distribution pipelines are located. At the time each of the principal properties were purchased, a title search was made. In general, no examination of titles as to rights-of-way for electric lines, gas pipelines or related facilities was made, other than examination, in certain cases, to verify the grantors' ownership and the lien status thereof.

ITEM 3. LEGAL PROCEEDINGS

For a description of our legal proceedings, see Note 19-C "Legal Proceedings" in the Notes to Consolidated Financial Statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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SUPPLEMENTAL ITEM. INFORMATION ABOUT OUR EXECUTIVE OFFICERS

NiSource Inc.

The following is a list of our executive officers, including their names, ages, offices held and other recent business experience.

Name	Age	Office(s) Held in Past 5 Years
Joseph Hamrock	56	President and Chief Executive Officer of NiSource since July 2015.
		Executive Vice President and Group Chief Executive Officer of NiSource from May 2012 to July 2015.
Donald E. Brown	48	Executive Vice President of NiSource since May 2015.
		Chief Financial Officer of NiSource since July 2015.
		Treasurer of NiSource from July 2015 to June 2016.
		Vice President and Chief Financial Officer of UGI Utilities, a division of UGI Corporation (gas and electric utility company) from 2010 to March 2015.
Peter T. Disser	51	Vice President, Internal Audit of NiSource since January 2019.
		Chief Operating Officer of NiSource from September 2018 to December 2018.
		Vice President, Audit of NiSource from November 2017 to September 2018.
		Vice President, Planning and Analysis of NiSource from June 2016 to November 2017.
		Vice President, Strategy and Planning of NiSource Corporate Services Company from July 2015 to May 2016.
		Chief Financial Officer of NIPSCO from 2012 to June 2015.
Carrie J. Hightman	62	Executive Vice President and Chief Legal Officer of NiSource since 2007.
Kenneth E. Keener	55	Senior Vice President and Chief Human Resources Officer of NiSource since August 2019.
		Vice President, Talent and Organizational Effectiveness of NiSource Corporate Services Company from June 2012 to July 2019.
Charles E. Shafer, II	50	Senior Vice President and Chief Safety Officer of NiSource since October 2019.
		Senior Vice President, Gas Engineering and Gas Support Services of NiSource Corporate Services Company from January 2019 to September 2019.
		Senior Vice President, Customer Services and New Business of NiSource Corporate Services Company from May 2016 through December 2018.
		Vice President, Engineering and Construction of NiSource Corporate Services Company from June 2012 to May 2016.
Violet G. Sistovaris	58	Executive Vice President and President, NIPSCO of NiSource since July 2015.
		Senior Vice President and Chief Information Officer of NiSource from May 2014 to June 2015.
Suzanne K. Surface	55	Chief Services Officer of NiSource since January 2019.
		Vice President, Audit of NiSource from September 2018 to December 2018.
		Vice President, Transformation Office of NiSource from August 2018 to September 2018.

		Vice President, Corporate Services Customer Value of NiSource from November 2017 to August 2018.
		Vice President, Audit of NiSource from July 2015 to November 2017.
		Vice President, Regulatory Strategy and Support of NiSource Corporate Services Company from July 2009 to June 2015.
Pablo A. Vegas	46	Executive Vice President and President, Gas Utilities of NiSource since January 2019.
		Executive Vice President and Chief Restoration Officer of NiSource from September 2018 to December 2018.
		Executive Vice President, Gas Business Segment and Chief Customer Officer of NiSource from May 2017 to September 2018.
		Executive Vice President and President, Columbia Gas Group from May 2016 to May 2017.
		President and Chief Operating Officer of American Electric Power Company of Ohio from May 2012 to May 2016.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

NISOURCE INC.

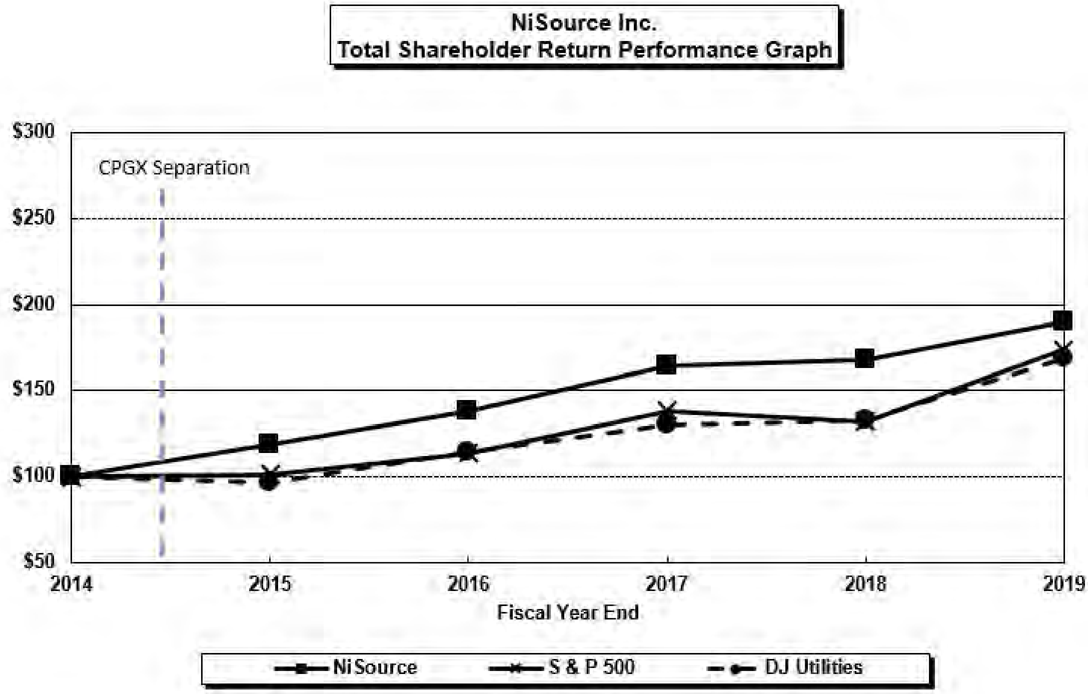
NiSource's common stock is listed and traded on the New York Stock Exchange under the symbol "NI."

Holders of shares of NiSource's common stock are entitled to receive dividends if and when declared by NiSource's Board out of funds legally available, subject to the prior dividend rights of holders of our preferred stock or the depositary shares representing such preferred stock outstanding, and if full dividends have not been declared and paid on all outstanding shares of preferred stock in any dividend period, no dividend may be declared or paid or set aside for payment on our common stock. The policy of the Board has been to declare cash dividends on a quarterly basis payable on or about the 20th day of February, May, August, and November. At its January 31, 2020 meeting, the Board declared a quarterly common dividend of $0.21 per share, payable on February 20, 2020 to holders of record on February 11, 2020.

Although the Board currently intends to continue the payment of regular quarterly cash dividends on common shares, the timing and amount of future dividends will depend on the earnings of NiSource's subsidiaries, their financial condition, cash requirements, regulatory restrictions, any restrictions in financing agreements and other factors deemed relevant by the Board. There can be no assurance that NiSource will continue to pay such dividends or the amount of such dividends.

As of February 18, 2020, NiSource had 18,868 common stockholders of record and 382,263,348 shares outstanding.

The graph below compares the cumulative total shareholder return of NiSource's common stock for the last five years with the cumulative total return for the same period of the S&P 500 and the Dow Jones Utility indices. On July 1, 2015, NiSource completed the Separation. Following the Separation, NiSource retained no ownership interest in CPG. The Separation is treated as a special dividend for purposes of calculating the total shareholder return, with the then-current market value of the distributed shares being deemed to have been reinvested on the Separation date in shares of NiSource common stock. A vertical line is included on the graph below to identify the periods before and after the Separation.



PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

NiSource Inc.

The foregoing performance graph is being furnished as part of this annual report solely in accordance with the requirement under Rule 14a-3(b)(9) to furnish stockholders with such information, and therefore, shall not be deemed to be filed or incorporated by reference into any filings by NiSource under the Securities Act or the Exchange Act.

The total shareholder return for NiSource common stock and the two indices is calculated from an assumed initial investment of $100 and assumes dividend reinvestment, including the impact of the distribution of CPG common stock in the Separation.

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ITEM 6. SELECTED FINANCIAL DATA

NISOURCE INC.

The selected data presented below as of and for the five years ended December 31, 2019, are derived from our Consolidated Financial Statements. The data should be read together with the Consolidated Financial Statements including the related notes thereto included in Item 8 of this Form 10-K.

Year Ended December 31, (*in millions except per share data*)	**2019**	2018	2017	2016	2015
Statement of Income Data:					
Total Operating Revenues	**$ 5,208.9**	$ 5,114.5	$ 4,874.6	$ 4,492.5	$ 4,651.8
Net Income (Loss) Available to Common Shareholders	**328.0**	(65.6)	128.5	331.5	198.6
Balance Sheet Data:					
Total Assets	**22,659.8**	21,804.0	19,961.7	18,691.9	17,492.5
Capitalization					
Stockholders' equity	**5,986.7**	5,750.9	4,320.1	4,071.2	3,843.5
Long-term debt, excluding amounts due within one year	**7,856.2**	7,105.4	7,512.2	6,058.2	5,948.5
Total Capitalization	**$ 13,842.9**	$ 12,856.3	$ 11,832.3	$ 10,129.4	$ 9,792.0
Per Share Data:					
Basic Earnings (Loss) Per Share ($)	**$ 0.88**	$ (0.18)	$ 0.39	$ 1.02	$ 0.63
Diluted Earnings (Loss) Per Share ($)	**$ 0.87**	$ (0.18)	$ 0.39	$ 1.01	$ 0.63
Other Data:					
Dividends declared per common share ($)	**$ 0.80**	$ 0.78	$ 0.70	$ 0.64	$ 0.83
Common shares outstanding at the end of the year (in thousands)	**382,136**	372,363	337,016	323,160	319,110
Number of common stockholders	**18,725**	19,889	21,009	22,272	30,190
Dividends declared per Series A preferred share ($)	**$ 56.50**	$ 28.88	$ —	$ —	$ —
Dividends declared per Series B preferred share ($)	**$ 1,674.65**	$ —	$ —	$ —	$ —
Capital expenditures	**$ 1,867.8**	$ 1,814.6	$ 1,753.8	$ 1,490.4	$ 1,367.5
Number of employees	**8,363**	8,087	8,175	8,007	7,596

- During 2019, we recorded a loss of approximately $284 million for third-party claims and approximately $154 million for other incident-related expenses in connection with the Greater Lawrence Incident. Columbia of Massachusetts recorded $665 million for insurance recoveries through December 31, 2019. For additional information, see Note 19-C, "Legal Proceedings," and E, "Other Matters" in the Notes to Consolidated Financial Statements.

- During the fourth quarter of 2019, we recorded an impairment charge of $204.8 million for goodwill and an impairment charge of $209.7 million for franchise rights, in each case related to Columbia of Massachusetts. For additional information, see Note 6, "Goodwill and Other Intangible Assets," in the Notes to Consolidated Financial Statements.

- During the third quarter of 2019, we closed our placement of $750.0 million of 2.95% senior unsecured notes maturing in 2029.

- During the second quarter of 2018, we completed the sale of 24,964,163 shares of $0.01 par value common stock at a price of $24.28 per share in a private placement to selected institutional and accredited investors and issued 400,000 shares of Series A preferred stock resulting in $400.0 million of gross proceeds or $393.9 million of net proceeds, after deducting commissions and sales expenses. Additionally, in the fourth quarter of 2018, we issued 20,000 shares of Series B preferred stock resulting in $500.0 million of gross proceeds or $486.1 million of net proceeds, after deducting commissions and sales expenses.

- During 2018, we recorded a loss of approximately $757 million for third-party claims and approximately $266 million for other incident-related expenses in connection with the Greater Lawrence Incident. Columbia of Massachusetts recorded $135 million for insurance recoveries through December 31, 2018. For additional information, see Note 19-C, "Legal Proceedings," and E, Other Matters." in the Notes to Consolidated Financial Statements.

- During the second quarter of 2018, we executed a tender offer for $209.0 million of outstanding notes consisting of a combination of our 6.80% notes due 2019, 5.45% notes due 2020 and 6.125% notes due 2022. During the third quarter of 2018, we redeemed $551.1 million of outstanding notes representing the remainder of our 6.80% notes due 2019, 5.45% notes due 2020 and 6.125% notes due 2022. In conjunction with our debt retired, we recorded a $45.5 million loss on early extinguishment of long-term debt primarily attributable to early redemption premiums.

ITEM 6. SELECTED FINANCIAL DATA

NISOURCE INC.

- The decrease in net income during 2017 was due primarily to increased tax expense as a result of the impact of adopting the provisions of the TCJA and a loss on early extinguishment of long-term debt, as discussed below.
- During the second quarter of 2017, we executed a tender offer for $990.7 million of outstanding notes consisting of a combination of our 6.40% notes due 2018, 6.80% notes due 2019, 5.45% notes due 2020, and 6.125% notes due 2022. In conjunction with the debt retired, we recorded a $111.5 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums.
- Prior to the Separation, CPG closed the placement of $2,750.0 million in aggregate principal amount of senior notes. Using the proceeds from this offering, CPG made cash payments to us representing the settlement of inter-company borrowings and the payment of a one-time special dividend. In May 2015, using proceeds from the cash payments from CPG, we settled two bank term loans in the amount of $1,075.0 million and executed a tender offer for $750.0 million consisting of a combination of its 5.25% notes due 2017, 6.40% notes due 2018 and 4.45% notes due 2021. In conjunction with the debt retired, we recorded a $97.2 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

NiSource Inc.

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EXECUTIVE SUMMARY

This Management's Discussion and Analysis of Financial Condition and Results of Operations (Management's Discussion) analyzes our financial condition, results of operations and cash flows and those of our subsidiaries. It also includes management's analysis of past financial results and certain potential factors that may affect future results, potential future risks and approaches that may be used to manage those risks. See "Note regarding forward-looking statements" at the beginning of this report for a list of factors that may cause results to differ materially.

Management's Discussion is designed to provide an understanding of our operations and financial performance and should be read in conjunction with our Consolidated Financial Statements and related Notes to Consolidated Financial Statements in this annual report.

We are an energy holding company under the Public Utility Holding Company Act of 2005 whose subsidiaries are fully regulated natural gas and electric utility companies serving customers in seven states. We generate substantially all of our operating income through these rate-regulated businesses which are summarized for financial reporting purposes into two primary reportable segments: Gas Distribution Operations and Electric Operations.

Refer to the "Business" section under Item 1 of this annual report and Note 23, "Segments of Business," in the Notes to Consolidated Financial Statements for further discussion of our regulated utility business segments.

Our goal is to develop strategies that benefit all stakeholders as we address changing customer conservation patterns, develops more contemporary pricing structures and embarks on long-term infrastructure investment and safety programs. These strategies are intended to improve reliability and safety, enhance customer services and reduce emissions while generating sustainable returns. Additionally, we continue to pursue regulatory and legislative initiatives that will allow residential customers not currently on our system to obtain gas service in a cost effective manner. Refer also to the discussion of *Electric Supply* within our Electric Operations Segment discussion for additional information on our long term electric generation strategy.

Greater Lawrence Incident: The Greater Lawrence Incident occurred on September 13, 2018. The following table summarizes expenses incurred and insurance recoveries recorded since the Greater Lawrence Incident. The amounts set forth in the table below do not include the capital cost of the pipeline replacement described below and as set forth in Note 19, "Other Commitments and Contingencies - E. Other Matters - Greater Lawrence Pipeline Replacement," in the Notes to Consolidated Financial Statements.

(in millions)	Year Ended December 31, 2018	**Year Ended December 31, 2019**	Incident to Date
Third-party claims and government fines, penalties and settlements	$ 757	**$ 284**	$ 1,041
Other incident-related costs	266	**154**	420
Total	1,023	**438**	1,461
Insurance recoveries recorded	(135)	**(665)**	(800)
Loss (benefit) to income before income taxes	$ 888	**$ (227)**	$ 661

Inclusive of the $1,041 million of third-party claims and fines, penalties and settlements associated with government investigations recorded incident to date, we estimate that total costs related to third-party claims and fines, penalties and settlements associated with government investigations as set forth in Note 19, "Other Commitments and Contingencies - C. Legal Proceedings," will range from $1,041 million to $1,065 million, depending on the number, nature, final outcome and value of third-party claims and the final outcome of government investigations. These costs do not include costs of certain third-party claims and fines, penalties or settlements with government investigations that we are not able to estimate. We expect to incur a total of $450 million to $460 million in other incident-related costs, inclusive of the $420 million recorded incident to date, as set forth in Note 19, "Other Commitments and Contingencies - E. Other Matters - Greater Lawrence Incident Restoration."

The process for estimating costs associated with third-party claims and fines, penalties and settlements associated with government investigations relating to the Greater Lawrence Incident requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including additional information regarding ongoing investigations, management's estimates and assumptions regarding the financial impact of the Greater Lawrence Incident may change.

The aggregate amount of third-party liability insurance coverage available for losses arising from the Greater Lawrence Incident is $800 million. We have collected the entire $800 million as of December 31, 2019. Expenses related to the incident have exceeded the total amount of insurance coverage available under our policies. The following table presents activity related to our Greater Lawrence Incident insurance recovery.

(in millions)		Insurance receivable[1]
Balance, December 31, 2018	**$**	**130**
Insurance recoveries recorded in first quarter of 2019		100
Cash collected from insurance recoveries in the first quarter of 2019		(108)
Balance, March 31, 2019		**122**
Insurance recoveries recorded in the second quarter of 2019		435
Cash collected from insurance recoveries in the second quarter of 2019		(297)
Balance, June 30, 2019	**$**	**260**
Insurance recoveries recorded in third quarter of 2019		—
Cash collected from insurance recoveries in the third quarter of 2019		(260)
Balance, September 30, 2019	**$**	**—**
Insurance recoveries recorded in the fourth quarter of 2019		130
Cash collected from insurance recoveries in the fourth quarter of 2019		(130)
Balance, December 31, 2019	**$**	**—**

[1]$5 million of insurance recoveries were collected during 2018.

Since the Greater Lawrence Incident and through December 31, 2019, we have invested approximately $258 million of capital spend for the pipeline replacement; this work was completed in 2019. We maintain property insurance for gas pipelines and other applicable property. Columbia of Massachusetts has filed a proof of loss with its property insurer for the full cost of the pipeline replacement. In January 2020, we filed a lawsuit against the property insurer, seeking payment of our property claim. We are currently unable to predict the timing or amount of any insurance recovery under the property policy. The recovery of any capital investment not reimbursed through insurance will be addressed in a future regulatory proceeding; a future regulatory proceeding is dependent on the outcome of the sale of the Massachusetts Business. The outcome of such a proceeding (if any) is uncertain. In accordance with ASC 980-360, if it becomes probable that a portion of the pipeline replacement cost will not be recoverable through customer rates and an amount can be reasonably estimated, we will reduce our regulated plant balance for the amount of the probable disallowance and record an associated charge to earnings. This could result in a material adverse effect on our financial condition, results of operations and cash flows. Additionally, if a rate order is received allowing recovery of the investment with no or reduced return on investment, a loss on disallowance may be required.

Refer to Note 19, "Other Commitments and Contingencies - C. Legal Proceedings" and " - E. Other Matters," in the Notes to Consolidated Financial Statements, "Summary of Consolidated Financial Results," "Results and Discussion of Segment Operation - Gas Distribution Operations," and "Liquidity and Capital Resources" in this Management's Discussion for additional information related to the Greater Lawrence Incident.

Additionally, as discussed in Note 6, "Goodwill and Other Intangible Assets," in the Notes to Consolidated Financial Statements, we assessed the totality of several factors that developed during the fourth quarter related to the Greater Lawrence Incident and concluded that it was more likely than not that the fair value of the Columbia of Massachusetts reporting unit was below its carrying value. As a result, a new impairment analysis was required for our Columbia of Massachusetts reporting unit. The year-end impairment analysis indicated that the fair value of the Columbia of Massachusetts reporting unit was below its carrying value. As a result, we reduced the Columbia of Massachusetts reporting unit goodwill balance to zero and recognized a goodwill impairment charge totaling $204.8 million, which is non-deductible for tax purposes. We assessed the same fourth quarter circumstances in reviewing the Columbia of Massachusetts franchise rights intangible assets. These factors led us to conclude that it was more likely than not that the fair value of the franchise rights was below its carrying amount. As a result, we performed a year-end impairment test and determined that the fair value of the franchise rights was zero. Therefore, we wrote off the entire franchise rights book value, which resulted in an impairment charge totaling $209.7 million.

Columbia of Massachusetts Asset Sale: On February 26, 2020, NiSource and Columbia of Massachusetts entered into the Asset Purchase Agreement with Eversource. Upon the terms and subject to the conditions set forth in the Asset Purchase Agreement, NiSource and Columbia of Massachusetts agreed to sell to Eversource the Massachusetts Business for a purchase price of $1,100 million, subject to adjustment. For additional information, see Note 26, "Subsequent Event," in the Notes to Consolidated Financial Statements.

Summary of Consolidated Financial Results

Our operations are affected by the cost of sales. Cost of sales for the Gas Distribution Operations segment is principally comprised of the cost of natural gas used while providing transportation and distribution services to customers. Cost of sales for the Electric Operations segment is comprised of the cost of coal, related handling costs, natural gas purchased for the internal generation of electricity at NIPSCO and the cost of power purchased from third-party generators of electricity.

The majority of the cost of sales are tracked costs that are passed through directly to the customer resulting in an equal and offsetting amount reflected in operating revenues. As a result, we believe net revenues, a non-GAAP financial measure defined as operating revenues less cost of sales (excluding depreciation and amortization), provides management and investors a useful measure to analyze profitability. The presentation of net revenues herein is intended to provide supplemental information for investors regarding operating performance. Net revenues do not intend to represent operating income, the most comparable GAAP measure, as an indicator of operating performance and is not necessarily comparable to similarly titled measures reported by other companies.

For the years ended December 31, 2019, 2018 and 2017, operating income and a reconciliation of net revenues to the most directly comparable GAAP measure, operating income, was as follows:

Year Ended December 31, *(in millions)*	**2019**	2018	2017	2019 vs. 2018	2018 vs. 2017
Operating Income	**$ 890.7**	$ 124.7	$ 921.2	$ 766.0	$ (796.5)

Year Ended December 31, *(in millions, except per share amounts)*	**2019**	2018	2017	2019 vs. 2018	2018 vs. 2017
Operating Revenues	**$ 5,208.9**	$ 5,114.5	$ 4,874.6	$ 94.4	$ 239.9
Cost of sales (excluding depreciation and amortization)	**1,534.8**	1,761.3	1,518.7	(226.5)	242.6
Total Net Revenues	**3,674.1**	3,353.2	3,355.9	320.9	(2.7)
Other Operating Expenses	**2,783.4**	3,228.5	2,434.7	(445.1)	793.8
Operating Income	**890.7**	124.7	921.2	766.0	(796.5)
Total Other Deductions, Net	**(384.1)**	(355.3)	(478.2)	(28.8)	122.9
Income Taxes	**123.5**	(180.0)	314.5	303.5	(494.5)
Net Income (Loss)	**383.1**	(50.6)	128.5	433.7	(179.1)
Preferred dividends	**(55.1)**	(15.0)	—	(40.1)	(15.0)
Net Income (Loss) Available to Common Shareholders	**328.0**	(65.6)	128.5	393.6	(194.1)
Basic Earnings (Loss) Per Share	**$ 0.88**	$ (0.18)	$ 0.39	$ 1.06	$ (0.57)
Basic Average Common Shares Outstanding	**374.6**	356.5	329.4	18.1	27.1

On a consolidated basis, we reported net income available to common shareholders of $328.0 million or $0.88 per basic share for the twelve months ended December 31, 2019 compared to a loss to common shareholders of $65.6 million or $0.18 per basic share for the same period in 2018. The increase in net income available to common shareholders during 2019 was primarily due to lower operating expenses related to the Greater Lawrence Incident, insurance recoveries recorded related to the Greater Lawrence Incident, and new rates from base rate proceedings and infrastructure replacement programs. These increases were partially offset by non-cash impairments of goodwill and other intangible assets in 2019 related to Columbia of Massachusetts (see Note 6, "Goodwill and Other Intangible Assets," in the Notes to Consolidated Financial Statements for additional information), higher income taxes (see "Income Taxes" below), higher depreciation expense due to regulatory outcomes at NIPSCO and Columbia of Ohio, and additional dilution in 2019 resulting from preferred stock dividend commitments.

Operating Income

For the twelve months ended December 31, 2019, we reported operating income of $890.7 million compared to $124.7 million for the same period in 2018. The increased operating income was primarily due to decreased operating expenses related to the Greater Lawrence Incident, insurance recoveries recorded related to the Greater Lawrence Incident, and new rates from base rate proceedings and infrastructure replacement programs. These increases were partially offset by non-cash impairments of goodwill and other intangible assets in 2019 related to Columbia of Massachusetts (see Note 6, "Goodwill and Other Intangible Asset," in the Notes to Consolidated Financial Statements for additional information), and increased depreciation due to the regulatory outcome of NIPSCO's gas rate case and an increase in amortization of depreciation previously deferred as a regulatory asset resulting from Columbia of Ohio's CEP.

Other Deductions, Net

Other deductions, net reduced income by $384.1 million in 2019 compared to a reduction in income of $355.3 million in 2018. This change is primarily due to lower actuarial investment returns on pension and other postretirement benefit assets of $34.6 million, and an increase in interest expense of $25.6 million driven by decreased regulatory deferrals from Columbia of Ohio's CEP. These unfavorable variances were partially offset by charitable contributions of $20.7 million in 2018 related to the Greater Lawrence Incident.

Income Taxes

The increase in income tax expense from 2018 to 2019 is primarily attributable to higher pre-tax income resulting from the items discussed above in "Operating Income" and "Other Deductions, Net," true-ups to tax expense in 2018 to reflect regulatory outcomes associated with excess deferred income taxes, and higher income tax expense in 2019 related to the non-deductible, non-cash impairment of goodwill, fines and penalties.

Refer to “Liquidity and Capital Resources” below and Note 10, "Income Taxes," in the Notes to Consolidated Financial Statements for additional information on income taxes and the change in the effective tax rate.

Capital Investment
In 2019, we invested approximately $1.9 billion in capital expenditures across the gas and electric utilities. These expenditures were primarily aimed at furthering the safety and reliability of our gas distribution system, and maintaining our existing electric generation fleet.

We continue to execute on an estimated $30 billion in total projected long-term regulated utility infrastructure investments and expect to invest approximately $1.8 to $1.9 billion in capital during 2020 as we continue to focus on growth, safety and modernization projects across our operating area.

Liquidity
A primary focus of ours is to ensure the availability of adequate financing to fund our ongoing safety and infrastructure investment programs which typically involves the issuance of debt and/or equity. In addition, expenses related to the Greater Lawrence Incident have exceeded the total amount of insurance coverage available under our policies. During 2020, we plan to pursue alternatives to cover this shortfall, including long-term financing and potential proceeds from the sale of the Massachusetts Business. For additional information, see Note 26, "Subsequent Event," in the Notes to Consolidated Financial Statements.

Through income generated from operating activities, amounts available under our short-term revolving credit facility, commercial paper program, accounts receivable securitization facilities, term loan borrowings, long-term debt agreements, our ability to access the capital markets and the potential sale of the Massachusetts Business, we believe there is adequate capital available to fund our operating activities and capital expenditures and the effects of the Greater Lawrence Incident in 2020 and beyond. At December 31, 2019 and 2018, we had approximately $1,409.1 million and $974.6 million, respectively, of net liquidity available, consisting of cash and available capacity under credit facilities.

These factors and other impacts to the financial results are discussed in more detail within the following discussions of “Results and Discussion of Segment Operations” and “Liquidity and Capital Resources.”

Regulatory Developments
In 2019, we continued to move forward on core infrastructure and environmental investment programs supported by complementary regulatory and customer initiatives across all seven states of our operating area. Refer to Note 8, “Regulatory Matters” and Note 19-E, "Other Matters," in the Notes to Consolidated Financial Statements for a complete discussion of key regulatory developments that transpired during 2019.

RESULTS AND DISCUSSION OF SEGMENT OPERATIONS

Presentation of Segment Information
Our operations are divided into two primary reportable segments: Gas Distribution Operations and Electric Operations.

NiSource Inc.
Gas Distribution Operations

For the years ended December 31, 2019, 2018 and 2017, operating income (loss) and a reconciliation of net revenues to the most directly comparable GAAP measure, operating income (loss), was as follows:

Year Ended December 31, *(in millions)*	2019	2018	2017	2019 vs. 2018	2018 vs. 2017
Operating Income (Loss)	**$ 675.4**	$ (254.1)	$ 550.1	$ 929.5	$ (804.2)

Year Ended December 31, *(in millions)*	2019	2018	2017	2019 vs. 2018	2018 vs. 2017
Net Revenues					
Operating revenues	**$ 3,522.8**	$ 3,419.5	$ 3,102.1	$ 103.3	$ 317.4
Less: Cost of sales (excluding depreciation and amortization)	**1,067.6**	1,259.3	1,005.0	(191.7)	254.3
Net Revenues	**2,455.2**	2,160.2	2,097.1	295.0	63.1
Operating Expenses					
Operation and maintenance	**935.7**	1,908.1	1,090.8	(972.4)	817.3
Depreciation and amortization	**403.2**	301.0	269.3	102.2	31.7
Impairment of other intangible assets	**209.7**	—	—	209.7	—
Loss on sale of fixed assets and impairments, net	**0.1**	0.2	2.8	(0.1)	(2.6)
Other taxes	**231.1**	205.0	184.1	26.1	20.9
Total Operating Expenses	**1,779.8**	2,414.3	1,547.0	(634.5)	867.3
Operating Income (Loss)	**$ 675.4**	$ (254.1)	$ 550.1	$ 929.5	$ (804.2)
Revenues					
Residential	**$ 2,317.2**	$ 2,248.3	$ 2,029.4	$ 68.9	$ 218.9
Commercial	**775.1**	753.7	669.4	21.4	84.3
Industrial	**245.8**	228.6	217.5	17.2	11.1
Off-System	**77.7**	92.4	111.8	(14.7)	(19.4)
Other	**107.0**	96.5	74.0	10.5	22.5
Total	**$ 3,522.8**	$ 3,419.5	$ 3,102.1	$ 103.3	$ 317.4
Sales and Transportation (MMDth)					
Residential	**274.9**	280.3	247.1	(5.4)	33.2
Commercial	**189.6**	187.6	169.3	2.0	18.3
Industrial	**542.5**	555.7	517.5	(13.2)	38.2
Off-System	**32.9**	30.0	39.0	2.9	(9.0)
Other	**0.3**	—	0.3	0.3	(0.3)
Total	**1,040.2**	1,053.6	973.2	(13.4)	80.4
Heating Degree Days	**5,375**	5,562	4,927	(187)	635
Normal Heating Degree Days	**5,452**	5,610	5,610	(158)	—
% Warmer than Normal	**(1)%**	(1)%	(12)%		
Gas Distribution Customers					
Residential	**3,221,178**	3,194,662	3,168,516	26,516	26,146
Commercial	**282,778**	281,517	280,362	1,261	1,155
Industrial	**5,982**	5,833	6,228	149	(395)
Other	**3**	3	4	—	(1)
Total	**3,509,941**	3,482,015	3,455,110	27,926	26,905

NISOURCE INC.
Gas Distribution Operations (continued)

Comparability of line item operating results may be impacted by regulatory, tax and depreciation trackers (other than those for cost of sales) that allow for the recovery in rates of certain costs. Therefore, increases in these tracked operating expenses are generally offset by increases in net revenues and have essentially no impact on net income.

2019 vs. 2018 Operating Income
For 2019, Gas Distribution Operations reported operating income of $675.4 million, an increase in income of $929.5 million from the comparable 2018 period.

Net revenues for 2019 were $2,455.2 million, an increase of $295.0 million from the same period in 2018. The change in net revenues was primarily driven by:

- New rates from base rate proceedings and infrastructure replacement programs of $243.2 million.
- Higher regulatory, depreciation, and tax trackers, which are offset in operating expense, of $36.2 million.
- Higher revenues of $14.5 million resulting from an update in the weather-related normal heating degree day methodology (see further detail below), partially offset by a $7.1 million revenue decrease from the effects of warmer weather in 2019.
- The effects of commercial and residential customer growth of $12.8 million.

Operating expenses were $634.5 million lower in 2019 compared to 2018. This change was primarily driven by:

- Decreased expenses related to third-party claims and other costs for the Greater Lawrence Incident of $1,090.7 million, net of insurance recoveries recorded.

Partially offset by:

- Non-cash impairment of the Columbia of Massachusetts franchise rights of $209.7 million.
- Increased depreciation of $103.8 million due to the regulatory outcome of NIPSCO's gas rate case, an increase in amortization of depreciation previously deferred as a regulatory asset resulting from Columbia of Ohio's CEP, and higher capital expenditures placed in service.
- Higher employee and administrative expenses of $50.2 million driven by resources shifting from the temporary assistance on the Greater Lawrence Incident restoration to normal operations (offset in the decreased Greater Lawrence Incident costs discussed above) and an increase in headcount.
- Increased regulatory, depreciation, and tax trackers, which are offset in net revenues, of $36.2 million.
- Higher property taxes of $22.2 million primarily due to increased amortization of property taxes previously deferred as a regulatory asset resulting from Columbia of Ohio's CEP, as well as higher capital expenditures placed in service.
- Higher outside services of $17.4 million primarily due to increased line location and safety-related work.
- Higher insurance expense of $9.1 million primarily driven by increased premiums.

2018 vs. 2017 Operating Income
For 2018, Gas Distribution Operations reported an operating loss of $254.1 million, a decrease in income of $804.2 million from the comparable 2017 period.

Net revenues for 2018 were $2,160.2 million, an increase of $63.1 million from the same period in 2017. The change in net revenues was primarily driven by:

- New rates from infrastructure replacement programs and base rate proceedings of $99.6 million.
- Higher revenues from the effects of colder weather in 2018 of $37.5 million.
- The effects of customer growth and increased usage of $17.4 million.
- Higher regulatory, tax and depreciation trackers, which are offset in operating expense, of $16.0 million.

Partially offset by:

- A revenue reserve of $85.0 million in 2018 resulting from the probable future refund of certain collections from customers as a result of the lower income tax rate from the TCJA.
- Decreased rates from implementation of regulatory outcomes related to the TCJA of $24.7 million.

NISOURCE INC.
Gas Distribution Operations (continued)

Operating expenses were $867.3 million higher in 2018 compared to 2017. This change was primarily driven by:

- Expenses related to third-party claims and other costs for the Greater Lawrence Incident of $864.4 million, net of insurance recoveries recorded.
- Increased depreciation of $29.6 million due to regulatory outcomes of NIPSCO's gas rate case and higher capital expenditures placed in service.
- Higher regulatory, tax and depreciation trackers, which are offset in net revenues, of $16.0 million.
- Increased property taxes of $11.0 million due to higher capital expenditures placed in service and the impact of regulatory-driven property tax deferrals.

Partially offset by:

- Decreased outside services of $33.2 million primarily due to IT service provider transition and other strategic initiative costs in 2017, lower ongoing IT costs and a temporary shift of resources to the Greater Lawrence Incident restoration.
- Lower employee and administrative expenses of $30.2 million driven by reduced incentive compensation and a temporary shift of resources to the Greater Lawrence Incident restoration.

Weather
In general, we calculate the weather-related revenue variance based on changing customer demand driven by weather variance from normal heating degree days. Our composite heating degree days reported do not directly correlate to the weather-related dollar impact on the results of Gas Distribution Operations. Heating degree days experienced during different times of the year or in different operating locations may have more or less impact on volume and dollars depending on when and where they occur. When the detailed results are combined for reporting, there may be weather-related dollar impacts on operations when there is not an apparent or significant change in our aggregated composite heating degree day comparison.

The definition of “normal” weather was updated during the first quarter of 2019 to reflect more current weather pattern data and to more closely align with the regulators' jurisdictional definitions of “normal” weather. Impacts of the change in methodology will be reflected prospectively and disclosed to the extent it results in notable year-over-year variances in net revenues.

Weather in the Gas Distribution Operations service territories for 2019 was about 1% warmer than normal and about 3% warmer than 2018; however, due to the aforementioned change in methodology, the change in net revenues attributed to weather resulted in an increase of $7.4 million for the year ended December 31, 2019 compared to 2018. The variance is detailed further below:

- An update in the weather-related normal heating degree day methodology resulting in a favorable variance attributed to weather of $14.5 million, as discussed above.

Offset by:

- The effects of warmer weather in 2019 of $7.1 million.

Weather in the Gas Distribution Operations service territories for 2018 was about 1% warmer than normal and about 13% colder than 2017, increasing net revenues $37.5 million for the year ended December 31, 2018 compared to 2017.

Throughput
Total volumes sold and transported for the year ended December 31, 2019 were 1,040.2 MMDth, compared to 1,053.6 MMDth for 2018. This decrease is primarily attributable to warmer weather experienced in 2019 compared to 2018.

Total volumes sold and transported for the year ended December 31, 2018 were 1,053.6 MMDth, compared to 973.2 MMDth for 2017. This increase is primarily attributable to colder weather experienced in 2018 compared to 2017.

Economic Conditions
All of our Gas Distribution Operations companies have state-approved recovery mechanisms that provide a means for full recovery of prudently incurred gas costs. Gas costs are treated as pass-through costs and have no impact on the net revenues recorded in the period. The gas costs included in revenues are matched with the gas cost expense recorded in the period and the difference is recorded on the Consolidated Balance Sheets as under-recovered or over-recovered gas cost to be included in future customer billings.

NISOURCE INC.
Gas Distribution Operations (continued)

Certain Gas Distribution Operations companies continue to offer choice opportunities, where customers can choose to purchase gas from a third-party supplier, through regulatory initiatives in their respective jurisdictions. These programs serve to further reduce our exposure to gas prices.

Greater Lawrence Incident
Refer to Note 19-C. "Legal Proceedings," and E. "Other Matters," in the Notes to Consolidated Financial Statements, "Summary of Consolidated Financial Results" and "Liquidity and Capital Resources" in this Management's Discussion, and Part I. Item 1A. "Risk Factors" for additional information related to the Greater Lawrence Incident.

Columbia of Massachusetts Asset Sale
On February 26, 2020, we entered into the Asset Purchase Agreement with Eversource providing for the sale of the Massachusetts Business to Eversource, subject to the terms and conditions set forth in the agreement. For additional information, see Note 26, "Subsequent Event," in the Notes to Consolidated Financial Statements.

NiSource Inc.
Electric Operations

For the years ended December 31, 2019, 2018 and 2017, operating income and a reconciliation of net revenues to the most directly comparable GAAP measure, operating income, was as follows:

Year Ended December 31, *(in millions)*	**2019**	2018	2017	2019 vs. 2018	2018 vs. 2017
Operating Income	**$ 406.8**	$ 386.1	$ 367.4	$ 20.7	$ 18.7

Year Ended December 31, *(in millions)*	**2019**	2018	2017	2019 vs. 2018	2018 vs. 2017
Net Revenues					
Operating revenues	**$ 1,699.2**	$ 1,708.2	$ 1,786.5	$ (9.0)	$ (78.3)
Less: Cost of sales (excluding depreciation and amortization)	**467.3**	502.1	513.9	(34.8)	(11.8)
Net Revenues	**1,231.9**	1,206.1	1,272.6	25.8	(66.5)
Operating Expenses					
Operation and maintenance	**495.0**	500.0	565.6	(5.0)	(65.6)
Depreciation and amortization	**277.3**	262.9	277.8	14.4	(14.9)
Loss (gain) on sale of fixed assets and impairments, net	**(0.1)**	—	1.9	(0.1)	(1.9)
Other taxes	**52.9**	57.1	59.9	(4.2)	(2.8)
Total Operating Expenses	**825.1**	820.0	905.2	5.1	(85.2)
Operating Income	**$ 406.8**	$ 386.1	$ 367.4	$ 20.7	$ 18.7
Revenues					
Residential	**$ 481.6**	$ 494.7	$ 476.9	$ (13.1)	$ 17.8
Commercial	**486.7**	492.6	501.2	(5.9)	(8.6)
Industrial	**608.4**	614.4	698.1	(6.0)	(83.7)
Wholesale	**11.7**	15.7	11.6	(4.0)	4.1
Other	**110.8**	90.8	98.7	20.0	(7.9)
Total	**$ 1,699.2**	$ 1,708.2	$ 1,786.5	$ (9.0)	$ (78.3)
Sales (Gigawatt Hours)					
Residential	**3,369.5**	3,535.2	3,301.7	(165.7)	233.5
Commercial	**3,760.3**	3,844.6	3,793.5	(84.3)	51.1
Industrial	**8,466.1**	8,829.5	9,469.7	(363.4)	(640.2)
Wholesale	**8.2**	114.3	32.5	(106.1)	81.8
Other	**117.2**	124.4	128.2	(7.2)	(3.8)
Total	**15,721.3**	16,448.0	16,725.6	(726.7)	(277.6)
Cooling Degree Days	**962**	1,180	837	(218)	343
Normal Cooling Degree Days	**803**	806	806	(3)	—
% Warmer than Normal	**20%**	46%	4%		
Electric Customers					
Residential	**415,534**	412,267	409,401	3,267	2,866
Commercial	**57,058**	56,605	56,134	453	471
Industrial	**2,256**	2,284	2,305	(28)	(21)
Wholesale	**726**	735	739	(9)	(4)
Other	**2**	2	2	—	—
Total	**475,576**	471,893	468,581	3,683	3,312

NISOURCE INC.
Electric Operations (continued)

Comparability of line item operating results may be impacted by regulatory and depreciation trackers (other than those for cost of sales) that allow for the recovery in rates of certain costs. Therefore, increases in these tracked operating expenses are offset by increases in net revenues and have essentially no impact on net income.

2019 vs. 2018 Operating Income
For 2019, Electric Operations reported operating income of $406.8 million, an increase of $20.7 million from the comparable 2018 period.

Net revenues for 2019 were $1,231.9 million, an increase of $25.8 million from the same period in 2018. The change in net revenues was primarily driven by:

- New rates from the recent rate case proceeding, incremental capital spend on infrastructure replacement programs, and electric transmission projects of $24.8 million.
- Decreased fuel handling costs of $11.0 million.
- Higher regulatory and depreciation trackers, which are offset in operating expense, of $8.4 million.
- Increased commercial and residential customer growth of $3.9 million.

Partially offset by:

- Lower revenues from the effects of cooler weather of $15.1 million.
- Decreased residential, commercial and industrial usage of $10.8 million.

Operating expenses were $5.1 million higher in 2019 than 2018. This change was primarily driven by:

- Higher regulatory and depreciation trackers, which are offset in net revenues, of $8.4 million.
- Increased depreciation of $8.7 million due to higher capital expenditures placed in service.

Partially offset by:

- Decreased materials and supplies costs of $7.8 million, primarily related to the retirement of Bailly Generating Station Units 7 and 8 on May 31, 2018.
- Decreased employee and administrative costs of $5.0 million.

2018 vs. 2017 Operating Income
For 2018, Electric Operations reported operating income of $386.1 million, an increase of $18.7 million from the comparable 2017 period.

Net revenues for 2018 were $1,206.1 million, a decrease of $66.5 million from the same period in 2017. The change in net revenues was primarily driven by:

- Lower regulatory and depreciation trackers, which are offset in operating expense, of $35.6 million.
- Decreased rates from implementation of regulatory outcomes related to the TCJA of $32.9 million.
- Decreased industrial usage of $17.1 million.
- A revenue reserve of $16.2 million in 2018 resulting from the probable future refund of certain collections from customers as a result of the lower income tax rate from the TCJA .
- Increased fuel handling costs of $7.3 million.

Partially offset by:

- The effects of warmer weather of $25.2 million.
- Increased rates from infrastructure replacement programs of $18.6 million.

Operating expenses were $85.2 million lower in 2018 than 2017. This change was primarily driven by:

- Lower regulatory and depreciation trackers, which are offset in net revenues, of $35.6 million.
- Lower outside service costs of $32.1 million and lower material and supplies costs of $10.2 million primarily related to the retirement of Bailly Generating Station Units 7 and 8 on May 31, 2018.
- Decreased employee and administrative costs of $18.4 million.

NISOURCE INC.
Electric Operations (continued)

Partially offset by:

- Increased depreciation of $10.0 million due to higher capital expenditures placed in service.

Weather
In general, we calculate the weather-related revenue variance based on changing customer demand driven by weather variance from normal heating or cooling degree days. Our composite heating or cooling degree days reported do not directly correlate to the weather-related dollar impact on the results of Electric Operations. Heating or cooling degree days experienced during different times of the year may have more or less impact on volume and dollars depending on when they occur. When the detailed results are combined for reporting, there may be weather-related dollar impacts on operations when there is not an apparent or significant change in our aggregated composite heating or cooling degree day comparison.

The definition of “normal” weather was updated during the first quarter of 2019 to reflect more current weather pattern data and to more closely align with the regulators' jurisdictional definitions of “normal” weather. Impacts of the change in methodology will be reflected prospectively and disclosed to the extent it results in notable year-over-year variances in net revenues.

Weather in the Electric Operations’ territories for 2019 was 20% warmer than normal and 18% cooler than the same period in 2018, decreasing net revenues $15.1 million for the year ended December 31, 2019 compared to 2018.

Weather in the Electric Operations’ territories for 2018 was 46% warmer than normal and 41% warmer than the same period in 2017, increasing net revenues $25.2 million for the year ended December 31, 2018 compared to 2017.

Sales
Electric Operations sales were 15,721.3 GWh for 2019, a decrease of 726.7 GWh, or 4.4% compared to 2018. This decrease was primarily attributable to higher internal generation from large industrial customers in 2019 and the effects of cooler weather on residential and commercial customers.

Electric Operations sales were 16,448.0 GWh for 2018, a decrease of 277.6 GWh, or 1.7% compared to 2017. This decrease was primarily attributable to higher internal generation from large industrial customers in 2018, partially offset by increased volumes for residential and commercial customers resulting from warmer weather.

BP Products North America. On March 29, 2018, WCE, which is currently owned by BP p.l.c ("BP") and BP Products North America, which operates the BP Refinery, filed a petition at the IURC asking that the combined operations of WCE and BP be treated as a single premise, and the WCE generation be dedicated primarily to BP Refinery operations beginning in May 2019 as WCE has self-certified as a qualifying facility at FERC. BP Refinery planned to continue to purchase electric service from NIPSCO at a reduced demand level beginning May 2019; however, a settlement agreement was filed on November 2, 2018 agreeing that BP and WCE would not move forward with construction of a private transmission line to serve BP until conclusion of NIPSCO's pending electric rate case. The IURC approved the settlement agreement as filed on February 20, 2019. On December 4, 2019, the IURC issued an order in the electric rate case approving the implementation of a new industrial service structure. This resolved the issues included in BP’s original petition. Refer to Note 8, "Regulatory Matters," in the Notes to Consolidated Financial Statements for additional information.

Economic Conditions
NIPSCO has a state-approved recovery mechanism that provides a means for full recovery of prudently incurred fuel costs. Fuel costs are treated as pass-through costs and have no impact on the net revenues recorded in the period. The fuel costs included in revenues are matched with the fuel cost expense recorded in the period and the difference is recorded on the Consolidated Balance Sheets as under-recovered or over-recovered fuel cost to be included in future customer billings.

NIPSCO's performance remains closely linked to the performance of the steel industry. NIPSCO’s MWh sales to steel-related industries accounted for approximately 51.5% and 49.7% of the total industrial MWh sales for the years ended December 31, 2019 and 2018, respectively.

Electric Supply
NIPSCO 2018 Integrated Resource Plan. Multiple factors, but primarily economic ones, including low natural gas prices, advancing cost effective renewable technology and increasing capital and operating costs associated with existing coal plants, have led NIPSCO to conclude in its October 2018 Integrated Resource Plan submission that NIPSCO’s current fleet of coal generation facilities will be retired earlier than previous Integrated Resource Plan’s had indicated.

NISOURCE INC.
Electric Operations (continued)

The Integrated Resource Plan evaluated demand-side and supply-side resource alternatives to reliably and cost effectively meet NIPSCO customers' future energy requirements over the ensuing 20 years. The preferred option within the Integrated Resource Plan retires R.M. Schahfer Generating Station (Units 14, 15, 17, and 18) by 2023 and Michigan City Generating Station (Unit 12) by 2028. These units represent 2,080 MW of generating capacity, equal to 72% of NIPSCO's remaining capacity after the retirement of Bailly Units 7 and 8 in May of 2018.

The current replacement plan includes renewable sources of energy, including wind, solar, and battery storage to be obtained through a combination of NIPSCO ownership and PPAs. Refer to Note 19-E, "Other Matters," in the Notes to Consolidated Financial Statements for further discussion.

Liquidity and Capital Resources

Greater Lawrence Incident: As discussed in the "Executive Summary" and in Note 19, “Other Commitments and Contingencies” in the Notes to Consolidated Financial Statements, we have recorded and paid costs associated with the Greater Lawrence Incident and have invested capital to replace the entire affected 45-mile cast iron and bare steel pipeline system that delivers gas to the impacted area. As discussed in the "Executive Summary," Note 19 referenced earlier in this paragraph, and Part I, Item 1A “Risk Factors,” we may incur additional expenses and liabilities in excess of our recorded liabilities and estimated additional costs associated with the Greater Lawrence Incident. Since the Greater Lawrence Incident and through December 31, 2019, we have collected $800 million from insurance providers; however, total costs related to the incident have exceeded the total amount of insurance coverage available under our policies. To date, this excess has primarily been funded through short-term borrowings. During 2020, we plan to pursue alternatives to these short-term borrowings, which include long-term financing and potential proceeds from the sale of the Massachusetts Business. For additional information, see Note 26, “Subsequent Event,” in the Notes to Consolidated Financial Statements.

Operating Activities
Net cash from operating activities for the year ended December 31, 2019 was $1,583.3 million, an increase of $1,043.2 million from 2018. This increase was driven primarily by the receipt of $795 million of insurance recoveries in 2019 related to the Greater Lawrence Incident and approximately $220 million lower cash spend for the Greater Lawrence Incident in 2019. Refer to Note 19, "Other Commitments and Contingencies" in the Notes to Consolidated Financial Statements for further information related to the Greater Lawrence Incident.

Pension and Other Postretirement Plan Funding. In 2019, we contributed $2.9 million to our pension plans and $23.0 million to our other postretirement benefit plans. In 2018, we contributed $2.9 million to our pension plans and $21.0 million to our other postretirement benefit plans. Given the current funded status of the pension plans, and barring unforeseen market volatility that may negatively impact the valuation of our plan assets, we do not believe additional material contributions to our pension plans will be required for the foreseeable future.

Income Taxes. Rates for our regulated customers include provisions for the collection of U.S. federal income taxes. The reduction in the U.S. federal corporate income tax rate as a result of the TCJA led to a decrease in the amount billed to customers through rates, ultimately resulting in lower cash collections from operating activities. In addition, we are required to pass back to customers “excess deferred taxes” which represent amounts collected from customers in the past to cover deferred tax liabilities which, as a result of the passage of the TCJA, are now less than the originally billed amounts. Approximately $1.5 billion of excess deferred taxes was recorded as a regulatory liability as of December 31, 2017 as a result of implementing the TCJA. The majority of this balance related to temporary book-to-tax differences on utility property protected by IRS normalization rules; this portion of the excess deferred taxes balance will be passed back to customers over the remaining average useful life of the associated property as required by the TCJA. The remainder of the excess deferred tax balance is passed back over periods determined by our state utility commissions. The pass back of excess deferred taxes has been approved in all our jurisdictions. As of December 31, 2019, we have approximately $1.3 billion of remaining regulatory liabilities associated with excess deferred taxes.

As of December 31, 2019, we have a deferred tax asset of $657.1 million related to a federal NOL carryforward, of which $406.1 million relates to years prior to the implementation of the TCJA. As a result of being in an NOL position, we were not required to make any cash payments for federal income tax purposes during the three years ended December 31, 2019. The carryforward periods for pre-TCJA tax benefits expire in various tax years from 2028 to 2037; however, we expect to fully utilize the carryforward benefit prior to its expiration. According to the TCJA, utilization of NOL carryforwards generated after December 31, 2017 do not expire but are limited to 80% of current year taxable income. Accordingly, we may be required to make cash payments for federal income taxes in future years despite having NOL carryforwards in excess of current taxes payable.

Investing Activities

Our cash used for investing activities varies year over year primarily as a result of changes in the level of annual capital expenditures. The table below reflects capital expenditures and certain other investing activities by segment for 2019, 2018 and 2017.

(in millions)	**2019**	2018[3]	2017
Gas Distribution Operations			
System Growth and Tracker	**$ 1,006.1**	$ 897.5	$ 909.2
Maintenance	**374.3**	417.8	216.4
Total Gas Distribution Operations	**1,380.3**	1,315.3	1,125.6
Electric Operations			
System Growth and Tracker	**279.5**	346.0	435.3
Maintenance	**189.4**	153.3	157.1
Total Electric Operations	**468.9**	499.3	592.4
Corporate and Other Operations - Maintenance[1]	**18.6**	—	35.8
Total[2]	**$ 1,867.8**	$ 1,814.6	$ 1,753.8

(1) Corporate and Other capital expenditures were zero in 2018 as specific IT assets were leased in 2018. Certain IT and other maintenance related assets were purchased in 2017 and 2019.
(2) Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the capitalized portion of the Corporate Incentive Plan payout, inclusion of capital expenditures included in current liabilities and AFUDC Equity.
(3) The 2018 capital expenditures for Gas Distribution Operations reflects reclassifying the Greater Lawrence Incident pipeline replacement from system growth and tracker to maintenance.

For 2019, capital expenditures and certain other investing activities were $1,867.8 million, which was $53.2 million higher than the 2018 capital program. This increased spending is primarily due to growth, safety and system modernization projects.

For 2018, capital expenditures and certain other investing activities were $1,814.6 million, which was $60.8 million higher than the 2017 capital program. This increased spending is due in part to costs associated with the Greater Lawrence Incident pipeline replacement, gas transmission projects, environmental investments and system modernization projects across all seven states in our operating area.

For 2020, we project to invest approximately $1.8 to $1.9 billion in our capital program. This projected level of spend is consistent with 2019 spend levels and is expected to focus on growth, safety, and modernization projects across our operating area.

Financing Activities

Short-term Debt. Refer to Note 15, "Short-Term Borrowings," in the Notes to Consolidated Financial Statements for information on short-term debt.

Long-term Debt. Refer to Note 14, "Long-Term Debt," in the Notes to Consolidated Financial Statements for information on long-term debt.

Net Available Liquidity. As of December 31, 2019, an aggregate of $1,409.1 million of net liquidity was available, including cash and credit available under the revolving credit facility and accounts receivable securitization programs.

The following table displays NiSource's liquidity position as of December 31, 2019 and 2018:

Year Ended December 31, *(in millions)*	**2019**	2018
Current Liquidity		
Revolving Credit Facility	**$ 1,850.0**	$ 1,850.0
Accounts Receivable Program[(1)]	**353.2**	399.2
Less:		
Commercial Paper	**570.0**	978.0
Accounts Receivable Program Utilized	**353.2**	399.2
Letters of Credit Outstanding Under Credit Facility	**10.2**	10.2
Add:		
Cash and Cash Equivalents	**139.3**	112.8
Net Available Liquidity	**$ 1,409.1**	$ 974.6

[(1)]Represents the lesser of the seasonal limit or maximum borrowings supportable by the underlying receivables.

Debt Covenants. We are subject to a financial covenant under our revolving credit facility and term loan agreement, which requires us to maintain a debt to capitalization ratio that does not exceed 70%. A similar covenant in a 2005 private placement note purchase agreement requires us to maintain a debt to capitalization ratio that does not exceed 75%. As of December 31, 2019, the ratio was 61.7%.

Sale of Trade Accounts Receivables. Refer to Note 18, "Transfers of Financial Assets," in the Notes to Consolidated Financial Statements for information on the sale of trade accounts receivable.

Credit Ratings. The credit rating agencies periodically review our ratings, taking into account factors such as our capital structure and earnings profile. The following table includes our and certain of our subsidiaries' credit ratings and ratings outlook as of December 31, 2019.

A credit rating is not a recommendation to buy, sell or hold securities, and may be subject to revision or withdrawal at any time by the assigning rating organization.

	S&P		Moody's		Fitch	
	Rating	Outlook	Rating	Outlook	Rating	Outlook
NiSource	BBB+	Negative	Baa2	Stable	BBB	Stable
NIPSCO	BBB+	Negative	Baa1	Stable	BBB	Stable
Columbia of Massachusetts	BBB+	Negative	Baa2	Stable	Not rated	Not rated
Commercial Paper	A-2	Negative	P-2	Stable	F2	Stable

Certain of our subsidiaries have agreements that contain "ratings triggers" that require increased collateral if our credit ratings or the credit ratings of certain of our subsidiaries are below investment grade. These agreements are primarily for insurance purposes and for the physical purchase or sale of power. As of December 31, 2019, the collateral requirement that would be required in the event of a downgrade below the ratings trigger levels would amount to approximately $72.1 million. In addition to agreements with ratings triggers, there are other agreements that contain "adequate assurance" or "material adverse change" provisions that could necessitate additional credit support such as letters of credit and cash collateral to transact business.

Equity. Our authorized capital stock consists of 620,000,000 shares, $0.01 par value, of which 600,000,000 are common stock and 20,000,000 are preferred stock. As of December 31, 2019, 382,135,680 shares of common stock and 440,000 shares of preferred stock were outstanding. For more information regarding our common and preferred stock, see Note 12, "Equity," in the Notes to Consolidated Financial Statements.

Contractual Obligations. We have certain contractual obligations requiring payments at specified periods. The obligations include long-term debt, lease obligations, energy commodity contracts and obligations for various services including pipeline capacity and outsourcing of IT services. The total contractual obligations in existence at December 31, 2019 and their maturities were:

(in millions)	Total	2020	2021	2022	2023	2024	After
Long-term debt [1]	$ 7,738.6	$ —	$ 63.6	$ 530.0	$ 600.0	$ —	$ 6,545.0
Interest payments on long-term debt	6,214.2	342.0	340.7	337.1	311.1	299.9	4,583.4
Finance leases[2]	325.9	27.2	27.3	26.8	23.1	19.9	201.6
Operating leases[3]	79.1	15.6	9.4	8.2	7.6	6.6	31.7
Energy commodity contracts[4]	95.9	65.5	30.4	—	—	—	—
Service obligations:							
Pipeline service obligations	3,450.7	605.0	590.1	546.8	357.2	237.5	1,114.1
IT service obligations	153.2	63.6	49.4	38.0	1.1	1.1	—
Other service obligations[5]	59.8	45.8	14.0	—	—	—	—
Other liabilities	27.3	27.3	—	—	—	—	—
Total contractual obligations	$ 18,144.7	$ 1,192.0	$ 1,124.9	$ 1,486.9	$ 1,300.1	$ 565.0	$ 12,475.8

(1) Long-term debt balance excludes unamortized issuance costs and discounts of $70.5 million.
(2) Finance lease payments shown above are inclusive of interest totaling $108.3 million.
(3) Operating lease payments shown above are inclusive of interest totaling $14.3 million. Operating lease balances do not include obligations for possible fleet vehicle lease renewals beyond the initial lease term. While we have the ability to renew these leases beyond the initial term, we are not reasonably certain (as that term is defined in ASC 842) to do so. If we were to continue the fleet vehicle leases outstanding at December 31, 2019, payments would be $34.5 million in 2020, $28.3 million in 2021, $23.4 million in 2022, $19.9 million in 2023, $15.2 million in 2024 and $15.2 million thereafter.
(4)In January 2020, NIPSCO signed new coal contract commitments of $14.4 million for 2020. These contracts are not included above.
(5)In February 2020, NIPSCO signed a new railcar coal transportation contract commitment of $12.0 million for 2020. This contract is not included above.

Our calculated estimated interest payments for long-term debt is based on the stated coupon and payment dates. For 2020, we project that we will be required to make interest payments of approximately $368.2 million, which includes $342.0 million of interest payments related to our long-term debt outstanding as of December 31, 2019. At December 31, 2019, we had $1,773.2 million in short-term borrowings outstanding.

Our expected payments included within "Other liabilities" in the table of contractual commitments above contains employer contributions to pension and other postretirement benefits plans expected to be made in 2020. Plan contributions beyond 2020 are dependent upon a number of factors, including actual returns on plan assets, which cannot be reliably estimated at this time. In 2020, we expect to make contributions of approximately $3.0 million to our pension plans and approximately $24.0 million to our postretirement medical and life plans. Refer to Note 11, "Pension and Other Postretirement Benefits," in the Notes to Consolidated Financial Statements for more information.

We cannot reasonably estimate the settlement amounts or timing of cash flows related to long-term obligations classified as "Total Other Liabilities" on the Consolidated Balance Sheets, other than those described above.

We also have obligations associated with income, property, gross receipts, franchise, payroll, sales and use, and various other taxes and expect to make tax payments of approximately $247.1 million in 2020, which are not included in the table above. In addition, we have uncertain income tax positions that are not included in the table above as we are unable to predict when the matters will be resolved. Refer to Note 10, "Income Taxes," in the Notes to Consolidated Financial Statements for more information.

Refer to Note 19-A, "Contractual Obligations," in the Notes to Consolidated Financial Statements for further information.

In January 2019, NIPSCO executed two 20 year PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per MWh. Payments under the PPAs will not begin until the associated generation facilities are constructed by the owner / seller which is currently scheduled to be complete by the end of 2020 for one facility. Payments that will be made under the agreements are not included in the table of contractual commitments above as there are no minimum payment obligations under the agreements. NIPSCO has filed a notice with the IURC of its intention not to move forward with one of its approved PPAs due to the failure to meet a condition precedent in the agreement as a result of local zoning restrictions. See Note 19-E, "Other Matters - NIPSCO 2018 Integrated Resource Plan," in the Notes to Consolidated Financial Statements for additional information.

In January 2019, NIPSCO executed a BTA with a developer to construct a renewable generation facility with a nameplate capacity of approximately 100 MW; construction of the facility is expected to be completed by the end of 2020. In October 2019, NIPSCO executed a BTA with a developer to construct an additional renewable generation facility with a nameplate capacity of approximately 300 MW; construction of this facility is expected to be completed by the end of 2021. Payments under these agreements are not included in the table of contractual commitments as NIPSCO's purchase requirement under these BTAs is dependent on satisfactory approval of the BTAs by the IURC, successful execution of agreements with a tax equity partner, and timely completion of construction. See Note 19-E, "Other Matters - NIPSCO 2018 Integrated Resource Plan," in the Notes to Consolidated Financial Statements for additional information.

Off-Balance Sheet Arrangements

We, along with certain of our subsidiaries, enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees and stand-by letters of credit.

Refer to Note 19, "Other Commitments and Contingencies," in the Notes to Consolidated Financial Statements for additional information about such arrangements.

Market Risk Disclosures

Risk is an inherent part of our businesses. The extent to which we properly and effectively identify, assess, monitor and manage each of the various types of risk involved in our businesses is critical to our profitability. We seek to identify, assess, monitor and manage, in accordance with defined policies and procedures, the following principal market risks that are involved in our businesses: commodity price risk, interest rate risk and credit risk. Risk management for us is a multi-faceted process with oversight by the Risk Management Committee that requires constant communication, judgment and knowledge of specialized products and markets. Our senior management takes an active role in the risk management process and has developed policies and procedures that require specific administrative and business functions to assist in the identification, assessment and control of various risks. These may include, but are not limited to market, operational, financial, compliance and strategic risk types. In recognition of the increasingly varied and complex nature of the energy business, our risk management process, policies and procedures continue to evolve and are subject to ongoing review and modification.

Commodity Price Risk

We are exposed to commodity price risk as a result of our subsidiaries' operations involving natural gas and power. To manage this market risk, our subsidiaries use derivatives, including commodity futures contracts, swaps, forwards and options. We do not participate in speculative energy trading activity.

Commodity price risk resulting from derivative activities at our rate-regulated subsidiaries is limited, since regulations allow recovery of prudently incurred purchased power, fuel and gas costs through the rate-making process, including gains or losses on these derivative instruments. If states should explore additional regulatory reform, these subsidiaries may begin providing services without the benefit of the traditional rate-making process and may be more exposed to commodity price risk.

Our subsidiaries are required to make cash margin deposits with their brokers to cover actual and potential losses in the value of outstanding exchange traded derivative contracts. The amount of these deposits, some of which is reflected in our restricted cash balance, may fluctuate significantly during periods of high volatility in the energy commodity markets.

Refer to Note 9, "Risk Management Activities," in the Notes to the Consolidated Financial Statements for further information on our commodity price risk assets and liabilities as of December 31, 2019 and 2018.

Interest Rate Risk

We are exposed to interest rate risk as a result of changes in interest rates on borrowings under our revolving credit agreement, commercial paper program, term loan agreement and accounts receivable programs, which have interest rates that are indexed to short-term market interest rates. Based upon average borrowings and debt obligations subject to fluctuations in short-term market interest rates, an increase (or decrease) in short-term interest rates of 100 basis points (1%) would have increased (or decreased) interest expense by $19.0 million and $13.3 million for 2019 and 2018, respectively. We are also exposed to interest rate risk as a result of changes in benchmark rates that can influence the interest rates of future debt issuances.

Refer to Note 9, "Risk Management Activities," in the Notes to Consolidated Financial Statements for further information on our interest rate risk assets and liabilities as of December 31, 2019 and 2018.

Credit Risk

Due to the nature of the industry, credit risk is embedded in many of our business activities. Our extension of credit is governed by a Corporate Credit Risk Policy. In addition, Risk Management Committee guidelines are in place which document management approval levels for credit limits, evaluation of creditworthiness, and credit risk mitigation efforts. Exposures to credit risks are monitored by the risk management function which is independent of commercial operations. Credit risk arises due to the possibility that a customer, supplier or counterparty will not be able or willing to fulfill its obligations on a transaction on or before the settlement date. For derivative-related contracts, credit risk arises when counterparties are obligated to deliver or purchase defined commodity units of gas or power to us at a future date per execution of contractual terms and conditions. Exposure to credit risk is measured in terms of both current obligations and the market value of forward positions net of any posted collateral such as cash and letters of credit.

We closely monitor the financial status of our banking credit providers. We evaluate the financial status of our banking partners through the use of market-based metrics such as credit default swap pricing levels, and also through traditional credit ratings provided by major credit rating agencies.

Other Information

Critical Accounting Policies

We apply certain accounting policies based on the accounting requirements discussed below that have had, and may continue to have, significant impacts on our operations and Consolidated Financial Statements.

Basis of Accounting for Rate-Regulated Subsidiaries. ASC Topic 980, *Regulated Operations*, provides that rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred on the Consolidated Balance Sheets and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. The total amounts of regulatory assets and liabilities reflected on the Consolidated Balance Sheets were $2,239.6 million and $2,512.2 million at December 31, 2019, and $2,237.5 million and $2,660.0 million at December 31, 2018, respectively. For additional information, refer to Note 8, “Regulatory Matters,” in the Notes to Consolidated Financial Statements.

In the event that regulation significantly changes the opportunity for us to recover our costs in the future, all or a portion of our regulated operations may no longer meet the criteria for the application of ASC Topic 980, *Regulated Operations*. In such event, a write-down of all or a portion of our existing regulatory assets and liabilities could result. If transition cost recovery is approved by the appropriate regulatory bodies that would meet the requirements under GAAP for continued accounting as regulatory assets and liabilities during such recovery period, the regulatory assets and liabilities would be reported at the recoverable amounts. If we were unable to continue to apply the provisions of ASC Topic 980, *Regulated Operations*, we would be required to apply the provisions of ASC Topic 980-20, *Discontinuation of Rate-Regulated Accounting*. In management’s opinion, our regulated subsidiaries will be subject to ASC Topic 980, *Regulated Operations* for the foreseeable future.

Certain of the regulatory assets reflected on our Consolidated Balance Sheets require specific regulatory action in order to be included in future service rates. Although recovery of these amounts is not guaranteed, we believe that these costs meet the requirements for deferral as regulatory assets. Regulatory assets requiring specific regulatory action amounted to $307.2 million at December 31, 2019. If we determine that the amounts included as regulatory assets were not recoverable, a charge to income would immediately be required to the extent of the unrecoverable amounts.

The passage of the TCJA into law in December 2017 necessitated the remeasurement of our deferred income tax balances to reflect the change in the statutory federal tax rate from 35% to 21%. For our regulated entities, substantially all of the impact of this remeasurement was recorded to a regulatory liability and is being passed backed to customers, as established during the rate making process. For additional information, refer to Note 8, "Regulatory Matters," and Note 10, "Income Taxes," in the Notes to Consolidated Financial Statements.

As discussed in Note 19-E, "Other Matters - Greater Lawrence Pipeline Replacement," since the Greater Lawrence Incident and through December 31, 2019, we have invested approximately $258 million of capital spend for the pipeline replacement in the affected communities; this work was completed in 2019. We maintain property insurance for gas pipelines and other applicable property. Columbia of Massachusetts has filed a proof of loss with its property insurer for the full cost of the pipeline replacement. In January 2020, we filed a lawsuit against the property insurer, seeking payment of our property claim. We are currently unable to predict the timing or amount of any insurance recovery under the property policy. The recovery of any capital investment not reimbursed through insurance will be addressed in a future regulatory proceeding; a future regulatory proceeding is dependent on the outcome of the sale of the Massachusetts Business. The outcome of such a proceeding (if any) is uncertain. In accordance with ASC 980-360, if it becomes probable that a portion of the pipeline replacement cost will not be recoverable through customer rates and an amount can be reasonably estimated, we will reduce our regulated plant balance for the amount of the probable disallowance and record an associated charge to earnings. This could result in a material adverse effect to our financial condition, results of operations and cash flows. Additionally, if a rate order is received allowing recovery of the investment with no or reduced return on investment, a loss on disallowance may be required.

Pension and Postretirement Benefits. We have defined benefit plans for both pension and other postretirement benefits. The calculation of the net obligations and annual expense related to the plans requires a significant degree of judgment regarding the discount rates to be used in bringing the liabilities to present value, expected long-term rates of return on plan assets, health care trend rates, and mortality rates, among other assumptions. Due to the size of the plans and the long-term nature of the associated liabilities, changes in the assumptions used in the actuarial estimates could have material impacts on the measurement of the net obligations and annual expense recognition. Differences between actuarial assumptions and actual plan results are deferred into AOCI or a regulatory balance sheet account, depending on the jurisdiction of our entity. These deferred gains or losses are then amortized into the income statement when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the fair value of plan assets (known in GAAP as the "corridor" method) or when settlement accounting is triggered.

The discount rates, expected long-term rates of return on plan assets, health care cost trend rates and mortality rates are critical assumptions. Methods used to develop these assumptions are described below. While a third party actuarial firm assists with the development of many of these assumptions, we are ultimately responsible for selecting the final assumptions.

The discount rate is utilized principally in calculating the actuarial present value of pension and other postretirement benefit obligations and net periodic pension and other postretirement benefit plan costs. Our discount rates for both pension and other postretirement benefits are determined using spot rates along an AA-rated above median yield curve with cash flows matching the expected duration of benefit payments to be made to plan participants.

The expected long-term rate of return on plan assets is a component utilized in calculating annual pension and other postretirement benefit plan costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, target asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets.

For measurement of 2020 net periodic benefit cost, we selected an expected pre-tax long-term rate of return of 5.70% and 5.67% for our pension and other postretirement benefit plan assets, respectively.

We estimate the assumed health care cost trend rate, which is used in determining our other postretirement benefit net expense, based upon our actual health care cost experience, the effects of recently enacted legislation, third-party actuarial surveys and general economic conditions.

We use the Society of Actuaries' most recently published mortality data in developing a best estimate of mortality as part of the calculation of the pension and other postretirement benefit obligations.

The following tables illustrate the effects of changes in these actuarial assumptions while holding all other assumptions constant:

	Impact on December 31, 2019 Projected Benefit Obligation Increase/(Decrease)	
Change in Assumptions *(in millions)*	Pension Benefits	Other Postretirement Benefits
+50 basis points change in discount rate	$ (89.9)	$ (29.0)
-50 basis points change in discount rate	97.7	31.8
+50 basis points change in health care trend rates		15.0
-50 basis points change in health care trend rates		(13.1)

	Impact on 2019 Expense Increase/(Decrease)(1)	
Change in Assumptions *(in millions)*	Pension Benefits	Other Postretirement Benefits
+50 basis points change in discount rate	$ (1.8)	$ 0.3
-50 basis points change in discount rate	1.9	0.7
+50 basis points change in expected long-term rate of return on plan assets	(8.9)	(1.2)
-50 basis points change in expected long-term rate of return on plan assets	8.9	1.2
+50 basis points change in health care trend rates		0.6
-50 basis points change in health care trend rates		(0.5)

(1)Before labor capitalization and regulatory deferrals.

In January 2017, we changed the method used to estimate the service and interest components of net periodic benefit cost for pension and other postretirement benefits. This change, compared to the previous method, resulted in a decrease in the actuarially-determined service and interest cost components. Historically, we estimated service and interest cost utilizing a single weighted-average discount rate derived from the yield curve used to measure the benefit obligation at the beginning of the period. For fiscal 2017 and beyond, we now utilize a full yield curve approach to estimate these components by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to the relevant projected cash flows. For further discussion of our pension and other postretirement benefits, see Note 11, "Pension and Other Postretirement Benefits," in the Notes to Consolidated Financial Statements.

Goodwill and Intangible Assets. We have seven goodwill reporting units, comprised of the seven state operating companies within the Gas Distribution Operations reportable segment. Our goodwill assets at December 31, 2019 were $1,486 million, most of which resulted from the acquisition of Columbia on November 1, 2000.

As required by GAAP, we test for impairment of goodwill on an annual basis and on an interim basis when events or circumstances indicate that a potential impairment may exist. Our annual goodwill test takes place in the second quarter of each year and was performed on May 1, 2019. A qualitative ("step 0") test was completed on May 1, 2019 for all reporting units other than our Columbia of Massachusetts reporting unit. In the Step 0 analysis, we assessed various assumptions, events and circumstances that would have affected the estimated fair value of the applicable reporting units as compared to their baseline May 1, 2016 "step 1" fair value measurement. The results of this assessment indicated that it is not more likely than not that these reporting units fair values are less than their reporting unit carrying values; therefore, no "step 1" analysis was required.

The results of our Columbia of Massachusetts reporting unit were negatively impacted by the Greater Lawrence Incident (see Note 19-C, "Legal Proceedings," in the Notes to Consolidated Financial Statements). As a result, we completed a quantitative "step 1" analysis for the May 1, 2019 goodwill analysis for this reporting unit. Consistent with our historical impairment testing of goodwill, fair value of this reporting unit was determined based on a weighting of income and market approaches. These approaches require significant judgments including appropriate long-term growth rates and discount rates for the income approach and appropriate multiples of earnings for peer companies and control premiums for the market approach. The discount rates were derived using peer company data compiled with the assistance of a third party valuation services firm. The discount rates used are subject to change based on changes in tax rates at both the state and federal level, debt and equity ratios at each reporting unit and general economic conditions. The long-term growth rate was derived by evaluating historic growth rates, new business and investment opportunities beyond the near term horizon. The long-term growth rate is subject to change depending on inflationary impacts to the U.S. economy and the individual business environments in which each reporting unit operates. The Step 1 analysis performed indicated that the fair value of the Columbia of Massachusetts reporting unit exceeds its carrying value. As a result, no impairment charge was recorded as of the May 1, 2019 test date.

Although our annual impairment test is performed during the second quarter, we continue to monitor changes in circumstances that may indicate that it is more likely than not that the fair value of our reporting units is less than the reporting unit carrying value. During the fourth quarter of 2019, in connection with the preparation of the year-end financial statements, we assessed matters related to Columbia of Massachusetts. While there was no single determinative event or factor, the consideration in totality of several factors that developed during the fourth quarter of 2019 led us to conclude that it was more likely than not that the fair value of the Columbia of Massachusetts reporting unit was below its carrying value. These factors included: (i) increased Massachusetts DPU regulatory enforcement activity related to Columbia of Massachusetts during the fourth quarter, including (a) an order imposing work restrictions on Columbia of Massachusetts, impacting Columbia of Massachusetts' infrastructure replacement program, (b) two orders opening public investigations into Columbia of Massachusetts related to the Greater Lawrence Incident and restoration efforts following the incident, and (c) an order defining the scope of the Massachusetts DPU's investigation into the preparation and response of Columbia of Massachusetts related to the incident; (ii) increased uncertainty as to the ability of Columbia of Massachusetts to execute its growth strategy, including utility infrastructure investments, and to obtain timely regulatory outcomes with reasonable rates of return; (iii) further damage to Columbia of Massachusetts' reputation as a result of concerns related to service lines abandoned during the restoration work following the Greater Lawrence Incident and the gas release event in Lawrence, Massachusetts on September 27, 2019; and (iv) a potential sale of the Massachusetts Business. See Note 19, "Other Commitments and Contingencies - C. Legal Proceedings," in the Notes to Consolidated Financial Statements for more information regarding Massachusetts DPU regulatory enforcement activity and Note 26, "Subsequent Event," in the Notes to Consolidated Financial Statements for more information regarding the potential sale of the Massachusetts Business.

As a result, a new impairment analysis was required for our Columbia of Massachusetts reporting unit. This analysis used a weighted average of income and market approaches for calculating fair value. The income approach calculated discounted cash flows using updated cash flow projections, discount rates and return on equity assumptions. The market approach applied a combination of comparable company multiples and comparable transactions and used updated cash flow projections. While certain assumptions, such as market multiples, remained unchanged in the year-end test, our cash flow projections, return on equity and rate case timing assumptions were all unfavorably updated at year-end compared to the May 1, 2019 test. The effects of these unfavorable developments were greater than the favorable change in weighted average cost of capital between the two tests. The year-end impairment analysis indicated that the fair value of the Columbia of Massachusetts reporting unit was below its carrying value. As a result, we reduced the Columbia of Massachusetts reporting unit goodwill balance to zero and recognized a goodwill impairment charge totaling $204.8 million, which is non-deductible for tax purposes.

Our intangible assets, apart from goodwill, consist of franchise rights. Franchise rights were identified as part of the purchase price allocations associated with the acquisition in February 1999 of Columbia of Massachusetts. We review our definite-lived intangible assets for impairment when events or changes in circumstances indicate its fair value might be below its carrying amount.

During the fourth quarter of 2019, in connection with the preparation of the year-end financial statements, we assessed the changes in circumstances that occurred during the quarter to determine if it was more likely than not that the fair value of the franchise rights was below its carrying amount. These factors were the same fourth quarter circumstances outlined in the goodwill impairment discussion above. As a result, we performed a year-end impairment test in which we compared the book value of Columbia of Massachusetts to its undiscounted future cash flow and estimated fair value. With this analysis, we determined that the fair value of the franchise rights was zero. Therefore, we wrote off the entire franchise rights book value, which resulted in an impairment charge totaling $209.7 million. See Note 6, "Goodwill and Other Intangible Assets," in the Notes to Consolidated Financial Statements for more information.

Revenue Recognition. Revenue is recorded as products and services are delivered. Utility revenues are billed to customers monthly on a cycle basis. Revenues are recorded on the accrual basis and include estimates for electricity and gas delivered but not billed.

We adopted the provisions of ASC 606 beginning on January 1, 2018 using a modified retrospective method, which was applied to all contracts. No material adjustments were made to January 1, 2018 opening balances and no material changes in the amount or timing of future revenue recognition occurred as a result of the adoption of ASC 606. Refer to Note 3 "Revenue Recognition," in the Notes to Consolidated Financial Statements.

Recently Issued Accounting Pronouncements

Refer to Note 2, "Recent Accounting Pronouncements," in the Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

NISOURCE INC.

Quantitative and Qualitative Disclosures about Market Risk are reported in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk Disclosures."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

NISOURCE INC.

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NISOURCE INC.
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of NiSource Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of NiSource Inc. and subsidiaries (the "Company") as of December 31, 2019 and 2018, the related statements of consolidated income (loss), comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2019, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2020, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Impact of Rate Regulation on the Financial Statements - Refer to Notes 1, 8, 19, and 26 to the financial statements

Critical Audit Matter Description

Certain subsidiaries of NiSource Inc. are fully regulated natural gas and electric utility companies serving customers in seven states. These rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the manner in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged to and collected from customers. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred on the consolidated balance sheets and are later recognized in income as the related amounts are included in customer rates and recovered from or refunded to customers.

Through December 31, 2019, the Company invested approximately $258 million of capital spend for the Greater Lawrence Incident pipeline replacement. As of December 31, 2019, the Company determined that a disallowance of the Greater Lawrence Incident pipeline replacement capital expenditures was not probable. On February 26, 2020, the Company and its wholly-owned subsidiary, Columbia of Massachusetts (CMA), agreed to sell substantially all of CMA's utility property, plant, and equipment (including the

Greater Lawrence Incident pipeline replacement assets) with other specified assets and liabilities, to a third party. The Company estimates that the total pre-tax loss resulting from this sale will be approximately $360 million, based on December 31, 2019 asset and liability balances and estimated transaction costs.

We identified the accounting for rate-regulated subsidiaries as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing (1) the likelihood of recovery in future rates of incurred costs, (2) the likelihood of refund of amounts previously collected from customers, and (3) the probability of recovery of amounts capitalized related to the Greater Lawrence Incident pipeline replacement. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by regulatory commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate making process due its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by regulatory commissions included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred as property, plant, and equipment and deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the initial recognition of amounts as property, plant, and equipment, including the Greater Lawrence Incident pipeline replacement; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments, that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by regulatory commissions, regulatory statutes, interpretations, filings made by interveners, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedence of regulatory commissions' treatment of similar costs under similar circumstances. We evaluated the external information and compared it to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, including those that could impact the Greater Lawrence Incident pipeline replacement, we inspected the Company's filings with regulatory commissions and the filings with regulatory commissions by intervenors for any evidence that might contradict management's assertions related to recoverability of recorded assets.
- We inquired of management about property, plant, and equipment that may be abandoned. We inspected minutes of meetings of the board of directors and regulatory orders and other filings with regulatory commissions to identify evidence that may contradict management's assertion regarding probability of an abandonment.
- We obtained an analysis from management regarding probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery or a future reduction in rates.
- We evaluated the impact of the February 26, 2020 sale transaction on the carrying value of the Company's utility property, plant, and equipment as of December 31, 2019.

Impairment of the Franchise Rights Intangible Asset & the Columbia of Massachusetts Reporting Unit Goodwill - Refer to Note 6 to the financial statements

Critical Audit Matter Description

The Company assessed the changes in circumstances that occurred during the fourth quarter to determine whether it was more likely than not that the fair values of the long-lived assets (including the franchise rights intangible asset) and goodwill of Columbia of Massachusetts (CMA), a wholly-owned subsidiary of the Company, were below their carrying amount. The totality of several factors led to the Company concluding that it was more likely than not that the fair value of the CMA reporting unit and the value of CMA's long-lived assets were below their carrying values. These factors included: (1) increased Massachusetts Department of Public Utilities (DPU) regulatory enforcement activity related to CMA, including (i) an order imposing work restrictions on CMA, (ii) two orders opening public investigations into CMA related to the Greater Lawrence Incident and restoration efforts following the incident, and (iii) an order defining the scope of the DPU's investigation into the preparation and response of CMA related to the incident; (2) increased uncertainty as to the ability of CMA to execute its growth strategy, including utility infrastructure

NiSource Inc.
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

investments, and CMA's ability to obtain timely regulatory outcomes with reasonable rates of return; (3) further damage to CMA's reputation; and (4) the potential sale of the Company's business in Massachusetts.

The Company performed a long-lived asset impairment test as of December 31, 2019 in which it compared the book value of the CMA asset group to its undiscounted future cash flows and determined that the carrying value of the asset group was not recoverable. The Company estimated the fair value of the CMA asset group using a weighting of income and market approaches and determined that the fair value was less than the carrying value. The resulting impairment loss was allocated to reduce the recorded franchise rights intangible asset to its fair value of zero, which resulted in an impairment charge totaling $209.7 million for the year ended December 31, 2019. The Company also performed a goodwill impairment test for the CMA reporting unit as of December 31, 2019. As part of this test, the Company estimated CMA's fair value based on a weighting of income and market approaches. This impairment analysis indicated that the fair value of the CMA reporting unit was below its carrying value and, as a result, the Company recognized a goodwill impairment charge totaling $204.8 million.

We identified the impairment of the franchise rights intangible asset and the CMA reporting unit goodwill as a critical audit matter as there was a high degree of auditor judgment and subjectivity in applying procedures relating to the allocation of impairment to CMA's long-lived assets and the fair value measurement of the reporting unit. This was driven by significant management judgment when determining fair value, including (1) the weightings of the fair value approaches, (2) the future cash flows used in the impairment tests, and (3) other inputs used in the valuation including comparable company multiples, discount rates, and return on equity. In addition, the audit effort involved the use of fair value specialists to assist in performing audit procedures over these assumptions and evaluating the audit evidence obtained.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the impairment of CMA's franchise rights intangible asset and CMA reporting unit goodwill included the following, among others:

- We tested the effectiveness of management's controls over the impairments, including (1) validation of the assumptions included in the impairment analysis for both the franchise rights intangible asset and goodwill, (2) the evaluation of the methodology used in determining the magnitude of impairment charges as of December 31, 2019, and (3) the verification of the completeness and accuracy of the journal entry made to record the impairments and the related disclosures.
- We evaluated the inputs used in the franchise rights intangible asset and goodwill impairment tests, including cash flow projections, scenario analysis, discount rates, return on equity assumptions, and comparable company multiples.
- We compared the undiscounted cash flows used in the franchise rights intangible asset impairment test to the carrying value of the asset group to evaluate whether an impairment existed at December 31, 2019.
- With the assistance of our fair value specialists, we evaluated the reasonableness of the calculated amount of fair value of the franchise rights intangible asset.
- We evaluated the allocation of impairment to the franchise rights intangible asset.
- We evaluated the relative weightings of the income and market approaches used to estimate fair value for the purposes of the goodwill impairment test.
- We evaluated the reasonableness of the fair value calculated under the combination of income and market approaches by comparing it to the fair value used in the May 1, 2019 goodwill impairment test.
- We evaluated the Company's disclosures related to the impairment charges.

/s/ DELOITTE & TOUCHE LLP
Columbus, Ohio
February 27, 2020

We have served as the Company's auditor since 2002.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

NISOURCE INC.
STATEMENTS OF CONSOLIDATED INCOME (LOSS)

Year Ended December 31, *(in millions, except per share amounts)*	**2019**	2018	2017
Operating Revenues			
Customer revenues	**$ 5,053.4**	$ 4,991.1	$ 4,730.2
Other revenues	**155.5**	123.4	144.4
Total Operating Revenues	**5,208.9**	5,114.5	4,874.6
Operating Expenses			
Cost of sales (excluding depreciation and amortization)	**1,534.8**	1,761.3	1,518.7
Operation and maintenance	**1,354.7**	2,352.9	1,601.7
Depreciation and amortization	**717.4**	599.6	570.3
Impairment of goodwill and other intangible assets	**414.5**	—	—
Loss on sale of fixed assets and impairments, net	**—**	1.2	5.5
Other taxes	**296.8**	274.8	257.2
Total Operating Expenses	**4,318.2**	4,989.8	3,953.4
Operating Income	**890.7**	124.7	921.2
Other Income (Deductions)			
Interest expense, net	**(378.9)**	(353.3)	(353.2)
Other, net	**(5.2)**	43.5	(13.5)
Loss on early extinguishment of long-term debt	**—**	(45.5)	(111.5)
Total Other Deductions, Net	**(384.1)**	(355.3)	(478.2)
Income (Loss) before Income Taxes	**506.6**	(230.6)	443.0
Income Taxes	**123.5**	(180.0)	314.5
Net Income (Loss)	**383.1**	(50.6)	128.5
Preferred dividends	**(55.1)**	(15.0)	—
Net Income (Loss) Available to Common Shareholders	**328.0**	(65.6)	128.5
Earnings (Loss) Per Share			
Basic Earnings (Loss) Per Share	**$ 0.88**	$ (0.18)	$ 0.39
Diluted Earnings (Loss) Per Share	**$ 0.87**	$ (0.18)	$ 0.39
Basic Average Common Shares Outstanding	**374.6**	356.5	329.4
Diluted Average Common Shares	**376.0**	356.5	330.8

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME (LOSS)

Year Ended December 31, *(in millions, net of taxes)*		**2019**		2018		2017
Net Income (Loss)	**$**	**383.1**	$	(50.6)	$	128.5
Other comprehensive income (loss):						
Net unrealized gain (loss) on available-for-sale securities[1]		**5.7**		(2.6)		0.8
Net unrealized gain (loss) on cash flow hedges[2]		**(64.2)**		22.7		(22.5)
Unrecognized pension and OPEB benefit (costs)[3]		**3.1**		(4.4)		3.4
Total other comprehensive income (loss)		**(55.4)**		15.7		(18.3)
Total Comprehensive Income (Loss)	**$**	**327.7**	$	(34.9)	$	110.2

(1) Net unrealized gain (loss) on available-for-sale securities, net of $1.5 million tax expense, $0.6 million tax benefit and $0.4 million tax expense in 2019, 2018 and 2017, respectively.
(2) Net unrealized gain (loss) on derivatives qualifying as cash flow hedges, net of $21.2 million tax benefit, $7.5 million tax expense and $13.9 million tax benefit in 2019, 2018 and 2017, respectively.
(3) Unrecognized pension and OPEB benefit (costs), net of $1.6 million tax expense, $1.5 million tax benefit and $2.1 million tax expense in 2019, 2018 and 2017, respectively.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

NISOURCE INC.
CONSOLIDATED BALANCE SHEETS

(in millions)	**December 31, 2019**	December 31, 2018
ASSETS		
Property, Plant and Equipment		
Utility plant	**$ 24,502.6**	$ 22,780.8
Accumulated depreciation and amortization	**(7,609.3)**	(7,257.9)
Net utility plant	**16,893.3**	15,522.9
Other property, at cost, less accumulated depreciation	**18.9**	19.6
Net Property, Plant and Equipment	**16,912.2**	15,542.5
Investments and Other Assets		
Unconsolidated affiliates	**1.3**	2.1
Other investments	**228.9**	204.0
Total Investments and Other Assets	**230.2**	206.1
Current Assets		
Cash and cash equivalents	**139.3**	112.8
Restricted cash	**9.1**	8.3
Accounts receivable (less reserve of $19.2 and $21.1, respectively)	**856.9**	1,058.5
Gas inventory	**250.9**	286.8
Materials and supplies, at average cost	**120.2**	101.0
Electric production fuel, at average cost	**53.6**	34.7
Exchange gas receivable	**48.5**	88.4
Regulatory assets	**225.7**	235.4
Prepayments and other	**149.7**	129.5
Total Current Assets	**1,853.9**	2,055.4
Other Assets		
Regulatory assets	**2,013.9**	2,002.1
Goodwill	**1,485.9**	1,690.7
Intangible assets, net	**—**	220.7
Deferred charges and other	**163.7**	86.5
Total Other Assets	**3,663.5**	4,000.0
Total Assets	**$ 22,659.8**	$ 21,804.0

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	**December 31, 2019**	December 31, 2018
CAPITALIZATION AND LIABILITIES		
Capitalization		
Stockholders’ Equity		
Common stock - $0.01 par value, 600,000,000 shares authorized; 382,135,680 and 372,363,656 shares outstanding, respectively	**$ 3.8**	$ 3.8
Preferred stock - $0.01 par value, 20,000,000 shares authorized; 440,000 and 420,000 shares outstanding, respectively	**880.0**	880.0
Treasury stock	**(99.9)**	(99.9)
Additional paid-in capital	**6,666.2**	6,403.5
Retained deficit	**(1,370.8)**	(1,399.3)
Accumulated other comprehensive loss	**(92.6)**	(37.2)
Total Stockholders’ Equity	**5,986.7**	5,750.9
Long-term debt, excluding amounts due within one year	**7,856.2**	7,105.4
Total Capitalization	**13,842.9**	12,856.3
Current Liabilities		
Current portion of long-term debt	**13.4**	50.0
Short-term borrowings	**1,773.2**	1,977.2
Accounts payable	**666.0**	883.8
Customer deposits and credits	**256.4**	238.9
Taxes accrued	**231.6**	222.7
Interest accrued	**99.4**	90.7
Exchange gas payable	**59.7**	85.5
Regulatory liabilities	**160.2**	140.9
Legal and environmental	**20.1**	18.9
Accrued compensation and employee benefits	**156.3**	149.7
Claims accrued	**165.4**	114.7
Other accruals	**144.1**	63.8
Total Current Liabilities	**3,745.8**	4,036.8
Other Liabilities		
Risk management liabilities	**134.0**	46.7
Deferred income taxes	**1,485.3**	1,330.5
Deferred investment tax credits	**9.7**	11.2
Accrued insurance liabilities	**81.5**	84.4
Accrued liability for postretirement and postemployment benefits	**373.2**	389.1
Regulatory liabilities	**2,352.0**	2,519.1
Asset retirement obligations	**416.9**	352.0
Other noncurrent liabilities	**218.5**	177.9
Total Other Liabilities	**5,071.1**	4,910.9
Commitments and Contingencies (Refer to Note 19, "Other Commitments and Contingencies")	**—**	—
Total Capitalization and Liabilities	**$ 22,659.8**	$ 21,804.0

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

NISOURCE INC.
STATEMENTS OF CONSOLIDATED CASH FLOWS

Year Ended December 31, *(in millions)*	**2019**	2018	2017
Operating Activities			
Net Income (Loss)	**$ 383.1**	$ (50.6)	$ 128.5
Adjustments to Reconcile Net Income (Loss) to Net Cash from Operating Activities:			
Loss on early extinguishment of debt	**—**	45.5	111.5
Depreciation and amortization	**717.4**	599.6	570.3
Deferred income taxes and investment tax credits	**118.2**	(188.2)	306.7
Stock compensation expense and 401(k) profit sharing contribution	**25.9**	28.6	40.1
Impairment of goodwill and other intangible assets	**414.5**	—	—
Amortization of discount/premium on debt	**8.2**	7.5	7.4
AFUDC equity	**(8.0)**	(14.2)	(12.6)
Other adjustments	**(0.9)**	1.7	6.6
Changes in Assets and Liabilities:			
Accounts receivable	**187.8**	(186.2)	(52.3)
Inventories	**(2.0)**	41.4	19.0
Accounts payable	**(299.9)**	268.4	49.0
Customer deposits and credits	**16.9**	(25.4)	(2.5)
Taxes accrued	**7.3**	20.2	10.2
Interest accrued	**8.8**	(21.7)	(33.9)
Exchange gas receivable/payable	**55.5**	(21.5)	(64.5)
Other accruals	**105.3**	43.5	31.8
Prepayments and other current assets	**(33.6)**	(14.5)	(13.3)
Regulatory assets/liabilities	**(85.6)**	(53.2)	57.5
Postretirement and postemployment benefits	**(21.1)**	58.2	(380.9)
Deferred charges and other noncurrent assets	**(76.1)**	3.8	(2.0)
Other noncurrent liabilities	**61.6**	(2.8)	(34.4)
Net Cash Flows from Operating Activities	**1,583.3**	540.1	742.2
Investing Activities			
Capital expenditures	**(1,802.4)**	(1,818.2)	(1,695.8)
Cost of removal	**(113.2)**	(104.3)	(109.0)
Purchases of available-for-sale securities	**(140.4)**	(90.0)	(168.4)
Sales of available-for-sale securities	**132.1**	82.3	163.1
Other investing activities	**1.5**	4.1	1.6
Net Cash Flows used for Investing Activities	**(1,922.4)**	(1,926.1)	(1,808.5)
Financing Activities			
Issuance of long-term debt	**750.0**	350.0	3,250.0
Repayments of long-term debt and finance lease obligations	**(51.6)**	(1,046.1)	(1,855.0)
Issuance of short-term debt (maturity > 90 days)	**600.0**	950.0	—
Repayment of short-term debt (maturity > 90 days)	**(700.0)**	—	—
Change in short-term borrowings, net (maturity ≤ 90 days)	**(104.0)**	(178.5)	(282.4)
Issuance of common stock, net of issuance costs	**244.4**	848.2	336.7
Issuance of preferred stock, net of issuance costs	**—**	880.0	—
Equity costs, premiums and other debt related costs	**(17.8)**	(46.0)	(144.3)
Acquisition of treasury stock	**—**	(4.0)	(7.2)
Dividends paid - common stock	**(298.5)**	(273.3)	(229.1)
Dividends paid - preferred stock	**(56.1)**	(11.6)	—
Net Cash Flows from Financing Activities	**366.4**	1,468.7	1,068.7
Change in cash, cash equivalents and restricted cash	**27.3**	82.7	2.4
Cash, cash equivalents and restricted cash at beginning of period	**121.1**	38.4	36.0
Cash, Cash Equivalents and Restricted Cash at End of Period	**$ 148.4**	$ 121.1	$ 38.4

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

NISOURCE INC.
STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY

(in millions)	Common Stock	Preferred Stock[(1)]	Treasury Stock	Additional Paid-In Capital	Retained Deficit	Accumulated Other Comprehensive Loss	Total
Balance as of January 1, 2017	**$ 3.3**	**$ —**	**$ (88.7)**	**$ 5,153.9**	**$ (972.2)**	**$ (25.1)**	**$ 4,071.2**
Comprehensive Income:							
Net Income	—	—	—	—	128.5	—	128.5
Other comprehensive loss, net of tax	—	—	—	—	—	(18.3)	(18.3)
Common stock dividends ($0.70 per share)	—	—	—	—	(229.4)	—	(229.4)
Treasury stock acquired	—	—	(7.2)	—	—	—	(7.2)
Stock issuances:							
Employee stock purchase plan	—	—	—	5.0	—	—	5.0
Long-term incentive plan	—	—	—	14.9	—	—	14.9
401(k) and profit sharing	—	—	—	34.3	—	—	34.3
Dividend reinvestment plan	—	—	—	6.4	—	—	6.4
ATM Program	0.1	—	—	314.6	—	—	314.7
Balance as of December 31, 2017	**$ 3.4**	**$ —**	**$ (95.9)**	**$ 5,529.1**	**$ (1,073.1)**	**$ (43.4)**	**$ 4,320.1**
Comprehensive Loss:							
Net Loss	—	—	—	—	(50.6)	—	(50.6)
Other comprehensive income, net of tax	—	—	—	—	—	15.7	15.7
Dividends							
Common stock ($0.78 per share)	—	—	—	—	(273.5)	—	(273.5)
Preferred stock ($28.88 per share)	—	—	—	—	(11.6)	—	(11.6)
Treasury stock acquired	—	—	(4.0)	—	—	—	(4.0)
Cumulative effect of change in accounting principle	—	—	—	—	9.5	(9.5)	—
Stock issuances:							
Common stock - private placement	0.3	—	—	599.3	—	—	599.6
Preferred stock	—	880.0	—	—	—	—	880.0
Employee stock purchase plan	—	—	—	5.5	—	—	5.5
Long-term incentive plan	—	—	—	15.4	—	—	15.4
401(k) and profit sharing	—	—	—	21.8	—	—	21.8
ATM Program	0.1	—	—	232.4	—	—	232.5
Balance as of December 31, 2018	**$ 3.8**	**$ 880.0**	**$ (99.9)**	**$ 6,403.5**	**$ (1,399.3)**	**$ (37.2)**	**$ 5,750.9**
Comprehensive Income:							
Net Income	—	—	—	—	383.1	—	383.1
Other comprehensive loss, net of tax	—	—	—	—	—	(55.4)	(55.4)
Dividends:							
Common stock ($0.80 per share)	—	—	—	—	(298.5)	—	(298.5)
Preferred stock (See Note 12)	—	—	—	—	(56.1)	—	(56.1)
Stock issuances:							
Employee stock purchase plan	—	—	—	5.6	—	—	5.6
Long-term incentive plan	—	—	—	10.4	—	—	10.4
401(k) and profit sharing	—	—	—	17.6	—	—	17.6
ATM program	—	—	—	229.1	—	—	229.1
Balance as of December 31, 2019	**$ 3.8**	**$ 880.0**	**$ (99.9)**	**$ 6,666.2**	**$ (1,370.8)**	**$ (92.6)**	**$ 5,986.7**

[(1)]Series A and Series B shares have an aggregate liquidation preference of $400M and $500M, respectively. See Note 12, "Equity" for additional information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NiSource Inc.
STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY

	Preferred	Common		
(in thousands)	Shares	Shares	Treasury	Outstanding
Balance as of January 1, 2017	**—**	**326,664**	**(3,504)**	**323,160**
Treasury stock acquired	—	—	(293)	(293)
Issued:				
Employee stock purchase plan	—	207	—	207
Long-term incentive plan	—	351	—	351
401(k) and profit sharing plan	—	1,396	—	1,396
Dividend reinvestment plan	—	264	—	264
ATM program	—	11,931	—	11,931
Balance as of December 31, 2017	**—**	**340,813**	**(3,797)**	**337,016**
Treasury stock acquired	—	—	(166)	(166)
Issued:				
Common stock - private placement	—	24,964	—	24,964
Preferred stock	420	—	—	—
Employee stock purchase plan	—	223	—	223
Long-term incentive plan	—	561	—	561
401(k) and profit sharing plan	—	882	—	882
ATM Program	—	8,883	—	8,883
Balance as of December 31, 2018	**420**	**376,326**	**(3,963)**	**372,363**
Issued:				
Preferred stock[(1)]	20	—	—	—
Employee stock purchase plan	—	201	—	201
Long-term incentive plan	—	518	—	518
401(k) and profit sharing plan	—	631	—	631
ATM program	—	8,423	—	8,423
Balance as of December 31, 2019	**440**	**386,099**	**(3,963)**	**382,136**

[(1)]See Note 12, "Equity," for additional information.

Accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

1. Nature of Operations and Summary of Significant Accounting Policies

A. Company Structure and Principles of Consolidation. We are an energy holding company incorporated in Delaware and headquartered in Merrillville, Indiana. Our subsidiaries are fully regulated natural gas and electric utility companies serving approximately 4.0 million customers in seven states. We generate substantially all of our operating income through these rate-regulated businesses. The consolidated financial statements include the accounts of us and our majority-owned subsidiaries after the elimination of all intercompany accounts and transactions.

On February 26, 2020, NiSource and Columbia of Massachusetts entered into the Asset Purchase Agreement with Eversource, a Massachusetts voluntary association. Upon the terms and subject to the conditions set forth in the Asset Purchase Agreement, NiSource and Columbia of Massachusetts agreed to sell to Eversource, with certain additions and exceptions, (1) substantially all of the assets of Columbia of Massachusetts and (2) all of the assets held by any of Columbia of Massachusetts' affiliates that primarily relate to the business of storing, distributing or transporting natural gas to residential, commercial and industrial customers in Massachusetts, as conducted by Columbia of Massachusetts, and Eversource agreed to assume certain liabilities of Columbia of Massachusetts and its affiliates. For additional information, see Note 26, "Subsequent Event."

B. Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

C. Cash, Cash Equivalents and Restricted Cash. We consider all highly liquid investments with original maturities of three months or less to be cash equivalents. We report amounts deposited in brokerage accounts for margin requirements as restricted cash. In addition, we have amounts deposited in trust to satisfy requirements for the provision of various property, liability, workers compensation, and long-term disability insurance, which is classified as restricted cash on the Consolidated Balance Sheets and disclosed with cash and cash equivalents on the Statements of Consolidated Cash Flows.

D. Accounts Receivable and Unbilled Revenue. Accounts receivable on the Consolidated Balance Sheets includes both billed and unbilled amounts. Unbilled amounts of accounts receivable relate to a portion of a customer's consumption of gas or electricity from the last cycle billing date through the last day of the month (balance sheet date). Factors taken into consideration when estimating unbilled revenue include historical usage, customer rates and weather. Accounts receivable fluctuates from year to year depending in large part on weather impacts and price volatility. Our accounts receivable on the Consolidated Balance Sheets include unbilled revenue, less reserves, in the amounts of $350.5 million and $324.2 million as of December 31, 2019 and 2018, respectively. The reserve for uncollectible receivables is our best estimate of the amount of probable credit losses in the existing accounts receivable. We determined the reserve based on historical experience and in consideration of current market conditions. Account balances are charged against the allowance when it is anticipated the receivable will not be recovered. Refer to Note 3, "Revenue Recognition," for additional information on customer-related accounts receivable.

E. Investments in Debt Securities. Our investments in debt securities are carried at fair value and are designated as available-for-sale. These investments are included within "Other investments" on the Consolidated Balance Sheets. Unrealized gains and losses, net of deferred income taxes, are recorded to accumulated other comprehensive income or loss. These investments are monitored for other than temporary declines in market value. Realized gains and losses and permanent impairments are reflected in the Statements of Consolidated Income (Loss). No material impairment charges were recorded for the years ended December 31, 2019, 2018 or 2017. Refer to Note 17, "Fair Value," for additional information.

F. Basis of Accounting for Rate-Regulated Subsidiaries. Rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged and collected. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred on the Consolidated Balance Sheets and are later recognized in income as the related amounts are included in customer rates and recovered from or refunded to customers.

In the event that regulation significantly changes the opportunity for us to recover our costs in the future, all or a portion of our regulated operations may no longer meet the criteria for regulatory accounting. In such an event, a write-down of all or a portion of our existing regulatory assets and liabilities could result. If transition cost recovery was approved by the appropriate regulatory bodies that would meet the requirements under GAAP for continued accounting as regulatory assets and liabilities during such recovery period, the regulatory assets and liabilities would be reported at the recoverable amounts. If unable to continue to apply the provisions of regulatory accounting, we would be required to apply the provisions of ASC 980-20, *Discontinuation of Rate-Regulated Accounting*. In management's opinion, our regulated subsidiaries will be subject to regulatory accounting for the foreseeable future. Refer to Note 8, "Regulatory Matters," for additional information.

G. Plant and Other Property and Related Depreciation and Maintenance. Property, plant and equipment (principally utility plant) is stated at cost. The rate-regulated subsidiaries record depreciation using composite rates on a straight-line basis over the remaining service lives of the electric, gas and common properties as approved by the appropriate regulators.

Non-utility property is generally depreciated on a straight-line basis over the life of the associated asset. Refer to Note 5, "Property, Plant and Equipment," for additional information related to depreciation expense.

For rate-regulated companies, AFUDC is capitalized on all classes of property except organization costs, land, autos, office equipment, tools and other general property purchases. The allowance is applied to construction costs for that period of time between the date of the expenditure and the date on which such project is placed in service. Our pre-tax rate for AFUDC was 3.0% in 2019, 3.5% in 2018 and 4.0% in 2017.

Generally, our subsidiaries follow the practice of charging maintenance and repairs, including the cost of removal of minor items of property, to expense as incurred. When our subsidiaries retire regulated property, plant and equipment, original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation. However, when it becomes probable a regulated asset will be retired substantially in advance of its original expected useful life or is abandoned, the cost of the asset and the corresponding accumulated depreciation is recognized as a separate asset. If the asset is still in operation, the net amount is classified as "Other property, at cost, less accumulated depreciation" on the Consolidated Balance Sheets. If the asset is no longer operating, the net amount is classified in "Regulatory assets" on the Consolidated Balance Sheets. If we are able to recover a full return of and on investment, the carrying value of the asset is based on historical cost. If we are not able to recover a full return on investment, a loss on impairment is recognized to the extent the net book value of the asset exceeds the present value of future revenues discounted at the incremental borrowing rate.

When our subsidiaries sell entire regulated operating units, or retire or sell nonregulated properties, the original cost and accumulated depreciation and amortization balances are removed from "Property, Plant and Equipment" on the Consolidated Balance Sheets. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body. Refer to Note 5, "Property, Plant and Equipment," for further information.

External and internal costs associated with computer software developed for internal use are capitalized. Capitalization of such costs commences upon the completion of the preliminary stage of each project. Once the installed software is ready for its intended use, such capitalized costs are amortized on a straight-line basis generally over a period of five years, except for certain significant enterprise-wide technology investments which are amortized over a ten-year period.

External and internal up-front implementation costs associated with cloud computing arrangements that are service contracts are deferred on the Consolidated Balance Sheets. Once the installed software is ready for its intended use, such deferred costs are amortized on a straight-line basis to "Operation and maintenance," over the minimum term of the contract plus contractually-provided renewal periods that are reasonable expected to be exercised -- generally up to a maximum of five years.

H. Goodwill and Other Intangible Assets. Substantially all of our goodwill relates to the excess of cost over the fair value of the net assets acquired in the Columbia acquisition on November 1, 2000. We test our goodwill for impairment annually as of May 1, or more frequently if events and circumstances indicate that goodwill might be impaired. Fair value of our reporting units is determined using a combination of income and market approaches.

We had other intangible assets consisting primarily of franchise rights apart from goodwill that were identified as part of the purchase price allocations associated with the acquisition of Columbia of Massachusetts, which were being amortized on a straight-line basis over forty years from the date of acquisition.

During the fourth quarter of 2019, we impaired goodwill and intangible assets related to Columbia of Massachusetts. See Note 6, "Goodwill and Other Intangible Assets," for additional information.

I. Accounts Receivable Transfer Program. Certain of our subsidiaries have agreements with third parties to transfer certain accounts receivable without recourse. These transfers of accounts receivable are accounted for as secured borrowings. The entire gross receivables balance remains on the December 31, 2019 and 2018 Consolidated Balance Sheets and short-term debt is recorded in the amount of proceeds received from the transferees involved in the transactions. Refer to Note 18, "Transfers of Financial Assets," for further information.

J. Gas Cost and Fuel Adjustment Clause. Our regulated subsidiaries defer most differences between gas and fuel purchase costs and the recovery of such costs in revenues, and adjust future billings for such deferrals on a basis consistent with applicable state-approved tariff provisions. These deferred balances are recorded as "Regulatory assets" or "Regulatory liabilities," as appropriate, on the Consolidated Balance Sheets. Refer to Note 8, "Regulatory Matters," for additional information.

K. Inventory. Both the LIFO inventory methodology and the weighted average cost methodology are used to value natural gas in storage, as approved by regulators for all of our regulated subsidiaries. Inventory valued using LIFO was $47.2 million and $47.5 million at December 31, 2019 and 2018, respectively. Based on the average cost of gas using the LIFO method, the estimated replacement cost of gas in storage was less than the stated LIFO cost by $25.5 million and $12.2 million at December 31, 2019 and 2018, respectively. Gas inventory valued using the weighted average cost methodology was $203.7 million at December 31, 2019 and $239.3 million at December 31, 2018.

Electric production fuel is valued using the weighted average cost inventory methodology, as approved by NIPSCO's regulator.

Materials and supplies are valued using the weighted average cost inventory methodology.

L. Accounting for Exchange and Balancing Arrangements of Natural Gas. Our Gas Distribution Operations segment enters into balancing and exchange arrangements of natural gas as part of its operations and off-system sales programs. We record a receivable or payable for any of our respective cumulative gas imbalances, as well as for any gas inventory borrowed or lent under a Gas Distribution Operations exchange agreement. Exchange gas is valued based on individual regulatory jurisdiction requirements (for example, historical spot rate, spot at the beginning of the month). These receivables and payables are recorded as “Exchange gas receivable” or “Exchange gas payable” on our Consolidated Balance Sheets, as appropriate.

M. Accounting for Risk Management Activities. We account for our derivatives and hedging activities in accordance with ASC 815. We recognize all derivatives as either assets or liabilities on the Consolidated Balance Sheets at fair value, unless such contracts are exempted as a normal purchase normal sale under the provisions of the standard. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation.

We have elected not to net fair value amounts for any of our derivative instruments or the fair value amounts recognized for the right to receive cash collateral or obligation to pay cash collateral arising from those derivative instruments recognized at fair value, which are executed with the same counterparty under a master netting arrangement. See Note 9, "Risk Management Activities," for additional information.

N. Income Taxes and Investment Tax Credits. We record income taxes to recognize full interperiod tax allocations. Under the asset and liability method, deferred income taxes are provided for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amount and the tax basis of existing assets and liabilities. Investment tax credits associated with regulated operations are deferred and amortized as a reduction to income tax expense over the estimated useful lives of the related properties.

To the extent certain deferred income taxes of the regulated companies are recoverable or payable through future rates, regulatory assets and liabilities have been established. Regulatory assets for income taxes are primarily attributable to property-related tax timing differences for which deferred taxes had not been provided in the past, when regulators did not recognize such taxes as costs in the rate-making process. Regulatory liabilities for income taxes are primarily attributable to the regulated companies’ obligation to refund to ratepayers deferred income taxes provided at rates higher than the current Federal income tax rate. Such property-related amounts are credited to ratepayers using either the average rate assumption method or the reverse South Georgia method. Non property-related amounts are credited to ratepayers consistent with state utility commission direction.

Pursuant to the Internal Revenue Code and relevant state taxing authorities, we and our subsidiaries file consolidated income tax returns for federal and certain state jurisdictions. We and our subsidiaries are parties to a tax sharing agreement. Income taxes recorded by each party represent amounts that would be owed had the party been separately subject to tax.

O. Environmental Expenditures. We accrue for costs associated with environmental remediation obligations when the incurrence of such costs is probable and the amounts can be reasonably estimated, regardless of when the expenditures are actually made. The undiscounted estimated future expenditures are based on currently enacted laws and regulations, existing technology and estimated site-specific costs where assumptions may be made about the nature and extent of site contamination, the extent of cleanup efforts, costs of alternative cleanup methods and other variables. The liability is adjusted as further information is discovered or circumstances change. The accruals for estimated environmental expenditures are recorded on the Consolidated Balance Sheets in “Legal and environmental” for short-term portions of these liabilities and “Other noncurrent liabilities” for the respective long-term portions of these liabilities. Rate-regulated subsidiaries applying regulatory accounting establish regulatory assets on the Consolidated Balance Sheets to the extent that future recovery of environmental remediation costs is probable through the regulatory process. Refer to Note 19, "Other Commitments and Contingencies," for further information.

P. Excise Taxes. As an agent for some state and local governments, we invoice and collect certain excise taxes levied by state and local governments on customers and record these amounts as liabilities payable to the applicable taxing jurisdiction. Such balances are presented within "Other accruals" on the Consolidated Balance Sheets. These types of taxes collected from customers, comprised largely of sales taxes, are presented on a net basis affecting neither revenues nor cost of sales. We account for excise taxes for which we are liable by recording a liability for the expected tax with a corresponding charge to “Other taxes” expense on the Statements of Consolidated Income (Loss).

Q. Accrued Insurance Liabilities. We accrue for insurance costs related to workers compensation, automobile, property, general and employment practices liabilities based on the most probable value of each claim. In general, claim values are determined by professional, licensed loss adjusters who consider the facts of the claim, anticipated indemnification and legal expenses, and respective state rules. Claims are reviewed by us at least quarterly and an adjustment is made to the accrual based on the most current information. Refer to Note 19-E "Other Matters" for further information on accrued insurance liabilities related to the Greater Lawrence Incident.

2. Recent Accounting Pronouncements

Recently Issued Accounting Pronouncements

We are currently evaluating the impact of certain ASUs on our Consolidated Financial Statements or Notes to Consolidated Financial Statements, which are described below:

Standard	Description	Effective Date	Effect on the financial statements or other significant matters
ASU 2018-14, *Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20): Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans*	The pronouncement modifies the disclosure requirements for defined benefit pension or other postretirement benefit plans. The guidance removes disclosures that are no longer considered cost beneficial, clarifies the specific requirements of disclosures and adds disclosure requirements identified as relevant. The modifications affect annual period disclosures and must be applied on a retrospective basis to all periods presented.	Annual periods ending after December 15, 2020. Early adoption is permitted.	We are currently evaluating the effects of this pronouncement on our Notes to Consolidated Financial Statements. We expect to adopt this ASU on its effective date.
ASU 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes*	This pronouncement simplifies the accounting for income taxes by eliminating certain exceptions to the general principles in ASC 740, income taxes. It also improves consistency of application for other areas of the guidance by clarifying and amending existing guidance.	Annual periods beginning after December 15, 2020. Early adoption is permitted.	We are currently evaluating the effects of this pronouncement on our Consolidated Financial Statements and Notes to Consolidated Financial Statements. We tentatively expect to adopt this ASU on its effective date.

Recently Adopted Accounting Pronouncements

Standard	Adoption
ASU 2019-01, *Leases (Topic 842): Codification Improvements*	See Note 16, "Leases," for our discussion of the effects of implementing these standards.
ASU 2018-11, *Leases (Topic 842): Targeted Improvements*	
ASU 2018-01, *Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842*	
ASU 2016-02, *Leases (Topic 842)*	
ASU 2019-04, *Codification Improvements to Topic 326, Financial Instruments-Credit Losses, Topic 815, Derivatives and Hedging, and Topic 825, Financial Instruments*	In June 2016, the FASB issued ASU 2016-13 that revised the guidance on the impairment of most financial assets and certain other instruments that are not measured at fair value through net income. This ASU replaces the current "incurred loss" model with an "expected loss" model for instruments measured at amortized cost. It also requires entities to record allowances for available-for-sale securities rather than impair the carrying amount of the securities. Subsequent improvements to the estimated credit losses of available-for-sale securities will be recognized immediately in earnings instead of over time as they are under historic guidance. We adopted this ASU effective January 1, 2020, using a modified retrospective method. Adoption of this standard did not have a material impact on our Consolidated Financial Statements. No material adjustments were made to January 1, 2020 opening balances as a result of adoption. For our investments that are classified as available for sale debt securities, we will recognize impairment using an allowance approach instead of an 'other than temporary' impairment (OTTI) model. Since we do not have amounts previously recognized in other comprehensive income related to previous OTTI charges, provisions of this ASU are adopted prospectively. In regards to our recorded balances of trade receivables that fall within the scope of this ASU, the ASU did not result in any significant modifications to our policies related to recognizing an allowance on our trade receivables. Based on shared risk characteristics, we segregate our trade receivables into separate pools. We will apply separate models to calculate reserves for uncollectible receivables, as well as consider factors other than time to determine whether a credit loss exists. ASC 326 also prescribes additional presentation and disclosure requirements. For reporting periods beginning after January 1, 2020, we will include additional disclosures in our Notes to Consolidated Financial Statements based on qualitative and quantitative assessment of materiality.
ASU 2016-13, *Financial Instruments-Credit Losses (Topic 326)*	

3. Revenue Recognition

In 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (ASC 606). ASU 2014-09 outlines a single, comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance. The core principle of the new standard is that an entity should recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (ASC 606): Principal versus Agent Considerations, and ASU 2016-12, Revenue from Contracts with Customers (ASC 606): Narrow-Scope Improvements and Practical Expedients. We adopted the provisions of ASC 606 beginning on January 1, 2018 using a modified retrospective method, which was applied to all contracts. No material adjustments were made to January 1, 2018 opening balances as a result of the adoption. As required under the modified retrospective method of adoption, results for reporting periods beginning after January 1, 2018 are presented under ASC 606, while prior period amounts are not adjusted and continue to be reported in accordance with ASC 605.

The table below provides results for the years ended December 31, 2019 and 2018 as if it had been prepared under historic accounting guidance. We included operating revenue information for the year ended December 31, 2017 for comparability.

Year Ended December 31, *(in millions)*	**2019**	2018	2017
Operating Revenues			
Gas Distribution	**$ 2,336.1**	$ 2,348.4	$ 2,063.2
Gas Transportation	**1,171.3**	1,055.2	1,021.5
Electric	**1,698.5**	1,707.4	1,785.5
Other	**3.0**	3.5	4.4
Total Operating Revenues	**$ 5,208.9**	$ 5,114.5	$ 4,874.6

Beginning in 2018 with the adoption of ASC 606, the Statements of Consolidated Income (Loss) disaggregates “Customer revenues” (i.e. ASC 606 Revenues) from “Other revenues,” both of which are discussed in more detail below.

Customer Revenues. Substantially all of our revenues are tariff-based, which we have concluded is within the scope of ASC 606. Under ASC 606, the recipients of our utility service meet the definition of a customer, while the operating company tariffs represent an agreement that meets the definition of a contract. ASC 606 defines a contract as an agreement between two or more parties, in this case us and the customer, which creates enforceable rights and obligations. In order to be considered a contract, we have determined that it is probable that substantially all of the consideration to which we are entitled from customers will be collected upon satisfaction of performance obligations. We maintain common utility credit risk mitigation practices, including requiring deposits and actively pursuing collection of past due amounts. In addition, our regulated operations utilize certain regulatory mechanisms that facilitate recovery of bad debt costs within tariff-based rates, which provides further evidence of collectibility.

Customers in certain of our jurisdictions participate in programs that allow for a fixed payment each month regardless of usage. Payments received that exceed the value of gas or electricity actually delivered are recorded as a liability and presented in "Customer Deposits and Credits" on the Consolidated Balance Sheets. Amounts in this account are reduced and revenue is recorded when customer usage begins to exceed payments received.

We have identified our performance obligations created under tariff-based sales as 1) the commodity (natural gas or electricity, which includes generation and capacity) and 2) delivery. These commodities are sold and / or delivered to and generally consumed by customers simultaneously, leading to satisfaction of our performance obligations over time as gas or electricity is delivered to customers. Due to the at-will nature of utility customers, performance obligations are limited to the services requested and received to date. Once complete, we generally maintain no additional performance obligations.

Transaction prices for each performance obligation are generally prescribed by each operating company’s respective tariff. Rates include provisions to adjust billings for fluctuations in fuel and purchased power costs and cost of natural gas. Revenues are adjusted for differences between actual costs subject to reconciliation and the amounts billed in current rates. Under or over recovered revenues related to these cost recovery mechanisms are included in "Regulatory Assets" or "Regulatory Liabilities" on the Consolidated Balance Sheets and are recovered from or returned to customers through adjustments to tariff rates. As we provide and deliver service to customers, revenue is recognized based on the transaction price allocated to each performance obligation. In general, revenue recognized from tariff-based sales is equivalent to the value of natural gas or electricity supplied and billed each period, in addition to an estimate for deliveries completed during the period but not yet billed to the customer.

In addition to tariff-based sales, our Gas Distribution Operations segment enters into balancing and exchange arrangements of natural gas as part of our operations and off-system sales programs. We have concluded that these sales are within the scope of ASC 606. Performance obligations for these types of sales include transportation and storage of natural gas and can be satisfied at a point in time or over a period of time, depending on the specific transaction. For those transactions that span a period of time, we record a receivable or payable for any cumulative gas imbalances, as well as for any gas inventory borrowed or lent under a Gas Distributions Operations exchange agreement.

Revenue Disaggregation and Reconciliation. We disaggregate revenue from contracts with customers based upon reportable segment as well as by customer class. As our revenues are primarily earned over a period of time, and we do not earn a material amount of revenues at a point in time, revenues are not disaggregated as such below. The Gas Distribution Operations segment provides natural gas service and transportation for residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, Maryland, Indiana and Massachusetts. The Electric Operations segment provides electric service in 20 counties in the northern part of Indiana.

The table below reconciles revenue disaggregation by customer class to segment revenue as well as to revenues reflected on the Statements of Consolidated Income (Loss):

Year Ended December 31, 2019 (in millions)	Gas Distribution Operations	Electric Operations	Corporate and Other	Total
Customer Revenues[(1)]				
Residential	$ 2,309.0	$ 481.6	$ —	$ 2,790.6
Commercial	771.3	486.6	—	1,257.9
Industrial	245.2	607.7	—	852.9
Off-system	77.7	—	—	77.7
Miscellaneous	52.0	21.5	0.8	74.3
Total Customer Revenues	$ 3,455.2	$ 1,597.4	$ 0.8	$ 5,053.4
Other Revenues	54.5	101.0	—	155.5
Total Operating Revenues	$ 3,509.7	$ 1,698.4	$ 0.8	$ 5,208.9

(1) Customer revenue amounts exclude intersegment revenues. See Note 23, "Segments of Business," for discussion of intersegment revenues.

Year Ended December 31, 2018 *(in millions)*	Gas Distribution Operations	Electric Operations	Corporate and Other	Total
Customer Revenues[(1)]				
Residential	$ 2,250.0	$ 494.7	$ —	$ 2,744.7
Commercial	751.9	492.7	—	1,244.6
Industrial	228.0	613.6	—	841.6
Off-system	92.4	—	—	92.4
Miscellaneous	49.7	17.4	0.7	67.8
Total Customer Revenues	$ 3,372.0	$ 1,618.4	$ 0.7	$ 4,991.1
Other Revenues	34.4	89.0	—	123.4
Total Operating Revenues	$ 3,406.4	$ 1,707.4	$ 0.7	$ 5,114.5

(1) Customer revenue amounts exclude intersegment revenues. See Note 23, "Segments of Business," for discussion of intersegment revenues.

Customer Accounts Receivable. Accounts receivable on our Consolidated Balance Sheets includes both billed and unbilled amounts, as well as certain amounts that are not related to customer revenues. Unbilled amounts of accounts receivable relate to a portion of a customer's consumption of gas or electricity from the date of the last cycle billing through the last day of the month (balance sheet date). Factors taken into consideration when estimating unbilled revenue include historical usage, customer rates and weather. The opening and closing balances of customer receivables for the years ended December 31, 2019 and 2018 are presented in the table below. We had no significant contract assets or liabilities during the period. Additionally, we have not incurred any significant costs to obtain or fulfill contracts.

(in millions)	Customer Accounts Receivable, Billed (less reserve)[(1)]	Customer Accounts Receivable, Unbilled (less reserve)
Balance as of December 31, 2018	$ 540.5	$ 349.1
Balance as of December 31, 2019	466.6	346.6
Decrease	$ (73.9)	$ (2.5)

(1) Customer billed receivables decreased due to decreased natural gas costs and warmer weather in 2019 compared to 2018.

Utility revenues are billed to customers monthly on a cycle basis. We generally expect that substantially all customer accounts receivable will be collected within the month following customer billing, as this revenue consists primarily of monthly, tariff-based billings for service and usage.

Other Revenues. As permitted by accounting principles generally accepted in the United States, regulated utilities have the ability to earn certain types of revenue that are outside the scope of ASC 606. These revenues primarily represent revenue earned under alternative revenue programs. Alternative revenue programs represent regulator-approved programs that allow for the adjustment of billings and revenue for certain broad, external factors, or for additional billings if the entity achieves certain objectives, such as a specified reduction of costs. We maintain a variety of these programs, including demand side management initiatives that recover costs associated with the implementation of energy efficiency programs, as well as normalization programs that adjust revenues for the effects of weather or other external factors. Additionally, we maintain certain programs with future test periods that operate similarly to FERC formula rate programs and allow for recovery of costs incurred to replace aging infrastructure. When the criteria to recognize alternative revenue have been met, we establish a regulatory asset and present revenue from alternative revenue programs on the Statements of Consolidated Income (Loss) as "Other revenues." When amounts previously recognized under alternative revenue accounting guidance are billed, we reduce the regulatory asset and record a customer account receivable.

4. Earnings Per Share

Basic EPS is computed by dividing net income attributable to common shareholders by the weighted-average number of shares of common stock outstanding for the period. The weighted-average shares outstanding for diluted EPS includes the incremental effects of the various long-term incentive compensation plans and forward agreements when the impact of such plans and agreements would be dilutive. The calculation of diluted earnings per share for the year ended December 31, 2018 does not include any dilutive potential common shares as we had a net loss on the Statements of Consolidated Income (Loss) for that period, and any incremental shares would have had an anti-dilutive impact on EPS. The calculation of diluted earnings per share for the year ended December 31, 2017 excludes the impact of forward agreements, which had an anti-dilutive effect for that period. The computation of diluted average common shares is as follows:

Year Ended December 31, *(in thousands)*	**2019**	2018	2017
Denominator			
Basic average common shares outstanding	**374,650**	356,491	329,388
Dilutive potential common shares:			
Shares contingently issuable under employee stock plans	**929**	—	547
Shares restricted under stock plans	**154**	—	821
Forward agreements	**253**	—	—
Diluted Average Common Shares	**375,986**	356,491	330,756

5. Property, Plant and Equipment

Our property, plant and equipment on the Consolidated Balance Sheets are classified as follows:

At December 31, *(in millions)*		**2019**		2018
Property, Plant and Equipment				
Gas Distribution Utility[1]	**$**	**14,989.7**	$	13,776.0
Electric Utility[1]		**8,902.3**		8,374.2
Corporate		**153.3**		155.8
Construction Work in Process		**457.3**		474.8
Non-Utility and Other		**39.3**		38.7
Total Property, Plant and Equipment	**$**	**24,541.9**	$	22,819.5
Accumulated Depreciation and Amortization				
Gas Distribution Utility[1]	**$**	**(3,556.0)**	$	(3,373.8)
Electric Utility[1]		**(3,973.8)**		(3,809.5)
Corporate		**(79.5)**		(74.6)
Non-Utility and Other		**(20.4)**		(19.1)
Total Accumulated Depreciation and Amortization	**$**	**(7,629.7)**	$	(7,277.0)
Net Property, Plant and Equipment	**$**	**16,912.2**	$	15,542.5

[1]NIPSCO's common utility plant and associated accumulated depreciation and amortization are allocated between Gas Distribution Utility and Electric Utility Property, Plant and Equipment.

The weighted average depreciation provisions for utility plant, as a percentage of the original cost, for the periods ended December 31, 2019, 2018 and 2017 were as follows:

	2019	2018	2017
Electric Operations[1]	**2.8%**	2.9%	3.4%
Gas Distribution Operations	**2.5%**	2.2%	2.1%

[1]Lower depreciation rate beginning in 2018 due to reduced EERM-related depreciation expense and higher depreciable base from transmission assets being placed into service in 2018.

We recognized depreciation expense of $612.2 million, $503.4 million and $501.5 million for the years ended 2019, 2018 and 2017, respectively.

Amortization of Software Costs. We amortized $55.5 million, $54.1 million and $44.0 million in 2019, 2018 and 2017, respectively, related to software costs. Our unamortized software balance was $169.6 million and $159.5 million at December 31, 2019 and 2018, respectively.

Amortization of Cloud Computing Costs. We amortized $1.6 million and $0.1 million in 2019 and 2018, respectively, related to cloud computing costs. Our unamortized cloud computing balance was $14.2 million and $4.9 million at December 31, 2019 and 2018, respectively.

6. Goodwill and Other Intangible Assets

Intangible and Other Long-Lived Assets Impairment. Our intangible assets, apart from goodwill, consist of franchise rights. Franchise rights were identified as part of the purchase price allocations associated with the acquisition in February 1999 of Columbia of Massachusetts. We review our definite-lived intangible assets, along with other long-lived assets (utility plant), for impairment when events or changes in circumstances indicate the assets' fair value might be below their carrying amount.

During the fourth quarter of 2019, in connection with the preparation of the year-end financial statements, we assessed the changes in circumstances that occurred during the quarter to determine if it was more likely than not that the fair value of our long-lived assets (including franchise rights) were below their carrying amount. While there was no single determinative event or factor, the consideration in totality of several factors that developed during the fourth quarter of 2019 led us to conclude that it was more likely than not that the fair value of the Columbia of Massachusetts reporting unit and the value of its long-lived assets was below its carrying value. These factors included: (i) increased Massachusetts DPU regulatory enforcement activity related to Columbia of Massachusetts during the fourth quarter, including (a) an order imposing work restrictions on Columbia of Massachusetts, impacting Columbia of Massachusetts' infrastructure replacement program, (b) two orders opening public investigations into Columbia of Massachusetts related to the Greater Lawrence Incident and restoration efforts following the incident, and (c) an order defining the scope of the Massachusetts DPU's investigation into the preparation and response of Columbia of Massachusetts related to the incident; (ii) increased uncertainty as to the ability of Columbia of Massachusetts to execute its growth strategy, including utility infrastructure investments, and to obtain timely regulatory outcomes with reasonable rates of return; (iii) further damage to Columbia of Massachusetts' reputation as a result of concerns related to service lines abandoned during the restoration work following the Greater Lawrence Incident and the gas release event in Lawrence, Massachusetts on September 27, 2019; and (iv) the potential sale of the Massachusetts Business. See Note 19, "Other Commitments and Contingencies - C. Legal Proceedings" for more information regarding Massachusetts DPU regulatory enforcement activity. See Note 26, "Subsequent Event" for more information on the potential sale of the Massachusetts Business.

As a result, we performed a year-end impairment test of the held and used long-lived assets in which we compared the book value of the Columbia of Massachusetts asset group to its undiscounted future cash flow and determined the carrying value of the asset group was not recoverable. We estimated the fair value of the Columbia of Massachusetts asset group using a weighting of income and market approaches and determined that the fair value was less than the carrying value. This resulting impairment was allocated to reduce the entire franchise rights book value to its fair value of zero, which resulted in an impairment charge totaling $209.7 million recorded in the Gas Distribution Operations segment.

We also considered if any regulatory assets or ROU assets were probable of disallowance and determined no disallowances were probable. All of Columbia of Massachusetts' regulatory assets represent incurred costs probable of recovery.

As of December 31, 2019 and 2018, the carrying amount of the franchise rights was $0.0 million and $220.7 million (net of accumulated amortization of $221.5 million), respectively. We recorded amortization expense of $11.0 million in 2019, 2018 and 2017 related to our franchise rights intangible asset.

Goodwill. Substantially all of our goodwill relates to the excess of cost over the fair value of the net assets acquired in the Columbia acquisition on November 1, 2000. The following presents our goodwill balance allocated by segment as of December 31, 2019 and 2018:

(in millions)	**2019**	2018
Gas Distribution Operations	$ 1,485.9	$ 1,690.7
Electric Operations	—	—
Corporate and Other	—	—
Total	**$ 1,485.9**	$ 1,690.7

For our annual goodwill impairment analysis performed as of May 1, 2019, we completed a qualitative "step 0" analysis for all reporting units other than our Columbia of Massachusetts reporting unit. In the step 0 analysis, we assessed various assumptions, events and circumstances that would have affected the estimated fair value of the applicable reporting units as compared to their baseline May 1, 2016 "step 1" fair value measurement. The results of this assessment indicated that it was not more likely than not that the fair values of these reporting units were less than their respective carrying values, accordingly, no "step 1" analysis was required.

The results of our Columbia of Massachusetts reporting unit were negatively impacted by the Greater Lawrence Incident (see Note 19-C, "Legal Proceedings"). As a result, we completed a quantitative "step 1" analysis for the May 1, 2019 goodwill analysis for this reporting unit. This analysis considered the progress Columbia of Massachusetts had made with its restoration efforts related to the Greater Lawrence Incident, including the replacement of previously repaired equipment and the settlement agreement with the three impacted municipalities, as well as the ability for Columbia of Massachusetts to sustain its infrastructure replacement growth strategy through GSEP and timely rate cases with reasonable rates of return. Consistent with our historical impairment testing of goodwill, fair value of the Columbia of Massachusetts reporting unit was determined based on a weighting of income and market approaches. These approaches require significant judgments, including appropriate long-term growth rates and discount rates for the income approach and appropriate multiples of earnings for peer companies and control premiums for the market approach. These approaches also incorporate the latest available cash flow projections reflecting the estimated ongoing impacts of the Greater Lawrence Incident on Columbia of Massachusetts' operations. The discount rates were derived using peer company data compiled with the assistance of a third party valuation services firm. The discount rates used are subject to change based on changes in tax rates at both the state and federal level, debt and equity ratios at each reporting unit and general economic conditions. The long-term growth rate was derived by evaluating historic growth rates, new business and investment opportunities beyond the near term horizon. The long-term growth rate is subject to change depending on inflationary impacts to the U.S. economy and the individual business environments in which each reporting unit operates. The step 1 analysis performed indicated that the fair value of the Columbia of Massachusetts reporting unit exceeds its carrying value. As a result, no impairment charge was recorded as of the May 1, 2019 test date.

Although our annual impairment test is performed during the second quarter, we continue to monitor changes in circumstances that may indicate that it is more likely than not that the fair value of our reporting units is less than the reporting unit carrying value. During the fourth quarter of 2019, in connection with the preparation of the year-end financial statements, we assessed the matters related to Columbia of Massachusetts. These factors were the same fourth quarter circumstances outlined in the intangible and other long-lived assets impairment above.

As a result, a new impairment analysis was required for our Columbia of Massachusetts reporting unit. Consistent with the May 1, 2019 test, fair value of this reporting unit was determined based on a weighting of income and market approaches. The income approach calculated discounted cash flows using updated cash flow projections, discount rates and return on equity assumptions. The market approach applied a combination of comparable company multiples and comparable transactions and used updated cash flow projections. While certain assumptions, such as market multiples, remained unchanged in the year-end test, our cash flow projections, return on equity and rate case assumptions were all unfavorably updated at year-end compared to the May 1, 2019 test. The effects of these unfavorable developments were greater than the favorable change in weighted average cost of capital between the two tests. The year-end impairment analysis indicated that the fair value of the Columbia of Massachusetts reporting unit was below its carrying value. As a result, we reduced the Columbia of Massachusetts reporting unit goodwill balance to zero and recognized a goodwill impairment charge totaling $204.8 million, which is non-deductible for tax purposes.

7. Asset Retirement Obligations

We have recognized asset retirement obligations associated with various legal obligations including costs to remove and dispose of certain construction materials located within many of our facilities, certain costs to retire pipeline, removal costs for certain underground storage tanks, removal of certain pipelines known to contain PCB contamination, closure costs for certain sites including ash ponds, solid waste management units and a landfill, as well as some other nominal asset retirement obligations. We also have a significant obligation associated with the decommissioning of our two hydro facilities located in Indiana. These hydro facilities have an indeterminate life, and as such, no asset retirement obligation has been recorded.

Changes in our liability for asset retirement obligations for the years 2019 and 2018 are presented in the table below:

(in millions)	**2019**		2018	
Beginning Balance	**$ 352.0**		$ 268.7	
Accretion recorded as a regulatory asset/liability	**15.7**		11.1	
Additions	**—**		63.3	(2)
Settlements	**(5.4)**		(5.9)	
Change in estimated cash flows	**54.6**	(1)	14.8	(2)
Ending Balance	**$ 416.9**		$ 352.0	

(1)The change in estimated cash flows for 2019 is primarily attributed to changes in estimated costs and settlement timing for electric generating stations and the changes in estimated costs for retirement of gas mains.
(2)In 2018, $59.8 million of additions and $17.7 million of the change in estimated cash flows are attributed to costs associated with refining the CCR compliance plan. See Note 19-D, "Environmental Matters," for additional information on CCRs.

Certain non-legal costs of removal that have been, and continue to be, included in depreciation rates and collected in the customer rates of the rate-regulated subsidiaries are classified as "Regulatory liabilities" on the Consolidated Balance Sheets.

8. Regulatory Matters

Regulatory Assets and Liabilities

We follow the accounting and reporting requirements of ASC Topic 980, which provides that regulated entities account for and report assets and liabilities consistent with the economic effect of regulatory rate-making procedures if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged and collected from customers. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income or expense are deferred on the balance sheet and are recognized in the income statement as the related amounts are included in customer rates and recovered from or refunded to customers.

Regulatory assets were comprised of the following items:

At December 31, *(in millions)*	**2019**	2018
Regulatory Assets		
Unrecognized pension and other postretirement benefit costs (see Note 11)	**$ 739.1**	$ 798.3
Deferred pension and other postretirement benefit costs (see Note 11)	**91.3**	74.1
Environmental costs (see Note 19-D)	**73.4**	61.5
Regulatory effects of accounting for income taxes (see Note 1-N and Note 10)	**234.0**	233.1
Under-recovered gas and fuel costs (see Note 1-J)	**3.9**	34.7
Depreciation	**210.7**	209.6
Post-in-service carrying charges	**219.8**	206.6
Safety activity costs	**118.6**	91.7
DSM programs	**50.1**	45.5
Bailly Generating Station	**221.8**	244.3
Other	**276.9**	238.1
Total Regulatory Assets	**$ 2,239.6**	$ 2,237.5

Regulatory liabilities were comprised of the following items:

At December 31, *(in millions)*	**2019**	2018
Regulatory Liabilities		
Over-recovered gas and fuel costs (see Note 1-J)	**$ 42.6**	$ 32.0
Cost of removal (see Note 7)	**1,047.5**	1,076.0
Regulatory effects of accounting for income taxes (see Note 1-N and Note 10)	**1,307.0**	1,428.3
Deferred pension and other postretirement benefit costs (see Note 11)	**64.7**	62.7
Other	**50.4**	61.0
Total Regulatory Liabilities	**$ 2,512.2**	$ 2,660.0

Regulatory assets, including under-recovered gas and fuel cost, of approximately $1,524.3 million as of December 31, 2019 are not earning a return on investment. These costs are recovered over a remaining life of up to 41 years. Regulatory assets of approximately $1,932.4 million include expenses that are recovered as components of the cost of service and are covered by regulatory orders. Regulatory assets of approximately $307.2 million at December 31, 2019, require specific rate action.

Assets:

Unrecognized pension and other postretirement benefit costs. In 2007, we adopted certain updates of ASC 715 which required, among other things, the recognition in other comprehensive income or loss of the actuarial gains or losses and the prior service costs or credits that arise during the period but that are not immediately recognized as components of net periodic benefit costs. Certain subsidiaries defer these gains or losses as a regulatory asset in accordance with regulatory orders or as a result of regulatory precedent, to be recovered through base rates.

Deferred pension and other postretirement benefit costs. Primarily relates to the difference between postretirement expense recorded by certain subsidiaries due to regulatory orders and the postretirement expense recorded in accordance with GAAP. These costs are expected to be collected through future base rates, revenue riders or tracking mechanisms.

Environmental costs. Includes certain recoverable costs of investigating, testing, remediating and other costs related to gas plant sites, disposal sites or other sites onto which material may have migrated. Certain of our companies defer the costs as a regulatory asset in accordance with regulatory orders, to be recovered in future base rates, billing riders or tracking mechanisms.

Regulatory effects of accounting for income taxes. Represents the deferral and under collection of deferred taxes in the rate making process. In prior years, we have lowered customer rates in certain jurisdictions for the benefits of accelerated tax deductions. Amounts are expensed for financial reporting purposes as we recover deferred taxes in the rate making process.

Under-recovered gas and fuel costs. Represents the difference between the costs of gas and fuel and the recovery of such costs in revenue and is used to adjust future billings for such deferrals on a basis consistent with applicable state-approved tariff provisions. Recovery of these costs is achieved through tracking mechanisms.

Depreciation. Represents differences between depreciation expense incurred on a GAAP basis and that prescribed through regulatory order. Significant components of this balance include:

- **Columbia of Ohio depreciation rates**. Prior to 2005, the PUCO-approved depreciation rates for rate-making had been lower than those which would have been utilized if Columbia of Ohio were not subject to regulation resulting in the creation of a regulatory asset. In 2005, the PUCO authorized Columbia of Ohio to revise its depreciation accrual rates for the period beginning January 1, 2005. The revised depreciation rates are higher than those which would have been utilized if Columbia of Ohio were not subject to regulation allowing for amortization of the previously created regulatory asset. The amount of depreciation that would have been recorded from 2005 through 2019 had Columbia of Ohio not been subject to rate regulation is a cumulative $923.5 million, $103.8 million less than that reflected in rates. The resulting regulatory asset balance was $27.9 million and $39.5 million as of December 31, 2019 and 2018, respectively.

- **Columbia of Ohio IRP and CEP.** Columbia of Ohio also has PUCO approval to defer depreciation and debt-based post-in-service carrying charges (see "*Post-in-service carrying charges*" below) associated with its IRP and CEP. As of December 31, 2019, depreciation of $31.9 million and $77.2 million was deferred for the respective programs. Depreciation deferral balances for the respective programs as of December 31, 2018 were $29.1 million and $76.0 million. Recovery of the depreciation is approved annually through the IRP and CEP riders. The equivalent of annual depreciation expense, based on the average life of the related assets, is included in the calculation of the IRP and CEP riders approved by the PUCO and billed to customers. Deferred depreciation expense is recognized as the IRP and CEP riders are billed to customers.

- **NIPSCO ECRM.** NIPSCO obtained approval from the IURC to recover certain environmental related costs including operation and maintenance and depreciation expense once the environmental facilities become operational. The ECRM deferred charges represent expenses that will be recovered from customers through an annual ECRM Cost Tracker (ECT) which authorizes the collection of deferred balances over a six month period. Depreciation of $15.2 million and $14.4 million was deferred to a regulatory asset as of December 31, 2019 and 2018, respectively. This regulatory asset was included in electric base rates, which was approved by the IURC on December 4, 2019.

- **NIPSCO TDSIC.** NIPSCO obtained approval from the IURC to recover costs for certain system modernization projects outside of a base rate proceeding. Eighty percent of the related costs, including depreciation, property taxes, and debt and equity based carrying charges (see *"Post-in-service carrying charges"* below) are recovered through a semi-annual recovery mechanism. Recovery of these costs will continue through the TDSIC tracker until such assets are included in rate base through a gas or electric base rate case, respectively. The remaining twenty percent of the costs are deferred until the next base rate case. As of December 31, 2019 and 2018, depreciation of $22.0 million and $16.5 million, respectively, was deferred as a regulatory asset.

Post-in-service carrying charges. Represents deferred debt-based carrying charges incurred on certain assets placed into service but not yet included in customer rates. This balance includes:

- **Columbia of Ohio IRP and CEP.** See description of IRP and CEP programs above under the heading "*Depreciation*." As of December 31, 2019 and 2018, Columbia of Ohio had deferred PISCC of $206.4 million and $197.1 million, respectively.
- **NIPSCO TDSIC.** See description of TDSIC program above under the heading "*Depreciation*." Deferral of equity-based carrying charges for the TDSIC program is allowed; however, such amounts are not reflected in regulatory asset balances for financial reporting as equity-based returns do not meet the definition of incurred costs under ASC 980. As of December 31, 2019 and 2018, NIPSCO had deferred PISCC of $13.4 million and $9.5 million, respectively.

Safety activity costs. Represents the difference between costs incurred in eligible safety programs in excess of those being recovered in rates. The eligible cost deferrals represent necessary business expenses incurred in compliance with PHMSA regulations and are targeted to enhance the safety of the pipeline systems. Certain subsidiaries defer the excess costs as a regulatory asset in accordance with regulatory orders and recovery of these costs will be addressed in future base rate proceedings.

DSM programs. Represents costs associated with Gas Distribution Operations and Electric Operations segments' energy efficiency and conservation programs. Costs are recovered through tracking mechanisms.

Bailly Generating Station. Represents the net book value of Units 7 and 8 of Bailly Generating Station that was retired during 2018. These amounts are currently being amortized at a rate consistent with their inclusion in customer rates.

Liabilities:

Over-recovered gas and fuel costs. Represents the difference between the cost of gas and fuel and the recovery of such costs in revenues and is the basis to adjust future billings for such refunds on a basis consistent with applicable state-approved tariff provisions. Refunding of these revenues is achieved through tracking mechanisms.

Cost of removal. Represents anticipated costs of removal that have been, and continue to be, included in depreciation rates and collected in customer rates of the rate-regulated subsidiaries for future costs to be incurred.

Regulatory effects of accounting for income taxes. Represents amounts owed to customers for deferred taxes collected at a higher rate than the current statutory rates and liabilities associated with accelerated tax deductions owed to customers that are established during the rate making process. Balance includes excess deferred taxes recorded upon implementation of the TCJA in December 2017, net of amounts amortized through 2019.

Deferred pension and other postretirement benefit costs. Primarily represents cash contributions in excess of postretirement benefit expense that is deferred as a regulatory liability by certain subsidiaries in accordance with regulatory orders.

Cost Recovery and Trackers

Comparability of our line item operating results is impacted by regulatory trackers that allow for the recovery in rates of certain costs such as those described below. Increases in the expenses that are the subject of trackers generally result in a corresponding increase in operating revenues and, therefore, have essentially no impact on total operating income results.

Certain costs of our operating companies are significant, recurring in nature and generally outside the control of the operating companies. Some states allow the recovery of such costs through cost tracking mechanisms. Such tracking mechanisms allow for abbreviated regulatory proceedings in order for the operating companies to implement charges and recover appropriate costs. Tracking mechanisms allow for more timely recovery of such costs as compared with more traditional cost recovery mechanisms. Examples of such mechanisms include GCR adjustment mechanisms, tax riders, bad debt recovery mechanisms, electric energy efficiency programs, MISO non-fuel costs and revenues, resource capacity charges, federally mandated costs and environmental-related costs.

A portion of the Gas Distribution revenue is related to the recovery of gas costs, the review and recovery of which occurs through standard regulatory proceedings. All states in our operating area require periodic review of actual gas procurement activity to determine prudence and to permit the recovery of prudently incurred costs related to the supply of gas for customers. Our distribution companies have historically been found prudent in the procurement of gas supplies to serve customers.

A portion of the Electric Operations revenue is related to the recovery of fuel costs to generate power and the fuel costs related to purchased power. These costs are recovered through a FAC, a quarterly regulatory proceeding in Indiana.

Infrastructure Replacement and Federally-Mandated Compliance Programs

All of our operating utility companies have completed rate proceedings involving infrastructure replacement or enhancement, and have embarked upon initiatives to replace significant portions of their operating systems that are nearing the end of their useful lives. Each company's approach to cost recovery is unique, given the different laws, regulations and precedent that exist in each jurisdiction.

Columbia of Ohio, IRP - On December 3, 2008, the PUCO issued an order which established Columbia of Ohio’s IRP. Pursuant to that order, the IRP provides for recovery of costs resulting from: (1) the maintenance, repair and replacement of customer-owned service lines that have been determined by Columbia of Ohio to present an existing or probable hazard to persons and property;

(2) Columbia of Ohio’s replacement of cast iron, wrought iron, unprotected coated steel and bare steel pipe and associated company and customer-owned metallic service lines; (3) the replacement of customer-owned natural gas risers identified by the PUCO as prone to failure; and (4) the installation of AMR devices on all residential and commercial meters served by Columbia of Ohio. Recoverable costs include a return on investment, depreciation and property taxes, offset by specified cost savings. Columbia of Ohio’s five-year IRP plan renewal was last approved on January 31, 2018 for the years 2018-2022.

Columbia of Ohio, CEP - On October 3, 2011, Columbia of Ohio filed an application for approval to establish the CEP that would provide for the deferral of PISCC on those assets placed into service, but not reflected in rates as plant in service, and the deferral of depreciation expense and property taxes directly attributable to the CEP assets for the period October 1, 2011 through December 31, 2012. Capital expenditures covered under this program included those placed into service that were not part of Columbia of Ohio's IRP. CEP was approved by the PUCO on August 29, 2012. Under this program, the PUCO’s approval provided for the deferral of related PISCC, depreciation and property taxes up to the point where the deferred amount, if included in rates, would exceed $1.50 per month impact on the Small General Service class of customers, subject to the PUCO’s determination of the prudence and reasonableness of investments covered under this program in a future regulatory proceeding. Subsequently, on October 3, 2013, the PUCO modified and approved Columbia of Ohio’s application to continue its CEP deferrals in 2013 and succeeding years, subject to the determination of the prudence, reasonableness and magnitude of the deferrals and capital expenditures in a future cost recovery proceeding. On December 1, 2017, Columbia of Ohio filed an application in which it requested authority to implement a rider to begin recovering plant and associated deferrals related to its CEP. On October 25, 2018, a joint stipulation and recommendation was filed to recover CEP investments and deferrals through December 31, 2017, with annual adjustments for capital investments made in subsequent years. Additionally, the signatory parties to the stipulation agreed to a reduction in rates to adjust for the impacts of the Tax Cut Jobs Act and for a base rate case filing to be made by Columbia of Ohio no later than June 30, 2021. On November 28, 2018 the PUCO issued an order unanimously approving the settlement, without modification.

NIPSCO Gas and Electric, TDSIC - On April 30, 2013, the Indiana Governor signed Senate Enrolled Act 560, known as the TDSIC statute, into law. Among other provisions, the TDSIC statute provides for cost recovery outside of a base rate proceeding for new or replacement electric and gas transmission, distribution, and storage projects that a public utility undertakes for the purposes of safety, reliability, system modernization or economic development. Provisions of the TDSIC statute require that, among other things, requests for recovery include a seven-year plan of eligible investments. Once the plan is approved by the IURC, eighty percent of eligible costs can be recovered using a periodic rate adjustment mechanism, known as the TDSIC mechanism. Recoverable costs include a return on the investment, including AFUDC, PISCC, depreciation and property taxes. The remaining twenty percent of recoverable costs are deferred for future recovery in NIPSCO's next general rate case. This rate adjustment mechanism is typically filed semi-annually and has a cap at an annual increase of two percent of total retail revenues. During the 2019 Legislative session, the Indiana General Assembly amended the TDSIC statute in House Enrolled Act 1470 that was signed into law by the Governor on April 24, 2019. The revisions that became effective on July 1, 2019 permit flexibility in TDSIC Plans between five and seven years in length, permits the IURC to authorize multi-unit projects that do not include specific locations or an exact number of inspections, repairs, or replacements and projects involving advanced technology investments to support the modernization of transmission, distribution, or storage systems. The amendments also authorize termination of TDSIC Plans prior to their expiration and provide that the projects associated with the terminated plan will continue to receive TDSIC treatment until an Order is issued in the utility’s next general rate case, and provide for the ability to seek approval of a new TDSIC Plan. The amended statute also provides that the two percent revenue cap applies to the aggregate of approved TDSIC Plans and requires that the utility file a base rate case at some point during the term of each TDSIC plan. On December 31, 2019, NIPSCO Gas filed a new 6-year TDSIC for the periods 2020 through 2025.

NIPSCO Electric, ECRM - NIPSCO has approval from the IURC to recover certain environmental related costs through an ECT (environmental cost tracker). Under the ECT, NIPSCO is permitted to recover (1) AFUDC and a return on the capital investment expended by NIPSCO to implement environmental compliance plan projects and (2) related operation and maintenance and depreciation expenses once the environmental facilities become operational. All deferred costs associated with ECRM were included in electric rate base and approved by the IURC on December 4, 2019.

NIPSCO Gas and Electric, FMCA - The FMCA statute provides for cost recovery outside of a base rate proceeding for projected federally mandated costs. Once the plan is approved by the IURC, eighty percent of eligible costs can be recovered using a periodic rate adjustment mechanism, known as the FMCA mechanism. Recoverable costs include a return on the investment, including AFUDC, PISCC, mandated operation and maintenance expenses, depreciation and property taxes. The remaining twenty percent of recoverable costs are deferred for future recovery in NIPSCO's next general rate case. Actual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent shall require specific justification by NIPSCO and specific approval by the IURC before being authorized in the next general rate case.

Columbia of Massachusetts, GSEP - On July 7, 2014, the Governor of Massachusetts signed into law Chapter 149 of the Acts of 2014, an Act Relative to Natural Gas Leaks (“the Act”). Adopted into the Massachusetts Utility Provisions, G.L. c. 164, § 145, the Act authorizes natural gas distribution companies to file a GSEP for capital investments made on or after January 1, 2015, that are not included in the company’s current rate base as determined in the most recent base rate case, with the Massachusetts DPU to (1) address the replacement or improvement of existing aging natural gas pipeline infrastructure to improve public safety or infrastructure reliability, and (2) reduce the lost and unaccounted for natural gas through a reduction in natural gas system leaks. In addition, the Act provides that the Massachusetts DPU may, after review of the plan, allow the proposed estimated costs of the plan into rates as of May 1 of the subsequent year. Recoverable costs include a return on investment, depreciation and property taxes, offset by identified operations and maintenance cost savings. Beginning with the 2019 GSEP, rates are subject to a capped annual revenue increase of three percent of total annual firm delivery revenues, plus imputed gas revenues for sales and transportation customers, calculated as the product of (1) the historical average cost of gas per therm, and (2) the average weather normalized sales, for the period beginning with 2013 and ending with the most recent year that actual data is available at the time of the October GSEP Plan filing, per the Massachusetts DPU order in Columbia of Massachusetts' 2019 GSEP. Prior to the 2019 GSEP, the annual revenue increase was capped at one and a half percent. At the end of each 12-month period, in May of the subsequent year, Columbia of Massachusetts must file a reconciliation of the amount collected and actual costs. Any over-collection or under-collection balance is passed back to, or recovered from, customers through the surcharge over a 12-month period beginning in November. On October 31, 2019, the Massachusetts DPU issued an order on Columbia of Massachusetts' GSEP reconciliation proceeding finding that, due to pending investigations of the Greater Lawrence Incident and other operational matters, the Massachusetts DPU could not, at this time, make a finding of prudence with respect to the Columbia of Massachusetts' 2018 GSEP investments and deferred the decision on the prudency of the 2018 GSEP investments in the annual GSEP and GSEP reconciliation filings until the investigations by the DPU are complete. The DPU added that its inability to make a finding of prudence did not constitute a finding of imprudence. Once new base rates are established under a base rate proceeding, the GSEP factor is re-set to remove the capital investment and associated revenue reflected in the base rates. Columbia of Massachusetts' current five year GSEP plan for the periods 2019-2023 was approved April 30, 2019.

Columbia of Pennsylvania, DSIC - On February 14, 2012, the Governor of Pennsylvania signed into law Act 11 of 2012, which provided a DSIC mechanism for certain utilities to recover costs related to repair, replacement or improvement of eligible distribution property that has not previously been reflected in rates or rate base. Through a DSIC, a utility may recover the fixed costs of eligible infrastructure incurred during the three months ended one month prior to the effective date of the charge, thereby reducing the historical regulatory lag associated with cost recovery through the traditional rate-making process. On March 14, 2013, the Pennsylvania PUC approved Columbia of Pennsylvania’s petition to implement a DSIC as of April 1, 2013. Accordingly, Columbia of Pennsylvania is authorized to recover the cost of eligible plant associated with repair, replacement or improvement that was not previously reflected in rate base and has been placed in service during the applicable three-month period. After the initial charge is established, the DSIC is updated quarterly to recover the cost of further plant additions and cannot exceed five percent of distribution revenues. Recoverable costs include a return on investment, exclusive of accumulated deferred income taxes from the calculation of rate base, and depreciation. Once new base rates are established under a base rate proceeding, the DSIC is set to zero. Additionally, the DSIC rate is also reset to zero if, in any quarter, the data reflected in the Columbia of Pennsylvania's most recent quarterly financial earnings report show that the utility will earn an overall rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the DSIC mechanism. A utility is exempt from filing a quarterly financial earnings report when a base rate proceeding is pending before the Pennsylvania PUC.

Columbia of Virginia, SAVE - On March 11, 2010, the Virginia Governor signed legislation into law that allows natural gas utilities to implement programs to replace qualifying infrastructure on an expedited basis and provides for timely cost recovery. Known as the SAVE Act, the law allows natural gas utilities to file programs with the VSCC providing a timeline and estimated costs for replacing eligible infrastructure. Eligible infrastructure replacement projects are those that (1) enhance safety or reliability by reducing system integrity risks associated with customer outages, corrosion, equipment failures, material failures, or natural forces; (2) do not increase revenues by directly connecting the infrastructure replacement to new customers; (3) reduce or have the potential to reduce greenhouse gas emissions; (4) are not included in the natural gas utility’s rate base in its most recent rate case; and (5) are commenced on or after January 1, 2010. The SAVE Act provides for recovery of costs associated with the eligible infrastructure through a rate rider. Recoverable costs include a return on investment, depreciation and property taxes. Columbia of Virginia’s current five year SAVE plan was approved by the VSCC in 2016 and amended in 2017 for the years 2016 through 2020 and amended in 2019 for calendar year 2020.

Columbia of Kentucky, SMRP (formerly AMRP) - On October 26, 2009, the Kentucky PSC approved a mechanism for recovering the costs of Columbia of Kentucky’s AMRP not previously reflected in rate base through an annual fixed monthly rate rider filed in October. In its 2013 rate case, Columbia of Kentucky was allowed to base the AMRP rider on the expected annual cost of service. Recoverable costs include a return on investment, depreciation and property taxes, offset by specific cost savings. At the end of each 12-month period, Columbia of Kentucky must file a reconciliation of the amount collected and actual costs. Any over-collection or under-collection balance is passed back to, or recovered from, customers through the surcharge over a 12-month period beginning in June of the subsequent year. Once new base rates are established under a base rate proceeding, the AMRP rider is set to zero. On July 29, 2019, CKY filed its SMRP to clarify approval of low pressure project spend and expand its AMRP to include for recovery of system safety investments, including low pressure project spend. On November 7, 2019, the Commission approved Columbia of Kentucky's request to amend and expand its annual AMRP to become the SMRP.

Columbia of Maryland, STRIDE - On May 2, 2013, the Governor of Maryland signed Senate Bill 8 into law, authorizing gas companies to accelerate recovery of eligible infrastructure replacement, effective June 1, 2013. The STRIDE statute provides recovery for gas pipeline upgrades outside of the context of a base rate proceeding through an annual surcharge, IRIS, as approved by the Maryland PSC. The STRIDE statute directs gas utilities to file a plan to invest in eligible infrastructure replacement projects and to list the specific projects and elements in any such STRIDE plan with the Maryland PSC. The calendar year projected capital projects to be placed into plant in service and included in Columbia of Maryland's surcharge recovery request must satisfy a number of criteria per the statute, including a requirement that they be designed to improve public safety or infrastructure reliability. Columbia of Maryland’s five-year STRIDE Plan renewal for years 2019 through 2023, as with the preceding five years, is focused on replacing (1) existing cast iron and bare steel mains, (2) associated services and meters, and (3) identified prone-to-failure vintage plastic piping. Columbia of Maryland’s IRIS mechanism recovers a return on investment, depreciation and property taxes of the STRIDE-eligible capital infrastructure statutorily capped at $2 per month for residential customers, and proportionally capped for commercial and industrial customer classes, and is reconciled to actual costs on an annual basis. Any over-collection or under-collection balance is passed back to, or recovered from, customers through the surcharge effective in May of the subsequent year, subject to the cap. STRIDE investments, and recovery thereof, are subject to prudency review by the Maryland PSC in the context of quarterly STRIDE update filings and in subsequent rate proceedings where STRIDE assets are rolled into rate base for recovery in base rates.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

The following table describes the most recent vintage of our regulatory programs to recover infrastructure replacement and other federally-mandated compliance investments currently in rates and those pending commission approval:

(in millions)

Company	Program	Incremental Revenue	Incremental Capital Investment	Investment Period	Filed	Status	Rates Effective
Columbia of Ohio	IRP - 2019[1]	$ 18.2	$ 199.6	1/18-12/18	February 28, 2019	Approved April 24, 2019	May 2019
Columbia of Ohio	CEP - 2018	$ 74.5	$ 659.9	1/11-12/17	December 1, 2017	Approved November 28, 2018	December 2018
Columbia of Ohio	CEP - 2019	$ 15.0	$ 121.7	1/18-12/18	February 28, 2019	Approved August 28, 2019	September 2019
NIPSCO - Gas	TDSIC 9[1][2]	$ (10.6)	$ 54.4	1/18-6/18	August 28, 2018	Approved December 27, 2018	January 2019
NIPSCO - Gas	TDSIC 10[3]	$ 1.6	$ 12.4	7/18-4/19	June 25, 2019	Approved October 16, 2019	November 2019
NIPSCO - Gas	TDSIC 11[4]	$ (1.7)	$ 38.7	5/19-12/19	February 25, 2020	Order Expected June 2020	July 2020
NIPSCO - Gas	FMCA 1[5]	$ 9.9	$ 1.5	11/17-9/18	November 30, 2018	Approved March 27, 2019	April 2019
NIPSCO - Gas	FMCA 2[5]	$ (3.5)	$ 1.8	10/18-3/19	May 29, 2019	Approved September 25, 2019	October 2019
NIPSCO - Gas	FMCA 3[5]	$ 0.3	$ 43.0	4/19-9/19	November 26, 2019	Order Expected March 2020	April 2020
Columbia of Massachusetts	GSEP - 2019[6]	$ 9.6	$ 36.0	1/19-12/19	October 31, 2018	Approved April 30, 2019	May 2019
Columbia of Massachusetts	GSEP - 2020[6][7]	$ 2.4	$ 75.0	1/20-12/20	October 31, 2019	Order Expected April 2020	May 2020
Columbia of Virginia	SAVE - 2019	$ 2.4	$ 36.0	1/19-12/19	August 17, 2018	Approved October 26, 2018	January 2019
Columbia of Virginia	SAVE - 2020	$ 3.8	$ 50.0	1/20-12/20	August 15, 2019	Approved December 6, 2019	January 2020
Columbia of Kentucky	AMRP - 2019	$ 3.6	$ 30.1	1/19-12/19	October 15, 2018	Approved December 5, 2018	January 2019
Columbia of Kentucky	SMRP - 2020	$ 4.2	$ 40.4	1/20-12/20	October 15, 2019	Approved December 20, 2019	January 2020
Columbia of Maryland	STRIDE - 2019	$ 1.2	$ 19.7	1/19-12/19	November 1, 2018	Approved December 12, 2018	January 2019
Columbia of Maryland	STRIDE - 2020	$ 1.3	$ 15.0	1/20-12/20	January 29, 2020	Approved February 19, 2020	February 2020
NIPSCO - Electric	TDSIC - 5[1]	$ 15.9	$ 58.8	6/18-11/18	January 29, 2019	Approved June 12, 2019	June 2019
NIPSCO - Electric	TDSIC - 6	$ 28.1	$ 131.1	12/18-6/19	August 21, 2019	Approved December 18, 2019	January 2020
NIPSCO - Electric	FMCA - 11[5]	$ 0.9	$ 22.4	9/18-2/19	April 17, 2019	Approved July 29, 2019	August 2019
NIPSCO - Electric	FMCA - 12[5]	$ 1.6	$ 4.7	3/19-8/19	October 18, 2019	Approved January 29, 2020	February 2020

(1)Incremental revenue is net of amounts due back to customers as a result of the TCJA.
(2)Incremental revenue is net of $5.2 million of adjustments in the TDSIC-9 settlement.
(3)Incremental capital and revenue are net of amounts included in the step 2 rates.
(4)Incremental revenue is net of amounts included in the step 2 rates and reflects a more typical filing period.
(5)Incremental revenue is inclusive of tracker eligible operations and maintenance expense.
(6)Due to an order from the Massachusetts DPU on October 3, 2019 imposing work restrictions on Columbia of Massachusetts, Columbia of Massachusetts did not meet the approved projected 2019 GSEP spend of $64 million and associated incremental revenue of $10.7 million. In the 2020 GSEP, Columbia of Massachusetts reduced the projected capital spend for calendar year 2019 to $36 million and the associated incremental revenue in 2019 GSEP to $9.6 million.
(7)Incremental capital investment is anticipated to be lower than $75 million in 2020 due to the Massachusetts DPU imposed work restrictions.

Rate Case Actions

The following table describes current rate case actions as applicable in each of our jurisdictions net of tracker impacts:

(in millions)

Company	Requested Incremental Revenue	Approved Incremental Revenue	Filed	Status	Rates Effective
NIPSCO - Gas[(1)]	$ 138.1	$ 105.6	September 27, 2017	Approved September 19, 2018	October 2018
Columbia of Virginia[(2)]	$ 14.2	$ 1.3	August 28, 2018	Approved June 12, 2019	February 2019
NIPSCO - Electric[(3)]	$ 21.4	$ (53.5)	October 31, 2018	Approved December 4, 2019	January 2020
Columbia of Maryland	$ 2.5	$ (0.1)	May 22, 2019	Approved December 18, 2019	December 2019

[(1)]Rates were implemented in three steps, with implementation of step 1 rates effective October 1, 2018. Step 2 rates were effective on March 1, 2019, and step 3 rates were effective on January 1, 2020. The step 3 increase was approved based on actual information and revised from $107.3 million to $105.6 million. The IURC's order also dismissed NIPSCO from phase 2 of the IURC's TCJA investigation.
[(2)]Rates, as originally filed, were implemented in February 2019 on an interim basis, subject to refund. The final approved rates, which replaced interim rates, were implemented in July 2019.
[(3)]An order was received on December 4, 2019, which included the resolution of outstanding TCJA impacts to rates. Incremental revenues decreased due to a reduction in fuel costs associated with the new industrial service structure. Rates will be implemented in two steps, with implementation of step 1 rates effective January 2, 2020 and step 2 rates effective March 2, 2020.

Additional Regulatory Matters

NIPSCO Electric. On March 29, 2018, WCE, which is currently owned by BP p.l.c ("BP") and BP Products North America, which operates the BP Refinery, filed a petition at the IURC asking that the combined operations of WCE and BP be treated as a single premise, and the WCE generation be dedicated primarily to BP Refinery operations beginning in May 2019 as WCE has self-certified as a qualifying facility at FERC. BP Refinery planned to continue to purchase electric service from NIPSCO at a reduced demand level beginning in May 2019; however, a settlement agreement was filed on November 2, 2018 agreeing that BP and WCE would not move forward with construction of a private transmission line to serve BP until conclusion of NIPSCO's pending electric rate case. The IURC approved the settlement agreement as filed on February 20, 2019. On December 4, 2019, the IURC issued an order in the electric rate case approving the implementation of a new industrial service structure. This resolved the issues included in BP's original petition.

The December 4, 2019 electric rate case order approved the revenue requirement settlement filed in the case, with the exception of a change in the agreed to return on equity; the approved return on equity is 9.75%. The order included approval of the depreciation rates as requested, as well as authorization to create a regulatory asset upon the retirement of R.M. Schahfer Generating Units 14, 15, 17 and 18 and Michigan City Generating Station Unit 12. The order allows for the recovery of and on the net book value of the units by the end of 2032.

9. Risk Management Activities

We are exposed to certain risks relating to ongoing business operations; namely commodity price risk and interest rate risk. We recognize that the prudent and selective use of derivatives may help to lower our cost of debt capital, manage interest rate exposure and limit volatility in the price of natural gas.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Risk management assets and liabilities on our derivatives are presented on the Consolidated Balance Sheets as shown below:

December 31, *(in millions)*	**2019**	2018
Risk Management Assets - Current[(1)]		
Interest rate risk programs	**$ —**	$ —
Commodity price risk programs	**0.6**	1.1
Total	**$ 0.6**	$ 1.1
Risk Management Assets - Noncurrent[(2)]		
Interest rate risk programs	**$ —**	$ 18.5
Commodity price risk programs	**3.8**	4.4
Total	**$ 3.8**	$ 22.9
Risk Management Liabilities - Current[(3)]		
Interest rate risk programs	**$ —**	$ —
Commodity price risk programs	**12.6**	5.0
Total	**$ 12.6**	$ 5.0
Risk Management Liabilities - Noncurrent		
Interest rate risk programs	**$ 76.2**	$ 9.5
Commodity price risk programs	**57.8**	37.2
Total	**$ 134.0**	$ 46.7

(1)Presented in "Prepayments and other" on the Consolidated Balance Sheets.
(2)Presented in "Deferred charges and other" on the Consolidated Balance Sheets.
(3)Presented in "Other accruals" on the Consolidated Balance Sheets.

Commodity Price Risk Management

We, along with our utility customers, are exposed to variability in cash flows associated with natural gas purchases and volatility in natural gas prices. We purchase natural gas for sale and delivery to our retail, commercial and industrial customers, and for most customers the variability in the market price of gas is passed through in their rates. Some of our utility subsidiaries offer programs whereby variability in the market price of gas is assumed by the respective utility. The objective of our commodity price risk programs is to mitigate the gas cost variability, for us or on behalf of our customers, associated with natural gas purchases or sales by economically hedging the various gas cost components using a combination of futures, options, forwards or other derivative contracts.

NIPSCO received IURC approval to lock in a fixed price for its natural gas customers using long-term forward purchase instruments. The term of these instruments range from five to ten years and is limited to twenty percent of NIPSCO’s average annual GCA purchase volume. Gains and losses on these derivative contracts are deferred as regulatory liabilities or assets and are remitted to or collected from customers through NIPSCO’s quarterly GCA mechanism. These instruments are not designated as accounting hedges.

Interest Rate Risk Management

As of December 31, 2019, we have forward-starting interest rate swaps with an aggregate notional value totaling $500.0 million to hedge the variability in cash flows attributable to changes in the benchmark interest rate during the periods from the effective dates of the swaps to the anticipated dates of forecasted debt issuances, which are expected to take place by the end of 2024. These interest rate swaps are designated as cash flow hedges. The effective portions of the gains and losses related to these swaps are recorded to AOCI and are recognized in "Interest expense, net" concurrently with the recognition of interest expense on the associated debt, once issued. If it becomes probable that a hedged forecasted transaction will no longer occur, the accumulated gains or losses on the derivative will be recognized currently in "Other, net" in the Statements of Consolidated Income (Loss).

The passage of the TCJA and Greater Lawrence Incident led to significant changes to our long-term financing plan. As a result, during 2018, we settled forward-starting interest rate swaps with a notional value of $750.0 million. These derivative contracts were accounted for as cash flow hedges. As part of the transactions, the associated net unrealized gain of $46.2 million was recognized immediately in "Other, net" on the Statements of Consolidated Income (Loss) due to the probability associated with the forecasted borrowing transactions no longer occurring.

There were no amounts excluded from effectiveness testing for derivatives in cash flow hedging relationships at December 31, 2019, 2018 and 2017.

Our derivative instruments measured at fair value as of December 31, 2019 and 2018 do not contain any credit-risk-related contingent features.

10. Income Taxes

Income Tax Expense

The components of income tax expense (benefit) were as follows:

Year Ended December 31, *(in millions)*	**2019**	2018	2017
Income Taxes			
Current			
Federal	**$ —**	$ —	$ —
State	**5.2**	8.2	7.8
Total Current	**5.2**	8.2	7.8
Deferred			
Federal	**110.7**	(209.4)	302.7
State	**9.0**	22.2	5.0
Total Deferred	**119.7**	(187.2)	307.7
Deferred Investment Credits	**(1.4)**	(1.0)	(1.0)
Income Taxes	**$ 123.5**	$ (180.0)	$ 314.5

Statutory Rate Reconciliation

The following table represents a reconciliation of income tax expense at the statutory federal income tax rate to the actual income tax expense from continuing operations:

Year Ended December 31, *(in millions)*	**2019**		2018		2017	
Book income (loss) before income taxes	**$ 506.6**		$ (230.6)		$ 443.0	
Tax expense (benefit) at statutory federal income tax rate	**106.5**	**21.0 %**	(48.4)	21.0 %	155.0	35.0 %
Increases (reductions) in taxes resulting from:						
State income taxes, net of federal income tax benefit	**10.1**	**2.0**	24.7	(10.7)	6.9	1.5
Amortization of regulatory liabilities	**(29.4)**	**(5.8)**	(29.3)	12.7	(2.4)	(0.5)
Goodwill impairment	**43.0**	**8.5**	—	—	—	—
Fines and penalties	**11.5**	**2.3**	0.2	(0.1)	2.8	0.6
Charitable contribution carryover	**(2.5)**	**(0.5)**	—	—	(1.2)	(0.3)
State regulatory proceedings	**(9.5)**	**(1.9)**	(127.8)	55.4	—	—
Remeasurement due to TCJA	**—**	**—**	—	—	161.1	36.4
Employee stock ownership plan dividends and other compensation	**(2.0)**	**(0.4)**	(2.2)	1.0	(6.5)	(1.5)
Other adjustments	**(4.2)**	**(0.8)**	2.8	(1.2)	(1.2)	(0.2)
Income Taxes	**$ 123.5**	**24.4 %**	$ (180.0)	78.1 %	$ 314.5	71.0 %

The effective income tax rates were 24.4%, 78.1% and 71.0% in 2019, 2018 and 2017, respectively. The 53.7% decrease in effective tax rate in 2019 versus 2018 was primarily the result of not having significant income tax decreases resulting from state regulatory proceedings as in 2018. Additionally, there was an increase in the effective tax rate related to the non-cash impairment of goodwill in 2019 related to Columbia of Massachusetts (see Note 6, "Goodwill and Other Intangible Assets" for additional information) and non-deductible fines and penalties related to the Greater Lawrence Incident (see Note 19, "Legal Proceedings" for additional information). The rate is also impacted by the relative impact of permanent differences on higher pre-tax income.

The 7.1% increase in the overall effective tax rate in 2018 versus 2017 was primarily the result of state regulatory proceedings which resulted in a $127.8 million decrease in federal income taxes offset by a related increase in state income taxes of $7.1 million. Additionally, the increase was driven by a $26.9 million decrease in income taxes related to amortization of the regulatory liability primarily associated with excess deferred taxes.

Net Deferred Income Tax Liability Components

Deferred income taxes result from temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The principal components of our net deferred tax liability were as follows:

At December 31, *(in millions)*	**2019**	2018
Deferred tax liabilities		
Accelerated depreciation and other property differences	**$ 2,516.9**	$ 2,458.0
Other regulatory assets	**381.5**	375.4
Total Deferred Tax Liabilities	**2,898.4**	2,833.4
Deferred tax assets		
Other regulatory liabilities and deferred investment tax credits (including TCJA)	**336.1**	365.5
Pension and other postretirement/postemployment benefits	**152.1**	157.5
Net operating loss carryforward and AMT credit carryforward	**765.9**	849.8
Environmental liabilities	**25.4**	24.4
Other accrued liabilities	**35.3**	37.5
Other, net	**98.3**	68.2
Total Deferred Tax Assets	**1,413.1**	1,502.9
Net Deferred Tax Liabilities	**$ 1,485.3**	$ 1,330.5

At December 31, 2019, we had $657.1 million of federal net operating loss carryforwards. The federal net operating loss carryforwards are available to offset taxable income and will begin to expire in 2028. We also have $1.6 million of federal alternative minimum tax credit carryforwards which do not expire. In addition, we have $1.4 million in charitable contribution carryforwards to offset future taxable income, which begin to expire in 2023. We also have $107.2 million (net) of state net operating loss carryforwards. Depending on the jurisdiction in which the state net operating loss was generated, the carryforwards will begin to expire in 2028. We believe it is more likely than not that we will realize the benefit from the state net operating loss carryforwards.

Unrecognized Tax Benefits

A reconciliation of the beginning and ending amounts of unrecognized tax benefits is as follows:

Reconciliation of Unrecognized Tax Benefits *(in millions)*	**2019**	2018	2017
Unrecognized Tax Benefits - Opening Balance	**$ 1.2**	$ 1.4	$ 2.6
Gross decreases - tax positions in prior period	**(0.6)**	(0.4)	(1.4)
Gross increases - current period tax positions	**22.6**	0.2	0.2
Unrecognized Tax Benefits - Ending Balance	**$ 23.2**	$ 1.2	$ 1.4
Offset for net operating loss carryforwards	**(22.6)**	—	—
Balance - Less Net Operating Loss Carryforwards	**$ 0.6**	$ 1.2	$ 1.4

In 2019, we resolved prior unrecognized tax benefits of $0.6 million and established new unrecognized tax benefits related to state matters of $22.6 million. We present accrued interest on unrecognized tax benefits, accrued interest on other income tax liabilities and tax penalties in "Income Taxes" on our Statements of Consolidated Income (Loss). Interest expense recorded on unrecognized tax benefits and other income tax liabilities was immaterial for all periods presented. There were no accruals for penalties recorded in the Statements of Consolidated Income (Loss) for the years ended December 31, 2019, 2018 and 2017, and there were no balances for accrued penalties recorded on the Consolidated Balance Sheets as of December 31, 2019 and 2018.

We are subject to income taxation in the United States and various state jurisdictions, primarily Indiana, Pennsylvania, Kentucky, Massachusetts, Maryland and Virginia.

We participate in the IRS CAP which provides the opportunity to resolve tax matters with the IRS before filing each year's consolidated federal income tax return. As of December 31, 2019, tax years through 2018 have been audited and are effectively closed to further assessment. The audit of tax year 2019 under the CAP program is expected to be completed in 2020.

The statute of limitations in each of the state jurisdictions in which we operate remains open until the years are settled for federal income tax purposes, at which time amended state income tax returns reflecting all federal income tax adjustments are filed. As of December 31, 2019, there were no state income tax audits in progress that would have a material impact on the consolidated financial statements.

In December 22, 2017, the TCJA was signed into law. As a result of the implementation of the TCJA, we remeasured deferred taxes and recognized $161.1 million of income tax expense in our Consolidated Statements of Income (Loss) for the year ended December 31, 2017. The result of this remeasurement was a reduction in the net deferred tax liability of approximately $1.3 billion, including approximately $0.4 billion of regulatory "gross up" to account for over collection of past taxes from customers. Offsetting the reduction in net deferred tax liabilities was an increase in regulatory liabilities of approximately $1.5 billion as of December 31, 2017. In 2018, we received regulatory orders on the treatment of excess deferred taxes from the jurisdictions in which we operate. As a result of these orders, we reduced our regulatory liability related to excess deferred income taxes by $120.7 million (net of tax). This adjustment is reflected in "Income Taxes" on our Consolidated Statements of Income (Loss) for the year ended December 31, 2018.

As of December 31, 2019, we received approval from regulators to return excess deferred taxes in all of our jurisdictions in accordance with regulatory proceedings.

On December 22, 2017, the SEC issued Staff Accounting Bulletin 118 ("SAB 118"), which provides guidance on accounting for tax effects of the TCJA. SAB 118 provides a measurement period that should not extend beyond one year from the TCJA enactment date for companies to complete the accounting under ASC 740. There were no adjustments recorded in the SAB 118 remeasurement period in 2018.

11. Pension and Other Postretirement Benefits

We provide defined contribution plans and noncontributory defined benefit retirement plans that cover certain of our employees. Benefits under the defined benefit retirement plans reflect the employees’ compensation, years of service and age at retirement. Additionally, we provide health care and life insurance benefits for certain retired employees. The majority of employees may become eligible for these benefits if they reach retirement age while working for us. The expected cost of such benefits is accrued during the employees’ years of service. Current rates of rate-regulated companies include postretirement benefit costs, including amortization of the regulatory assets that arose prior to inclusion of these costs in rates. For most plans, cash contributions are remitted to grantor trusts.

Our Pension and Other Postretirement Benefit Plans’ Asset Management. We employ a liability-driven investing strategy for the pension plan, as noted below. A mix of equities and fixed income investments are used to maximize the long-term return of plan assets and hedge the liabilities at a prudent level of risk. We utilize a total return investment approach for the other postretirement benefit plans. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and asset class volatility. The investment portfolio contains a diversified blend of equity and fixed income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, small and large capitalizations. Other assets such as private equity funds are used judiciously to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives may not be used to leverage the portfolio beyond the market value of the underlying assets. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

We utilize a building block approach with proper consideration of diversification and rebalancing in determining the long-term rate of return for plan assets. Historical markets are studied and long-term historical relationships between equities and fixed income are analyzed to ensure that they are consistent with the widely accepted capital market principle that assets with higher volatility generate greater return over the long run. Current market factors, such as inflation and interest rates, are evaluated before long-term capital market assumptions are determined. Peer data and historical returns are reviewed to check for reasonability and appropriateness.

The most important component of an investment strategy is the portfolio asset mix, or the allocation between the various classes of securities available to the pension and other postretirement benefit plans for investment purposes. The asset mix and acceptable minimum and maximum ranges established for our plan assets represents a long-term view and are listed in the table below.

In 2012, a dynamic asset allocation policy for the pension fund was approved. This policy calls for a gradual reduction in the allocation of return-seeking assets (equities, real estate and private equity) and a corresponding increase in the allocation of liability-hedging assets (fixed income) as the funded status of the plans increase above 90% (as measured by the market value of qualified pension plan assets divided by the projected benefit obligations of the qualified pension plans). A new asset-liability study was completed in 2018 resulting in a more conservative glide path and an increase in the allocation to liability-hedging assets held in the portfolio.

As of December 31, 2019, the asset mix and acceptable minimum and maximum ranges established by the policy for the pension and other postretirement benefit plans are as follows:

Asset Mix Policy of Funds:

	Defined Benefit Pension Plan		Postretirement Benefit Plan	
Asset Category	Minimum	Maximum	Minimum	Maximum
Domestic Equities	12%	32%	0%	55%
International Equities	6%	16%	0%	25%
Fixed Income	59%	71%	20%	100%
Real Estate	0%	7%	0%	0%
Short-Term Investments/Other	0%	15%	0%	10%

As of December 31, 2018, the asset mix and acceptable minimum and maximum ranges established by the policy for the pension and other postretirement benefit plans were as follows:

Asset Mix Policy of Funds:

	Defined Benefit Pension Plan		Postretirement Benefit Plan	
Asset Category	Minimum	Maximum	Minimum	Maximum
Domestic Equities	12%	32%	0%	55%
International Equities	6%	16%	0%	25%
Fixed Income	59%	71%	20%	100%
Real Estate	0%	7%	0%	0%
Short-Term Investments/Other	0%	15%	0%	10%

Pension Plan and Postretirement Plan Asset Mix at December 31, 2019 and December 31, 2018:

	Defined Benefit Pension Assets	December 31, 2019	Postretirement Benefit Plan Assets	December 31, 2019
Asset Class *(in millions)*	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	$ 446.4	21.5%	$ 93.8	35.9%
International Equities	205.0	9.9%	40.7	15.6%
Fixed Income	1,337.2	64.2%	119.5	45.7%
Real Estate	53.9	2.6%	—	—
Cash/Other	38.4	1.8%	7.4	2.8%
Total	$ 2,080.9	100.0%	$ 261.4	100.0%

	Defined Benefit Pension Assets	December 31, 2018	Postretirement Benefit Plan Assets	December 31, 2018
Asset Class *(in millions)*	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	$ 355.5	19.0%	$ 78.8	36.4%
International Equities	165.5	8.9%	17.5	8.1%
Fixed Income	1,241.9	66.5%	115.1	53.2%
Real Estate	52.7	2.8%	—	—
Cash/Other	52.1	2.8%	4.9	2.3%
Total	$ 1,867.7	100.0%	$ 216.3	100.0%

The categorization of investments into the asset classes in the table above are based on definitions established by our Benefits Committee.

Fair Value Measurements. The following table sets forth, by level within the fair value hierarchy, the Master Trust and other postretirement benefits investment assets at fair value as of December 31, 2019 and 2018. Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Total Master Trust and other postretirement benefits investment assets at fair value classified within Level 3 were $0 million and $86.1 million as of December 31, 2019 and December 31, 2018, respectively. Such amounts were approximately 0% and 4% of the Master Trust and other postretirement benefits' total investments as reported on the statement of net assets available for benefits at fair value as of December 31, 2019 and 2018, respectively.

Valuation Techniques Used to Determine Fair Value:

Level 1 Measurements

Most common and preferred stocks are traded in active markets on national and international securities exchanges and are valued at closing prices on the last business day of each period presented. Cash is stated at cost which approximates fair value, with the exception of cash held in foreign currencies which fluctuates with changes in the exchange rates. Short-term bills and notes are priced based on quoted market values.

Level 2 Measurements

Most U.S. Government Agency obligations, mortgage/asset-backed securities, and corporate fixed income securities are generally valued by benchmarking model-derived prices to quoted market prices and trade data for identical or comparable securities. To the extent that quoted prices are not available, fair value is determined based on a valuation model that includes inputs such as interest rate yield curves and credit spreads. Securities traded in markets that are not considered active are valued based on quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. Other fixed income includes futures and options which are priced on bid valuation or settlement pricing.

Level 3 Measurements

Investments with unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets and liabilities are classified as level 3 investments.

Not Classified

Commingled funds, private equity limited partnerships and real estate partnerships hold underlying investments that have prices derived from quoted prices in active markets and are not classified within the fair value hierarchy. Instead, these assets are measured at estimated fair value using the net asset value per share of the investments. Commingled funds' underlying assets are principally marketable equity and fixed income securities. Units held in commingled funds are valued at the unit value as reported by the investment managers. Private equity and real estate funds invest in natural resources, commercial real estate and distressed real estate. The fair value of these investments is determined by reference to the funds’ underlying assets.

For the year ended December 31, 2019, there were no significant changes to valuation techniques to determine the fair value of our pension and other postretirement benefits' assets.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Fair Value Measurements at December 31, 2019:

(in millions)	December 31, 2019	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Pension plan assets:				
Cash	$ 6.7	$ 6.7	$ —	$ —
Fixed income securities				
Government	319.6	—	319.6	—
Corporate	651.8	—	651.8	—
Mutual Funds				
U.S. multi-strategy	140.5	140.5	—	—
International equities	56.9	56.9	—	—
Private equity limited partnerships(3)				
U.S. multi-strategy(1)	14.0	—	—	—
International multi-strategy(2)	8.5	—	—	—
Distressed opportunities	0.5	—	—	—
Real estate	53.9	—	—	—
Commingled funds(3)				
Short-term money markets	14.8	—	—	—
U.S. equities	305.9	—	—	—
International equities	148.1	—	—	—
Fixed income	351.8	—	—	—
Pension plan assets subtotal	2,073.0	204.1	971.4	—
Other postretirement benefit plan assets:				
Mutual funds				
U.S. multi-strategy	81.7	81.7	—	—
International equities	20.6	20.6	—	—
Fixed income	119.2	119.2	—	—
Commingled funds(3)				
Short-term money markets	7.7	—	—	—
U.S. equities	12.1	—	—	—
International equities	20.1	—	—	—
Other postretirement benefit plan assets subtotal	261.4	221.5	—	—
Due to brokers, net(4)	(2.8)	—	(2.8)	—
Accrued income/dividends	10.7	10.7	—	—
Total pension and other postretirement benefit plan assets	$ 2,342.3	$ 436.3	$ 968.6	$ —

(1) This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily inside the United States.
(2) This class includes limited partnerships/fund of funds that invest in diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily outside the United States.
(3) This class of investments is measured at fair value using the net asset value per share and has not been classified in the fair value hierarchy.
(4) This class represents pending trades with brokers.

The table below sets forth a summary of changes in the fair value of the Plan’s Level 3 assets for the year ended December 31, 2019:

	Balance at January 1, 2019	Transfers out (Level 3)[1]	Balance at December 31, 2019
Private equity limited partnerships			
U.S. multi-strategy	18.5	(18.5)	—
International multi-strategy	12.5	(12.5)	—
Distressed opportunities	2.4	(2.4)	—
Real estate	52.7	(52.7)	—
Total	$ 86.1	$ (86.1)	$ —

[1] Level 3 assets from the prior year were reclassified in the current year presentation and included within the fair value hierarchy table as of December 31, 2019 as “Not Classified" investments for which fair value is measured using net asset value per share, consistent with the definitions described above.

The table below sets forth a summary of unfunded commitments, redemption frequency and redemption notice periods for certain investments that are measured at fair value using the net asset value per share for the year ended December 31, 2019:

(in millions)	Fair Value	Redemption Frequency	Redemption Notice Period
Commingled Funds			
Short-term money markets	$ 22.5	Daily	1 day
U.S. equities	318.0	Monthly	1 day
International equities	168.2	Monthly	10-30 days
Fixed income	351.8	Daily	3 days
Total	$ 860.5		

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Fair Value Measurements at December 31, 2018:

(in millions)	December 31, 2018	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Pension plan assets:				
Cash	$ 9.2	$ 8.8	$ 0.4	$ —
Equity securities				
U.S. equities	0.2	0.2	—	—
Fixed income securities				
Government	250.2	—	250.2	—
Corporate	442.8	—	442.8	—
Mutual Funds				
U.S. multi-strategy	110.3	110.3	—	—
International equities	43.2	43.2	—	—
Fixed income	166.8	166.8	—	—
Private equity limited partnerships				
U.S. multi-strategy[(1)]	18.5	—	—	18.5
International multi-strategy[(2)]	12.5	—	—	12.5
Distressed opportunities	2.4	—	—	2.4
Real Estate	52.7	—	—	52.7
Commingled funds[(3)]				
Short-term money markets	18.3	—	—	—
U.S. equities	245.2	—	—	—
International equities	122.3	—	—	—
Fixed income	365.7	—	—	—
Pension plan assets subtotal	1,860.3	329.3	693.4	86.1
Other postretirement benefit plan assets:				
Mutual funds				
U.S. equities	68.4	68.4	—	—
International equities	17.5	17.5	—	—
Fixed income	114.8	114.8	—	—
Commingled funds[(3)]				
Short-term money markets	5.2	—	—	—
U.S. equities	10.4	—	—	—
Other postretirement benefit plan assets subtotal	216.3	200.7	—	—
Due to brokers, net[(4)]	(1.1)	—	(1.1)	—
Accrued investment income/dividends	8.6	8.6	—	—
Total pension and other postretirement benefit plan assets	$ 2,084.1	$ 538.6	$ 692.3	$ 86.1

(1) This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily inside the United States.
(2) This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily outside the United States.
(3) This class of investments is measured at fair value using the net asset value per share and has not been classified in the fair value hierarchy.
(4) This class represents pending trades with brokers.

The table below sets forth a summary of changes in the fair value of the Plan's Level 3 assets for the year ended December 31, 2018:

	Balance at January 1, 2018	Total gains or losses (unrealized / realized)	Purchases	(Sales)	Balance at December 31, 2018
Private equity limited partnerships					
U.S. multi-strategy	26.7	2.4	0.7	(11.3)	18.5
International multi-strategy	19.1	(0.6)	—	(6.0)	12.5
Distress opportunities	3.2	(0.8)	—	—	2.4
Real estate	49.9	1.7	1.8	(0.7)	52.7
Total	$ 98.9	$ 2.7	$ 2.5	$ (18.0)	$ 86.1

The table below sets forth a summary of unfunded commitments, redemption frequency and redemption notice periods for certain investments that are measured at fair value using the net asset value per share for the year ended December 31, 2018:

(in millions)	Fair Value	Redemption Frequency	Redemption Notice Period
Commingled Funds			
Short-term money markets	$ 23.5	Daily	1 day
U.S. equities	255.6	Monthly	3 days
International equities	122.3	Monthly	10-30 days
Fixed income	365.7	Monthly	3 days
Total	$ 767.1		

Our Pension and Other Postretirement Benefit Plans' Funded Status and Related Disclosure. The following table provides a reconciliation of the plans' funded status and amounts reflected in our Consolidated Balance Sheets at December 31 based on a December 31 measurement date:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2019**	2018	**2019**	2018
Change in projected benefit obligation[(1)]				
Benefit obligation at beginning of year	**$ 1,981.3**	$ 2,192.6	**$ 492.5**	$ 556.3
Service cost	**29.2**	31.3	**5.1**	5.0
Interest cost	**72.3**	67.1	**19.2**	17.6
Plan participants' contributions	**—**	—	**4.8**	5.7
Plan amendments	**—**	0.2	**5.1**	0.1
Actuarial (gain) loss	**204.3**	(103.9)	**88.8**	(51.7)
Settlement loss	**—**	0.8	**—**	—
Benefits paid	**(156.6)**	(206.8)	**(39.5)**	(41.1)
Estimated benefits paid by incurred subsidy	**—**	—	**0.5**	0.6
Projected benefit obligation at end of year	**$ 2,130.5**	$ 1,981.3	**$ 576.5**	$ 492.5
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 1,867.7**	$ 2,160.0	**$ 216.3**	$ 262.5
Actual (loss) return on plan assets	**366.8**	(88.4)	**56.9**	(31.8)
Employer contributions	**2.9**	2.9	**23.0**	21.0
Plan participants' contributions	**—**	—	**4.7**	5.7
Benefits paid	**(156.5)**	(206.8)	**(39.5)**	(41.1)
Fair value of plan assets at end of year	**$ 2,080.9**	$ 1,867.7	**$ 261.4**	$ 216.3
Funded Status at end of year	**$ (49.6)**	$ (113.6)	**$ (315.1)**	$ (276.2)
Amounts recognized in the statement of financial position consist of:				
Noncurrent assets	**8.2**	—	**—**	—
Current liabilities	**(3.0)**	(3.0)	**(0.8)**	(0.8)
Noncurrent liabilities	**(54.8)**	(110.6)	**(314.3)**	(275.4)
Net amount recognized at end of year[(2)]	**$ (49.6)**	$ (113.6)	**$ (315.1)**	$ (276.2)
Amounts recognized in accumulated other comprehensive income or regulatory asset/liability[(3)]				
Unrecognized prior service credit	**$ 3.0**	$ 3.2	**$ (10.7)**	$ (19.0)
Unrecognized actuarial loss	**652.8**	761.2	**118.4**	75.3
Net amount recognized at end of year	**$ 655.8**	$ 764.4	**$ 107.7**	$ 56.3

[(1)] The change in benefit obligation for Pension Benefits represents the change in Projected Benefit Obligation while the change in benefit obligation for Other Postretirement Benefits represents the change in accumulated postretirement benefit obligation.
[(2)] We recognize our Consolidated Balance Sheets underfunded and overfunded status of our various defined benefit postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation.
[(3)] We determined that for certain rate-regulated subsidiaries the future recovery of pension and other postretirement benefits costs is probable. These rate-regulated subsidiaries recorded regulatory assets and liabilities of $739.1 million and $0.1 million, respectively, as of December 31, 2019, and $798.3 million and $0.1 million, respectively, as of December 31, 2018 that would otherwise have been recorded to accumulated other comprehensive loss.

Our accumulated benefit obligation for our pension plans was $2,111.5 million and $1,965.6 million as of December 31, 2019 and 2018, respectively. The accumulated benefit obligation as of a date is the actuarial present value of benefits attributed by the pension benefit formula to employee service rendered prior to that date and based on current and past compensation levels. The accumulated benefit obligation differs from the projected benefit obligation disclosed in the table above in that it includes no assumptions about future compensation levels.

We are required to reflect the funded status of the pension and postretirement benefit plans on the Consolidated Balance Sheet. The funded status of the plans is measured as the difference between the plan assets' fair value and the projected benefit obligation. We present the noncurrent aggregate of all underfunded plans within "Accrued liability for postretirement and postemployment benefits." The portion of the amount by which the actuarial present value of benefits included in the projected benefit obligation exceeds the fair value of plan assets, payable in the next 12 months, is reflected in "Accrued compensation and other benefits." We present the aggregate of all overfunded plans within "Deferred charges and other."

Information for pension plans with a projected benefit obligation in excess of plan assets:

	December 31,	
	2019	2018
Accumulated Benefit Obligation	**$ 1,473.9**	$ 1,965.6
Funded Status		
Projected Benefit Obligation	**1,492.9**	1,981.3
Fair Value of Plan Assets	**1,435.1**	1,867.7
Funded Status of Underfunded Pension Plans at End of Year	**$ (57.8)**	$ (113.6)

Information for pension plans with plan assets in excess of the projected benefit obligation:

	December 31,	
	2019	2018
Accumulated Benefit Obligation	**$ 637.6**	$ —
Funded Status		
Projected Benefit Obligation	**637.6**	—
Fair Value of Plan Assets	**645.8**	—
Funded Status of Overfunded Pension Plans at End of Year	**$ 8.2**	$ —

Our pension plans were underfunded, in aggregate, by $49.6 million at December 31, 2019 compared to being underfunded by $113.6 million at December 31, 2018. The improvement in the funded status was due primarily to favorable asset returns offset by a decrease in discount rates. We contributed $2.9 million to our pension plans in both 2019 and 2018.

Our other postretirement benefit plans were underfunded by $315.1 million at December 31, 2019 compared to being underfunded by $276.2 million at December 31, 2018. The decline in funded status was primarily due to a decrease in discount rates offset by favorable asset returns. We contributed $23.0 million and $21.0 million to our other postretirement benefit plans in 2019 and 2018, respectively.

No amounts of our pension or other postretirement benefit plans' assets are expected to be returned to us or any of our subsidiaries in 2019.

In 2019 and 2018, some of our qualified pension plans paid lump sum payouts in excess of the respective plan's service cost plus interest cost, thereby meeting the requirement for settlement accounting. We recorded settlement charges of $9.5 million and $18.5 million in 2019 and 2018, respectively. Net periodic pension benefit cost for 2019 was decreased by $0.7 million as a result of the interim remeasurement.

The following table provides the key assumptions that were used to calculate the pension and other postretirement benefits obligations for our various plans as of December 31:

	Pension Benefits		Other Postretirement Benefits	
	2019	2018	**2019**	2018
Weighted-average assumptions to Determine Benefit Obligation				
Discount Rate	**3.12%**	4.26%	**3.21%**	4.31%
Rate of Compensation Increases	**4.00%**	4.00%	**—**	—
Health Care Trend Rates				
Trend for Next Year	**—**	—	**6.68%**	8.48%
Ultimate Trend	**—**	—	**4.50%**	4.50%
Year Ultimate Trend Reached	**—**	—	**2028**	2026

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(in millions)	1% point increase	1% point decrease
Effect on service and interest components of net periodic cost	$ 1.2	$ (1.1)
Effect on accumulated postretirement benefit obligation	30.1	(26.3)

We expect to make contributions of approximately $3.0 million to our pension plans and approximately $24.0 million to our postretirement medical and life plans in 2020.

The following table provides benefits expected to be paid in each of the next five fiscal years, and in the aggregate for the five fiscal years thereafter. The expected benefits are estimated based on the same assumptions used to measure our benefit obligation at the end of the year and include benefits attributable to the estimated future service of employees:

(in millions)	Pension Benefits	Other Postretirement Benefits	Federal Subsidy Receipts
Year(s)			
2020	$ 178.8	$ 38.1	$ 0.5
2021	177.8	38.6	0.4
2022	175.8	38.4	0.4
2023	168.5	38.1	0.4
2024	164.4	37.9	0.4
2025-2029	723.7	181.0	1.5

The following table provides the components of the plans' actuarially determined net periodic benefits cost for each of the three years ended December 31, 2019, 2018 and 2017:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2019**	2018	2017	**2019**	2018	2017
Components of Net Periodic Benefit Cost[(1)]						
Service cost	**$ 29.2**	$ 31.3	$ 30.0	**$ 5.1**	$ 5.0	$ 4.8
Interest cost	**72.3**	67.1	68.3	**19.2**	17.6	17.8
Expected return on assets	**(108.8)**	(142.3)	(123.1)	**(13.1)**	(14.9)	(15.9)
Amortization of prior service cost (credit)	**0.2**	(0.4)	(0.7)	**(3.2)**	(4.0)	(4.4)
Recognized actuarial loss	**45.2**	40.6	52.9	**2.0**	3.8	3.0
Settlement loss	**9.5**	18.5	13.7	**—**	—	—
Total Net Periodic Benefits Cost	**$ 47.6**	$ 14.8	$ 41.1	**$ 10.0**	$ 7.5	$ 5.3

(1)Service cost is presented in "Operation and maintenance" on the Statements of Consolidated Income (Loss). Non-service cost components are presented within "Other, net."

The following table provides the key assumptions that were used to calculate the net periodic benefits cost for our various plans:

	Pension Benefits			Other Postretirement Benefits		
	2019	2018	2017	**2019**	2018	2017
Weighted-average Assumptions to Determine Net Periodic Benefit Cost						
Discount rate - service cost[(1)]	**4.48%**	3.79%	4.40%	**4.59%**	3.89%	4.58%
Discount rate - interest cost[(1)]	**3.84%**	3.15%	3.31%	**3.94%**	3.27%	3.48%
Expected Long-Term Rate of Return on Plan Assets	**6.10%**	7.00%	7.25%	**5.83%**	5.80%	6.99%
Rate of Compensation Increases	**4.00%**	4.00%	4.00%	**—**	—	—

(1) In January 2017, we changed the method used to estimate the service and interest components of net periodic benefit cost for pension and other postretirement benefits. This change, compared to the previous method, resulted in a decrease in the actuarially-determined service and interest cost components. Historically, we estimated service and interest cost utilizing a single weighted-average discount rate derived from the yield curve used to measure the benefit obligation at the beginning of the period. For fiscal 2017 and beyond, we now utilize a full yield curve approach to estimate these components by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to the relevant projected cash flows.

We believe it is appropriate to assume a 6.10% and 5.83% rate of return on pension and other postretirement plan assets, respectively, for our calculation of 2019 pension benefits cost. These rates are primarily based on asset mix and historical rates of return and were adjusted in the current year due to anticipated changes in asset allocation and projected market returns.

The following table provides other changes in plan assets and projected benefit obligations recognized in other comprehensive income or regulatory asset or liability:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2019**	2018	**2019**	2018
Other Changes in Plan Assets and Projected Benefit Obligations Recognized in Other Comprehensive Income or Regulatory Asset or Liability				
Net prior service cost	**$ —**	$ 0.2	**$ 5.1**	$ 0.1
Net actuarial loss (gain)	**(53.8)**	127.5	**45.1**	(5.0)
Settlements	**(9.5)**	(18.5)	**—**	—
Less: amortization of prior service cost	**(0.2)**	0.4	**3.2**	4.0
Less: amortization of net actuarial loss	**(45.2)**	(40.6)	**(2.0)**	(3.8)
Total Recognized in Other Comprehensive Income or Regulatory Asset or Liability	**$ (108.7)**	$ 69.0	**$ 51.4**	$ (4.7)
Amount Recognized in Net Periodic Benefits Cost and Other Comprehensive Income or Regulatory Asset or Liability	**$ (61.1)**	$ 83.8	**$ 61.4**	$ 2.8

Based on a December 31 measurement date, the estimated net unrecognized actuarial loss, unrecognized prior service cost, and unrecognized transition obligation that will be amortized into net periodic benefit cost during 2020 for the pension plans are $34.7 million, $0.8 million and zero, respectively, and for other postretirement benefit plans are $4.9 million, $(1.8) million and zero, respectively.

12. Equity

We raise equity financing through a variety of programs including traditional common equity issuances and preferred stock issuances. As of December 31, 2019, we had 600,000,000 shares of common stock and 20,000,000 shares of preferred stock authorized for issuance, of which 382,135,680 shares of common stock and 440,000 shares of preferred stock are currently outstanding.

Holders of shares of our common stock are entitled to receive dividends when, as and if declared by the Board out of funds legally available. The policy of the Board has been to declare cash dividends on a quarterly basis payable on or about the 20th day of February, May, August and November. We have paid quarterly common dividends totaling $0.80, $0.78, and $0.70 per share for the years ended December 31, 2019, 2018 and 2017, respectively. Our Board declared a quarterly common dividend of $0.21 per share, payable on February 20, 2020 to holders of record on February 11, 2020. We have certain debt covenants which could potentially limit the amount of dividends the Company could pay in order to maintain compliance with these covenants. Refer to Note 14, "Long-Term Debt," for more information. As of December 31, 2019, these covenants did not restrict the amount of dividends that were available to be paid.

Dividends paid to preferred shareholders vary based on the series of preferred stock owned. Additional information is provided below. Holders of our shares of common stock are subject to the prior dividend rights of holders of our preferred stock or the depositary shares representing such preferred stock outstanding, and if full dividends have not been declared and paid on all outstanding shares of preferred stock in any dividend period, no dividend may be declared or paid or set aside for payment on our common stock.

Common and preferred stock activity for 2019, 2018 and 2017 is described further below:

ATM Program and Forward Sale Agreements. On May 3, 2017, we entered into four separate equity distribution agreements, pursuant to which we were able to sell up to an aggregate of $500.0 million of our common stock.

On November 13, 2017, under the ATM program, we executed a forward agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. On November 6, 2018, the forward agreement was settled for $26.43 per share, resulting in $167.7 million of net proceeds. The equity distribution agreements entered into on May 3, 2017 expired December 31, 2018.

On November 1, 2018, we entered into five separate equity distribution agreements pursuant to which we were able to sell up to an aggregate of $500.0 million of our common stock. Four of these agreements were then amended on August 1, 2019 and one was terminated, pursuant to which we may sell, from time to time, up to an aggregate of $434.4 million of our common stock.

On December 6, 2018, under the ATM program, we executed a forward agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. From December 6, 2018 to December 10, 2018, 4,708,098 shares were borrowed from third parties and sold by the dealer at a weighted average price of $26.55 per share. On November 21, 2019, the forward agreement was settled for $26.01 per share, resulting in $122.5 million of net proceeds.

On August 12, 2019, under the ATM program, we executed a separate forward agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. From August 12, 2019 to September 13, 2019, 3,714,400 shares were borrowed from third parties and sold by the dealer at a weighted average price of $29.26 per share. On December 11, 2019, the forward agreement was settled for $28.83 per share, resulting in $107.1 million of net proceeds.

As of December 31, 2019, the ATM program had approximately $200.7 million of equity available for issuance. The program expires on December 31, 2020.

The following table summarizes our activity under the ATM program:

Year Ending December 31,	**2019**	2018	2017
Number of shares issued	**8,422,498**	8,883,014	11,931,376
Average price per share	**$ 27.75**	$ 26.85	$ 26.58
Proceeds, net of fees (*in millions*)	**$ 229.1**	$ 232.5	$ 314.7

Private Placement of Common Stock. On May 4, 2018, we completed the sale of 24,964,163 shares of $0.01 par value common stock at a price of $24.28 per share in a private placement to selected institutional and accredited investors. The private placement resulted in $606.0 million of gross proceeds or $599.6 million of net proceeds, after deducting commissions and sale expenses. The common stock issued in connection with the private placement was registered on Form S-1, filed with the SEC on May 11, 2018.

Preferred Stock. On June 11, 2018, we completed the sale of 400,000 shares of 5.650% Series A Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (the "Series A Preferred Stock") at a price of $1,000 per share. The transaction resulted in $400.0 million of gross proceeds or $393.9 million of net proceeds, after deducting commissions and sale expenses. The Series A Preferred Stock was issued in a private placement pursuant to SEC Rule 144A. On December 13, 2018, we filed a registration statement with the SEC enabling holders to exchange their unregistered shares of Series A Preferred Stock for publicly registered shares with substantially identical terms.

Proceeds from the issuance of the Series A Preferred Stock were used to pay a portion of the notes tendered in June 2018 and the redemption of the remaining notes in July 2018. See Note 14, “Long-term Debt” for additional information regarding the tender offer and redemption.

Dividends on the Series A Preferred Stock accrue and are cumulative from the date the shares of Series A Preferred Stock were originally issued to, but not including, June 15, 2023 at a rate of 5.650% per annum of the $1,000 liquidation preference per share. On and after June 15, 2023, dividends on the Series A Preferred Stock will accumulate for each five year period at a percentage of the $1,000 liquidation preference equal to the five-year U.S. Treasury Rate plus (i) in respect of each five year period commencing on or after June 15, 2023 but before June 15, 2043, a spread of 2.843% (the “Initial Margin”), and (ii) in respect of each five year period commencing on or after June 15, 2043, the Initial Margin plus 1.000%. The Series A Preferred Stock may be redeemed by us at our option on June 15, 2023, or on each date falling on the fifth anniversary thereafter, or in connection with a ratings event (as defined in the Certificate of Designation of the Series A Preferred Stock).

As of December 31, 2019 and 2018, Series A Preferred Stock had $1.0 million of cumulative preferred dividends in arrears, or $2.51 per share.

Holders of Series A Preferred Stock generally have no voting rights, except for limited voting rights with respect to (i) potential amendments to our certificate of incorporation that would have a material adverse effect on the existing preferences, rights, powers or duties of the Series A Preferred Stock, (ii) the creation or issuance of any security ranking on a parity with the Series A Preferred Stock if the cumulative dividends payable on then outstanding Series A Preferred Stock are in arrears, or (iii) the creation or issuance of any security ranking senior to the Series A Preferred Stock. The Series A Preferred Stock does not have a stated maturity and is not subject to mandatory redemption or any sinking fund. The Series A Preferred Stock will remain outstanding indefinitely unless repurchased or redeemed by us. Any such redemption would be effected only out of funds legally available for such purposes and will be subject to compliance with the provisions of our outstanding indebtedness.

On December 5, 2018, we completed the sale of 20,000,000 depositary shares with an aggregate liquidation preference of $500,000,000 under the Company's registration statement on Form S-3. Each depositary share represents 1/1,000th ownership interest in a share of our 6.500% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock, liquidation preference $25,000 per share (equivalent to $25 per depositary share) (the "Series B Preferred Stock"). The transaction resulted in $500.0 million of gross proceeds or $486.1 million of net proceeds, after deducting commissions and sale expenses.

Dividends on the Series B Preferred Stock accrue and are cumulative from the date the shares of Series B Preferred Stock were originally issued to, but not including, March 15, 2024 at a rate of 6.500% per annum of the $25,000 liquidation preference per share. On and after March 15, 2024, dividends on the Series B Preferred Stock will accumulate for each five year period at a percentage of the $25,000 liquidation preference equal to the five-year U.S. Treasury Rate plus (i) in respect of each five year period commencing on or after March 15, 2024 but before March 15, 2044, a spread of 3.632% (the "Initial Margin"), and (ii) in respect of each five year period commencing on or after March 15, 2044, the Initial Margin plus 1.000%. The Series B Preferred Stock may be redeemed by us at our option on March 15, 2024, or on each date falling on the fifth anniversary thereafter, or in connection with a ratings event (as defined in the Certificate of Designation of the Series B Preferred Stock).

As of December 31, 2019 and 2018, Series B Preferred Stock had $1.4 million and $2.4 million, respectively, of cumulative preferred dividends in arrears, or $72.23 and $121.88 per share, respectively.

In addition, we issued 20,000 shares of "Series B-1 Preferred Stock", par value $0.01 per share, ("Series B-1 Preferred Stock"), as a distribution with respect to the Series B Preferred Stock. As a result, each of the depositary shares issued on December 5, 2018 now represents a 1/1,000th ownership interest in a share of Series B Preferred Stock and a 1/1,000th ownership interest in a share of Series B-1 Preferred Stock. We issued the Series B-1 Preferred Stock to enhance the voting rights of the Series B Preferred Stock to comply with the minimum voting rights policy of the New York Stock Exchange. The Series B-1 Preferred Stock is paired with the Series B Preferred Stock and may not be transferred, redeemed or repurchased except in connection with the simultaneous transfer, redemption or repurchase of a like number of shares of the underlying Series B Preferred Stock.

Holders of Series B Preferred Stock generally have no voting rights, except for limited voting rights with respect to (i) potential amendments to our certificate of incorporation that would have a material adverse effect on the existing preferences, rights, powers or duties of the Series B Preferred Stock, (ii) the creation or issuance of any security ranking on a parity with the Series B Preferred Stock if the cumulative dividends payable on then outstanding Series B Preferred Stock are in arrears, or (iii) the creation or issuance of any security ranking senior to the Series B Preferred Stock. In addition, if and whenever dividends on any shares of Series B Preferred Stock shall not have been declared and paid for at least six dividend periods, whether or not consecutive, the number of directors then constituting our Board of Directors shall automatically be increased by two until all accumulated and unpaid dividends on the Series B Preferred Stock shall have been paid in full, and the holders of Series B-1 Preferred Stock, voting as a class together with the holders of any outstanding securities ranking on a parity with the Series B-1 Preferred Stock and having like voting rights that are exercisable at the time and entitled to vote thereon, shall be entitled to elect the two additional directors. The Series B Preferred Stock does not have a stated maturity and is not subject to mandatory redemption or any sinking fund. The Series B Preferred Stock will remain outstanding indefinitely unless repurchased or redeemed by us. Any such redemption would be effected only out of funds legally available for such purposes and will be subject to compliance with the provisions of our outstanding indebtedness.

The following table summarizes preferred stock by outstanding series of shares:

			Year ended December 31,			December 31,	December 31,
			2019	2018	2017	2019	2018
(in millions except shares and per share amounts)	Liquidation Preference Per Share	Shares	Dividends Declared Per Share			Outstanding	
5.650% Series A	$ 1,000.00	400,000	$ 56.50	$ 28.88	$ —	$ 393.9	$ 393.9
6.500% Series B	$ 25,000.00	20,000	$ 1,674.65	$ —	$ —	$ 486.1	$ 486.1

13. Share-Based Compensation

Our stockholders most recently approved the NiSource Inc. 2010 Omnibus Incentive Plan (“Omnibus Plan”) at the Annual Meeting of Stockholders held on May 12, 2015. The Omnibus Plan provides for awards to employees and non-employee directors of incentive and nonqualified stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock-based awards and supersedes the long-term incentive plan approved by stockholders on April 13, 1994 (“1994 Plan”) and the Director Stock Incentive Plan (“Director Plan”). The Omnibus Plan provides that the number of shares of common stock of NiSource available for awards is 8,000,000 plus the number of shares subject to outstanding awards that expire or terminate for any reason that were granted under either the 1994 Plan or the Director Plan, plus the number of shares that were awarded as a result of the Separation-related adjustments. At December 31, 2019, there were 3,313,183 shares reserved for future awards under the Omnibus Plan.

We recognized stock-based employee compensation expense of $16.3 million, $15.2 million and $15.3 million, during 2019, 2018 and 2017, respectively, as well as related tax benefits of $4.0 million, $3.7 million and $5.9 million, respectively. We recognized related excess tax benefits from the distribution of vested share-based employee compensation of $0.8 million, $1.0 million and $4.4 million in 2019, 2018 and 2017, respectively.

As of December 31, 2019, the total remaining unrecognized compensation cost related to non-vested awards amounted to $19.5 million, which will be amortized over the weighted-average remaining requisite service period of 1.8 years.

Restricted Stock Units and Restricted Stock. In 2019, we granted 166,031 restricted stock units and shares of restricted stock to employees, subject to service conditions. The total grant date fair value of the restricted stock units and shares of restricted stock was $4.1 million, based on the average market price of our common stock at the date of each grant less the present value of any dividends not received during the vesting period, which will be expensed over the vesting period which is generally three years. As of December 31, 2019, 157,786 non-vested restricted stock units and shares of restricted stock granted in 2019 were outstanding as of December 31, 2019.

In 2018, we granted 158,689 restricted stock units and shares of restricted stock to employees, subject to service conditions. The total grant date fair value of the restricted stock units and shares of restricted stock was $3.5 million, based on the average market price of our common stock at the date of each grant less the present value of any dividends not received during the vesting period, which will be expensed over the vesting period which is generally three years. As of December 31, 2019, 136,820 non-vested restricted stock units and shares of restricted stock granted in 2018 were outstanding as of December 31, 2019.

Restricted stock units and shares of restricted stock granted to employees in 2017 were immaterial.

If an employee terminates employment before the service conditions lapse under the 2017, 2018 or 2019 awards due to (1) retirement or disability (as defined in the award agreement), or (2) death, the service conditions will lapse on the date of such termination with respect to a pro rata portion of the restricted stock units and shares of restricted stock based upon the percentage of the service period satisfied between the grant date and the date of the termination of employment. In the event of a change in control (as defined in the award agreement), all unvested shares of restricted stock and restricted stock units awarded will immediately vest upon termination of employment occurring in connection with a change in control. Termination due to any other reason will result in all unvested shares of restricted stock and restricted stock units awarded being forfeited effective on the employee’s date of termination.

(shares)	Restricted Stock Units	Weighted Average Award Date Fair Value Per Unit ($)
Non-vested at December 31, 2018	178,678	21.82
Granted	166,031	24.93
Forfeited	(21,547)	22.99
Vested	(20,556)	21.08
Non-vested at December 31, 2019	**302,606**	**23.49**

Performance Shares. In 2019, we granted 552,389 performance shares subject to service, performance and market conditions. The service conditions for these awards lapse on February 28, 2022. The performance period for the awards is the period beginning January 1, 2019 and ending December 31, 2021. The performance conditions are based on the achievement of one non-GAAP financial measure and additional operational measures as outlined below.

The financial measure is cumulative net operating earnings per share ("NOEPS"), which we define as income from continuing operations adjusted for certain unusual or non-recurring items. The number of cumulative NOEPS shares determined using this measure shall be increased or decreased based on our relative total shareholder return, a market condition which we define as the annualized growth in dividends and share price of a share of our common stock (calculated using a 20 trading day average of our closing price beginning on December 31, 2018 and ending on December 31, 2021) compared to the total shareholder return of a predetermined peer group of companies. A relative shareholder return result within the first quartile will result in an increase to the NOEPS shares of 25%, while a relative shareholder return result within the fourth quartile will result in a decrease of 25%. A Monte Carlo analysis was used to value the portion of these awards dependent on market conditions. The grant date fair value of the awards was $11.7 million, based on the average market price of our common stock at the date of each grant less the present value of dividends not received during the vesting period which will be expensed over the requisite service period of three years. As of December 31, 2019, 422,825 of these non-vested performance shares granted in 2019 remained outstanding.

If a threshold level of cumulative NOEPS financial performance is achieved, additional operational measures which we refer to as the customer value index, which consists of five equally weighted areas of focus including safety, customer satisfaction, financial, culture and environmental apply. Each area of focus represents 20% of the customer value index shares, and the targets for all areas must be met for these awards to be eligible for 100% payout of these awards. The grant date fair value of the awards was $2.5 million, based on the average market price of our common stock on the grant date of each award less the present value of dividends not received during the vesting period which will be expensed over the requisite service period of three years. As of December 31, 2019, 97,574 of these awards that were issued in 2019 remained outstanding.

In 2018, we awarded 514,338 performance shares subject to service, performance and market conditions. The service conditions for these awards lapse on February 26, 2021. The performance period for the awards is the period beginning January 1, 2018 and ending December 31, 2020. The performance conditions are based on the achievement of one non-GAAP financial measure and additional operational measures as outlined below.

The financial measure is cumulative net operating earnings per share ("NOEPS"), which we define as income from continuing operations adjusted for certain unusual or non-recurring items. The number of cumulative NOEPS shares determined using this measure shall be increased or decreased based on our relative total shareholder return, a market condition which we define as the annualized growth in dividends and share price of a share of our common stock (calculated using a 20 trading day average of our closing price beginning on December 31, 2017 and ending on December 31, 2020) compared to the total shareholder return of a predetermined peer group of companies. A relative shareholder return result within the first quartile will result in an increase to the NOEPS shares of 25% while a relative shareholder return result within the fourth quartile will result in a decrease of 25%. A Monte Carlo analysis was used to value the portion of these awards dependent on market conditions. The grant date fair value of the awards was $9.2 million, based on the average market price of our common stock at the date of each grant less the present value of dividends not received during the vesting period which will be expensed over the requisite service period of three years. As of December 31, 2019, 368,811 of these non-vested performance shares granted in 2018 remained outstanding.

If a threshold level of cumulative NOEPS financial performance is achieved, additional operational measures which we refer to as the customer value index, which consists of five equally weighted areas of focus including safety, customer satisfaction, financial, culture and environmental apply. Each area of focus represents 20% of the customer value index shares and the targets for all areas must be met for these awards to be eligible for 100% payout of these awards. Individual payout percentages for these shares may range from 0%-200% as determined by the compensation committee in its sole discretion. Due to this discretion, these shares are not considered to be granted under ASC 718. The service inception date fair value of the awards was $2.4 million, based on the closing market price of our common stock on the service inception date of each award. This value will be reassessed at each reporting period to be based on our closing market price of our common stock at the reporting period date with adjustments to expense recorded as appropriate. As of December 31, 2019, 85,111 of these awards that were issued in 2018 remained outstanding. The service conditions for these awards lapse on February 26, 2021.

In 2017, we granted 660,750 performance shares subject to service, performance and market conditions. The grant date fair value of the awards was $12.9 million, based on the average market price of our common stock at the date of each grant less the present value of dividends not received during the vesting period which will be expensed over the requisite service period of three years. The performance conditions are based on achievement of non-GAAP financial measures similar to those discussed above: cumulative net operating earnings per share for the three-year period ending December 31, 2019 and relative total shareholder return (calculated using a 20 trading day average of our closing price beginning on December 31, 2016 and ending on December 31, 2019). As of December 31, 2019, 528,928 non-vested performance shares granted in 2017 remained outstanding. The service conditions for these awards lapse on February 28, 2020.

(shares)	Performance Awards	Weighted Average Grant Date Fair Value Per Unit ($)[(1)]
Non-vested at December 31, 2018	1,634,718	20.45
Granted	552,389	25.77
Forfeited	(156,700)	26.72
Vested	(527,156)	28.11
Non-vested at December 31, 2019	**1,503,251**	**22.74**

[(1)]2018 performance shares awarded based on the customer value index are included at reporting date fair value as these awards have not been granted under ASC 718 as discussed above.

Non-employee Director Awards. As of May 11, 2010, awards to non-employee directors may be made only under the Omnibus Plan. Currently, restricted stock units are granted annually to non-employee directors, subject to a non-employee director's election to defer receipt of such restricted stock unit award. The non-employee director's annual award of restricted stock units vest on the first anniversary of the grant date subject to special pro-rata vesting rules in the event of retirement or disability (as defined in the award agreement), or death. The vested restricted stock units are payable as soon as practicable following vesting except as otherwise provided pursuant to the non-employee director's election to defer. Certain restricted stock units remain outstanding from the Director Plan. All such awards are fully vested and shall be distributed to the directors upon their separation from the Board.

As of December 31, 2019, 165,768 restricted stock units are outstanding to non-employee directors under either the Omnibus Plan or the Director Plan. Of this amount, 49,926 restricted stock units are unvested and expected to vest.

401(k) Match, Profit Sharing and Company Contribution. We have a voluntary 401(k) savings plan covering eligible employees that allows for periodic discretionary matches as a percentage of each participant's contributions payable in cash for nonunion employees and generally payable in shares of NiSource common stock for union employees, subject to collective bargaining. We also have a retirement savings plan that provides for discretionary profit sharing contributions similarly payable in cash or shares of NiSource common stock to eligible employees based on earnings results, and eligible employees hired after January 1, 2010 receive a non-elective company contribution of 3% of eligible pay similarly payable in cash or shares of NiSource common stock. For the years ended December 31, 2019, 2018 and 2017, we recognized 401(k) match, profit sharing and non-elective contribution expense of $37.5 million, $37.6 million and $37.6 million, respectively.

14. Long-Term Debt

Our long-term debt as of December 31, 2019 and 2018 is as follows:

Long-term debt type	Maturity as of December 31, 2019	Weighted average interest rate (%)	Outstanding balance as of December 31, *(in millions)* 2019	2018
Senior notes:				
NiSource	December 2021	4.45%	**63.6**	63.6
NiSource	November 2022	2.65%	**500.0**	500.0
NiSource	February 2023	3.85%	**250.0**	250.0
NiSource	June 2023	3.65%	**350.0**	350.0
NiSource	November 2025	5.89%	**265.0**	265.0
NiSource	May 2027	3.49%	**1,000.0**	1,000.0
NiSource	December 2027	6.78%	**3.0**	3.0
NiSource	September 2029	2.95%	**750.0**	—
NiSource	December 2040	6.25%	**250.0**	250.0
NiSource	June 2041	5.95%	**400.0**	400.0
NiSource	February 2042	5.80%	**250.0**	250.0
NiSource	February 2043	5.25%	**500.0**	500.0
NiSource	February 2044	4.80%	**750.0**	750.0
NiSource	February 2045	5.65%	**500.0**	500.0
NiSource	May 2047	4.38%	**1,000.0**	1,000.0
NiSource	March 2048	3.95%	**750.0**	750.0
Total senior notes			**$ 7,581.6**	$ 6,831.6
Medium term notes:				
NiSource	April 2022 to May 2027	7.99%	**$ 49.0**	$ 49.0
NIPSCO	August 2022 to August 2027	7.61%	**68.0**	68.0
Columbia of Massachusetts	December 2025 to February 2028	6.30%	**40.0**	40.0
Total medium term notes			**$ 157.0**	$ 157.0
Finance leases:				
NiSource Corporate Services	January 2020 to November 2023	3.47%	**22.3**	11.6
Columbia of Ohio	October 2021 to March 2044	6.16%	**94.8**	91.5
Columbia of Virginia	July 2029 to November 2039	6.31%	**19.1**	15.2
Columbia of Kentucky	May 2027	3.79%	**0.3**	0.3
Columbia of Pennsylvania	August 2027 to May 2035	5.67%	**20.7**	30.0
Columbia of Massachusetts	December 2033 to November 2043	5.49%	**44.3**	45.7
Total finance leases			**201.5**	194.3
Pollution control bonds - NIPSCO	April 2019	5.85%	**—**	41.0
Unamortized issuance costs and discounts			**(70.5)**	$ (68.5)
Total Long-Term Debt			**$ 7,869.6**	$ 7,155.4

Details of our 2019 long-term debt related activity are summarized below:

- On April 1, 2019, NIPSCO repaid $41.0 million of 5.85% pollution control bonds at maturity.
- On August 12, 2019, we closed our placement of $750.0 million of 2.95% senior unsecured notes maturing in 2029 which resulted in approximately $742.4 million of net proceeds after deducting commissions and expenses.

Details of our 2018 long-term debt related activity are summarized below:

- On March 15, 2018, we redeemed $275.1 million of 6.40% senior unsecured notes at maturity.
- In June 2018, we executed a tender offer for $209.0 million of outstanding notes consisting of a combination of our 6.80% notes due 2019, 5.45% notes due 2020, and 6.125% notes due 2022. In conjunction with the debt retired, we recorded a $12.5 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums.
- On June 11, 2018, we closed our private placement of $350.0 million of 3.65% senior unsecured notes maturing in 2023 which resulted in approximately $346.6 million of net proceeds after deducting commissions and expenses. We used the net proceeds from this private placement to pay a portion of the redemption price for the notes subject to the tender offer described above.
- In July 2018, we redeemed $551.1 million of outstanding notes representing the remainder of our 6.80% notes due 2019, 5.45% notes due 2020 and 6.125% notes due 2022. During the third quarter of 2018, we recorded a $33.0 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums.

See Note 19-A, "Contractual Obligations," for the outstanding long-term debt maturities at December 31, 2019.

Unamortized debt expense, premium and discount on long-term debt applicable to outstanding bonds are being amortized over the life of such bonds.

We are subject to a financial covenant under our revolving credit facility and term loan agreement which requires us to maintain a debt to capitalization ratio that does not exceed 70%. A similar covenant in a 2005 private placement note purchase agreement requires us to maintain a debt to capitalization ratio that does not exceed 75%. As of December 31, 2019, the ratio was 61.7%.

We are also subject to certain other non-financial covenants under the revolving credit facility. Such covenants include a limitation on the creation or existence of new liens on our assets, generally exempting liens on utility assets, purchase money security interests, preexisting security interests and an additional subset of assets equal to $150 million. An asset sale covenant generally restricts the sale, conveyance, lease, transfer or other disposition of our assets to those dispositions that are for a price not materially less than fair market of such assets, that would not materially impair our ability to perform obligations under the revolving credit facility, and that together with all other such dispositions, would not have a material adverse effect. The covenant also restricts dispositions to no more than 10% of our consolidated total assets on December 31, 2015. The revolving credit facility also includes a cross-default provision, which triggers an event of default under the credit facility in the event of an uncured payment default relating to any indebtedness of us or any of our subsidiaries in a principal amount of $50.0 million or more.

Our indentures generally do not contain any financial maintenance covenants. However, our indentures are generally subject to cross-default provisions ranging from uncured payment defaults of $5 million to $50 million, and limitations on the incurrence of liens on our assets, generally exempting liens on utility assets, purchase money security interests, preexisting security interests and an additional subset of assets capped at 10% of our consolidated net tangible assets.

15. Short-Term Borrowings

We generate short-term borrowings from our revolving credit facility, commercial paper program, accounts receivable transfer programs and term loan borrowings. Each of these borrowing sources is described further below.

We maintain a revolving credit facility to fund ongoing working capital requirements, including the provision of liquidity support for our commercial paper program, provide for issuance of letters of credit and also for general corporate purposes. Our revolving credit facility has a program limit of $1.85 billion and is comprised of a syndicate of banks led by Barclays. On February 20, 2019, we extended the termination date of our revolving credit facility to February 20, 2024. At December 31, 2019 and 2018, we had no outstanding borrowings under this facility.

Our commercial paper program has a program limit of up to $1.5 billion with a dealer group comprised of Barclays, Citigroup, Credit Suisse and Wells Fargo. We had $570.0 million and $978.0 million of commercial paper outstanding as of December 31, 2019 and 2018, respectively.

Transfers of accounts receivable are accounted for as secured borrowings resulting in the recognition of short-term borrowings on the Consolidated Balance Sheets. We had $353.2 million and $399.2 million in transfers as of December 31, 2019 and 2018, respectively. Refer to Note 18, "Transfers of Financial Assets," for additional information.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

On April 17, 2019, we amended our existing term loan agreement with a syndicate of banks, with MUFG Bank Ltd. as the Administrative Agent, Sole Lead Arranger and Sole Bookrunner. The amendment increased the amount of our term loan from $600.0 million to $850.0 million and extended the maturity date to April 16, 2020. Interest charged on borrowings depends on the variable rate structure we elect at the time of each borrowing. The available variable rate structures from which we may choose are defined in the term loan agreement. Under the agreement, we borrowed $850.0 million on April 17, 2019 with an interest rate of LIBOR plus 60 basis points.

Short-term borrowings were as follows:

At December 31, *(in millions)*		**2019**		2018
Commercial Paper weighted-average interest rate of 2.03% and 2.96% at December 31, 2019 and 2018, respectively	**$**	**570.0**	$	978.0
Accounts receivable securitization facility borrowings		**353.2**		399.2
Term loan weighted-average interest rate of 2.40% and 3.07% at December 31, 2019 and 2018, respectively		**850.0**	$	600.0
Total Short-Term Borrowings	**$**	**1,773.2**	$	1,977.2

Other than for the term loan and certain commercial paper borrowings, cash flows related to the borrowings and repayments of the items listed above are presented net in the Statements of Consolidated Cash Flows as their maturities are less than 90 days.

16. Leases

ASC 842 Adoption. In February 2016, the FASB issued ASU 2016-02, Leases (ASC 842). ASU 2016-02 introduces a lessee model that brings most leases onto the balance sheet. The standard requires that lessees recognize the following for all leases (with the exception of short-term leases, as that term is defined in the standard) at the lease commencement date: (1) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. In 2018, the FASB issued ASU 2018-01, Leases (ASC 842): Land Easement Practical Expedient for Transition to ASC 842, which allows us to not evaluate existing land easements under ASC 842, and ASU 2018-11, Leases (ASC 842): Targeted Improvements, which allows calendar year entities to initially apply ASC 842 prospectively from January 1, 2019.

We adopted the provisions of ASC 842 beginning on January 1, 2019, using the transition method provided in ASU 2018-11, which was applied to all existing leases at that date. As such, results for reporting periods beginning after January 1, 2019 will be presented under ASC 842, while prior period amounts will continue to be reported in accordance with ASC 840. We elected a number of practical expedients, including the "practical expedient package" described in ASC 842-10-65-1 and the provisions of ASU 2018-01, which allows us to not evaluate existing land easements under ASC 842. Further, ASC 842 provides lessees the option of electing an accounting policy, by class of underlying asset, in which the lessee may choose not to separate nonlease components from lease components. We elected this practical expedient for our leases of fleet vehicles, IT assets and railcars. We elected to use a practical expedient that allows the use of hindsight in determining lease terms when evaluating leases that existed at the implementation date. We also elected the short-term lease recognition exemption, allowing us to not recognize ROU assets or lease liabilities for all leases that qualify.

Adoption of the new standard resulted in the recording of additional lease liabilities and corresponding ROU assets of $57.0 million on our Consolidated Balance Sheets as of January 1, 2019. The standard had no material impact on our Statements of Consolidated Income (Loss) or our Statements of Consolidated Cash Flows.

Lease Descriptions. We are the lessee for substantially all of our leasing activity, which includes operating and finance leases for corporate and field offices, railcars, fleet vehicles and certain IT assets. Our corporate and field office leases have remaining lease terms between 1 and 24 years with options to renew the leases for up to 25 years. We lease railcars to transport coal to and from our electric generation facilities in Indiana. Our railcars are specifically identified in the lease agreements and have lease terms between 1 and 3 years with options to renew for 1 year. Our fleet vehicles include trucks, trailers and equipment that have been customized specifically for use in the utility industry. We lease fleet vehicles on 1 year terms, after which we have the option to extend on a month-to-month basis or terminate with written notice. ROU assets and liabilities on our Consolidated Balance Sheets do not include obligations for possible fleet vehicle lease renewals beyond the initial lease term. While we have the ability to renew these leases beyond the initial term, we are not reasonably certain (as that term is defined in ASC 842) to do so. We lease the majority of our IT assets under 4 year lease terms. Ownership of leased IT assets is transferred to us at the end of the lease term.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

We have not provided material residual value guarantees for our leases, nor do our leases contain material restrictions or covenants. Lease contracts containing renewal and termination options are mostly exercisable at our sole discretion. Certain of our real estate and railcar leases include renewal periods in the measurement of the lease obligation if we have deemed the renewals reasonably certain to be exercised.

With respect to service contracts involving the use of assets, if we have the right to direct the use of the asset and obtain substantially all economic benefits from the use of an asset, we account for the service contract as a lease. Unless specifically provided to us by the lessor, we utilize NiSource's collateralized incremental borrowing rate commensurate to the lease term as the discount rate for all of our leases.

Lease costs for the year ended December 31, 2019 are presented in the table below. These costs include both amounts recognized in expense and amounts capitalized as part of the cost of another asset. Income statement presentation for these costs (when ultimately recognized on the income statement) is also included:

Year Ended December 31, *(in millions)*	Income Statement Classification		**2019**
Finance lease cost			
Amortization of right-of-use assets	Depreciation and amortization	**$**	**15.5**
Interest on lease liabilities	Interest expense, net		**11.3**
Total finance lease cost			**26.8**
Operating lease cost	Operation and maintenance		**17.9**
Short-term lease cost	Operation and maintenance		**1.0**
Total lease cost		**$**	**45.7**

Our right-of-use assets and liabilities are presented in the following lines on the Consolidated Balance Sheets:

(in millions)	Balance Sheet Classification		**December 31, 2019**
Assets			
Finance leases	Net Property, Plant and Equipment	**$**	**179.5**
Operating leases	Deferred charges and other		**64.2**
Total leased assets			**243.7**
Liabilities			
Current			
Finance leases	Current portion of long-term debt		**13.4**
Operating leases	Other accruals		**13.2**
Noncurrent			
Finance leases	Long-term debt, excluding amounts due within one year		**188.1**
Operating leases	Other noncurrent liabilities		**51.6**
Total lease liabilities		**$**	**266.3**

Other pertinent information related to leases was as follows:

Year Ended December 31, *(in millions)*		2019
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows used for finance leases	**$**	**11.3**
Operating cash flows used for operating leases		**17.9**
Financing cash flows used for finance leases		**10.6**
Right-of-use assets obtained in exchange for lease obligations		
Finance leases		**26.4**
Operating leases	**$**	**13.4**

	December 31, 2019
Weighted-average remaining lease term (years)	
Finance leases	**14.8**
Operating leases	**9.2**
Weighted-average discount rate	
Finance leases	**5.9%**
Operating leases	**4.3%**

Maturities of our lease liabilities presented on a rolling 12-month basis were as follows:

As of December 31, 2019, *(in millions)*	Total	Finance Leases	Operating Leases
Year 1	$ 42.8	$ 27.2	$ 15.6
Year 2	36.7	27.3	9.4
Year 3	35.0	26.8	8.2
Year 4	30.7	23.1	7.6
Year 5	26.5	19.9	6.6
Thereafter	233.3	201.6	31.7
Total lease payments[(1)]	405.0	325.9	79.1
Less: Imputed interest	(116.6)	(102.3)	(14.3)
Less: Leases not yet commenced	(22.1)	(22.1)	—
Total	266.3	201.5	64.8
Reported as of December 31, 2019			
Short-term lease liabilities	26.6	13.4	13.2
Long-term lease liabilities	239.7	188.1	51.6
Total lease liabilities	$ 266.3	$ 201.5	$ 64.8

[(1)] Expected payments include obligations for leases not yet commenced of approximately $22.1 million for IT assets and interconnection facilities. These leases have terms between 4 years and 20 years, with estimated commencements in the first quarter of 2020 and in the third quarter of 2020.

Disclosures Related to Periods Prior to Adoption of ASC 842. We lease assets in several areas of our operations including fleet vehicles and equipment, rail cars for coal delivery and certain operations centers. Payments made in connection with operating leases were $49.1 million in 2018 and $49.5 million in 2017, and are primarily charged to operation and maintenance expense as incurred.

As of December 31, 2018, total contractual obligations for capital and operating leases were as follows:

As of December 31, 2018, *(in millions)*	Total	Capital Leases[(1)]	Operating Leases[(2)]
2019	$ 34.0	$ 23.0	$ 11.0
2020	29.8	22.5	7.3
2021	28.7	22.6	6.1
2022	26.3	22.1	4.2
2023	22.6	19.8	2.8
Thereafter	226.9	212.4	14.5
Total lease payments	$ 368.3	$ 322.4	$ 45.9

[(1)]Capital lease payments shown above are inclusive of interest totaling $114.6 million.

[(2)]Operating lease balances do not include obligations for possible fleet vehicle lease renewals beyond the initial lease term. While we have the ability to renew these leases beyond the initial term, we are not reasonably certain to do so. Expected payments are $26.7 million in 2019, $22.4 million in 2020, $16.6 million in 2021, $12.3 million in 2022, $9.3 million in 2023 and $8.8 million thereafter.

17. Fair Value

A. Fair Value Measurements

Recurring Fair Value Measurements. The following tables present financial assets and liabilities measured and recorded at fair value on our Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2019 and December 31, 2018:

Recurring Fair Value Measurements December 31, 2019 (*in millions*)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2019
Assets				
Risk management assets	$ —	$ 4.4	$ —	$ 4.4
Available-for-sale securities	—	154.2	—	154.2
Total	**$ —**	**$ 158.6**	**$ —**	**$ 158.6**
Liabilities				
Risk management liabilities	$ —	$ 146.6	$ —	$ 146.6
Total	**$ —**	**$ 146.6**	**$ —**	**$ 146.6**

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Recurring Fair Value Measurements December 31, 2018 (*in millions*)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2018
Assets				
Risk management assets	$ —	$ 24.0	$ —	$ 24.0
Available-for-sale securities	—	138.3	—	138.3
Total	**$ —**	**$ 162.3**	**$ —**	**$ 162.3**
Liabilities				
Risk management liabilities	$ —	$ 51.7	$ —	$ 51.7
Total	**$ —**	**$ 51.7**	**$ —**	**$ 51.7**

Risk management assets and liabilities include interest rate swaps, exchange-traded NYMEX futures and NYMEX options and non-exchange-based forward purchase contracts. When utilized, exchange-traded derivative contracts are based on unadjusted quoted prices in active markets and are classified within Level 1. These financial assets and liabilities are secured with cash on deposit with the exchange; therefore, nonperformance risk has not been incorporated into these valuations. Certain non-exchange-traded derivatives are valued using broker or over-the-counter, on-line exchanges. In such cases, these non-exchange-traded derivatives are classified within Level 2. Non-exchange-based derivative instruments include swaps, forwards, and options. In certain instances, these instruments may utilize models to measure fair value. We use a similar model to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability and market-corroborated inputs, (i.e., inputs derived principally from or corroborated by observable market data by correlation or other means). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized within Level 2. Certain derivatives trade in less active markets with a lower availability of pricing information and models may be utilized in the valuation. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized within Level 3. Credit risk is considered in the fair value calculation of derivative instruments that are not exchange-traded. Credit exposures are adjusted to reflect collateral agreements which reduce exposures. As of December 31, 2019 and 2018, there were no material transfers between fair value hierarchies. Additionally, there were no changes in the method or significant assumptions used to estimate the fair value of our financial instruments.

We have entered into forward-starting interest rate swaps to hedge the interest rate risk on coupon payments of forecasted issuances of long-term debt. These derivatives are designated as cash flow hedges. Credit risk is considered in the fair value calculation of each agreement. As they are based on observable data and valuations of similar instruments, the hedges are categorized within Level 2 of the fair value hierarchy. There was no exchange of premium at the initial date of the swaps and we can settle the contracts at any time. For additional information, see Note 9, "Risk Management Activities."

NIPSCO has entered into long-term forward natural gas purchase instruments that range from five to ten years to lock in a fixed price for its natural gas customers. We value these contracts using a pricing model that incorporates market-based information when available, as these instruments trade less frequently and are classified within Level 2 of the fair value hierarchy. For additional information see Note 9, “Risk Management Activities.”

Available-for-sale securities are investments pledged as collateral for trust accounts related to our wholly-owned insurance company. Available-for-sale securities are included within “Other investments” in the Consolidated Balance Sheets. We value U.S. Treasury, corporate debt and mortgage-backed securities using a matrix pricing model that incorporates market-based information. These securities trade less frequently and are classified within Level 2. Total unrealized gains and losses from available-for-sale securities are included in other comprehensive income. The amortized cost, gross unrealized gains and losses and fair value of available-for-sale securities at December 31, 2019 and 2018 were:

December 31, 2019 *(in millions)*	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
Available-for-sale securities				
U.S. Treasury debt securities	$ 31.4	$ 0.1	$ (0.1)	$ 31.4
Corporate/Other debt securities	118.7	4.2	(0.1)	122.8
Total	**$ 150.1**	**$ 4.3**	**$ (0.2)**	**$ 154.2**

December 31, 2018 *(in millions)*	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
Available-for-sale securities				
U.S. Treasury debt securities	$ 23.6	$ 0.1	$ (0.1)	$ 23.6
Corporate/Other debt securities	117.7	0.4	(3.4)	114.7
Total	**$ 141.3**	**$ 0.5**	**$ (3.5)**	**$ 138.3**

Realized gains and losses on available-for-sale securities were immaterial for the year-ended December 31, 2019 and 2018.

The cost of maturities sold is based upon specific identification. At December 31, 2019, approximately $7.7 million of U.S. Treasury debt securities and approximately $6.0 million of Corporate/Other debt securities have maturities of less than a year.

There are no material items in the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis for the years ended December 31, 2019 and 2018.

Non-recurring Fair Value Measurements. We measure the fair value of certain assets on a non-recurring basis, typically annually or when events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. These assets include goodwill and other intangible assets.

At December 31, 2019, we recorded an impairment charge of $204.8 million for goodwill and an impairment charge of $209.7 million for franchise rights, in each case related to Columbia of Massachusetts. For additional information, see Note 6, “Goodwill and Other Intangible Assets.”

B. Other Fair Value Disclosures for Financial Instruments. The carrying amount of cash and cash equivalents, restricted cash, notes receivable, customer deposits and short-term borrowings is a reasonable estimate of fair value due to their liquid or short-term nature. Our long-term borrowings are recorded at historical amounts.

The following method and assumptions were used to estimate the fair value of each class of financial instruments.

Long-term debt. The fair value of outstanding long-term debt is estimated based on the quoted market prices for the same or similar securities. Certain premium costs associated with the early settlement of long-term debt are not taken into consideration in determining fair value. These fair value measurements are classified within Level 2 of the fair value hierarchy. For the years ended December 31, 2019 and 2018, there was no change in the method or significant assumptions used to estimate the fair value of long-term debt.

The carrying amount and estimated fair values of these financial instruments were as follows:

At December 31, *(in millions)*	**Carrying Amount 2019**	**Estimated Fair Value 2019**	Carrying Amount 2018	Estimated Fair Value 2018
Long-term debt (including current portion)	**$ 7,869.6**	**$ 8,764.4**	$ 7,155.4	$ 7,228.3

18. Transfers of Financial Assets

Columbia of Ohio, NIPSCO and Columbia of Pennsylvania each maintain a receivables agreement whereby they transfer their customer accounts receivables to third party financial institutions through wholly-owned and consolidated special purpose entities. The three agreements expire between May 2020 and October 2020 and may be further extended if mutually agreed to by the parties thereto.

All receivables transferred to third parties are valued at face value, which approximates fair value due to their short-term nature. The amount of the undivided percentage ownership interest in the accounts receivables transferred is determined in part by required loss reserves under the agreements.

Transfers of accounts receivable are accounted for as secured borrowings resulting in the recognition of short-term borrowings on the Consolidated Balance Sheets. As of December 31, 2019, the maximum amount of debt that could be recognized related to our accounts receivable programs is $465.0 million.

The following table reflects the gross receivables balance and net receivables transferred as well as short-term borrowings related to the securitization transactions as of December 31, 2019 and 2018:

At December 31, *(in millions)*	**2019**	2018
Gross receivables	**$ 569.1**	$ 694.4
Less: receivables not transferred	**215.9**	295.2
Net receivables transferred	**$ 353.2**	$ 399.2
Short-term debt due to asset securitization	**$ 353.2**	$ 399.2

During 2019, $46.0 million was recorded as cash flows used for financing activities related to the change in short-term borrowings due to securitization transactions. During 2018, $62.5 million was recorded as cash flows from financing activities related to the change in short-term borrowings due to securitization transactions. Fees associated with the securitization transactions were $2.6 million, $2.6 million and $2.5 million for the years ended December 31, 2019, 2018 and 2017, respectively. Columbia of Ohio, NIPSCO and Columbia of Pennsylvania remain responsible for collecting on the receivables securitized, and the receivables cannot be transferred to another party.

19. Other Commitments and Contingencies

A. Contractual Obligations. We have certain contractual obligations requiring payments at specified periods. The obligations include long-term debt, lease obligations, energy commodity contracts and obligations for various services including pipeline capacity and outsourcing of IT services. The total contractual obligations in existence at December 31, 2019 and their maturities were:

(in millions)	Total	2020	2021	2022	2023	2024	After
Long-term debt [1]	$ 7,738.6	$ —	$ 63.6	$ 530.0	$ 600.0	$ —	$ 6,545.0
Interest payments on long-term debt	6,214.2	342.0	340.7	337.1	311.1	299.9	4,583.4
Finance leases[2]	325.9	27.2	27.3	26.8	23.1	19.9	201.6
Operating leases[3]	79.1	15.6	9.4	8.2	7.6	6.6	31.7
Energy commodity contracts[4]	95.9	65.5	30.4	—	—	—	—
Service obligations:							
Pipeline service obligations	3,450.7	605.0	590.1	546.8	357.2	237.5	1,114.1
IT service obligations	153.2	63.6	49.4	38.0	1.1	1.1	—
Other service obligations[5]	59.8	45.8	14.0	—	—	—	—
Other liabilities	27.3	27.3	—	—	—	—	—
Total contractual obligations	$ 18,144.7	$ 1,192.0	$ 1,124.9	$ 1,486.9	$ 1,300.1	$ 565.0	$ 12,475.8

[1] Long-term debt balance excludes unamortized issuance costs and discounts of $70.5 million.
[2] Finance lease payments shown above are inclusive of interest totaling $108.3 million.
[3] Operating lease payments shown above are inclusive of interest totaling $14.3 million. Operating lease balances do not include obligations for possible fleet vehicle lease renewals beyond the initial lease term. While we have the ability to renew these leases beyond the initial term, we are not reasonably certain (as that term is defined in ASC 842) to do so. If we were to continue the fleet vehicle leases outstanding at December 31, 2019, payments would be $34.5 million in 2020, $28.3 million in 2021, $23.4 million in 2022, $19.9 million in 2023, $15.2 million in 2024 and $15.2 million thereafter.
[4]In January 2020, NIPSCO signed new coal contract commitments of $14.4 million for 2020. These contracts are not included above.
[5]In February 2020, NIPSCO signed a new railcar coal transportation contract commitment of $12.0 million for 2020. This contract is not included above.

Operating and Finance Lease Commitments. We lease assets in several areas of our operations including corporate and field offices, railcars, fleet vehicles and certain IT assets. Payments made in connection with operating and month-to-month leases were $52.5 million in 2019, $49.1 million in 2018 and $49.5 million in 2017, and are primarily charged to operation and maintenance expense as incurred. See Note 16, "Leases" for additional details.

Purchase and Service Obligations. We have entered into various purchase and service agreements whereby we are contractually obligated to make certain minimum payments in future periods. Our purchase obligations are for the purchase of physical quantities of natural gas, electricity and coal. Our service agreements encompass a broad range of business support and maintenance functions which are generally described below.

Our subsidiaries have entered into various energy commodity contracts to purchase physical quantities of natural gas, electricity and coal. These amounts represent minimum quantities of these commodities we are obligated to purchase at both fixed and variable prices. To the extent contractual purchase prices are variable, obligations disclosed in the table above are valued at market prices as of December 31, 2019.

In July 2008, the IURC issued an order approving NIPSCO's purchase power agreements with subsidiaries of Iberdrola Renewables, Buffalo Ridge I LLC and Barton Windpower LLC. These agreements provide NIPSCO the opportunity and obligation to purchase up to 100 MW of wind power generated commencing in early 2009. The contracts extend 15 and 20 years, representing 50 MW of wind power each. No minimum quantities are specified within these agreements due to the variability of electricity generation from wind, so no amounts related to these contracts are included in the table above. Upon any termination of the agreements by NIPSCO for any reason (other than material breach by Buffalo Ridge I LLC or Barton Windpower LLC), NIPSCO may be required to pay a termination charge that could be material depending on the events giving rise to termination and the timing of the termination. NIPSCO began purchasing wind power in April 2009.

We have pipeline service agreements that provide for pipeline capacity, transportation and storage services. These agreements, which have expiration dates ranging from 2020 to 2045, require us to pay fixed monthly charges.

NIPSCO has contracts with three major rail operators providing for coal transportation services for which there are certain minimum payments. These service contracts extend for various periods through 2021.

We have executed agreements with multiple IT service providers. The agreements extend for various periods through 2024.

B. Guarantees and Indemnities. We and certain subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries as part of normal business. Such agreements include guarantees and stand-by letters of credit. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. At December 31, 2019 and 2018, we had issued stand-by letters of credit of $10.2 million for the benefit of third parties.

C. Legal Proceedings.

On September 13, 2018, a series of fires and explosions occurred in Lawrence, Andover and North Andover, Massachusetts related to the delivery of natural gas by Columbia of Massachusetts (the "Greater Lawrence Incident"). The Greater Lawrence Incident resulted in one fatality and a number of injuries, damaged multiple homes and businesses, and caused the temporary evacuation of significant portions of each municipality. The Massachusetts Governor's Office declared a state of emergency, authorizing the Massachusetts DPU to order another utility company to coordinate the restoration of utility services in Lawrence, Andover and North Andover. The incident resulted in the interruption of gas for approximately 7,500 gas meters, the majority of which served residences and approximately 700 of which served businesses, and the interruption of other utility service more broadly in the area. Columbia of Massachusetts has replaced the cast iron and bare steel gas pipeline system in the affected area and restored service to nearly all of the gas meters. See " - E. Other Matters - Greater Lawrence Pipeline Replacement" below for more information.

We are subject to inquiries and investigations by government authorities and regulatory agencies regarding the Greater Lawrence Incident, including the Massachusetts DPU and the Massachusetts Attorney General's Office, as described below. We are cooperating with all inquiries and investigations. In addition, on February 26, 2020, the Company and Columbia of Massachusetts entered into agreements with the U.S. Attorney's Office to resolve the U.S. Attorney's Office's investigation relating to the Greater Lawrence Incident, as described below.

NTSB Investigation. As previously disclosed, the NTSB concluded its investigation into the Greater Lawrence Incident, and we are implementing the one remaining safety recommendation resulting from the investigation.

Massachusetts Investigations. Under Massachusetts law, the DPU is authorized to investigate potential violations of pipeline safety regulations and to assess a civil penalty of up to $218,647 for a violation of federal pipeline safety regulations. A separate violation occurs for each day of violation up to $2.2 million for a related series of violations. The Massachusetts DPU also is authorized to investigate potential violations of the Columbia of Massachusetts emergency response plan and to assess penalties of up to $250,000 per violation per day, or up to $20 million per related series of violations. Further, as a result of the declaration of emergency by the Governor, the DPU is authorized to investigate potential violations of the DPU's operational directives during the restoration efforts and assess penalties of up to $1 million per violation. Pursuant to these authorities, the DPU is investigating Columbia of Massachusetts as described below. Columbia of Massachusetts will likely be subject to potential compliance actions related to the Greater Lawrence Incident and the restoration work following the incident, the timing and outcomes of which are uncertain at this time.

After the Greater Lawrence Incident, the Massachusetts DPU retained an independent evaluator to conduct a statewide examination of the safety of the natural gas distribution system and the operational and maintenance functions of natural gas companies in the Commonwealth of Massachusetts. Through authority granted by the Massachusetts Governor under the state of emergency, the Chair of the Massachusetts DPU has directed all natural gas distribution companies operating in the Commonwealth to fund the statewide examination. The statewide examination is complete. The Phase I report, which was issued in May 2019, included a program level assessment and evaluation of natural gas distribution companies. The Phase I report's conclusions were statewide and contained no specific conclusions about Columbia of Massachusetts. Phase II, which was focused on field assessments of each Massachusetts gas company, concluded in December 2019. The Phase II report made several observations about and recommendations to Massachusetts gas companies, including Columbia of Massachusetts, with regard to safety culture and assets. The final report was issued in late January 2020, and the DPU directed each natural gas distribution company operating in Massachusetts to submit a plan in response to the report no later than February 28, 2020.

On September 11, 2019, the Massachusetts DPU issued an order directing Columbia of Massachusetts to take several specific actions to address concerns related to service lines abandoned during the restoration work following the Greater Lawrence Incident and to furnish certain information and periodic reports to the DPU.

On October 1, 2019, the Massachusetts DPU issued four orders to Columbia of Massachusetts in connection with the service lines abandoned during the Greater Lawrence Incident restoration, which require: (1) the submission of a detailed work plan to the DPU, (2) the completion of quality control work on certain abandoned services, (3) the payment for a third-party independent audit, to be contracted through the DPU, of all gas pipeline work completed as part of the incident restoration effort, and (4) prompt and full response to any requests for information by the third-party auditor. The Massachusetts DPU retained an independent evaluator to conduct this audit, and that third party is currently evaluating compliance with Massachusetts and federal law, as well as any other operational or safety risks that may be posed by the pipeline work. The audit scope also includes Columbia of Massachusetts' operations in the Lawrence Division and other service territories as appropriate.

Also in October 2019, the Massachusetts DPU issued three additional orders requiring: (1) daily leak surveillance and reporting in areas where abandoned services are located, (2) completion by November 15, 2019 of the work plan previously submitted describing how Columbia of Massachusetts would address the estimated 2,200 locations at which an inside meter set was moved outside the property as part of the abandoned service work completed during the Greater Lawrence Incident restoration, and (3) submission of a report by December 2, 2019 showing any patterns, trends or correlations among the non-compliant work related to the abandonment of service lines, gate boxes and curb boxes during the incident restoration.

On October 3, 2019, the Massachusetts DPU notified Columbia of Massachusetts that, absent DPU approval, it is currently allowed to perform only emergency work on its gas distribution system throughout its service territories in Massachusetts. The restrictions do not apply to Columbia of Massachusetts' work to address the previously identified issues with abandoned service lines and valve boxes in the Greater Lawrence, Massachusetts area. Columbia of Massachusetts is subject to daily monitoring by the DPU on any work that Columbia of Massachusetts conducts in Massachusetts. Such restrictions on work remain in place until modified by the DPU.

On October 25, 2019, the Massachusetts DPU issued two orders opening public investigations into Columbia of Massachusetts with respect to the Greater Lawrence Incident. The Massachusetts DPU opened the first investigation under its authority to determine compliance with federal and state pipeline safety laws and regulations, and to investigate Columbia of Massachusetts' responsibility for and response to the Greater Lawrence Incident and its restoration efforts following the incident. The Massachusetts DPU opened the second investigation under its authority to determine whether a gas distribution company has violated established standards regarding acceptable performance for emergency preparedness and restoration of service to investigate efforts by Columbia of Massachusetts to prepare for and restore service following the Greater Lawrence Incident. Separate penalties are applicable under each exercise of authority.

On December 23, 2019, the Massachusetts DPU issued an order defining the scope of its investigation into the response of Columbia of Massachusetts related to the Greater Lawrence Incident. The DPU identified three distinct time frames in which Columbia of Massachusetts handled emergency response and restoration directly: (1) September 13-14, 2018, (2) September 21 through December 16, 2018 (the Phase I restoration), and (3) September 27, 2019 through completion of restoration of outages resulting from the gas release event in Lawrence, Massachusetts that occurred on September 27, 2019. The DPU determined that it is appropriate to investigate separately, for each time period described above, the areas of response, recovery and restoration for which Columbia of Massachusetts was responsible. The DPU noted that it also may investigate the continued restoration and related repair work that took place after December 16, 2018 and, depending on the outcome of that investigation, may deem it appropriate to consider that period of restoration as an additional separate time period.

The DPU also noted that its investigation into all of the above described time periods is ongoing and that if the DPU determines, based on its investigation, that it is appropriate to treat the separate time frames as separate emergency events, it may impose up to the maximum statutory penalty for each event, pursuant to Mass. G.L. c. 164 Section 1J. This provision authorizes the DPU to investigate potential violations of the Columbia of Massachusetts emergency response plan and to assess penalties of up to $250,000 per violation per day, or up to $20 million per related series of violations. The DPU noted that at this preliminary stage of the investigation, it does not have the factual basis to make those determinations.

In connection with its investigation related to the Greater Lawrence Incident, on February 4, 2020, the Massachusetts Attorney General's Office issued a request for documents primarily focused on the restoration work following the incident.

Columbia of Massachusetts is cooperating with the investigations set forth above as well as other inquiries resulting from an increased amount of enforcement activity, for all of which the outcomes are uncertain at this time.

Massachusetts Legislative Matters. On November 12, 2019, the Joint Committee on Telecommunications, Utilities and Energy held a hearing that focused on gas safety, but the Committee has not taken action on any bills. Increased scrutiny related to gas system safety and regulatory oversight in Massachusetts, including additional legislative oversight hearings and new legislative proposals, is expected to continue during the current two-year legislative session that ends in December 2020.

U.S. Department of Justice Investigation. As previously disclosed, the Company and Columbia of Massachusetts are subject to a criminal investigation related to the Greater Lawrence Incident that is being conducted under the supervision of the U.S. Attorney's Office. The initial grand jury subpoenas were served on the Company and Columbia of Massachusetts on September 24, 2018.

On February 26, 2020, the Company and Columbia of Massachusetts entered into agreements with the U.S. Attorney's Office to resolve the U.S. Attorney's Office's investigation relating to the Greater Lawrence Incident. Columbia of Massachusetts agreed to plead guilty in the United States District Court for the District of Massachusetts (the "Court") to violating the Natural Gas Pipeline Safety Act (the "Plea Agreement"), and the Company entered into a DPA.

Under the Plea Agreement, which must be approved by the Court, Columbia of Massachusetts will be subject to the following terms, among others: (i) a criminal fine in the amount of $53,030,116 paid within 30 days of sentencing; (ii) a three year probationary period that will early terminate upon a sale of Columbia of Massachusetts or a sale of its gas distribution business to a qualified third-party buyer consistent with certain requirements; (iii) compliance with each of the NTSB recommendations stemming from the Greater Lawrence Incident; and (iv) employment of an in-house monitor during the term of the probationary period.

Under the DPA, the U.S. Attorney's Office agreed to defer prosecution of the Company in connection with the Greater Lawrence Incident for a three-year period (which three-year period may be extended for twelve (12) months upon the U.S. Attorney's Office's determination of a breach of the DPA) subject to certain obligations of the Company, including, but not limited to, the following: (i) the Company will use reasonable best efforts to sell Columbia of Massachusetts or Columbia of Massachusetts' gas distribution business to a qualified third-party buyer consistent with certain requirements, and, upon the completion of any such sale, the Company will cease and desist any and all gas pipeline and distribution activities in the District of Massachusetts; (ii) the Company will forfeit and pay, within 30 days of the later of the sale becoming final or the date on which post-closing adjustments to the purchase price are finally determined in accordance with the agreement to sell Columbia Gas of Massachusetts or its gas distribution business, a fine equal to the total amount of any profit or gain from any sale of Columbia of Massachusetts or its gas distribution business, with the amount of profit or gain determined as provided in the DPA; and (iii) the Company agrees as to each of the Company's subsidiaries involved in the distribution of gas through pipeline facilities in Massachusetts, Indiana, Ohio, Pennsylvania, Maryland, Kentucky and Virginia to implement and adhere to each of the recommendations from the NTSB stemming from the Greater Lawrence Incident. Pursuant to the DPA, if the Company complies with all of its obligations under the DPA, including, but not limited to those identified above, the U.S. Attorney's Office will not file any criminal charges against the Company related to the Greater Lawrence Incident. If Columbia of Massachusetts' guilty plea is not accepted by the Court or is withdrawn for any reason, or if Columbia of Massachusetts should fail to perform an obligation under the Plea Agreement prior to the sale of Columbia of Massachusetts or its gas distribution business, the U.S. Attorney's Office may, at its sole option, render the DPA null and void.

U.S. Congressional Activity. On September 30, 2019, the U.S. Pipeline Safety Act expired. There is no effect on PHMSA's authority. Action on past re-authorization bills has extended past the expiration date and action on this re-authorization is expected to continue well into 2020. Pipeline safety jurisdiction resides with the U.S. Senate Commerce Committee, and is divided between two committees in the U.S. House of Representatives (Energy and Commerce, and Transportation and Infrastructure). Legislative proposals are currently in various stages of committee development and the timing of further action is uncertain. Certain legislative proposals, if enacted into law, may increase costs for natural gas industry companies, including the Company and Columbia of Massachusetts.

SEC Investigation. On November 27, 2019, the SEC staff notified the Company that it concluded its investigation related to disclosures made by the Company prior to the Greater Lawrence Incident and, based on the information provided as of such date, it does not intend to recommend an enforcement action against the Company.

Private Actions. Various lawsuits, including several purported class action lawsuits, have been filed by various affected residents or businesses in Massachusetts state courts against the Company and/or Columbia of Massachusetts in connection with the Greater Lawrence Incident. A special judge has been appointed to hear all pending and future cases and the class actions have been consolidated into one class action. On January 14, 2019, the special judge granted the parties' joint motion to stay all cases until

April 30, 2019 to allow mediation, and the parties subsequently agreed to extend the stay until July 25, 2019. The class action lawsuits allege varying causes of action, including those for strict liability for ultra-hazardous activity, negligence, private nuisance, public nuisance, premises liability, trespass, breach of warranty, breach of contract, failure to warn, unjust enrichment, consumer protection act claims, negligent, reckless and intentional infliction of emotional distress and gross negligence, and seek actual compensatory damages, plus treble damages, and punitive damages.

On July 26, 2019, the Company, Columbia of Massachusetts and NiSource Corporate Services Company, a subsidiary of the Company, entered into a term sheet with the class action plaintiffs under which they agreed to settle the class action claims in connection with the Greater Lawrence Incident. Columbia of Massachusetts agreed to pay $143 million into a settlement fund to compensate the settlement class and the settlement class agreed to release Columbia of Massachusetts and affiliates from all claims arising out of or related to the Greater Lawrence Incident. The following claims are not covered under the proposed settlement because they are not part of the consolidated class action: (1) physical bodily injury and wrongful death; (2) insurance subrogation, whether equitable, contractual or otherwise; and (3) claims arising out of appliances that are subject to the Massachusetts DPU orders. Emotional distress and similar claims are covered under the proposed settlement unless they are secondary to a physical bodily injury. The settlement class is defined under the term sheet as all persons and businesses in the three municipalities of Lawrence, Andover and North Andover, Massachusetts, subject to certain limited exceptions. The motion for preliminary approval and the settlement documents were filed on September 25, 2019. The preliminary approval court hearing was held on October 7, 2019 and the court issued an order granting preliminary approval of the settlement on October 11, 2019. The proposed settlement is subject to final court approval, and a hearing occurred on February 27, 2020. The court took the matter under advisement.

Many residents and business owners have submitted individual damage claims to Columbia of Massachusetts. Most of the wrongful death and bodily injury claims that have been asserted have been settled, and we continue to discuss potential settlements with plaintiffs asserting such claims. In addition, the Commonwealth of Massachusetts is seeking reimbursement from Columbia of Massachusetts for its expenses incurred in connection with the Greater Lawrence Incident. The outcomes and impacts of such private actions are uncertain at this time.

Financial Impact. Since the Greater Lawrence Incident, we have recorded expenses of approximately $1,041 million for third-party claims and fines, penalties and settlements associated with government investigations. We estimate that total costs related to third-party claims and fines, penalties and settlements associated with government investigations resulting from the incident will range from $1,041 million to $1,065 million, depending on the number, nature, final outcome and value of third-party claims and the final outcome of government investigations. With regard to third-party claims, these costs include, but are not limited to, personal injury and property damage claims, damage to infrastructure, business interruption claims, and mutual aid payments to other utilities assisting with the restoration effort. These costs do not include costs of certain third-party claims and fines, penalties or settlements associated with government investigations that we are not able to estimate, nor do they include non-claims related and government investigation-related legal expenses resulting from the incident and the capital cost of the pipeline replacement, which are set forth in " - E. Other Matters - Greater Lawrence Incident Restoration" and "- Greater Lawrence Incident Pipeline Replacement," respectively, below.

The process for estimating costs associated with third-party claims and fines, penalties, and settlements associated with government investigations relating to the Greater Lawrence Incident requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including additional information regarding ongoing investigations, management’s estimates and assumptions regarding the financial impact of the Greater Lawrence Incident may change.

The aggregate amount of third-party liability insurance coverage available for losses arising from the Greater Lawrence Incident is $800 million. We have collected the entire $800 million as of December 31, 2019. Total expenses related to the incident have exceeded the total amount of insurance coverage available under our policies. Refer to "- E. Other Matters - Greater Lawrence Incident Restoration," below for a summary of third-party claims-related expense activity and associated insurance recoveries recorded since the Greater Lawrence Incident.

We are also party to certain other claims, regulatory and legal proceedings arising in the ordinary course of business in each state in which we have operations, none of which is deemed to be individually material at this time.

Due to the inherent uncertainty of litigation, there can be no assurance that the resolution of any particular claim, proceeding or investigation related to the Greater Lawrence Incident or otherwise would not have a material adverse effect on our results of operations, financial position or liquidity. Certain matters in connection with the Greater Lawrence Incident have had or may have a material impact as described above. If one or more of such additional or other matters were decided against us, the effects could be material to our results of operations in the period in which we would be required to record or adjust the related liability and could also be material to our cash flows in the periods that we would be required to pay such liability.

D. Environmental Matters. Our operations are subject to environmental statutes and regulations related to air quality, water quality, hazardous waste and solid waste. We believe that we are in substantial compliance with the environmental regulations currently applicable to our operations.

It is management's continued intent to address environmental issues in cooperation with regulatory authorities in such a manner as to achieve mutually acceptable compliance plans. However, there can be no assurance that fines and penalties will not be incurred. Management expects a significant portion of environmental assessment, improvement and remediation costs to be recoverable through rates for certain of our companies.

As of December 31, 2019 and 2018, we had recorded a liability of $104.4 million and $101.2 million, respectively, to cover environmental remediation at various sites. The current portion of this liability is included in "Legal and environmental" in the Consolidated Balance Sheets. The noncurrent portion is included in "Other noncurrent liabilities." We recognize costs associated with environmental remediation obligations when the incurrence of such costs is probable and the amounts can be reasonably estimated. The original estimates for remediation activities may differ materially from the amount ultimately expended. The actual future expenditures depend on many factors, including currently enacted laws and regulations, the nature and extent of impact and the method of remediation. These expenditures are not currently estimable at some sites. We periodically adjust our liability as information is collected and estimates become more refined.

Electric Operations' compliance estimates disclosed below are reflective of NIPSCO's Integrated Resource Plan submitted to the IURC on October 31, 2018. See section " - E. Other Matters - NIPSCO 2018 Integrated Resource Plan," below for additional information.

Air

Future legislative and regulatory programs could significantly limit allowed GHG emissions or impose a cost or tax on GHG emissions. Additionally, rules that require further GHG reductions or impose additional requirements for natural gas facilities could impose additional costs. NiSource will carefully monitor all GHG reduction proposals and regulations.

ACE Rule. On July 8, 2019, the EPA published the final ACE rule, which establishes emission guidelines for states to use when developing plans to limit carbon dioxide at coal-fired electric generating units based on heat rate improvement measures. The coal-fired units at NIPSCO’s R.M. Schahfer Generating Station and Michigan City Generating Station are potentially affected sources, and compliance requirements for these units which NIPSCO plans to retire by 2023 and 2028, respectively, will be determined by future Indiana rulemaking. The ACE rule notes that states have “broad flexibility in setting standards of performance for designated facilities” and that a state may set a “business as usual” standard for sources that have a remaining useful life “so short that imposing any costs on the electric generating unit is unreasonable.” State plans are due by 2022, and the EPA will have six months to determine completeness and then one additional year to determine whether to approve the submitted plan. States have the discretion to determine the compliance period for each source. As a result, NIPSCO will continue to monitor this matter and cannot estimate its impact at this time.

Waste

CERCLA. Our subsidiaries are potentially responsible parties at waste disposal sites under the CERCLA (commonly known as Superfund) and similar state laws. Under CERCLA, each potentially responsible party can be held jointly, severally and strictly liable for the remediation costs as the EPA, or state, can allow the parties to pay for remedial action or perform remedial action themselves and request reimbursement from the potentially responsible parties. Our affiliates have retained CERCLA environmental liabilities, including remediation liabilities, associated with certain current and former operations. These liabilities are not material to the Consolidated Financial Statements.

MGP. A program has been instituted to identify and investigate former MGP sites where Gas Distribution Operations subsidiaries or predecessors may have liability. The program has identified 63 such sites where liability is probable. Remedial actions at many of these sites are being overseen by state or federal environmental agencies through consent agreements or voluntary remediation agreements.

We utilize a probabilistic model to estimate our future remediation costs related to MGP sites. The model was prepared with the assistance of a third party and incorporates our experience and general industry experience with remediating MGP sites. We complete an annual refresh of the model in the second quarter of each fiscal year. No material changes to the estimated future remediation costs were noted as a result of the refresh completed as of June 30, 2019. Our total estimated liability related to the facilities subject to remediation was $102.2 million and $97.5 million at December 31, 2019 and 2018, respectively. The liability represents our best estimate of the probable cost to remediate the facilities. We believe that it is reasonably possible that remediation costs could vary by as much as $20 million in addition to the costs noted above. Remediation costs are estimated based on the best available information, applicable remediation standards at the balance sheet date, and experience with similar facilities.

CCRs. On April 17, 2015, the EPA issued a final rule for regulation of CCRs. The rule regulates CCRs under the RCRA Subtitle D, which determines them to be nonhazardous. The rule is implemented in phases and requires increased groundwater monitoring, reporting, recordkeeping and posting of related information to the Internet. The rule also establishes requirements related to CCR management and disposal. The rule will allow NIPSCO to continue its byproduct beneficial use program.

To comply with the rule, NIPSCO completed capital expenditures to modify its infrastructure and manage CCRs during 2019. The CCR rule also resulted in revisions to previously recorded legal obligations associated with the retirement of certain NIPSCO facilities. The actual asset retirement costs related to the CCR rule may vary substantially from the estimates used to record the increased asset retirement obligation due to the uncertainty about the requirements that will be established by environmental authorities, compliance strategies that will be used and the preliminary nature of available data used to estimate costs. As allowed by the rule, NIPSCO will continue to collect data over time to determine the specific compliance solutions and associated costs and, as a result, the actual costs may vary. NIPSCO has filed initial CCR closure plans for R.M. Schahfer Generating Station and Michigan City Generating Station with the Indiana Department of Environmental Management.

Water
ELG. On November 3, 2015, the EPA issued a final rule to amend the ELG and standards for the Steam Electric Power Generating category. Based upon a study performed in 2016 of the final rule, capital compliance costs were expected to be approximately $170.0 million. The EPA has proposed revisions to the final rule, and public comments were due on January 21, 2020. NIPSCO does not anticipate material ELG compliance costs based on the preferred option announced as part of NIPSCO's 2018 Integrated Resource Plan (discussed below).

E. Other Matters.

NIPSCO 2018 Integrated Resource Plan. Multiple factors, but primarily economic ones, including low natural gas prices, advancing cost effective renewable technology and increasing capital and operating costs associated with existing coal plants, have led NIPSCO to conclude in its October 2018 Integrated Resource Plan submission that NIPSCO’s current fleet of coal generation facilities will be retired earlier than previous Integrated Resource Plans had indicated.

The Integrated Resource Plan evaluated demand-side and supply-side resource alternatives to reliably and cost effectively meet NIPSCO customers' future energy requirements over the ensuing 20 years. The preferred option within the Integrated Resource Plan retires R.M. Schahfer Generating Station (Units 14, 15, 17, and 18) by 2023 and Michigan City Generating Station (Unit 12) by 2028. These units represent 2,080 MW of generating capacity, equal to 72% of NIPSCO’s remaining generating capacity (and 100% of NIPSCO's remaining coal-fired generating capacity) after the retirement of Bailly Units 7 and 8 on May 31, 2018.

The current replacement plan includes renewable sources of energy, including wind, solar, and battery storage to be obtained through a combination of NIPSCO ownership and PPAs.

In January 2019, NIPSCO executed two 20 year PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per MWh. NIPSCO submitted the PPAs to the IURC for approval in February 2019 and the IURC approved the PPAs on June 5, 2019. Payments under the PPAs will not begin until the associated generation facilities are constructed by the owner / seller which is currently scheduled to be complete by the end of 2020 for one facility. NIPSCO has filed a notice with the IURC of its intention not to move forward with one of its approved PPAs due to the failure to meet a condition precedent in the agreement as a result of local zoning restrictions.

Also in January 2019, NIPSCO executed a BTA with a developer to construct a renewable generation facility with a nameplate capacity of approximately 100 MW. Once complete, ownership of the facility would be transferred to a joint venture owned by NIPSCO, the developer and an unrelated tax equity partner. The aforementioned joint venture is expected to be fully owned by NIPSCO after the PTC are monetized from the project (approximately 10 years after the facility goes into service). NIPSCO's purchase requirement under the BTA is dependent on satisfactory approval of the BTA by the IURC, successful execution of an agreement with a tax equity partner, and timely completion of construction. NIPSCO submitted the BTA to the IURC for approval in February 2019 and the IURC approved the BTA on August 7, 2019. Required FERC filings occurred after receiving the IURC order and the related approvals were received. Construction of the facility is expected to be completed by the end of 2020.

On October 1, 2019, NIPSCO announced the opening of its next round of RFP to consider potential resources to meet the future electric needs of its customers. The RFP closed on November 20, 2019, and NIPSCO continues to evaluate the results. NIPSCO is considering all sources in the RFP process.

In October 2019, NIPSCO executed a BTA with a developer to construct an additional renewable generation facility with a nameplate capacity of approximately 300 MW. Once complete, ownership of the facility would be transferred to a joint venture owned by NIPSCO, the developer and an unrelated tax equity partner. The aforementioned joint venture is expected to be fully owned by NIPSCO after the PTC are monetized from the project (approximately 10 years after the facility goes into service). NIPSCO's purchase requirement under the BTA is dependent on satisfactory approval of the BTA by the IURC, successful execution of an agreement with a tax equity partner, and timely completion of construction. NIPSCO submitted the BTA to the IURC for approval on October 22, 2019, and the IURC approved the BTA on February 19, 2020. Required FERC filings are expected to be filed by the end of June 2020. Construction of the facility is expected to be completed by the end of 2021.

Greater Lawrence Incident Restoration. In addition to the amounts estimated for third-party claims and fines, penalties and settlements associated with government investigations described above, since the Greater Lawrence Incident, we have recorded expenses of approximately $420 million for other incident-related costs. We estimate that total other incident-related costs will range from $450 million to $460 million, depending on the incurrence of costs associated with resolving outstanding inquiries and investigations discuss above in " - C. Legal Proceedings." Such costs include certain consulting costs, legal costs, vendor costs, claims center costs, labor and related expenses incurred in connection with the incident, and insurance-related loss surcharges. The amounts set forth above do not include the capital cost of the pipeline replacement, which is set forth below, or any estimates for fines and penalties, which are discussed above in " - C. Legal Proceedings."

As discussed in "- C. Legal Proceedings," the aggregate amount of third-party liability insurance coverage available for losses arising from the Greater Lawrence Incident is $800 million. We have collected the entire $800 million as of December 31, 2019. Expenses related to the incident have exceeded the total amount of insurance coverage available under our policies.

The following table summarizes expenses incurred and insurance recoveries recorded since the Greater Lawrence Incident. This activity is presented within "Operation and maintenance" and "Other, net" in our Statements of Consolidated Income (Loss).

(in millions)	Year Ended December 31, 2018	**Year Ended December 31, 2019**	Incident to Date
Third-party claims and government fines, penalties and settlements	$ 757	**$ 284**	$ 1,041
Other incident-related costs	266	**154**	420
Total	1,023	**438**	1,461
Insurance recoveries recorded	(135)	**(665)**	(800)
Loss (benefit) to income before income taxes	$ 888	**$ (227)**	$ 661

The following table presents activity related to our Greater Lawrence Incident insurance recovery, which we have recovered in full as of December 31, 2019.

(in millions)		Insurance receivable[(1)]
Balance, December 31, 2018	**$**	**130**
Insurance recoveries recorded in first quarter of 2019		100
Cash collected from insurance recoveries in the first quarter of 2019		(108)
Balance, March 31, 2019		**122**
Insurance recoveries recorded in the second quarter of 2019		435
Cash collected from insurance recoveries in the second quarter of 2019		(297)
Balance, June 30, 2019	**$**	**260**
Insurance recoveries recorded in third quarter of 2019		—
Cash collected from insurance recoveries in the third quarter of 2019		(260)
Balance, September 30, 2019	**$**	**—**
Insurance recoveries recorded in the fourth quarter of 2019		130
Cash collected from insurance recoveries in the fourth quarter of 2019		(130)
Balance, December 31, 2019	**$**	**—**

(1)$5 million of insurance recoveries were collected during 2018.

Greater Lawrence Pipeline Replacement. In connection with the Greater Lawrence Incident, Columbia of Massachusetts, in cooperation with the Massachusetts Governor's office, replaced the entire affected 45-mile cast iron and bare steel pipeline system that delivers gas to approximately 7,500 gas meters, the majority of which serve residences and approximately 700 of which serve businesses impacted in the Greater Lawrence Incident. This system was replaced with plastic distribution mains and service lines, as well as enhanced safety features such as pressure regulation and excess flow valves at each premise.

Since the Greater Lawrence Incident and through December 31, 2019, we have invested approximately $258 million of capital spend for the pipeline replacement; this work was completed in 2019. We maintain property insurance for gas pipelines and other applicable property. Columbia of Massachusetts has filed a proof of loss with its property insurer for the full cost of the pipeline replacement. In January 2020, we filed a lawsuit against the property insurer, seeking payment of our property claim. We are currently unable to predict the timing or amount of any insurance recovery under the property policy. The recovery of any capital investment not reimbursed through insurance will be addressed in a future regulatory proceeding; a future regulatory proceeding is dependent on the outcome of the sale of the Massachusetts Business. The outcome of such a proceeding (if any) is uncertain. In accordance with ASC 980-360, if it becomes probable that a portion of the pipeline replacement cost will not be recoverable through customer rates and an amount can be reasonably estimated, we will reduce our regulated plant balance for the amount of the probable disallowance and record an associated charge to earnings. This could result in a material adverse effect to our financial condition, results of operations and cash flows. Additionally, if a rate order is received allowing recovery of the investment with no or reduced return on investment, a loss on disallowance may be required.

State Income Taxes Related to Greater Lawrence Incident Expenses. As of December 31, 2018, expenses related to the Greater Lawrence Incident were $1,023 million. In the fourth quarter of 2019, we filed an application for Alternative Apportionment with the MA DOR to request an allocable approach to these expenses for purposes of Massachusetts state income taxes, which, if approved, would result in a state deferred tax asset of approximately $50 million, net. The MA DOR is expected to review the application within nine months from the date of filing, and we believe it is reasonably possible that the application will be accepted, or an alternative method proposed.

20. Accumulated Other Comprehensive Loss

The following table displays the activity of Accumulated Other Comprehensive Loss, net of tax:

(in millions)	Gains and Losses on Securities[1]	Gains and Losses on Cash Flow Hedges[1]	Pension and OPEB Items[1]	Accumulated Other Comprehensive Loss[1]
Balance as of January 1, 2017	**$ (0.6)**	**$ (6.9)**	**$ (17.6)**	**$ (25.1)**
Other comprehensive income (loss) before reclassifications	0.6	(24.2)	1.9	(21.7)
Amounts reclassified from accumulated other comprehensive loss	0.2	1.7	1.5	3.4
Net current-period other comprehensive income (loss)	0.8	(22.5)	3.4	(18.3)
Balance as of December 31, 2017	**$ 0.2**	**$ (29.4)**	**$ (14.2)**	**$ (43.4)**
Other comprehensive income (loss) before reclassifications	(3.0)	55.8	(4.4)	48.4
Amounts reclassified from accumulated other comprehensive loss	0.4	(33.1)	—	(32.7)
Net current-period other comprehensive income (loss)	(2.6)	22.7	(4.4)	15.7
Reclassification due to adoption of ASU 2018-02	—	(6.3)	(3.2)	(9.5)
Balance as of December 31, 2018	**$ (2.4)**	**$ (13.0)**	**$ (21.8)**	**$ (37.2)**
Other comprehensive income (loss) before reclassifications	6.1	(64.3)	2.3	(55.9)
Amounts reclassified from accumulated other comprehensive loss	(0.4)	0.1	0.8	0.5
Net current-period other comprehensive income (loss)	5.7	(64.2)	3.1	(55.4)
Balance as of December 31, 2019	**$ 3.3**	**$ (77.2)**	**$ (18.7)**	**$ (92.6)**

[1]All amounts are net of tax. Amounts in parentheses indicate debits.

21. Other, Net

Year Ended December 31, *(in millions)*	**2019**	2018	2017
Interest income	**$ 7.7**	$ 6.6	$ 4.6
AFUDC equity	**8.0**	14.2	12.6
Charitable contributions[1]	**(5.1)**	(45.3)	(19.9)
Pension and other postretirement non-service cost[2]	**(16.5)**	18.0	(10.6)
Interest rate swap settlement gain[3]	**—**	46.2	—
Miscellaneous	**0.7**	3.8	(0.2)
Total Other, net	**$ (5.2)**	$ 43.5	$ (13.5)

[1] 2018 charitable contributions include $20.7 million related to the Greater Lawrence Incident and $20.0 million of discretionary contributions made to the Nisource Charitable Foundation. See Note 19, "Other Commitments and Contingencies" for additional information on the Greater Lawrence Incident.
[2] See Note 11, "Pension and Other Postretirement Benefits" for additional information.
[3] See Note 9, "Risk Management Activities" for additional information.

22. Interest Expense, Net

Year Ended December 31, *(in millions)*	**2019**	2018	2017
Interest on long-term debt	**$ 327.7**	$ 342.2	$ 354.8
Interest on short-term borrowings	**50.8**	31.8	14.9
Debt discount/cost amortization	**8.3**	7.7	7.2
Accounts receivable securitization fees	**2.6**	2.6	2.5
Allowance for borrowed funds used and interest capitalized during construction	**(7.5)**	(9.1)	(6.2)
Debt-based post-in-service carrying charges	**(18.7)**	(35.0)	(36.4)
Other	**15.7**	13.1	16.4
Total Interest Expense, net	**$ 378.9**	$ 353.3	$ 353.2

23. Segments of Business

At December 31, 2019, our operations are divided into two primary reportable segments. The Gas Distribution Operations segment provides natural gas service and transportation for residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, Maryland, Indiana and Massachusetts. The Electric Operations segment provides electric service in 20 counties in the northern part of Indiana.

The following table provides information about our reportable segments. We use operating income as our primary measurement for each of the reported segments and make decisions on finance, dividends and taxes at the corporate level on a consolidated basis. Segment revenues include intersegment sales to affiliated subsidiaries, which are eliminated in consolidation. Affiliated sales are recognized on the basis of prevailing market, regulated prices or at levels provided for under contractual agreements. Operating income is derived from revenues and expenses directly associated with each segment.

Year Ended December 31, *(in millions)*	**2019**	2018	2017
Operating Revenues			
Gas Distribution Operations			
Unaffiliated	**$ 3,509.7**	$ 3,406.4	$ 3,087.9
Intersegment	**13.1**	13.1	14.2
Total	**3,522.8**	3,419.5	3,102.1
Electric Operations			
Unaffiliated	**1,698.4**	1,707.4	1,785.7
Intersegment	**0.8**	0.8	0.8
Total	**1,699.2**	1,708.2	1,786.5
Corporate and Other			
Unaffiliated	**0.8**	0.7	1.0
Intersegment	**468.1**	517.6	510.8
Total	**468.9**	518.3	511.8
Eliminations	**(482.0)**	(531.5)	(525.8)
Consolidated Operating Revenues	**$ 5,208.9**	$ 5,114.5	$ 4,874.6

Year Ended December 31, *(in millions)*		**2019**		2018		2017
Operating Income (Loss)						
Gas Distribution Operations	**$**	**675.4**	$	(254.1)	$	550.1
Electric Operations		**406.8**		386.1		367.4
Corporate and Other[2]		**(191.5)**		(7.3)		3.7
Consolidated Operating Income	**$**	**890.7**	$	124.7	$	921.2
Depreciation and Amortization						
Gas Distribution Operations	**$**	**403.2**	$	301.0	$	269.3
Electric Operations		**277.3**		262.9		277.8
Corporate and Other		**36.9**		35.7		23.2
Consolidated Depreciation and Amortization	**$**	**717.4**	$	599.6	$	570.3
Assets						
Gas Distribution Operations	**$**	**14,224.5**	$	13,527.0	$	12,048.8
Electric Operations		**6,027.6**		5,735.2		5,478.6
Corporate and Other		**2,407.7**		2,541.8		2,434.3
Consolidated Assets	**$**	**22,659.8**	$	21,804.0	$	19,961.7
Capital Expenditures[1]						
Gas Distribution Operations	**$**	**1,380.3**	$	1,315.3	$	1,125.6
Electric Operations		**468.9**		499.3		592.4
Corporate and Other		**18.6**		—		35.8
Consolidated Capital Expenditures	**$**	**1,867.8**	$	1,814.6	$	1,753.8

[1]Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the inclusion of capital expenditures included in current liabilities and AFUDC Equity.
[2] In 2019, Corporate and Other reflects an impairment charge of $204.8 million for goodwill related to Columbia of Massachusetts. For additional information, see Note 6, "Goodwill and Other Intangible Assets."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

24. Quarterly Financial Data (Unaudited)

Quarterly financial data does not always reveal the trend of our business operations due to nonrecurring items and seasonal weather patterns, which affect earnings and related components of revenue and operating income.

(in millions, except per share data)	First Quarter[(1)]	Second Quarter[(2)]	Third Quarter[(3)]	Fourth Quarter[(4)]
2019				
Operating Revenues	$ 1,869.8	$ 1,010.4	$ 931.5	$ 1,397.2
Operating Income (Loss)	374.2	463.5	91.0	(38.0)
Net Income (Loss)	218.9	296.9	6.6	(139.3)
Preferred Dividends	(13.8)	(13.8)	(13.8)	(13.7)
Net Income (Loss) Available to Common Shareholders	205.1	283.1	(7.2)	(153.0)
Earnings (Loss) Per Share				
Basic Earnings (Loss) Per Share	$ 0.55	$ 0.76	$ (0.02)	$ (0.41)
Diluted Earnings (Loss) Per Share	$ 0.55	$ 0.75	$ (0.02)	$ (0.41)
2018				
Operating Revenues	$ 1,750.8	$ 1,007.0	$ 895.0	$ 1,461.7
Operating Income (Loss)	400.6	118.4	(315.9)	(78.4)
Net Income (Loss)	276.1	24.5	(339.5)	(11.7)
Preferred Dividends	—	(1.3)	(5.6)	(8.1)
Net Income (Loss) Available to Common Shareholders	276.1	23.2	(345.1)	(19.8)
Earnings (Loss) Per Share				
Basic Earnings (Loss) Per Share	$ 0.82	$ 0.07	$ (0.95)	$ (0.05)
Diluted Earnings (Loss) Per Share	$ 0.81	$ 0.07	$ (0.95)	$ (0.05)

(1) Net income for the first quarter of 2019 was impacted by $108.0 million in insurance recoveries (pretax) related to the Greater Lawrence Incident. See Note 19-E, "Other Matters" for additional information.
(2) Net income for the second quarter of 2019 was impacted by $297.0 million in insurance recoveries (pretax) related to the Greater Lawrence Incident. See Note 19-E, "Other Matters" for additional information.
(3) Net loss for the third quarter of 2018 was impacted by approximately $462 million in expenses (pretax) related to the Greater Lawrence Incident restoration and a $33.0 million loss (pretax) on an early extinguishment of long-term debt. See Note 19-E, "Other Matters" and Note 14, "Long-Term Debt" for additional information.
(4) Net loss for the fourth quarter of 2019 was impacted by an impairment charge of $204.8 million for goodwill and an impairment charge of $209.7 million for franchise rights, in each case related to Columbia of Massachusetts. For additional information, see Note 6, "Goodwill and Other Intangible Assets."

25. Supplemental Cash Flow Information

The following table provides additional information regarding our Consolidated Statements of Cash Flows for the years ended December 31, 2019, 2018 and 2017:

Year Ended December 31, *(in millions)*	**2019**	2018	2017
Supplemental Disclosures of Cash Flow Information			
Non-cash transactions:			
Capital expenditures included in current liabilities	**$ 223.6**	$ 152.0	$ 173.0
Assets acquired under a finance lease	**26.4**	54.6	11.5
Assets acquired under an operating lease	**13.4**	—	—
Reclassification of other property to regulatory assets[(1)]	**—**	245.3	—
Assets recorded for asset retirement obligations[(2)]	**54.6**	78.1	11.4
Schedule of interest and income taxes paid:			
Cash paid for interest, net of interest capitalized amounts	**$ 349.7**	$ 354.2	$ 339.9
Cash paid for income taxes, net of refunds	**10.8**	3.3	5.5

(1)See Note 8 "Regulatory Matters" for additional information.
(2)See Note 7 "Asset Retirement Obligations" for additional information.

26. Subsequent Event

On February 26, 2020, NiSource and Columbia of Massachusetts entered into the Asset Purchase Agreement with Eversource. Upon the terms and subject to the conditions set forth in the Asset Purchase Agreement, NiSource and Columbia of Massachusetts agreed to sell to Eversource, with certain additions and exceptions: (1) substantially all of the assets of Columbia of Massachusetts and (2) all of the assets held by any of Columbia of Massachusetts' affiliates that primarily relate to the Massachusetts Business, and Eversource agreed to assume certain liabilities of Columbia of Massachusetts and its affiliates. The liabilities assumed by Eversource under the Asset Purchase Agreement do not include, among others, any liabilities arising out of the Greater Lawrence Incident or liabilities of Columbia of Massachusetts or its affiliates pursuant to civil claims for injury of persons or damage to property to the extent such injury or damage occurs prior to the closing in connection with the Massachusetts Business. The Asset Purchase Agreement provides for a purchase price of $1,100 million in cash, subject to adjustment based on Columbia of Massachusetts' net working capital as of the closing. The closing of the transactions contemplated by the Asset Purchase Agreement is subject to Hart-Scott Rodino Antitrust Improvements Act of 1976 and regulatory approvals, resolution of certain proceedings before governmental bodies and other conditions. The Massachusetts Business did not meet the requirements under GAAP to be classified as held-for-sale as of December 31, 2019. When the Massachusetts Business meets the requirements to be classified as held-for-sale, in each period leading up to the closing date of the transaction, the assets and liabilities of the Massachusetts Business will be measured at fair value, less costs to sell. The final pre-tax gain or loss on the transaction will be determined as of the closing date. Assuming the Massachusetts Business is classified as held-for-sale at March 31, 2020, we estimate that the total pre-tax loss to be measured in the quarter ended March 31, 2020 will be approximately $360 million, based on December 31, 2019 asset and liability balances and estimated transaction costs. This estimated pre-tax loss is subject to change based on estimated transaction costs, working capital adjustments and asset and liability balances at each measurement date leading up to the closing date. The sale is expected to close by September 30, 2020, subject to closing conditions.

NISOURCE INC.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS

Twelve months ended December 31, 2019

($ in millions)	Balance Jan. 1, 2019	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [1]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2019
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 21.1	$ 21.6	$ 41.3	$ 64.8	$ 19.2
Reserve for other investments	3.0	—	—	—	3.0

Twelve months ended December 31, 2018

($ in millions)	Balance Jan. 1, 2018	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [1]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2018
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 18.3	$ 20.2	$ 43.7	$ 61.1	$ 21.1
Reserve for other investments	3.0	—	—	—	3.0

Twelve months ended December 31, 2017

($ in millions)	Balance Jan. 1, 2017	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [1]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2017
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 23.3	$ 14.8	$ 39.1	$ 58.9	$ 18.3
Reserve for other investments	3.0	—	—	—	3.0

[1] Charged to Other Accounts reflects the deferral of bad debt expense to a regulatory asset.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our chief executive officer and chief financial officer are responsible for evaluating the effectiveness of disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)). Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by the Company in reports that are filed or submitted under the Exchange Act are accumulated and communicated to management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our chief executive officer and chief financial officer concluded that, as of the end of the period covered by this report, disclosure controls and procedures were effective to provide reasonable assurance that financial information was processed, recorded and reported accurately.

Management's Annual Report on Internal Control over Financial Reporting

Our management, including our chief executive officer and chief financial officer, are responsible for establishing and maintaining internal control over financial reporting, as such term is defined under Rule 13a-15(f) or Rule 15d-15(f) promulgated under the Exchange Act. However, management would note that a control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our management has adopted the 2013 framework set forth in the Committee of Sponsoring Organizations of the Treadway Commission report, Internal Control - Integrated Framework, the most commonly used and understood framework for evaluating internal control over financial reporting, as its framework for evaluating the reliability and effectiveness of internal control over financial reporting. During 2019, we conducted an evaluation of our internal control over financial reporting. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of the end of the period covered by this annual report.

Deloitte & Touche LLP, our independent registered public accounting firm, issued an attestation report on our internal controls over financial reporting which is included herein.

Changes in Internal Controls

There have been no changes in our internal control over financial reporting during the most recently completed quarter covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9A. CONTROLS AND PROCEDURES

NISOURCE INC.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of NiSource Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of NiSource Inc. and subsidiaries (the “Company”) as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2019, of the Company and our report dated February 27, 2020, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP
Columbus, Ohio
February 27, 2020

ITEM 9B. OTHER INFORMATION

NISOURCE INC.

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Except for the information required by this item with respect to our executive officers included at the end of Part I of this report on Form 10-K, the information required by this Item 10 is incorporated herein by reference to the discussion in "Proposal 1 Election of Directors," and "Corporate Governance" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 19, 2020.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item 11 is incorporated herein by reference to the discussion in "Corporate Governance - Compensation Committee Interlocks and Insider Participation," "Director Compensation," "Executive Compensation," and "Executive Compensation - Compensation Committee Report," of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 19, 2020.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item 12 is incorporated herein by reference to the discussion in "Security Ownership of Certain Beneficial Owners and Management" and "Equity Compensation Plan Information" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 19, 2020.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item 13 is incorporated herein by reference to the discussion in "Corporate Governance - Policies and Procedures with Respect to Transactions with Related Persons" and "Corporate Governance - Director Independence" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 19, 2020.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item 14 is incorporated herein by reference to the discussion in "Independent Auditor Fees" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 19, 2020.

PART IV

NiSource Inc.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

Financial Statements and Financial Statement Schedules

The following financial statements and financial statement schedules filed as a part of the Annual Report on Form 10-K are included in Item 8, "Financial Statements and Supplementary Data."

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Exhibits

The exhibits filed herewith as a part of this report on Form 10-K are listed on the Exhibit Index below. Each management contract or compensatory plan or arrangement of ours, listed on the Exhibit Index, is separately identified by an asterisk.

Pursuant to Item 601(b), paragraph (4)(iii)(A) of Regulation S-K, certain instruments representing long-term debt of our subsidiaries have not been included as Exhibits because such debt does not exceed 10% of the total assets of ours and our subsidiaries on a consolidated basis. We agree to furnish a copy of any such instrument to the SEC upon request.

EXHIBIT NUMBER	DESCRIPTION OF ITEM
(1.1)	Form of Equity Distribution Agreement (incorporated by reference to Exhibit 1.1 to the NiSource Inc. Form 8-K filed on November 1, 2018).
(1.2)	Form of Master Forward Sale Confirmation (incorporated by reference to Exhibit 1.2 to the NiSource Inc. Form 8-K filed on November 1, 2018).
(2.1)	Separation and Distribution Agreement, dated as of June 30, 2015, by and between NiSource Inc. and Columbia Pipeline Group, Inc. (incorporated by reference to Exhibit 2.1 to the NiSource Inc. Form 8-K filed on July 2, 2015).
(2.2)	Asset Purchase Agreement, dated as of February 26, 2020, by and among NiSource Inc., Bay State Gas Company d/b/a Columbia Gas of Massachusetts and Eversource Energy (incorporated by reference to Exhibit 2.1 of the NiSource Inc. Form 8-K filed on February 27, 2020).***
(3.1)	Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Registrant’s Form 10-Q, filed with the Commission on August 3, 2015).
(3.2)	Certificate of Amendment of Amended and Restated Certificate of Incorporation of NiSource dated May 7, 2019 (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on May 8, 2019).
(3.3)	Bylaws of NiSource Inc., as amended and restated through January 26, 2018 (incorporated by reference to Exhibit 3.1 to the NiSource Inc. Form 8-K filed on January 26, 2018).
(3.4)	Certificate of Designations of 5.65% Series A Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on June 12, 2018).
(3.5)	Form of Certificate of Designations of 6.50% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on November 29, 2018).
(3.6)	Certificate of Designations of 6.50% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on December 6, 2018).

(3.7)	Certificate of Designations of Series B-1 Preferred Stock (incorporated by reference to Exhibit 3.1 to the NiSource Inc. Form 8-K filed on December 27, 2018).
(4.1)	Indenture, dated as of March 1, 1988, by and between Northern Indiana Public Service Company ("NIPSCO") and Manufacturers Hanover Trust Company, as Trustee (incorporated by reference to Exhibit 4 to the NIPSCO Registration Statement (Registration No. 33-44193)).
(4.2)	First Supplemental Indenture, dated as of December 1, 1991, by and between Northern Indiana Public Service Company and Manufacturers Hanover Trust Company, as Trustee (incorporated by reference to Exhibit 4.1 to the NIPSCO Registration Statement (Registration No. 33-63870)).
(4.3)	Indenture Agreement, dated as of February 14, 1997, by and between NIPSCO Industries, Inc., NIPSCO Capital Markets, Inc. and Chase Manhattan Bank as trustee (incorporated by reference to Exhibit 4.1 to the NIPSCO Industries, Inc. Registration Statement (Registration No. 333-22347)).
(4.4)	Second Supplemental Indenture, dated as of November 1, 2000, by and among NiSource Capital Markets, Inc., NiSource Inc., New NiSource Inc., and The Chase Manhattan Bank, as trustee (incorporated by reference to Exhibit 4.45 to the NiSource Inc. Form 10-K for the period ended December 31, 2000).
(4.5)	Indenture, dated November 14, 2000, among NiSource Finance Corp., NiSource Inc., as guarantor, and The Chase Manhattan Bank, as Trustee (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form S-3, dated November 17, 2000 (Registration No. 333-49330)).
(4.6)	Form of 3.490% Notes due 2027 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on May 17, 2017).
(4.7)	Form of 4.375% Notes due 2047 (incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on May 17, 2017).
(4.8)	Form of 3.950% Notes due 2048 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on September 8, 2017).
(4.9)	Form of 2.650% Notes due 2022 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on November 14, 2017).
(4.10)	Second Supplemental Indenture, dated as of November 30, 2017, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.4 to Post-Effective Amendment No. 1 to Form S-3 filed November 30, 2017 (Registration No. 333-214360)).
(4.11)	Third Supplemental Indenture, dated as of November 30, 2017, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on December 1, 2017).
(4.12)	Second Supplemental Indenture, dated as of February 12, 2018, between Northern Indiana Public Service Company and The Bank of New York Mellon, solely as successor trustee under the Indenture dated as of March 1, 1988 between the Company and Manufacturers Hanover Trust Company, as original trustee. (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 10-Q filed on May 2, 2018).
(4.13)	Third Supplemental Indenture, dated as of June 11, 2018, by and between NiSource Inc. and The Bank of New York Mellon, as trustee (including form of 3.650% Notes due 2023) (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on June 12, 2018).
(4.14)	Deposit Agreement, dated as of December 5, 2018, among NiSource, Inc., Computershare Inc. and Computershare Trust Company, N.A., acting jointly as depositary, and the holders from time to time of the depositary receipts described therein (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on December 6, 2018).
(4.15)	Form of Depositary Receipt (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on December 6, 2018).
(4.16)	Amended and Restated Deposit Agreement, dated as of December 27, 2018, among NiSource, Inc., Computershare Inc. and Computershare Trust Company, N.A., acting jointly as depositary, and the holders from time to time of the depositary receipts described therein (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on December 27, 2018).
(4.17)	Form of Depositary Receipt (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on December 27, 2018).

(4.18) Form of 2.950% Notes due 2029 (incorporated by reference to Exhibit 4.1 to NiSource Inc. Form 8-K filed on August 12, 2019).

(4.19)	Amended and Restated NiSource Inc. Employee Stock Purchase Plan (incorporated by reference to Exhibit C to the Registrant's Definitive Proxy Statement on Schedule 14A, filed with the Commission on April 1, 2019).
(4.20)	Description of NiSource Inc.'s Securities Registered Under Section 12 of the Exchange Act. **
(10.1)	2010 Omnibus Incentive Plan (incorporated by reference to Exhibit B to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting held on May 11, 2010, filed on April 2, 2010).*
(10.2)	First Amendment to the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 10-K filed on February 18, 2014.)*
(10.3)	2010 Omnibus Incentive Plan (incorporated by reference to Exhibit C to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting held on May 12, 2015, filed on April 7, 2015).*
(10.4)	Second Amendment to the NiSource Inc. 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 8-K filed October 23, 2015.)*
(10.5)	Form of Amended and Restated 2013 Performance Share Agreement effective on implementation of the spin-off on July 1, 2015, (under the 2010 Omnibus Incentive Plan)(incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on November 3, 2015).*
(10.6)	Form of Amended and Restated 2014 Performance Share Agreement effective on the implementation of the spin-off on July 1, 2015, (under the 2010 Omnibus Incentive Plan)(incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 10-Q filed on November 3, 2015).*
(10.7)	Form of Amendment to Restricted Stock Unit Award Agreement related to Vested but Unpaid NiSource Restricted Stock Unit Awards for Nonemployee Directors of NiSource entered into as of July 13, 2015 (incorporated by reference to Exhibit 10.3 to the NiSource Inc. Form 10-Q filed on November 3, 2015).*
(10.8)	NiSource Inc. Nonemployee Director Retirement Plan, as amended and restated effective May 13, 2008 (incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 10-K filed on February 27, 2009).*
(10.9)	Supplemental Life Insurance Plan effective January 1, 1991, as amended, (incorporated by reference to Exhibit 2 to the NIPSCO Industries, Inc. Form 8-K filed on March 25, 1992).*
(10.10)	Revised Form of Change in Control and Termination Agreement (incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 8-K filed on October 23, 2015.)*
(10.11)	Form of Restricted Stock Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.18 to the NiSource Inc. Form 10-K filed on February 28, 2011).*
(10.12)	Form of Restricted Stock Unit Award Agreement for Non-employee directors under the Non-employee Director Stock Incentive Plan (incorporated by reference to Exhibit 10.19 to the NiSource Inc. Form 10-K filed on February 28, 2011).*
(10.13)	Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 to NiSource Inc. Form 10-Q filed on August 2, 2011).*
(10.14)	Form of Restricted Stock Unit Award Agreement under the 2010 Omnibus Incentive Plan.* (incorporated by reference to Exhibit 10.17 to the NiSource Inc. Form 10-K filed on February 22, 2017)
(10.15)	Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2010 Omnibus Incentive Plan. (incorporated by reference to Exhibit 10.18 to the NiSource Inc. Form 10-K filed on February 22, 2017) *
(10.16)	Amended and Restated NiSource Inc. Executive Deferred Compensation Plan effective November 1, 2012 (incorporated by reference to Exhibit 10.21 to the NiSource Inc. Form 10-K filed on February 19, 2013).*
(10.17)	NiSource Inc. Executive Severance Policy, as amended and restated, effective January 1, 2015 (incorporated by reference to Exhibit 10.21 to the NiSource Inc. Form 10-K filed on February 18, 2015).*
(10.18)	Note Purchase Agreement, dated as of August 23, 2005, by and among NiSource Finance Corp., as issuer, NiSource Inc., as guarantor, and the purchasers named therein (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Current Report on Form 8-K filed on August 26, 2005).
(10.19)	Amendment No. 1, dated as of November 10, 2008, to the Note Purchase Agreement by and among NiSource Finance Corp., as issuer, NiSource Inc., as guarantor, and the purchasers whose names appear on the signature page thereto (incorporated by reference to Exhibit 10.30 to the NiSource Inc. Form 10-K filed on February 27, 2009).

(10.20)	Letter Agreement, dated as of March 17, 2015, by and between NiSource Inc. and Donald Brown. (incorporated by reference Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on April 30, 2015).*
(10.21)	Letter Agreement, dated as of February 23, 2016, by and between NiSource Inc. and Pablo A. Vegas. (incorporated by reference Exhibit 10.29 to the NiSource Inc. Form 10-K filed on February 22, 2017).*
(10.22)	Employee Matters Agreement, dated as of June 30, 2015, by and between NiSource Inc. and Columbia Pipeline Group, Inc. (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on July 2, 2015).
(10.23)	Form of Change in Control and Termination Agreement (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on August 2, 2017).
(10.24)	Form of Performance Share Award Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.33 to the NiSource Form 10-K filed on February 20, 2018).*
(10.25)	Form of Restricted Stock Unit Award Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.34 to the NiSource Form 10-K filed on February 20, 2018).*
(10.26)	Common Stock Subscription Agreement, dated as of May 2, 2018, by and among NiSource Inc. and the purchasers named therein (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on May 2, 2018).
(10.27)	Registration Rights Agreement, dated as of May 2, 2018, by and among NiSource Inc. and the purchasers named therein (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on May 2, 2018).
(10.28)	Purchase Agreement, dated as of June 6, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 5.650% Series A Preferred Stock (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on June 12, 2018).
(10.29)	Purchase Agreement, dated as of June 6, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 3.650% Notes due 2023 (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on June 12, 2018).
(10.30)	Registration Rights Agreement, dated as of June 11, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 5.650% Series A Preferred Stock (incorporated by reference to Exhibit 10.3 of the NiSource Inc. Form 8-K filed on June 12, 2018).
(10.31)	Registration Rights Agreement, dated as of June 11, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 3.650% Notes due 2023 (incorporated by reference to Exhibit 10.4 of the NiSource Inc. Form 8-K filed on June 12, 2018).
(10.32)	Amended and Restated NiSource Inc. Supplemental Executive Retirement Plan effective August 10, 2017 (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 10-Q filed on November 1, 2018).
(10.33)	Amended and Restated Pension Restoration Plan for NiSource Inc. and Affiliates effective August 10, 2017 (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 10-Q filed on November 1, 2018).
(10.34)	Amended Restated Savings Restoration Plan for NiSource Inc. and Affiliates effective August 10, 2017 (incorporated by reference to Exhibit 10.3 of the NiSource Inc. Form 10-Q filed on November 1, 2018).
(10.35)	Form of 2019 Performance Share Award Agreement under the 2010 Omnibus Incentive Plan. (incorporated by reference to Exhibit 10.45 of the NiSource Inc. Form 10-K filed on February 20, 2019).
(10.36)	Fifth Amended and Restated Revolving Credit Agreement, dated as of February 20, 2019, among NiSource Inc., as Borrower, the Lenders party thereto, Barclays Bank PLC, as Administrative Agent, Citibank, N.A. and MUFG Bank, Ltd., as Co-Syndication Agents, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A. and Wells Fargo Bank, National Association, as Co-Documentation Agents, and Barclays Bank PLC, Citibank, N.A., MUFG Bank, Ltd., Credit Suisse Loan Funding LLC, JPMorgan Chase Bank, N.A. and Wells Fargo Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on February 20, 2019).

(10.37) Amended and Restated NiSource Inc. Employee Stock Purchase Plan adopted as of February 1, 2019 (incorporated by reference to Exhibit C to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting to be held on May 7, 2019, filed on April 1, 2019).

(10.38)	Amended and Restated Term Loan Agreement, dated as of April 17, 2019, among NiSource Inc., as Borrower, the Lenders party thereto, and MUFG Bank Ltd., as Administrative Agent and Sole Lead Arranger and Sole Bookrunner (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on April 17, 2019).
(10.39)	Form of Performance Share Award Agreement* **
(10.40)	Form of Restricted Stock Unit Award Agreement* **
(10.41)	Form of Cash-Based Award Agreement* **
(10.42)	Columbia Gas of Massachusetts Plea Agreement dated February 26, 2020 (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on February 27, 2020).
(10.43)	NiSource Deferred Prosecution Agreement dated February 26, 2020 (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on February 27, 2020).
(21)	List of Subsidiaries.**
(23)	Consent of Deloitte & Touche LLP.**
(31.1)	Certification of Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.**
(31.2)	Certification of Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.**
(32.1)	Certification of Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).**
(32.2)	Certification of Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).**
(101.INS)	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document. **
(101.SCH)	Inline XBRL Schema Document.**
(101.CAL)	Inline XBRL Calculation Linkbase Document.**
(101.LAB)	Inline XBRL Labels Linkbase Document.**
(101.PRE)	Inline XBRL Presentation Linkbase Document.**
(101.DEF)	Inline XBRL Definition Linkbase Document.**
(104)	Cover page Interactive Data File (formatted as inline XBRL, and contained in Exhibit 101.)

* Management contract or compensatory plan or arrangement of NiSource Inc.

** Exhibit filed herewith.

*** Schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K. NiSource agrees to furnish supplementally a copy of any omitted schedules or exhibits to the SEC upon request.

References made to NIPSCO filings can be found at Commission File Number 001-04125. References made to NiSource Inc. filings made prior to November 1, 2000 can be found at Commission File Number 001-09779.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

NiSource Inc.

(Registrant)

Date: February 27, 2020

By: /s/ JOSEPH HAMROCK

Joseph Hamrock

President, Chief Executive Officer and Director

(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ JOSEPH HAMROCK Joseph Hamrock	President, Chief Executive Officer and Director (Principal Executive Officer)	Date: February 27, 2020
/s/ DONALD E. BROWN Donald E. Brown	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	Date: February 27, 2020
/s/ JOSEPH W. MULPAS Joseph W. Mulpas	Vice President and Chief Accounting Officer (Principal Accounting Officer)	Date: February 27, 2020
/s/ KEVIN T. KABAT Kevin T. Kabat	Chairman and Director	Date: February 27, 2020
/s/ PETER A. ALTABEF Peter A. Altabef	Director	Date: February 27, 2020
/s/ THEODORE H. BUNTING, JR. Theodore H. Bunting, Jr.	Director	Date: February 27, 2020
/s/ ERIC L. BUTLER Eric L. Butler	Director	Date: February 27, 2020
/s/ ARISTIDES S. CANDRIS Aristides S. Candris	Director	Date: February 27, 2020
/s/ WAYNE S. DEVEYDT Wayne S. DeVeydt	Director	Date: February 27, 2020
/s/ DEBORAH A. HENRETTA Deborah A. Henretta	Director	Date: February 27, 2020
/s/ DEBORAH A.P. HERSMAN Deborah A. P. Hersman	Director	Date: February 27, 2020
/s/ MICHAEL E. JESANIS Michael E. Jesanis	Director	Date: February 27, 2020
/s/ CAROLYN Y. WOO Carolyn Y. Woo	Director	Date: February 27, 2020

Exhibit 4.20

**DESCRIPTION OF THE REGISTRANT'S SECURITIES
REGISTERED PURSUANT TO SECTION 12 OF THE
SECURITIES EXCHANGE ACT OF 1934**

NiSource Inc. ("NiSource") has two classes of securities registered under Section 12 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"):

(i) common stock, par value $0.01 per share (the "common stock"); and
(ii) depositary shares, each representing a 1/1,000th ownership interest in a share of 6.50% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock ("Series B Preferred Stock"), par value $0.01 per share, liquidation preference $25,000 per share and a 1/1,000th ownership interest in a share of Series B-1 Preferred Stock ("Series B-1 Preferred Stock"), par value $0.01 per share, liquidation preference $0.01 per share (the "Depositary Shares").

The following is a summary description of the material terms of such securities. It may not contain all the information that is important to you. For additional information, you should refer to the provisions of our Amended and Restated Certificate of Incorporation (the "certificate of incorporation") and our bylaws, as amended and restated (the "bylaws"), each of which is an exhibit to the Annual Report on Form 10-K to which this description is an exhibit and are incorporated herein by reference.

GENERAL

Authorized Capital Stock

The authorized capital stock of NiSource consists of 620,000,000 shares, of which 600,000,000 are common stock, par value $0.01, and 20,000,000 are preferred stock, par value $0.01. The board of directors of NiSource has designated (i) 400,000 shares of the preferred stock as 5.650% Series A Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock ("Series A Preferred Stock"), liquidation preference $1,000 per share, (ii) 20,000 shares of the preferred stock as Series B Preferred Stock, and (iii) 20,000 shares of the preferred stock as Series B-1 Preferred Stock. The shares of Series B Preferred Stock and Series B-1 Preferred Stock are represented by 20,000,000 Depositary Shares, each representing 1/1000th ownership interest in a share of each of the Series B Preferred Stock and the Series B-1 Preferred Stock.

The shares of Series A Preferred Stock are not registered pursuant to Section 12 of the Exchange Act and are not separately described below, but they are referenced as relevant when describing the other securities discussed herein.

Anti-Takeover Provisions

NiSource's certificate of incorporation includes provisions that may have the effect of deterring hostile takeovers or delaying or preventing changes in control of management of NiSource. More specifically, the certificate of incorporation provides that stockholders may not cumulate their votes and stockholder action may be taken only at a duly called meeting and not by written consent. In addition, NiSource's bylaws contain requirements for advance notice of stockholder proposals and director nominations. These and other provisions of the certificate of incorporation and bylaws and Delaware law could discourage potential acquisition proposals and could delay or prevent a change in control of management of NiSource.

Under Delaware law, the approval of the holders of a majority of the outstanding shares of a class of NiSource's capital stock would be necessary to authorize any amendment to the certificate of incorporation that would increase or decrease the aggregate number of authorized shares of such class of capital stock or that would adversely alter or change the powers, preferences or special right of such class of capital stock. Further, pursuant to the certificates of designations for the Series A Preferred Stock, Series B Preferred Stock and Series B-1 Preferred Stock, the holders of two-thirds of any series of such preferred stock must approve certain amendments to the certificate of incorporation that would have a material adverse effect on the existing preferences, rights, powers, duties or obligations of such series of preferred stock. The effect of these provision may permit the holders of NiSource's outstanding shares of capital stock to block a proposed amendment to the certificate of incorporation in connection with a potential acquisition of NiSource if such amendment would adversely affect the powers, preferences or special rights of such capital stock.

NiSource is subject to the provisions of Section 203 of the Delaware General Corporation Law regulating corporate takeovers. Section 203 prevents certain Delaware corporations, including those whose securities are listed on a national securities exchange, such as the New York Stock Exchange, from engaging, under certain circumstances, in a "business combination" (as defined therein), which includes, among other things, a merger or sale of more than 10% of the corporation's assets, with any interested stockholder for three years following the date that the stockholder became an interested stockholder. An interested stockholder is a stockholder who acquired 15% or more of the corporation's outstanding voting stock or an affiliate or associate of such person.

DESCRIPTION OF COMMON STOCK

Liquidation Rights

In the event of any liquidation, dissolution or winding up of NiSource, whether voluntary or involuntary, after payment or provision for payment of the debts and other liabilities of NiSource and the distribution in full of all preferential amounts (including any accumulated and unpaid dividends) to which the holders of the Series A Preferred Stock, Series B Preferred Stock, Series B-1 Preferred Stock and any other series of preferred stock of NiSource hereafter created are entitled, the holders of common stock will share ratably in the remaining assets in proportion to the number of shares of common stock held by them respectively. A consolidation or merger of NiSource with or into any other corporation, or any purchase or redemption of shares of any class of NiSource's capital stock, will not be deemed to be a liquidation, dissolution or winding up of NiSource's affairs.

Voting Rights

Except as otherwise required by Delaware law or as otherwise provided in the certificate of designations for the Series A Preferred Stock, Series B Preferred Stock, Series B-1 Preferred Stock or any other series of preferred stock of NiSource hereafter created, holders of NiSource's common stock exclusively possess voting power for the election of NiSource's directors and all other matters requiring stockholder action. Each holder of common stock, if entitled to vote on a matter, is entitled to one vote per share. Holders of common stock are not entitled to cumulative voting rights. Holders of common stock will be notified of any stockholders' meeting according to applicable law.

Dividend Rights

Holders of common stock will be entitled to receive dividends, when, as and if declared by NiSource's board of directors out of legally available funds for such purpose in accordance with Delaware law, subject to the powers, preferences and rights afforded to the holders of the Series A Preferred Stock, Series B Preferred Stock and any other series of preferred stock of NiSource hereafter created. Dividends may be paid in cash, capital stock or other property of NiSource.

NiSource is prohibited by the terms of each of its Series A Preferred Stock and its Series B Preferred Stock from declaring or paying dividends on any shares of NiSource's common stock (other than dividends payable solely in shares of its common stock) or redeeming, repurchasing or acquiring shares of its common stock unless full cumulative dividends have been paid with respect to the Series A Preferred Stock and the Series B Preferred Stock, respectively, through the most recently completed respective dividend periods.

NiSource is an energy holding company that derives substantially all of its revenues and earnings from the operating results of the rate-regulated businesses of its subsidiaries. Accordingly, NiSource's ability to pay dividends on its capital stock is dependent primarily upon the earnings and cash flows of its subsidiaries and the distribution or other payment of such earnings to NiSource. NiSource's subsidiaries are separate and distinct legal entities and have no obligation, contingent or otherwise, to pay any amounts on the capital stock of NiSource or to make any funds available therefor, whether by dividends, loans or other payments.

No Preemptive Rights

Holders of NiSource's common stock are not entitled to, as holders of common stock, any preemptive rights with respect to any shares of NiSource's capital stock or any of its securities convertible into or exercisable for its capital stock.

SERIES B PREFERRED STOCK

Ranking

The Series B Preferred Stock ranks, with respect to dividends and distributions upon liquidation: (i) senior to NiSource's common stock and any other class or series of capital stock that does not expressly provide that it ranks on a parity with or senior to the Series B Preferred Stock with respect to dividends and such distributions (the "Series B Junior Securities"); (ii) on a parity with the Series A Preferred Stock, the Series B-1 Preferred Stock (except with respect to dividends) and any other class or series of capital stock that does not expressly provide that it ranks junior or senior to the Series B Preferred Stock with respect to dividends and such distributions (the "Series B Parity Securities"); and (iii) junior to any class or series of capital stock that expressly provides that it ranks senior to the Series B Preferred Stock with respect to dividends and such distributions (the "Series B Senior Securities").

Liquidation Rights

In the event of any liquidation, the holders of the Series B Preferred Stock are entitled to receive out of NiSource's assets available for distribution to stockholders (subject to the rights of holders of Series B Senior Securities and Series B Parity Securities in respect of distributions upon the liquidation) before any distribution of assets is made to holders of Series B Junior Securities, a liquidation preference of $25,000 per share. Any accumulated and unpaid dividends on the Series B Preferred Stock and Series B Parity Securities will be paid prior to any distributions in liquidation. A consolidation or merger of NiSource with or into any other entity will not be deemed to be a liquidation.

Voting Rights

The Series B Preferred Stock has no voting, consent or approval rights except as set forth below or as otherwise provided by Delaware law. On any matter described below in which the holders of the Series B Preferred Stock are entitled to vote as a class (whether separately or together with the holders of any Series B Parity Securities), such holders will be entitled to twenty-five votes per share. The Series B Preferred Stock is paired with the Series B-1 Preferred Stock and the holders of the Series B-1 Preferred Stock are entitled to the voting rights described below under the heading "-Series B-1 Preferred Stock-Voting Rights."

Adverse Changes. Unless NiSource has received the affirmative vote or consent of the holders of at least two-thirds of the outstanding shares of Series B Preferred Stock, voting as a single class, no amendment to the certificate of incorporation may be adopted that would have a material adverse effect on the existing preferences, rights, powers, duties or obligations of the Series B Preferred Stock. However, such voting requirement shall not be implicated by any amendment to the certificate of incorporation (i) relating to the issuance of additional shares of preferred stock (subject to the voting rights discussed in the following paragraph) and (ii) in connection with a merger or another transaction in which either the Series B Preferred Stock remains outstanding or is exchanged for a series of preferred stock of the surviving entity, in either case, with the terms thereof materially unchanged in any respect adverse to the holders of Series B Preferred Stock.

Parity and Senior Preferred Stock. Unless NiSource has received the affirmative vote or consent of the holders of at least two-thirds of the outstanding shares of Series B Preferred Stock, voting as a class together with holders of the Series A Preferred Stock and any other Series B Parity Securities and upon which like voting rights have been conferred and are exercisable, NiSource may not: (i) create or issue any Series B Parity Securities (including any additional shares of Series A Preferred Stock or Series B Preferred Stock, but excluding any payments-in-kind on such shares) if the cumulative dividends payable on the outstanding shares of Series B Preferred Stock (or Series B Parity Securities, if applicable) are in arrears; or (ii) create or issue any Series B Senior Securities.

Dividends

Holders of Series B Preferred Stock will be entitled to receive, when, as and if declared by NiSource's board of directors out of legally available funds for such purpose, cumulative quarterly cash dividends (subject to the dividend rights of any Series B Parity Securities or Series B Senior Securities) at an initial rate of 6.50% per annum of the $25,000 liquidation preference per share (equal to $1,625 per share per annum). On and after March 15, 2024, dividends will accumulate for each five-year period thereafter according to a formula based on the rate of certain U.S. Treasury securities with a five year maturity plus the applicable margin.

NiSource is prohibited by the terms of the Series B Preferred Stock from declaring or paying dividends on any Series B Junior Securities (other than a dividend payable solely in such Series B Junior Securities) or redeeming, repurchasing or acquiring shares of any Series B Junior Securities unless full cumulative dividends have been paid on all outstanding shares of Series B Preferred Stock and any Series B Parity Securities entitled to dividends through the most recently completed respective dividend periods. In addition, NiSource may not repurchase, redeem or otherwise acquire any shares of Series A Preferred Stock or Series A Parity Securities, unless (i) effected pursuant to a purchase or exchange offer made on the same relative terms to all holders of such shares of preferred stock or (ii) (A) full cumulative dividends have been paid or provided for on all outstanding shares of such preferred stock entitled to dividends through the most recently completed respective dividend periods and (B) NiSource expects to have sufficient funds to pay in full the next dividend on all such outstanding shares of preferred stock.

Redemption

NiSource may redeem the Series B Preferred Stock, at its option, in whole or in part, on March 15, 2024 or on any fifth anniversary thereafter by paying $25,000 per share plus an amount equal to all accumulated and unpaid dividends thereon to, but not including, the redemption date, whether or not declared. In addition, following the occurrence of a "Ratings Event" (as defined in the certificate of designations of the Series B Preferred Stock), NiSource may, at its option, redeem the Series B Preferred Stock in whole, but not in part, at a redemption price equal to $25,500 per share (102% of the liquidation preference) plus an amount equal to all accumulated and unpaid dividends thereon to the redemption date, whether or not declared.

No Conversion or Preemptive Rights

The Series B Preferred Stock is not convertible into any other class of NiSource's capital stock and the holders of the Series B Preferred Stock do not, as holders of Series B Preferred Stock, have any preemptive rights with respect to any shares of NiSource's capital stock or any of its securities convertible into or exercisable for its capital stock.

SERIES B-1 PREFERRED STOCK

The Series B-1 Preferred Stock was issued as a distribution with respect to the Series B Preferred Stock in order to enhance the voting rights of the Series B Preferred Stock to comply with the New York Stock Exchange's minimum voting rights policy. The Series B-1 Preferred Stock is paired with the Series B Preferred Stock and may not be transferred, redeemed or repurchased except in connection with the simultaneous transfer, redemption or repurchase of the underlying Series B Preferred Stock, and upon the transfer, redemption or repurchase of the underlying Series B Preferred Stock, the same number of shares of Series B-1 Preferred Stock must simultaneously be transferred (to the same transferee), redeemed or repurchased, as the case may be. A summary of certain powers, preferences, rights, qualifications, limitations and restrictions of the Series B-1 Preferred Stock are set forth below.

Ranking

The Series B-1 Preferred Stock ranks, with respect to distributions upon liquidation: (i) senior to NiSource's common stock and any other class or series of capital stock that does not expressly provide that it ranks on a parity with or senior to the Series B-1 Preferred Stock with respect to such distributions (the "Series B-1 Junior Securities"); (ii) on a parity with the Series A Preferred Stock, the Series B Preferred Stock and any other class or series of capital stock that does not expressly provide that it ranks junior or senior to the Series B-1 Preferred Stock with respect to such distributions (the "Series B-1 Parity Securities"); and (iii) junior to any class or series of capital stock that expressly provides that it ranks senior to the Series B-1 Preferred Stock with respect to such distributions (the "Series B-1 Senior Securities").

Liquidation Rights

In the event of any liquidation, the holders of the Series B-1 Preferred Stock are entitled to receive out of NiSource's assets available for distribution to stockholders (subject to the rights of holders of Series B-1 Senior Securities and Series B-1 Parity Securities in respect of distributions upon liquidation), before any distribution of assets is made to holders of Series B-1 Junior Securities, a liquidation preference of $0.01 per share. Any accumulated and unpaid dividends on the Series B-1 Parity Securities will be paid prior to any distributions in liquidation. A consolidation or merger of NiSource with or into any other entity will not be deemed to be a liquidation.

Voting Rights

The Series B-1 Preferred Stock has no voting, consent or approval rights except as set forth below or as otherwise provided by Delaware law. On any matter described below in which the holders of the Series B-1 Preferred Stock are entitled to vote as a class (whether separately or together with the holders of any Series B-1 Parity Securities), such holders will be entitled to twenty-five votes per share.

Adverse Changes. Unless NiSource has received the affirmative vote or consent of the holders of at least two-thirds of the outstanding shares of Series B-1 Preferred Stock, voting as a single class, no amendment to the certificate of incorporation may be adopted that would have a material adverse effect on the existing preferences, rights, powers, duties or obligations of the Series B-1 Preferred Stock. However, such voting requirement shall not be implicated by any amendment to the certificate of incorporation (i) relating to the issuance of additional shares of preferred stock and (ii) in connection with a merger or another transaction in which either the Series B-1 Preferred Stock remains outstanding or is exchanged for a series of preferred stock of the surviving entity, in either case, with the terms thereof materially unchanged in any respect adverse to the holders of Series B-1 Preferred Stock.

Election of Directors upon Nonpayment Events. If and whenever dividends on any shares of Series B Preferred Stock shall not have been declared and paid for at least six dividend periods, whether or not consecutive (a “Nonpayment Event”), the number of directors then constituting NiSource’s board of directors will automatically be increased by two and the holders of Series B-1 Preferred Stock, voting as a class together with the holders of any outstanding Series B-1 Parity Securities having like voting rights that are exercisable at that time (“Director Voting Preferred Stock”), shall be entitled to elect the two additional directors (the “Preferred Stock Directors”), provided that (i) such election does not violate the corporate governance requirements of the New York Stock Exchange that companies must have a majority of independent directors and (ii) such director is not prohibited or disqualified from serving as a director of NiSource by any applicable law. The Preferred Stock Directors shall each be entitled to one vote per director on any matter before NiSource’s board of directors for a vote.

When all accumulated and unpaid dividends on the Series B Preferred Stock have been paid in full, then (a) the right of the holders of Series B-1 Preferred Stock to elect the Preferred Stock Directors shall cease, (b) the terms of office of the Preferred Stock Directors will automatically terminate and (c) the number of directors constituting NiSource’s board of directors will automatically decrease by two. Any Preferred Stock Director may be removed at any time without cause by holders of a majority of the outstanding shares of the Series B-1 Preferred Stock and Director Voting Preferred Stock (voting together as a single class). So long as a Nonpayment Event continues, any vacancy in the office of a Preferred Stock Director (after the initial election of Preferred Stock Directors) may be filled by the written consent of the Preferred Stock Director remaining in office (if any), in lieu of a vote by the Series B-1 Preferred Stock and Voting Preferred Stock (voting together as a single class).

Dividends

Holders of Series B-1 Preferred Stock are not entitled to receive dividends.

Redemption

The shares of Series B-1 Preferred Stock are subject to mandatory redemption, in whole or in part, at a redemption price of $0.01 per share upon the redemption of the underlying shares of Series B Preferred Stock with which such shares of Series B-1 Preferred Stock are paired. The shares of Series B-1 Preferred Stock are not otherwise subject to redemption.

No Conversion or Preemptive Rights

The Series B-1 Preferred Stock is not convertible into any other class of NiSource’s capital stock and the holders of the Series B-1 Preferred Stock do not, as holders of Series B-1 Preferred Stock, have any preemptive rights with respect to any shares of NiSource’s capital stock or any of its securities convertible into or exercisable for its capital stock.

DEPOSITARY SHARES REPRESENTING
SERIES B PREFERRED STOCK AND SERIES B-1 PREFERRED STOCK

General

Each Depositary Share represents a 1/1,000th ownership interest in a share of the Series B Preferred Stock and a 1/1,000th ownership interest in a share of the Series B-1 Preferred Stock. The Depositary Shares are evidenced by depositary receipts issued pursuant to a deposit agreement (the “Deposit Agreement”) among NiSource, Computershare Inc. and Computershare Trust Company, N.A., acting jointly as the depositary (the “depositary”), and the holders from time to time of the depositary receipts evidencing the Depositary Shares. This description of the Depositary Shares is qualified in its entirety by the provisions of the respective certificates of designations of the Series B Preferred Stock and Series B-1 Preferred Stock and the Deposit Agreement, each of which is an exhibit to the Annual Report on Form 10-K to which this description is an exhibit and are incorporated herein by reference.

Dividends and Other Distributions

The depositary will distribute any cash dividends or other cash distributions received in respect of the deposited Series B Preferred Stock and Series B-1 Preferred Stock to the record holders of Depositary Shares relating to the underlying Series B Preferred Stock and Series B-1 Preferred Stock in proportion to the number of Depositary Shares held by the holders. The depositary will distribute any property received by it other than cash to the record holders of Depositary Shares entitled to those distributions, unless it determines, in consultation with NiSource, that the distribution cannot be made proportionally among those holders or that it is not feasible to make a distribution. In that event, the depositary may, with NiSource's approval, sell the property (at a public or private sale) and distribute the net proceeds from the sale to the holders of the Depositary Shares in proportion to the number of Depositary Shares they hold.

Redemption of Depositary Shares

If NiSource redeems the Series B Preferred Stock and Series B-1 Preferred Stock represented by the Depositary Shares, a proportionate number of Depositary Shares will be redeemed from the proceeds received by the depositary resulting from the redemption of the Series B Preferred Stock and Series B-1 Preferred Stock held by the depositary. The redemption price per depositary share will be equal to 1/1,000th of the redemption price per share payable with respect to each of the Series B Preferred Stock and Series B-1 Preferred Stock. Whenever NiSource redeems shares of Series B Preferred Stock and Series B-1 Preferred Stock held by the depositary, the depositary will redeem, as of the same redemption date, the number of Depositary Shares representing shares of Series B Preferred Stock and Series B-1 Preferred Stock so redeemed.

Voting the Preferred Stock

When the depositary receives notice of any meeting at which the holders of the Series B Preferred Stock and/or Series B-1 Preferred Stock are entitled to vote, the depositary will mail, or otherwise transmit by an authorized method, the information contained in the notice to the record holders of the Depositary Shares. Each record holder of the Depositary Shares on the record date, which will be the same date as the record date for the Series B Preferred Stock and/or Series B-1 Preferred Stock, may instruct the depositary to vote the amount of the Series B Preferred Stock and/or Series B-1 Preferred Stock entitled to vote represented by the holder's Depositary Shares. To the extent practicable, the depositary will vote the number of shares entitled to vote represented by such Depositary Shares in accordance with the instructions it receives. If the depositary does not receive specific instructions from the holders of any Depositary Shares representing the Series B Preferred Stock and/or Series B-1 Preferred Stock entitled to vote, it will abstain from voting the number of shares of Series B Preferred Stock and/or Series B-1 Preferred Stock represented thereby.

Amendment and Termination of the Depositary Agreement

The form of depositary receipt evidencing the Depositary Shares and any provision of the Depositary Agreement may be amended by agreement between the depositary and NiSource. However, any amendment that materially and adversely alters the rights of the holders of Depositary Shares will not be effective unless such amendment has been approved by the holders of at least a majority of the Depositary Shares then outstanding. The Depositary Agreement may be terminated by NiSource upon sixty days' prior written notice to the depositary or by the depositary upon mailing notice to NiSource and the holders of all Depositary Shares then outstanding if at any time sixty days have expired after the depositary provided written notice to NiSource of its resignation and a successor depositary has not been appointed. The Depositary Agreement shall automatically terminate after there has been a final distribution in respect of the Series B Preferred Stock and Series B-1 Preferred Stock in connection with NiSource's liquidation, dissolution or winding and such distribution has been distributed to the holders of Depositary Shares.

NiSource Inc.

20__ Omnibus Incentive Plan

20__ Performance Share Award Agreement

This Performance Share Award Agreement (the "Agreement") is made and entered into as of _______________ (the "Grant Date"), by and between NiSource Inc., a Delaware corporation (the "Company"), and __________________ an Employee of the Company (the "Grantee"), pursuant to the terms of the NiSource Inc. 20__ Omnibus Incentive Plan, as amended (the "Plan"). Any term capitalized but not defined in this Agreement shall have the meaning set forth in the Plan.

Section 1. Performance Share Award. The Company hereby grants to the Grantee, on the terms and conditions hereinafter set forth, a target award of ______________Performance Shares (the "Performance Shares"). The Performance Shares shall be represented by a bookkeeping entry with respect to the Grantee (the "Performance Share Account"), and each Performance Share shall be settled in one Share, to the extent provided under this Agreement and the Plan. This Agreement and the award shall be null and void unless the Grantee accepts this Agreement electronically within the Grantee's stock plan account with the Company's stock plan administrator according to the procedures then in effect.

Section 2. Performance-Based Vesting Conditions.

(a) General. Subject to the remainder of this Agreement, the Performance Shares shall vest pursuant to the terms of this Agreement and the Plan based on the achievement of the performance goals set forth in this Section 2 over the performance period beginning on _________________ and ending on _________________ (the "Performance Period"), provided (i) that that the Grantee remains in continuous Service through _________________ (the "Vesting Date") and (ii) the Company achieves the threshold cumulative NOEPS goal set forth in Section 2(b). Attainment of the performance goals shall be determined and certified by the Compensation Committee of the Board of Directors of the Company (the "Committee") prior to the settlement of the Performance Shares.

(b) Financial Performance Goal. Subject to the terms of this Agreement and the Plan, _________________shall be eligible to vest based on the Company's achievement of cumulative NOEPS during the Performance Period, as follows:

Performance Level(1)	Cumulative NOEPS	Percentage of Performance Shares that Shall Vest(2)
Threshold	$________	____________
Target	$________	____________
Maximum	$_______and above	____________

(1) The vesting percentage for performance between performance levels shall be determined based on linear interpolation.

(2) The number of Performance Shares that shall vest based on the Company's cumulative NOEPS performance shall be subject to a performance modifier of +/- 25% based on the Company's RTSR over the Performance Period, with such Performance Shares (i) increasing by 25% if the Company's RTSR is in the top quartile of the TSR Peer Group, (ii) decreasing by 25% if the Company's RTSR is in the bottom quartile of the TSR Peer Group, and (iii) remaining the same if the Company's RTSR is in the second or third quartiles of the TSR Peer Group. No other adjustment shall be made based on the Company's RTSR.

(c) [Insert Secondary] Performance Goals. Subject to the terms of this Agreement and the Plan and provided the Company's threshold cumulative NOEPS goal is met, _________________shall be eligible to vest based on the achievement of the [Insert Secondary Performance] Goals set forth below, with each goal equally weighted:

Performance Measure	Goal(1)

(1) If the Company fails to achieve the applicable performance goal, then the Performance Shares allocated to such performance goal shall not be eligible to vest.

(d) Definitions.

(i) "cumulative NOEPS" means the Company's cumulative net operating earnings per share, as reported in the Company's annual financial statements. Additional adjustments to cumulative net operating earnings per share shall be made to the targets and results for: (x) transactions that the Company discloses on Form 8-K filed with the Securities and Exchange Commission, including merger, acquisition, divestiture, consolidation or corporate restructuring, any recapitalization, reorganization, spin-off, split-up, combination, liquidation, dissolution, sale of assets or similar corporate transactions that meet disclosure thresholds; and (y) pending transactions as a result of requirements to present operations as "held for sale" under Accounting Standard Codification 205.

(ii)

(iii) "RTSR" means the annualized growth in the dividends and share price of a Share, calculated using a 20 day trading average of the Company's closing price beginning on ___________________ and ending _________________ compared to the TSR performance of the TSR Peer Group. The starting and ending share prices for the computation of RTSR will equal the average closing price of each company's common stock over the 20 trading days immediately preceding the first and last day of the performance period.

(iv) "TSR Peer Group" means the peer group of companies determined by the Committee at its meeting on __________________.

Section 3. Termination of Employment.

(a) Termination of Service Prior to Vesting Date. Except as set forth below, if the Grantee's Service is terminated for any reason prior to the Vesting Date, then the Grantee shall forfeit the Performance Shares credited to the Grantee's Performance Share Account.

(b) Retirement, Disability or Death.

(i) Notwithstanding the foregoing, in the event that the Grantee's Service terminates prior to the Vesting Date as a result of the Grantee's (i) Retirement, (ii) Disability, or (iii) death and such death occurs with less than or equal to twelve months remaining in the Performance Period, then the Grantee (or the Grantee's beneficiary or estate in the case of the Grantee's death) shall vest in a pro rata portion of the Performance Shares, based on the actual performance results for the Performance Period. Such pro rata portion of the Performance Shares shall be determined by multiplying the number of Performance Shares earned based on actual performance by a fraction, where the numerator shall equal the number of calendar months (including partial calendar months) that have elapsed from the Grant Date through the date of the Grantee's termination of Service, and the denominator shall be the number of calendar months (including partial calendar months) that have elapsed between the Grant Date and the Vesting Date.

(ii) If the Grantee terminates Service due to death prior to the Vesting Date and with more than 12 months remaining in the Performance Period, then the Grantee's beneficiary or estate shall vest, on the date of termination, in a pro rata portion of the target Performance Shares. Such pro rata portion of the Performance Shares shall be determined by multiplying the number of target Performance Shares by a fraction, where the numerator shall equal the number of calendar months (including partial calendar months) that have elapsed from the Grant Date through the date of the Grantee's termination of Service, and the denominator shall be the number of calendar months (including partial calendar months) that have elapsed between the Grant Date and the Vesting Date.

(iii) "Retirement" means the Grantee's termination from Service at or after attainment of age 55 and completing at least ten years of service (within the meaning of the Company's tax-qualified pension plan as in effect on the Grant Date, regardless of whether the Grantee is eligible for such plan).

(c) Change in Control. Notwithstanding the foregoing provisions, in the event of a Change in Control, the Performance Shares under this Agreement shall be subject to the Change in Control provisions set forth in the Plan. In the event of any conflict between the Plan and this Agreement, the Plan shall control. Notwithstanding any other agreement between the Company and the Grantee, the "Good Reason" definition set forth in the Plan shall govern this award.

Section 4. Delivery of Shares. Subject to the terms of this Agreement and except as otherwise provided for herein, the Company shall convert the Performance Shares in the Grantee's Performance Share Account into Shares and issue or deliver the total number of Shares due to the Grantee within 60 days following the Vesting Date (but in any event no later than the March 15th immediately following the year in which the substantial risk of forfeiture with respect to the Performance Shares lapses) or, if earlier, within 30 days following (a) the Grantee's death in accordance with Section 3(b)(ii), (b) Grantee's termination of Service without Cause or due to Good Reason in accordance with the Change in Control provisions of the Plan or (c) a Change in Control in the event the Performance Shares do not become Alternative Awards under the Plan. The delivery of the Shares shall be subject to payment of the applicable withholding tax liability and the forfeiture provisions of this Agreement. If the Grantee dies before the Company has issued or distributed the vested Performance Shares, the Company shall transfer any Shares with respect to the vested Performance Shares in accordance with the Grantee's written beneficiary designation or to the Grantee's estate if no written beneficiary designation is provided. The issuance or deliver of the Shares hereunder shall be evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company. The Company shall pay all original issue or transfer taxes and all fees and expenses incident to such issuance or delivery, except as otherwise provided in Section 5.

Section 5. Withholding of Taxes. As a condition precedent to the delivery to Grantee of any Shares upon vesting of the Performance Shares, Grantee shall, upon request by the Company, pay to the Company such amount of cash as the Company may be required, under all applicable federal, state, local or other laws or regulations, to withhold and pay over as income or other withholding taxes (the "Required Tax Payments") with respect to the Performance Shares. If Grantee shall fail to advance the Required Tax Payments after request by the Company, the Company may, in its discretion, deduct any Required Tax Payments from any amount then or thereafter payable by the Company to Grantee or withhold Shares. Grantee may elect to satisfy his or her obligation to advance the Required Tax Payments by any of the following means: (a) a cash payment to the Company; (b) delivery to the Company (either actual delivery or by attestation procedures established by the Company) of previously owned whole Shares having a Fair Market Value, determined as of the date the obligation to withhold or pay taxes first arises in connection with the Performance Shares (the "Tax Date"), equal to the Required Tax Payments; (c) authorizing the Company to withhold from the Shares otherwise to be delivered to Grantee upon the vesting of the Performance Shares, a number of whole Shares having a Fair Market Value, determined as of the Tax Date, equal to the Required Tax Payments; or (d) any combination of (a), (b) and (c). Shares to be delivered or withheld may not have a Fair Market Value in excess of the minimum amount of the Required Tax Payments. Any fraction of a Share which would be required to satisfy such an obligation shall be disregarded and the remaining amount due shall be paid in cash by Grantee. No Shares shall be delivered until the Required Tax Payments have been satisfied in full.

Section 6. Compliance with Applicable Law. Notwithstanding anything contained herein to the contrary, the Company's obligation to issue or deliver certificates evidencing the Performance Shares shall be subject to all applicable laws, rules and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required. The delivery of all or any Shares that relate to the Performance Shares shall be effective only at such time that the issuance of such Shares shall not violate any state or federal securities or other laws. The Company is under no obligation to effect any registration of Shares under the Securities Act of 1933 or to effect any state registration or qualification of the Shares that may be issued under this Agreement. Subject to Section 409A of the Code (the "Section 409A"), the Company may, in its sole discretion, delay the delivery of Shares or place restrictive legends on Shares in order to ensure that the issuance of any Shares shall be in compliance with federal or state securities laws and the rules of any exchange upon which the Company's Shares are traded. If the Company delays the delivery of Shares in order to ensure compliance with any state or federal securities or other laws, the Company shall deliver the Shares at the earliest date at which the Company reasonably believes that such delivery shall not cause such violation, or at such later date that may be permitted under Section 409A.

Section 7. Restriction on Transferability. Except as otherwise provided under the Plan, until the Performance Shares have vested under this Agreement, the Performance Shares granted herein and the rights and privileges conferred hereby may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated (by operation of law or otherwise), other than by will or the laws of descent and distribution. Any attempted transfer in violation of the provisions of this paragraph shall be void, and the purported transferee shall obtain no rights with respect to such Performance Shares.

Section 8. Grantee's Rights Unsecured. The right of the Grantee or his or her beneficiary to receive a distribution hereunder shall be an unsecured claim against the general assets of the Company, and neither the Grantee nor his or her beneficiary shall have any rights in or against any amounts credited to the Grantee's Performance Share Account, any Shares or any other specific assets of the Company. All amounts credited to the Grantee's Performance Share Account shall constitute general assets of the Company and may be disposed of by the Company at such time and for such purposes as it may deem appropriate.

Section 9. No Rights as Stockholder or Employee. The Grantee shall not have any privileges of a stockholder of the Company (including, without limitation, any voting rights or rights to receive dividends) with respect to the Performance Shares subject to this Agreement. Furthermore, nothing in this Agreement shall confer upon the Grantee any right to continue as an Employee of the Company or any Affiliate or to interfere in any way with the right of the Company or any Affiliate to terminate the Grantee's Service at any time.

Section 10. Adjustments. If at any time while the award is outstanding, the number of outstanding Performance Shares is changed by reason of a reorganization, recapitalization, stock split or any of the other events described in the Plan, the number and kind of Performance Shares and the performance goals, as applicable, shall be adjusted in accordance with the provisions of the Plan.

Section 11. Notices. Any notice hereunder by the Grantee shall be given to the Company in writing, and such notice shall be deemed duly given only upon receipt thereof at the following address: Corporate Secretary, NiSource Inc., 801 East 86th Avenue, Merrillville, IN 46410-6271 (or at such other address as the Company may designate by notice to the Grantee). Any notice hereunder by the Company shall be given to the Grantee in writing, and such notice shall be deemed duly given only upon receipt thereof at such address as the Grantee may have on file with the Company.

Section 12. Administration. The administration of this Agreement, including the interpretation and amendment or termination of this Agreement, shall be performed in accordance with the Plan. All determinations and decisions made by the Committee, the Board, or any delegate of the Committee as to the provisions of this Agreement shall be conclusive, final, and binding on all persons. Notwithstanding the foregoing, if subsequent guidance is issued under Section 409A that would impose additional taxes, penalties, or interest to either the Company or the Grantee, the Company may administer this Agreement in accordance with such guidance and amend this Agreement without the consent of the Grantee to the extent such actions, in the reasonable judgment of the Company, are considered necessary to avoid the imposition of such additional taxes, penalties, or interest.

Section 13. Governing Law. This Agreement shall be construed and enforced in accordance with the laws of the State of Indiana, without giving effect to the choice of law principles thereof.

Section 14. Entire Agreement; Agreement Subject to Plan. This Agreement and the Plan contain all of the terms and conditions with respect to the subject matter hereof and supersede any previous agreements, written or oral, relating to the subject matter hereof. This Agreement is subject to the provisions of the Plan and shall be interpreted in accordance therewith. In the event that the provisions of this Agreement and the Plan conflict, the Plan shall control. The Grantee hereby acknowledges receipt of a copy of the Plan.

Section 15. Section 409A Compliance. This Agreement and the Performance Shares granted hereunder are intended to be exempt from Section 409A to the maximum extent possible, and shall be interpreted and construed accordingly.

[SIGNATURE PAGE TO FOLLOW]

IN WITNESS WHEREOF, the Company has caused the Performance Shares subject to this Agreement to be granted, and the Grantee has accepted the Performance Shares subject to the terms of the Agreement, as of the date first above written.

NiSource Inc.

____

By: __________________

Its: __________________

GRANTEE

By: ____

____

NiSource Inc.
20__ Omnibus Incentive Plan

20__ Restricted Stock Unit Award Agreement

This Restricted Stock Unit Award Agreement (the "Agreement"), is made and entered into as of [________] (the "Date of Grant"), by and between NiSource Inc., a Delaware corporation (the "Company"), and [________], an Employee of the Company (the "Grantee").

Section 1. Restricted Stock Unit Award. The Company hereby grants to the Grantee, on the terms and conditions hereinafter set forth, an Award of [________] Restricted Stock Units. The Restricted Stock Units will be represented by a bookkeeping entry (the "RSU Account") of the Company, and each Restricted Stock Unit shall be equivalent to one share of the Company's common stock.

Section 2. Grantee Accounts. The number of Restricted Stock Units granted pursuant to this Agreement shall be credited to the Grantee's RSU Account. Each RSU Account shall be maintained on the books of the Company until full payment of the balance thereof has been made to the Grantee (or the Grantee's beneficiaries or estate if the Grantee is deceased) in accordance with Section 1 above. No funds shall be set aside or earmarked for any RSU Account, which shall be purely a bookkeeping device.

Section 3. Vesting and Lapse of Restrictions.

(a) Vesting. Subject to the forfeiture conditions described later in this Agreement, the Restricted Stock Units shall vest [________] (the "Vesting Date"), at which date they shall become 100% vested, provided that the Grantee is continuously employed by the Company through and including the Vesting Date. Except as set forth in subsection (b) hereof, if Grantee's Service is terminated for any reason prior to the Vesting Date, the unvested Restricted Stock Units subject to this Agreement shall immediately terminate and be automatically forfeited by Grantee.

(b) Effect of Termination of Service Prior to Vesting. Notwithstanding the foregoing, in the event that the Grantee's Service terminates prior to the Vesting Date as a result of (i) the Grantee's Retirement, (ii) the Grantee's death, or (iii) the Grantee's Disability, the restrictions set forth in subsection (a) above shall lapse with respect to a *pro rata* portion of such Restricted Stock Units on the date of termination of Service. Such *pro rat*a lapse of restrictions shall be determined using a fraction, where the numerator shall be the number of full or partial calendar months elapsed between the Date of Grant and the date the Grantee terminates Service, and the denominator shall be the number of full or partial calendar months between the Date of Grant and the Vesting Date. For purposes of this Agreement, "Retirement" means the Grantee's termination from Service with the Company at or after attainment of age 55 and completing 10 years of service (within the meaning of the Company's tax-qualified pension plan in effect on the Date of Grant, regardless of whether the Grantee is eligible for such plan).

(c) Change in Control. Notwithstanding the foregoing provisions, in the event of a Change in Control, the Restricted Stock Units under this Agreement shall be subject to the Change in Control provisions set forth in the Plan. In the event of any conflict between the Plan and this Agreement, the Plan shall control. Notwithstanding the foregoing or anything herein to the contrary, in the event the Restricted Stock Units do not become Alternative Awards under the Plan, then the Restricted Stock Units shall be settled within 60 days following the Change in Control; provided, however, in the event the Restricted Stock Units constitute nonqualified deferred compensation subject to Code Section 409A and the Change in Control is not a "change in control event" within the meaning of Code Section 409A, then, to the extent required to comply with Code Section 409A, the vested Restricted Stock Units shall be settled within 60 days following the Vesting Date or, if earlier and subject to Section 4, upon Grantee's termination of Service.

Section 4. Delivery of Shares. Once Restricted Stock Units have vested under this Agreement, the Company will determine the number of Shares represented by the vested Restricted Stock Units in the Grantee's RSU Account and deliver the total number of Shares due to the Grantee within 60 days following the Vesting Date or, if earlier, Grantee's termination of Service in accordance with Section 3(b). Notwithstanding the foregoing, to the extent any portion of the Restricted Stock Units are subject to Code Section 409A, if any Restricted Stock Units vest prior to the Vesting Date in connection with a Grantee's "separation from service" within the meaning of Code Section 409A and the Grantee is a "specified employee" within the meaning of Code Section 409A at the time of such separation from service, the Shares represented by the vested Restricted Stock Units shall be issued and delivered on the first business day after the date that is six (6) months following the date of the Grantee's separation from service (or if earlier, the Grantee's date of death). The delivery of the Shares shall be subject to payment of the applicable withholding tax liability and the forfeiture provisions of this Agreement. If the Grantee dies before the Company has distributed any portion of the vested Restricted Stock Units, the Company will transfer any Shares payable with respect to the vested Restricted Stock Units in accordance with the Grantee's written beneficiary designation or to the Grantee's estate if no written beneficiary designation is provided.

Section 5. Withholding of Taxes. The Company shall have the power and the right to deduct or withhold, or require the Grantee to remit to the Company, an amount sufficient to satisfy federal, state, and local taxes, domestic or foreign, required by law or regulation to be withheld with respect to any taxable event arising as a result of this Agreement.

Section 6. Securities Law Compliance. The delivery of all or any Shares that relate to the Restricted Stock Units shall only be effective at such time that the issuance of such Shares will not violate any state or federal securities or other laws. The Company is under no obligation to effect any registration of Shares under the Securities Act of 1933 or to effect any state registration or qualification of the Shares that may be issued under this Agreement. The Company may, in its sole discretion, delay the delivery of Shares or place restrictive legends on Shares in order to ensure that the issuance of any Shares will be in compliance with federal or state securities laws and the rules of any exchange upon which the Shares are then traded. If the Company delays the delivery of Shares in order to ensure compliance with any state or federal securities or other laws, the Company shall deliver the Shares at the earliest date at which the Company reasonably believes that such delivery will not cause such violation, or at such later date that may be permitted under Code Section 409A.

Section 7. Restriction on Transferability. Except as otherwise provided under the Plan, until the Restricted Stock Units have vested under this Agreement, the Restricted Stock Units granted herein and the rights and privileges conferred hereby may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated (by operation of law or otherwise), other than by will or the laws of descent and distribution. Any attempted transfer in violation of the provisions of this paragraph shall be void, and the purported transferee shall obtain no rights with respect to such Restricted Stock Units.

Section 8. Grantee's Rights Unsecured. The right of the Grantee or his or her beneficiary to receive a distribution hereunder shall be an unsecured claim against the general assets of the Company, and neither the Grantee nor his or her beneficiary shall have any rights in or against any amounts credited to the Grantee's RSU Account or any other specific assets of the Company. All amounts credited to the Grantee's RSU Account shall constitute general assets of the Company and may be disposed of by the Company at such time and for such purposes, as it may deem appropriate.

Section 9. No Rights as Stockholder or Employee.

(a) Unless and until Shares have been issued to the Grantee, the Grantee shall not have any privileges of a stockholder of the Company with respect to any Restricted Stock Units subject to this Agreement, nor shall the Company have any obligation to issue any dividends or otherwise afford any rights to which Shares are entitled with respect to any such Restricted Stock Units.

(b) Nothing in this Agreement or the Award shall confer upon the Grantee any right to continue as an Employee of the Company or any Affiliate or to interfere in any way with the right of the Company or any Affiliate to terminate the Grantee's Service at any time.

Section 10. Adjustments. If at any time while the Award is outstanding, the number of outstanding Restricted Stock Units is changed by reason of a reorganization, recapitalization, stock split or any of the other events described in the Plan, the number and kind of Restricted Stock Units shall be adjusted in accordance with the provisions of the Plan. In the event of certain corporate events specified in the Change in Control provisions of the Plan, any unvested Restricted Stock Units may be replaced by substituted Awards or forfeited in exchange for payment of cash in accordance with the Change in Control procedures and provisions of the Plan.

Section 11. Notices. Any notice hereunder by the Grantee shall be given to the Company in writing and such notice shall be deemed duly given only upon receipt thereof at the following address: Corporate Secretary, NiSource Inc., 801 East 86th Avenue, Merrillville, IN 46410-6271, or at such other address as the Company may designate by notice to the Grantee. Any notice hereunder by the Company shall be given to the Grantee in writing and such notice shall be deemed duly given only upon receipt thereof at such address as the Grantee may have on file with the Company.

Section 12. Administration. The administration of this Agreement, including the interpretation and amendment or termination of this Agreement, will be performed in accordance with the Plan. All determinations and decisions made by the Committee, the Board, or any delegate of the Committee as to the provisions of this Agreement shall be conclusive, final, and binding on all persons. This Agreement at all times shall be governed by the Plan, which is incorporated in this Agreement by reference, and in no way alter or modify the Plan. All capitalized terms used in this Agreement and not defined herein shall have the meaning set forth in the Plan. To the extent a conflict exists between this Agreement and the Plan, the provisions of the Plan shall govern. Notwithstanding the foregoing, if subsequent guidance is issued under Code Section 409A that would impose additional taxes, penalties, or interest to either the Company or the Grantee, the Company may administer this Agreement in accordance with such guidance and amend this Agreement without the consent of the Grantee to the extent such actions, in the reasonable judgment of the Company, are considered necessary to avoid the imposition of such additional taxes, penalties, or interest.

Section 13. Governing Law. This Agreement shall be construed and enforced in accordance with the laws of the State of Indiana, without giving effect to the choice of law principles thereof.

Section 14. Government Regulations. Notwithstanding anything contained herein to the contrary, the Company's obligation to issue or deliver certificates evidencing the Restricted Stock Units shall be subject to all applicable laws, rules and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

Section 15. **<u>Entire Agreement; Code Section 409A Compliance</u>.** This Agreement and the Plan contain the terms and conditions with respect to the subject matter hereof and supersede any previous agreements, written or oral, relating to the subject matter hereof. This Agreement is pursuant to the terms of the Company's 20__ Omnibus Incentive Plan (the "Plan"). The applicable terms of the Plan are incorporated herein by reference, including the definition of capitalized terms contained in the Plan, and including the Code Section 409A provisions of the Plan. This Agreement shall be interpreted in accordance with Code Section 409A including the rules related to payment timing for "specified employees" within the meaning of Code Section 409A. This Agreement shall be deemed to be modified to the maximum extent necessary to be in compliance with Code Section 409A's rules. If the Grantee is unexpectedly required to include in the Grantee's current year's income any amount of compensation relating to the Restricted Stock Units because of a failure to meet the requirements of Code Section 409A, then to the extent permitted by Code Section 409A, the Grantee may receive a distribution of cash or Shares in an amount not to exceed the amount required to be included in income as a result of the failure to comply with Code Section 409A.

[SIGNATURE PAGE TO FOLLOW]

IN WITNESS WHEREOF, the Company has caused this Award to be granted, and the Grantee has accepted this Award, as of the date first above written.

NiSource Inc.

____
By:
Its:

GRANTEE

By: ______________________

Exhibit 10.41

NiSource Inc.

20__ Omnibus Incentive Plan

20__ Cash Based Award Agreement

This Cash-Based Award Agreement (the "Agreement"), is made and entered into as of _____ 20__ (the "Date of Grant"), by and between NiSource Inc., a Delaware corporation (the "Company"), and ___________, an Employee of the Company (the "Grantee").

Section 1. <u>Cash-Based Award</u>. The Company hereby grants to the Grantee, on the terms and conditions hereinafter set forth, an Award of $__________________as a Cash-Based Award. The Cash-Based Award may be recorded as a bookkeeping entry (the "Cash-Based Account") of the Company.

Section 2. <u>Grantee Accounts</u>. If determined to be desirable by the Company, the amount of the Cash-Based Award pursuant to this Agreement will be credited to the Grantee's Cash-Based Account and each Cash-Based Account will be maintained on the books of the Company until full payment of the balance thereof has been made to the Grantee (or the Grantee's beneficiaries or estate if the Grantee is deceased) in accordance with Section 1 above. No funds shall be set aside or earmarked for any Cash-Based Account, which, if utilized, shall be purely a bookkeeping device.

Section 3. <u>Vesting and Lapse of Restrictions</u>.

(a) <u>Vesting</u>. Subject to the forfeiture conditions described later in this Agreement, the Cash-Based Award shall vest as set forth on Schedule A, attached hereto, provided that the Grantee is continuously employed by the Company through and including the vesting dates as described on Schedule A. Except as set forth in subsection (b) hereof, if Grantee's Service is terminated for any reason prior to the applicable Vesting Date(s) (as defined on Schedule A), any unvested portion of the Cash-Based Award subject to this Agreement shall immediately terminate and be automatically forfeited by Grantee.

(b) <u>Effect of Termination of Service Prior to Vesting</u>. Notwithstanding the foregoing, in the event that the Grantee's Service terminates prior to the Vesting Date as a result of (i) the Grantee's death or (ii) the Grantee's Disability, any remaining vesting conditions set forth in subsection (a) above shall lapse with respect to a *pro rata* portion of any remaining unvested portion of such Cash-Based Award on the date of termination of Service. Such *pro rata* lapse of the remaining vesting conditions shall be determined using a fraction, where the numerator shall be the number of full or partial calendar months elapsed between the Date of Grant and the date the Grantee terminates Service, and the denominator shall be the number of full or partial calendar months between the Date of Grant and the final Vesting Date. In addition, notwithstanding the foregoing, in the event that the Grantee's Service terminates prior to the Vesting Date as a result of the termination of the Grantee's Service by the Company without Cause, any remaining vesting conditions set forth in subsection (a) above shall lapse with respect to one-hundred percent (100%) of any remaining unvested portion of such Cash-Based Award on the date of termination of Service.

(c) <u>Change in Control</u>. Notwithstanding the foregoing provisions, in the event of a Change in Control, the Cash-Based Award under this Agreement shall be subject to the Change in Control

Provisions set forth in the Plan. In the event of any conflict between the Plan and this Agreement, the Plan shall control.

Section 4. <u>Payment of Cash Amount</u>. Once the Cash-Based Award has vested under this Agreement, the Company will deliver the total amount in the Cash-Based Account of the Grantee, without interest or any other appreciation factor, within 60 days following the Vesting Date, or if earlier, the Grantee's termination of service in accordance with Section 3(b). Notwithstanding the foregoing, to the extent any portion of the Cash-Based Award is subject to Code Section 409A, if any portion of the Cash-Based Award vests prior to the Vesting Date in connection with a Grantee's "separation from service" within the meaning of Code Section 409A and the Grantee is a "specified employee" within the meaning of Code Section 409A at the time of such separation from service, that portion of the Cash-Based Award will be paid on the first business day after the date that is six (6) months following the date of the Grantee's separation from service (or if earlier, the Grantee's date of death). The payment of the Cash-Based Award shall be subject to payment of the applicable withholding tax liability and the forfeiture provisions of this Agreement. If the Grantee dies before the Company has distributed any portion of the vested Cash-Based Award, the Company will transfer any amount payable with respect to the vested Cash-Based Award in accordance with the Grantee's written beneficiary designation or to the Grantee's estate if no written beneficiary designation is provided.

Section 5. <u>Withholding of Taxes</u>. The Company shall have the power and the right to deduct or withhold, or require the Grantee to remit to the Company, an amount sufficient to satisfy federal, state, and local taxes, domestic or foreign, required by law or regulation to be withheld with respect to any taxable event arising as a result of this Agreement.

Section 6. <u>Restriction on Transferability</u>. Except as otherwise provided under the Plan, until the Cash-Based Award has vested under this Agreement, the right to the value of the Cash-Based Award granted herein and the rights and privileges conferred hereby may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated (by operation of law or otherwise), other than by will or the laws of descent and distribution. Any attempted transfer in violation of the provisions of this paragraph shall be void, and the purported transferee shall obtain no rights with respect to such Cash-Based Award.

Section 7. <u>Grantee's Rights Unsecured</u>. The right of the Grantee or his or her beneficiary to receive a distribution hereunder shall be an unsecured claim against the general assets of the Company, and neither the Grantee nor his or her beneficiary shall have any rights in or against any amounts credited to the Grantee's Cash-Based Account or any other specific assets of the Company. All amounts credited to the Grantee's Cash-Based Account shall constitute general assets of the Company and may be disposed of by the Company at such time and for such purposes, as it may deem appropriate.

Section 8. <u>No Rights as Employee</u>. Nothing in this Agreement or the Award shall confer upon the Grantee any right to continue as an Employee of the Company or any Affiliate or to interfere in any way with the right of the Company or any Affiliate to terminate the Grantee's Service at any time.

Section 9. <u>Notices</u>. Any notice hereunder by the Grantee shall be given to the Company in writing and such notice shall be deemed duly given only upon receipt thereof at the following address: Corporate Secretary, NiSource Inc., 801 East 86th Avenue, Merrillville, IN 46410-6271, or at such other address as the Company may designate by notice to the Grantee. Any notice hereunder by the Company shall be given to the Grantee in writing and such notice shall be deemed duly given only upon receipt thereof at such address as the Grantee may have on file with the Company.

Section 10. <u>Administration</u>. The administration of this Agreement, including the interpretation and amendment or termination of this Agreement, will be performed in accordance with the Plan. All determinations and decisions made by the Committee, the Board, or any delegate of the Committee as to the provisions of this Agreement shall be conclusive, final, and binding on all persons. This Agreement at all times shall be governed by the Plan, which is incorporated in this Agreement by reference, and in no way alter or modify the Plan. All capitalized terms used in this Agreement and not defined herein shall have the meaning set forth in the Plan. To the extent a conflict exists between this Agreement and the Plan, the provisions of the Plan shall govern. Notwithstanding the foregoing, if subsequent guidance is issued under Code Section 409A that would impose additional taxes, penalties, or interest to either the Company or the Grantee, the Company may administer this Agreement in accordance with such guidance and amend this Agreement without the consent of the Grantee to the extent such actions, in the reasonable judgment of the Company, are considered necessary to avoid the imposition of such additional taxes, penalties, or interest.

Section 11. **Governing Law.** This Agreement shall be construed and enforced in accordance with the laws of the State of Indiana, without giving effect to the choice of law principles thereof.

Section 12. **Government Regulations.** Notwithstanding anything contained herein to the contrary, the Company's obligation to issue or deliver certificates evidencing the Restricted Stock Units shall be subject to all applicable laws, rules and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

Section 13. **Entire Agreement; Code Section 409A Compliance.** This Agreement and the Plan contain the terms and conditions with respect to the subject matter hereof and supersede any previous agreements, written or oral, relating to the subject matter hereof. This Agreement is pursuant to the terms of the Company's 20__ Omnibus Incentive Plan, as amended (the "Plan"). The applicable terms of the Plan are incorporated herein by reference, including the definition of capitalized terms contained in the Plan, and including the Code Section 409A provisions of the Plan. This Agreement shall be interpreted in accordance with Code Section 409A including the rules related to payment timing for "specified employees" within the meaning of Code Section 409A. This Agreement shall be deemed to be modified to the maximum extent necessary to be in compliance with Code Section 409A's rules. If the Grantee is unexpectedly required to include in the Grantee's current year's income any amount of compensation relating to the Cash-Based Award because of a failure to meet the requirements of Code Section 409A, then to the extent permitted by Code Section 409A, the Grantee may receive a distribution of cash in an amount not to exceed the amount required to be included in income as a result of the failure to comply with Code Section 409A.

[SIGNATURE PAGE TO FOLLOW]

IN WITNESS WHEREOF, the Company has caused this Award to be granted, and the Grantee has accepted this Award, as of the date first above written.

NiSource Inc.

By:

Its:

GRANTEE

By: ____
[_____________]

SCHEDULE A

Exhibit 21

SUBSIDIARIES OF NISOURCE

as of December 31, 2019

Segment/Subsidiary	
GAS DISTRIBUTION OPERATIONS	**State of Incorporation**
Bay State Gas Company d/b/a Columbia Gas of Massachusetts	Massachusetts
Central Kentucky Transmission Company	Delaware
Columbia Gas of Kentucky, Inc.	Kentucky
Columbia Gas of Maryland, Inc.	Delaware
Columbia Gas of Ohio, Inc.	Ohio
Columbia Gas of Pennsylvania, Inc.	Pennsylvania
Columbia Gas of Virginia, Inc.	Virginia
NiSource Gas Distribution Group, Inc.	Delaware
ELECTRIC OPERATIONS	
Northern Indiana Public Service Company LLC*	Indiana
CORPORATE AND OTHER OPERATIONS	
Columbia Gas of Ohio Receivables Corporation	Delaware
Columbia Gas of Pennsylvania Receivables Corporation	Delaware
Indiana Crossroads Wind Generation LLC	Indiana
NIPSCO Accounts Receivable Corporation	Indiana
NiSource Corporate Group, LLC	Delaware
NiSource Corporate Services Company	Delaware
NiSource Development Company, Inc.	Indiana
NiSource Energy Technologies, Inc.	Indiana
NiSource Strategic Sourcing Inc.	Ohio
NiSource Insurance Corporation, Inc.	Utah
Lake Erie Land Company	Indiana
RoseWater Wind Generation LLC	Indiana
NiSource Retail Services, Inc.	Delaware (Inactive)
EnergyUSA-TPC, Inc.	Indiana (Inactive)

* Reported under Gas Distribution Operations and Electric Operations.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-234422 on Form S-3, Registration Statement Nos. 333-107743, 333-166888, 333-204168, and 333-233382 on Form S-8, and Registration Statement Nos. 333-228790 and 333-228791 on Form S-4 of our reports dated February 27, 2020, relating to the financial statements of NiSource Inc. and subsidiaries (the “Company”) and the effectiveness of the Company’s internal control over financial reporting appearing in this Annual Report on Form 10-K for the year ended December 31, 2019.

/s/ DELOITTE & TOUCHE LLP
Columbus, Ohio
February 27, 2020

Exhibit 31.1

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Joseph Hamrock, certify that:

1. I have reviewed this Annual Report on Form 10-K of NiSource Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date:	February 27, 2020	By:	/s/ Joseph Hamrock
			Joseph Hamrock
			President and Chief Executive Officer

Exhibit 31.2

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Donald E. Brown, certify that:

1. I have reviewed this Annual Report on Form 10-K of NiSource Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date:	February 27, 2020	By:	/s/ Donald E. Brown
			Donald E. Brown
			Executive Vice President and Chief Financial Officer

Exhibit 32.1

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of NiSource Inc. (the “Company”) on Form 10-K for the year ending December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Joseph Hamrock, Chief Executive Officer of the Company, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Joseph Hamrock

Joseph Hamrock
President and Chief Executive Officer

Date: February 27, 2020

Exhibit 32.2

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of NiSource Inc. (the "Company") on Form 10-K for the year ending December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Donald E. Brown, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Donald E. Brown

Donald E. Brown
Executive Vice President and Chief Financial Officer

Date: February 27, 2020

2018 INTEGRATED ANNUAL REPORT

NiSource®

87%
ESTIMATED TIME OF RESTORATION (ETR) ACCURACY

NIPSCO'S ELECTRIC ETR **EXCEEDED ITS 2018 MILESTONE OF 85%**; UP FROM 80% IN 2017

During service outages, NIPSCO customers experienced the benefits of increased collaboration and continuous improvement across our teams. Among the many improvements, all customers with an email address on file were enrolled in outage alerts. Thanks to increased employee communication and technology enhancements, customers now view outage details including the ETR and outage cause.

NISOURCE STAKEHOLDERS

This 2018 Integrated Annual Report is an opportunity to share the many ways in which we continue to focus on delivering value for our customers, communities and stakeholders.

JOE HAMROCK

Yet no discussion of 2018 performance would be complete if we didn't take time to reflect on the September event that resulted in the loss of a young life and affected nearly 10,000 customers in Andover, Lawrence and North Andover, Massachusetts. On September 13, trust in us was broken for many in the Merrimack Valley. We take responsibility for this tragic event and the hardships it has brought. We witnessed the heart, strength and resilience of the residents, heroic efforts of first responders and compassion of community partners. As we continue working with the communities during our restoration efforts, we remain humbled by their dedication and sacrifices.

In the aftermath of the event, we worked to assist in rebuilding the affected communities. We provided support for essential needs and mobilized significant resources to begin the recovery process. We launched a series of safety enhancements, and then began the largest natural gas restoration project in our company's history. This involved replacing 43.5 miles of natural gas pipelines, installing equipment, appliances, smoke alarms and carbon monoxide detectors for customers and processing nearly 25,000 claims for residents and businesses.

I'm deeply grateful to the more than 4,500 NiSource employees and contractor partners who came to provide support and help ensure the safety of these communities. This response embodies the values and dedication of our NiSource team. Our company is built by employees, crossing multiple generations, who have worked tirelessly for more than 100 years to provide service to millions of our customers across seven states.

We know our work in the Merrimack Valley isn't done, and we will continue to meet the commitments we have made to our customers and these communities.

While this incident doesn't define the rich history or legacy of our company, it certainly defines our path forward. Our commitment will be resolute and unwavering to take steps to prevent a similar event happening again.

This report shares how our dedicated NiSource team continues to invest in safety upgrades and infrastructure enhancements, deliver on our financial and environmental commitments, build a strong culture, and seek to ensure we attract, develop and retain our workforce for the future. NiSource is well positioned to continue to deliver long-term shareholder value.

Thank you for your continued interest and support, and for your investment in NiSource.

Joe Hamrock

JOE HAMROCK
President &
Chief Executive Officer
NiSource Inc.

Senior Management TEAM

JOSEPH HAMROCK
President &
Chief Executive Officer

DONALD E. BROWN
Executive Vice President &
Chief Financial Officer

CARRIE J. HIGHTMAN
Executive Vice President &
Chief Legal Officer

VIOLET G. SISTOVARIS
Executive Vice President &
President, NIPSCO

PABLO A. VEGAS
Executive Vice President &
President, Gas Utilities

SUZANNE K. SURFACE
Chief Services Officer

PETER T. DISSER
Vice President, Internal Audit

SENIOR MANAGEMENT TEAM WORKFORCE STATS
(AS OF MARCH 1, 2019)
7 TOTAL
57% MEN | **43%** WOMEN
29% MINORITIES

LETTER FROM THE CHAIRMAN

As I reflect on 2018, it was undoubtedly one of the most challenging years for our company. The event in the Merrimack Valley forever changed NiSource.

As your Board of Directors, our role is to learn from that day and, most importantly, use what we have learned to guide management and our future direction.

The Board remains fully engaged with Joe Hamrock and the leadership team in regular briefings, while providing oversight of our executives leading the response.

The Board and I have now reviewed and endorsed an accelerated schedule for implementing a Safety Management System across all of our companies. In conjunction with meeting our commitments in the Merrimack Valley and executing on the urgent recommendations from the National Transportation Safety Board, we view this as the top priority for our natural gas business.

While the restoration and recovery in Massachusetts was a major focus, disciplined execution throughout the year has allowed our teams to deliver solid results.

Continuing our emphasis on sustainability, NiSource advanced an electric generation strategy in Indiana with submission of a long-term plan to transition its coal-fired generating fleet to lower-cost renewable resources.

In 2018, we welcomed Theodore Bunting, Jr. to the Board. A former group president, utility operations, at Entergy Corporation, Theo brings industry experience in customer service, safety and regulatory relations which will be valuable as we continue executing on our safety and infrastructure investments.

The Board remains closely engaged as we deliver on our long-term plan to create value for customers, shareholders and all stakeholders.

Sincerely,

Rich Thompson

Rich Thompson
Chairman of the Board
NiSource Inc.

Board of DIRECTORS

RICHARD L. THOMPSON
Chairman of the Board,
NiSource Inc.

KEVIN T. KABAT
Vice Chairman of the Board,
NiSource Inc. and
Retired Vice Chairman & CEO,
Fifth Third Bancorp

PETER A. ALTABEF
Chairman, President & CEO,
Unisys Corporation

THEODORE H. BUNTING, JR.
Retired Group President,
Entergy Corporation

ERIC L. BUTLER
Retired Executive Vice President,
Union Pacific Corporation

ARISTIDES S. CANDRIS
Retired President & CEO,
Westinghouse Electric Company

WAYNE S. DEVEYDT
Chief Executive Officer,
Surgery Partners, Inc.

JOSEPH HAMROCK
President & CEO,
NiSource Inc.

DEBORAH A. HENRETTA
Partner, G100 Companies and
Retired Group President,
Procter & Gamble Co.

MICHAEL E. JESANIS
Retired President & CEO,
National Grid USA

CAROLYN Y. WOO
Retired President & CEO,
Catholic Relief Services

BOARD OF DIRECTORS
WORKFORCE STATS
(AS OF MARCH 1, 2019)
11 TOTAL
82% MEN | **18%** WOMEN
27% MINORITIES

INVESTING IN SAFETY

Safety is not just a commitment we talk about — it is our top priority, the foundation of our business and what guides all of our actions.

In 2018, we completed the four state-of-the-art training centers we announced in 2016 to enhance training for gas operations employees and first responders across our service territory.

We continue to invest in safety improvements, implement policies and procedures, develop technical training and guidelines for our employees, and leverage new tools and technology to improve our maps, records and infrastructure performance.

We are focused on establishing a framework for identifying and mitigating risk, continuously improving pipeline safety and integrity and safeguarding against over-pressurization. We continue to evaluate every opportunity to engineer increased safety measures in our gas delivery systems, including the accelerated implementation of a Safety Management System (SMS). Our SMS is aligned with the framework developed for pipeline operators by the American Petroleum Institute. This framework helps operators proactively identify and mitigate risk, communicate with stakeholders, ensure effective operation of key processes, promote a learning environment and continuously improve pipeline safety and integrity.

At its core, SMS is an advanced, comprehensive approach to safety that enhances how we predict and mitigate risks.

We initially launched SMS in Indiana and Virginia, and are now accelerating implementation across the rest of the company. Our initial progress resulted in the development of our SMS policy, tools and processes including a risk register to capture and prioritize risks, a performance improvement process that identifies the risk and tracks it to closure, and foundational employee training.

We will continue to build a strong safety culture that encourages transparency and two-way communication between leaders and employees, and promotes safety leadership and individual accountability at all levels in the organization.

EMPLOYEE SAFETY

Our employees take actions each day to keep themselves, one another, our customers and our communities safe. We've operated for several years with the milestone of top-decile employee safety performance within the utility industry. In 2018, we did not achieve our top-decile goals in our core metrics of two

Occupational, Health & Safety Administration (OSHA) standards — incident rates and recordable injury rates.

We are focused on learning and continuous improvement. We have operating areas across our company that continue to sustain high employee safety performance year after year, and we will learn from these groups. In the Merrimack Valley restoration, with more than 4,500 people working and more than 11,000 job observations conducted by safety professionals, we had no recordable injuries during the pipeline installation. We will leverage the lessons learned across our company.

LOW-PRESSURE SYSTEM ENHANCEMENTS

Immediately following the events in Merrimack Valley, we conducted a field survey of our low-pressure regulator systems to identify available options to enhance the safe, reliable operation of these systems. We also conducted an engineering design review to determine how best to install additional over-pressure protection systems, monitoring and enhanced facility protection.

We used the information we gathered to add new details to our electronic mapping system that front-line and engineering employees can easily access and leverage to enhance safe operations.

We have committed to invest an initial estimate of $150 million to install automatic shut-off devices to protect against over-pressurization on low-pressure systems across our operating area.

Automatic shut-off devices provide an additional level of control and protection, operating like circuit-breakers at our regulator stations. When the device senses an operating pressure that is too high or too low, it immediately shuts down gas to the system, regardless of the cause.

Our low-pressure distribution systems — containing approximately 2,000 regulators across our operating area — will have automatic shut-off devices in place to enhance customer safety.

We have committed to increasing remote monitoring capabilities on our low-pressure systems, leveraging technology that will be installed throughout 2019. Building on existing monitoring capabilities, these will allow us to see more comprehensive details on the current health and status of our systems as well as how those systems perform throughout the year.

We have further enhanced our damage prevention practices around low-pressure regulator stations, including field inspection and monitoring of excavators working for third parties. These enhanced work practices were implemented at the end of 2018 across all of our states and help to reduce the risk of potential facility damage.

Throughout 2019 and into the future, we will continue enhancing safety measures and seeking to reduce potential risks across all our low-pressure systems.

Safety BY THE NUMBERS

MEASURE	SAFETY MILESTONE	2018 STATUS	2017 STATUS	CURRENT PERFORMANCE
DART RATE*	INDUSTRY TOP DECILE	0.84	0.43	SECOND QUARTILE
RECORDABLE INJURY RATE	INDUSTRY TOP DECILE	1.36	0.91	SECOND QUARTILE
VEHICLE COLLISION RATE	INDUSTRY TOP DECILE	1.96	1.67	FIRST QUARTILE
BUSINESS PARTNER DART RATE*	INDUSTRY TOP DECILE	0.29	0.50	TOP DECILE
BUSINESS PARTNER RECORDABLE INJURY RATE	INDUSTRY TOP DECILE	0.78	1.22	TOP DECILE

* DAYS AWAY, RESTRICTED OR TRANSFERRED

PRESERVING THE ENVIRONMENT

We are part of the communities we have served for generations and consider the economic, social, and environmental impact our operations have on our customers and communities today and in the future.

OUR ELECTRIC GENERATION STRATEGY – YOUR ENERGY, YOUR FUTURE

We are taking steps for a cleaner, more sustainable energy future. In late 2018, our Indiana-based company, Northern Indiana Public Service Company (NIPSCO), announced plans to retire all of its coal-fired electric generation by 2028 and replace that capacity with renewable energy sources, such as wind, solar, and battery storage technology. This generation strategy is projected to result in a **90 percent reduction** in greenhouse gas emissions, a **99 percent reduction** in water withdrawal, wastewater discharge, nitrogen oxides, sulfur dioxide, and mercury and a **100 percent reduction** in coal ash generated.

NIPSCO outlined this electric generation strategy at a September public meeting with customers, consumer representatives, environmental organizations and other stakeholders taking part in the company's Integrated Resource Planning (IRP) process. NIPSCO submitted the plan to the Indiana Utility Regulatory Commission in October 2018.

HELPING OUR POLLINATORS

Safety and reliability requirements call for low-growing vegetation on the thousands of miles that make up our pipeline and electric transmission rights-of-way. Through integrated vegetation management, NiSource is transforming rights-of-way into pollinator habitats, managing ecosystems of native grasses and wildflowers that attract important wildlife like monarch butterflies, bees and hummingbirds at a time when their populations are falling. The program first launched in Kentucky followed by projects in Ohio and Virginia. Our programs are being certified by the Wildlife Habitat Council.

NIPSCO has already retired two coal-fired electric generating units and has plans to retire four additional coal-fired units by 2023. Overall, once approved, our plan to replace coal-fired generation with renewable sources is projected to result in more than $4 billion in long-term customer cost savings.

REDUCING METHANE EMISSIONS

Our companies are committed to meeting current and future environmental obligations that align with our business needs, and we have demonstrated a commitment to emissions reductions in our gas distribution operations. Through our modernization programs and the five-year commitment we made in 2016 through U.S. EPA's Natural Gas STAR Methane Challenge Program, we estimate our companies will collectively reduce pipeline methane emissions from main and service lines by 50 percent by 2025 compared to 2005 levels. This is equivalent to taking more than 100,000 passenger vehicles off the road.

Environmental Impact Targets BY THE NUMBERS

	CURRENT REDUCTIONS BY 2025 FROM 2005 LEVELS	NEW REDUCTIONS BY 2030 FROM 2005 LEVELS	
NITROGEN OXIDES, SULFUR DIOXIDE & MERCURY	90%	99%	ON TRACK
WATER WITHDRAWAL	90%	99%	ON TRACK
WASTEWATER DISCHARGE	60%	99%	ON TRACK
COAL ASH GENERATED	50%	100%	ON TRACK
GREENHOUSE GAS (ELECTRIC GENERATION)	50%	90%+	ON TRACK
METHANE (PIPELINE REPLACEMENT)	50%	50%+	ON TRACK

NISOURCE GREENHOUSE GAS REDUCTIONS

BY 2025 (FROM 2005 LEVELS)	50%
BY 2030 (FROM 2005 LEVELS)	90%

See **Sustainability Scorecard** on **NiSource.com/Sustainability** for more details.

SERVING OUR CUSTOMERS AND COMMUNITIES

We are focused on improving the way we serve customers. Our investments are designed to enhance safety and reliability and meet customer needs across NiSource.

CUSTOMER EXPERIENCE ENHANCEMENTS

Carefully crafted with customers in mind, we launched a redesigned Columbia Gas of Maryland website (ColumbiaGasMD.com) with a modern look that is easy to navigate and adjusts to all devices and browsers. We will launch the rest of our redesigned Columbia Gas and NIPSCO websites in 2019.

We're taking these steps to build a solid foundation for our customers online and to simplify how our customers interact with us. We continue to learn by monitoring industry best practices and gathering customer feedback following service interactions and through external surveys to address pain points, streamline the customer experience and anticipate future customer needs.

AMBASSADORS TO OUR CUSTOMERS

Our employees know they can make a difference in a customer's experience with us, and we've asked them to own the opportunity. No matter their roles, or day-to-day interactions with our customers, our employees are empowered to be ambassadors for our customers.

The Ambassador Program is an internal tool that provides a simple way to serve customers. Through the program, employees can submit non-emergency questions or issues which will be shared with the right team to get them addressed in a timely manner. Employees who use the Ambassador Program help answer customers' service questions and respond to inquiries about billing and energy use.

PHILANTHROPY AND CITIZENSHIP

Our employees are committed to serving the communities where they live and work. Throughout 2018, **our NiSource team spent more than 12,000 hours volunteering at local nonprofits**.

In addition, more than $242,000 was contributed to local nonprofit organizations in 2018 through the NiSource Charitable Foundation Dollars for Doers program, which matches employee

$47.2M
2018 LIHEAP FUNDING

PROVIDED TO OUR MOST VULNERABLE CUSTOMERS;
WE CONTINUE TO ADVOCATE FOR FULL LIHEAP FUNDING

volunteerism with a financial contribution by the company.

Across our operating area, we contributed more than $23 million to organizations in our communities, which includes contributions in the Merrimack Valley. Of this total, the NiSource Charitable Foundation contributed approximately $1.2 million.

2018 highlights of our volunteer and giving impact include:

- Funding first responder training and providing access to training resources for local fire and police departments and other emergency responders including grants provided to the Tri-Creek Ambulance Service and the Multi Agency Academic Cooperative in Indiana.

- Sponsoring research and youth engagement in science, technology, engineering and math (STEM) through events like Introduce a Girl to Engineering Day, an event that brought in Girl Scouts to learn about NiSource operations and STEM through employee-led activities in Ohio and Indiana.

- Supporting basic needs and providing hardship assistance for those in need, including volunteering at local food banks, hosting food and clothing drives, helping build homes and spreading awareness about life-threatening diseases that can be managed with access to proper care.

ENERGY EFFICIENCY

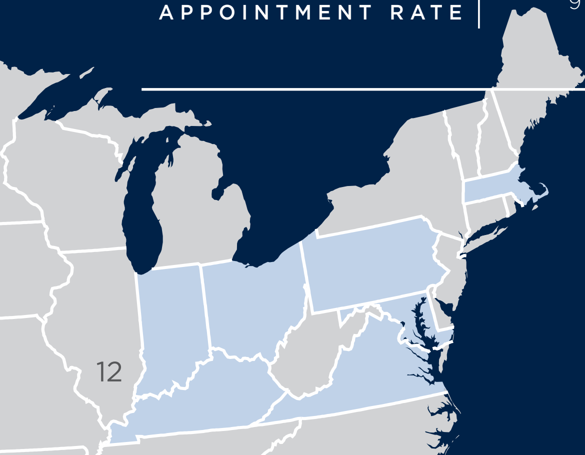
We offer programs that enhance comfort, boost energy efficiency, help customers manage their bills and reduce their environmental impact. NiSource energy efficiency programs offer rebates or discounts on home energy audits, high-efficiency appliances and HVAC equipment, weatherization projects and even smart thermostats. We strive to educate our customers about using energy wisely, while maintaining or increasing their homes' comfort.

NEARLY
800,000 CUSTOMERS
PARTICIPATED IN OUR PROGRAMS LAST YEAR, SAVING APPROXIMATELY
$23 MILLION
ON THEIR ENERGY BILLS

~27,000
NEW NATURAL GAS CUSTOMERS
ADDED (NET) IN 2018

Customer Satisfaction BY THE NUMBERS

MEASURE	CUSTOMER SATISFACTION MILESTONE	2018 STATUS	2017 STATUS	CURRENT PERFORMANCE
CUSTOMER SATISFACTION	91%	90%	88%	ON TARGET
J.D. POWER RESIDENTIAL SCORE	FIRST QUARTILE	SECOND QUARTILE	SECOND QUARTILE	IMPROVING WITH INDUSTRY
ON-TIME APPOINTMENT RATE	99%	97%	97%	ON TARGET



SERVING **NEARLY 4 MILLION NATURAL GAS AND ELECTRIC CUSTOMERS** ACROSS SEVEN STATES UNDER OUR COLUMBIA GAS AND NIPSCO BRANDS

FINANCIAL PERFORMANCE

One of our core commitments is to deliver long-term financial growth and value for our investors, and in 2018 our non-GAAP net operating earnings per share (NOEPS)* were $1.30 for the year, in line with our guidance range and more than 7 percent higher than 2017.

The biggest driver of our non-GAAP financial performance continues to be our long-term infrastructure modernization investments, supported by constructive regulatory outcomes and established infrastructure trackers.

We invested approximately $1.8 billion in our capital programs in 2018, with a goal of enhancing the safety, reliability and environmental performance of our systems and supporting improved customer service, employee training and development. We replaced more than 430 miles of natural gas pipeline, including 302 miles of priority pipe, across our service territories, as well as 64 miles of underground electric cable and more than 1,300 electric poles in northern Indiana.

As noted in last year's report, the landmark federal tax reform legislation which took effect on January 1, 2018, supports our continued robust investment in critical utility infrastructure, while also saving customers money. We worked throughout 2018 and early 2019 to implement federal tax reform across our states, and we're

Infrastructure BY THE NUMBERS

$30B
IDENTIFIED LONG-TERM **INVESTMENTS**

302 MILES
PRIORITY PIPE REPLACED IN 2018

64 MILES
UNDERGROUND ELECTRIC CABLE REPLACED IN 2018

>1,300
ELECTRIC POLES REPLACED IN 2018

* Net operating earnings per share (non-GAAP); for a reconciliation to GAAP, see Schedule 1 on page 18; see also Regulation G statement on the inside back cover.

pleased to report that all of our customers are enjoying savings made possible by the lower corporate income tax rates.

In 2019, we expect to make capital investments of $1.6 to $1.7 billion and deliver non-GAAP net operating earnings per share in the range of $1.27 to $1.33. Our earnings guidance reflects the near-term impact of financing the restoration in the Merrimack Valley, expenses associated with accelerating the enterprise-wide SMS implementation, and increased pension costs related to market volatility that occurred late in 2018.

From 2019 forward, we expect to grow our non-GAAP earnings per share and dividend by 5 to 7 percent annually through 2022, a two-year extension of our prior long-term growth forecast. We expect to make capital investments of $1.6 to $2 billion annually from 2020 through 2022.

Our long-term growth plan is intact and resilient. We're confident our infrastructure investment program, underpinned by investment grade credit ratings and a strengthening balance sheet, will continue to deliver value for all our stakeholders — with safety enhancements for our customers and communities and long-term financial growth for investors.

GAAP RESULTS REFLECT MERRIMACK VALLEY COSTS

Our 2018 GAAP results include our emergency response, system restoration, third-party claims and other expenses associated with the Greater Lawrence

Financial METRICS

2018 Non-GAAP Net Operating EPS*: $1.30

2018 GAAP EPS (Loss): ($0.18)

2018 Per Share Annual Dividend: $0.78

2018 Total Shareholder Return: 2%

2019 Non-GAAP Net Operating EPS* Projected: $1.27 - $1.33

2019 Per Share Annual Dividend Projected: $0.80**

2019 CapEx Projected: $1.6B - $1.7B

Annual NOEPS/Dividend Growth Projected: 5 - 7% from 2019 through 2022

* Net operating earnings per share (non-GAAP); for a reconciliation to GAAP, see Schedule 1 on page 18; see also Regulation G statement on the inside back cover.

** Dividends are subject to board approval.

incident, and we reported a GAAP loss of 18 cents per share for the year. We estimate the total cost of the event at approximately $1.1 billion, plus $220 to $230 million in capital costs associated with the distribution system replacement.

We have $800 million of casualty insurance coverage and $300 million of property insurance that we expect will cover a substantial portion of these costs. We began filing claims in December and recorded insurance recoveries of $135 million during 2018.

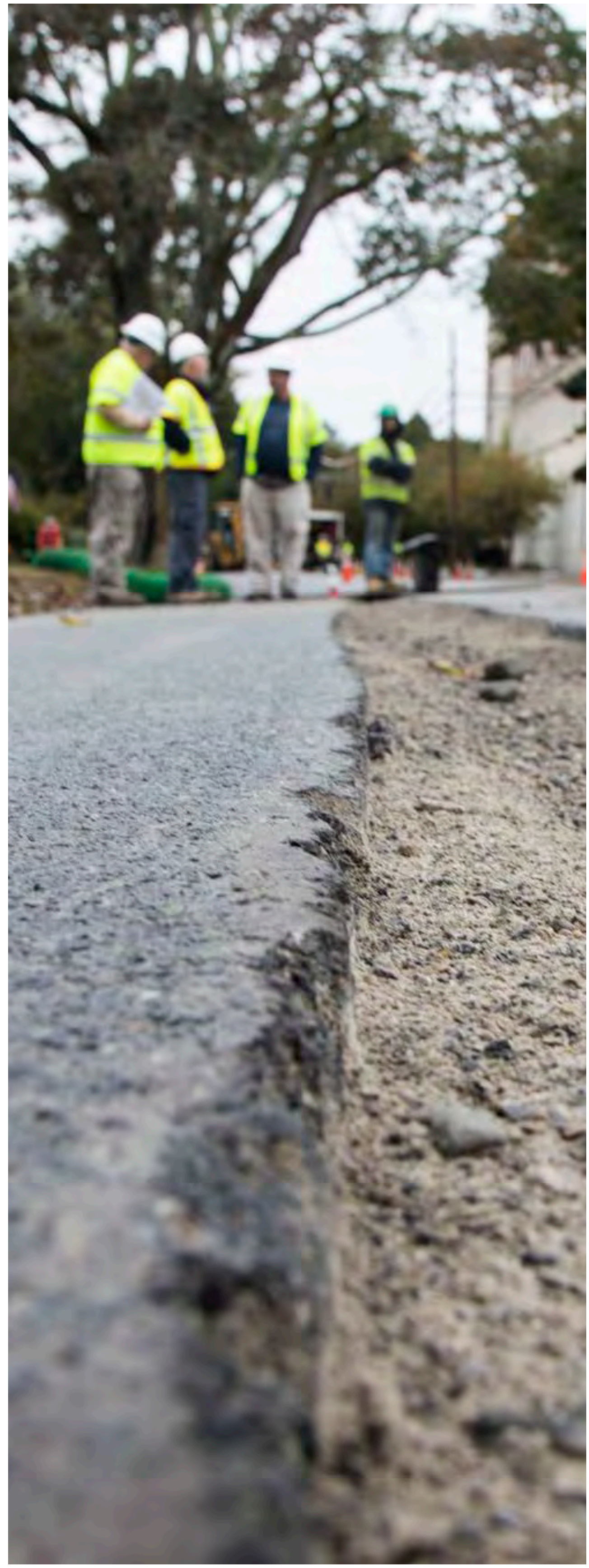
REGULATORY OUTCOMES IN 2018

Constructive regulatory outcomes are a key driver of our financial results, and we had several notable achievements in 2018.

In Ohio, a new Capital Expenditure Program Rider was approved. The initial $74.5 million rider allows us to begin recovering capital investments and other deferred expenses made between 2011 and 2017 that are not recovered under our infrastructure modernization tracker.

Rates will be adjusted annually. The approved settlement benefits Ohio customers through reduced base rates and bill credits related to federal tax reform.

We also received regulatory approval of gas base rate case settlements in Indiana, Maryland and Pennsylvania, and we filed a gas base rate case in Virginia and an electric base rate case in Indiana.



GROWING OUR TEAM

We're committed to providing learning and development opportunities that help our employees reach their professional goals, while also enabling a satisfying and productive career.

A few ways we support our employees in developing their potential include:

- **Leadership Development and Training** — To foster a culture of learning, thousands of employees experience the benefits of classroom-based, hands-on and on-the-job training for field operations and office-based roles.

- **The NiSource Mentoring Program** — To enhance our pipeline of traditionally underrepresented leaders. The program focuses on helping to grow, develop and retain high-potential diverse employees by providing networking and mentoring from our senior leaders. Eighteen leaders participated in the 2018 Mentoring Program.

- **Targeted Development for Diverse Talent Program** — To support the career development of high-performing individual contributors, supervisors or managers who are either female or ethnically diverse. Participants are matched with NiSource leaders, acting as career guides, to receive enhanced coaching and support. Participants partner with career guides

Employee POPULATION
AS OF DECEMBER 31, 2018

TOTAL EMPLOYEES
8,087 TOTAL
72% MEN | **28%** WOMEN
15% MINORITIES

TOTAL MANAGEMENT
(MANAGER & ABOVE)
742 TOTAL
70% MEN | **30%** WOMEN
14% MINORITIES

GENERATIONS
4 TOTAL GENERATIONS REPRESENTED
<1% TRADITIONALISTS 1925-1948
27% BABY BOOMERS 1949-1964
28% GENERATION X 1965-1976
45% MILLENNIALS/GEN Y 1977-PRESENT

to create and work through their career development plans. Twenty-five employees participated in the Targeted Development for Diverse Talent program in 2018.

- **Leadership NiSource** — To strengthen the competencies critical to NiSource's success in mid-level rising leaders. The program focuses on developing others, formulating strategy and leading change. Leadership NiSource is our flagship development program. Eighteen leaders graduated from the 2018 Leadership NiSource program.

To support talent and employee development, we foster a culture of inclusion and diversity. Our success depends on being open to new ways of thinking that can make us a better community partner and a stronger company. We value the perspective each employee brings and measure employee engagement and experience through our employee survey. Our most recent survey showed engagement was rated at 89 percent, and over the past three years, the organization was rated above average in the Inclusive Culture Index, a benchmark that measures employees' perspectives on an inclusive working environment.

Throughout all levels of the organization, we have a large number of local inclusion and diversity efforts, as well as corporate-wide initiatives such as our employee resource groups.

Our commitment to inclusion and diversity is more than just the right thing to do. It drives tangible benefits for our company, our customers and all of our stakeholders.

SELECT RECOGNITION

Across our company, we're proud to have been recognized as strong community partners and for what makes us a great place to work. Some of our 2018 highlights include:

- Named one of the **World's Most Ethical Companies by Ethisphere** — We were one of 135 companies from 23 countries honored for leadership in ethical business standards. This recognition honors companies that lead with integrity and prioritize ethical business practices.

- Named to the **Dow Jones Sustainability Index (DJSI) – North America** — In recognition of our sustainable business practices and performance.

- Named in **Forbes' ranking of America's Best Large Employers** — In 2018, we were ranked as the No. 7 utility and No. 105 overall out of 500 listed companies.

- Named to the **Bloomberg Gender-Equality Index** — We were one of 104 global companies from 10 sectors in 24 countries to be included in the inaugural Bloomberg Gender Equality Index, recognizing our efforts to create a work environment that supports gender equality.

Schedule 1 - Reconciliation of Consolidated Net Income (Loss) Available to Common Shareholders to Net Operating Earnings Available to Common Shareholders (Non-GAAP)

(unaudited)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
(in millions, except per share amounts)	**2018**	2017	**2018**	2017
GAAP Net Income (Loss) Available to Common Shareholders	**$ (19.8)**	$ (52.4)	**$ (65.6)**	$ 128.5
Adjustments to Operating Income (Loss):				
Operating Revenues:				
Weather - compared to normal	**(10.6)**	(6.9)	**(32.5)**	30.2
Greater Lawrence Incident(1)	**3.9**	—	**3.9**	—
Operating Expenses:				
Plant retirement costs(2)	**—**	—	**3.3**	1.5
IT service provider transition costs(3)	**—**	8.3	**—**	21.6
Greater Lawrence Incident(4)	**379.0**	—	**830.6**	—
Loss on sale of assets and impairments, net	**0.8**	0.1	**1.2**	—
Total adjustments to operating income (loss)	**373.1**	1.5	**806.5**	53.3
Other Income (Deductions):				
Greater Lawrence Incident - Charitable contribution(4)	**10.4**	—	**20.7**	—
Interest rate swap settlement gain	**(25.0)**	—	**(46.2)**	—
Loss on early extinguishment of long-term debt	**—**	—	**45.5**	111.5
Income Taxes:				
Tax effect of above items	**(79.8)**	0.1	**(180.6)**	(56.9)
Income taxes - discrete items(5)	**(117.0)**	161.1	**(117.0)**	161.1
Total adjustments to net income (loss)	**161.7**	162.7	**528.9**	269.0
Net Operating Earnings Available to Common Shareholders (Non-GAAP)	**$ 141.9**	$ 110.3	**$ 463.3**	$ 397.5
Basic Average Common Shares Outstanding	**369.4**	337.5	**356.5**	329.4
GAAP Basic Earnings (Loss) Per Share	**$ (0.05)**	$ (0.16)	**$ (0.18)**	$ 0.39
Adjustments to basic earnings (loss) per share	**0.43**	0.49	**1.48**	0.82
Non-GAAP Basic Net Operating Earnings Per Share	**$ 0.38**	$ 0.33	**$ 1.30**	$ 1.21

(1) Represents revenues not billed to impacted customers as a result of the Greater Lawrence Incident.
(2) Represents costs incurred associated with the planned retirement of Units 7 and 8 at Bailly Generating Station.
(3) Represents contract termination costs and external legal and consulting costs associated with termination of the IBM IT services agreement and the transition to a new multi-vendor strategy for IT service delivery.
(4) Represents costs incurred for estimated third-party claims and related other expenses as a result of the Greater Lawrence Incident net of insurance recoveries recorded to date.
(5) 2017 activity represents the impact of adopting the provisions of the Tax Cuts and Jobs Act of 2017. 2018 activity represents adjustments to the impact of the Tax Cuts and Jobs Act of 2017 due to regulatory actions in 2018.

Additional Metrics and Data

Our **Sustainability Scorecard** highlights the key metrics and milestones we track regarding the company's priorities and stakeholder materiality. The **Supplemental Sustainability Data** includes more detail, including historical measurements, additional sustainability metrics commonly tracked and requested by individual stakeholders. These supporting materials and the **Global Reporting Initiative (GRI) Table** are available at **NiSource.com/Sustainability**.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)**
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)**
OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______ to ______

Commission file number 001-16189

NiSource Inc.
(Exact name of registrant as specified in its charter)

Delaware	35-2108964
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
801 East 86th Avenue Merrillville, Indiana	46410
(Address of principal executive offices)	(Zip Code)

(877) 647-5990
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	New York

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).
Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definition of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12-b-2 of the Exchange Act.

Large accelerated filer ☑	Accelerated filer ☐	Emerging growth company ☐
Non-accelerated filer ☐	Smaller reporting company ☐	

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the registrant's common stock, par value $0.01 per share (the "Common Stock") held by non-affiliates was approximately $9,506,346,286 based upon the June 29, 2018, closing price of $26.28 on the New York Stock Exchange.

There were 372,494,365 shares of Common Stock outstanding as of February 12, 2019.

Documents Incorporated by Reference

Part III of this report incorporates by reference specific portions of the Registrant's Notice of Annual Meeting and Proxy Statement relating to the Annual Meeting of Stockholders to be held on May 7, 2019.

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DEFINED TERMS

The following is a list of abbreviations or acronyms that are used in this report:

NiSource Subsidiaries, Affiliates and Former Subsidiaries	
Capital Markets (former subsidiary)	NiSource Capital Markets, Inc.
Columbia (former subsidiary)	Columbia Energy Group
Columbia of Kentucky	Columbia Gas of Kentucky, Inc.
Columbia of Maryland	Columbia Gas of Maryland, Inc.
Columbia of Massachusetts	Bay State Gas Company
Columbia of Ohio	Columbia Gas of Ohio, Inc.
Columbia of Pennsylvania	Columbia Gas of Pennsylvania, Inc.
Columbia of Virginia	Columbia Gas of Virginia, Inc.
Company	NiSource Inc. and its subsidiaries, unless otherwise indicated by the context
CPG (former subsidiary)	Columbia Pipeline Group, Inc.
NIPSCO	Northern Indiana Public Service Company LLC
NiSource ("we," "us" or "our")	NiSource Inc.
NiSource Corporate Services	NiSource Corporate Services Company
NiSource Finance (former subsidiary)	NiSource Finance Corporation

Abbreviations	
ACE	Affordable clean energy
AFUDC	Allowance for funds used during construction
AMR	Automatic meter reading
AMRP	Accelerated Main Replacement Program
AOCI	Accumulated Other Comprehensive Income
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
ATM	At-the-market
Board	Board of Directors
BTA	Build-transfer agreement
CAA	Clean Air Act
CAP	Compliance Assurance Process
CCGT	Combined Cycle Gas Turbine
CCRs	Coal Combustion Residuals
CEP	Capital Expenditure Program
CERCLA	Comprehensive Environmental Response Compensation and Liability Act (also known as Superfund)
CO_2	Carbon dioxide
CPP	Clean Power Plan
DPU	Department of Public Utilities
DSIC	Distribution System Investment Charge
DSM	Demand Side Management
ECT	Environmental Cost Tracker
EERM	Environmental Expense Recovery Mechanism
EGUs	Electric Utility Steam Generating Units

DEFINED TERMS

ELG	Effluence limitations guidelines
EPA	United States Environmental Protection Agency
EPS	Earnings per share
FAC	Fuel adjustment clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FMCA	Federally Mandated Cost Adjustment
FTRs	Financial Transmission Rights
GAAP	Generally Accepted Accounting Principles
GCA	Gas cost adjustment
GCR	Gas cost recovery
GHG	Greenhouse gas
GSEP	Gas System Enhancement Program
GWh	Gigawatt hours
IRIS	Infrastructure Replacement and Improvement Surcharge
IRP	Infrastructure Replacement Program
IRS	Internal Revenue Service
IURC	Indiana Utility Regulatory Commission
LDCs	Local distribution companies
LIBOR	London inter-bank offered rate
LIFO	Last-in, first-out
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator
Mizuho	Mizuho Corporate Bank Ltd.
MMDth	Million dekatherms
MW	Megawatts
MWh	Megawatt hours
NOL	Net Operating Loss
NTSB	National Transportation Safety Board
NYMEX	The New York Mercantile Exchange
NYSE	The New York Stock Exchange
OPEB	Other Postretirement and Postemployment Benefits
PCB	Polychlorinated biphenyls
PHMSA	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration
PISCC	Post-in-service carrying charges
PPA	Purchase plan agreement
PSC	Public Service Commission
PTC	Production Tax Credits
PUC	Public Utility Commission
PUCO	Public Utilities Commission of Ohio
RCRA	Resource Conservation and Recovery Act
ROU	Right of use
SAB	Staff accounting bulletin
SAVE	Steps to Advance Virginia's Energy Plan

DEFINED TERMS

Separation	The separation of our natural gas pipeline, midstream and storage business from our natural gas and electric utility business accomplished through a pro rata distribution to holders of our outstanding common stock of all the outstanding shares of common stock of CPG. The separation was completed on July 1, 2015.
SEC	Securities and Exchange Commission
STRIDE	Strategic Infrastructure Development and Enhancement
Sugar Creek	Sugar Creek electric generating plant
TCJA	Tax Cuts and Jobs Act of 2017
TDSIC	Transmission, Distribution and Storage System Improvement Charge
VIE	Variable Interest Entity
VSCC	Virginia State Corporation Commission
WCE	Whiting Clean Energy

Note regarding forward-looking statements

This Annual Report on Form 10-K contains “forward-looking statements,” within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Investors and prospective investors should understand that many factors govern whether any forward-looking statement contained herein will be or can be realized. Any one of those factors could cause actual results to differ materially from those projected. These forward-looking statements include, but are not limited to, statements concerning our plans, strategies, objectives, expected performance, expenditures, recovery of expenditures through rates, stated on either a consolidated or segment basis, and any and all underlying assumptions and other statements that are other than statements of historical fact. All forward-looking statements are based on assumptions that management believes to be reasonable; however, there can be no assurance that actual results will not differ materially.

Factors that could cause actual results to differ materially from the projections, forecasts, estimates and expectations discussed in this Annual Report on Form 10-K include, among other things, our debt obligations; any changes to the credit rating of our or certain of our subsidiaries; our ability to execute our growth strategy; changes in general economic, capital and commodity market conditions; pension funding obligations; economic regulation and the impact of regulatory rate reviews; our ability to obtain expected financial or regulatory outcomes; our ability to adapt to, and manage costs related to, advances in technology; any changes in our assumptions regarding the financial implications of the Greater Lawrence Incident; potential incidents and other operating risks associated with our business; our ability to obtain sufficient insurance coverage; the outcome of legal and regulatory proceedings, investigations, incidents, claims and litigation; any damage to our reputation, including in connection with the Greater Lawrence Incident; compliance with environmental laws and the costs of associated liabilities; fluctuations in demand from residential and commercial customers; economic conditions of certain industries; the success of NIPSCO's electric generation strategy; the price of energy commodities and related transportation costs; the reliability of customers and suppliers to fulfill their payment and contractual obligations; potential impairments of goodwill or definite-lived intangible assets; changes in taxation and accounting principles; the impact of an aging infrastructure; the impact of climate change; potential cyber-attacks; construction risks and natural gas costs and supply risks; extreme weather conditions; the attraction and retention of a qualified workforce; the ability of our subsidiaries to generate cash; uncertainties related to the expected benefits of the Separation; our ability to manage new initiatives and organizational changes; the performance of third-party suppliers and service providers; and other matters set forth in Item 1A, “Risk Factors” of this report, many of which risks are beyond our control. In addition, the relative contributions to profitability by each business segment, and the assumptions underlying the forward-looking statements relating thereto, may change over time.

All forward-looking statements are expressly qualified in their entirety by the foregoing cautionary statements. We undertake no obligation to, and expressly disclaims any such obligation to, update or revise any forward-looking statements to reflect changed assumptions, the occurrence of anticipated or unanticipated events or changes to the future results over time or otherwise, except as required by law.

ITEM 1. BUSINESS

NISOURCE INC.

NiSource Inc. is an energy holding company under the Public Utility Holding Company Act of 2005 whose subsidiaries are fully regulated natural gas and electric utility companies serving approximately 4.0 million customers in seven states. NiSource is the successor to an Indiana corporation organized in 1987 under the name of NIPSCO Industries, Inc., which changed its name to NiSource on April 14, 1999.

NiSource is one of the nation's largest natural gas distribution companies, as measured by number of customers. NiSource's principal subsidiaries include NiSource Gas Distribution Group, Inc., a natural gas distribution holding company, and NIPSCO, a gas and electric company. NiSource derives substantially all of its revenues and earnings from the operating results of these rate-regulated businesses.

On September 13, 2018, a series of fires and explosions occurred in Lawrence, Andover and North Andover, Massachusetts related to the delivery of natural gas by Columbia of Massachusetts (referred to herein as the "Greater Lawrence Incident"). The Greater Lawrence Incident resulted in one fatality and a number of injuries, damaged multiple homes and businesses, and caused the temporary evacuation of significant portions of each municipality. The Massachusetts Governor's Office declared a state of emergency, authorizing the Massachusetts DPU to order another utility company to coordinate the restoration of utility services in Lawrence, Andover and North Andover. The incident resulted in the interruption of gas for approximately 7,500 gas meters, the majority of which serve residences and of which approximately 700 serve businesses, and the interruption of other utility service more broadly in the area. Columbia of Massachusetts has replaced the cast iron and bare steel gas pipeline system in the affected area and restored service to nearly all of the gas meters. Refer to Note 18-C. "Legal Proceedings," and E. "Other Matters," in the Notes to Consolidated Financial Statements for more information.

NiSource's reportable segments are: Gas Distribution Operations and Electric Operations. The following is a summary of the business for each reporting segment. Refer to Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 22, "Segments of Business," in the Notes to Consolidated Financial Statements for additional information for each segment.

Gas Distribution Operations

Our natural gas distribution operations serve approximately 3.5 million customers in seven states and operate approximately 60,000 miles of pipeline located in our service areas described below. Through our wholly-owned subsidiary NiSource Gas Distribution Group, Inc., we own six distribution subsidiaries that provide natural gas to approximately 2.6 million residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, Maryland and Massachusetts. Additionally, we distribute natural gas to approximately 832,000 customers in northern Indiana through our wholly-owned subsidiary NIPSCO.

Electric Operations

We generate, transmit and distribute electricity through our subsidiary NIPSCO to approximately 472,000 customers in 20 counties in the northern part of Indiana and engage in wholesale and transmission transactions. NIPSCO owns and operates two coal-fired electric generating stations: four units at R.M. Schahfer located in Wheatfield, IN and one unit at Michigan City located in Michigan City, IN. The two operating facilities have a generating capacity of 2,080 MW. NIPSCO also owns and operates Sugar Creek, a CCGT plant located in West Terre Haute, IN with generating capacity of 571 MW, three gas-fired generating units located at NIPSCO's coal-fired electric generating stations with a generating capacity of 186 MW and two hydroelectric generating plants with a generating capacity of 16 MW: Oakdale located at Lake Freeman in Carroll County, IN and Norway located at Lake Schahfer in White County, IN. These facilities provide for a total system operating generating capacity of 2,853 MW.

In May 2018, NIPSCO completed the retirement of two coal-burning units (Units 7 and 8) at Bailly Generating Station, located in Chesterton, IN. These units had a generating capacity of approximately 460 MW. Refer to Note 18-E, "Other Matters," in the Notes to Consolidated Financial Statements for additional information on these retirements.

NIPSCO's transmission system, with voltages from 69,000 to 765,000 volts, consists of 2,963 circuit miles. NIPSCO is interconnected with five neighboring electric utilities. During the year ended December 31, 2018, NIPSCO generated 69.4% and purchased 30.6% of its electric requirements.

NIPSCO participates in the MISO transmission service and wholesale energy market. MISO is a nonprofit organization created in compliance with FERC regulations to improve the flow of electricity in the regional marketplace and to enhance electric reliability. Additionally, MISO is responsible for managing energy markets, transmission constraints and the day-ahead, real-time, FTR and ancillary markets. NIPSCO transferred functional control of its electric transmission assets to MISO, and transmission service for NIPSCO occurs under the MISO Open Access Transmission Tariff.

ITEM 1. BUSINESS

NISOURCE INC.

Business Strategy

We focus our business strategy on our core, rate-regulated asset-based businesses with most of our operating income generated from the rate-regulated businesses. Our utilities continue to move forward on core infrastructure and environmental investment programs supported by complementary regulatory and customer initiatives across all seven states in which we operate. Our goal is to develop strategies that benefit all stakeholders as we address changing customer conservation patterns, develop more contemporary pricing structures, and embark on long-term investment programs. These strategies are intended to improve reliability and safety, enhance customer services and reduce emissions while generating sustainable returns.

In its 2018 Integrated Resource Plan submission to the IURC, NIPSCO laid out a plan to retire the R.M. Schahfer Generating Station (Units 14, 15, 17, and 18) by 2023 and Michigan City Generating Station (Unit 12) by 2028. These units represent 2,080 MW of generating capacity, equal to 72% of NIPSCO's remaining capacity after the retirement of Bailly Units 7 and 8 in May of 2018. The current replacement plan includes renewable sources of energy, including wind, solar, and battery storage to be obtained through a combination of NIPSCO ownership and PPAs. Refer to Note 18-E, "Other Matters," in the Notes to Consolidated Financial Statements for further discussion of these plans.

Competition and Changes in the Regulatory Environment

The regulatory frameworks applicable to our operations, at both the state and federal levels, continue to evolve. These changes have had and will continue to have an impact on our operations, structure and profitability. Management continually seeks new ways to be more competitive and profitable in this environment.

The Gas Distribution Operations companies have pursued non-traditional revenue sources within the evolving natural gas marketplace. These efforts include the sale of products and services upstream of the companies' service territory, the sale of products and services in the companies' service territories, and gas supply cost incentive mechanisms for service to their core markets. The upstream products are made up of transactions that occur between an individual Gas Distribution Operations company and a buyer for the sales of unbundled or rebundled gas supply and capacity. The on-system services are offered by us to customers and include products such as the transportation and balancing of gas on the Gas Distribution Operations company system. The incentive mechanisms give the Gas Distribution Operations companies an opportunity to share in the savings created from such situations as gas purchase prices paid below an agreed upon benchmark and their ability to reduce pipeline capacity charges with their customers.

Increased efficiency of natural gas appliances and improvements in home building codes and standards has contributed to a long-term trend of declining average use per customer. Residential usage for the year ended December 31, 2018 increased primarily due to colder weather in our operating area compared to the prior year. While historically rate design at the distribution level has been structured such that a large portion of cost recovery is based upon throughput rather than in a fixed charge, operating costs are largely incurred on a fixed basis and do not fluctuate due to changes in customer usage. As a result, Gas Distribution Operations have pursued changes in rate design to more effectively match recoveries with costs incurred. Each of the states in which Gas Distribution Operations operate has different requirements regarding the procedure for establishing changes to rate design. Columbia of Ohio restructured its rate design through a base rate proceeding and has adopted a "de-coupled" rate design which more closely links the recovery of fixed costs with fixed charges. Columbia of Massachusetts received regulatory approval of a decoupling mechanism which adjusts revenues to an approved benchmark level through a volumetric adjustment factor. Columbia of Maryland and Columbia of Virginia have regulatory approval for a revenue normalization adjustment for certain customer classes, a decoupling mechanism whereby monthly revenues that exceed or fall short of approved levels are reconciled in subsequent months. In a prior base rate proceeding, Columbia of Pennsylvania implemented a pilot residential weather normalization adjustment. Columbia of Maryland, Columbia of Virginia and Columbia of Kentucky have had approval for a weather normalization adjustment for many years. In a prior base rate proceeding, NIPSCO implemented a higher fixed customer charge for residential and small customer classes moving toward full straight fixed variable rate design.

Natural Gas Competition. Open access to natural gas supplies over interstate pipelines and the deregulation of the commodity price of gas has led to tremendous change in the energy markets. LDC customers and marketers can purchase gas directly from producers and marketers as an open, competitive market for gas supplies has emerged. This separation or "unbundling" of the transportation and other services offered by pipelines and LDCs allows customers to purchase the commodity independent of services provided by the pipelines and LDCs. The LDCs continue to purchase gas and recover the associated costs from their customers. Our Gas Distribution Operations' subsidiaries are involved in programs that provide customers the opportunity to purchase their natural gas requirements from third parties and use our Gas Distribution Operations' subsidiaries for transportation services.

Gas Distribution Operations competes with investor-owned, municipal, and cooperative electric utilities throughout its service areas as well as other regulated and unregulated natural gas intra and interstate pipelines and other alternate fuels, such as propane and fuel oil. Gas Distribution Operations continues to be a strong competitor in the energy market as a result of strong customer preference for natural gas. Competition with providers of electricity has traditionally been the strongest in the residential and commercial markets of Kentucky, southern Ohio, central Pennsylvania and western Virginia due to comparatively low electric rates. Natural gas competes with fuel oil and propane in the Massachusetts market mainly due to the installed base of fuel oil and propane-based heating which has comprised a declining percentage of the overall market over the last few years. However, fuel oil and propane are more viable in today's oil market.

Electric Competition. Indiana electric utilities generally have exclusive service areas under Indiana regulations, and retail electric customers in Indiana do not have the ability to choose their electric supplier. NIPSCO faces non-utility competition from other energy sources, such as self-generation by large industrial customers and other distributed energy sources.

Seasonality

A significant portion of our operations are subject to seasonal fluctuations in sales. During the heating season, which is primarily from November through March, revenues from gas sales are more significant, and during the cooling season, which is primarily June through September, revenues from electric sales are more significant, than in other months.

Other Relevant Business Information

Our customer base is broadly diversified, with no single customer accounting for a significant portion of revenues.

As of December 31, 2018, we had 8,087 employees of whom 3,154 were subject to collective bargaining agreements. Collective bargaining agreements for 1,918 employees are set to expire within one year.

For a listing of certain subsidiaries of NiSource refer to Exhibit 21.

We electronically file various reports with the SEC, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to such reports, as well as our proxy statements for the Company's annual meetings of stockholders at *http://www.sec.gov*. Additionally, we make all SEC filings available without charge to the public on our web site at *http://www.nisource.com.*

ITEM 1A. RISK FACTORS

NISOURCE INC.

Our operations and financial results are subject to various risks and uncertainties, including those described below, that could adversely affect our business, financial condition, results of operations, cash flows, and the trading price of our common stock.

We have substantial indebtedness which could adversely affect our financial condition.

Our businesses are capital intensive and we rely significantly on long-term debt to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations. We had total consolidated indebtedness of $9,132.6 million outstanding as of December 31, 2018. Our substantial indebtedness could have important consequences. For example, it could:

- limit our ability to borrow additional funds or increase the cost of borrowing additional funds;
- reduce the availability of cash flow from operations to fund working capital, capital expenditures and other general corporate purposes;
- limit our flexibility in planning for, or reacting to, changes in the business and the industries in which we operate;
- lead parties with whom we do business to require additional credit support, such as letters of credit, in order for us to transact such business;
- place us at a competitive disadvantage compared to competitors that are less leveraged;
- increase vulnerability to general adverse economic and industry conditions; and
- limit our ability to execute on our growth strategy, which is dependent upon access to capital to fund our substantial infrastructure investment program.

Some of our debt obligations contain financial covenants related to debt-to-capital ratios and cross-default provisions. Our failure to comply with any of these covenants could result in an event of default, which, if not cured or waived, could result in the acceleration of outstanding debt obligations.

A drop in our credit ratings could adversely impact our cash flows, results of operation, financial condition and liquidity.

The availability and cost of credit for our businesses may be greatly affected by credit ratings. The credit rating agencies periodically review our ratings, taking into account factors such as our capital structure, earnings profile, and, in 2018, the impacts of the TCJA and the Greater Lawrence Incident. In March 2018, Moody’s affirmed our senior unsecured rating of Baa2 and our commercial paper rating of P-2, with stable outlooks. Moody’s also affirmed NIPSCO’s Baa1 rating and Columbia of Massachusetts’s Baa2 rating, with stable outlooks. In May 2018, Standard & Poor’s affirmed our BBB+ senior unsecured ratings and affirmed our commercial paper rating of A-2, but changed the outlook on each rating from stable to negative in September 2018 as a result of potential impacts of the Greater Lawrence Incident. In June 2018, Fitch affirmed our and NIPSCO's long-term issuer default ratings of BBB and upgraded the commercial paper rating to F2 from F3, with stable outlooks. A credit rating is not a recommendation to buy, sell or hold securities, and may be subject to revision or withdrawal at any time by the assigning rating organization.

We are committed to maintaining investment grade credit ratings, however, there is no assurance we will be able to do so in the future. Our credit ratings could be lowered or withdrawn entirely by a rating agency if, in its judgment, the circumstances warrant. Any negative rating action could adversely affect our ability to access capital at rates and on terms that are attractive. A negative rating action could also adversely impact our business relationships with suppliers and operating partners, who may be less willing to extend credit or offer us similarly favorable terms as secured in the past under such circumstances.

Certain of our subsidiaries have agreements that contain “ratings triggers” that require increased collateral in the form of cash, a letter of credit or other forms of security for new and existing transactions if the credit ratings of our or certain of our subsidiaries are dropped below investment grade. These agreements are primarily for insurance purposes and for the physical purchase or sale of gas or power. As of December 31, 2018, the collateral requirement that would be required in the event of a downgrade below the ratings trigger levels would amount to approximately $53.8 million. In addition to agreements with ratings triggers, there are other agreements that contain “adequate assurance” or “material adverse change” provisions that could necessitate additional credit support such as letters of credit and cash collateral to transact business.

If our or certain of our subsidiaries credit ratings were downgraded, especially below investment grade, financing costs and the principal amount of borrowings would likely increase due to the additional risk of our debt and because certain counterparties may require additional credit support as described above. Such amounts may be material and could adversely affect our cash flows, results of operations and financial condition. Losing investment grade credit ratings may also result in more restrictive covenants and reduced flexibility on repayment terms in debt issuances, lower share price and greater stockholder dilution from common equity issuances, in addition to reputational damage within the investment community.

We may not be able to execute our business plan or growth strategy, including utility infrastructure investments.

Business or regulatory conditions may result in us not being able to execute our business plan or growth strategy, including identified, planned and other utility infrastructure investments. Our customer and regulatory initiatives may not achieve planned results. Utility infrastructure investments may not materialize, may cease to be achievable or economically viable and may not be successfully completed. Natural gas may cease to be viewed as an economically and environmentally attractive fuel. Certain groups may continue to oppose natural gas delivery and infrastructure investments because of perceived environmental impacts associated with the natural gas supply chain and end use. Energy conservation, energy efficiency, distributed generation, energy storage, policies favoring electric heat over gas heat and other factors may reduce energy demand. Any of these developments could adversely affect our results of operations and growth prospects.

Adverse economic and market conditions or increases in interest rates could materially and adversely affect our results of operations, cash flows, financial condition and liquidity.

While the national economy is experiencing modest growth, we cannot predict how robust future growth will be or whether it will be sustained. Deteriorating or sluggish economic conditions in our operating jurisdictions could adversely impact our ability to maintain or grow our customer base and collect revenues from customers, which could reduce revenue growth and increase operating costs. In addition, a rising interest rate environment may lead to higher borrowing costs, which may adversely impact reported earnings, cost of capital and capital holdings. Rising interest rates and negative market or company events may also result in a decrease in the price of our shares of common stock.

We rely on access to the capital markets to finance our liquidity and long-term capital requirements, including expenditures for our utility infrastructure and to comply with future regulatory requirements, to the extent not satisfied by the cash flow generated by our operations. We have historically relied on long-term debt and on the issuance of equity securities to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations. Successful implementation of our long-term business strategies, including capital investment, is dependent upon our ability to access the capital and credit markets, including the banking and commercial paper markets, on competitive terms and rates. An economic downturn or uncertainty, market turmoil, changes in tax policy, challenges faced by financial institutions, changes in our credit ratings, or a change in investor sentiment toward us or the utilities industry generally could adversely affect our ability to raise additional capital or refinance debt. Reduced access to capital markets and/or increased borrowing costs could reduce future net income and cash flows. Refer to Note 14, “Long-Term Debt,” in the Notes to Consolidated Financial Statements for information related to outstanding long-term debt and maturities of that debt.

If any of these risks or uncertainties limit our access to the credit and capital markets or significantly increase our cost of capital, it could limit our ability to implement, or increase the costs of implementing, our business plan, which, in turn, could materially and adversely affect our results of operations, cash flows, financial condition and liquidity.

Capital market performance and other factors may decrease the value of benefit plan assets, which then could require significant additional funding and impact earnings.

The performance of the capital markets affects the value of the assets that are held in trust to satisfy future obligations under defined benefit pension and other postretirement benefit plans. We have significant obligations in these areas and hold significant assets in these trusts. These assets are subject to market fluctuations and may yield uncertain returns, which fall below our projected rates of return. A decline in the market value of assets may increase the funding requirements of the obligations under the defined benefit pension and other postretirement benefit plans. Additionally, changes in interest rates affect the liabilities under these benefit plans; as interest rates decrease, the liabilities increase, which could potentially increase funding requirements. Further, the funding requirements of the obligations related to these benefits plans may increase due to changes in governmental regulations and participant demographics, including increased numbers of retirements or changes in life expectancy assumptions. In addition, lower asset returns result in increased expenses. Ultimately, significant funding requirements and increased pension or other postretirement benefit plan expense could negatively impact our results of operations and financial position.

ITEM 1A. RISK FACTORS

NISOURCE INC.

The majority of our revenues are subject to economic regulation and are exposed to the impact of regulatory rate reviews and proceedings.

Most of our revenues are subject to economic regulation at either the federal or state level. As such, the revenues generated by us are subject to regulatory review by the applicable federal or state authority. These rate reviews determine the rates charged to customers and directly impact revenues. Our financial results are dependent on frequent regulatory proceedings in order to ensure timely recovery of costs. In addition to our ongoing regulatory proceedings, the recovery of the Greater Lawrence pipeline replacement capital investment will be addressed in a future regulatory proceeding as discussed in Note 18, "Other Commitments and Contingencies - E. Other Matters" in the Notes to Consolidated Financial Statements. The outcomes of these proceedings are uncertain. Additionally, the costs of complying with current and future changes in environmental and federal pipeline safety laws and regulations are expected to be significant, and their recovery through rates will also be contingent on regulatory approval.

As a result of efforts to introduce market-based competition in certain markets where the regulated businesses conduct operations, we may compete with independent marketers for customers. This competition exposes us to the risk that certain infrastructure investments may not be recoverable and may affect results of our growth strategy and financial position.

Failure to adapt to advances in technology and manage the related costs could make us less competitive and negatively impact our results of operations and financial condition.

A key element of our business model is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. We continue to research, plan for, and implement new technologies that produce power or reduce power consumption. These technologies include renewable energy, distributed generation, energy storage, and energy efficiency. Advances in technology and changes in laws or regulations are reducing the cost of these or other alternative methods of producing power to a level that is competitive with that of most central station power electric production or result in smaller-scale, more fuel efficient, and/or more cost effective distributed generation. This could cause power sales to decline and the value of our generating facilities to decline. In addition, customers are increasingly expecting enhanced communications regarding their electric and natural gas services, which, in some cases, may involve additional investments in technology. New technologies may require us to make significant expenditures to remain competitive and may result in the obsolescence of certain of our operating assets.

Our future success will depend, in part, on our ability to anticipate and successfully adapt to technological changes, to offer services that meet customer demands and evolving industry standards, and to recover all, or a significant portion of, any unrecovered investment in obsolete assets. A failure by us to effectively adapt to changes in technology and manage the related costs could harm our ability to remain competitive in the marketplace for our products, services and processes and could have a material adverse impact on our results of operations and financial condition.

The Greater Lawrence Incident has had and may have an additional material adverse impact on our financial condition, results of operations and cash flows.

In connection with the Greater Lawrence Incident, we have incurred and will incur various costs and expenses as set forth in Note 18 "Other Commitments and Contingencies - C. Legal Proceedings," and " - E. Other Matters" in the Notes to Consolidated Financial Statements.

As more information becomes known, including information resulting from the NTSB investigation, management's estimates and assumptions regarding the costs and expenses to be incurred and the financial impact of the Greater Lawrence Incident may change. A change in management’s estimates or assumptions could result in an adjustment that would have a material impact on our financial condition, results of operations and cash flows during the period in which such change occurred.

In addition, we are unable to predict the timing and amount of insurance recoveries. Total expenses related to the incident have exceeded the total amount of liability insurance coverage available under our policies. In addition, there may be certain types of damages, expenses or claimed costs, such as fines or penalties, that may be excluded under the policies. Losses for which we are not fully insured or that are not covered by insurance at all could materially adversely affect our results of operations, cash flows and financial position.

We may also incur additional costs associated with the Greater Lawrence Incident, beyond the amount currently anticipated, in connection with investigations by regulators, including the NTSB and Massachusetts DPU, as well as civil litigations. Further, state or federal legislation may be enacted that would require us to incur additional costs by mandating various changes, including changes to our operating practice standards for natural gas distribution operations and safety. If we are unable to recover the capital cost of the gas pipeline replacement in the impacted area or we incur a material amount of other costs that we are unable to recover through rates or offset through operational or other cost savings, our financial condition, results of operations, and cash flows could be materially and adversely affected.

Further, if it is determined that we did not comply with applicable statutes, regulations, rules, tariffs, or orders in connection with the Greater Lawrence Incident or in connection with the operations or maintenance of our natural gas system, and we are ordered to pay a material amount in customer refunds, penalties, or other amounts, our financial condition, results of operations, and cash flows could be materially and adversely affected.

Our gas distribution activities, as well as generation, transmission and distribution of electricity, involve a variety of inherent hazards and operating risks.

Our gas distribution activities, as well as generation, transmission, and distribution of electricity, involve a variety of inherent hazards and operating risks, including, but not limited to, gas leaks and over-pressurization, downed power lines, damage to our infrastructure by third parties, outages, environmental spills, mechanical problems and other incidents, which could cause substantial financial losses, as demonstrated in part by the Greater Lawrence Incident. In addition, these hazards and risks have resulted and may in the future result in serious injury or loss of life to employees and/or the general public, significant damage to property, environmental pollution, impairment of our operations, adverse regulatory rulings and reputational harm, which in turn could lead to substantial losses for us. The location of pipeline facilities, or generation, transmission, substation and distribution facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from such incidents. As with the Greater Lawrence Incident, certain incidents have subjected and may in the future subject us to litigation or administrative or other legal proceedings from time to time, both civil and criminal, which could result in substantial monetary judgments, fines, or penalties against us, be resolved on unfavorable terms, and require us to incur significant operational expenses. The occurrence of incidents has in certain instances adversely affected and could in the future adversely affect our reputation, cash flows, financial position and/or results of operations. We maintain insurance against some, but not all, of these risks and losses.

We may be unable to obtain insurance on acceptable terms or at all, and the insurance coverage we do obtain may not provide protection against all significant losses.

Our ability to obtain insurance, as well as the cost and coverage of such insurance, are affected by developments affecting our business; international, national, state, or local events; and the financial condition of insurers. Insurance coverage may not continue to be available at all or at rates or terms acceptable to us. We expect the premiums we pay for our insurance coverage to significantly increase as a result of the Greater Lawrence Incident and market conditions. In addition, our insurance is not sufficient or effective under all circumstances and against all hazards or liabilities to which we are subject. For example, total expenses related to the Greater Lawrence Incident have exceeded the total amount of liability coverage available under our policies. Also, certain types of damages, expenses or claimed costs, such as fines and penalties, may be excluded under the policies. In addition, insurers providing liability insurance to us may raise defenses to coverage under the terms and conditions of the respective insurance policies that could result in a denial of coverage or limit the amount of insurance proceeds available to us. Any losses for which we are not fully insured or that are not covered by insurance at all could materially adversely affect our results of operations, cash flows, and financial position. For more information regarding our insurance programs in the context of the Greater Lawrence Incident, see Note 18, "Other Commitments and Contingencies - C. Legal Proceedings," and " - E. Other Matters" in the Notes to Condensed Consolidated Financial Statements.

The outcome of legal and regulatory proceedings, investigations, inquiries, claims and litigation related to our business operations, including those related to the Greater Lawrence Incident, may have a material adverse effect on our results of operations, financial position or liquidity.

We are involved in legal and regulatory proceedings, investigations, inquiries, claims and litigation in connection with our business operations, including the Greater Lawrence Incident, the most significant of which are summarized in Note 18, “Other Commitments and Contingencies” in the Notes to Consolidated Financial Statements. Our insurance is not expected to cover all costs and expenses we may incur relating to the Greater Lawrence Incident and may not fully cover other incidents that may occur in the future. Due to the inherent uncertainty of the outcomes of such matters, there can be no assurance that the resolution of any particular claim or proceeding would not have a material adverse effect on our results of operations, financial position or liquidity. If one or more of such matters were decided against us, the effects could be material to our results of operations in the period in which we would be required to record or adjust the related liability and could also be material to our cash flows in the periods that we would be required to pay such liability.

ITEM 1A. RISK FACTORS

NISOURCE INC.

We are exposed to significant reputational risks, which make us vulnerable to a loss of cost recovery, increased litigation and negative public perception.

As a utility company, we are subject to adverse publicity focused on the reliability of our services, the speed with which we are able to respond effectively to electric outages, natural gas leaks or events and related accidents and similar interruptions caused by storm damage or other unanticipated events, as well as our own or third parties' actions or failure to act. We are also subject to adverse publicity related to perceived environmental impacts. If customers, legislators, or regulators have or develop a negative opinion of us, this could result in less favorable legislative and regulatory outcomes or increased regulatory oversight, increased litigation and negative public perception. Recently, we have been subject to adverse publicity as a result of the Greater Lawrence Incident, and it is difficult to predict the ultimate impact of this adverse publicity. The foregoing may have continuing adverse effects on our business, results of operations, cash flow and financial condition.

Our businesses are regulated under numerous environmental laws. The cost of compliance with these laws, and changes to or additions to, or reinterpretations of the laws, could be significant. Liability from the failure to comply with existing or changed laws could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Our businesses are subject to extensive federal, state and local environmental laws and rules that regulate, among other things, air emissions, water usage and discharges, and waste products such as coal combustion residuals. Compliance with these legal obligations require us to make expenditures for installation of pollution control equipment, remediation, environmental monitoring, emissions fees, and permits at many of our facilities. These expenditures are significant, and we expect that they will continue to be significant in the future. Furthermore, if we fail to comply with environmental laws and regulations or are found to have caused damage to the environment or persons, even if caused by factors beyond our control, that failure or harm may result in the assessment of civil or criminal penalties and damages against us and injunctions to remedy the failure or harm.

Existing environmental laws and regulations may be revised and new laws and regulations seeking to change environmental regulation of the energy industry may be adopted or become applicable to us. Revised or additional laws and regulations may result in significant additional expense and operating restrictions on our facilities or increased compliance costs, which may not be fully recoverable from customers through regulated rates and could, therefore, impact our financial position, financial results and cash flow. Moreover, such costs could materially affect the continued economic viability of one or more of our facilities.

An area of significant uncertainty and risk are the laws concerning emission of GHG. While we continue to reduce GHG emissions through priority pipeline replacement, energy efficiency, leak detection, and other programs, and expect to further reduce GHG emissions through increased use of renewable energy, GHG emissions are currently an expected aspect of the electric and natural gas business. Revised or additional future GHG legislation and/or regulation related to the generation of electricity or the extraction, production, distribution, transmission, storage and end use of natural gas could materially impact our financial position, financial results and cash flows.

Even in instances where legal and regulatory requirements are already known or anticipated, the original cost estimates for environmental capital projects, remediation of past environmental harm, or pollution reduction strategies and equipment can differ materially from the amount ultimately expended. The actual future expenditures depend on many factors, including the nature and extent of impact, the method of cleanup, the cost of raw materials, contractor costs, and the availability of cost recovery. Changes in costs and the ability to recover under regulatory mechanisms could affect our financial position, financial results and cash flows.

A significant portion of the gas and electricity we sell is used by residential and commercial customers for heating and air conditioning. Accordingly, fluctuations in weather, gas and electricity commodity costs and economic conditions impact demand of our customers and our operating results.

Energy sales are sensitive to variations in weather. Forecasts of energy sales are based on “normal” weather, which represents a long-term historical average. Significant variations from normal weather could have, and have had, a material impact on energy sales. Additionally, residential usage, and to some degree commercial usage, is sensitive to fluctuations in commodity costs for gas and electricity, whereby usage declines with increased costs, thus affecting our financial results. Lastly, residential and commercial customers’ usage is sensitive to economic conditions and factors such as unemployment, consumption and consumer confidence. Therefore, prevailing economic conditions affecting the demand of our customers may in turn affect our financial results.

Our business operations are subject to economic conditions in certain industries.

ITEM 1A. RISK FACTORS

NISOURCE INC.

Business operations throughout our service territories have been and may continue to be adversely affected by economic events at the national and local level where it operates. In particular, sales to large industrial customers, such as those in the steel, oil refining, industrial gas and related industries, may be impacted by economic downturns. The U.S. manufacturing industry continues to adjust to changing market conditions including international competition, increasing costs, and fluctuating demand for its products.

The implementation of NIPSCO's electric generation strategy, including the retirement of its coal generation units, may not achieve intended results.

On October 31, 2018, NIPSCO submitted its 2018 Integrated Resource Plan with the IURC setting forth its short- and long-term electric generation plans in an effort to maintain affordability while providing reliable, flexible and cleaner sources of power. The plan evaluated demand-side and supply-side resource alternatives to reliably and cost-effectively meet NIPSCO customers' future energy requirements over the ensuing 20 years. The preferred option within the Integrated Resource Plan sets forth a schedule to retire R.M. Schahfer Generating Station (Units 14, 15, 17, and 18) by 2023 and Michigan City Generating Station (Unit 12) by 2028. The current replacement plan includes renewable sources of energy, including wind, solar, and battery storage. However, there are inherent risks and uncertainties, including changes in market conditions, regulatory approvals, environmental regulations, commodity costs and customer expectations, which may impede NIPSCO's ability to achieve these intended results. NIPSCO's future success will depend, in part, on its ability to successfully implement its long-term electric generation plans, to offer services that meet customer demands and evolving industry standards, and to recover all, or a significant portion of, any unrecovered investment in obsolete assets. NIPSCO's electric generation strategy could require significant future capital expenditures, operating costs and charges to earnings that may negatively impact our financial position, financial results and cash flows.

Fluctuations in the price of energy commodities or their related transportation costs or an inability to obtain an adequate, reliable and cost-effective fuel supply to meet customer demands may have a negative impact on our financial results.

Our electric generating fleet is dependent on coal and natural gas for fuel, and our gas distribution operations purchase and resell much of the natural gas we deliver to our customers. These energy commodities are vulnerable to price fluctuations and fluctuations in associated transportation costs. From time to time, we have also used hedging in order to offset fluctuations in commodity supply prices. We rely on regulatory recovery mechanisms in the various jurisdictions in order to fully recover the commodity costs incurred in providing service. However, while we have historically been successful in the recovery of costs related to such commodity prices, there can be no assurance that such costs will be fully recovered through rates in a timely manner.

In addition, we depend on electric transmission lines, natural gas pipelines, and other transportation facilities owned and operated by third parties to deliver the electricity and natural gas we sell to wholesale markets, supply natural gas to our gas storage and electric generation facilities, and provide retail energy services to customers. If transportation is disrupted, or if capacity is inadequate, we may be unable to sell and deliver our gas and electric services to some or all of our customers. As a result, we may be required to procure additional or alternative electricity and/or natural gas supplies at then-current market rates, which, if recovery of related costs is disallowed, could have a material adverse effect on our businesses, financial condition, cash flows, results of operations and/or prospects.

We are exposed to risk that customers will not remit payment for delivered energy or services, and that suppliers or counterparties will not perform under various financial or operating agreements.

Our extension of credit is governed by a Corporate Credit Risk Policy, involves considerable judgment and is based on an evaluation of a customer or counterparty's financial condition, credit history and other factors. We monitor our credit risk exposure by obtaining credit reports and updated financial information for customers and suppliers, and by evaluating the financial status of our banking partners and other counterparties by reference to market-based metrics such as credit default swap pricing levels, and to traditional credit ratings provided by the major credit rating agencies. Adverse economic conditions could result in an increase in defaults by customers, suppliers and counterparties.

We have significant goodwill and definite-lived intangible assets. An impairment of goodwill or definite-lived intangible assets could result in a significant charge to earnings and negatively impact our compliance with certain covenants under financing agreements.

In accordance with GAAP, we test goodwill for impairment at least annually and review our definite-lived intangible assets for impairment when events or changes in circumstances indicate the carrying value may not be recoverable. Goodwill also is tested for impairment when factors, examples of which include reduced cash flow estimates, a sustained decline in stock price or market capitalization below book value, indicate that the carrying value may not be recoverable. We have tested and will continue to monitor the goodwill of Columbia of Massachusetts for impairment in connection with the Greater Lawrence Incident. To date, these tests do not indicate the need for an impairment of the goodwill balance. We would be required to record a charge in our financial statements for the period in which any impairment of the goodwill or definite-lived intangible assets is determined, negatively impacting the results of operations. A significant charge could impact the capitalization ratio covenant under certain financing agreements. We are subject to a financial covenant under our five-year revolving credit facility, which requires us to maintain a debt to capitalization ratio that does not exceed 70%. A similar covenant in a 2005 private placement note purchase agreement requires us to maintain a debt to capitalization ratio that does not exceed 75%. As of December 31, 2018, the ratio was 61.4%.

Changes in taxation and the ability to quantify such changes could adversely affect our financial results.

We are subject to taxation by the various taxing authorities at the federal, state and local levels where we do business. Legislation or regulation which could affect our tax burden could be enacted by any of these governmental authorities. For example, the TCJA includes numerous provisions that affect businesses, including changes to U.S. corporate tax rates, business-related exclusions, and deductions and credits. The outcome of regulatory proceedings regarding the extent to which the effect of reduced corporate tax rate will be shared with customers and the time period over which it will be shared could significantly impact future earnings and cash flows. Separately, a challenge by a taxing authority, our ability to utilize tax benefits such as carryforwards or tax credits, or a deviation from other tax-related assumptions may cause actual financial results to deviate from previous estimates.

Changes in accounting principles may adversely affect our financial results.

Future changes in accounting rules and associated changes in regulatory accounting may negatively impact the way we record revenues, expenses, assets and liabilities. These changes in accounting standards may adversely affect our financial condition and results of operations.

Aging infrastructure may lead to disruptions in operations and increased capital expenditures and maintenance costs, all of which could negatively impact our financial results.

We have risks associated with aging infrastructure assets. The age of these assets may result in a need for replacement, a higher level of maintenance costs, or unscheduled outages, despite efforts by us to properly maintain or upgrade these assets through inspection, scheduled maintenance and capital investment. In addition, the nature of the information available on aging infrastructure assets may make inspections, maintenance, upgrading and replacement of the assets particularly challenging. The failure to operate these assets as desired could result in gas leaks and other incidents and in our inability to meet firm service obligations, which could adversely impact revenues, and could also result in increased capital expenditures and maintenance costs, which, if not fully recovered from customers, could negatively impact our financial results.

The impacts of climate change, natural disasters, acts of terrorism, accidents or other catastrophic events may disrupt operations and reduce the ability to service customers.

A disruption or failure of natural gas distribution systems, or within electric generation, transmission or distribution systems, in the event of a major hurricane, tornado, terrorist attack, accident or other catastrophic event could cause delays in completing sales, providing services, or performing other critical functions. We have experienced disruptions in the past from hurricanes and tornadoes and other events of this nature. The occurrence of such events could adversely affect our financial position and results of operations. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. There is also a concern that climate change may exacerbate the risks to physical infrastructure. Such risks include heat stresses to power lines, storms that damage infrastructure, lake and sea level changes that damage the manner in which services are currently provided, droughts or other stresses on water used to supply services, and other extreme weather conditions. Climate change and the costs that may be associated with its impacts have the potential to affect our business in many ways, including increasing the costs we incur in providing our products and services, impacting the demand for and consumption of our products and services (due to change in both costs and weather patterns), and affecting the economic health of the regions in which we operate.

ITEM 1A. RISK FACTORS

NISOURCE INC.

A cyber-attack on any of our or certain third-party computer systems upon which we rely may adversely affect our ability to operate.

We are reliant on technology to run our business, which is dependent upon financial and operational computer systems to process critical information necessary to conduct various elements of our business, including the generation, transmission and distribution of electricity, operation of our gas pipeline facilities and the recording and reporting of commercial and financial transactions to regulators, investors and other stakeholders. In addition to general information and cyber risks that all large corporations face (*e.g.*, malware, unauthorized access attempts, phishing attacks, malicious intent by insiders and inadvertent disclosure of sensitive information), the utility industry faces evolving cybersecurity risks associated with protecting sensitive and confidential customer information, electric grid infrastructure, and natural gas infrastructure. Deployment of new business technologies represents a new and large-scale opportunity for attacks on our information systems and confidential customer information, as well as on the integrity of the energy grid and the natural gas infrastructure. Increasing large-scale corporate attacks in conjunction with more sophisticated threats continue to challenge power and utility companies. Any failure of our computer systems, or those of our customers, suppliers or others with whom we do business, could materially disrupt our ability to operate our business and could result in a financial loss and possibly do harm to our reputation.

Additionally, our information systems experience ongoing, often sophisticated, cyber-attacks by a variety of sources, including foreign sources, with the apparent aim to breach our cyber-defenses. Although we attempt to maintain adequate defenses to these attacks and work through industry groups and trade associations to identify common threats and assess our countermeasures, a security breach of our information systems could (i) impact the reliability of our generation, transmission and distribution systems and potentially negatively impact our compliance with certain mandatory reliability standards, (ii) subject us to reputational and other harm associated with theft or inappropriate release of certain types of information such as system operating information or information, personal or otherwise, relating to our customers or employees, (iii) impact our ability to manage our businesses, and/or (iv) subject us to legal and regulatory proceedings and claims from third parties, in addition to remediation costs, any of which, in turn, could have a material adverse effect on our businesses, cash flows, financial condition, results of operations and/or prospects.

Our capital projects and programs subject us to construction risks and natural gas costs and supply risks, and require numerous permits, approvals and certificates from various governmental agencies.

Our business requires substantial capital expenditures for investments in, among other things, capital improvements to our electric generating facilities, electric and natural gas distribution infrastructure, natural gas storage, and other projects, including projects for environmental compliance. We are engaged in intrastate natural gas pipeline modernization programs to maintain system integrity and enhance service reliability and flexibility. NIPSCO also is currently engaged in a number of capital projects, including environmental improvements to its electric generating stations, the construction of new transmission facilities, and new projects related to renewable energy. As we undertake these projects and programs, we may be unable to complete them on schedule or at the anticipated costs. Additionally, we may construct or purchase some of these projects and programs to capture anticipated future growth in natural gas production, which may not materialize, and may cause the construction to occur over an extended period of time.

Our existing and planned capital projects require numerous permits, approvals and certificates from federal, state, and local governmental agencies. If there is a delay in obtaining any required regulatory approvals or if we fail to obtain or maintain any required approvals or to comply with any applicable laws or regulations, we may not be able to construct or operate our facilities, we may be forced to incur additional costs, or we may be unable to recover any or all amounts invested in a project. We also may not receive the anticipated increases in revenue and cash flows resulting from such projects and programs until after their completion

To the extent that delays occur, costs become unrecoverable, or we otherwise become unable to effectively manage and complete our capital projects, our results of operations, cash flows, and financial condition may be adversely affected.

Sustained extreme weather conditions may negatively impact our operations.

We conduct our operations across a wide geographic area subject to varied and potentially extreme weather conditions, which may from time to time persist for sustained periods of time. Despite preventative maintenance efforts, persistent weather related stress on our infrastructure may reveal weaknesses in our systems not previously known to us or otherwise present various operational challenges across all business segments. Further, adverse weather may affect our ability to conduct operations in a manner that satisfies customer expectations or contractual obligations, including by causing service disruptions.

ITEM 1A. RISK FACTORS

NISOURCE INC.

Failure to attract and retain an appropriately qualified workforce could harm our results of operations.

We operate in an industry that requires many of our employees to possess unique technical skill sets. Events such as an aging workforce without appropriate replacements, the mismatch of skill sets to future needs, or the unavailability of contract resources may lead to operating challenges or increased costs. These operating challenges include lack of resources, loss of knowledge, and a lengthy time period associated with skill development. In addition, current and prospective employees may determine that they do not wish to work for us due to market, economic, employment and other conditions. Failure to hire and retain qualified employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, safety, service reliability, customer satisfaction and our results of operations could be adversely affected.

Some of our employees are subject to collective bargaining agreements. Our collective bargaining agreements are generally negotiated on an operating company basis. Any failure to reach an agreement on new labor contracts or to negotiate these labor contracts might result in strikes, boycotts or other labor disruptions. Labor disruptions, strikes or significant negotiated wage and benefit increases, whether due to union activities, employee turnover or otherwise, could have a material adverse effect on our businesses, results of operations and/or cash flows.

We are a holding company and are dependent on cash generated by our subsidiaries to meet our debt obligations and pay dividends on our stock.

We are a holding company and conduct our operations primarily through our subsidiaries. Substantially all of our consolidated assets are held by our subsidiaries. Accordingly, our ability to meet our debt obligations or pay dividends on our common stock and preferred stock is largely dependent upon cash generated by these subsidiaries. In the event a major subsidiary is not able to pay dividends or transfer cash flows to us, our ability to service our debt obligations or pay dividends could be negatively affected.

The Separation may result in significant tax liabilities.

The Separation, which was completed in July 2015, was conditioned on the receipt by us of a legal opinion to the effect that the distribution of CPG shares to our stockholders is expected to qualify as tax-free under Section 355 of the U.S. Internal Revenue Code (the "Internal Revenue Code"). Even though we have received such an opinion, the IRS could determine on audit that the distribution is taxable. Both us and our stockholders could incur significant U.S. Federal income tax liabilities if taxing authorities conclude the distribution is taxable.

If we cannot effectively manage new initiatives and organizational changes, we will be unable to address the opportunities and challenges presented by our strategy and the business and regulatory environment.

In order to execute on our sustainable growth strategy and enhance our culture of ongoing continuous improvement, we must effectively manage the complexity and frequency of new initiatives and organizational changes. If we are unable to make decisions quickly, assess our opportunities and risks, and implement new governance, managerial and organizational processes as needed to execute our strategy in this increasingly dynamic and competitive business and regulatory environment, our financial condition, results of operations and relationships with our business partners, regulators, customers and stockholders may be negatively impacted.

We outsource certain business functions to third-party suppliers and service providers, and substandard performance by those third parties could harm our business, reputation and results of operations.

Utilities rely on extensive networks of business partners and suppliers to support critical enterprise capabilities across their organizations. Global metrics indicate that deliveries from suppliers are slowing and that labor shortages are occurring in the energy sector. We outsource certain services to third parties in areas including construction services, information technology, materials, fleet, environmental, operational services and other areas. Outsourcing of services to third parties could expose us to inferior service quality or substandard deliverables, which may result in non-compliance (including with applicable legal requirements and industry standards), interruption of service or accidents, or reputational harm, which could negatively impact our results of operations. If any difficulties in the operations of these third-party suppliers and service providers, including their systems, were to occur, they could adversely affect our results of operations, or adversely affect our ability to work with regulators, unions, customers or employees.

Changes in the method for determining LIBOR and the potential replacement of the LIBOR benchmark interest rate could adversely affect our business, financial condition, results of operations and cash flows.

ITEM 1A. RISK FACTORS

NISOURCE INC.

Some of our indebtedness, including borrowings under our revolving credit agreement, bears interest at a variable rate based on LIBOR. From time to time, we also enter into hedging instruments to manage our exposure to fluctuations in the LIBOR benchmark interest rate. In addition, these hedging instruments, as well as hedging instruments that our subsidiaries use for hedging natural gas price and basis risk, rely on LIBOR-based rates to calculate interest accrued on certain payments that may be required to be made under these agreements, such as late payments or interest accrued if any cash collateral should be held by a counterparty. In July 2017, the United Kingdom Financial Conduct Authority (“FCA”), which regulates LIBOR, announced that the FCA intends to stop compelling banks to submit rates for the calculation of LIBOR after 2021. It is not possible to predict the effect of these changes, other reforms or the establishment of alternative reference rates in the United Kingdom or elsewhere. In the United States, efforts to identify a set of alternative U.S. dollar reference interest rates include proposals by the Alternative Reference Rates Committee of the Federal Reserve Board and the Federal Reserve Bank of New York. The Alternative Reference Rates Committee has proposed the Secured Overnight Financing Rate ("SOFR") as its recommended alternative to LIBOR, and the Federal Reserve Bank of New York began publishing SOFR rates in April 2018. SOFR is intended to be a broad measure of the cost of borrowing cash overnight that is collateralized by U.S. Treasury securities.

Any changes announced by the FCA, other regulators or any other successor governance or oversight body, or future changes adopted by such body, in the method pursuant to which the LIBOR rates are determined may result in a sudden or prolonged increase or decrease in the reported LIBOR rates. If that were to occur, the level of interest payments we incur may change. In addition, although certain of our LIBOR based obligations provide for alternative methods of calculating the interest rate payable on certain of our obligations if LIBOR is not reported, which include, without limitation, requesting certain rates from major reference banks in London or New York, uncertainty as to the extent and manner of future changes may result in interest rates and/or payments that are higher than, lower than or that do not otherwise correlate over time with, the interest rates or payments that would have been made on our obligations if a LIBOR-based rate was available in its current form.

ITEM 1B. UNRESOLVED STAFF COMMENTS

NISOURCE INC.

None.

ITEM 2. PROPERTIES

Discussed below are the principal properties held by us and our subsidiaries as of December 31, 2018.

Gas Distribution Operations
Refer to Item 1, "Business - Gas Distribution Operations" of this report for further information on Gas Distribution Operations properties.

Electric Operations
Refer to Item 1, "Business - Electric Operations" of this report for further information on Electric Operations properties.

Corporate and Other Operations
We own the Southlake Complex, our 325,000 square foot headquarters building located in Merrillville, Indiana.

Character of Ownership
Our principal properties and our subsidiaries principal properties are owned free from encumbrances, subject to minor exceptions, none of which are of such a nature as to impair substantially the usefulness of such properties. Many of our subsidiary offices in various communities served are occupied under leases. All properties are subject to routine liens for taxes, assessments and undetermined charges (if any) incidental to construction. It is our practice to regularly pay such amounts, as and when due, unless contested in good faith. In general, the electric lines, gas pipelines and related facilities are located on land not owned by us or our subsidiaries, but are covered by necessary consents of various governmental authorities or by appropriate rights obtained from owners of private property. We do not, however, generally have specific easements from the owners of the property adjacent to public highways over, upon or under which our electric lines and gas distribution pipelines are located. At the time each of the principal properties were purchased a title search was made. In general, no examination of titles as to rights-of-way for electric lines, gas pipelines or related facilities was made, other than examination, in certain cases, to verify the grantors' ownership and the lien status thereof.

ITEM 3. LEGAL PROCEEDINGS

For a description of our legal proceedings, see Note 18-C "Legal Proceedings" in the Notes to Consolidated Financial Statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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SUPPLEMENTAL ITEM. EXECUTIVE OFFICERS OF THE REGISTRANT

NISOURCE INC.

The following is a list of the Executive Officers of the Registrant, including their names, ages, offices held and other recent business experience, as of February 1, 2019.

Name	Age	Office(s) Held in Past 5 Years
Joseph Hamrock	55	President and Chief Executive Officer of NiSource since July 1, 2015.
		Executive Vice President and Group Chief Executive Officer of NiSource from May 2012 to July 2015.
Donald E. Brown	47	Executive Vice President and Chief Financial Officer of NiSource since June 2016.
		Executive Vice President, Chief Financial Officer and Treasurer of NiSource from July 2015 to June 2016.
		Executive Vice President, Finance Department of NiSource from March 2015 to July 2015.
		Vice President and Chief Financial Officer of UGI Utilities, a division of UGI Corporation (gas and electric utility company) from 2010 to March 2015.
Peter T. Disser	50	Vice President, Internal Audit of NiSource since January 2019.
		Chief Operating Officer of NiSource Corporate Services from September 2018 through December 2018.
		Vice President, Audit of NiSource from November 2017 to September 2018.
		Vice President of Planning and Analysis of NiSource from June 2016 to November 2017.
		Chief Financial Officer of NIPSCO from 2012 to June 2016.
Carrie J. Hightman	61	Executive Vice President and Chief Legal Officer of NiSource since 2007.
Violet G. Sistovaris	57	Executive Vice President and President, NIPSCO since October 2016.
		Executive Vice President, NIPSCO from June 2015 to October 2016.
		Senior Vice President and Chief Information Officer of NiSource from May 2014 to June 2015.
		Senior Vice President and Chief Information Officer of NiSource Corporate Services from 2008 to May 2014.
Suzanne K. Surface	54	Chief Services Officer of NiSource since January 2019.
		Vice President, Audit of NiSource from September 2018 through December 2018.
		Vice President, Transformation Office of NiSource from August 2018 to September 2018.
		Vice President, Corporate Services Customer Value of NiSource Corporate Services from November 2017 to August 2018.
		Vice President, Audit of NiSource from July 2015 to November 2017.
		Vice President Regulatory Strategy and Support of NiSource from July 2009 through June 2015.
Pablo A. Vegas	45	Executive Vice President and President, Gas Utilities since January 2019.
		Executive Vice President and Chief Restoration Officer of NiSource Corporate Services since September 2018 through December 2018.
		Executive President, Gas Segment and Chief Customer Officer of NiSource from May 2017 to September 2018.
		Executive Vice President and President, Columbia Gas Group from May 2016 to May 2017.
		President and Chief Operating Officer of American Electric Power Ohio Company from May 2012 to May 2016.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

NISOURCE INC.

NiSource's common stock is listed and traded on the New York Stock Exchange under the symbol "NI."

Holders of shares of NiSource's common stock are entitled to receive dividends if and when declared by NiSource's Board out of funds legally available, subject to the prior dividend rights of holders of our preferred stock or the depositary shares representing such preferred stock outstanding, and if full dividends have not been declared and paid on all outstanding shares of preferred stock in any dividend period, no dividend may be declared or paid or set aside for payment on our common stock. The policy of the Board has been to declare cash dividends on a quarterly basis payable on or about the 20th day of February, May, August, and November. At its February 1, 2019 meeting, the Board declared a quarterly common dividend of $0.20 per share, payable on February 20, 2019 to holders of record on February 11, 2019.

Although the Board currently intends to continue the payment of regular quarterly cash dividends on common shares, the timing and amount of future dividends will depend on the earnings of NiSource's subsidiaries, their financial condition, cash requirements, regulatory restrictions, any restrictions in financing agreements and other factors deemed relevant by the Board. There can be no assurance that NiSource will continue to pay such dividends or the amount of such dividends.

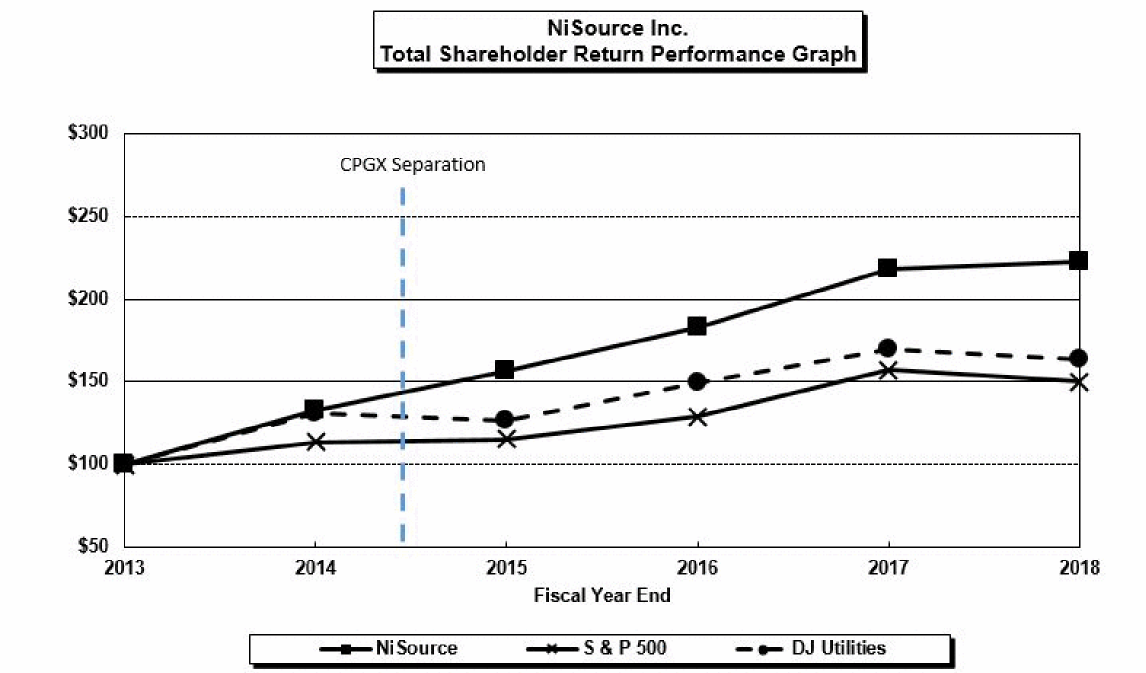
As of February 12, 2019, NiSource had 20,064 common stockholders of record and 372,494,365 shares outstanding.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

NISOURCE INC.

The graph below compares the cumulative total shareholder return of NiSource's common stock for the last five years with the cumulative total return for the same period of the S&P 500 and the Dow Jones Utility indices. On July 1, 2015, NiSource completed the Separation. Following the Separation, NiSource retained no ownership interest in CPG. The Separation is treated as a special dividend for purposes of calculating the total shareholder return, with the then-current market value of the distributed shares being deemed to have been reinvested on the Separation date in shares of NiSource common stock. A vertical line is included on the graph below to identify the periods before and after the Separation.



The foregoing performance graph is being furnished as part of this annual report solely in accordance with the requirement under Rule 14a-3(b)(9) to furnish stockholders with such information, and therefore, shall not be deemed to be filed or incorporated by reference into any filings by NiSource under the Securities Act or the Exchange Act.

The total shareholder return for NiSource common stock and the two indices is calculated from an assumed initial investment of $100 and assumes dividend reinvestment, including the impact of the distribution of CPG common stock in the Separation.

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ITEM 6. SELECTED FINANCIAL DATA

NISOURCE INC.

The selected data presented below as of and for the five years ended December 31, 2018, are derived from our Consolidated Financial Statements. The data should be read together with the Consolidated Financial Statements including the related notes thereto included in Item 8 of this Form 10-K.

Year Ended December 31, (*dollars in millions except per share data*)		**2018**		2017		2016		2015		2014
Statement of Income Data:										
Total Operating Revenues	**$**	**5,114.5**	$	4,874.6	$	4,492.5	$	4,651.8	$	5,272.4
Net Income (Loss) Available to Common Shareholders		**(65.6)**		128.5		331.5		198.6		256.2
Balance Sheet Data:										
Total Assets		**21,804.0**		19,961.7		18,691.9		17,492.5		24,589.8
Capitalization										
Stockholders' equity		**5,750.9**		4,320.1		4,071.2		3,843.5		6,175.3
Long-term debt, excluding amounts due within one year		**7,105.4**		7,512.2		6,058.2		5,948.5		8,151.5
Total Capitalization	**$**	**12,856.3**	$	11,832.3	$	10,129.4	$	9,792.0	$	14,326.8
Per Share Data:										
Basic Earnings (Loss) Per Share ($)	**$**	**(0.18)**	$	0.39	$	1.02	$	0.63	$	0.81
Diluted Earnings (Loss) Per Share ($)	**$**	**(0.18)**	$	0.39	$	1.01	$	0.63	$	0.81
Other Data:										
Dividends declared per common share ($)	**$**	**0.78**	$	0.70	$	0.64	$	0.83	$	1.02
Common shares outstanding at the end of the year (in thousands)		**372,363**		337,016		323,160		319,110		316,037
Number of common stockholders		**19,889**		21,009		22,272		30,190		25,233
Dividends declared per Series A preferred share ($)	**$**	**28.88**	$	—	$	—	$	—	$	—
Capital expenditures	**$**	**1,814.6**	$	1,753.8	$	1,490.4	$	1,367.5	$	1,339.6
Number of employees		**8,087**		8,175		8,007		7,596		8,982

- In the second quarter of 2018, we completed the sale of 24,964,163 shares of $0.01 par value common stock at a price of $24.28 per share in a private placement to selected institutional and accredited investors and issued 400,000 shares of Series A preferred stock resulting in $400.0 million of gross proceeds or $393.9 million of net proceeds, after deducting commissions and sales expenses. Additionally, in the fourth quarter of 2018 we issued 20,000 shares of Series B preferred stock resulting in $500.0 million of gross proceeds or $486.1 million of net proceeds, after deducting commissions and sales expenses.
- During 2018 we recorded a loss of approximately $757 million for third-party claims and approximately $266 million for other incident-related expenses in connection with the Greater Lawrence Incident. Columbia of Massachusetts recorded $135 million for insurance recoveries through December 31, 2018. The amounts set forth above do not include the estimated capital cost of the pipeline replacement, which is set forth in " - E. Other Matters - Greater Lawrence Pipeline Replacement."
- During the second quarter of 2018 we executed a tender offer for $209.0 million of outstanding notes consisting of a combination of our 6.80% notes due 2019, 5.45% notes due 2020 and 6.125% notes due 2022. During the third quarter of 2018, we redeemed $551.1 million of outstanding notes representing the remainder of our 6.80% notes due 2019, 5.45% notes due 2020 and 6.125% notes due 2022. In conjunction with our debt retired, we recorded a $45.5 million loss on early extinguishment of long-term debt primarily attributable to early redemption premiums.
- The decrease in net income during 2017 was due primarily to increased tax expense as a result of the impact of adopting the provisions of the TCJA and a loss on early extinguishment of long-term debt, as discussed below.
- During the second quarter of 2017, we executed a tender offer for $990.7 million of outstanding notes consisting of a combination of our 6.40% notes due 2018, 6.80% notes due 2019, 5.45% notes due 2020, and 6.125% notes due 2022. In conjunction with the debt retired, we recorded a $111.5 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums.
- Prior to the Separation, CPG closed the placement of $2,750.0 million in aggregate principal amount of senior notes. Using the proceeds from this offering, CPG made cash payments to us representing the settlement of inter-company borrowings and the payment of a one-time special dividend. In May 2015, using proceeds from the cash payments from CPG, we settled two bank term loans in the amount of $1,075.0 million and executed a tender offer for $750.0 million consisting of a combination of its 5.25% notes due 2017, 6.40% notes due 2018 and 4.45% notes due 2021. In conjunction with the debt

retired, we recorded a $97.2 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

NISOURCE INC.

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EXECUTIVE SUMMARY

This Management's Discussion and Analysis of Financial Condition and Results of Operations (Management's Discussion) analyzes our financial condition, results of operations and cash flows and those of our subsidiaries. It also includes management's analysis of past financial results and certain potential factors that may affect future results, potential future risks and approaches that may be used to manage those risks. See "Note regarding forward-looking statements" at the beginning of this report for a list of factors that may cause results to differ materially.

Management's Discussion is designed to provide an understanding of our operations and financial performance and should be read in conjunction with our Consolidated Financial Statements and related Notes to Consolidated Financial Statements in this annual report.

We are an energy holding company under the Public Utility Holding Company Act of 2005 whose subsidiaries are fully regulated natural gas and electric utility companies serving customers in seven states. We generate substantially all of our operating income through these rate-regulated businesses which are summarized for financial reporting purposes into two primary reportable segments: Gas Distribution Operations and Electric Operations.

Refer to the "Business" section under Item 1 of this annual report and Note 22, "Segments of Business," in the Notes to the Consolidated Financial Statements for further discussion of our regulated utility business segments.

Our goal is to develop strategies that benefit all stakeholders as we address changing customer conservation patterns, develops more contemporary pricing structures and embarks on long-term infrastructure investment programs. These strategies are intended to improve reliability and safety, enhance customer services and reduce emissions while generating sustainable returns. Additionally, we continue to pursue regulatory and legislative initiatives that will allow residential customers not currently on our system to obtain gas service in a cost effective manner. Refer also to the discussion of *Electric Supply* within our Electric Operations Segment discussion for additional information on our long term electric generation strategy.

Greater Lawrence Incident: The Greater Lawrence Incident occurred on September 13, 2018. During the year ended December 31, 2018, we recorded a loss of approximately $757 million for third-party claims and approximately $266 million for other incident-related expenses in connection with the Greater Lawrence Incident. The amounts set forth above do not include the estimated capital cost of the pipeline replacement described below and as set forth in " - E. Other Matters - Greater Lawrence Pipeline Replacement."

We estimate that total costs related to third-party claims as set forth in Note 18, "Other Commitments and Contingencies - C. Legal Proceedings," will range from $757 million to $790 million, depending on the final outcome of ongoing reviews and the number, nature, and value of third-party claims. We expect to incur a total of $330 million to $345 million in other incident-related costs.

We also expect to incur expenses for which we cannot estimate the amounts of or the timing at this time, including expenses associated with government investigations and fines, penalties or settlements with governmental authorities in connection with the Greater Lawrence Incident.

Columbia of Massachusetts recorded $135 million for insurance recoveries during 2018. Of this amount, $5 million was collected during 2018. We are currently unable to predict the amount and timing of future insurance recoveries. To the extent that we are not successful in collecting reimbursement in the amount recorded for such recoveries as of December 31, 2018, it could result in a charge to earnings.

Columbia of Massachusetts paid approximately $167 million for the replacement of the entire affected 45-mile cast iron and bare steel pipeline system that delivers gas to those impacted in the Greater Lawrence Incident during 2018. We estimate this replacement work will cost between $220 million and $230 million in total. Columbia of Massachusetts has provided notice to its property insurer of the Greater Lawrence Incident and discussions around the claim and recovery have commenced. The recovery of any capital investment not reimbursed through insurance will be addressed in a future regulatory proceeding. The outcome of such a proceeding is uncertain. If at any point Columbia of Massachusetts concludes it is probable that any portion of this capital investment is not recoverable through customer rates, that portion of the capital investment, if estimable, would be immediately charged to earnings.

As discussed in Note 8, "Regulatory Matters," in the Notes to Consolidated Financial Statements, Columbia of Massachusetts withdrew its petition for a base rate revenue increase, resulting in delayed increases in forecasted revenues and cash flows beginning the first quarter of 2019.

Additionally, as discussed in Note 6, "Goodwill and Other Intangible Assets," we concluded the Greater Lawrence Incident was a triggering event requiring a quantitative analysis of goodwill for the Columbia of Massachusetts reporting unit. While no impairment of the goodwill balance was recorded in 2018, future unfavorable events that transpire at Columbia of Massachusetts could trigger the need for another quantitative analysis and a goodwill impairment loss would be required if it's determined Columbia of Massachusetts fair value is less than its book value.

Refer to Note 18-C and E, "Legal Proceedings" and "Other Matters," in the Notes to Consolidated Financial Statements, "Summary of Consolidated Financial Results," "Results and Discussion of Segment Operation - Gas Distribution Operations," and "Liquidity and Capital Resources" in this Management's Discussion, and Part I. Item 1A. "Risk Factors" for additional information related to the Greater Lawrence Incident.

Summary of Consolidated Financial Results

Our operations are affected by the cost of sales. Cost of sales for the Gas Distribution Operations segment is principally comprised of the cost of natural gas used while providing transportation and distribution services to customers. Cost of sales for the Electric Operations segment is comprised of the cost of coal, related handling costs, natural gas purchased for the internal generation of electricity at NIPSCO and the cost of power purchased from third-party generators of electricity.

The majority of the cost of sales are tracked costs that are passed through directly to the customer resulting in an equal and offsetting amount reflected in operating revenues. As a result, we believe net revenues, a non-GAAP financial measure defined as operating revenues less cost of sales (excluding depreciation and amortization), provides management and investors a useful measure to analyze profitability. The presentation of net revenues herein is intended to provide supplemental information for investors regarding operating performance. Net revenues do not intend to represent operating income, the most comparable GAAP measure, as an indicator of operating performance and is not necessarily comparable to similarly titled measures reported by other companies.

For the years ended December 31, 2018, 2017 and 2016, operating income and a reconciliation of net revenues to the most directly comparable GAAP measure, operating income, was as follows:

Year Ended December 31, *(in millions)*	**2018**	2017	2016	2018 vs. 2017	2017 vs. 2016
Operating Income	**$ 124.7**	$ 921.2	$ 866.1	$ (796.5)	$ 55.1

Year Ended December 31, *(in millions, except per share amounts)*	**2018**	2017	2016	2018 vs. 2017	2017 vs. 2016
Operating Revenues	**$ 5,114.5**	$ 4,874.6	$ 4,492.5	$ 239.9	$ 382.1
Cost of sales (excluding depreciation and amortization)	**1,761.3**	1,518.7	1,390.2	242.6	128.5
Total Net Revenues	**3,353.2**	3,355.9	3,102.3	(2.7)	253.6
Other Operating Expenses	**3,228.5**	2,434.7	2,236.2	793.8	198.5
Operating Income	**124.7**	921.2	866.1	(796.5)	55.1
Total Other Deductions, Net	**(355.3)**	(478.2)	(352.5)	122.9	(125.7)
Income Taxes	**(180.0)**	314.5	182.1	(494.5)	132.4
Net Income (Loss)	**(50.6)**	128.5	331.5	(179.1)	(203.0)
Preferred dividends	**(15.0)**	—	—	(15.0)	—
Net Income (Loss) Available to Common Shareholders	**(65.6)**	128.5	331.5	(194.1)	(203.0)
Basic Earnings (Loss) Per Share	**$ (0.18)**	$ 0.39	$ 1.03	$ (0.57)	$ (0.64)
Basic Average Common Shares Outstanding	**356.5**	329.4	321.8	27.1	7.6

On a consolidated basis, we reported a loss to common shareholders of $65.6 million or $0.18 per basic share for the twelve months ended December 31, 2018 compared to net income available to common shareholders of $128.5 million or $0.39 per basic share for the same period in 2017. The decrease in net income during 2018 was primarily due to expenses related to the Greater Lawrence Incident restoration, dilution resulting from preferred stock dividend commitments and other changes in operating income, as discussed below, partially offset by the effects of implementing the TCJA and higher losses on early extinguishment of long-term debt expenses in 2017.

Operating Income

For the twelve months ended December 31, 2018, we reported operating income of $124.7 million compared to $921.2 million for the same period in 2017. The decreased operating income was primarily due to increased operation and maintenance expenses related to the Greater Lawrence Incident, decreased net revenues resulting from TCJA impacts on revenue and increased depreciation due to capital expenditures placed in service. These increases were partially offset by higher rates from infrastructure replacement programs and base-rate proceedings, decreased outside service costs and employee and administrative expenses, as well as net favorable effects of year-over-year weather variations, which increased revenue in 2018.

Other Deductions, Net

Other deductions, net reduced income by $355.3 million in 2018 compared to a reduction in income of $478.2 million in 2017. This change is primarily due to lower losses on early extinguishment of long-term debt in 2018 of $66.0 million, an interest rate swap settlement gain in 2018 of $46.2 million and higher actuarial investment returns resulting from pension contributions made in 2017. These favorable variances were partially offset by charitable contributions of $20.7 million in 2018 related to the Greater Lawrence Incident.

Income Taxes

On December 22, 2017, the President signed into law the TCJA, which, among other things, enacted significant changes to the Internal Revenue Code, as amended, including a reduction in the maximum U.S. federal corporate income tax rate from 35% to 21%, and certain other provisions related specifically to the public utility industry, including the continuation of certain interest expense deductibility and excluding 100% expensing of capital investments. These changes are effective January 1, 2018. GAAP requires the effect of a change in tax law to be recorded in the period of enactment. As a result, in December 2017, NiSource recorded a $161.1 million net increase in tax expense related primarily to the remeasurement of deferred tax assets for NOL carryforwards.

The decrease in income tax expense from 2017 to 2018 is primarily attributable to the decrease in the federal corporate income tax rate, true-ups to tax expense in 2018 to reflect regulatory outcomes associated with excess deferred income taxes, the effect of amortizing the regulatory liability associated with excess deferred income taxes and lower pre-tax income resulting from expenses incurred for the Greater Lawrence Incident.

Refer to "Liquidity and Capital Resources" below and Note 10, "Income Taxes," in the Notes to Consolidated Financial Statements for additional information on income taxes and the change in the effective tax rate.

Capital Investment

In 2018, we invested approximately $1.8 billion in cash capital expenditures across the gas and electric utilities. These expenditures were primarily aimed at furthering the safety and reliability of our gas distribution system, the Greater Lawrence Incident pipeline replacement, construction of new electric transmission assets and maintaining our existing electric generation fleet.

We continue to execute on an estimated $30 billion in total projected long-term regulated utility infrastructure investments and expect to invest approximately $1.6 to $1.7 billion in capital during 2019 to continue to modernize and improve our system across all seven states of our operating area.

Liquidity

As discussed in further detail below in "Liquidity and Capital Resources," the TCJA has and will continue to have an unfavorable impact on our liquidity. Additionally, expenses paid for the Greater Lawrence Incident are expected to have a short term negative impact on liquidity as recoveries from insurance lag behind our cash outlay. Liquidity will also be negatively impacted to the extent certain costs associated with the Greater Lawrence Incident are not recovered from insurance. Through income generated from operating activities, amounts available under our short-term revolving credit facility, commercial paper program, accounts receivable securitization facilities, long-term debt agreements and our ability to access the capital markets, we believe there is adequate capital available to fund our operating activities and capital expenditures and the effects of the Greater Lawrence Incident in 2019 and beyond. At December 31, 2018 and 2017, we had approximately $974.6 million and $998.9 million, respectively, of net liquidity available, consisting of cash and available capacity under credit facilities.

These factors and other impacts to the financial results are discussed in more detail within the following discussions of "Results and Discussion of Segment Operations" and "Liquidity and Capital Resources."

Regulatory Developments

In 2018, we continued to move forward on core infrastructure and environmental investment programs supported by complementary regulatory and customer initiatives across all seven states of our operating area. Refer to Note 8, "Regulatory Matters" and Note 18-E, "Other Matters," in the Notes to Consolidated Financial Statements for a complete discussion of key regulatory developments that transpired during 2018.

RESULTS AND DISCUSSION OF SEGMENT OPERATIONS

Presentation of Segment Information

Our operations are divided into two primary reportable segments: Gas Distribution Operations and Electric Operations.

NISOURCE INC.
Gas Distribution Operations

For the years ended December 31, 2018, 2017 and 2016, operating income and a reconciliation of net revenues to the most directly comparable GAAP measure, operating income, was as follows:

Year Ended December 31, *(in millions)*	2018	2017	2016	2018 vs. 2017	2017 vs. 2016
Operating Income (Loss)	**$ (254.1)**	$ 550.1	$ 569.7	$ (804.2)	$ (19.6)

Year Ended December 31, *(dollars in millions)*	2018	2017	2016	2018 vs. 2017	2017 vs. 2016
Net Revenues					
Operating revenues	**$ 3,419.5**	$ 3,102.1	$ 2,830.6	$ 317.4	$ 271.5
Less: Cost of sales (excluding depreciation and amortization)	**1,259.3**	1,005.0	895.4	254.3	109.6
Net Revenues	**2,160.2**	2,097.1	1,935.2	63.1	161.9
Operating Expenses					
Operation and maintenance	**1,908.1**	1,090.8	941.5	817.3	149.3
Depreciation and amortization	**301.0**	269.3	252.9	31.7	16.4
Loss on sale of assets and impairments, net	**0.2**	2.8	—	(2.6)	2.8
Other taxes	**205.0**	184.1	171.1	20.9	13.0
Total Operating Expenses	**2,414.3**	1,547.0	1,365.5	867.3	181.5
Operating Income (Loss)	**$ (254.1)**	$ 550.1	$ 569.7	$ (804.2)	$ (19.6)
Revenues					
Residential	**$ 2,248.3**	$ 2,029.4	$ 1,823.4	$ 218.9	$ 206.0
Commercial	**753.7**	669.4	588.1	84.3	81.3
Industrial	**228.6**	217.5	194.3	11.1	23.2
Off-System	**92.4**	111.8	94.4	(19.4)	17.4
Other	**96.5**	74.0	130.4	22.5	(56.4)
Total	**$ 3,419.5**	$ 3,102.1	$ 2,830.6	$ 317.4	$ 271.5
Sales and Transportation (MMDth)					
Residential	**280.3**	247.1	248.9	33.2	(1.8)
Commercial	**187.6**	169.3	165.6	18.3	3.7
Industrial	**555.7**	517.5	517.7	38.2	(0.2)
Off-System	**30.0**	39.0	39.6	(9.0)	(0.6)
Other	**—**	0.3	(0.1)	(0.3)	0.4
Total	**1,053.6**	973.2	971.7	80.4	1.5
Heating Degree Days	**5,562**	4,927	5,148	635	(221)
Normal Heating Degree Days	**5,610**	5,610	5,642	—	(32)
% Warmer than Normal	**(1)%**	(12)%	(9)%		
Gas Distribution Customers					
Residential	**3,194,662**	3,168,516	3,141,736	26,146	26,780
Commercial	**281,563**	280,362	279,556	1,201	806
Industrial	**6,038**	6,228	6,240	(190)	(12)
Other	**3**	4	—	(1)	4
Total	**3,482,266**	3,455,110	3,427,532	27,156	27,578

NISOURCE INC.
Gas Distribution Operations (continued)

Comparability of line item operating results may be impacted by regulatory, tax and depreciation trackers (other than those for cost of sales) that allow for the recovery in rates of certain costs. Therefore, increases in these tracked operating expenses are generally offset by increases in net revenues and have essentially no impact on net income.

2018 vs. 2017 Operating Income
For 2018, Gas Distribution Operations reported an operating loss of $254.1 million, a decrease in income of $804.2 million from the comparable 2017 period.

Net revenues for 2018 were $2,160.2 million, an increase of $63.1 million from the same period in 2017. The change in net revenues was primarily driven by:

- New rates from infrastructure replacement programs and base rate proceedings of $99.6 million.
- Higher revenues from the effects of colder weather in 2018 of $37.5 million.
- The effects of customer growth and increased usage of $17.4 million.
- Higher regulatory, tax and depreciation trackers, which are offset in operating expense, of $16.0 million.

Partially offset by:

- A revenue reserve of $85.0 million in 2018 resulting from the probable future refund of certain collections from customers as a result of the lower income tax rate from the TCJA.
- Decreased rates from implementation of regulatory outcomes related to the TCJA of $24.7 million.

Operating expenses were $867.3 million higher in 2018 compared to 2017. This change was primarily driven by:

- Expenses related to third-party claims and other costs following the Greater Lawrence Incident of $864.4 million, net of insurance recoveries recorded.
- Increased depreciation of $29.6 million due to regulatory outcomes of NIPSCO's gas rate case and higher capital expenditures placed in service.
- Higher regulatory, tax and depreciation trackers, which are offset in net revenues, of $16.0 million.
- Increased property taxes of $11.0 million due to higher capital expenditures placed in service and the impact of regulatory-driven property tax deferrals.

Partially offset by:

- Decreased outside services of $33.2 million primarily due to IT service provider transition and other strategic initiative costs in 2017, lower ongoing IT costs and a temporary shift of resources to the Greater Lawrence Incident restoration.
- Lower employee and administrative expenses of $30.2 million driven by reduced incentive compensation and a temporary shift of resources to the Greater Lawrence Incident restoration.

2017 vs. 2016 Operating Income
For 2017, Gas Distribution Operations reported operating income of $550.1 million, a decrease of $19.6 million from the comparable 2016 period.

Net revenues for 2017 were $2,097.1 million, an increase of $161.9 million from the same period in 2016. The change in net revenues was primarily driven by:

- New rates from base-rate proceedings and infrastructure replacement programs of $124.2 million.
- Higher regulatory, tax and depreciation trackers, which are offset in operating expense, of $26.9 million.
- The effects of increased customer growth of $10.3 million.
- Higher revenues from increased industrial usage of $5.8 million.

Operating expenses were $181.5 million higher in 2017 compared to 2016. This change was primarily driven by:

- Increased employee and administrative expenses of $53.4 million.
- Higher outside service costs of $52.8 million due to IT service provider transition costs, increased spend on strategic initiatives to enhance safety, reliability and customer value and higher pipeline maintenance expenses.
- Increased regulatory, tax and depreciation trackers, which are offset in net revenues, of $26.9 million.
- Higher depreciation of $15.2 million due to increased capital expenditures placed in service.

NISOURCE INC.
Gas Distribution Operations (continued)

- Increased property taxes of $8.1 million due to higher capital expenditures placed in service and an accrual adjustment recorded in 2016.
- Higher environmental costs of $4.7 million.
- Increased materials and supplies expenses of $3.4 million from maintenance-related activities.

Weather
In general, we calculate the weather-related revenue variance based on changing customer demand driven by weather variance from normal heating degree days. Our composite heating degree days reported do not directly correlate to the weather-related dollar impact on the results of Gas Distribution Operations. Heating degree days experienced during different times of the year or in different operating locations may have more or less impact on volume and dollars depending on when and where they occur. When the detailed results are combined for reporting, there may be weather-related dollar impacts on operations when there is not an apparent or significant change in our aggregated composite heating degree day comparison.

Weather in the Gas Distribution Operations service territories for 2018 was about 1% warmer than normal and about 13% colder than 2017, increasing net revenues $37.5 million for the year ended December 31, 2018 compared to 2017.

Weather in the Gas Distribution Operations service territories for 2017 was about 12% warmer than normal and about 4% warmer than 2016, decreasing net revenues $1.7 million for the year ended December 31, 2017 compared to 2016.

Throughput
Total volumes sold and transported for the year ended December 31, 2018 were 1,053.6 MMDth, compared to 973.2 MMDth for 2017. This increase is primarily attributable to colder weather experienced in 2018 compared to 2017.

Total volumes sold and transported for the year ended December 31, 2017 were 973.2 MMDth, compared to 971.7 MMDth for 2016.

Economic Conditions
All of our Gas Distribution Operations companies have state-approved recovery mechanisms that provide a means for full recovery of prudently incurred gas costs. Gas costs are treated as pass-through costs and have no impact on the net revenues recorded in the period. The gas costs included in revenues are matched with the gas cost expense recorded in the period and the difference is recorded on the Consolidated Balance Sheets as under-recovered or over-recovered gas cost to be included in future customer billings.

Certain Gas Distribution Operations companies continue to offer choice opportunities, where customers can choose to purchase gas from a third-party supplier, through regulatory initiatives in their respective jurisdictions. These programs serve to further reduce our exposure to gas prices.

Greater Lawrence Incident
Refer to Note 18-C. "Legal Proceedings," and E. "Other Matters," in the Notes to Consolidated Financial Statements, "Summary of Consolidated Financial Results,""Liquidity and Capital Resources" in this Management's Discussion, and Part I. Item 1A. "Risk Factors" for additional information related to the Greater Lawrence Incident.

NISOURCE INC.
Electric Operations

For the years ended December 31, 2018, 2017 and 2016, operating income and a reconciliation of net revenues to the most directly comparable GAAP measure, operating income, was as follows:

Year Ended December 31, *(in millions)*	2018	2017	2016	2018 vs. 2017	2017 vs. 2016
Operating Income	**$ 386.1**	$ 367.4	$ 301.3	$ 18.7	$ 66.1

Year Ended December 31, *(dollars in millions)*	2018	2017	2016	2018 vs. 2017	2017 vs. 2016
Net Revenues					
Operating revenues	**$ 1,708.2**	$ 1,786.5	$ 1,661.6	$ (78.3)	$ 124.9
Less: Cost of sales (excluding depreciation and amortization)	**502.1**	513.9	495.0	(11.8)	18.9
Net Revenues	**1,206.1**	1,272.6	1,166.6	(66.5)	106.0
Operating Expenses					
Operation and maintenance	**500.0**	565.6	528.9	(65.6)	36.7
Depreciation and amortization	**262.9**	277.8	274.5	(14.9)	3.3
Loss on sale of assets	**—**	1.9	—	(1.9)	1.9
Other taxes	**57.1**	59.9	61.9	(2.8)	(2.0)
Total Operating Expenses	**820.0**	905.2	865.3	(85.2)	39.9
Operating Income	**$ 386.1**	$ 367.4	$ 301.3	$ 18.7	$ 66.1
Revenues					
Residential	**$ 494.7**	$ 476.9	$ 457.4	$ 17.8	$ 19.5
Commercial	**492.6**	501.2	456.6	(8.6)	44.6
Industrial	**614.4**	698.1	631.6	(83.7)	66.5
Wholesale	**15.7**	11.6	11.6	4.1	—
Other	**90.8**	98.7	104.4	(7.9)	(5.7)
Total	**$ 1,708.2**	$ 1,786.5	$ 1,661.6	$ (78.3)	$ 124.9
Sales (Gigawatt Hours)					
Residential	**3,535.2**	3,301.7	3,514.8	233.5	(213.1)
Commercial	**3,844.6**	3,793.5	3,878.7	51.1	(85.2)
Industrial	**8,829.5**	9,469.7	9,281.8	(640.2)	187.9
Wholesale	**114.3**	32.5	19.0	81.8	13.5
Other	**124.4**	128.2	136.9	(3.8)	(8.7)
Total	**16,448.0**	16,725.6	16,831.2	(277.6)	(105.6)
Cooling Degree Days	**1,180**	837	988	343	(151)
Normal Cooling Degree Days	**806**	806	806	—	—
% Warmer than Normal	**46%**	4%	23%		
Electric Customers					
Residential	**412,267**	409,401	407,268	2,866	2,133
Commercial	**56,605**	56,134	55,605	471	529
Industrial	**2,284**	2,305	2,313	(21)	(8)
Wholesale	**735**	739	744	(4)	(5)
Other	**2**	2	2	—	—
Total	**471,893**	468,581	465,932	3,312	2,649

Electric Operations (continued)

Comparability of line item operating results may be impacted by regulatory and depreciation trackers (other than those for cost of sales) that allow for the recovery in rates of certain costs. Therefore, increases in these tracked operating expenses are offset by increases in net revenues and have essentially no impact on net income.

2018 vs. 2017 Operating Income

For 2018, Electric Operations reported operating income of $386.1 million, an increase of $18.7 million from the comparable 2017 period.

Net revenues for 2018 were $1,206.1 million, a decrease of $66.5 million from the same period in 2017. The change in net revenues was primarily driven by:

- Lower regulatory and depreciation trackers, which are offset in operating expense, of $35.6 million.
- Decreased rates from implementation of regulatory outcomes related to the TCJA of $32.9 million.
- Decreased industrial usage of $17.1 million.
- A revenue reserve of $16.2 million in 2018 resulting from the probable future refund of certain collections from customers as a result of the lower income tax rate from the TCJA .
- Increased fuel handling costs of $7.3 million.

Partially offset by:

- The effects of warmer weather of $25.2 million.
- Increased rates from infrastructure replacement programs of $18.6 million.

Operating expenses were $85.2 million lower in 2018 than 2017. This change was primarily driven by:

- Lower regulatory and depreciation trackers, which are offset in net revenues, of $35.6 million.
- Lower outside service costs of $32.1 million and lower material and supplies costs of $10.2 million primarily related to the retirement of Bailly Generating Station Units 7 and 8 on May 31, 2018.
- Decreased employee and administrative costs of $18.4 million.

Partially offset by:

- Increased depreciation of $10.0 million due to higher capital expenditures placed in service.

2017 vs. 2016 Operating Income

For 2017, Electric Operations reported operating income of $367.4 million, an increase of $66.1 million from the comparable 2016 period.

Net revenues for 2017 were $1,272.6 million, an increase of $106.0 million from the same period in 2016. The change in net revenues was primarily driven by:

- New rates from base-rate proceedings of $63.6 million.
- Increased rates from incremental capital spend on electric transmission projects of $24.2 million.
- Higher regulatory and depreciation trackers, which are offset in operating expense, of $18.0 million.
- New rates from infrastructure replacement programs of $6.0 million.
- The effects of increased customer count of $3.4 million.

Partially offset by:

- The effects of cooler weather of $16.1 million.

Operating expenses were $39.9 million higher in 2017 than 2016. This change was primarily driven by:

- Higher outside service costs of $20.1 million, primarily due to increased spend on strategic initiatives to enhance safety, reliability and customer value, generation-related maintenance, IT service provider transition costs and vegetation management activities.
- Higher employee and administrative costs of $19.2 million.
- Increased regulatory and depreciation trackers, which are offset in net revenues, of $18.0 million.

NISOURCE INC.
Electric Operations (continued)

- Increased depreciation of $5.6 million due to higher capital expenditures placed in service.
- Higher materials and supplies costs of $4.5 million driven by generation-related maintenance.

Partially offset by:

- Plant retirement costs of $22.1 million in 2016.
- Decreased amortization of regulatory assets of $10.8 million.

Weather
In general, we calculate the weather-related revenue variance based on changing customer demand driven by weather variance from normal heating or cooling degree days. Our composite heating or cooling degree days reported do not directly correlate to the weather-related dollar impact on the results of Electric Operations. Heating or cooling degree days experienced during different times of the year may have more or less impact on volume and dollars depending on when they occur. When the detailed results are combined for reporting, there may be weather-related dollar impacts on operations when there is not an apparent or significant change in our aggregated composite heating or cooling degree day comparison

Weather in the Electric Operations' territories for 2018 was 46% warmer than normal and 41% warmer than the same period in 2017, increasing net revenues $25.2 million for the year ended December 31, 2018 compared to 2017.

Weather in the Electric Operations' territories for 2017 was 4% warmer than normal and 15% cooler than the same period in 2016, decreasing net revenues $16.1 million for the year ended December 31, 2017 compared to 2016.

Sales
Electric Operations sales were 16,448.0 GWh for 2018, a decrease of 277.6 GWh, or 1.7% compared to 2017. This decrease was primarily attributable to higher internal generation from large industrial customers in 2018, partially offset by increased volumes for residential and commercial customers resulting from warmer weather.

Electric Operations sales were 16,725.6 GWh for 2017, a decrease of 105.6 GWh, or 0.6% compared to 2016.

BP Products North America. On March 29, 2018, WCE, which is currently owned by BP p.l.c ("BP") and BP Products North America, which operates the BP Refinery, filed a petition at the IURC asking that the combined operations of WCE and BP be treated as a single premise, and the WCE generation be dedicated primarily to BP Refinery operations beginning in May 2019 as WCE has self-certified as a qualifying facility at FERC. BP Refinery plans to continue to purchase electric service from NIPSCO at a reduced demand level beginning May 2019. Refer to Note 8, "Regulatory Matters," in the Notes to Consolidated Financial Statements for additional information.

Economic Conditions
NIPSCO has a state-approved recovery mechanism that provides a means for full recovery of prudently incurred fuel costs. Fuel costs are treated as pass-through costs and have no impact on the net revenues recorded in the period. The fuel costs included in revenues are matched with the fuel cost expense recorded in the period and the difference is recorded on the Consolidated Balance Sheets as under-recovered or over-recovered fuel cost to be included in future customer billings.

NIPSCO's performance remains closely linked to the performance of the steel industry. NIPSCO's MWh sales to steel-related industries accounted for approximately 49.67% and 54.5% of the total industrial MWh sales for the years ended December 31, 2018 and 2017, respectively.

Electric Supply
Bailly Generating Station. NIPSCO completed the retirement of Units 7 and 8 at Bailly Generating Station on May 31, 2018. These units had a generating capacity of approximately 460 MW. The remaining net book value of the retired units is presented in "Regulatory assets (noncurrent)" on the Consolidated Balance Sheets. This balance continues to be amortized at a rate consistent with its inclusion in customer rates. The ongoing recovery of our remaining investment in these units will be addressed in NIPSCO's rate case filed on October 31, 2018. Refer to Note 8, "Regulatory Matters," and Note 18-E, "Other Matters," in the Notes to Consolidated Financial Statements for additional information.

NIPSCO 2018 Integrated Resource Plan. Multiple factors, but primarily economic ones, including low natural gas prices, advancing cost effective renewable technology and increasing capital and operating costs associated with existing coal plants, have led

Electric Operations (continued)

NIPSCO to conclude in its October 2018 Integrated Resource Plan submission that NIPSCO's current fleet of coal generation facilities will be retired earlier than previous Integrated Resource Plan's had indicated.

The Integrated Resource Plan evaluated demand-side and supply-side resource alternatives to reliably and cost effectively meet NIPSCO customers' future energy requirements over the ensuing 20 years. The preferred option within the Integrated Resource Plan retires R.M. Schahfer Generating Station (Units 14, 15, 17, and 18) by 2023 and Michigan City Generating Station (Unit 12) by 2028. These units represent 2,080 MW of generating capacity, equal to 72% of NIPSCO's remaining capacity after the retirement of Bailly Units 7 and 8 in May of 2018.

The current replacement plan includes renewable sources of energy, including wind, solar, and battery storage to be obtained through a combination of NIPSCO ownership and PPAs. Refer to Note 18-E, "Other Matters," in the Notes to Consolidated Financial Statements for further discussion.

Liquidity and Capital Resources

Greater Lawrence Incident: As discussed in the "Executive Summary" and Note 18, "Other Commitments and Contingencies," we have recorded losses associated with the Greater Lawrence Incident and have invested capital to replace the entire affected 45-mile cast iron and bare steel pipeline system that delivers gas to the impacted area. As discussed in the Executive Summary and Note 18 referenced earlier in this paragraph, and Part I, Item 1A "Risk Factors," in this report, we may incur additional expenses and liabilities in excess of our recorded liabilities and estimated additional costs associated with the Greater Lawrence Incident. The timing and amount of future financing needs arising from the Greater Lawrence Incident, if any, will depend on the ultimate timing and amount of payments made in connection with the Greater Lawrence Incident and the timing and amount of associated insurance recoveries. Through income generated from operating activities, amounts available under our short-term revolving credit facility, commercial paper program, accounts receivable securitization facilities, term loan borrowings, long-term debt agreements and our ability to access the capital markets, we believe there is adequate capital available to fund these expenditures.

Operating Activities

Net cash from operating activities for the year ended December 31, 2018 was $540.1 million, a decrease of $202.1 million from 2017. This decrease was driven by cash spend for the Greater Lawrence Incident in 2018 offset by decreased pension plan contributions as discussed below as well as decreased operation and maintenance expenses (excluding expenses related to the Greater Lawrence Incident). The decrease in cash from operations was further offset by higher sales due to colder weather during the 2018 winter heating season compared to 2017 and increased rates from infrastructure replacement programs and rate case outcomes.

Greater Lawrence Incident. During 2018, we paid approximately $731 million in operating cash flow related to the Greater Lawrence Incident. Refer to Note 18-E "Other Matters" for further information.

Pension and Other Postretirement Plan Funding. In 2017, we contributed $282.3 million to our pension plans (including a $277 million discretionary contribution made during the third quarter of 2017) and $31.6 million to our other postretirement benefit plans.

In 2018, we contributed $2.9 million to our pension plans and $21.0 million to our other postretirement benefit plans. Given the current funded status of the pension plans, and barring unforeseen market volatility that may negatively impact the valuation of our plan assets, we do not believe additional material contributions to our pension plans will be required for the foreseeable future.

Income Taxes. Rates for our regulated customers include provisions for the collection of U.S. federal income taxes. The reduction in the U.S. federal corporate income tax rate as a result of the TCJA has led to a decrease in the amount billed to customers through rates, ultimately resulting in lower cash collections from operating activities. As discussed in further detail in Note 7, "Regulatory Matters," in the Notes to the Consolidated Financial Statements, our regulated subsidiaries are engaged with the relevant state utility commissions to address the impacts of the TCJA on future customer rates. During 2018, billings to customers decreased approximately $57.6 million compared to the same period in 2017 as a result of adjustments to certain rates in our Kentucky, Ohio, Maryland, Pennsylvania, Massachusetts and Indiana jurisdictions. Additionally, during 2018, we recorded additional TCJA-related regulatory liabilities related to 2018 collections from customers, which are being refunded back to customers once new customer rates are approved by our regulators.

In addition, we will be required to pass back to customers "excess deferred taxes" which represent amounts collected from customers in the past to cover deferred tax liabilities which, as a result of the passage of the TCJA, are now less than the originally billed amounts. Approximately $1.5 billion of excess deferred taxes was recorded to "Regulatory liabilities (noncurrent)" on the Consolidated Balance Sheets as of December 31, 2017 as a result of implementing the TCJA. The majority of this balance related to temporary book-to-tax differences on utility property protected by IRS normalization rules. As modified rates are approved by each of our regulators, we expect this portion of the balance will be passed back to customers over the remaining average useful life of the associated property as required by the TCJA. The pass back period for the remainder of this balance will be determined by our state utility commissions in future proceedings. Our estimate of the amount and pass-back period of excess deferred taxes is subject to change pending final review by the utility commissions of the states in which we operate. As noted above, this pass back of excess deferred taxes has already begun in certain of our jurisdictions. As of December 31, 2018 we have approximately $1.4 billion of remaining regulatory liabilities associated with excess deferred taxes. See Note 8, "Regulatory Matters," for additional information.

As of December 31, 2018, we had a recorded deferred tax asset of $759.6 million related to a federal NOL carryforward, of which $508.5 million relates to years prior to the implementation of the TCJA. As a result of being in an NOL position, we were not required to make any cash payments for federal income tax purposes during the three years ended December 31, 2018. The carryforward periods for pre-TCJA tax benefits expire in various tax years from 2028 to 2037, however, we expect to fully utilize the carryforward benefit prior to its expiration. Per the TCJA, utilization of NOL carryforwards generated after December 31, 2017 do not expire, but are limited to 80% of current year taxable income. Accordingly, we may be required to make cash payments for federal income taxes in future years despite having NOL carryforwards in excess of current taxes payable.

Investing Activities
Our cash used for investing activities varies year over year primarily as a result of changes in the level of annual capital expenditures. The table below reflects capital expenditures and certain other investing activities by segment for 2018, 2017 and 2016.

(in millions)	**2018**	2017	2016
Gas Distribution Operations			
System Growth and Tracker	**$ 1,073.7**	$ 909.2	$ 835.0
Maintenance	**241.6**	216.4	219.4
Total Gas Distribution Operations	**1,315.3**	1,125.6	1,054.4
Electric Operations			
System Growth and Tracker	**346.0**	435.3	314.1
Maintenance	**153.3**	157.1	106.5
Total Electric Operations	**499.3**	592.4	420.6
Corporate and Other Operations - Maintenance[1]	**—**	35.8	15.4
Total[2]	**$ 1,814.6**	$ 1,753.8	$ 1,490.4

[1]Zero Corporate and Other capital expenditures in 2018 driven by the leasing of IT assets beginning in Q1 2018 versus historical practice of purchasing.
[2]Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the capitalized portion of the Corporate Incentive Plan payout, inclusion of capital expenditures included in current liabilities and AFUDC Equity.

For 2018, capital expenditures and certain other investing activities were $1,814.6 million, which was $60.8 million higher than the 2017 capital program. This increased spending is due in part to costs associated with the Greater Lawrence Incident pipeline replacement, gas transmission projects, environmental investments and system modernization projects.

For 2017, capital expenditures and certain other investing activities were $1,753.8 million, which was $263.4 million higher than the 2016 capital program. This increased spending is mainly due to electric transmission projects, environmental investments and system modernization projects.

For 2019, we project to invest approximately $1.6 to $1.7 billion in our capital program. This projected level of spend is consistent with 2018 spend levels and is expected to focus primarily on the continuation of the modernization projects, segment growth across the Gas Distribution Operations segment, and TDSIC spend.

Financing Activities
Short-term Debt. Refer to Note 15, "Short-Term Borrowings," in the Notes to Consolidated Financial Statements for information on short-term debt.

Long-term Debt. Refer to Note 14, "Long-Term Debt," in the Notes to Consolidated Financial Statements for information on long-term debt.

Net Available Liquidity. As of December 31, 2018, an aggregate of $974.6 million of net liquidity was available, including cash and credit available under the revolving credit facility and accounts receivable securitization programs.

The following table displays NiSource's liquidity position as of December 31, 2018 and 2017:

Year Ended December 31, *(in millions)*	**2018**	2017
Current Liquidity		
Revolving Credit Facility	**$ 1,850.0**	$ 1,850.0
Accounts Receivable Program[1]	**399.2**	336.7
Less:		
Commercial Paper	**978.0**	869.0
Accounts Receivable Program Utilized	**399.2**	336.7
Letters of Credit Outstanding Under Credit Facility	**10.2**	11.1
Add:		
Cash and Cash Equivalents	**112.8**	29.0
Net Available Liquidity	**$ 974.6**	$ 998.9

[1]Represents the lesser of the seasonal limit or maximum borrowings supportable by the underlying receivables.

Debt Covenants. We are subject to a financial covenant under our revolving credit facility and term loan agreement, which requires us to maintain a debt to capitalization ratio that does not exceed 70%. A similar covenant in a 2005 private placement note purchase agreement requires us to maintain a debt to capitalization ratio that does not exceed 75%. As of December 31, 2018, the ratio was 61.4%.

Sale of Trade Accounts Receivables. Refer to Note 17, "Transfers of Financial Assets," in the Notes to Consolidated Financial Statements for information on the sale of trade accounts receivable.

Credit Ratings. The credit rating agencies periodically review our ratings, taking into account factors such as our capital structure and earnings profile. The following table includes our and certain of our subsidiaries' credit ratings and ratings outlook as of December 31, 2018.

A credit rating is not a recommendation to buy, sell or hold securities, and may be subject to revision or withdrawal at any time by the assigning rating organization.

	S&P		Moody's		Fitch	
	Rating	Outlook	Rating	Outlook	Rating	Outlook
NiSource	BBB+	Negative	Baa2	Stable	BBB	Stable
NIPSCO	BBB+	Negative	Baa1	Stable	BBB	Stable
Columbia of Massachusetts	BBB+	Negative	Baa2	Stable	Not rated	Not rated
Commercial Paper	A-2	Negative	P-2	Stable	F2	Stable

Certain of our subsidiaries have agreements that contain "ratings triggers" that require increased collateral if our credit ratings or the credit ratings of certain of our subsidiaries are below investment grade. These agreements are primarily for insurance purposes and for the physical purchase or sale of power. As of December 31, 2018, the collateral requirement that would be required in the event of a downgrade below the ratings trigger levels would amount to approximately $53.8 million. In addition to agreements with ratings triggers, there are other agreements that contain "adequate assurance" or "material adverse change" provisions that could necessitate additional credit support such as letters of credit and cash collateral to transact business.

Equity. Our authorized capital stock consists of 420,000,000 shares, $0.01 par value, of which 400,000,000 are common stock and 20,000,000 are preferred stock. As of December 31, 2018, 372,363,656 shares of common stock and 420,000 shares of preferred stock were outstanding. For more information regarding our common and preferred stock, see Note 12, "Equity," in the Notes to Consolidated Financial Statements.

Contractual Obligations. We have certain contractual obligations requiring payments at specified periods. The obligations include long-term debt, lease obligations, energy commodity contracts and obligations for various services including pipeline capacity and outsourcing of IT services. The total contractual obligations in existence at December 31, 2018 and their maturities were:

(in millions)	Total	2019	2020	2021	2022	2023	After
Long-term debt [1]	$ 7,029.6	$ 41.0	$ —	$ 63.6	$ 530.0	$ 600.0	$ 5,795.0
Capital leases[2]	322.4	23.0	22.5	22.6	22.1	19.8	212.4
Interest payments on long-term debt	6,311.7	319.8	318.6	318.6	315.0	289.0	4,750.7
Operating leases[3]	45.9	11.0	7.3	6.1	4.2	2.8	14.5
Energy commodity contracts	154.3	99.2	55.1	—	—	—	—
Service obligations:							
Pipeline service obligations	3,566.7	592.3	487.7	450.5	437.5	260.8	1,337.9
IT service obligations	211.0	68.3	60.0	47.1	35.6	—	—
Other service obligations	86.7	33.5	43.6	9.6	—	—	—
Other liabilities	24.2	24.2	—	—	—	—	—
Total contractual obligations	$ 17,752.5	$ 1,212.3	$ 994.8	$ 918.1	$ 1,344.4	$ 1,172.4	$ 12,110.5

[1] Long-term debt balance excludes unamortized issuance costs and discounts of $68.5 million.
[2] Capital lease payments shown above are inclusive of interest totaling $114.6 million.
[3] Operating lease balances do not include amounts for fleet leases that can be renewed beyond the initial lease term. The Company anticipates renewing the leases beyond the initial term, but the anticipated payments associated with the renewals do not meet the definition of expected minimum lease payments and therefore are not included above. Expected payments are $26.7 million in 2019, $22.4 million in 2020, $16.6 million in 2021, $12.3 million in 2022, $9.3 million in 2023 and $8.8 million thereafter.

Our calculated estimated interest payments for long-term debt is based on the stated coupon and payment dates. For 2019, we project that we will be required to make interest payments of approximately $363.1 million, which includes $319.8 million of interest payments related to our long-term debt outstanding as of December 31, 2018. At December 31, 2018, we had $1,977.2 million in short-term borrowings outstanding.

Our expected payments included within "Other liabilities" in the table of contractual commitments above contains employer contributions to pension and other postretirement benefits plans expected to be made in 2019. Plan contributions beyond 2019 are dependent upon a number of factors, including actual returns on plan assets, which cannot be reliably estimated at this time. In 2019, we expect to make contributions of approximately $3.0 million to our pension plans and approximately $20.6 million to our postretirement medical and life plans. Refer to Note 11, "Pension and Other Postretirement Benefits," in the Notes to Consolidated Financial Statements for more information.

We cannot reasonably estimate the settlement amounts or timing of cash flows related to long-term obligations classified as "Total Other Liabilities" on the Consolidated Balance Sheets, other than those described above.

We also have obligations associated with income, property, gross receipts, franchise, payroll, sales and use, and various other taxes and expect to make tax payments of approximately $240.6 million in 2019, which are not included in the table above.

Refer to Note 18-A, "Contractual Obligations," in the Notes to Consolidated Financial Statements for further information.

In January 2019, NIPSCO executed two 20 year PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per mwh and a BTA with a developer to construct a renewable generation facility. Payments under these agreement are not included in the table above as these agreements were executed in 2019 and remain subject to approval by the relevant regulatory authorities before the deals would commence. See 18-E. "Other Matters - NIPSCO 2018 Integrated Resource Plan," for additional information.

Off-Balance Sheet Arrangements

We, along with certain of our subsidiaries, enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees and stand-by letters of credit.

Refer to Note 18, "Other Commitments and Contingencies," in the Notes to Consolidated Financial Statements for additional information about such arrangements.

Market Risk Disclosures

Risk is an inherent part of our businesses. The extent to which we properly and effectively identify, assess, monitor and manage each of the various types of risk involved in our businesses is critical to our profitability. We seek to identify, assess, monitor and manage, in accordance with defined policies and procedures, the following principal market risks that are involved in our businesses: commodity price risk, interest rate risk and credit risk. Risk management for us is a multi-faceted process with oversight by the Risk Management Committee that requires constant communication, judgment and knowledge of specialized products and markets. Our senior management takes an active role in the risk management process and has developed policies and procedures that require specific administrative and business functions to assist in the identification, assessment and control of various risks. These may include, but are not limited to market, operational, financial, compliance and strategic risk types. In recognition of the increasingly varied and complex nature of the energy business, our risk management process, policies and procedures continue to evolve and are subject to ongoing review and modification.

Commodity Price Risk

We are exposed to commodity price risk as a result of our subsidiaries' operations involving natural gas and power. To manage this market risk, our subsidiaries use derivatives, including commodity futures contracts, swaps, forwards and options. We do not participate in speculative energy trading activity.

Commodity price risk resulting from derivative activities at our rate-regulated subsidiaries is limited, since regulations allow recovery of prudently incurred purchased power, fuel and gas costs through the rate-making process, including gains or losses on these derivative instruments. If states should explore additional regulatory reform, these subsidiaries may begin providing services without the benefit of the traditional rate-making process and may be more exposed to commodity price risk.

Our subsidiaries are required to make cash margin deposits with their brokers to cover actual and potential losses in the value of outstanding exchange traded derivative contracts. The amount of these deposits, some of which is reflected in our restricted cash balance, may fluctuate significantly during periods of high volatility in the energy commodity markets.

Refer to Note 9, "Risk Management Activities," in the Notes to the Consolidated Financial Statements for further information on our commodity price risk assets and liabilities as of December 31, 2018 and 2017.

Interest Rate Risk

We are exposed to interest rate risk as a result of changes in interest rates on borrowings under our revolving credit agreement, commercial paper program, term loan borrowings and accounts receivable programs, which have interest rates that are indexed to short-term market interest rates. Based upon average borrowings and debt obligations subject to fluctuations in short-term market interest rates, an increase (or decrease) in short-term interest rates of 100 basis points (1%) would have increased (or decreased) interest expense by $13.3 million and $15.8 million for 2018 and 2017, respectively. We are also exposed to interest rate risk as a result of changes in benchmark rates that can influence the interest rates of future debt issuances.

Refer to Note 9, "Risk Management Activities," in the Notes to Consolidated Financial Statements for further information on our interest rate risk assets and liabilities as of December 31, 2018 and 2017.

Credit Risk

Due to the nature of the industry, credit risk is embedded in many of our business activities. Our extension of credit is governed by a Corporate Credit Risk Policy. In addition, Risk Management Committee guidelines are in place which document management approval levels for credit limits, evaluation of creditworthiness, and credit risk mitigation efforts. Exposures to credit risks are monitored by the risk management function which is independent of commercial operations. Credit risk arises due to the possibility that a customer, supplier or counterparty will not be able or willing to fulfill its obligations on a transaction on or before the settlement date. For derivative-related contracts, credit risk arises when counterparties are obligated to deliver or purchase defined commodity units of gas or power to us at a future date per execution of contractual terms and conditions. Exposure to credit risk is measured in terms of both current obligations and the market value of forward positions net of any posted collateral such as cash and letters of credit.

We closely monitor the financial status of our banking credit providers. We evaluate the financial status of our banking partners through the use of market-based metrics such as credit default swap pricing levels, and also through traditional credit ratings provided by major credit rating agencies.

Other Information

Critical Accounting Policies

We apply certain accounting policies based on the accounting requirements discussed below that have had, and may continue to have, significant impacts on our operations and Consolidated Financial Statements.

Basis of Accounting for Rate-Regulated Subsidiaries. ASC Topic 980, *Regulated Operations*, provides that rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred on the Consolidated Balance Sheets and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. The total amounts of regulatory assets and liabilities reflected on the Consolidated Balance Sheets were $2,237.5 million and $2,660.0 million at December 31, 2018, and $1,801.2 million and $2,795.6 million at December 31, 2017, respectively. For additional information, refer to Note 8, "Regulatory Matters," in the Notes to Consolidated Financial Statements.

In the event that regulation significantly changes the opportunity for us to recover our costs in the future, all or a portion of our regulated operations may no longer meet the criteria for the application of ASC Topic 980, *Regulated Operations*. In such event, a write-down of all or a portion of our existing regulatory assets and liabilities could result. If transition cost recovery is approved by the appropriate regulatory bodies that would meet the requirements under GAAP for continued accounting as regulatory assets and liabilities during such recovery period, the regulatory assets and liabilities would be reported at the recoverable amounts. If we were unable to continue to apply the provisions of ASC Topic 980, *Regulated Operations*, we would be required to apply the provisions of ASC Topic 980-20, *Discontinuation of Rate-Regulated Accounting*. In management's opinion, our regulated subsidiaries will be subject to ASC Topic 980, *Regulated Operations* for the foreseeable future.

Certain of the regulatory assets reflected on our Consolidated Balance Sheets require specific regulatory action in order to be included in future service rates. Although recovery of these amounts is not guaranteed, we believe that these costs meet the requirements for deferral as regulatory assets. Regulatory assets requiring specific regulatory action amounted to $320.4 million at December 31, 2018. If we determine that the amounts included as regulatory assets were not recoverable, a charge to income would immediately be required to the extent of the unrecoverable amounts.

The passage of the TCJA into law necessitated the remeasurement of our deferred income tax balances to reflect the new U.S. corporate income tax rate of 21%. For our regulated entities, substantially all of the impact of this remeasurement was recorded to a regulatory asset or regulatory liability, as appropriate, until such time that we receive final regulatory orders prescribing the required accounting treatment and related impact on future customer rates. For additional information, refer to Note 10, "Income Taxes," in the Notes to Consolidated Financial Statements.

As discussed in Note 18-E, "Other Matters - Greater Lawrence Pipeline Replacement," we incurred approximately $167 million of capital spend for pipeline replacement in the affected communities during 2018. We estimate this replacement work will cost between $220 million and $230 million in total. Columbia of Massachusetts has provided notice to its property insurer of the Greater Lawrence Incident and discussions around the claim and recovery have commenced. The recovery of any capital investment not reimbursed through insurance will be addressed in a future regulatory proceeding. The outcome of such a proceeding is uncertain. In accordance with ASC 980-360, if it becomes probable that a portion of the pipeline replacement cost will not be recoverable through customer rates and an amount can be reasonably estimated, we will reduce our regulated plant balance for the amount of the probable disallowance and record an associated charge to earnings. This could result in a material adverse effect to our financial condition, results of operations and cash flows. Additionally, if a rate order is received allowing recovery of the investment with no or reduced return on investment, a loss on disallowance may be required.

Pension and Postretirement Benefits. We have defined benefit plans for both pension and other postretirement benefits. The calculation of the net obligations and annual expense related to the plans requires a significant degree of judgment regarding the discount rates to be used in bringing the liabilities to present value, expected long-term rates of return on plan assets, health care trend rates, and mortality rates, among other assumptions. Due to the size of the plans and the long-term nature of the associated liabilities, changes in the assumptions used in the actuarial estimates could have material impacts on the measurement of the net obligations and annual expense recognition. Differences between actuarial assumptions and actual plan results are deferred into AOCI or a regulatory balance sheet account, depending on the jurisdiction of our entity. These deferred gains or losses are then amortized into the income statement when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the fair value of plan assets (known in GAAP as the "corridor" method) or when settlement accounting is triggered.

The discount rates, expected long-term rates of return on plan assets, health care cost trend rates and mortality rates are critical assumptions. Methods used to develop these assumptions are described below. While a third party actuarial firm assists with the development of many of these assumptions, we are ultimately responsible for selecting the final assumptions.

The discount rate is utilized principally in calculating the actuarial present value of pension and other postretirement benefit obligations and net periodic pension and other postretirement benefit plan costs. Our discount rates for both pension and other postretirement benefits are determined using spot rates along an AA-rated above median yield curve with cash flows matching the expected duration of benefit payments to be made to plan participants.

The expected long-term rate of return on plan assets is a component utilized in calculating annual pension and other postretirement benefit plan costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, target asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets.

For measurement of 2019 net periodic benefit cost, we selected an expected pre-tax long-term rate of return of 6.10% and 5.80% for our pension and other postretirement benefit plan assets, respectively.

We estimate the assumed health care cost trend rate, which is used in determining our other postretirement benefit net expense, based upon our actual health care cost experience, the effects of recently enacted legislation, third-party actuarial surveys and general economic conditions.

We use the Society of Actuaries' most recently published mortality data in developing a best estimate of mortality as part of the calculation of the pension and other postretirement benefit obligations.

The following tables illustrate the effects of changes in these actuarial assumptions while holding all other assumptions constant:

	Impact on December 31, 2018 Projected Benefit Obligation Increase/(Decrease)	
Change in Assumptions *(in millions)*	Pension Benefits	Other Postretirement Benefits
+50 basis points change in discount rate	$ (79.6)	$ (23.6)
-50 basis points change in discount rate	86.2	25.8
+50 basis points change in health care trend rates		12.5
-50 basis points change in health care trend rates		(11.0)

	Impact on 2018 Expense Increase/(Decrease)[1]	
Change in Assumptions *(in millions)*	Pension Benefits	Other Postretirement Benefits
+50 basis points change in discount rate	$ (3.3)	$ (0.7)
-50 basis points change in discount rate	2.8	0.8
+50 basis points change in expected long-term rate of return on plan assets	(10.3)	(1.3)
-50 basis points change in expected long-term rate of return on plan assets	10.3	1.3
+50 basis points change in health care trend rates		0.6
-50 basis points change in health care trend rates		(0.5)

[1]Before labor capitalization and regulatory deferrals.

In January 2017, we changed the method used to estimate the service and interest components of net periodic benefit cost for pension and other postretirement benefits. This change, compared to the previous method, resulted in a decrease in the actuarially-determined service and interest cost components. Historically, we estimated service and interest cost utilizing a single weighted-average discount rate derived from the yield curve used to measure the benefit obligation at the beginning of the period. For fiscal 2017 and beyond, we now utilize a full yield curve approach to estimate these components by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to the relevant projected cash flows. For further discussion of our pension and other postretirement benefits, see Note 11, "Pension and Other Postretirement Benefits," in the Notes to Consolidated Financial Statements.

Goodwill. We have seven goodwill reporting units, comprised of the seven state operating companies within the Gas Distribution Operations reportable segment. Our goodwill assets at December 31, 2018 were $1,690.7 million, most of which resulted from the acquisition of Columbia on November 1, 2000.

As required by GAAP, we test for impairment of goodwill on an annual basis and on an interim basis when events or circumstances indicate that a potential impairment may exist. Our annual goodwill test takes place in the second quarter of each year and was most recently finalized as of May 1, 2018. In the third quarter of 2018, we determined the Greater Lawrence Incident represented a triggering event that required an impairment analysis of goodwill. The incident specifically impacts our Columbia of Massachusetts reporting unit. The quantitative impairment analysis as of September 30, 2018 determined the fair value of Columbia of Massachusetts reporting unit continued to exceed its carrying value. For additional information, refer to Note 6, "Goodwill and Other Intangible Assets," in the Notes to Consolidated Financial Statements.

We completed a quantitative ("step 1") fair value measurement of our reporting units during the May 1, 2016 goodwill test. Consistent with our historical impairment testing of goodwill, fair value of the reporting units was determined based on a weighting of income and market approaches. These approaches require significant judgments including appropriate long-term growth rates and discount rates for the income approach and appropriate multiples of earnings for peer companies and control premiums for the market approach. A qualitative ("step 0") test was completed on May 1, 2018. We assessed various assumptions, events and circumstances that would have affected the estimated fair value of the reporting units in our baseline May 1, 2016 test. The results of this assessment indicated that it is not more likely than not that its reporting unit fair values are less than the reporting unit carrying values and no impairments are necessary.

The discount rates were derived using peer company data compiled with the assistance of a third party valuation services firm. The discount rates used are subject to change based on changes in tax rates at both the state and federal level, debt and equity ratios at each reporting unit and general economic conditions.

The long-term growth rate was derived by evaluating historic growth rates, new business and investment opportunities beyond the near term horizon. The long-term growth rate is subject to change depending on inflationary impacts to the U.S. economy and the individual business environments in which each reporting unit operates.

The May 1, 2016 test indicated the fair value of each of the reporting units that carry or are allocated goodwill exceeded their carrying values, indicating that no impairment existed under the step 1 annual impairment test. If the estimates of free cash flow used in this step 1 analysis had been 10% lower, the resulting fair values would have still been greater than the carrying value for each of the reporting units tested, holding all other assumptions constant.

Revenue Recognition. Revenue is recorded as products and services are delivered. Utility revenues are billed to customers monthly on a cycle basis. Revenues are recorded on the accrual basis and include estimates for electricity and gas delivered but not billed.

We adopted the provisions of ASC 606 beginning on January 1, 2018 using a modified retrospective method, which was applied to all contracts. No material adjustments were made to January 1, 2018 opening balances and no material changes in the amount or timing of future revenue recognition occurred as a result of the adoption of ASC 606. Refer to Note 3 "Revenue Recognition," in the Notes to Consolidated Financial Statements.

Recently Issued Accounting Pronouncements

Refer to Note 2, "Recent Accounting Pronouncements," in the Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Quantitative and Qualitative Disclosures about Market Risk are reported in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk Disclosures."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

NISOURCE INC.

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NISOURCE INC.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NiSource Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of NiSource Inc. and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related statements of consolidated income (loss), comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and the schedule listed in the Index at item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 20, 2019, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP
Columbus, Ohio
February 20, 2019

We have served as the Company's auditor since 2002.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NiSource Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of NiSource Inc. and subsidiaries (the "Company") as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the financial statements as of and for year ended December 31, 2018, of the Company and our report dated February 20, 2019, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP
Columbus, Ohio
February 20, 2019

NISOURCE INC.
STATEMENTS OF CONSOLIDATED INCOME (LOSS)

Year Ended December 31, *(in millions, except per share amounts)*		**2018**		2017		2016
Operating Revenues						
Customer revenues	**$**	**4,991.1**	$	4,730.2	$	4,392.5
Other revenues		**123.4**		144.4		100.0
Total Operating Revenues		**5,114.5**		4,874.6		4,492.5
Operating Expenses						
Cost of sales (excluding depreciation and amortization)		**1,761.3**		1,518.7		1,390.2
Operation and maintenance		**2,352.9**		1,601.7		1,445.8
Depreciation and amortization		**599.6**		570.3		547.1
Loss (Gain) on sale of assets and impairments, net		**1.2**		5.5		(1.0)
Other taxes		**274.8**		257.2		244.3
Total Operating Expenses		**4,989.8**		3,953.4		3,626.4
Operating Income		**124.7**		921.2		866.1
Other Income (Deductions)						
Interest expense, net		**(353.3)**		(353.2)		(349.5)
Other, net		**43.5**		(13.5)		(3.0)
Loss on early extinguishment of long-term debt		**(45.5)**		(111.5)		—
Total Other Deductions, Net		**(355.3)**		(478.2)		(352.5)
Income (Loss) before Income Taxes		**(230.6)**		443.0		513.6
Income Taxes		**(180.0)**		314.5		182.1
Net Income (Loss)		**(50.6)**		128.5		331.5
Preferred dividends		**(15.0)**		—		—
Net Income (Loss) Available to Common Shareholders		**(65.6)**		128.5		331.5
Earnings (Loss) Per Share						
Basic Earnings (Loss) Per Share	**$**	**(0.18)**	$	0.39	$	1.03
Diluted Earnings (Loss) Per Share	**$**	**(0.18)**	$	0.39	$	1.02
Basic Average Common Shares Outstanding		**356.5**		329.4		321.8
Diluted Average Common Shares		**356.5**		330.8		323.5

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME (LOSS)

Year Ended December 31, *(in millions, net of taxes)*		**2018**		2017		2016
Net Income (Loss)	**$**	**(50.6)**	$	128.5	$	331.5
Other comprehensive income (loss):						
Net unrealized gain (loss) on available-for-sale securities[1]		**(2.6)**		0.8		(0.1)
Net unrealized gain (loss) on cash flow hedges[2]		**22.7**		(22.5)		8.6
Unrecognized pension and OPEB benefit (costs)[3]		**(4.4)**		3.4		1.5
Total other comprehensive income (loss)		**15.7**		(18.3)		10.0
Total Comprehensive Income	**$**	**(34.9)**	$	110.2	$	341.5

(1) Net unrealized gain (loss) on available-for-sale securities, net of $0.6 million tax benefit, $0.4 million tax expense and $0.1 million tax benefit in 2018, 2017 and 2016, respectively.
(2) Net unrealized gain (loss) on derivatives qualifying as cash flow hedges, net of $7.5 million tax expense, $13.9 million tax benefit and $5.6 million tax expense in 2018, 2017 and 2016, respectively.
(3) Unrecognized pension and OPEB benefit (costs), net of $1.5 million tax benefit, $2.1 million tax expense and $0.1 million tax expense in 2018, 2017 and 2016, respectively.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
CONSOLIDATED BALANCE SHEETS

(in millions)	**December 31, 2018**	December 31, 2017
ASSETS		
Property, Plant and Equipment		
Utility plant	**$ 22,780.8**	$ 21,026.6
Accumulated depreciation and amortization	**(7,257.9)**	(6,953.6)
Net utility plant	**15,522.9**	14,073.0
Other property, at cost, less accumulated depreciation	**19.6**	286.5
Net Property, Plant and Equipment	**15,542.5**	14,359.5
Investments and Other Assets		
Unconsolidated affiliates	**2.1**	5.5
Other investments	**204.0**	204.1
Total Investments and Other Assets	**206.1**	209.6
Current Assets		
Cash and cash equivalents	**112.8**	29.0
Restricted cash	**8.3**	9.4
Accounts receivable (less reserve of $21.1 and $18.3, respectively)	**1,058.5**	898.9
Gas inventory	**286.8**	285.1
Materials and supplies, at average cost	**101.0**	105.9
Electric production fuel, at average cost	**34.7**	80.1
Exchange gas receivable	**88.4**	45.8
Regulatory assets	**235.4**	176.3
Prepayments and other	**129.5**	132.8
Total Current Assets	**2,055.4**	1,763.3
Other Assets		
Regulatory assets	**2,002.1**	1,624.9
Goodwill	**1,690.7**	1,690.7
Intangible assets, net	**220.7**	231.7
Deferred charges and other	**86.5**	82.0
Total Other Assets	**4,000.0**	3,629.3
Total Assets	**$ 21,804.0**	$ 19,961.7

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	**December 31, 2018**	December 31, 2017
CAPITALIZATION AND LIABILITIES		
Capitalization		
Stockholders' Equity		
Common stock - $0.01 par value, 400,000,000 shares authorized; 372,363,656 and 337,015,806 shares outstanding, respectively	**$ 3.8**	$ 3.4
Preferred stock - $0.01 par value, 20,000,000 shares authorized; 420,000 shares outstanding	**880.0**	—
Treasury stock	**(99.9)**	(95.9)
Additional paid-in capital	**6,403.5**	5,529.1
Retained deficit	**(1,399.3)**	(1,073.1)
Accumulated other comprehensive loss	**(37.2)**	(43.4)
Total Stockholders' Equity	**5,750.9**	4,320.1
Long-term debt, excluding amounts due within one year	**7,105.4**	7,512.2
Total Capitalization	**12,856.3**	11,832.3
Current Liabilities		
Current portion of long-term debt	**50.0**	284.3
Short-term borrowings	**1,977.2**	1,205.7
Accounts payable	**883.8**	625.6
Customer deposits and credits	**238.9**	262.6
Taxes accrued	**222.7**	208.1
Interest accrued	**90.7**	112.3
Risk management liabilities	**5.0**	43.2
Exchange gas payable	**85.5**	59.6
Regulatory liabilities	**140.9**	58.7
Legal and environmental	**18.9**	32.1
Accrued compensation and employee benefits	**149.7**	195.4
Claims accrued	**114.7**	12.5
Other accruals	**58.8**	78.3
Total Current Liabilities	**4,036.8**	3,178.4
Other Liabilities		
Risk management liabilities	**46.7**	28.5
Deferred income taxes	**1,330.5**	1,292.9
Deferred investment tax credits	**11.2**	12.4
Accrued insurance liabilities	**84.4**	80.1
Accrued liability for postretirement and postemployment benefits	**389.1**	337.1
Regulatory liabilities	**2,519.1**	2,736.9
Asset retirement obligations	**352.0**	268.7
Other noncurrent liabilities	**177.9**	194.4
Total Other Liabilities	**4,910.9**	4,951.0
Commitments and Contingencies (Refer to Note 18, "Other Commitments and Contingencies")	**—**	—
Total Capitalization and Liabilities	**$ 21,804.0**	$ 19,961.7

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED CASH FLOWS

Year Ended December 31, (in millions)	2018	2017	2016
Operating Activities			
Net Income (Loss)	$ (50.6)	$ 128.5	$ 331.5
Adjustments to Reconcile Net Income (Loss) to Net Cash from Operating Actvities:			
Loss on early extinguishment of debt	45.5	111.5	—
Depreciation and amortization	599.6	570.3	547.1
Deferred income taxes and investment tax credits	(188.2)	306.7	182.3
Stock compensation expense and 401(k) profit sharing contribution	28.6	40.1	46.5
Amortization of discount/premium on debt	7.5	7.4	7.6
AFUDC equity	(14.2)	(12.6)	(11.6)
Other adjustments	1.7	6.6	(7.2)
Changes in Assets and Liabilities:			
Accounts receivable	(186.2)	(52.3)	(188.0)
Inventories	41.4	19.0	38.9
Accounts payable	268.4	49.0	108.8
Customer deposits and credits	(25.4)	(2.5)	(52.3)
Taxes accrued	20.2	10.2	12.1
Interest accrued	(21.7)	(33.9)	(8.7)
Exchange gas receivable/payable	(21.5)	(64.5)	36.9
Other accruals	43.5	31.8	(6.0)
Prepayments and other current assets	(14.5)	(13.3)	(0.4)
Regulatory assets/liabilities	(53.2)	57.5	(187.9)
Postretirement and postemployment benefits	58.2	(380.9)	(44.8)
Deferred charges and other noncurrent assets	3.8	(2.0)	(1.2)
Other noncurrent liabilities	(2.8)	(34.4)	(0.3)
Net Cash Flows from Operating Activities	540.1	742.2	803.3
Investing Activities			
Capital expenditures	(1,818.2)	(1,695.8)	(1,475.2)
Cost of removal	(104.3)	(109.0)	(110.1)
Purchases of available-for-sale securities	(90.0)	(168.4)	(38.3)
Sales of available-for-sale securities	82.3	163.1	33.0
Other investing activities	4.1	1.6	(12.4)
Net Cash Flows used for Investing Activities	(1,926.1)	(1,808.5)	(1,603.0)
Financing Activities			
Issuance of long-term debt	350.0	3,250.0	500.0
Repayments of long-term debt and capital lease obligations	(1,046.1)	(1,855.0)	(434.6)
Premiums and other debt related costs	(46.0)	(144.3)	(3.7)
Issuance of short-term debt (maturity > 90 days)	950.0	—	—
Change in short-term borrowings, net (maturity ≤ 90 days)	(178.5)	(282.4)	920.6
Issuance of common stock, net of issuance costs	848.2	336.7	23.1
Issuance of preferred stock, net of issuance costs	880.0	—	—
Acquisition of treasury stock	(4.0)	(7.2)	(9.4)
Dividends paid - common stock	(273.3)	(229.1)	(205.5)
Dividends paid - preferred stock	(11.6)	—	—
Net Cash Flows from Financing Activities	1,468.7	1,068.7	790.5
Change in cash, cash equivalents and restricted cash	82.7	2.4	(9.2)
Cash, cash equivalents and restricted cash at beginning of period	38.4	36.0	45.2
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 121.1	$ 38.4	$ 36.0

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

NISOURCE INC.
STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY

(in millions)	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Deficit	Accumulated Other Comprehensive Loss	Total
Balance as of January 1, 2016	**$ 3.2**	**$ (79.3)**	**$ 5,078.0**	**$ (1,123.3)**	**$ (35.1)**	**$ 3,843.5**
Comprehensive Income:						
Net Income	—	—	—	331.5	—	331.5
Other comprehensive income, net of tax	—	—	—	—	10.0	10.0
Common stock dividends ($0.64 per share)	—	—	—	(205.7)	—	(205.7)
Treasury stock acquired	—	(9.4)	—	—	—	(9.4)
Cumulative effect of change in accounting principle[(1)]	—	—	—	25.3	—	25.3
Stock issuances:						
Common stock	0.1	—	—	—	—	0.1
Employee stock purchase plan	—	—	4.7	—	—	4.7
Long-term incentive plan	—	—	20.9	—	—	20.9
401(k) and profit sharing	—	—	41.4	—	—	41.4
Dividend reinvestment plan	—	—	8.9	—	—	8.9
Balance as of December 31, 2016	**$ 3.3**	**$ (88.7)**	**$ 5,153.9**	**$ (972.2)**	**$ (25.1)**	**$ 4,071.2**
Comprehensive Loss:						
Net Income	—	—	—	128.5	—	128.5
Other comprehensive loss, net of tax	—	—	—	—	(18.3)	(18.3)
Common stock dividends ($0.70 per share)	—	—	—	(229.4)	—	(229.4)
Treasury stock acquired	—	(7.2)	—	—	—	(7.2)
Stock issuances:						
Employee stock purchase plan	—	—	5.0	—	—	5.0
Long-term incentive plan	—	—	14.9	—	—	14.9
401(k) and profit sharing	—	—	34.3	—	—	34.3
Dividend reinvestment plan	—	—	6.4	—	—	6.4
ATM Program	0.1	—	314.6	—	—	314.7
Balance as of December 31, 2017	**$ 3.4**	**$ (95.9)**	**$ 5,529.1**	**$ (1,073.1)**	**$ (43.4)**	**$ 4,320.1**

[(1)]See Note 2, "Recent Accounting Pronouncements," for additional information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY

(in millions)	Common Stock	Preferred Stock	Treasury Stock	Additional Paid-In Capital	Retained Deficit	Accumulated Other Comprehensive Loss	Total
Balance as of December 31, 2017	**$ 3.4**	**$ —**	**$ (95.9)**	**$ 5,529.1**	**$ (1,073.1)**	**$ (43.4)**	**$ 4,320.1**
Comprehensive Income:							
Net Loss	—	—	—	—	(50.6)	—	(50.6)
Other comprehensive income, net of tax	—	—	—	—	—	15.7	15.7
Dividends:							
Common stock ($0.78 per share)	—	—	—	—	(273.5)	—	(273.5)
Preferred stock ($28.88 per share)	—	—	—	—	(11.6)	—	(11.6)
Treasury stock acquired	—	—	(4.0)	—	—	—	(4.0)
Cumulative effect of change in accounting principle(1)	—	—	—	—	9.5	(9.5)	—
Stock issuances:							
Common stock - private placement	0.3	—	—	599.3	—	—	599.6
Preferred stock	—	880.0	—	—	—	—	880.0
Employee stock purchase plan	—	—	—	5.5	—	—	5.5
Long-term incentive plan	—	—	—	15.4	—	—	15.4
401(k) and profit sharing	—	—	—	21.8	—	—	21.8
ATM program	0.1	—	—	232.4	—	—	232.5
Balance as of December 31, 2018	**$ 3.8**	**$ 880.0**	**$ (99.9)**	**$ 6,403.5**	**$ (1,399.3)**	**$ (37.2)**	**$ 5,750.9**

(1)See Note 2, "Recent Accounting Pronouncements," for additional information.

NiSource Inc.
STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY

	Preferred	Common		
(in thousands)	Shares	Shares	Treasury	Outstanding
Balance as of January 1, 2016	**—**	**322,181**	**(3,071)**	**319,110**
Treasury stock acquired			(433)	(433)
Issued:				
Employee stock purchase plan	—	201	—	201
Long-term incentive plan	—	2,103	—	2,103
401(k) and profit sharing plan	—	1,793	—	1,793
Dividend reinvestment plan	—	386	—	386
Balance as of December 31, 2016	**—**	**326,664**	**(3,504)**	**323,160**
Treasury stock acquired			(293)	(293)
Issued:				
Employee stock purchase plan	—	207	—	207
Long-term incentive plan	—	351	—	351
401(k) and profit sharing plan	—	1,396	—	1,396
Dividend reinvestment plan	—	264	—	264
ATM Program	—	11,931	—	11,931
Balance as of December 31, 2017	**—**	**340,813**	**(3,797)**	**337,016**
Treasury stock acquired			(166)	(166)
Issued:				
Common stock - private placement(1)	—	24,964	—	24,964
Preferred stock(1)	420			
Employee stock purchase plan	—	223	—	223
Long-term incentive plan	—	561	—	561
401(k) and profit sharing plan	—	882	—	882
ATM program	—	8,883	—	8,883
Balance as of December 31, 2018	**420**	**376,326**	**(3,963)**	**372,363**

(1)See Note 12, "Equity," for additional information.

Accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

1. Nature of Operations and Summary of Significant Accounting Policies

A. Company Structure and Principles of Consolidation. We are an energy holding company incorporated in Delaware and headquartered in Merrillville, Indiana. Our subsidiaries are fully regulated natural gas and electric utility companies serving approximately 4.0 million customers in seven states. We generate substantially all of our operating income through these rate-regulated businesses. The consolidated financial statements include the accounts of us and our majority-owned subsidiaries after the elimination of all intercompany accounts and transactions.

B. Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

C. Cash, Cash Equivalents and Restricted Cash. We consider all highly liquid investments with original maturities of three months or less to be cash equivalents. We report amounts deposited in brokerage accounts for margin requirements as restricted cash. In addition, we have amounts deposited in trust to satisfy requirements for the provision of various property, liability, workers compensation, and long-term disability insurance, which is classified as restricted cash on the Consolidated Balance Sheets and disclosed with cash and cash equivalents on the Statements of Consolidated Cash Flows.

D. Accounts Receivable and Unbilled Revenue. Accounts receivable on the Consolidated Balance Sheets includes both billed and unbilled amounts. Unbilled amounts of accounts receivable relate to a portion of a customer's consumption of gas or electricity from the date of the last cycle billing date through the last day of the month (balance sheet date). Factors taken into consideration when estimating unbilled revenue include historical usage, customer rates and weather. Accounts receivable fluctuates from year to year depending in large part on weather impacts and price volatility. Our accounts receivable on the Consolidated Balance Sheets include unbilled revenue, less reserves, in the amounts of $324.2 million and $359.4 million as of December 31, 2018 and 2017, respectively. The reserve for uncollectible receivables is our best estimate of the amount of probable credit losses in the existing accounts receivable. We determined the reserve based on historical experience and in consideration of current market conditions. Account balances are charged against the allowance when it is anticipated the receivable will not be recovered. Refer to Note 3, "Revenue Recognition," for additional information on customer-related accounts receivable.

E. Investments in Debt Securities. Our investments in debt securities are carried at fair value and are designated as available-for-sale. These investments are included within "Other investments" on the Consolidated Balance Sheets. Unrealized gains and losses, net of deferred income taxes, are recorded to accumulated other comprehensive income or loss. These investments are monitored for other than temporary declines in market value. Realized gains and losses and permanent impairments are reflected in the Statements of Consolidated Income (Loss). No material impairment charges were recorded for the years ended December 31, 2018, 2017 or 2016. Refer to Note 16, "Fair Value," for additional information.

F. Basis of Accounting for Rate-Regulated Subsidiaries. Rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged and collected. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred on the Consolidated Balance Sheets and are later recognized in income as the related amounts are included in customer rates and recovered from or refunded to customers.

In the event that regulation significantly changes the opportunity for us to recover our costs in the future, all or a portion of our regulated operations may no longer meet the criteria for regulatory accounting. In such an event, a write-down of all or a portion of our existing regulatory assets and liabilities could result. If transition cost recovery was approved by the appropriate regulatory bodies that would meet the requirements under GAAP for continued accounting as regulatory assets and liabilities during such recovery period, the regulatory assets and liabilities would be reported at the recoverable amounts. If unable to continue to apply the provisions of regulatory accounting, we would be required to apply the provisions of ASC 980-20, *Discontinuation of Rate-Regulated Accounting*. In management's opinion, our regulated subsidiaries will be subject to regulatory accounting for the foreseeable future. Refer to Note 8, "Regulatory Matters," for additional information.

G. Plant and Other Property and Related Depreciation and Maintenance. Property, plant and equipment (principally utility plant) is stated at cost. The rate-regulated subsidiaries record depreciation using composite rates on a straight-line basis over the remaining service lives of the electric, gas and common properties as approved by the appropriate regulators.

Non-utility property is generally depreciated on a straight-line basis over the life of the associated asset. Refer to Note 5, "Property, Plant and Equipment," for additional information related to depreciation expense.

For rate-regulated companies, AFUDC is capitalized on all classes of property except organization costs, land, autos, office equipment, tools and other general property purchases. The allowance is applied to construction costs for that period of time between the date of the expenditure and the date on which such project is placed in service. Our pre-tax rate for AFUDC was 3.5% in 2018, 4.0% in 2017 and 4.5% in 2016.

Generally, our subsidiaries follow the practice of charging maintenance and repairs, including the cost of removal of minor items of property, to expense as incurred. When our subsidiaries retire regulated property, plant and equipment, original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation. However, when it becomes probable a regulated asset will be retired substantially in advance of its original expected useful life or is abandoned, the cost of the asset and the corresponding accumulated depreciation is recognized as a separate asset. If the asset is still in operation, the net amount is classified as "Other property, at cost, less accumulated depreciation" on the Consolidated Balance Sheets. If the asset is no longer operating, the net amount is classified in "Regulatory assets" on the Consolidated Balance Sheets. If we are able to recover a full return of and on investment, the carrying value of the asset is based on historical cost. If we are not able to recover a full return on investment, a loss on impairment is recognized to the extent the net book value of the asset exceeds the present value of future revenues discounted at the incremental borrowing rate.

When our subsidiaries sell entire regulated operating units, or retire or sell nonregulated properties, the original cost and accumulated depreciation and amortization balances are removed from "Property, Plant and Equipment" on the Consolidated Balance Sheets. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body. Refer to Note 5, "Property, Plant and Equipment," for further information.

External and internal costs associated with computer software developed for internal use are capitalized. Capitalization of such costs commences upon the completion of the preliminary stage of each project. Once the installed software is ready for its intended use, such capitalized costs are amortized on a straight-line basis generally over a period of five years, except for certain significant enterprise-wide technology investments which are amortized over a ten-year period.

External and internal up-front implementation costs associated with cloud computing arrangements that are service contracts are deferred on the Consolidated Balance Sheets. Once the installed software is ready for its intended use, such deferred costs are amortized on a straight-line basis to "Operation and maintenance," over the minimum term of the contract plus contractually-provided renewal periods that are reasonable expected to be exercised -- generally up to a maximum of five years.

H. Goodwill and Other Intangible Assets. Substantially all of our goodwill relates to the excess of cost over the fair value of the net assets acquired in the Columbia acquisition on November 1, 2000. We test our goodwill for impairment annually as of May 1, or more frequently if events and circumstances indicate that goodwill might be impaired. Fair value of our reporting units is determined using a combination of income and market approaches.

We have other intangible assets consisting primarily of franchise rights apart from goodwill that were identified as part of the purchase price allocations associated with the acquisition of Columbia of Massachusetts which is being amortized on a straight-line basis over forty years from the date of acquisition. See Note 6, "Goodwill and Other Intangible Assets," for additional information.

I. Accounts Receivable Transfer Program. Certain of our subsidiaries have agreements with third parties to transfer certain accounts receivable without recourse. These transfers of accounts receivable are accounted for as secured borrowings. The entire gross receivables balance remains on the December 31, 2018 and 2017 Consolidated Balance Sheets and short-term debt is recorded in the amount of proceeds received from the transferees involved in the transactions. Refer to Note 17, "Transfers of Financial Assets," for further information.

J. Gas Cost and Fuel Adjustment Clause. Our regulated subsidiaries defer most differences between gas and fuel purchase costs and the recovery of such costs in revenues, and adjust future billings for such deferrals on a basis consistent with applicable state-approved tariff provisions. These deferred balances are recorded as "Regulatory assets" or "Regulatory liabilities," as appropriate, on the Consolidated Balance Sheets. Refer to Note 8, "Regulatory Matters," for additional information.

K. Inventory. Both the LIFO inventory methodology and the weighted average cost methodology are used to value natural gas in storage, as approved by regulators for all of our regulated subsidiaries. Inventory valued using LIFO was $47.5 million and $45.5 million at December 31, 2018 and 2017, respectively. Based on the average cost of gas using the LIFO method, the estimated replacement cost of gas in storage was less than the stated LIFO cost by $12.2 million and $17.4 million at December 31, 2018 and 2017, respectively. Gas inventory valued using the weighted average cost methodology was $239.3 million at December 31, 2018 and $239.6 million at December 31, 2017.

Electric production fuel is valued using the weighted average cost inventory methodology, as approved by NIPSCO's regulator.

Materials and supplies are valued using the weighted average cost inventory methodology.

L. Accounting for Exchange and Balancing Arrangements of Natural Gas. Our Gas Distribution Operations segment enters into balancing and exchange arrangements of natural gas as part of its operations and off-system sales programs. We record a receivable or payable for any of our respective cumulative gas imbalances, as well as for any gas inventory borrowed or lent under a Gas Distribution Operations exchange agreement. Exchange gas is valued based on individual regulatory jurisdiction requirements (for example, historical spot rate, spot at the beginning of the month). These receivables and payables are recorded as “Exchange gas receivable” or “Exchange gas payable” on our Consolidated Balance Sheets, as appropriate.

M. Accounting for Risk Management Activities. We account for our derivatives and hedging activities in accordance with ASC 815. We recognize all derivatives as either assets or liabilities on the Consolidated Balance Sheets at fair value, unless such contracts are exempted as a normal purchase normal sale under the provisions of the standard. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation.

We have elected not to net fair value amounts for any of our derivative instruments or the fair value amounts recognized for the right to receive cash collateral or obligation to pay cash collateral arising from those derivative instruments recognized at fair value, which are executed with the same counterparty under a master netting arrangement. See Note 9, "Risk Management Activities," for additional information.

N. Income Taxes and Investment Tax Credits. We record income taxes to recognize full interperiod tax allocations. Under the asset and liability method, deferred income taxes are provided for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amount and the tax basis of existing assets and liabilities. Previously recorded investment tax credits of the regulated subsidiaries were deferred on the balance sheet and are being amortized to book income over the regulatory life of the related properties to conform to regulatory policy.

To the extent certain deferred income taxes of the regulated companies are recoverable or payable through future rates, regulatory assets and liabilities have been established. Regulatory assets for income taxes are primarily attributable to property-related tax timing differences for which deferred taxes had not been provided in the past, when regulators did not recognize such taxes as costs in the rate-making process. Regulatory liabilities for income taxes are primarily attributable to the regulated companies’ obligation to refund to ratepayers deferred income taxes provided at rates higher than the current Federal income tax rate. Such property-related amounts are credited to ratepayers using either the average rate assumption method or the reverse South Georgia method. Non property-related amounts are credited to ratepayers consistent with state utility commission direction.

Pursuant to the Internal Revenue Code and relevant state taxing authorities, we and our subsidiaries file consolidated income tax returns for federal and certain state jurisdictions. We and our subsidiaries are parties to an agreement (the “Intercompany Income Tax Allocation Agreement”) that provides for the allocation of consolidated tax liabilities. The Intercompany Income Tax Allocation Agreement generally provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax.

O. Environmental Expenditures. We accrue for costs associated with environmental remediation obligations when the incurrence of such costs is probable and the amounts can be reasonably estimated, regardless of when the expenditures are actually made. The undiscounted estimated future expenditures are based on currently enacted laws and regulations, existing technology and estimated site-specific costs where assumptions may be made about the nature and extent of site contamination, the extent of cleanup efforts, costs of alternative cleanup methods and other variables. The liability is adjusted as further information is discovered or circumstances change. The accruals for estimated environmental expenditures are recorded on the Consolidated Balance Sheets in “Legal and environmental” for short-term portions of these liabilities and “Other noncurrent liabilities” for the respective long-term portions of these liabilities. Rate-regulated subsidiaries applying regulatory accounting establish regulatory assets on the Consolidated Balance Sheets to the extent that future recovery of environmental remediation costs is probable through the regulatory process. Refer to Note 18, "Other Commitments and Contingencies," for further information.

P. Excise Taxes. We account for excise taxes that are customer liabilities by separately stating on our invoices the tax to our customers and recording amounts invoiced as liabilities payable to the applicable taxing jurisdiction. Such balances are presented within "Other accruals" on the Consolidated Balance Sheets. These types of taxes collected from customers, comprised largely of sales taxes, are presented on a net basis affecting neither revenues nor cost of sales. We account for excise taxes for which we are liable by recording a liability for the expected tax with a corresponding charge to “Other taxes” expense on the Statements of Consolidated Income (Loss).

Q. Accrued Insurance Liabilities. We accrue for insurance costs related to workers compensation, automobile, property, general and employment practices liabilities based on the most probable value of each claim. In general, claim values are determined by professional, licensed loss adjusters who consider the facts of the claim, anticipated indemnification and legal expenses, and respective state rules. Claims are reviewed by us at least quarterly and an adjustment is made to the accrual based on the most current information. Refer to Note 18-E "Other Matters" for further information on accrued insurance liabilities related to the Greater Lawrence Incident.

2. Recent Accounting Pronouncements

Recently Issued Accounting Pronouncements

We are currently evaluating the impact of certain ASUs on our Consolidated Financial Statements or Notes to Consolidated Financial Statements, which are described below:

Standard	Description	Effective Date	Effect on the financial statements or other significant matters
ASU 2018-14, *Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20): Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans*	The pronouncement modifies the disclosure requirements for defined benefit pension and other postretirement benefit plans. The guidance removes disclosures that are no longer considered cost beneficial, clarifies the specific requirements of disclosures and adds disclosure requirements identified as relevant. The modifications affect annual period disclosures and must be applied on a retrospective basis to all periods presented.	Annual periods ending after December 15, 2020. Early adoption is permitted.	We are currently evaluating the effects of this pronouncement on our Notes to Consolidated Financial Statements. We tentatively expect to adopt this ASU on its effective date.
ASU 2016-13, *Financial Instruments-Credit Losses (Topic 326)*	The pronouncement changes the impairment model for most financial assets, replacing the current "incurred loss" model. ASU 2016-13 will require the use of an "expected loss" model for instruments measured at amortized cost. It will also require entities to record allowances for available-for-sale debt securities rather than impair the carrying amount of the securities. Subsequent improvements to the estimated credit losses of available-for-sale securities will be recognized immediately in earnings instead of over time as they are under historic guidance.	Annual periods beginning after December 15, 2019, including interim periods therein. Early adoption is permitted for annual or interim periods beginning after December 15, 2018.	We maintain investments in U.S. Treasury, corporate and mortgage-backed debt securities, which are pledged as collateral for trust accounts related to our wholly-owned insurance company. These debt securities are classified as available for sale. We also have recorded balances for trade receivables that fall within the scope of the standard. We are currently evaluating the impact of adoption, if any, on our Consolidated Financial Statements and Notes to Consolidated Financial Statements.

Recently Adopted Accounting Pronouncements

<table>
<tr><th>Standard</th><th>Adoption</th></tr>
<tr><td>ASU 2018-15, Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract</td><td>In August 2018, the FASB issued this ASU, which amends current guidance to align the accounting for costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing costs associated with developing or obtaining internal-use software.

We elected to early adopt the ASU on a prospective basis, effective October 1, 2018. As a result of adopting this ASU, we will defer onto the Consolidated Balance Sheets up-front implementation costs of cloud computing arrangements if they would have been capitalized in a similar on-premise software solution.</td></tr>
<tr><td>ASU 2018-02, Income Statement—Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income</td><td>We adopted this ASU effective March 31, 2018. Upon adoption, $9.5 million of tax effects that were stranded in accumulated other comprehensive income (loss) as a result of the implementation of the TCJA were reclassified to retained deficit. This change is reflected on our Statements of Consolidated Stockholders' Equity.</td></tr>
<tr><td>ASU 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force)</td><td>We adopted this ASU effective January 1, 2018. The adoption of this standard did not have a material impact on our Consolidated Financial Statements or Notes to Consolidated Financial Statements.</td></tr>
<tr><td>ASU 2018-11, Leases (Topic 842): Targeted Improvements</td><td rowspan="3">We adopted the provisions of ASC 842 beginning on January 1, 2019, using the transition method provided in ASU 2018-11, which was applied to all existing leases at that date. As such, results for reporting periods beginning after January 1, 2019 will be presented under ASC 842, while prior period amounts will continue to be reported in accordance with ASC 840. To ease the process of implementing ASC 842, we elected a number of practical expedients, including the "practical expedient package" described in ASC 842-10-65-1 and the provisions of ASU 2018-01, which allows us to not evaluate existing land easements under ASC 842. We elected the short-term lease recognition exemption for all leases that qualify. As such, for those leases with terms less than 12 months, we will not recognize ROU assets or lease liabilities. Further, ASC 842 provides lessees the option of electing an accounting policy, by class of underlying asset, in which the lessee may choose not to separate nonlease components from lease components. We elected this practical expedient for our leases of fleet vehicles and railcars. We also elected to use a practical expedient that allows the use of hindsight in determining lease terms when evaluating leases that existed at the implementation date.

We are the lessee for substantially all of our current leasing activity. Upon adopting ASC 842 we began recognizing right-of-use assets and liabilities associated with operating leases (other than short term operating leases) on our Consolidated Balance Sheets resulting in an increase in assets and liabilities of approximately $60 million. The adoption of ASC 842 did not have a material impact to our results of operations or cash flows. We have implemented key system functionality and internal controls to facilitate the preparation of financial information upon adoption. Our SEC filings will include expanded disclosures to comply with the provisions of ASC 842 beginning with our quarterly report on Form 10-Q for the first quarter of 2019.</td></tr>
<tr><td>ASU 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842</td></tr>
<tr><td>ASU 2016-02, Leases (Topic 842)</td></tr>
</table>

Standard	Adoption
ASU 2016-12, *Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients*	See Note 3, "Revenue Recognition," for our discussion of the effects of implementing these standards.
ASU 2016-08, *Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations*	
ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*	

We also adopted ASU 2017-07, *Compensation - Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,* effective January 1, 2018. We continue to present the service cost component of net periodic benefit cost within "Operation and maintenance;" however, other components of the net periodic benefit cost (including regulatory deferrals and settlement charges) are now presented separately within "Other, net" on our Statements of Consolidated Income (Loss).

Changes in income statement presentation were implemented on a retrospective basis. The impact of this ASU on previously issued annual financial statements is summarized in the tables below:

Year Ended December 31, 2016 *(in millions)*	**As Previously Reported**	**Effect of Change**[1]	**As Adjusted**
Operation and maintenance	$ 1,453.7	$ (7.9)	$ 1,445.8
Total Operating Expenses	3,634.3	(7.9)	3,626.4
Operating Income	858.2	7.9	866.1
Other Income (Deductions)			
Other, net	1.5	(7.9)	(6.4)
Total Other Deductions	$ (348.0)	$ (7.9)	$ (355.9)

[1] The effect of this change is attributable to our business segments: Gas Distribution Operations, Electric Operations, and Corporate and Other in the amounts of $4.3 million, $(9.8) million, and $(2.4) million, respectively.

Year Ended December 31, 2017 *(in millions)*	**As Previously Reported**	**Effect of Change**[1]	**As Adjusted**
Operation and maintenance	$ 1,612.3	$ (10.6)	$ 1,601.7
Total Operating Expenses	3,964.0	(10.6)	3,953.4
Operating Income	910.6	10.6	921.2
Other Income (Deductions)			
Other, net	(2.8)	(10.6)	(13.4)
Total Other Deductions	$ (467.5)	$ (10.6)	$ (478.1)

[1] The effect of this change is attributable to our business segments: Gas Distribution Operations, Electric Operations, and Corporate and Other in the amounts of $(4.4) million, $(2.6) million, and $(3.6) million, respectively.

3. Revenue Recognition

ASC 606 Adoption. In 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (ASC 606). ASU 2014-09 outlines a single, comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance. The core principle of the new standard is that an entity should recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (ASC 606): Principal versus Agent Considerations, and ASU 2016-12, Revenue from Contracts with Customers (ASC 606): Narrow-Scope Improvements and Practical Expedients. We adopted the provisions of ASC 606 beginning on January 1, 2018 using a modified retrospective method, which was applied to all contracts. No material adjustments were made to January 1, 2018 opening balances as a result of the adoption. As required under the modified retrospective method of adoption, results for reporting periods beginning after January 1, 2018 are presented under ASC 606, while prior period amounts are not adjusted and continue to be reported in accordance with ASC 605.

The table below provides results for the year ended December 31, 2018 as if it had been prepared under historic accounting guidance. We included operating revenue information for the years ended December 31, 2017 and 2016 for comparability.

Year Ended December 31, *(in millions)*	2018	2017	2016
Operating Revenues			
Gas Distribution	**$ 2,348.4**	$ 2,063.2	$ 1,850.9
Gas Transportation	**1,055.2**	1,021.5	964.6
Electric	**1,707.4**	1,785.5	1,660.8
Other	**3.5**	4.4	16.2
Total Operating Revenues	**$ 5,114.5**	$ 4,874.6	$ 4,492.5

Beginning in 2018 with the adoption of ASC 606, the Statements of Consolidated Income (Loss) disaggregates "Customer revenues" (i.e. ASC 606 Revenues) from "Other revenues," both of which are discussed in more detail below.

Customer Revenues. Substantially all of our revenues are tariff-based, which we have concluded is within the scope of ASC 606. Under ASC 606, the recipients of our utility service meet the definition of a customer, while the operating company tariffs represent an agreement that meets the definition of a contract. ASC 606 defines a contract as an agreement between two or more parties, in this case us and the customer, which creates enforceable rights and obligations. In order to be considered a contract, we have determined that it is probable that substantially all of the consideration to which we are entitled from customers will be collected upon satisfaction of performance obligations. We maintain common utility credit risk mitigation practices, including requiring deposits and actively pursuing collection of past due amounts. In addition, our regulated operations utilize certain regulatory mechanisms that facilitate recovery of bad debt costs within tariff-based rates, which provides further evidence of collectibility.

Customers in certain of our jurisdictions participate in programs that allow for a fixed payment each month regardless of usage. Payments received that exceed the value of gas or electricity actually delivered are recorded as a liability and presented in "Customer Deposits and Credits." Amounts in this account are reduced and revenue is recorded when customer usage begins to exceed payments received.

We have identified our performance obligations created under tariff-based sales as 1) the commodity (natural gas or electricity, which includes generation and capacity) and 2) delivery. These commodities are sold and / or delivered to and generally consumed by customers simultaneously, leading to satisfaction of our performance obligations over time as gas or electricity is delivered to customers. Due to the at-will nature of utility customers, performance obligations are limited to the services requested and received to date. Once complete, we generally maintain no additional performance obligations.

Transaction prices for each performance obligation are generally prescribed by each operating company's respective tariff. Rates include provisions to adjust billings for fluctuations in fuel and purchased power costs and cost of natural gas. Revenues are adjusted for differences between actual costs subject to reconciliation and the amounts billed in current rates. Under or over recovered revenues related to these cost recovery mechanisms are included in regulatory assets or liabilities on the Consolidated Balance Sheets and are recovered from or returned to customers through adjustments to tariff rates. As we provide and deliver service to customers, revenue is recognized based on the transaction price allocated to each performance obligation. In general, revenue recognized from tariff-based sales is equivalent to the value of natural gas or electricity supplied and billed each period, in addition to an estimate for deliveries completed during the period but not yet billed to the customer.

In addition to tariff-based sales, our Gas Distribution Operations segment enters into balancing and exchange arrangements of natural gas as part of our operations and off-system sales programs. We have concluded that these sales are within the scope of ASC 606. Performance obligations for these types of sales include transportation and storage of natural gas and can be satisfied at a point in time or over a period of time, depending on the specific transaction. For those transactions that span a period of time, we record a receivable or payable for any cumulative gas imbalances, as well as for any gas inventory borrowed or lent under a Gas Distributions Operations exchange agreement.

Revenue Disaggregation and Reconciliation. We disaggregate revenue from contracts with customers based upon reportable segment as well as by customer class. As our revenues are primarily earned over a period of time, and we do not earn a material amount of revenues at a point in time, revenues are not disaggregated as such below. The Gas Distribution Operations segment provides natural gas service and transportation for residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, Maryland, Indiana and Massachusetts. The Electric Operations segment provides electric service in 20 counties in the northern part of Indiana.

The table below reconciles revenue disaggregation by customer class to segment revenue as well as to revenues reflected on the Statements of Consolidated Income (Loss):

Year Ended December 31, 2018 *(in millions)*	Gas Distribution Operations	Electric Operations	Corporate and Other	Total
Customer Revenues(1)				
Residential	$ 2,250.0	$ 494.7	$ —	$ 2,744.7
Commercial	751.9	492.7	—	1,244.6
Industrial	228.0	613.6	—	841.6
Off-system	92.4	—	—	92.4
Miscellaneous	49.7	17.4	0.7	67.8
Total Customer Revenues	$ 3,372.0	$ 1,618.4	$ 0.7	$ 4,991.1
Other Revenues	34.4	89.0	—	123.4
Total Operating Revenues	$ 3,406.4	$ 1,707.4	$ 0.7	$ 5,114.5

(1) Customer revenue amounts exclude intersegment revenues. See Note 22, "Segments of Business," for discussion of intersegment revenues.

Customer Accounts Receivable. Accounts receivable on our Consolidated Balance Sheets includes both billed and unbilled amounts, as well as certain amounts that are not related to customer revenues. Unbilled amounts of accounts receivable relate to a portion of a customer's consumption of gas or electricity from the date of the last cycle billing through the last day of the month (balance sheet date). Factors taken into consideration when estimating unbilled revenue include historical usage, customer rates and weather. The opening and closing balances of customer receivables for the years ended December 31, 2018 and 2017 are presented in the table below. We had no significant contract assets or liabilities during the period. Additionally, we have not incurred any significant costs to obtain or fulfill contracts.

(in millions)	Customer Accounts Receivable, Billed (less reserve)(1)	Customer Accounts Receivable, Unbilled (less reserve)(2)
Balance as of December 31, 2017	$ 477.0	$ 378.6
Balance as of December 31, 2018	540.5	349.1
Increase (Decrease)	$ 63.5	$ (29.5)

(1) Customer billed receivables increased over the period due to November 2018 being colder than November 2017, leading to more gas usage included in December bills.
(2) Customer unbilled receivables decreased over the period due December 2018 being warmer than December 2017, leading to less estimated gas usage.

Utility revenues are billed to customers monthly on a cycle basis. We generally expect that substantially all customer accounts receivable will be collected within the month following customer billing, as this revenue consists primarily of monthly, tariff-based billings for service and usage.

Other Revenues. As permitted by accounting principles generally accepted in the United States, regulated utilities have the ability to earn certain types of revenue that are outside the scope of ASC 606. These revenues primarily represent revenue earned under alternative revenue programs. Alternative revenue programs represent regulator-approved programs that allow for the adjustment of billings and revenue for certain broad, external factors, or for additional billings if the entity achieves certain objectives, such as a specified reduction of costs. We maintain a variety of these programs, including demand side management initiatives that recover costs associated with the implementation of energy efficiency programs, as well as normalization programs that adjust revenues for the effects of weather or other external factors. Additionally, we maintain certain programs with future test periods that operate similarly to FERC formula rate programs and allow for recovery of costs incurred to replace aging infrastructure. When the criteria to recognize Alternative Revenue have been met, we establish a regulatory asset and present revenue from alternative revenue programs on the Statements of Consolidated Income (Loss) as “Other revenues.” When amounts previously recognized under Alternative Revenue accounting guidance are billed, we reduce the regulatory asset and record a customer account receivable.

4. Earnings Per Share

Basic EPS is computed by dividing net income attributable to common shareholders by the weighted-average number of shares of common stock outstanding for the period. The weighted-average shares outstanding for diluted EPS includes the incremental effects of the various long-term incentive compensation plans when the impact of such plans would be dilutive. The calculation of diluted earnings per share excludes the impact of forward agreements (see Note 12, "Equity"), which had an anti-dilutive effect for the periods outstanding. The computation of diluted average common shares for the year ended December 31, 2018 is not presented as we are presenting a net loss on the Statements of Consolidated Income (Loss) for the period, and any incremental shares would have an anti-dilutive impact on EPS. The computation of diluted average common shares is as follows:

Year Ended December 31, *(in thousands)*	2017	2016
Denominator		
Basic average common shares outstanding	329,388	321,805
Dilutive potential common shares:		
Shares contingently issuable under employee stock plans	547	165
Shares restricted under stock plans	821	1,554
Diluted Average Common Shares	330,756	323,524

5. Property, Plant and Equipment

Our property, plant and equipment on the Consolidated Balance Sheets are classified as follows:

At December 31, *(in millions)*		**2018**		2017
Property, Plant and Equipment				
Gas Distribution Utility[1]	**$**	**13,776.0**	$	12,531.0
Electric Utility[1]		**8,374.2**		7,403.8
Corporate		**155.8**		141.3
Construction Work in Process		**474.8**		950.5
Non-Utility and Other[2]		**38.7**		623.3
Total Property, Plant and Equipment	**$**	**22,819.5**	$	21,649.9
Accumulated Depreciation and Amortization				
Gas Distribution Utility[1]	**$**	**(3,373.8)**	$	(3,227.8)
Electric Utility[1]		**(3,809.5)**		(3,673.2)
Corporate		**(74.6)**		(52.6)
Non-Utility and Other[2]		**(19.1)**		(336.8)
Total Accumulated Depreciation and Amortization	**$**	**(7,277.0)**	$	(7,290.4)
Net Property, Plant and Equipment	**$**	**15,542.5**	$	14,359.5

[1]NIPSCO's common utility plant and associated accumulated depreciation and amortization are allocated between Gas Distribution Utility and Electric Utility Property, Plant and Equipment.
[2]Non-Utility and Other as of December 31, 2017 includes net book value of $247.8 million related to Bailly Generating Station (Units 7 and 8) which was reclassified from Electric Utility in the fourth quarter of 2016. In May 2018, Units 7 and 8 were retired from service and the remaining balance was reclassified to "Regulatory assets (noncurrent)" on the Consolidated Balance Sheets. See Note 18-E, "Other Matters," and Note 8, "Regulatory Matters," for additional information.

The weighted average depreciation provisions for utility plant, as a percentage of the original cost, for the periods ended December 31, 2018, 2017 and 2016 were as follows:

	2018	2017	2016
Electric Operations[1]	**2.9%**	3.4%	3.3%
Gas Distribution Operations	**2.2%**	2.1%	2.1%

[1]Lower depreciation rate in 2018 due to reduced EERM-related depreciation expense and higher depreciable base from transmission assets being placed into service in 2018.

We recognized depreciation expense of $503.4 million, $501.5 million and $475.1 million for the years ended 2018, 2017 and 2016, respectively.

Amortization of Software Costs. We amortized $54.1 million in 2018, $44.0 million in 2017 and $41.4 million in 2016 related to software costs. Our unamortized software balance was $159.5 million and $189.0 million at December 31, 2018 and 2017, respectively.

6. Goodwill and Other Intangible Assets

Goodwill. Substantially all of our goodwill relates to the excess of cost over the fair value of the net assets acquired in the Columbia acquisition on November 1, 2000. The following presents our goodwill balance allocated by segment as of December 31, 2018:

(in millions)		Gas Distribution Operations		Electric Operations		Corporate and Other		**Total**
Goodwill	$	1,690.7	$	—	$	—	**$**	**1,690.7**

We applied the qualitative "step 0" analysis to our reporting units for the annual impairment test performed as of May 1, 2018. For this test, we assessed various assumptions, events and circumstances that would have affected the estimated fair value of the reporting units as compared to their base line May 1, 2016 "step 1" fair value measurement. The results of this assessment indicated that it was not more likely than not that our reporting unit fair values were less than the reporting unit carrying values, accordingly, no "step 1" analysis was required.

In the third quarter of 2018, we determined the Greater Lawrence Incident (see Note 18, "Other Commitments and Contingencies") represented a triggering event that required an impairment analysis of goodwill. This incident specifically impacts our Columbia of Massachusetts reporting unit in which the associated goodwill totaled $204.8 million immediately prior to the incident. We performed a quantitative impairment analysis as of September 30, 2018 and determined that the fair value of the Columbia of Massachusetts reporting unit continues to exceed its carrying value. Therefore, no goodwill impairment charges were recorded in the third quarter of 2018. This interim analysis was performed using then-current cash flow projections reflecting the estimated ongoing impacts of the Greater Lawrence Incident on Columbia of Massachusetts' operations. We also updated other significant inputs to the fair value calculation (e.g. discount rate, market multiples) to reflect then-current market conditions and increased risk and uncertainty resulting from the incident. No additional facts came to light since the third quarter impairment analysis was completed that would indicate it was more likely than not that the fair value of the Columbia of Massachusetts reporting unit would have decreased below its carrying value; therefore no goodwill impairment charges were recorded in the fourth quarter of 2018. We will continue to monitor the impacts of the incident for events that could trigger a new impairment analysis including, but not limited to, unfavorable regulatory outcomes and NTSB investigation results.

Intangible Assets. Our intangible assets, apart from goodwill, consist of franchise rights. Franchise rights were identified as part of the purchase price allocations associated with the acquisition in February 1999 of Columbia of Massachusetts. These amounts were $220.7 million and $231.7 million, net of accumulated amortization of $221.5 million and $210.5 million, at December 31, 2018 and 2017, respectively, and are being amortized on a straight-line basis over forty years from the date of acquisition through 2039. NiSource recorded amortization expense of $11.0 million in 2018, 2017, and 2016 related to its franchise right intangible asset.

7. Asset Retirement Obligations

We have recognized asset retirement obligations associated with various legal obligations including costs to remove and dispose of certain construction materials located within many of our facilities, certain costs to retire pipeline, removal costs for certain underground storage tanks, removal of certain pipelines known to contain PCB contamination, closure costs for certain sites including ash ponds, solid waste management units and a landfill, as well as some other nominal asset retirement obligations. We also have a significant obligation associated with the decommissioning of our two hydro facilities located in Indiana. These hydro facilities have an indeterminate life, and as such, no asset retirement obligation has been recorded.

Changes in our liability for asset retirement obligations for the years 2018 and 2017 are presented in the table below:

(in millions)		**2018**			2017	
Beginning Balance	**$**	**268.7**		$	262.6	
Accretion recorded as a regulatory asset/liability		**11.1**			10.3	
Additions		**63.3**	(1)		2.4	
Settlements		**(5.9)**			(15.6)	
Change in estimated cash flows		**14.8**	(1)		9.0	(2)
Ending Balance	**$**	**352.0**		$	268.7	

(1)In 2018, $59.8 million of additions and $17.7 million of the change in estimated cash flows are attributed to costs associated with refining the CCR compliance plan. See Note 18-D, "Environmental Matters," for additional information on CCRs.
(2)The change in estimated cash flows for 2017 is primarily attributed to changes in estimated costs and settlement timing for electric generating stations and the changes in estimated costs for retirement of gas mains.

Certain non-legal costs of removal that have been, and continue to be, included in depreciation rates and collected in the customer rates of the rate-regulated subsidiaries are classified as "Regulatory liabilities" on the Consolidated Balance Sheets.

8. Regulatory Matters

Regulatory Assets and Liabilities

We follow the accounting and reporting requirements of ASC Topic 980, which provides that regulated entities account for and report assets and liabilities consistent with the economic effect of regulatory rate-making procedures if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged and collected from customers. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income or expense are deferred on the balance sheet and are recognized in the income statement as the related amounts are included in customer rates and recovered from or refunded to customers.

Regulatory assets were comprised of the following items:

At December 31, *(in millions)*		**2018**		2017
Regulatory Assets				
Unrecognized pension and other postretirement benefit costs (see Note 11)	**$**	**798.3**	$	733.5
Deferred pension and other postretirement benefit costs (see Note 11)		**74.1**		70.7
Environmental costs (see Note 18-D)		**61.5**		63.4
Regulatory effects of accounting for income taxes (see Note 1-N and Note 10)		**233.1**		238.8
Under-recovered gas and fuel costs (see Note 1-K)		**34.7**		25.5
Depreciation		**209.6**		181.0
Post-in-service carrying charges		**206.6**		173.3
Safety activity costs		**91.7**		66.5
DSM programs		**45.5**		40.0
Bailly Generating Station		**244.3**		—
Other		**238.1**		208.5
Total Regulatory Assets	**$**	**2,237.5**	$	1,801.2

Regulatory liabilities were comprised of the following items:

At December 31, *(in millions)*		**2018**		2017
Regulatory Liabilities				
Over-recovered gas and fuel costs (see Note 1-K)	**$**	**32.0**	$	27.6
Cost of removal (see Note 7)		**1,076.0**		1,096.8
Regulatory effects of accounting for income taxes (see Note 1-O and Note 10)		**1,428.3**		1,563.4
Deferred pension and other postretirement benefit costs (see Note 11)		**62.7**		59.0
Other		**61.0**		48.8
Total Regulatory Liabilities	**$**	**2,660.0**	$	2,795.6

Regulatory assets, including under-recovered gas and fuel cost, of approximately $1,552.6 million as of December 31, 2018 are not earning a return on investment. These costs are recovered over a remaining life of up to 41 years. Regulatory assets of approximately $1,917.1 million include expenses that are recovered as components of the cost of service and are covered by regulatory orders. Regulatory assets of approximately $320.4 million at December 31, 2018, require specific rate action.

Assets:

Unrecognized pension and other postretirement benefit costs. In 2007, we adopted certain updates of ASC 715 which required, among other things, the recognition in other comprehensive income or loss of the actuarial gains or losses and the prior service costs or credits that arise during the period but that are not immediately recognized as components of net periodic benefit costs. Certain subsidiaries defer these gains or losses as a regulatory asset in accordance with regulatory orders or as a result of regulatory precedent, to be recovered through base rates.

Deferred pension and other postretirement benefit costs. Primarily relates to the difference between postretirement expense recorded by certain subsidiaries due to regulatory orders and the postretirement expense recorded in accordance with GAAP. These costs are expected to be collected through future base rates, revenue riders or tracking mechanisms.

Environmental costs. Includes certain recoverable costs of investigating, testing, remediating and other costs related to gas plant sites, disposal sites or other sites onto which material may have migrated. Certain of our companies defer the costs as a regulatory asset in accordance with regulatory orders, to be recovered in future base rates, billing riders or tracking mechanisms.

Regulatory effects of accounting for income taxes. Represents the deferral and under collection of deferred taxes in the rate making process. In prior years, we have lowered customer rates in certain jurisdictions for the benefits of accelerated tax deductions. Amounts are expensed for financial reporting purposes as we recover deferred taxes in the rate making process.

Under-recovered gas and fuel costs. Represents the difference between the costs of gas and fuel and the recovery of such costs in revenue and is used to adjust future billings for such deferrals on a basis consistent with applicable state-approved tariff provisions. Recovery of these costs is achieved through tracking mechanisms.

Depreciation. Represents differences between depreciation expense incurred on a GAAP basis and that prescribed through regulatory order. Significant components of this balance include:

- **Columbia of Ohio depreciation rates**. Prior to 2005, the PUCO-approved depreciation rates for rate-making had been lower than those which would have been utilized if Columbia of Ohio were not subject to regulation resulting in the creation of a regulatory asset. In 2005, the PUCO authorized Columbia of Ohio to revise its depreciation accrual rates for the period beginning January 1, 2005. The revised depreciation rates are now higher than those which would have been utilized if Columbia of Ohio were not subject to regulation allowing for amortization of the previously created regulatory asset. The amount of depreciation that would have been recorded from 2005 through 2018 had Columbia of Ohio not been subject to rate regulation is a cumulative $806.8 million, $92.2 million less than that reflected in rates. The resulting regulatory asset balance was $39.5 million and $49.3 million as of December 31, 2018 and 2017, respectively.

- **Columbia of Ohio IRP and CEP.** Columbia of Ohio also has PUCO approval to defer depreciation and debt-based post-in-service carrying charges (see "*Post-in-service carrying charges"* below) associated with its IRP and CEP. As of December 31, 2018, depreciation of $29.1 million and $76.0 million was deferred for the respective programs. Depreciation deferral balances for the respective programs as of December 31, 2017 were $26.5 million and $49.8 million. Recovery of the IRP depreciation is approved annually through the IRP rider. The equivalent of annual depreciation expense, based on the average life of the related assets, is included in the calculation of the IRP rider approved by the PUCO and billed to customers. Deferred depreciation expense is recognized as the IRP rider is billed to customers. The recovery mechanism for depreciation associated with the CEP is discussed in "Additional Regulatory Matters," below.

- **NIPSCO ECRM.** NIPSCO obtained approval from the IURC to recover certain environmental related costs including operation and maintenance and depreciation expense once the environmental facilities become operational. The ECRM deferred charges represent expenses that will be recovered from customers through an annual ECRM Cost Tracker (ECT) which authorizes the collection of deferred balances over a six month period. Recovery of these costs will continue until such assets are included in rate base through an electric base rate case. Depreciation of $14.4 million and $13.9 million was deferred to a regulatory asset as of December 31, 2018 and 2017, respectively.

- **NIPSCO TDSIC.** NIPSCO obtained approval from the IURC to recover costs for certain system modernization projects outside of a base rate proceeding. Eighty percent of the related costs, including depreciation, property taxes, and debt and equity based carrying charges (see *"Post-in-service carrying charges"* below) are recovered through a semi-annual recovery mechanism. Recovery of these costs will continue through the TDSIC tracker until such assets are included in rate base through a gas or electric base rate case, respectively. The remaining twenty percent of the costs are deferred until the next base rate case. As of December 31, 2018 and 2017, depreciation of $16.5 million and $10.3 million, respectively, was deferred as a regulatory asset.

Post-in-service carrying charges. Represents deferred debt-based carrying charges incurred on certain assets placed into service but not yet included in customer rates. This balance includes:

- **Columbia of Ohio IRP and CEP.** See description of IRP and CEP programs above under the heading "*Depreciation*." As of December 31, 2018 and 2017, Columbia of Ohio had deferred PISCC of $197.1 million and $164.6 million, respectively.

- **NIPSCO TDSIC.** See description of TDSIC program above under the heading "*Depreciation*." Deferral of equity-based carrying charges for the TDSIC program is allowed; however, such amounts are not reflected in regulatory asset balances for financial reporting as equity-based returns do not meet the definition of incurred costs under ASC 980. As of December 31, 2018 and 2017, NIPSCO had deferred PISCC of $9.5 million and $8.7 million, respectively.

Safety activity costs. Represents the difference between costs incurred in eligible safety programs in excess of those being recovered in rates. The eligible cost deferrals represent necessary business expenses incurred in compliance with PHMSA regulations and are targeted to enhance the safety of the pipeline systems. Certain subsidiaries defer the excess costs as a regulatory asset in accordance with regulatory orders and recovery of these costs will be address in future base rate proceedings.

DSM programs. Represents costs associated with Gas Distribution Operations and Electric Operations segments' energy efficiency and conservation programs. Costs are recovered through tracking mechanisms.

Bailly Generating Station. Represents the net book value of Units 7 and 8 of Bailly Generating Station that was retired during 2018. These amounts are currently being amortized at a rate consistent with their inclusion in customer rates.

Liabilities:

Over-recovered gas and fuel costs. Represents the difference between the cost of gas and fuel and the recovery of such costs in revenues, and is the basis to adjust future billings for such refunds on a basis consistent with applicable state-approved tariff provisions. Refunding of these revenues is achieved through tracking mechanisms.

Cost of removal. Represents anticipated costs of removal that have been, and continue to be, included in depreciation rates and collected in customer rates of the rate-regulated subsidiaries for future costs to be incurred.

Regulatory effects of accounting for income taxes. Represents amounts owed to customers for deferred taxes collected at a higher rate than the current statutory rates and liabilities associated with accelerated tax deductions owed to customers that are established during the rate making process. Balance includes excess deferred taxes recorded upon implementation of the TCJA in December 2017, net of amounts amortized during 2018.

Deferred pension and other postretirement benefit costs. Primarily represents cash contributions in excess of postretirement benefit expense that is deferred as a regulatory liability by certain subsidiaries in accordance with regulatory orders.

Cost Recovery and Trackers

Comparability of our line item operating results is impacted by regulatory trackers that allow for the recovery in rates of certain costs such as those described below. Increases in the expenses that are the subject of trackers generally result in a corresponding increase in operating revenues and therefore have essentially no impact on total operating income results.

Certain costs of our operating companies are significant, recurring in nature and generally outside the control of the operating companies. Some states allow the recovery of such costs through cost tracking mechanisms. Such tracking mechanisms allow for abbreviated regulatory proceedings in order for the operating companies to implement charges and recover appropriate costs. Tracking mechanisms allow for more timely recovery of such costs as compared with more traditional cost recovery mechanisms. Examples of such mechanisms include GCR adjustment mechanisms, tax riders, bad debt recovery mechanisms, electric energy efficiency programs, MISO non-fuel costs and revenues, resource capacity charges, federally mandated costs and environmental-related costs.

A portion of the Gas Distribution revenue is related to the recovery of gas costs, the review and recovery of which occurs through standard regulatory proceedings. All states in our operating area require periodic review of actual gas procurement activity to determine prudence and to permit the recovery of prudently incurred costs related to the supply of gas for customers. Our distribution companies have historically been found prudent in the procurement of gas supplies to serve customers.

A portion of the Electric Operations revenue is related to the recovery of fuel costs to generate power and the fuel costs related to purchased power. These costs are recovered through a FAC, a quarterly regulatory proceeding in Indiana.

Infrastructure Replacement and Federally-Mandated Compliance Programs

Certain of our operating companies have completed rate proceedings involving infrastructure replacement or enhancement or are embarking upon regulatory initiatives to replace significant portions of their operating systems that are nearing the end of their useful lives. Each operating company's approach to cost recovery may be unique, given the different laws, regulations and precedent that exist in each jurisdiction.

Columbia of Ohio, IRP - On December 3, 2008, the PUCO issued an order which established Columbia of Ohio’s IRP. Pursuant to that order, the IRP provides for recovery of costs resulting from: (1) the maintenance, repair and replacement of customer-owned service lines that have been determined by Columbia of Ohio to present an existing or probable hazard to persons and property; (2) Columbia of Ohio’s replacement of cast iron, wrought iron, unprotected coated steel and bare steel pipe and associated company and customer-owned metallic service lines; (3) the replacement of customer-owned natural gas risers identified by the PUCO as prone to failure; and (4) the installation of AMR devices on all residential and commercial meters served by Columbia of Ohio. Recoverable costs include a return on investment, depreciation and property taxes, offset by specified cost savings. Columbia of Ohio’s five-year IRP plan renewal was last approved on January 31, 2018 for the years 2018-2022.

NIPSCO Gas and Electric, TDSIC - On April 30, 2013, the Indiana Governor signed Senate Enrolled Act 560, known as the TDSIC statute, into law. Among other provisions, the TDSIC statute provides for cost recovery outside of a base rate proceeding for new or replacement electric and gas transmission, distribution, and storage projects that a public utility undertakes for the purposes of safety, reliability, system modernization or economic development. Provisions of the TDSIC statute require that, among other things, requests for recovery include a seven-year plan of eligible investments. Once the plan is approved by the IURC, eighty percent of eligible costs can be recovered using a periodic rate adjustment mechanism, known as the TDSIC mechanism. Recoverable costs include a return on the investment, including AFUDC, PISCC, operation and maintenance expenses, depreciation and property taxes. The remaining twenty percent of recoverable costs are deferred for future recovery in NIPSCO's next general rate case. The semi-annual rate adjustment mechanism is capped at an annual increase of two percent of total retail revenues.

NIPSCO Electric, ECRM - NIPSCO has approval from the IURC to recover certain environmental related costs through an ECT (environmental cost tracker). Under the ECT, NIPSCO is permitted to recover (1) AFUDC and a return on the capital investment expended by NIPSCO to implement environmental compliance plan projects and (2) related operation and maintenance and depreciation expenses once the environmental facilities become operational.

NIPSCO Gas and Electric, FMCA - The FMCA statute provides for cost recovery outside of a base rate proceeding for projected federally mandated costs. Once the plan is approved by the IURC, eighty percent of eligible costs can be recovered using a periodic rate adjustment mechanism, known as the FMCA mechanism. Recoverable costs include a return on the investment, including AFUDC, PISCC, mandated operation and maintenance expenses, depreciation and property taxes. The remaining twenty percent of recoverable costs are deferred for future recovery in NIPSCO's next general rate case. Actual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent shall require specific justification by NIPSCO and specific approval by the IURC before being authorized in the next general rate case.

Columbia of Massachusetts, GSEP - On July 7, 2014, the Governor of Massachusetts signed into law Chapter 149 of the Acts of 2014, an Act Relative to Natural Gas Leaks (“the Act”). The Act authorizes natural gas distribution companies to file a GSEP for capital investments made on or after January 1, 2015, that are not included in the Company’s current rate base as determined in the most recent base rate case, with the Massachusetts DPU to (1) address the replacement or improvement of existing aging natural gas pipeline infrastructure to improve public safety or infrastructure reliability, and (2) reduce the lost and unaccounted for natural gas through a reduction in natural gas system leaks. In addition, the Act provides that the Massachusetts DPU may, after review of the plan, allow the proposed estimated costs of the plan into rates as of May 1 of the subsequent year. Recoverable costs include a return on investment, depreciation and property taxes, offset by identified operations and maintenance cost savings. Rates are subject to a capped annual revenue increase of one and a half percent of total annual delivery and cost of gas revenues from sales and transportation, including imputed gas revenues for transportation, for the calendar year preceding the projected GSEP calendar year being filed. At the end of each 12-month period, in May of the subsequent year, Columbia of Massachusetts must file a reconciliation of the amount collected and actual costs. Any over-collection or under-collection balance is passed back to, or recovered from, customers over a 12-month period beginning in November. Once new base rates are established under a base rate proceeding, the GSEP factor is re-set to remove the capital investment and associated revenue reflected in the base rates.

Columbia of Pennsylvania, DSIC - On February 14, 2012, the Governor of Pennsylvania signed into law Act 11 of 2012, which provided a DSIC mechanism for certain utilities to recover costs related to repair, replacement or improvement of eligible distribution property that has not previously been reflected in rates or rate base. Through a DSIC, a utility may recover the fixed costs of eligible infrastructure incurred during the three months ended one month prior to the effective date of the charge, thereby reducing the historical regulatory lag associated with cost recovery through the traditional rate-making process. On March 14, 2013, the Pennsylvania PUC approved Columbia of Pennsylvania’s petition to implement a DSIC as of April 1, 2013. Accordingly, Columbia of Pennsylvania is authorized to recover the cost of eligible plant associated with repair, replacement or improvement that was not previously reflected in rate base and has been placed in service during the applicable three-month period. After the initial charge is established, the DSIC is updated quarterly to recover the cost of further plant additions and cannot exceed five percent of distribution revenues. Recoverable costs include a return on investment, exclusive of accumulated deferred income taxes from the calculation of rate base, and depreciation. Once new base rates are established under a base rate proceeding, the DSIC is set to zero. Additionally, the DSIC rate is also reset to zero if, in any quarter, the data reflected in the Columbia of Pennsylvania's most recent quarterly financial earnings report show that the utility will earn an overall rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the DSIC mechanism. A utility is exempt from filing a quarterly financial earnings report when a base rate proceeding is pending before the Pennsylvania PUC.

Columbia of Virginia, SAVE - On March 11, 2010, the Virginia Governor signed legislation into law that allows natural gas utilities to implement programs to replace qualifying infrastructure on an expedited basis and provides for timely cost recovery. Known as the SAVE Act, the law allows natural gas utilities to file programs with the VSCC providing a timeline and estimated costs for replacing eligible infrastructure. Eligible infrastructure replacement projects are those that (1) enhance safety or reliability by reducing system integrity risks associated with customer outages, corrosion, equipment failures, material failures, or natural forces; (2) do not increase revenues by directly connecting the infrastructure replacement to new customers; (3) reduce or have the potential to reduce greenhouse gas emissions; (4) are not included in the natural gas utility's rate base in its most recent rate case; and (5) are commenced on or after January 1, 2010. The SAVE Act provides for recovery of costs associated with the eligible infrastructure through a rate rider. Recoverable costs include a return on investment, depreciation and property taxes. Columbia of Virginia's current five year SAVE plan was approved by the VSCC in 2016 and amended in 2017 for the years 2016 through 2020.

Columbia of Kentucky, AMRP - On October 26, 2009, the Kentucky PSC approved a mechanism for recovering the costs of Columbia of Kentucky's AMRP not previously reflected in rate base through an annual fixed monthly rate rider filed in October. In its 2013 rate case, Columbia of Kentucky was allowed to base the AMRP rider on the expected annual cost of service. Recoverable costs include a return on investment, depreciation and property taxes, offset by specific cost savings. At the end of each 12-month period, Columbia of Kentucky must file a reconciliation of the amount collected and actual costs. Any over-collection or under-collection balance is passed back to, or recovered from, customers through the surcharge over a 12-month period beginning in June of the subsequent year. Once new base rates are established under a base rate proceeding, the AMRP rider is set to zero.

Columbia of Maryland, STRIDE - On May 2, 2013, the Governor of Maryland signed Senate Bill 8 into law, authorizing gas companies to accelerate recovery of eligible infrastructure replacement, effective June 1, 2013. The STRIDE statute provides recovery for gas pipeline upgrades outside of the context of a base rate proceeding through an annual surcharge, IRIS, as approved by, Maryland PSC. The STRIDE statute directs gas utilities to file a plan to invest in eligible infrastructure replacement projects and to list the specific projects and elements in any such STRIDE plan with the Maryland PSC. The calendar year projected capital projects to be placed into plant in service and included in Columbia of Maryland's surcharge recovery request must satisfy a number of criteria per the statute, including a requirement that they be designed to improve public safety or infrastructure reliability. Columbia of Maryland's five-year STRIDE Plan renewal for years 2019 through 2023, as with the preceding five years, is focused on replacing (1) existing cast iron and bare steel mains, (2) associated services and meters, and (3) identified prone-to-failure vintage plastic piping. Columbia of Maryland's IRIS mechanism recovers a return on investment, depreciation and property taxes of the STRIDE-eligible capital infrastructure statutorily capped at $2 per month for residential customers, and proportionally capped for commercial and industrial customer classes, and is reconciled to actual costs on an annual basis. Any over-collection or under-collection balance is passed back to, or recovered from, customers through the surcharge effective in May of the subsequent year.

The following table describes regulatory programs to recover infrastructure replacement and other federally-mandated compliance investments currently in rates and those pending commission approval:

(in millions)

Company	Program	Incremental Revenue	Incremental Capital Investment	Investment Period	Filed	Status	Rates Effective
Columbia of Ohio	IRP - 2018[1]	$ 2.3	$ 207.0	1/17-12/17	February 27, 2018	Approved April 25, 2018	May 2018
NIPSCO - Gas	TDSIC 7	$ 1.5	$ 59.0	1/17-6/17	August 31, 2017	Approved December 28, 2017	January 2018
NIPSCO - Gas	TDSIC 8	$ 1.8	$ 54.0	7/17-12/17	February 27, 2018	Approved August 22, 2018	September 2018
NIPSCO - Gas	TDSIC 9[1][2]	$ (10.6)	$ 54.4	1/18 - 6/18	August 28, 2018	Approved December 27, 2018	January 2019
NIPSCO - Gas	FMCA 1	$ 9.9	$ 1.5	11/17-9/18	November 30, 2018	Order Expected Q1 2019	April 2019
Columbia of Massachusetts	GSEP - 2018[1][3]	$ 6.5	$ 80.0	1/18-12/18	October 31, 2017	Approved April 30, 2018	May 2018
Columbia of Massachusetts	GSEP - 2019[4]	$ 10.7	$ 64.0	1/19-12/19	October 31, 2018	Order expected Q2 2019	May 2019
Columbia of Pennsylvania	DSIC - 2018	$ 0.4	$ 14.8	12/17-2/18	March 22, 2018	Approved March 29, 2018	April 2018
Columbia of Pennsylvania	DSIC - 2018	$ 0.9	$ 31.8	3/18-5/18	June 20, 2018	Approved June 28, 2018	July 2018
Columbia of Pennsylvania	DSIC - 2018	$ 1.6	$ 55.4	6/18-8/18	September 20, 2018	Approved September 28, 2018	October 2018
Columbia of Virginia	SAVE - 2018	$ 2.9	$ 33.3	1/18-12/18	August 18, 2017	Approved December 13, 2017	January 2018
Columbia of Virginia	SAVE - 2019	$ 2.4	$ 36.0	1/19-12/19	August 17, 2018	Approved October 26, 2018	January 2019
Columbia of Kentucky	AMRP - 2018	$ 4.5	$ 24.0	1/18-12/18	October 13, 2017	Approved December 22, 2017	January 2018
Columbia of Kentucky	AMRP - 2019	$ 3.6	$ 30.1	1/19-12/19	October 15, 2018	Approved December 5, 2018	January 2019
Columbia of Maryland	STRIDE - 2018	$ 1.2	$ 20.8	1/18-12/18	November 1, 2017	Approved December 20, 2017	January 2018
Columbia of Maryland	STRIDE - 2019	$ 1.2	$ 19.7	1/19-12/19	November 1, 2018	Approved December 12, 2018	January 2019
NIPSCO - Electric	TDSIC - 3	$ (2.0)	$ 75.0	5/17-11/17	January 30, 2018	Approved May 30, 2018	June 2018
NIPSCO - Electric	TDSIC - 4[1]	$ (11.8)	$ 72.2	12/17-5/18	July 31, 2018	Approved November 28, 2018	December 2018
NIPSCO - Electric	TDSIC - 5[1]	$ 15.9	$ 58.8	6/18-11/18	January 29, 2019	Order Expected Q2 2019	June 2019
NIPSCO - Electric	ECRM - 31	$ (2.1)	$ 2.9	6/17-12/17	January 31, 2018	Approved April 25, 2018	May 2018
NIPSCO - Electric	ECRM - 32	$ 1.0	$ —	1/18-6/18	July 31, 2018	Approved October 11, 2018	November 2018
NIPSCO - Electric	FMCA - 8	$ 1.3	$ 4.4	4/17-9/17	November 1, 2017	Approved January 31, 2018	February 2018
NIPSCO - Electric	FMCA - 9	$ 4.1	$ 90.2	10/17-3/18	April 27, 2018	Approved July 25, 2018	August 2018
NIPSCO - Electric	FMCA - 10	$ 2.2	$ 45.7	4/18-8/18	October 18, 2018	Approved January 29, 2019	February 2019

[1]Incremental revenue is net of amounts due back to customers as a result of the TCJA.
[2]Incremental revenue is net of $5.2 million of adjustments in the TDSIC-9 settlement.

[3]A cap waiver was approved by the Massachusetts DPU on June 21, 2018 and related rates became effective July 2018.
[4]The filing included a request for approval of a waiver to allow collection of the $2.9 million revenue requirement that exceeds the GSEP cap provision.

Rate Case Actions

The following table describes current rate case actions as applicable in each of our jurisdictions net of tracker impacts:

(in millions)

Company	Requested Incremental Revenue	Approved Incremental Revenue	Filed	Status	Rates Effective
NIPSCO - Gas[(1)]	$ 138.1	$ 107.3	September 27, 2017	Approved September 19, 2018	October 2018
Columbia of Massachusetts	$ 24.1	N/A	April 13, 2018	Withdrawn September 19, 2018	N/A
Columbia of Pennsylvania	$ 46.9	$ 26.0	March 16, 2018	Approved December 6, 2018	December 2018
Columbia of Virginia[(2)]	$ 14.2	In process	August 28, 2018	Order expected Second half of 2019	February 2019
Columbia of Maryland	$ 4.6	$ 2.2	April 13, 2018	Approved November 21, 2018	November 2018
NIPSCO - Electric	$ 21.4	In process	October 31, 2018	Order expected Q3 2019	September 2019

(1)Rates will be implemented in three steps, with implementation of step 1 rates effective October 1, 2018. Step 2 rates will be effective on or about March 1, 2019, and step 3 rates will be effective on January 1, 2020. The IURC's order also dismissed NIPSCO from phase 2 of the IURC's TCJA investigation.
(2)Rates implemented subject to refund pending a final order from the VSCC.

Additional Regulatory Matters

Columbia of Ohio. On December 1, 2017, Columbia of Ohio filed an application that requested authority to implement a rider to begin recovering plant and associated deferrals related to its CEP. The CEP was established in 2011 and allows for deferral of interest, depreciation and property taxes on certain plant investments not recovered through its IRP modernization tracker. The application requested authority to increase annual revenues, through the requested rider, by approximately $70 million, with biennial increases up to approximately $98 million in 2022. On May 9, 2018, the PUCO appointed an independent auditor to assist the PUCO with the review of the accounting accuracy, prudency and compliance of Columbia of Ohio with its PUCO-approved CEP deferrals. The independent audit report was filed on September 4, 2018 and the PUCO Staff's Report on the investigation was filed on September 14, 2018. On October 25, 2018, a joint stipulation and recommendation was filed recommending an initial revenue requirement of $74.5 million to recover CEP investments and deferrals through December 31, 2017, with annual adjustments for capital investments made in subsequent years. Additionally, the signatory parties to the stipulation agreed to a reduction in rates to adjust for the impacts of the TCJA and for a base rate case filing to be made by Columbia of Ohio with a test period of calendar year 2021. On November 28, 2018 the PUCO issued an order unanimously approving the settlement filed on October 25, 2018, without modification, for rates effective beginning November 29, 2018. This order finalizes Columbia of Ohio's TCJA resolution related to the CEP tracker, as well as base rates.

NIPSCO Gas. On November 8, 2017, NIPSCO filed a petition with the IURC seeking approval of NIPSCO's federally mandated pipeline safety compliance plan. As part of the settlement agreement filed in NIPSCO's gas base rate case proceeding, NIPSCO and the parties to the settlement agreement settled all issues in this proceeding as well, including moving certain costs from the base rate proceeding to this pipeline safety compliance plan. The updated four year compliance plan includes a total estimated $91.5 million of capital costs and $35.5 million of expected operating and maintenance costs. NIPSCO received approval for accounting and rate-making relief, including establishment of a periodic rate adjustment mechanism. NIPSCO filed the first tracker proceeding in this case on November 30, 2018. On December 31, 2018, NIPSCO filed a petition with the IURC seeking approval of an additional PHMSA compliance plan including capital expenditures of $228.8 million. An IURC order is expected in the second half of 2019.

On January 3, 2018, the IURC initiated an investigation to review and consider the possible implications of the TCJA on utility rates. The IURC ordered a two phase investigation. Phase 1 solely dealt with the prospective changes in rates to reflect the change in tax rates. In accordance with the procedural schedule, on March 26, 2018, NIPSCO filed revised gas tariffs reflecting the impact of the change in tax rate for its applicable rates and charges. The IURC approved NIPSCO's Phase 1 filing on April 26, 2018. The revised tariffs were effective May 1, 2018. The stipulation and settlement agreement filed on April 20, 2018, in NIPSCO's gas rate case resolved all issues in Phase 2, including the return of excess income tax revenue recovered through its base rates and any applicable charges between January 1, 2018 and April 30, 2018. Beginning January 2019, and continuing through June 2019, NIPSCO is passing back the excess tax expense through the TDSIC mechanism.

On December 27, 2018, the IURC issued an order for TDSIC-9 approving the settlement agreement filed on November 4, 2018. This order, along with the Court of Appeals dismissal on December 31, 2018 and January 8, 2019, resolved all outstanding issues related to the appeals of TDSIC-4 though TDSIC-8.

Columbia of Massachusetts. On October 9, 2018, Columbia of Massachusetts filed an application with the Massachusetts DPU, seeking authority to pass back approximately $95.8 million in excess deferred taxes associated with TCJA with an effective date of rates to be determined by the Massachusetts DPU. On December 21, 2018 the Massachusetts DPU issued an order approving the treatment of TCJA-related excess deferred taxes. Columbia Gas of Massachusetts filed a compliance filing on January 4, 2019, reflecting revised LDAF rates inclusive of credit factors to return excess deferred taxes associated with TCJA to customers for rates effective on February 1, 2019, per the Massachusetts DPU's order.

Columbia of Kentucky. On April 30, 2018, Columbia of Kentucky received an order from the Kentucky PSC requiring implementation of interim proposed rates effective May 1, 2018 reflecting the impact of TCJA subject to future adjustment. The order directed Columbia of Kentucky to file, by September 1, 2018, revised TCJA adjustment factors reflecting the tax expense savings from January 1, 2018 through April 30, 2018, and an estimate of the annual reduction due to the excess deferred taxes to be effective with the first billing cycle of October 2018. On August 31, 2018, Columbia of Kentucky filed updated rate schedules with the Kentucky PSC for rates proposed to be effective October 1, 2018. On October 25, 2018, the Kentucky PSC authorized the TCJA adjustment factors, as proposed, with an October 29, 2018 effective date to pass-back the overcollection of taxes over a six month period.

Columbia of Maryland. On February 13, 2018, Columbia of Maryland filed a proposal with the Maryland PSC to reduce rates as a result of TCJA with an annual revenue decrease of $1.3 million. Columbia of Maryland was directed to account for any revenues associated with the difference between previous and current income tax rates and excess deferred taxes as regulatory liabilities effective January 1, 2018. On March 14, 2018, Columbia of Maryland received approval, effective April 2, 2018, to implement new rates and pass-back the overcollection of taxes from the first quarter of 2018 over a seven month period.

NIPSCO Electric. On October 31, 2018, NIPSCO submitted its 2018 Integrated Resource Plan with the IURC. The plan evaluated demand-side and supply-side resource alternatives to reliably and cost effectively meet NIPSCO customers' future energy requirements over the ensuing 20 years. Refer to Note 18-E, "Other Matters," in the Notes to Consolidated Financial Statements for additional information.

On March 29, 2018, WCE, which is currently owned by BP p.l.c ("BP") and BP Products North America, which operates the BP Refinery, filed a petition at the IURC asking that the combined operations of WCE and BP be treated as a single premise, and the WCE generation be dedicated primarily to BP Refinery operations beginning in May 2019 as WCE has self-certified as a qualifying facility at FERC. BP Refinery planned to continue to purchase electric service from NIPSCO at a reduced demand level beginning in May 2019. A settlement agreement was filed on November 2, 2018 agreeing that BP and WCE would not move forward with construction of a private transmission line to serve BP until conclusion of NIPSCO's pending electric rate case.

On February 1, 2018, NIPSCO and certain other MISO transmission owners filed with the FERC a request for waiver of tariff provisions to allow for implementation of TCJA tax rate change provisions into 2018 transmission formula rates. On March 15, 2018, the FERC issued an order granting the request for waiver and set the effective date of the waiver at January 1, 2018. In the March billing cycle, the MISO began billing the new transmission rates reflecting the lower federal tax rate. In addition, the MISO began to re-bill January and February 2018 affected revenues and costs in the March 2018 billing cycle, and completed the re-settlement in the April 2018 billing cycle. The new 2018 transmission formula rates will reduce revenue by $8.5 million in 2018 associated with NIPSCO's multi-value projects. Additionally, on November 1, 2018, MISO submitted revised tariffs to provide for adjustments to income tax, including accumulated deferred income tax, resulting from tax law or rate changes. On December 20, 2018, FERC accepted the submission, effective January 1, 2019, as requested.

As noted above in the NIPSCO Gas regulatory matters, the IURC initiated an investigation on January 3, 2018, to review and consider the implications of the TCJA on utility rates. The commission ordered a two phase investigation. Phase 1 solely dealt with the prospective changes in rates to reflect the change in tax rates. On March 26, 2018, NIPSCO filed revised electric tariffs reflecting the impact of the change in tax rate for its applicable rates and charges. The IURC approved NIPSCO's phase 1 filing on April 26, 2018. The revised tariffs were effective May 1, 2018. On July 31, 2018, NIPSCO filed an unopposed motion requesting that the over-collection of income taxes from January 1, 2018 through April 30, 2018 be passed back in NIPSCO's TDSIC-4 filing, also filed on July 31, 2018, and requesting that all other phase 2 issues be handled in a rate case filing to be made in the fourth quarter of 2018. On August 15, 2018, the IURC approved the motion to pass back the over-collection through the TDSIC-4 rates effective December 2018 through May 2019. All other phase 2 issues are addressed in the base rate case filed October 31, 2018.

9. Risk Management Activities

We are exposed to certain risks relating to ongoing business operations; namely commodity price risk and interest rate risk. We recognize that the prudent and selective use of derivatives may help to lower our cost of debt capital, manage interest rate exposure and limit volatility in the price of natural gas.

Risk management assets and liabilities on our derivatives are presented on the Consolidated Balance Sheets as shown below:

December 31, *(in millions)*	**2018**	2017
Risk Management Assets - Current[1]		
Interest rate risk programs	**$ —**	$ 14.0
Commodity price risk programs	**1.1**	0.5
Total	**$ 1.1**	$ 14.5
Risk Management Assets - Noncurrent[2]		
Interest rate risk programs	**$ 18.5**	$ 5.6
Commodity price risk programs	**4.4**	1.0
Total	**$ 22.9**	$ 6.6
Risk Management Liabilities - Current		
Interest rate risk programs	**$ —**	$ 38.6
Commodity price risk programs	**5.0**	4.6
Total	**$ 5.0**	$ 43.2
Risk Management Liabilities - Noncurrent		
Interest rate risk programs	**$ 9.5**	$ —
Commodity price risk programs	**37.2**	28.5
Total	**$ 46.7**	$ 28.5

[1]Presented in "Prepayments and other" on the Consolidated Balance Sheets.
[2]Presented in "Deferred charges and other" on the Consolidated Balance Sheets.

Commodity Price Risk Management
We, along with our utility customers, are exposed to variability in cash flows associated with natural gas purchases and volatility in natural gas prices. We purchase natural gas for sale and delivery to our retail, commercial and industrial customers, and for most customers the variability in the market price of gas is passed through in their rates. Some of our utility subsidiaries offer programs whereby variability in the market price of gas is assumed by the respective utility. The objective of our commodity price risk programs is to mitigate the gas cost variability, for us or on behalf of our customers, associated with natural gas purchases or sales by economically hedging the various gas cost components using a combination of futures, options, forwards or other derivative contracts.

NIPSCO received IURC approval to lock in a fixed price for its natural gas customers using long-term forward purchase instruments. The term of these instruments range from five to ten years and is limited to twenty percent of NIPSCO's average annual GCA purchase volume. Gains and losses on these derivative contracts are deferred as regulatory liabilities or assets and are remitted to or collected from customers through NIPSCO's quarterly GCA mechanism. These instruments are not designated as accounting hedges.

Interest Rate Risk Management
As of December 31, 2018, we have forward-starting interest rate swaps with an aggregate notional value totaling $500.0 million to hedge the variability in cash flows attributable to changes in the benchmark interest rate during the periods from the effective dates of the swaps to the anticipated dates of forecasted debt issuances, which are expected to take place by the end of 2024. These interest rate swaps are designated as cash flow hedges. The effective portions of the gains and losses related to these swaps are

recorded to AOCI and are recognized in "Interest expense, net" concurrently with the recognition of interest expense on the associated debt, once issued. If it becomes probable that a hedged forecasted transaction will no longer occur, the accumulated gains or losses on the derivative will be recognized currently in "Other, net" in the Statements of Consolidated Income (Loss).

The passage of the TCJA and Greater Lawrence Incident led to significant changes to our long-term financing plan. As a result, during 2018, we settled forward-starting interest rate swaps with a notional value of $750.0 million. These derivative contracts were accounted for as cash flow hedges. As part of the transactions, the associated net unrealized gain of $46.2 million was recognized immediately in "Other, net" on the Statements of Consolidated Income (Loss) due to the probability associated with the forecasted borrowing transactions no longer occurring.

There were no amounts excluded from effectiveness testing for derivatives in cash flow hedging relationships at December 31, 2018, 2017 and 2016.

Our derivative instruments measured at fair value as of December 31, 2018 and 2017 do not contain any credit-risk-related contingent features.

10. Income Taxes

On December 22, 2017, the President signed into law the TCJA, which, among other things, enacted significant changes to the Internal Revenue Code, as amended, including a reduction in the maximum U.S. federal corporate income tax rate from 35% to 21%, and certain other provisions related specifically to the public utility industry, including the continuation of certain interest expense deductibility. These changes were effective January 1, 2018. Under GAAP, the effects of a change in tax law are recorded as a discrete item in the period of enactment.

Rates for our regulated customers include provisions for the collection of U.S. federal income taxes. Accordingly, accounting effects related to changes in tax rates here that would normally be recognized as a component of income tax expense may instead be deferred as a regulatory asset or liability and reflected in future rate-making. In December 2017, we remeasured our deferred tax assets and liabilities to the new federal corporate income tax rate. The result of this remeasurement was a reduction in the net deferred tax liability of approximately $1.3 billion, including approximately $0.4 billion of regulatory "gross up" to account for over-collection of past taxes from customers. Offsetting the reduction in net deferred tax liabilities was an increase in regulatory liabilities of approximately $1.5 billion and an increase in income tax expense of $0.2 billion. In 2018, we received regulatory orders from most of the jurisdictions in which we operate regarding the treatment and pass back of excess deferred taxes. As a result of these orders we reduced our regulatory liability related to excess deferred income taxes by $120.7 million (net of tax). This adjustment is reflected in "Income Taxes" on our Consolidated Statements of Income (Loss).

On December 22, 2017, the SEC issued Staff Accounting Bulletin 118 (“SAB 118”), which provides guidance on accounting for tax effects of the TCJA. SAB 118 provides a measurement period that should not extend beyond one year from the TCJA enactment date for companies to complete the accounting under ASC 740. There were no adjustments recorded in the SAB 118 remeasurement period in 2018.

The components of income tax expense (benefit) were as follows:

Year Ended December 31, *(in millions)*	**2018**	2017	2016
Income Taxes			
Current			
Federal	**$ —**	$ —	$ —
State	**8.2**	7.8	(0.1)
Total Current	**8.2**	7.8	(0.1)
Deferred			
Federal	**(209.4)**	302.7	165.6
State	**22.2**	5.0	18.0
Total Deferred	**(187.2)**	307.7	183.6
Deferred Investment Credits	**(1.0)**	(1.0)	(1.4)
Income Taxes	**$ (180.0)**	$ 314.5	$ 182.1

Total income taxes were different from the amount that would be computed by applying the statutory federal income tax rate to book income before income tax. The major reasons for this difference were as follows:

Year Ended December 31, *(in millions)*	**2018**		2017		2016	
Book income (loss) before income taxes	**$ (230.6)**		$ 443.0		$ 513.6	
Tax expense (benefit) at statutory federal income tax rate	**(48.4)**	**21.0 %**	155.0	35.0 %	179.8	35.0 %
Increases (reductions) in taxes resulting from:						
State income taxes, net of federal income tax benefit	**24.7**	**(10.7)**	6.9	1.5	11.3	2.2
Amortization of regulatory liabilities	**(29.3)**	**12.7**	(2.4)	(0.5)	(1.5)	(0.3)
Charitable contribution carryover	**—**	**—**	(1.2)	(0.3)	2.8	0.5
State regulatory proceedings	**(127.8)**	**55.4**	—	—	—	—
Remeasurement due to TCJA	**—**	**—**	161.1	36.4	—	—
Employee stock ownership plan dividends and other compensation	**(2.2)**	**1.0**	(6.5)	(1.5)	(9.5)	(1.8)
Other adjustments	**3.0**	**(1.3)**	1.6	0.4	(0.8)	(0.1)
Income Taxes	**$ (180.0)**	**78.1 %**	$ 314.5	71.0 %	$ 182.1	35.5 %

The effective income tax rates were 78.1%, 71.0% and 35.5% in 2018, 2017 and 2016, respectively. The 7.1% increase in the overall effective tax rate in 2018 versus 2017 was primarily the result of state regulatory proceedings which resulted in a $127.8 million decrease in federal income taxes offset by a related increase in state income taxes of $7.1 million. Additionally, the increase was driven by a $26.9 million decrease in income taxes related to amortization of the regulatory liability primarily associated with excess deferred taxes.

The 35.5% increase in the overall effective tax rate in 2017 versus 2016 was primarily the result of a $161.1 million increase in income taxes related to implementing the provisions of the TCJA. The charge to income tax expense resulting from implementation of the TCJA relates primarily to remeasurement of parent company deferred tax assets for NOL carryforwards.

In March 2016, the FASB issued ASU 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. Among other provisions, the standard requires that all income tax effects of awards are recognized in the income statement when the awards vest and are distributed.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Deferred income taxes result from temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The principal components of our net deferred tax liability were as follows:

At December 31, *(in millions)*	**2018**	2017
Deferred tax liabilities		
Accelerated depreciation and other property differences	**$ 2,458.0**	$ 2,260.7
Other regulatory assets	**375.4**	309.5
Total Deferred Tax Liabilities	**2,833.4**	2,570.2
Deferred tax assets		
Other regulatory liabilities and deferred investment tax credits (including TCJA)	**365.5**	406.0
Pension and other postretirement/postemployment benefits	**157.5**	136.7
Net operating loss carryforward and AMT credit carryforward	**849.8**	576.0
Environmental liabilities	**24.4**	24.0
Other accrued liabilities	**37.5**	37.2
Other, net	**68.2**	97.4
Total Deferred Tax Assets	**1,502.9**	1,277.3
Net Deferred Tax Liabilities	**$ 1,330.5**	$ 1,292.9

State income tax net operating loss benefits are recorded at their realizable value. We anticipate it is more likely than not that we will realize $88.5 million and $65.8 million of these tax benefits as of December 31, 2018 and 2017, respectively, prior to their expiration. These tax benefits are primarily related to Indiana, Massachusetts and Pennsylvania. The remaining net operating loss carryforward tax benefits represent a federal carryforward of $759.6 million ($508.5 million of which relates to years prior to the implementation of the TCJA) and an Alternative Minimum Tax credit of $1.7 million. The carryforward periods for pre-TCJA tax benefits expire in various tax years from 2028 to 2037. Per the TCJA, federal NOL carryforwards generated after December 31, 2017 do not expire, but are limited to 80% of current year taxable income.

Unrecognized tax benefits for the periods reported are immaterial. We present accrued interest on unrecognized tax benefits, accrued interest on other income tax liabilities and tax penalties in "Income Taxes" on our Statements of Consolidated Income (Loss). Interest expense recorded on unrecognized tax benefits and other income tax liabilities was immaterial for all periods presented. There were no accruals for penalties recorded in the Statements of Consolidated Income (Loss) for the years ended December 31, 2018, 2017 and 2016, and there were no balances for accrued penalties recorded on the Consolidated Balance Sheets as of December 31, 2018 and 2017.

We are subject to income taxation in the United States and various state jurisdictions; primarily Indiana, Pennsylvania, Kentucky, Massachusetts, Maryland and Virginia.

We participate in the IRS CAP which provides the opportunity to resolve tax matters with the IRS before filing each year's consolidated federal income tax return. As of December 31, 2018, tax years through 2017 have been audited and are effectively closed to further assessment. The audit of tax year 2018 under the CAP program is expected to be completed in 2019.

The statute of limitations in each of the state jurisdictions in which we operate remains open until the years are settled for federal income tax purposes, at which time amended state income tax returns reflecting all federal income tax adjustments are filed. As of December 31, 2018, there were no state income tax audits in progress that would have a material impact on the consolidated financial statements.

11. Pension and Other Postretirement Benefits

We provide defined contribution plans and noncontributory defined benefit retirement plans that cover certain of our employees. Benefits under the defined benefit retirement plans reflect the employees' compensation, years of service and age at retirement. Additionally, we provide health care and life insurance benefits for certain retired employees. The majority of employees may become eligible for these benefits if they reach retirement age while working for us. The expected cost of such benefits is accrued during the employees' years of service. Current rates of rate-regulated companies include postretirement benefit costs, including amortization of the regulatory assets that arose prior to inclusion of these costs in rates. For most plans, cash contributions are remitted to grantor trusts.

Our Pension and Other Postretirement Benefit Plans' Asset Management. We employ a liability-driven investing strategy for the pension plan, as noted below. A mix of equities and fixed income investments are used to maximize the long-term return of plan assets and hedge the liabilities at a prudent level of risk. We utilize a total return investment approach for the other postretirement benefit plans. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and asset class volatility. The investment portfolio contains a diversified blend of equity and fixed income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, small and large capitalizations. Other assets such as private equity funds are used judiciously to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives may not be used to leverage the portfolio beyond the market value of the underlying assets. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

We utilize a building block approach with proper consideration of diversification and rebalancing in determining the long-term rate of return for plan assets. Historical markets are studied and long-term historical relationships between equities and fixed income are analyzed to ensure that they are consistent with the widely accepted capital market principle that assets with higher volatility generate greater return over the long run. Current market factors, such as inflation and interest rates, are evaluated before long-term capital market assumptions are determined. Peer data and historical returns are reviewed to check for reasonability and appropriateness.

The most important component of an investment strategy is the portfolio asset mix, or the allocation between the various classes of securities available to the pension and other postretirement benefit plans for investment purposes. The asset mix and acceptable minimum and maximum ranges established for our plan assets represents a long-term view and are listed in the table below.

In 2012, a dynamic asset allocation policy for the pension fund was approved. This policy calls for a gradual reduction in the allocation of return-seeking assets (equities, real estate and private equity) and a corresponding increase in the allocation of liability-hedging assets (fixed income) as the funded status of the plans increase above 90% (as measured by the market value of qualified pension plan assets divided by the projected benefit obligations of the qualified pension plans). During 2017, a $277 million discretionary contribution was made to the pension plans. A new asset-liability study was completed in 2018 resulting in a more conservative glide path and an increase in the allocation to liability-hedging assets held in the portfolio.

As of December 31, 2018, the asset mix and acceptable minimum and maximum ranges established by the policy for the pension and other postretirement benefit plans are as follows:

Asset Mix Policy of Funds:

	Defined Benefit Pension Plan		Postretirement Benefit Plan	
Asset Category	Minimum	Maximum	Minimum	Maximum
Domestic Equities	12%	32%	0%	55%
International Equities	6%	16%	0%	25%
Fixed Income	59%	71%	20%	100%
Real Estate	0%	7%	0%	0%
Short-Term Investments/Other	0%	15%	0%	10%

As of December 31, 2017, the asset mix and acceptable minimum and maximum ranges established by the policy for the pension and other postretirement benefit plans were as follows:

Asset Mix Policy of Funds:

	Defined Benefit Pension Plan		Postretirement Benefit Plan	
Asset Category	Minimum	Maximum	Minimum	Maximum
Domestic Equities	16%	36%	0%	55%
International Equities	8%	18%	0%	25%
Fixed Income	39%	51%	20%	100%
Diversified Credit	0%	13%	0%	0%
Real Estate	0%	13%	0%	0%
Short-Term Investments	0%	10%	0%	10%

Pension Plan and Postretirement Plan Asset Mix at December 31, 2018 and December 31, 2017:

	Defined Benefit Pension Assets	December 31, 2018	Postretirement Benefit Plan Assets	December 31, 2018
Asset Class *(in millions)*	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	$ 355.5	19.0%	$ 78.8	36.4%
International Equities	165.5	8.9%	17.5	8.1%
Fixed Income	1,241.9	66.5%	115.1	53.2%
Real Estate	52.7	2.8%	—	—
Cash/Other	52.1	2.8%	4.9	2.3%
Total	$ 1,867.7	100.0%	$ 216.3	100.0%

	Defined Benefit Pension Assets	December 31, 2017	Postretirement Benefit Plan Assets	December 31, 2017
Asset Class *(in millions)*	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	$ 698.2	32.3%	$ 96.0	36.6%
International Equities	351.0	16.2%	39.8	15.2%
Fixed Income	977.6	45.3%	117.5	44.8%
Real Estate	49.9	2.3%	—	—
Cash/Other	83.3	3.9%	9.2	3.4%
Total	$ 2,160.0	100.0%	$ 262.5	100.0%

The categorization of investments into the asset classes in the table above are based on definitions established by our Benefits Committee.

Fair Value Measurements. The following table sets forth, by level within the fair value hierarchy, the Master Trust and other postretirement benefits investment assets at fair value as of December 31, 2018 and 2017. Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Total Master Trust and other postretirement benefits investment assets at fair value classified within Level 3 were $86.1 million and $98.9 million as of December 31, 2018 and December 31, 2017, respectively. Such amounts were approximately 4% of the Master Trust and other postretirement benefits' total investments as reported on the statement of net assets available for benefits at fair value as of December 31, 2018 and 2017.

Valuation Techniques Used to Determine Fair Value:

Level 1 Measurements

Most common and preferred stocks are traded in active markets on national and international securities exchanges and are valued at closing prices on the last business day of each period presented. Cash is stated at cost which approximates fair value, with the exception of cash held in foreign currencies which fluctuates with changes in the exchange rates. Short-term bills and notes are priced based on quoted market values.

Level 2 Measurements

Most U.S. Government Agency obligations, mortgage/asset-backed securities, and corporate fixed income securities are generally valued by benchmarking model-derived prices to quoted market prices and trade data for identical or comparable securities. To the extent that quoted prices are not available, fair value is determined based on a valuation model that includes inputs such as interest rate yield curves and credit spreads. Securities traded in markets that are not considered active are valued based on quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. Other fixed income includes futures and options which are priced on bid valuation or settlement pricing.

Level 3 Measurements

Private equity investment strategies include buy-out, venture capital, growth equity, distressed debt, and mezzanine debt. Private equity investments are held through limited partnerships.

Limited partnerships are valued at estimated fair market value based on their proportionate share of the partnership's fair value as recorded in the partnerships' audited financial statements. Partnership interests represent ownership interests in private equity funds and real estate funds. Real estate partnerships invest in natural resources, commercial real estate and distressed real estate. The fair value of these investments is determined by reference to the funds' underlying assets, which are principally securities, private businesses, and real estate properties. The value of interests held in limited partnerships, other than securities, is determined by the general partner, based upon third-party appraisals of the underlying assets, which include inputs such as cost, operating results, discounted cash flows and market based comparable data. Private equity and real estate limited partnerships typically call capital over a three to five year period and pay out distributions as the underlying investments are liquidated. The typical expected life of these limited partnerships is 10-15 years and these investments typically cannot be redeemed prior to liquidation.

Not Classified

Commingled funds that hold underlying investments that have prices which are derived from the quoted prices in active markets are not classified within the fair value hierarchy. Instead, these assets are measured at estimated fair value using the net asset value per share of the investments. The funds' underlying assets are principally marketable equity and fixed income securities. Units held in commingled funds are valued at the unit value as reported by the investment managers.

For the year ended December 31, 2018, there were no significant changes to valuation techniques to determine the fair value of our pension and other postretirement benefits' assets.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Fair Value Measurements at December 31, 2018:

(in millions)	December 31, 2018	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Pension plan assets:				
Cash	$ 9.2	$ 8.8	$ 0.4	$ —
Equity securities				
U.S. equities	0.2	0.2	—	—
Fixed income securities				
Government	250.2	—	250.2	—
Corporate	442.8	—	442.8	—
Mutual Funds				
U.S. multi-strategy	110.3	110.3	—	—
International equities	43.2	43.2	—	—
Fixed income	166.8	166.8	—	—
Private equity limited partnerships				
U.S. multi-strategy[(1)]	18.5	—	—	18.5
International multi-strategy[(2)]	12.5	—	—	12.5
Distressed opportunities	2.4	—	—	2.4
Real estate	52.7	—	—	52.7
Commingled funds[(3)]				
Short-term money markets	18.3	—	—	—
U.S. equities	245.2	—	—	—
International equities	122.3	—	—	—
Fixed income	365.7	—	—	—
Pension plan assets subtotal	1,860.3	329.3	693.4	86.1
Other postretirement benefit plan assets:				
Mutual funds				
U.S. equities	68.4	68.4	—	—
International equities	17.5	17.5	—	—
Fixed income	114.8	114.8	—	—
Commingled funds[(3)]				
Short-term money markets	5.2	—	—	—
U.S. equities	10.4	—	—	—
Other postretirement benefit plan assets subtotal	216.3	200.7	—	—
Due to brokers, net[(4)]	(1.1)	—	(1.1)	—
Accrued income/dividends	8.6	8.6	—	—
Total pension and other postretirement benefit plan assets	$ 2,084.1	$ 538.6	$ 692.3	$ 86.1

(1) This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily inside the United States.
(2) This class includes limited partnerships/fund of funds that invest in diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily outside the United States.
(3) This class of investments is measured at fair value using the net asset value per share and has not been classified in the fair value hierarchy.
(4) This class represents pending trades with brokers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

The table below sets forth a summary of changes in the fair value of the Plan's Level 3 assets for the year ended December 31, 2018:

	Balance at January 1, 2018	Total gains or losses (unrealized / realized)	Purchases	(Sales)	Balance at December 31, 2018
Private equity limited partnerships					
U.S. multi-strategy	26.7	2.4	0.7	(11.3)	18.5
International multi-strategy	19.1	(0.6)	—	(6.0)	12.5
Distressed opportunities	3.2	(0.8)	—	—	2.4
Real estate	49.9	1.7	1.8	(0.7)	52.7
Total	$ 98.9	$ 2.7	$ 2.5	$ (18.0)	$ 86.1

The table below sets forth a summary of unfunded commitments, redemption frequency and redemption notice periods for certain investments that are measured at fair value using the net asset value per share for the year ended December 31, 2018:

(in millions)	Fair Value	Redemption Frequency	Redemption Notice Period
Commingled Funds			
Short-term money markets	$ 23.5	Daily	1 day
U.S. equities	255.6	Monthly	3 days
International equities	122.3	Monthly	10-30 days
Fixed income	365.7	Monthly	3 days
Total	$ 767.1		

Fair Value Measurements at December 31, 2017:

(in millions)	December 31, 2017	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Pension plan assets:				
Cash	$ 9.7	$ 9.7	$ —	$ —
Equity securities				
U.S. equities	0.3	0.3	—	—
Fixed income securities				
Government	143.4	—	143.4	—
Corporate	332.6	—	332.6	—
Mutual Funds				
U.S. multi-strategy	231.5	231.5	—	—
International equities	85.8	85.8	—	—
Fixed income	242.3	242.3	—	—
Private equity limited partnerships				
U.S. multi-strategy(1)	26.7	—	—	26.7
International multi-strategy(2)	19.1	—	—	19.1
Distressed opportunities	3.2	—	—	3.2
Real Estate	49.9	—	—	49.9
Commingled funds(3)				
Short-term money markets	34.1	—	—	—
U.S. equities	466.6	—	—	—
International equities	265.1	—	—	—
Fixed income	244.9	—	—	—
Pension plan assets subtotal	2,155.2	569.6	476.0	98.9
Other postretirement benefit plan assets:				
Mutual funds				
U.S. equities	83.8	83.8	—	—
International equities	39.8	39.8	—	—
Fixed income	117.3	117.3	—	—
Commingled funds(3)				
Short-term money markets	9.4	—	—	—
U.S. equities	12.2	—	—	—
Other postretirement benefit plan assets subtotal	262.5	240.9	—	—
Due to brokers, net(4)	(2.5)	—	—	—
Accrued investment income/dividends	7.3	—	—	—
Total pension and other postretirement benefit plan assets	$ 2,422.5	$ 810.5	$ 476.0	$ 98.9

(1) This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily inside the United States.
(2) This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily outside the United States.
(3) This class of investments is measured at fair value using the net asset value per share and has not been classified in the fair value hierarchy.
(4) This class represents pending trades with brokers.

The table below sets forth a summary of changes in the fair value of the Plan's Level 3 assets for the year ended December 31, 2017:

	Balance at January 1, 2017	Total gains or losses (unrealized / realized)	Purchases	(Sales)	Balance at December 31, 2017
Fixed income securities					
Other fixed income	$ 0.1	$ (0.1)	$ —	$ —	$ —
Private equity limited partnerships					
U.S. multi-strategy	34.8	2.1	0.9	(11.1)	26.7
International multi-strategy	24.9	1.1	0.1	(7.0)	19.1
Distress opportunities	4.1	0.4	—	(1.3)	3.2
Real estate	9.2	(0.6)	42.1	(0.8)	49.9
Total	$ 73.1	$ 2.9	$ 43.1	$ (20.2)	$ 98.9

The table below sets forth a summary of unfunded commitments, redemption frequency and redemption notice periods for certain investments that are measured at fair value using the net asset value per share for the year ended December 31, 2017:

(in millions)	Fair Value	Redemption Frequency	Redemption Notice Period
Commingled Funds			
Short-term money markets	$ 43.5	Daily	1 day
U.S. equities	478.8	Monthly	3 days
International equities	265.1	Monthly	14-30 days
Fixed income	244.9	Monthly	3 days
Total	$ 1,032.3		

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

Our Pension and Other Postretirement Benefit Plans' Funded Status and Related Disclosure. The following table provides a reconciliation of the plans' funded status and amounts reflected in our Consolidated Balance Sheets at December 31 based on a December 31 measurement date:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2018**	2017	**2018**	2017
Change in projected benefit obligation[1]				
Benefit obligation at beginning of year	**$ 2,192.6**	$ 2,165.8	**$ 556.3**	$ 529.0
Service cost	**31.3**	30.0	**5.0**	4.8
Interest cost	**67.1**	68.3	**17.6**	17.8
Plan participants' contributions	**—**	—	**5.7**	5.7
Plan amendments	**0.2**	0.9	**0.1**	1.6
Actuarial (gain) loss	**(103.9)**	98.3	**(51.7)**	36.2
Settlement loss	**0.8**	1.6	**—**	—
Benefits paid	**(206.8)**	(172.3)	**(41.1)**	(39.3)
Estimated benefits paid by incurred subsidy	**—**	—	**0.6**	0.5
Projected benefit obligation at end of year	**$ 1,981.3**	$ 2,192.6	**$ 492.5**	$ 556.3
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 2,160.0**	$ 1,750.9	**$ 262.5**	$ 231.4
Actual (loss) return on plan assets	**(88.4)**	299.1	**(31.8)**	33.1
Employer contributions	**2.9**	282.3	**21.0**	31.6
Plan participants' contributions	**—**	—	**5.7**	5.7
Benefits paid	**(206.8)**	(172.3)	**(41.1)**	(39.3)
Fair value of plan assets at end of year	**$ 1,867.7**	$ 2,160.0	**$ 216.3**	$ 262.5
Funded Status at end of year	**$ (113.6)**	$ (32.6)	**$ (276.2)**	$ (293.8)
Amounts recognized in the statement of financial position consist of:				
Noncurrent assets	**—**	9.8	**—**	—
Current liabilities	**(3.0)**	(2.8)	**(0.8)**	(0.7)
Noncurrent liabilities	**(110.6)**	(39.6)	**(275.4)**	(293.1)
Net amount recognized at end of year[2]	**$ (113.6)**	$ (32.6)	**$ (276.2)**	$ (293.8)
Amounts recognized in accumulated other comprehensive income or regulatory asset/liability[3]				
Unrecognized prior service credit	**$ 3.2**	$ 2.5	**$ (19.0)**	$ (23.1)
Unrecognized actuarial loss	**761.2**	692.9	**75.3**	84.2
Net amount recognized at end of year	**$ 764.4**	$ 695.4	**$ 56.3**	$ 61.1

[1] The change in benefit obligation for Pension Benefits represents the change in Projected Benefit Obligation while the change in benefit obligation for Other Postretirement Benefits represents the change in accumulated postretirement benefit obligation.
[2] We recognize our Consolidated Balance Sheets underfunded and overfunded status of our various defined benefit postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation.
[3] We determined that for certain rate-regulated subsidiaries the future recovery of pension and other postretirement benefits costs is probable. These rate-regulated subsidiaries recorded regulatory assets and liabilities of $798.3 million and $0.1 million, respectively, as of December 31, 2018, and $733.5 million and $0.1 million, respectively, as of December 31, 2017 that would otherwise have been recorded to accumulated other comprehensive loss.

Our accumulated benefit obligation for our pension plans was $1,965.6 million and $2,170.4 million as of December 31, 2018 and 2017, respectively. The accumulated benefit obligation as of a date is the actuarial present value of benefits attributed by the pension benefit formula to employee service rendered prior to that date and based on current and past compensation levels. The accumulated benefit obligation differs from the projected benefit obligation disclosed in the table above in that it includes no assumptions about future compensation levels.

Our pension plans were underfunded by $113.6 million at December 31, 2018 compared to being underfunded, in aggregate, by $32.6 million at December 31, 2017. The decline in the funded status was due primarily to unfavorable asset returns offset by an increase in discount rates. We contributed $2.9 million and $282.3 million to our pension plans in 2018 and 2017, respectively.

Our other postretirement benefit plans were underfunded by $276.2 million at December 31, 2018 compared to being underfunded by $293.8 million at December 31, 2017. The improvement in funded status was primarily due to employer contributions and an increase in discount rates, offset by unfavorable asset returns. We contributed $21.0 million and $31.6 million to our other postretirement benefit plans in 2018 and 2017, respectively.

No amounts of our pension or other postretirement benefit plans' assets are expected to be returned to us or any of our subsidiaries in 2018.

In 2018 and 2017, some of our qualified pension plans paid lump sum payouts in excess of the respective plan's service cost plus interest cost, thereby meeting the requirement for settlement accounting. We recorded settlement charges of $18.5 million and $13.7 million in 2018 and 2017, respectively. Net periodic pension benefit cost for 2018 was increased by $3.0 million as a result of the interim remeasurement.

The following table provides the key assumptions that were used to calculate the pension and other postretirement benefits obligations for our various plans as of December 31:

	Pension Benefits		**Other Postretirement Benefits**	
	2018	2017	**2018**	2017
Weighted-average assumptions to Determine Benefit Obligation				
Discount Rate	**4.26%**	3.58%	**4.31%**	3.67%
Rate of Compensation Increases	**4.00%**	4.00%	**—**	—
Health Care Trend Rates				
Trend for Next Year	**—**	—	**8.48%**	8.52%
Ultimate Trend	**—**	—	**4.50%**	4.50%
Year Ultimate Trend Reached	**—**	—	**2026**	2025

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(in millions)	1% point increase	1% point decrease
Effect on service and interest components of net periodic cost	$ 1.3	$ (1.1)
Effect on accumulated postretirement benefit obligation	25.0	(22.0)

We expect to make contributions of approximately $3.0 million to our pension plans and approximately $20.6 million to our postretirement medical and life plans in 2018.

The following table provides benefits expected to be paid in each of the next five fiscal years, and in the aggregate for the five fiscal years thereafter. The expected benefits are estimated based on the same assumptions used to measure our benefit obligation at the end of the year and include benefits attributable to the estimated future service of employees:

(in millions)	Pension Benefits	Other Postretirement Benefits	Federal Subsidy Receipts
Year(s)			
2019	$ 177.4	$ 34.3	$ 0.5
2020	176.0	35.0	0.5
2021	176.5	35.7	0.5
2022	174.4	36.0	0.4
2023	166.5	35.8	0.4
2024-2028	748.7	171.8	1.7

The following table provides the components of the plans' actuarially determined net periodic benefits cost for each of the three years ended December 31, 2018, 2017 and 2016:

	Pension Benefits			**Other Postretirement Benefits**		
(in millions)	**2018**	2017	2016	**2018**	2017	2016
Components of Net Periodic Benefit Cost[1]						
Service cost	**$ 31.3**	$ 30.0	$ 30.7	**$ 5.0**	$ 4.8	$ 5.0
Interest cost	**67.1**	68.3	89.7	**17.6**	17.8	22.0
Expected return on assets	**(142.3)**	(123.1)	(132.9)	**(14.9)**	(15.9)	(17.2)
Amortization of prior service cost (credit)	**(0.4)**	(0.7)	(0.2)	**(4.0)**	(4.4)	(4.9)
Recognized actuarial loss	**40.6**	52.9	61.2	**3.8**	3.0	3.1
Settlement loss	**18.5**	13.7	—	**—**	—	—
Total Net Periodic Benefits Cost	**$ 14.8**	$ 41.1	$ 48.5	**$ 7.5**	$ 5.3	$ 8.0

[1]Service cost is presented in "Operation and maintenance" on the Statements of Consolidated Income (Loss). Non-service cost components are presented within "Other, net."

The following table provides the key assumptions that were used to calculate the net periodic benefits cost for our various plans:

	Pension Benefits			**Other Postretirement Benefits**		
	2018	2017	2016	**2018**	2017	2016
Weighted-average Assumptions to Determine Net Periodic Benefit Cost						
Discount rate - service cost[1]	**3.79%**	4.40%	4.24%	**3.89%**	4.58%	4.33%
Discount rate - interest cost[1]	**3.15%**	3.31%	4.24%	**3.27%**	3.48%	4.33%
Expected Long-Term Rate of Return on Plan Assets	**7.00%**	7.25%	8.00%	**5.80%**	6.99%	7.85%
Rate of Compensation Increases	**4.00%**	4.00%	4.00%	**—**	—	—

[1] In January 2017, we changed the method used to estimate the service and interest components of net periodic benefit cost for pension and other postretirement benefits. This change, compared to the previous method, resulted in a decrease in the actuarially-determined service and interest cost components. Historically, we estimated service and interest cost utilizing a single weighted-average discount rate derived from the yield curve used to measure the benefit obligation at the beginning of the period. For fiscal 2017 and beyond, we now utilize a full yield curve approach to estimate these components by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to the relevant projected cash flows.

We believe it is appropriate to assume a 7.00% and 5.80% rate of return on pension and other postretirement plan assets, respectively, for our calculation of 2018 pension benefits cost. These rates are primarily based on asset mix and historical rates of return and were adjusted in the current year due to anticipated changes in asset allocation and projected market returns.

The following table provides other changes in plan assets and projected benefit obligations recognized in other comprehensive income or regulatory asset or liability:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2018**	2017	**2018**	2017
Other Changes in Plan Assets and Projected Benefit Obligations Recognized in Other Comprehensive Income or Regulatory Asset or Liability				
Net prior service cost	**$ 0.2**	$ 0.9	**$ 0.1**	$ 1.6
Net actuarial loss (gain)	**127.5**	(76.1)	**(5.0)**	18.9
Settlements	**(18.5)**	(13.7)	**—**	—
Less: amortization of prior service cost	**0.4**	0.7	**4.0**	4.4
Less: amortization of net actuarial loss	**(40.6)**	(52.9)	**(3.8)**	(3.0)
Total Recognized in Other Comprehensive Income or Regulatory Asset or Liability	**$ 69.0**	$ (141.1)	**$ (4.7)**	$ 21.9
Amount Recognized in Net Periodic Benefits Cost and Other Comprehensive Income or Regulatory Asset or Liability	**$ 83.8**	$ (100.0)	**$ 2.8**	$ 27.2

Based on a December 31 measurement date, the net unrecognized actuarial loss, unrecognized prior service cost (credit), and unrecognized transition obligation that will be amortized into net periodic benefit cost during 2019 for the pension plans are $45.5 million, $0.2 million and zero, respectively, and for other postretirement benefit plans are $2.4 million, $(3.2) million and zero, respectively.

12. Equity

We raise equity financing through a variety of programs including traditional common equity issuances, ATM issuances and preferred stock issuances. As of December 31, 2018, we had 400,000,000 shares of common stock and 20,000,000 shares of preferred stock authorized for issuance, of which 372,363,656 shares of common stock and 420,000 shares of preferred stock are currently outstanding.

Holders of shares of our common stock are entitled to receive dividends when, as and if declared by the Board out of funds legally available. The policy of the Board has been to declare cash dividends on a quarterly basis payable on or about the 20th day of February, May, August and November. We have paid quarterly common dividends totaling $0.78, $0.70 and $0.64 per share for the years ended December 31, 2018, 2017 and 2016, respectively. Our Board declared a quarterly common dividend of $0.20 per share, payable on February 20, 2019 to holders of record on February 11, 2019. We have certain debt covenants which could potentially limit the amount of dividends the Company could pay in order to maintain compliance with these covenants. Refer to Note 14, "Long-Term Debt," for more information. As of December 31, 2018, these covenants did not restrict the amount of dividends that were available to be paid.

Dividends paid to preferred shareholders vary based on the series of preferred stock owned. Additional information is provided below. Holders of our shares of common stock are subject to the prior dividend rights of holders of our preferred stock or the depositary shares representing such preferred stock outstanding, and if full dividends have not been declared and paid on all outstanding shares of preferred stock in any dividend period, no dividend may be declared or paid or set aside for payment on our common stock.

Common and preferred stock activity for 2018 and 2017 is described further below:

ATM Program and Forward Sale Agreements. On May 3, 2017, we entered into four separate equity distribution agreements, pursuant to which we were able to sell up to an aggregate of $500.0 million of our common stock.

On November 13, 2017, under the ATM program, we executed a forward agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. On November 6, 2018 the forward agreement was settled for $26.43 per share, resulting in $167.7 million of net proceeds. The equity distribution agreements entered into on May 3, 2017 expired December 31, 2018.

On November 1, 2018, we entered into five separate equity distribution agreements, pursuant to which we may sell, from time to time, up to an aggregate of $500.0 million of our common stock.

On December 6, 2018, under the ATM program described immediately above, we executed a forward agreement which allows us to issue a fixed number of shares at a price to be settled in the future. From December 6, 2018 to December 10, 2018, 4,708,098 shares were borrowed from third parties and sold by the dealer at a weighted average price of $26.55 per share. We may settle this agreement in shares, cash, or net shares by December 6, 2019. Had we settled all the shares under the forward agreement at December 31, 2018, we would have received approximately $124.8 million, based on a net price of $26.51 per share.

As of December 31, 2018, the ATM program (including the impacts of the aforementioned forward sales agreement) had approximately $309.4 million of equity available for issuance. The program expires on December 31, 2020.

The following table summarizes our activity under the ATM program:

Year Ending December 31,		**2018**		2017		2016
Number of shares issued		**8,883,014**		11,931,376		—
Average price per share	**$**	**26.85**	$	26.58	$	—
Proceeds, net of fees (*in millions)*	**$**	**232.5**	$	314.7	$	—

Private Placement of Common Stock. On May 4, 2018, we completed the sale of 24,964,163 shares of $0.01 par value common stock at a price of $24.28 per share in a private placement to selected institutional and accredited investors. The private placement resulted in $606.0 million of gross proceeds or $599.6 million of net proceeds, after deducting commissions and sale expenses. The common stock issued in connection with the private placement was registered on Form S-1, filed with the SEC on May 11, 2018.

Preferred Stock. On June 11, 2018, we completed the sale of 400,000 shares of 5.650% Series A Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (the "Series A Preferred Stock") at a price of $1,000 per share. The transaction resulted in $400.0 million of gross proceeds or $393.9 million of net proceeds, after deducting commissions and sale expenses. The Series A Preferred Stock was issued in a private placement pursuant to SEC Rule 144A. On December 13, 2018, we filed a registration statement with the SEC enabling holders to exchange their unregistered shares of Series A Preferred Stock for publicly registered shares with substantially identical terms.

Proceeds from the issuance of the Series A Preferred Stock were used to pay a portion of the notes tendered in June 2018 and the redemption of the remaining notes in July 2018. See Note 14, “Long-term Debt” for additional information regarding the tender offer and redemption.

Dividends on the Series A Preferred Stock accrue and are cumulative from the date the shares of Series A Preferred Stock were originally issued to, but not including, June 15, 2023 at a rate of 5.650% per annum of the $1,000 liquidation preference per share. On and after June 15, 2023, dividends on the Series A Preferred Stock will accumulate for each five year period at a percentage of the $1,000 liquidation preference equal to the five-year U.S. Treasury Rate plus (i) in respect of each five year period commencing on or after June 15, 2023 but before June 15, 2043, a spread of 2.843% (the “Initial Margin”), and (ii) in respect of each five year period commencing on or after June 15, 2043, the Initial Margin plus 1.000%. The Series A Preferred Stock may be redeemed by us at our option on June 15, 2023, or on each date falling on the fifth anniversary thereafter, or in connection with a ratings event (as defined in the Certificate of Designation of the Series A Preferred Stock).

Holders of Series A Preferred Stock generally have no voting rights, except for limited voting rights with respect to (i) potential amendments to our certificate of incorporation that would have a material adverse effect on the existing preferences, rights, powers or duties of the Series A Preferred Stock, (ii) the creation or issuance of any security ranking on a parity with the Series A Preferred

Stock if the cumulative dividends payable on then outstanding Series A Preferred Stock are in arrears, or (iii) the creation or issuance of any security ranking senior to the Series A Preferred Stock. The Series A Preferred Stock does not have a stated maturity and is not subject to mandatory redemption or any sinking fund. The Series A Preferred Stock will remain outstanding indefinitely unless repurchased or redeemed by us. Any such redemption would be effected only out of funds legally available for such purposes and will be subject to compliance with the provisions of our outstanding indebtedness.

On December 5, 2018, we completed the sale of 20,000,000 depositary shares with an aggregate liquidation preference of $500,000,000 under the Company's registration statement on Form S-3. Each depositary share represents 1/1,000th ownership interest in a share of our 6.500% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock, liquidation preference $25,000 per share (equivalent to $25 per depositary share) (the "Series B Preferred Stock). The transaction resulted in $500.0 million of gross proceeds or $486.1 million of net proceeds, after deducting commissions and sale expenses.

Dividends on the Series B Preferred Stock accrue and are cumulative from the date the shares of Series B Preferred Stock were originally issued to, but not including, March 15, 2024 at a rate of 6.500% per annum of the $25,000 liquidation preference per share. On and after March 15, 2024, dividends on the Series B Preferred Stock will accumulate for each five year period at a percentage of the $25,000 liquidation preference equal to the five-year U.S. Treasury Rate plus (i) in respect of each five year period commencing on or after March 15, 2024 but before March 15, 2044, a spread of 3.632% (the "Initial Margin"), and (ii) in respect of each five year period commencing on or after March 15, 2044, the Initial Margin plus 1.000%. The Series B Preferred Stock may be redeemed by us at our option on March 15, 2024, or on each date falling on the fifth anniversary thereafter, or in connection with a ratings event (as defined in the Certificate of Designation of the Series B Preferred Stock).

On December 27, 2018, we issued 20,000 shares of "Series B-1 Preferred Stock", par value $0.01 per share, liquidation preference $0.01 per share ("Series B-1 Preferred Stock"), as a distribution with respect to the Series B Preferred Stock. As a result, each of the depositary shares issued on December 5, 2018 now represents a 1/1,000th ownership interest in a share of Series B Preferred Stock and a 1/1,000th ownership interest in a share of Series B-1 Preferred Stock. The Company issued the Series B-1 Preferred Stock to enhance the voting rights of the Series B Preferred Stock to comply with the minimum voting rights policy of the New York Stock Exchange. The Series B-1 Preferred Stock is paired with the Series B Preferred Stock and may not be transferred, redeemed or repurchased except in connection with the simultaneous transfer, redemption or repurchase of a like number of shares of the underlying Series B Preferred Stock.

Holders of Series B Preferred Stock generally have no voting rights, except for limited voting rights with respect to (i) potential amendments to our certificate of incorporation that would have a material adverse effect on the existing preferences, rights, powers or duties of the Series B Preferred Stock, (ii) the creation or issuance of any security ranking on a parity with the Series B Preferred Stock if the cumulative dividends payable on then outstanding Series B Preferred Stock are in arrears, or (iii) the creation or issuance of any security ranking senior to the Series B Preferred Stock. In addition, if and whenever dividends on any shares of Series B Preferred Stock shall not have been declared and paid for at least six dividend periods, whether or not consecutive, the number of directors then constituting our Board of Directors shall automatically be increased by two until all accumulated and unpaid dividends on the Series B Preferred Stock shall have been paid in full, and the holders of Series B-1 Preferred Stock, voting as a class together with the holders of any outstanding securities ranking on a parity with the Series B-1 Preferred Stock and having like voting rights that are exercisable at the time and entitled to vote thereon, shall be entitled to elect the two additional directors. The Series B Preferred Stock does not have a stated maturity and is not subject to mandatory redemption or any sinking fund. The Series B Preferred Stock will remain outstanding indefinitely unless repurchased or redeemed by us. Any such redemption would be effected only out of funds legally available for such purposes and will be subject to compliance with the provisions of our outstanding indebtedness.

13. Share-Based Compensation

Our stockholders most recently approved the NiSource Inc. 2010 Omnibus Incentive Plan ("Omnibus Plan") at the Annual Meeting of Stockholders held on May 12, 2015. The Omnibus Plan provides for awards to employees and non-employee directors of incentive and nonqualified stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock-based awards and supersedes the long-term incentive plan approved by stockholders on April 13, 1994 ("1994 Plan") and the Director Stock Incentive Plan ("Director Plan"). The Omnibus Plan provides that the number of shares of common stock of NiSource available for awards is 8,000,000 plus the number of shares subject to outstanding awards that expire or terminate for any reason that were granted under either the 1994 Plan or the Director Plan, plus the number of shares that were awarded as a result of the Separation-related adjustments (discussed below). At December 31, 2018, there were 3,793,557 shares reserved for future awards under the Omnibus Plan.

We recognized stock-based employee compensation expense of $15.2 million, $15.3 million and $15.1 million, during 2018, 2017 and 2016, respectively, as well as related tax benefits of $3.7 million, $5.9 million and $5.8 million, respectively. Additionally, we adopted ASU 2016-09 in the third quarter of 2016. We recognized related excess tax benefits from the distribution of vested share-based employee compensation of $1.0 million, $4.4 million and $7.2 million in 2018, 2017 and 2016, respectively.

As of December 31, 2018, the total remaining unrecognized compensation cost related to non-vested awards amounted to $16.6 million, which will be amortized over the weighted-average remaining requisite service period of 1.7 years.

Restricted Stock Units and Restricted Stock. In 2018, we granted 158,689 restricted stock units and shares of restricted stock to employees, subject to service conditions. The total grant date fair value of the restricted stock units and shares of restricted stock was $3.5 million, based on the average market price of our common stock at the date of each grant less the present value of any dividends not received during the vesting period, which will be expensed over the vesting period which is generally three years. As of December 31, 2018, 154,799 non-vested restricted stock units and shares of restricted stock granted in 2018 were outstanding as of December 31, 2018.

Restricted stock units and shares of restricted stock granted to employees in 2017 and 2016 were immaterial.

If an employee terminates employment before the service conditions lapse under the 2016, 2017 or 2018 awards due to (1) Retirement or Disability (as defined in the award agreement), or (2) death, the service conditions will lapse on the date of such termination with respect to a pro rata portion of the restricted stock units and shares of restricted stock based upon the percentage of the service period satisfied between the grant date and the date of the termination of employment. In the event of a change in control (as defined in the award agreement), all unvested shares of restricted stock and restricted stock units awarded will immediately vest upon termination of employment occurring in connection with a change in control. Termination due to any other reason will result in all unvested shares of restricted stock and restricted stock units awarded being forfeited effective on the employee's date of termination.

(shares)	Restricted Stock Units	Weighted Average Award Date Fair Value Per Unit ($)
Non-vested at December 31, 2017	698,126	15.09
Granted	158,689	21.94
Forfeited	(6,890)	21.42
Vested	(671,247)	14.91
Non-vested at December 31, 2018	**178,678**	**21.82**

Performance Shares. In 2018, we awarded 514,338 performance shares subject to service, performance and market conditions. The service conditions for these awards lapse on February 26, 2021. The performance period for the awards is the period beginning January 1, 2018 and ending December 31, 2020. The performance conditions are based on the achievement of one non-GAAP financial measure and additional operational measures as outlined below.

The financial measure is cumulative net operating earnings per share ("NOEPS"), which we define as income from continuing operations adjusted for certain unusual or non-recurring items. The number of cumulative NOEPS shares determined using this measure shall be increased or decreased based on our relative total shareholder return, a market condition which we define as the annualized growth in dividends and share price of a share of our common stock (calculated using a 20 trading day average of our closing price beginning on December 31, 2017 and ending on December 31, 2020) compared to the total shareholder return of a predetermined peer group of companies. A relative shareholder return result within the first quartile will result in an increase to the NOEPS shares of 25% while a relative shareholder return result within the fourth quartile will result in a decrease of 25%. A Monte Carlo analysis was used to value the portion of these awards dependent on market conditions. The grant date fair value of the awards was $9.2 million, based on the average market price of NiSource's common stock at the date of each grant less the present value of dividends not received during the vesting period which will be expensed over the three year requisite service period. As of December 31, 2018, 405,255 of these non-vested performance shares granted in 2018 remained outstanding.

If a threshold level of cumulative NOEPS financial performance is achieved, additional operational measures which we refer to as the customer value index, which consists of five equally weighted areas of focus including safety, customer satisfaction, financial, culture and environmental apply. Each area of focus represents 20% of the customer value index shares and the targets for all areas must be met for these awards to be eligible for 100% payout of these awards. Individual payout percentages for these shares may range from 0%-200% as determined by the compensation committee in its sole discretion. Due to this discretion, these shares are not considered to be granted under ASC 718. The service inception date fair value of the awards was $2.4 million, based on the closing market price of our common stock on the service inception date of each award. This value will be reassessed at each reporting period to be based on our closing market price of our common stock at the reporting period date with adjustments to expense recorded as appropriate. As of December 31, 2018, 93,522 of these awards that were issued in 2018 remained outstanding. The service conditions for these awards lapse on February 28, 2021.

In 2017, we granted 660,750 performance shares subject to service, performance and market conditions. The grant date fair value of the awards was $12.9 million, based on the average market price of our common stock at the date of each grant less the present value of dividends not received during the vesting period which will be expensed over the three year requisite service period. The performance conditions are based on achievement of non-GAAP financial measures similar to those discussed above: cumulative net operating earnings per share for the three-year period ending December 31, 2019 and relative total shareholder return (calculated using a 20 trading day average of our closing price beginning on December 31, 2016 and ending on December 31, 2019). As of December 31, 2018, 579,292 non-vested performance shares granted in 2017 remained outstanding. The service conditions for these awards lapse on February 28, 2020.

In 2016, we granted 647,305 performance shares subject to service, performance and market conditions. The grant date fair value of the awards was $12.6 million, based on the average market price of our common stock at the date of each grant less the present value of dividends not received during the vesting period which will be expensed over the three year requisite service period. Similar to the above grants, performance conditions for these awards are based on achievement of certain non-GAAP financial measures: cumulative net operating earnings per share for the three-year period ending December 31, 2018 and relative total shareholder return (calculated using a 20 trading day average of our closing price beginning on December 31, 2015 and ending on December 31, 2018). As of December 31, 2018, 556,649 non-vested performance shares granted in 2016 remained outstanding. The service conditions for these awards lapse on February 28, 2019.

(shares)	Performance Awards	Weighted Average Grant Date Fair Value Per Unit ($)[1]
Non-vested at December 31, 2017	1,184,773	19.52
Granted	514,338	22.51
Forfeited	(64,393)	26.79
Vested	—	—
Non-vested at December 31, 2018	**1,634,718**	**20.45**

[1]2018 performance shares awarded based on the customer value index are included at reporting date fair value as these awards have not been granted under ASC 718 as discussed above.

Non-employee Director Awards. As of May 11, 2010, awards to non-employee directors may be made only under the Omnibus Plan. Currently, restricted stock units are granted annually to non-employee directors, subject to a non-employee director's election to defer receipt of such restricted stock unit award. The non-employee director's annual award of restricted stock units vest on the first anniversary of the grant date subject to special pro-rata vesting rules in the event of retirement or disability (as defined in the award agreement), or death. The vested restricted stock units are payable as soon as practicable following vesting except as otherwise provided pursuant to the non-employee director's election to defer. Certain restricted stock units remain outstanding from the Director Plan. All such awards are fully vested and shall be distributed to the directors upon their separation from the Board.

As of December 31, 2018, 142,414 restricted stock units are outstanding to non-employee directors under either the Omnibus Plan or the Director Plan. Of this amount, 53,422 restricted stock units are unvested and expected to vest.

401(k) Match, Profit Sharing and Company Contribution. We have a voluntary 401(k) savings plan covering eligible employees that allows for periodic discretionary matches as a percentage of each participant's contributions payable in cash for nonunion employees and generally payable in shares of NiSource common stock for union employees, subject to collective bargaining. We also have a retirement savings plan that provides for discretionary profit sharing contributions similarly payable in cash or shares of NiSource common stock to eligible employees based on earnings results; and eligible employees hired after January 1, 2010 receive a non-elective company contribution of 3% of eligible pay similarly payable in cash or shares of NiSource common stock.

For the years ended December 31, 2018, 2017 and 2016, we recognized 401(k) match, profit sharing and non-elective contribution expense of $37.6 million, $37.6 million and $32.3 million, respectively.

14. Long-Term Debt

Our long-term debt as of December 31, 2018 and 2017 is as follows:

Long-term debt type	Maturity as of December 31, 2018	Weighted average interest rate (%)	Outstanding balance as of December 31, *(in millions)* 2018	2017
Senior notes:				
NiSource	March 2018	6.40%	—	275.1
NiSource	January 2019	6.80%	—	255.1
NiSource	September 2020	5.45%	—	325.1
NiSource	December 2021	4.45%	**63.6**	63.6
NiSource	March 2022	6.13%	—	180.0
NiSource	November 2022	2.65%	**500.0**	500.0
NiSource	February 2023	3.85%	**250.0**	250.0
NiSource	June 2023	3.65%	**350.0**	—
NiSource	November 2025	5.89%	**265.0**	265.0
NiSource	May 2027	3.49%	**1,000.0**	1,000.0
NiSource	December 2027	6.78%	**3.0**	3.0
NiSource	December 2040	6.25%	**250.0**	250.0
NiSource	June 2041	5.95%	**400.0**	400.0
NiSource	February 2042	5.80%	**250.0**	250.0
NiSource	February 2043	5.25%	**500.0**	500.0
NiSource	February 2044	4.80%	**750.0**	750.0
NiSource	February 2045	5.65%	**500.0**	500.0
NiSource	May 2047	4.38%	**1,000.0**	1,000.0
NiSource	March 2048	3.95%	**750.0**	750.0
Total senior notes			**$ 6,831.6**	$ 7,516.9
Medium term notes:				
NiSource	April 2022 to May 2027	7.99%	**$ 49.0**	$ 49.0
NIPSCO	August 2022 to August 2027	7.61%	**68.0**	68.0
Columbia of Massachusetts	December 2025 to February 2028	6.30%	**40.0**	40.0
Total medium term notes			**$ 157.0**	$ 157.0
Capital leases:				
NIPSCO	May 2018	3.95%	**$ —**	$ 3.8
NiSource Corporate Services	January 2019 to October 2022	3.68%	**11.6**	1.4
Columbia of Ohio	October 2021 to June 2038	6.33%	**91.5**	88.5
Columbia of Virginia	July 2029 to December 2037	7.12%	**15.2**	5.2
Columbia of Kentucky	May 2027	3.79%	**0.3**	0.4
Columbia of Pennsylvania	August 2027 to June 2036	5.42%	**30.0**	31.0
Columbia of Massachusetts	December 2033 to November 2043	5.48%	**45.7**	22.8
Total capital leases			**194.3**	153.1
Pollution control bonds - NIPSCO	April 2019	5.85%	**41.0**	41.0
Unamortized issuance costs and discounts			**(68.5)**	$ (71.5)
Total Long-Term Debt			**$ 7,155.4**	$ 7,796.5

Details of our 2018 long-term debt related activity are summarized below:

- On March 15, 2018, we redeemed $275.1 million of 6.40% senior unsecured notes at maturity.
- In June 2018, we executed a tender offer for $209.0 million of outstanding notes consisting of a combination of our 6.80% notes due 2019, 5.45% notes due 2020, and 6.125% notes due 2022. In conjunction with the debt retired, we recorded a $12.5 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums.
- On June 11, 2018, we closed our private placement of $350.0 million of 3.65% senior unsecured notes maturing in 2023 which resulted in approximately $346.6 million of net proceeds after deducting commissions and expenses. We used the net proceeds from this private placement to pay a portion of the redemption price for the notes subject to the tender offer described above.
- In July 2018, we redeemed $551.1 million of outstanding notes representing the remainder of our 6.80% notes due 2019, 5.45% notes due 2020 and 6.125% notes due 2022. During the third quarter of 2018, we recorded a $33.0 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums.

Details of our 2017 long-term debt related activity are summarized below:

- On March 27, 2017, we redeemed $30.0 million of 7.86% and $2.0 million of 7.85% medium-term notes at maturity.
- On April 3, 2017, we redeemed $12.0 million of 7.82%, $10.0 million of 7.92%, $2.0 million of 7.93% and $1.0 million of 7.94% medium-term notes at maturity.
- On May 22, 2017, we closed our placement of $2.0 billion in aggregate principal amount of our senior notes, comprised of $1.0 billion of 3.49% senior notes due 2027 and $1.0 billion of 4.375% senior notes due 2047. Related to this placement, we settled $950.0 million of aggregate notional value forward-starting interest rate swaps, originally entered into to mitigate interest risk associated with the planned issuance of these notes. Refer to Note 9, "Risk Management Activities," for additional information.
- During the second quarter of 2017, we executed a tender offer for $990.7 million of outstanding notes consisting of a combination of our 6.40% notes due 2018, 6.80% notes due 2019, 5.45% notes due 2020, and 6.125% notes due 2022. In conjunction with the debt retired, we recorded a $111.5 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums.
- On June 12, 2017, NIPSCO redeemed $22.5 million of 7.59% medium-term notes at maturity.
- On July 1, 2017, NIPSCO redeemed $55.0 million of 5.70% pollution control bonds at maturity.
- On August 4, 2017, NIPSCO redeemed $5.0 million of 7.02% medium-term notes at maturity.
- On September 14, 2017, we closed our placement of $750.0 million of 3.95% senior notes due 2048. Related to this placement, we settled $750.0 million of aggregate notional value treasury lock agreements, originally entered into to mitigate the interest risk associated with the planned issuance of these notes. Refer to Note 9, "Risk Management Activities," for additional information.
- On September 15, 2017, we redeemed $210.4 million of 5.25% senior unsecured notes at maturity.
- On November 17, 2017, we closed our placement of $500.0 million of 2.65% senior notes due 2022 to repay a $500.0 million variable-rate term loan due March 29, 2019. Related to this placement, we settled $250.0 million of aggregate notional value treasury lock agreements originally entered into to mitigate the interest risk associated with the planned issuance of these notes. Refer to Note 9, “Risk Management Activities,” for additional information.

See Note 18-A, "Contractual Obligations," for the outstanding long-term debt maturities at December 31, 2018.

Unamortized debt expense, premium and discount on long-term debt applicable to outstanding bonds are being amortized over the life of such bonds.

We are subject to a financial covenant under our revolving credit facility which requires us to maintain a debt to capitalization ratio that does not exceed 70%. A similar covenant in a 2005 private placement note purchase agreement requires us to maintain a debt to capitalization ratio that does not exceed 75%. As of December 31, 2018, the ratio was 61.4%.

We are also subject to certain other non-financial covenants under the revolving credit facility. Such covenants include a limitation on the creation or existence of new liens on our assets, generally exempting liens on utility assets, purchase money security interests, preexisting security interests and an additional subset of assets equal to $150 million. An asset sale covenant generally restricts the sale, conveyance, lease, transfer or other disposition of our assets to those dispositions that are for a price not materially less than fair market of such assets, that would not materially impair our ability to perform obligations under the revolving credit facility, and that together with all other such dispositions, would not have a material adverse effect. The covenant also restricts dispositions to no more than 10% of our consolidated total assets on December 31, 2015. The revolving credit facility also includes a cross-default provision, which triggers an event of default under the credit facility in the event of an uncured payment default relating to any indebtedness of us or any of our subsidiaries in a principal amount of $50.0 million or more.

Our indentures generally do not contain any financial maintenance covenants. However, our indentures are generally subject to cross-default provisions ranging from uncured payment defaults of $5 million to $50 million, and limitations on the incurrence of liens on our assets, generally exempting liens on utility assets, purchase money security interests, preexisting security interests and an additional subset of assets capped at 10% of our consolidated net tangible assets.

15. Short-Term Borrowings

We generate short-term borrowings from our revolving credit facility, commercial paper program, letter of credit issuances, accounts receivable transfer programs and term loan borrowings. Each of these borrowing sources is described further below.

We maintain a revolving credit facility to fund ongoing working capital requirements, including the provision of liquidity support for our commercial paper program, provide for issuance of letters of credit and also for general corporate purposes. Our revolving credit facility has a program limit of $1.85 billion and is comprised of a syndicate of banks led by Barclays. At December 31, 2018 and 2017, we had no outstanding borrowings under this facility.

Our commercial paper program has a program limit of up to $1.5 billion with a dealer group comprised of Barclays, Citigroup, Credit Suisse and Wells Fargo. At December 31, 2018 and 2017, we had $978.0 million and $869.0 million, respectively, of commercial paper outstanding.

As of December 31, 2018 and 2017, we had issued $10.2 million and $11.1 million of stand-by letters of credit, respectively. All stand-by letters of credit were under the revolving credit facility.

Transfers of accounts receivable are accounted for as secured borrowings resulting in the recognition of short-term borrowings on the Consolidated Balance Sheets in the amount of $399.2 million and $336.7 million as of December 31, 2018 and 2017, respectively. Refer to Note 17, "Transfers of Financial Assets," for additional information.

On April 18, 2018, we entered into a multiple-draw $600.0 million term loan agreement with a syndicate of banks led by MUFG Bank, Ltd. The term loan matures April 17, 2019, at which point any and all outstanding borrowings under the agreement are due. Interest charged on borrowings depends on the variable rate structure we elected at the time of each borrowing. Under the agreement, we borrowed an initial tranche of $150.0 million on April 18, 2018 with an interest rate of LIBOR plus 50 basis points and a second tranche of $450.0 million on May 31, 2018 with an interest rate of LIBOR plus 55 basis points.

Short-term borrowings were as follows:

At December 31, *(in millions)*		**2018**		2017
Commercial Paper weighted average interest rate of 2.96% and 1.97% at December 31, 2018 and 2017, respectively.	**$**	**978.0**	$	869.0
Accounts receivable securitization facility borrowings		**399.2**		336.7
Term loan weighted-average interest rate of 3.07% at December 31, 2018		**600.0**		—
Total Short-Term Borrowings	**$**	**1,977.2**	$	1,205.7

Other than for the term loan and certain commercial paper borrowings, cash flows related to the borrowings and repayments of the items listed above are presented net in the Statements of Consolidated Cash Flows as their maturities are less than 90 days.

16. Fair Value

A. Fair Value Measurements

Recurring Fair Value Measurements. The following tables present financial assets and liabilities measured and recorded at fair value on our Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2018 and December 31, 2017:

Recurring Fair Value Measurements December 31, 2018 (*in millions*)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2018
Assets				
Risk management assets	$ —	$ 24.0	$ —	$ 24.0
Available-for-sale securities	—	138.3	—	138.3
Total	**$ —**	**$ 162.3**	**$ —**	**$ 162.3**
Liabilities				
Risk management liabilities	$ —	$ 51.7	$ —	$ 51.7
Total	**$ —**	**$ 51.7**	**$ —**	**$ 51.7**

Recurring Fair Value Measurements December 31, 2017 (*in millions*)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2017
Assets				
Risk management assets	$ —	$ 21.1	$ —	$ 21.1
Available-for-sale securities	—	133.9	—	133.9
Total	**$ —**	**$ 155.0**	**$ —**	**$ 155.0**
Liabilities				
Risk management liabilities	$ —	$ 71.4	$ 0.3	$ 71.7
Total	**$ —**	**$ 71.4**	**$ 0.3**	**$ 71.7**

Risk management assets and liabilities include interest rate swaps, exchange-traded NYMEX futures and NYMEX options and non-exchange-based forward purchase contracts. When utilized, exchange-traded derivative contracts are based on unadjusted quoted prices in active markets and are classified within Level 1. These financial assets and liabilities are secured with cash on deposit with the exchange; therefore, nonperformance risk has not been incorporated into these valuations. Certain non-exchange-traded derivatives are valued using broker or over-the-counter, on-line exchanges. In such cases, these non-exchange-traded derivatives are classified within Level 2. Non-exchange-based derivative instruments include swaps, forwards, options and treasury lock agreements. In certain instances, these instruments may utilize models to measure fair value. We use a similar model to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability and market-corroborated inputs, (i.e., inputs derived principally from or corroborated by observable market data by correlation or other means). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized within Level 2. Certain derivatives trade in less active markets with a lower availability of pricing information and models may be utilized in the valuation. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized within Level 3. Credit risk is considered in the fair value calculation of derivative instruments that are not exchange-traded. Credit exposures are adjusted to reflect collateral agreements which reduce exposures. As of

December 31, 2018 and 2017, there were no material transfers between fair value hierarchies. Additionally, there were no changes in the method or significant assumptions used to estimate the fair value of our financial instruments.

We have entered into forward-starting interest rate swaps to hedge the interest rate risk on coupon payments of forecasted issuances of long-term debt. These derivatives are designated as cash flow hedges. Credit risk is considered in the fair value calculation of each agreement. As they are based on observable data and valuations of similar instruments, the hedges are categorized within Level 2 of the fair value hierarchy. There was no exchange of premium at the initial date of the swaps and we can settle the contracts at any time. For additional information, see Note 9, "Risk Management Activities."

NIPSCO has entered into long-term forward natural gas purchase instruments that range from five to ten years to lock in a fixed price for its natural gas customers. We value these contracts using a pricing model that incorporates market-based information when available, as these instruments trade less frequently and are classified within Level 2 of the fair value hierarchy. For additional information see Note 9, “Risk Management Activities.”

Available-for-sale securities are investments pledged as collateral for trust accounts related to our wholly-owned insurance company. Available-for-sale securities are included within “Other investments” in the Consolidated Balance Sheets. We value U.S. Treasury, corporate debt and mortgage-backed securities using a matrix pricing model that incorporates market-based information. These securities trade less frequently and are classified within Level 2. Total unrealized gains and losses from available-for-sale securities are included in other comprehensive income. The amortized cost, gross unrealized gains and losses and fair value of available-for-sale securities at December 31, 2018 and 2017 were:

December 31, 2018 *(in millions)*	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
Available-for-sale securities				
U.S. Treasury debt securities	$ 23.6	$ 0.1	$ (0.1)	$ 23.6
Corporate/Other debt securities	117.7	0.4	(3.4)	114.7
Total	**$ 141.3**	**$ 0.5**	**$ (3.5)**	**$ 138.3**

December 31, 2017 *(in millions)*	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
Available-for-sale securities				
U.S. Treasury debt securities	$ 26.9	$ —	$ (0.1)	$ 26.8
Corporate/Other debt securities	106.8	0.9	(0.6)	107.1
Total	**$ 133.7**	**$ 0.9**	**$ (0.7)**	**$ 133.9**

Realized gains and losses on available-for-sale securities were immaterial for the year-ended December 31, 2018 and 2017.

The cost of maturities sold is based upon specific identification. At December 31, 2018, approximately $2.9 million of U.S. Treasury debt securities and approximately $2.7 million of Corporate/Other debt securities have maturities of less than a year.

There are no material items in the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis for the years ended December 31, 2018 and 2017.

Non-recurring Fair Value Measurements. There were no significant non-recurring fair value measurements recorded during the twelve months ended December 31, 2018.

B. **Other Fair Value Disclosures for Financial Instruments**. The carrying amount of cash and cash equivalents, restricted cash, notes receivable, customer deposits and short-term borrowings is a reasonable estimate of fair value due to their liquid or short-term nature. Our long-term borrowings are recorded at historical amounts.

The following method and assumptions were used to estimate the fair value of each class of financial instruments.

Long-term debt. The fair value of outstanding long-term debt is estimated based on the quoted market prices for the same or similar securities. Certain premium costs associated with the early settlement of long-term debt are not taken into consideration in determining fair value. These fair value measurements are classified within Level 2 of the fair value hierarchy. For the years ended December 31, 2018 and 2017, there was no change in the method or significant assumptions used to estimate the fair value of long-term debt.

The carrying amount and estimated fair values of these financial instruments were as follows:

At December 31, *(in millions)*	**Carrying Amount 2018**	**Estimated Fair Value 2018**	Carrying Amount 2017	Estimated Fair Value 2017
Long-term debt (including current portion)	**$ 7,155.4**	**$ 7,228.3**	$ 7,796.5	$ 8,603.4

17. Transfers of Financial Assets

Columbia of Ohio, NIPSCO and Columbia of Pennsylvania each maintain a receivables agreement whereby they transfer their customer accounts receivables to third party financial institutions through wholly-owned and consolidated special purpose entities. The three agreements expire between March 2019 and October 2019 and may be further extended if mutually agreed to by the parties thereto.

All receivables transferred to third parties are valued at face value, which approximates fair value due to their short-term nature. The amount of the undivided percentage ownership interest in the accounts receivables transferred is determined in part by required loss reserves under the agreements.

Transfers of accounts receivable are accounted for as secured borrowings resulting in the recognition of short-term borrowings on the Consolidated Balance Sheets. As of December 31, 2018, the maximum amount of debt that could be recognized related to our accounts receivable programs is $455.0 million.

The following table reflects the gross receivables balance and net receivables transferred as well as short-term borrowings related to the securitization transactions as of December 31, 2018 and 2017:

At December 31, *(in millions)*	**2018**	2017
Gross Receivables	**$ 694.4**	$ 635.3
Less: Receivables not transferred	**295.2**	298.6
Net receivables transferred	**$ 399.2**	$ 336.7
Short-term debt due to asset securitization	**$ 399.2**	$ 336.7

During 2018 and 2017, $62.5 million and $26.7 million, respectively, was recorded as cash flows from financing activities related to the change in short-term borrowings due to securitization transactions. Fees associated with the securitization transactions were $2.6 million, $2.5 million and $2.3 million for the years ended December 31, 2018, 2017 and 2016, respectively. We remain responsible for collecting on the receivables securitized and the receivables cannot be transferred to another party.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

18. Other Commitments and Contingencies

A. Contractual Obligations. We have certain contractual obligations requiring payments at specified periods. The obligations include long-term debt, lease obligations, energy commodity contracts and obligations for various services including pipeline capacity and outsourcing of IT services. The total contractual obligations in existence at December 31, 2018 and their maturities were:

(in millions)	Total	2019	2020	2021	2022	2023	After
Long-term debt [1]	$ 7,029.6	$ 41.0	$ —	$ 63.6	$ 530.0	$ 600.0	$ 5,795.0
Capital leases[2]	322.4	23.0	22.5	22.6	22.1	19.8	212.4
Interest payments on long-term debt	6,311.7	319.8	318.6	318.6	315.0	289.0	4,750.7
Operating leases[3]	45.9	11.0	7.3	6.1	4.2	2.8	14.5
Energy commodity contracts	154.3	99.2	55.1	—	—	—	—
Service obligations:							
Pipeline service obligations	3,566.7	592.3	487.7	450.5	437.5	260.8	1,337.9
IT service obligations	211.0	68.3	60.0	47.1	35.6	—	—
Other service obligations	86.7	33.5	43.6	9.6	—	—	—
Other liabilities	24.2	24.2	—	—	—	—	—
Total contractual obligations	$ 17,752.5	$ 1,212.3	$ 994.8	$ 918.1	$ 1,344.4	$ 1,172.4	$ 12,110.5

[1] Long-term debt balance excludes unamortized issuance costs and discounts of $68.5 million.
[2] Capital lease payments shown above are inclusive of interest totaling $114.6 million.
[3] Operating lease balances do not include amounts for fleet leases that can be renewed beyond the initial lease term. The Company anticipates renewing the leases beyond the initial term, but the anticipated payments associated with the renewals do not meet the definition of expected minimum lease payments and therefore are not included above. Expected payments are $26.7 million in 2019, $22.4 million in 2020, $16.6 million in 2021, $12.3 million in 2022, $9.3 million in 2023 and $8.8 million thereafter.

Operating and Capital Lease Commitments. We lease assets in several areas of our operations including fleet vehicles and equipment, rail cars for coal delivery and certain operations centers. Payments made in connection with operating leases were $49.1 million in 2018, $49.5 million in 2017 and $52.0 million in 2016, and are primarily charged to operation and maintenance expense as incurred. Capital lease assets and related accumulated depreciation included in the Consolidated Balance Sheets were $213.9 million and $37.1 million at December 31, 2018, and $171.2 million and $32.4 million at December 31, 2017, respectively.

Purchase and Service Obligations. We have entered into various purchase and service agreements whereby we are contractually obligated to make certain minimum payments in future periods. Our purchase obligations are for the purchase of physical quantities of natural gas, electricity and coal. Our service agreements encompass a broad range of business support and maintenance functions which are generally described below.

Our subsidiaries have entered into various energy commodity contracts to purchase physical quantities of natural gas, electricity and coal. These amounts represent minimum quantities of these commodities we are obligated to purchase at both fixed and variable prices. To the extent contractual purchase prices are variable, obligations disclosed in the table above are valued at market prices as of December 31, 2018.

In July 2008, the IURC issued an order approving NIPSCO's purchase power agreements with subsidiaries of Iberdrola Renewables, Buffalo Ridge I LLC and Barton Windpower LLC. These agreements provide NIPSCO the opportunity and obligation to purchase up to 100 MW of wind power generated commencing in early 2009. The contracts extend 15 and 20 years, representing 50 MW of wind power each. No minimum quantities are specified within these agreements due to the variability of electricity generation from wind, so no amounts related to these contracts are included in the table above. Upon any termination of the agreements by NIPSCO for any reason (other than material breach by Buffalo Ridge I LLC or Barton Windpower LLC), NIPSCO may be required to pay a termination charge that could be material depending on the events giving rise to termination and the timing of the termination. NIPSCO began purchasing wind power in April 2009.

We have pipeline service agreements that provide for pipeline capacity, transportation and storage services. These agreements, which have expiration dates ranging from 2019 to 2045, require us to pay fixed monthly charges.

NIPSCO has contracts with three major rail operators providing for coal transportation services for which there are certain minimum payments. These service contracts extend for various periods through 2021.

In May and June 2017, we executed agreements with three separate IT service providers. The new agreements have terms ending at various dates throughout 2022.

Related to the NTSB's safety recommendations issued on November 14, 2018 (see "- C. Legal Proceedings" for further detail), we committed to the installation of over-pressurization protection devices at all of the remaining low pressure systems in our operating footprint. This installation is expected to result in a capital investment of approximately $150 million. This amount is not included in the table above.

B. Guarantees and Indemnities. We and certain subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries as part of normal business. Such agreements include guarantees and stand-by letters of credit. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. At December 31, 2018 and 2017, we had issued stand-by letters of credit of $10.2 million and $11.1 million, respectively, for the benefit of third parties.

C. Legal Proceedings.

On September 13, 2018, a series of fires and explosions occurred in Lawrence, Andover and North Andover, Massachusetts related to the delivery of natural gas by Columbia of Massachusetts. The Greater Lawrence Incident resulted in one fatality and a number of injuries, damaged multiple homes and businesses, and caused the temporary evacuation of significant portions of each municipality. The Massachusetts Governor's Office declared a state of emergency, authorizing the Massachusetts DPU to order another utility company to coordinate the restoration of utility services in Lawrence, Andover and North Andover. The incident resulted in the interruption of gas for approximately 7,500 gas meters, the majority of which serve residences and of which approximately 700 serve businesses, and the interruption of other utility service more broadly in the area. Columbia of Massachusetts has replaced the cast iron and bare steel gas pipeline system in the affected area and restored service to nearly all of the gas meters. See " - E. Other Matters - Greater Lawrence Pipeline Replacement" below for more information.

We are subject to inquiries by federal and state government authorities and regulatory agencies regarding the Greater Lawrence Incident. The NTSB, the U.S Attorney's office and the SEC have pending investigations related to the Greater Lawrence Incident, as described below. We are also subject to inquiries from the Massachusetts DPU and the Massachusetts Attorney General's Office. We are cooperating with all inquiries and investigations. The outcomes and impacts of the current investigations and any future investigations that may be commenced related to such inquiries are uncertain at this time.

NTSB Investigation. As noted above, the NTSB is investigating the Greater Lawrence Incident. The parties to the investigation include the PHMSA, the Massachusetts DPU, Columbia of Massachusetts, and police and fire first responders. We are cooperating with the NTSB and have provided information to assist in its ongoing investigation into relevant facts related to the event, the probable cause, and its development of safety recommendations.

According to the preliminary public report that the NTSB issued on October 11, 2018, an over-pressurization of a low pressure gas distribution system occurred that was related to work being done on behalf of Columbia of Massachusetts on a pipeline replacement project in Lawrence. According to the report, sensing lines detected a drop in pressure in a portion of mainline that was being abandoned, causing a regulator to open up and increase pressure in the system to a level that exceeded the maximum allowable operating pressure of the distribution system.

On November 14, 2018, the NTSB issued an urgent safety recommendation report regarding natural gas distribution system project development and review. In its report, the NTSB identified certain factors that it believes contributed to the Greater Lawrence Incident and made safety recommendations. The NTSB recommended that the Commonwealth of Massachusetts eliminate the professional engineer licensure exemption for public utility work and require a professional engineer's seal on public utility engineering drawings, which is now law in Massachusetts. The NTSB also made recommendations to us related to engineering plan and constructability review processes, records and documentation, management of change processes, and control procedures during modifications to gas mains. We are in the process of implementing these recommendations. The NTSB investigation is ongoing. While the NTSB investigation is pending, we are prohibited from disclosing information related to the investigation without approval from the NTSB.

Since the Greater Lawrence Incident, we have identified, and moved ahead with, new steps to enhance system safety and reliability and to safeguard against over-pressurization. Some of these measures have already been completed and others are in process. These Company-wide safety measures will include enhanced measures as called for in the NTSB's recommendations. We have committed to a program to install over-pressurization protection devices on all of our low-pressure systems, the cost of which is described in " - E. Other Matters."

Massachusetts Regulatory and Legislative Matters. The Massachusetts DPU has retained an independent evaluator to conduct a statewide examination of the safety of the natural gas distribution system and the operational and maintenance functions of natural gas companies in the Commonwealth of Massachusetts. Through authority granted by the Massachusetts Governor under the state of emergency, the Chair of the Massachusetts DPU will direct all natural gas distribution companies operating in the Commonwealth to fund the statewide examination. The statewide examination is underway and we are in the process of responding to the evaluator's information requests. The independent evaluator is expected to produce a report with recommendations. The examination is expected to complement, but not duplicate, the NTSB's investigation.

On November 30, 2018, Columbia of Massachusetts entered into a consent order with the Massachusetts DPU in connection with a notice of probable violation issued in March 2018, stemming from a 2016 report. The Division found that Columbia of Massachusetts violated certain pipeline safety regulations related to pressure limiting and regulating stations in Taunton, Massachusetts. As part of the consent order, Columbia of Massachusetts was fined $75,000 and entered into a compliance agreement under which it agreed to take several actions related to its pressure regulator stations within various timeframes, including the adoption of a Pipeline Safety Management System ("SMS"), the American Petroleum Institute's (API) Recommended Practice 1173. Columbia of Massachusetts is complying with the order.

On December 18, 2018, the Massachusetts DPU issued an order requiring Columbia of Massachusetts to enter into an agreement with a Massachusetts-based engineering firm to monitor Columbia of Massachusetts' remaining restoration and recovery work in the Greater Lawrence area. The order requires Columbia of Massachusetts to take measures to ensure that adequate heat and hot water and gas appliances are provided to all affected properties, repave all affected streets, roadways, sidewalks and other areas in accordance with applicable DPU standards and precedents, consult with the affected communities and discuss plans for restoring affected hard or soft surfaces, and replace all gas boilers and furnaces and other gas-fired equipment at affected residences. Under the order, all restoration work beginning in 2019 is required to be completed no later than October 31, 2019, unless an earlier or later date is agreed to with any of the affected communities. We have agreed to complete the work by September 15, 2019. Also, under the order, Columbia of Massachusetts will be required to maintain quantitative measures, which must be verified by officials of the affected communities, to track its progress in completing all of the remaining work. Estimates for the cost of this work are included in the estimated ranges of loss noted below, which is discussed in "- E. Other Matters - Greater Lawrence Incident Restoration" and " - Greater Lawrence Pipeline Replacement" below. Our failure to adhere to any of the requirements in the order may result in penalties of up to $1 million per violation.

Under Massachusetts law, the DPU is authorized to investigate potential violations of pipeline safety regulations and to assess a civil penalty of up to $209,000 for a violation of federal pipeline safety regulations. A separate violation occurs for each day of violation up to $2.1 million for a related series of violations. The Massachusetts DPU also is authorized to investigate potential violations of the Columbia of Massachusetts emergency response plan and to assess penalties of up to $250,000 per violation, or up to $20 million per related series of violations. Further, as a result of the declaration of emergency by the Governor, the DPU is authorized to investigate potential violations of the DPU's operational directives during the restoration efforts and assess penalties of up to $1 million per violation. The timing and outcome of any such investigations are uncertain at this time.

In December 2018, the President of Columbia of Massachusetts testified before a joint state legislative committee on telecommunications, utilities and energy with other industry officials about gas system safety in Massachusetts and regulatory oversight. Increased scrutiny related to these matters, including additional legislative oversight hearings and new legislative proposals, is expected during the current two-year legislative session.

On December 31, 2018, the Massachusetts Governor signed into law legislation requiring a certified professional engineer to review and approve gas pipeline work that could pose a "material risk" to public safety, consistent with the NTSB's recommendation. The Massachusetts DPU has issued interim guidelines and the existing moratorium has been lifted.

U.S. Department of Justice Investigation. The Company and Columbia of Massachusetts are subject to a criminal investigation related to the Greater Lawrence Incident that is being conducted under the supervision of the U.S. Attorney's Office for the District of Massachusetts. The initial grand jury subpoenas were served on the Company and Columbia of Massachusetts on September 24, 2018. The Company and Columbia of Massachusetts are cooperating with the investigation. We are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with any civil or criminal penalties that could be imposed on the Company or Columbia of Massachusetts.

U.S. Congressional Hearing. In November 2018, executives of the Company and Columbia of Massachusetts testified at a U.S. Senate hearing regarding the Greater Lawrence Incident and natural gas pipeline safety. Increased scrutiny related to these matters, including additional federal congressional hearings and new legislative proposals, is expected in 2019.

SEC Investigation. On February 11, 2019, the SEC notified the Company that it is conducting an investigation of the Company related to disclosures made prior to the Greater Lawrence Incident. We intend to cooperate with the investigation.

Private Actions. Various lawsuits, including several purported class action lawsuits, have been filed by various affected residents or businesses in Massachusetts state courts against the Company and/or Columbia of Massachusetts in connection with the Greater Lawrence Incident. A special judge has been appointed to hear all pending and future cases and the class actions will be consolidated into one class action. On January 14, 2019, the special judge granted the parties' joint motion to stay all cases for 90 days to allow mediation. The parties are in the process of filing a request with the special judge to extend this period. The class action lawsuits allege varying causes of action, including those for strict liability for ultra-hazardous activity, negligence, private nuisance, public nuisance, premises liability, trespass, breach of warranty, breach of contract, failure to warn, unjust enrichment, consumer protection act claims, negligent and reckless infliction of emotional distress, and gross negligence, and seek actual compensatory damages, plus treble damages, and punitive damages. Many residents and business owners have submitted individual damage claims to Columbia of Massachusetts. We also have received notice from three parties indicating an intent to assert wrongful death claims. In Massachusetts, punitive damages are available in a wrongful death action upon proof of gross negligence or willful or reckless conduct causing the death. In addition, the Commonwealth of Massachusetts and the municipalities of Lawrence, Andover and North Andover are seeking reimbursement from Columbia of Massachusetts for their respective expenses incurred in connection with the Greater Lawrence Incident. The outcomes and impacts of the private actions are uncertain at this time.

Financial Impact. During the year ended December 31, 2018, we expensed approximately $757 million for estimated third-party claims related to the Greater Lawrence Incident, including, but not limited to, personal injury and property damage claims, damage to infrastructure, business interruption claims, and other damage claims, which include mutual aid payments to other utilities assisting with the restoration effort; gas-fueled appliance replacement, repair and related services for impacted customers; temporary lodging for displaced customers; evacuation expense claims; and claims-related legal fees. We estimate that total costs related to third-party claims resulting from the incident will range from $757 million to $790 million, depending on the final outcome of ongoing reviews and the number, nature, and value of third-party claims. The amounts set forth above do not include non-claims related expenses resulting from the incident or the estimated capital cost of the pipeline replacement, which is set forth in " - E. Other Matters - Greater Lawrence Incident Restoration" and " - Greater Lawrence Pipeline Replacement," respectively, below.

The process for estimating costs associated with third-party claims relating to the Greater Lawrence Incident requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including additional information resulting from the NTSB investigation, management's estimates and assumptions regarding the financial impact of the Greater Lawrence Incident may change. The increase in estimated total costs related to third-party claims from those disclosed in our Form 10-Q for the quarter ended September 30, 2018 resulted primarily from receiving additional information regarding the required scope of the restoration work inside the affected homes and the extended period of time over which the restoration work would take place.

It is not possible at this time to reasonably estimate the total amount of any expenses associated with government investigations and fines, penalties or settlements with governmental authorities, including the Massachusetts DPU and other regulators, that we may incur in connection with the Greater Lawrence Incident. Therefore, the foregoing amounts do not include estimates of the total amount that we may incur for any such fines, penalties or settlements.

Expenses described above are presented within "Operation and maintenance" in our Statements of Consolidated Income.

We maintain liability insurance for damages in the approximate amount of $800 million and property insurance for gas pipelines and other applicable property in the approximate amount of $300 million. Total expenses related to the incident have exceeded the total amount of liability insurance coverage available under our policies. Certain of these expenses may be covered under our property insurance. While we believe that a substantial amount of expenses related to the Greater Lawrence Incident will be covered by insurance, insurers providing property and liability insurance to the Company or Columbia of Massachusetts may raise defenses to coverage under the terms and conditions of the respective insurance policies which contain various exclusions and conditions that could limit the amount of insurance proceeds to the Company or Columbia of Massachusetts. We are not able to estimate the amount of expenses that will not be covered or exceed insurance limits, but these amounts could be material to our financial statements. Certain types of damages, expenses or claimed costs, such as fines or penalties, may be excluded under the policies. An amount of $135 million for insurance recoveries was recorded through December 31, 2018. Of this amount, $5 million was collected during 2018. The remaining insurance receivable balance of $130 million is presented within “Accounts receivable.” To the extent that we are not successful in obtaining insurance recoveries in the amount recorded for such recoveries as of December 31, 2018, it could result in a charge against "Operation and maintenance" expense. We are currently unable to predict the amount and timing of additional future insurance recoveries.

In addition, we are party to certain other claims and legal proceedings arising in the ordinary course of business, none of which is deemed to be individually material at this time. Due to the inherent uncertainty of litigation, there can be no assurance that the resolution of any particular claim or proceeding related to the Greater Lawrence Incident or otherwise would not have a material adverse effect on our results of operations, financial position or liquidity. If one or more of such matters were decided against us, the effects could be material to our results of operations in the period in which we would be required to record or adjust the related liability and could also be material to our cash flows in the periods that we would be required to pay such liability.

D. Environmental Matters. Our operations are subject to environmental statutes and regulations related to air quality, water quality, hazardous waste and solid waste. We believe that we are in substantial compliance with the environmental regulations currently applicable to our operations.

It is management's continued intent to address environmental issues in cooperation with regulatory authorities in such a manner as to achieve mutually acceptable compliance plans. However, there can be no assurance that fines and penalties will not be incurred. Management expects a significant portion of environmental assessment and remediation costs to be recoverable through rates for certain of our companies.

As of December 31, 2018 and 2017, we had recorded a liability of $101.2 million and $111.4 million, respectively, to cover environmental remediation at various sites. The current portion of this liability is included in "Legal and environmental" in the Consolidated Balance Sheets. The noncurrent portion is included in "Other noncurrent liabilities." We recognize costs associated with environmental remediation obligations when the incurrence of such costs is probable and the amounts can be reasonably estimated. The original estimates for remediation activities may differ materially from the amount ultimately expended. The actual future expenditures depend on many factors, including currently enacted laws and regulations, the nature and extent of impact and the method of remediation. These expenditures are not currently estimable at some sites. We periodically adjust our liability as information is collected and estimates become more refined.

Electric Operations' compliance estimates disclosed below are reflective of NIPSCO's Integrated Resource Plan submitted to the IURC on October 31, 2018. See section " - E. Other Matters - NIPSCO 2018 Integrated Resource Plan," below for additional information.

Air

Future legislative and regulatory programs could significantly limit allowed GHG emissions or impose a cost or tax on GHG emissions. Additionally, rules that increase methane leak detection, require emission reductions or impose additional requirements for natural gas facilities could restrict GHG emissions and impose additional costs. NiSource will carefully monitor all GHG reduction proposals and regulations.

CPP and ACE Rules. On October 23, 2015, the EPA issued the CPP to regulate CO_2 emissions from existing fossil-fuel EGUs under section 111(d) of the CAA. The U.S. Supreme Court has stayed implementation of the CPP until litigation is decided on its merits, and the EPA has proposed to repeal the CPP. On August 31, 2018, the EPA published a proposal to replace the CPP with the ACE rule, which establishes guidelines for states to use when developing plans to reduce CO_2 emissions from existing coal-fired EGUs. The proposal would provide states three years after a final rule is issued to develop state-specific plans, and the EPA would have twelve months to act on a complete state plan submittal. Within two years after a finding of failure to submit a complete plan, or disapproval of a state plan, the EPA would issue a federal plan. NIPSCO will continue to monitor this matter and cannot estimate its impact at this time.

Waste

CERCLA. Our subsidiaries are potentially responsible parties at waste disposal sites under the CERCLA (commonly known as Superfund) and similar state laws. Under CERCLA, each potentially responsible party can be held jointly, severally and strictly liable for the remediation costs as the EPA, or state, can allow the parties to pay for remedial action or perform remedial action themselves and request reimbursement from the potentially responsible parties. Our affiliates have retained CERCLA environmental liabilities, including remediation liabilities, associated with certain current and former operations. These liabilities are not material to the Consolidated Financial Statements.

MGP. A program has been instituted to identify and investigate former MGP sites where Gas Distribution Operations subsidiaries or predecessors may have liability. The program has identified 63 such sites where liability is probable. Remedial actions at many of these sites are being overseen by state or federal environmental agencies through consent agreements or voluntary remediation agreements.

We utilize a probabilistic model to estimate our future remediation costs related to MGP sites. The model was prepared with the assistance of a third party and incorporates our experience and general industry experience with remediating MGP sites. We complete an annual refresh of the model in the second quarter of each fiscal year. No material changes to the estimated future remediation costs were noted as a result of the refresh completed as of June 30, 2018. Our total estimated liability related to the facilities subject to remediation was $97.5 million and $106.9 million at December 31, 2018 and 2017, respectively. The liability represents our best estimate of the probable cost to remediate the facilities. We believe that it is reasonably possible that remediation costs could vary by as much as $20 million in addition to the costs noted above. Remediation costs are estimated based on the best available information, applicable remediation standards at the balance sheet date, and experience with similar facilities.

CCRs. On April 17, 2015, the EPA issued a final rule for regulation of CCRs. The rule regulates CCRs under the RCRA Subtitle D, which determines them to be nonhazardous. The rule is implemented in phases and requires increased groundwater monitoring, reporting, recordkeeping and posting of related information to the Internet. The rule also establishes requirements related to CCR management and disposal. The rule will allow NIPSCO to continue its byproduct beneficial use program.

The publication of the CCR rule resulted in revisions to previously recorded legal obligations associated with the retirement of certain NIPSCO facilities. The actual asset retirement costs related to the CCR rule may vary substantially from the estimates used to record the increased asset retirement obligation due to the uncertainty about the compliance strategies that will be used and the preliminary nature of available data used to estimate costs. In addition, to comply with the rule, NIPSCO is incurring capital expenditures to modify its infrastructure and manage CCRs. Capital compliance costs are currently expected to total approximately $193 million. As allowed by the EPA, NIPSCO will continue to collect data over time to determine the specific compliance solutions and associated costs and, as a result, the actual costs may vary.

NIPSCO filed a petition on November 1, 2016 with the IURC seeking approval of the projects and recovery of the costs associated with CCR compliance. On June 9, 2017, NIPSCO filed with the IURC a settlement reached with certain parties regarding the CCR projects and treatment of associated costs. The IURC approved the settlement in an order on December 13, 2017.

Water

ELG. On November 3, 2015, the EPA issued a final rule to amend the ELG and standards for the Steam Electric Power Generating category. The final rule became effective January 4, 2016. Based upon a preliminary study of the November 3, 2015 final rule, capital compliance costs were expected to be approximately $170.0 million. However, NIPSCO does not anticipate material ELG compliance costs based on the preferred option announced as part of NIPSCO's 2018 Integrated Resource Plan (discussed below).

E. Other Matters.

Bailly Generating Station. On February 1, 2018, as previously approved by MISO, NIPSCO commenced a four-month outage of Bailly Generating Station Unit 8 in order to begin work on converting the unit to a synchronous condenser (a piece of equipment designed to maintain voltage to ensure continued reliability on the transmission system). Approximately $15 million of net book value of Unit 8 remained in “Net Utility Plant” as it will remain used and useful after completion of the synchronous condenser, while the remaining net book value of approximately $142 million was reclassified to “Regulatory assets (noncurrent)” on the Consolidated Balance Sheets. On May 31, 2018, Units 7 and 8 were retired from service. These units had a combined generating capacity of approximately 460 MW. As a result of the retirement, the remaining net book value of Unit 7 of approximately $103 million was reclassified to “Regulatory assets (noncurrent)” on the Consolidated Balance Sheets.These amounts continue to be amortized at a rate consistent with their inclusion in customer rates. Refer to Note 8, "Regulatory Matters," for additional information.

NIPSCO Pure Air. NIPSCO had a service agreement with Pure Air, a general partnership between Air Products and Chemicals, Inc. and First Air Partners LP, under which Pure Air provided scrubber services to reduce sulfur dioxide emissions for Units 7 and 8 at the Bailly Generating Station. Payments under this agreement were $8.3 million and $22.0 million for the years ended December 31, 2018 and 2017, respectively.

As discussed above in "Bailly Generating Station," NIPSCO retired the generation station units serviced by Pure Air on May 31, 2018. In December 2016, as allowed by the provisions of the service agreement, NIPSCO provided Pure Air formal notice of intent to terminate the service agreement, effective May 31, 2018. Providing this notice to Pure Air triggered a contract termination liability of $16 million which was recorded in fourth quarter of 2016. In connection with the closure of Bailly Units 7 and 8, NIPSCO paid the termination payment to Pure Air during the second quarter of 2018. Cash flows associated with this payment are presented within operating activities on the Statements of Consolidated Cash Flows.

NIPSCO 2018 Integrated Resource Plan. Multiple factors, but primarily economic ones, including low natural gas prices, advancing cost effective renewable technology and increasing capital and operating costs associated with existing coal plants, have led NIPSCO to conclude in its October 2018 Integrated Resource Plan submission that NIPSCO's current fleet of coal generation facilities will be retired earlier than previous Integrated Resource Plan's had indicated.

The Integrated Resource Plan evaluated demand-side and supply-side resource alternatives to reliably and cost effectively meet NIPSCO customers' future energy requirements over the ensuing 20 years. The preferred option within the Integrated Resource Plan retires R.M. Schahfer Generating Station (Units 14, 15, 17, and 18) by 2023 and Michigan City Generating Station (Unit 12) by 2028. These units represent 2,080 MW of generating capacity, equal to 72% of NIPSCO's remaining generating capacity (and 100% of NIPSCO's remaining coal-fired generating capacity) after the retirement of Bailly Units 7 and 8 discussed above.

The current replacement plan includes renewable sources of energy, including wind, solar, and battery storage to be obtained through a combination of NIPSCO ownership and PPAs.

In January 2019, NIPSCO executed two 20 year PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per MWh. The facilities supplying the energy will have a combined nameplate capacity of approximately 700 MW. NIPSCO's purchase requirement under the PPAs is dependent on satisfactory approval of the PPAs by the IURC. NIPSCO submitted the PPAs to the IURC for approval in February 2019. An IURC order is anticipated in the second quarter of 2019. If approved by the IURC, payments under the PPAs will not begin until the associated generation facilities are constructed by the owner / seller which is expected to be complete by the end of 2020.

Also in January 2019, NIPSCO executed a BTA with a developer to construct a renewable generation facility with a nameplate capacity of approximately 100 MW. Once complete, ownership of the facility would be transferred to a partnership owned by NIPSCO, the developer and an unrelated tax equity partner. The aforementioned partnership structure will result in full NIPSCO ownership after the PTC are monetized from the project (approximately 10 years after the facility goes into service). NIPSCO's purchase requirement under the BTA is dependent on satisfactory approval of the BTA by the IURC and timely completion of construction. The estimated procedural timeline for receiving an IURC order is the same as the aforementioned PPAs with required FERC filings occurring after receiving the IURC order. Construction of the facility is expected to be complete by the end of 2020.

Greater Lawrence Incident Restoration. During the year ended December 31, 2018, we expensed approximately $1,023 million in connection with the Greater Lawrence Incident. Included in this expense is approximately $757 million for estimated third-party claims associated with the incident as described above in " - C. Legal Proceedings." The additional $266 million included in the expense recorded includes certain consulting costs, claims center costs, charitable contributions, labor and related expenses, lodging and meals for employees and contractors, and security costs in connection with the incident. We expect to incur a total of $330 million to $345 million in such incident-related costs, depending on the incurrence of future restoration work. The amounts set forth above do not include the estimated capital cost of the pipeline replacement, which is set forth below. The increase in estimated total incident-related expenses from those disclosed in our Form 10-Q for the quarter ended September 30, 2018 resulted primarily from receiving additional information regarding the extended period of time over which the restoration work would take place, higher than anticipated costs from vendors and increased estimates for non-claims-related legal fees.

We maintain liability insurance for damages in the approximate amount of $800 million and property insurance for gas pipelines and other applicable property in the approximate amount of $300 million. Total expenses related to the incident have exceeded the total amount of liability insurance coverage available under our policies. Certain of these expenses may be covered under our property insurance. While we believe that a substantial amount of expenses related to the Greater Lawrence Incident will be covered by insurance, insurers providing property and liability insurance to the Company or Columbia of Massachusetts may raise defenses to coverage under the terms and conditions of the respective insurance policies which contain various exclusions and conditions that could limit the amount of insurance proceeds to the Company or Columbia of Massachusetts. We are not able to estimate the amount of expenses that will not be covered or exceed insurance limits, but these amounts could be material to our financial statements. Certain types of damages, expenses or claimed costs, such as fines or penalties, may be excluded under the policies. As discussed above in "- C. Legal Proceedings," $135 million of insurance recoveries were recorded through December 31, 2018. Of this amount, $5 million was collected during 2018. We are currently unable to predict the amount and timing of future insurance recoveries. To the extent that we are not successful in obtaining insurance recoveries in the amount recorded for such recoveries as of December 31, 2018, it could result in a charge against "Operation and maintenance" expense.

Costs associated with charitable contributions are presented within "Other, Net" in our Statements of Consolidated Income. All other expenses incurred are presented within "Operation and maintenance." Substantially all of the $292 million liability for third-party claims and other incident-related costs remaining as of December 31, 2018 is presented within current liabilities in our Consolidated Balance Sheets. The remaining insurance receivable balance of $130 million is presented within "Accounts receivable."

Greater Lawrence Pipeline Replacement. In connection with the Greater Lawrence Incident, Columbia of Massachusetts, in cooperation with the Massachusetts Governor's Office, replaced the entire affected 45-mile cast iron and bare steel pipeline system that delivers gas to approximately 7,500 gas meters, the majority of which serve residences and of which approximately 700 serve businesses impacted in the Greater Lawrence Incident. This system was replaced with plastic distribution mains and service lines, as well as enhanced safety features such as pressure regulation and excess flow valves at each premise. At the request of the Massachusetts DPU, which was instructed by the Massachusetts Governor through his executive authority under a state of emergency, Columbia of Massachusetts hired an outside contractor to serve as the Chief Recovery Officer for the Greater Lawrence Incident, responsible for command, control and communications. Columbia of Massachusetts restored gas service to nearly all homes and workplaces in December 2018. With the restoration and recovery efforts now substantially complete, the service of the Chief Recovery Officer is complete and the next phase of the effort is being managed by Columbia of Massachusetts under the third party oversight of a Massachusetts-based engineering firm as set forth above under " - C. Legal Proceedings."

We incurred approximately $167 million of capital spend for the pipeline replacement during 2018. We estimate this replacement work will cost between $220 million and $230 million in total. Columbia of Massachusetts has provided notice to its property insurer of the Greater Lawrence Incident and discussions around the claim and recovery have commenced. The recovery of any capital investment not reimbursed through insurance will be addressed in a future regulatory proceeding. The outcome of such a proceeding is uncertain. In accordance with ASC 980-360, if it becomes probable that a portion of the pipeline replacement cost will not be recoverable through customer rates and an amount can be reasonably estimated, we will reduce our regulated plant balance for the amount of the probable disallowance and record an associated charge to earnings. This could result in a material adverse effect to our financial condition, results of operations and cash flows. Additionally, if a rate order is received allowing recovery of the investment with no or reduced return on investment, a loss on disallowance may be required.

In addition, we have committed to an approximately $150 million capital investment program to install over-pressurization protection devices on all of our low-pressure systems as described above in "-C. Legal Proceedings." These devices operate like circuit-breakers, so that if operating pressure is too high or too low, regardless of the cause, they are designed to immediately shut down gas to the system. The program also includes installing remote monitoring devices on all low-pressure systems, enabling gas control centers to continuously monitor pressure at regulator stations in real time. In addition, we have conducted a field survey of all regulator stations and initiated an engineering review of those regulator stations; we are verifying and enhancing our maps and records of low-pressure regulator stations; and we initiated a process so that our personnel will be present whenever excavation work is being done in close proximity to a regulator station.

19. Accumulated Other Comprehensive Loss

The following table displays the activity of Accumulated Other Comprehensive Loss, net of tax:

(in millions)	Gains and Losses on Securities[1]	Gains and Losses on Cash Flow Hedges[1]	Pension and OPEB Items[1]	Accumulated Other Comprehensive Loss[1]
Balance as of January 1, 2016	**$ (0.5)**	**$ (15.5)**	**$ (19.1)**	**$ (35.1)**
Other comprehensive loss before reclassifications	—	7.1	0.5	7.6
Amounts reclassified from accumulated other comprehensive loss	(0.1)	1.5	1.0	2.4
Net current-period other comprehensive loss	(0.1)	8.6	1.5	10.0
Balance as of December 31, 2016	**$ (0.6)**	**$ (6.9)**	**$ (17.6)**	**$ (25.1)**
Other comprehensive income before reclassifications	0.6	(24.2)	1.9	(21.7)
Amounts reclassified from accumulated other comprehensive loss	0.2	1.7	1.5	3.4
Net current-period other comprehensive income (loss)	0.8	(22.5)	3.4	(18.3)
Balance as of December 31, 2017	**$ 0.2**	**$ (29.4)**	**$ (14.2)**	**$ (43.4)**
Other comprehensive income (loss) before reclassifications	(3.0)	55.8	(4.4)	48.4
Amounts reclassified from accumulated other comprehensive loss	0.4	(33.1)	—	(32.7)
Net current-period other comprehensive income (loss)	(2.6)	22.7	(4.4)	15.7
Reclassification due to adoption of ASU 2018-02 (Refer to Note 2)	—	(6.3)	(3.2)	(9.5)
Balance as of December 31, 2018	**$ (2.4)**	**$ (13.0)**	**$ (21.8)**	**$ (37.2)**

[1]All amounts are net of tax. Amounts in parentheses indicate debits.

20. Other, Net

Year Ended December 31, *(in millions)*	**2018**	2017	2016
Interest Income	**$ 6.6**	$ 4.6	$ 3.4
AFUDC Equity	**14.2**	12.6	11.6
Charitable Contributions[1]	**(45.3)**	(19.9)	(4.5)
Pension and other postretirement non-service cost[2]	**18.0**	(10.6)	(7.9)
Interest rate swap settlement gain[3]	**46.2**	—	—
Miscellaneous	**3.8**	(0.2)	(5.6)
Total Other, net	**$ 43.5**	$ (13.5)	$ (3.0)

[1] Includes $20.7 million related to the Greater Lawrence Incident. See Note 18, "Other Commitments and Contingencies" for additional information.
[2] See Note 11, "Pension and Other Postretirement Benefits" for additional information.
[3] See Note 9, "Risk Management Activities" for additional information.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (continued)

21. Interest Expense, Net

Year Ended December 31, *(in millions)*	**2018**	2017	2016
Interest on long-term debt	**$ 342.2**	$ 354.8	$ 352.3
Interest on short-term borrowings	**31.8**	14.9	9.2
Debt discount/cost amortization	**7.7**	7.2	7.6
Accounts receivable securitization fees	**2.6**	2.5	2.3
Allowance for borrowed funds used and interest capitalized during construction	**(9.1)**	(6.2)	(5.6)
Debt-based post-in-service carrying charges	**(35.0)**	(36.4)	(35.1)
Other	**13.1**	16.4	18.8
Total Interest Expense, net	**$ 353.3**	$ 353.2	$ 349.5

22. Segments of Business

At December 31, 2018, our operations are divided into two primary reportable segments. The Gas Distribution Operations segment provides natural gas service and transportation for residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, Maryland, Indiana and Massachusetts. The Electric Operations segment provides electric service in 20 counties in the northern part of Indiana.

The following table provides information about our reportable segments. We use operating income as our primary measurement for each of the reported segments and make decisions on finance, dividends and taxes at the corporate level on a consolidated basis. Segment revenues include intersegment sales to affiliated subsidiaries, which are eliminated in consolidation. Affiliated sales are recognized on the basis of prevailing market, regulated prices or at levels provided for under contractual agreements. Operating income is derived from revenues and expenses directly associated with each segment.

Year Ended December 31, *(in millions)*	**2018**	2017	2016
Operating Revenues			
Gas Distribution Operations			
Unaffiliated	**$ 3,406.4**	$ 3,087.9	$ 2,818.2
Intersegment	**13.1**	14.2	12.4
Total	**3,419.5**	3,102.1	2,830.6
Electric Operations			
Unaffiliated	**1,707.4**	1,785.7	1,660.8
Intersegment	**0.8**	0.8	0.8
Total	**1,708.2**	1,786.5	1,661.6
Corporate and Other			
Unaffiliated	**0.7**	1.0	13.5
Intersegment	**517.6**	510.8	413.3
Total	**518.3**	511.8	426.8
Eliminations	**(531.5)**	(525.8)	(426.5)
Consolidated Operating Revenues	**$ 5,114.5**	$ 4,874.6	$ 4,492.5

Year Ended December 31, *(in millions)*		**2018**		2017		2016
Operating Income (Loss)						
Gas Distribution Operations	**$**	**(254.1)**	$	550.1	$	569.7
Electric Operations		**386.1**		367.4		301.3
Corporate and Other		**(7.3)**		3.7		(4.9)
Consolidated Operating Income	**$**	**124.7**	$	921.2	$	866.1
Depreciation and Amortization						
Gas Distribution Operations	**$**	**301.0**	$	269.3	$	252.9
Electric Operations		**262.9**		277.8		274.5
Corporate and Other		**35.7**		23.2		19.7
Consolidated Depreciation and Amortization	**$**	**599.6**	$	570.3	$	547.1
Assets						
Gas Distribution Operations	**$**	**13,527.0**	$	12,048.8	$	11,096.4
Electric Operations		**5,735.2**		5,478.6		5,233.3
Corporate and Other		**2,541.8**		2,434.3		2,362.2
Consolidated Assets	**$**	**21,804.0**	$	19,961.7	$	18,691.9
Capital Expenditures(1)						
Gas Distribution Operations	**$**	**1,315.3**	$	1,125.6	$	1,054.4
Electric Operations		**499.3**		592.4		420.6
Corporate and Other		**—**		35.8		15.4
Consolidated Capital Expenditures	**$**	**1,814.6**	$	1,753.8	$	1,490.4

(1 Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the inclusion of capital expenditures included in current liabilities and AFUDC Equity.

23. Quarterly Financial Data (Unaudited)

Quarterly financial data does not always reveal the trend of our business operations due to nonrecurring items and seasonal weather patterns, which affect earnings and related components of revenue and operating income.

(in millions, except per share data)	First Quarter(1)	Second Quarter(2)	Third Quarter(3)	Fourth Quarter(4)
2018				
Operating Revenues	$ 1,750.8	$ 1,007.0	$ 895.0	$ 1,461.7
Operating Income (Loss)	400.6	118.4	(315.9)	(78.4)
Net Income (Loss)	276.1	24.5	(339.5)	(11.7)
Preferred Dividends	—	(1.3)	(5.6)	(8.1)
Net Income (Loss) Available to Common Shareholders	276.1	23.2	(345.1)	(19.8)
Earnings (Loss) Per Share				
Basic Earnings (Loss) Per Share	$ 0.82	$ 0.07	$ (0.95)	$ (0.05)
Diluted Earnings (Loss) Per Share	$ 0.81	$ 0.07	$ (0.95)	$ (0.05)
2017				
Operating Revenues	$ 1,598.6	$ 990.7	$ 917.0	$ 1,368.3
Operating Income	415.4	124.0	111.2	270.6
Net Income (Loss)	211.3	(44.4)	14.0	(52.4)
Earnings (Loss) Per Share				
Basic Earnings (Loss) Per Share	$ 0.65	$ (0.14)	$ 0.04	$ (0.16)
Diluted Earnings (Loss) Per Share	$ 0.65	$ (0.14)	$ 0.04	$ (0.16)

(1) Net income for the first quarter of 2018 was impacted by an interest rate swap settlement gain of $21.2 million (pretax). See Note 9, "Risk Management Activities" for additional information.
(2) Net income for the second quarter of 2017 was impacted by a $111.5 million loss (pretax) on an early extinguishment of long-term debt. See Note 14, "Long-Term Debt" for additional information.
(3) Net income for the third quarter of 2018 was impacted by approximately $462 million in expenses (pretax) related to the Greater Lawrence Incident restoration and a $33.0 million loss (pretax) on an early extinguishment of long-term debt. See Note 18-E, "Other Matters" and Note 14, "Long-Term Debt" for additional information.
(4) Net income for the fourth quarter of 2018 was impacted by approximately $426 million in expenses (pretax, net of insurance recoveries) related to the Greater Lawrence Incident restoration, partially offset by an interest rate swap settlement gain of $25.0 million (pretax) and a $120.7 million income tax benefit from true-ups to reflect regulatory outcomes associated with excess deferred income taxes. Net income for the fourth quarter of 2017 was impacted by a $161.1 million increase in tax expense as a result of implementing the provisions of the TCJA. See Note 18-E, "Other Matters," Note 9, "Risk Management Activities" and Note 10, "Income Taxes" for additional information.

24. Supplemental Cash Flow Information

The following table provides additional information regarding our Consolidated Statements of Cash Flows for the years ended December 31, 2018, 2017 and 2016:

Year Ended December 31, *(in millions)*	2018	2017	2016
Supplemental Disclosures of Cash Flow Information			
Non-cash transactions:			
Capital expenditures included in current liabilities	**$ 152.0**	$ 173.0	$ 125.3
Assets acquired under a capital lease	**54.6**	11.5	4.0
Reclassification of other property to regulatory assets[1]	**245.3**	—	—
Assets recorded for asset retirement obligations[2]	**78.1**	11.4	6.9
Schedule of interest and income taxes paid:			
Cash paid for interest, net of interest capitalized amounts	**$ 354.2**	$ 339.9	$ 337.8
Cash paid for income taxes, net of refunds	**3.3**	5.5	8.0

[1]See Note 8 "Regulatory Matters" for additional information.
[2]See Note 7 "Asset Retirement Obligations" for additional information.

NISOURCE INC.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS

Twelve months ended December 31, 2018

($ in millions)	Balance Jan. 1, 2018	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [1]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2018
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 18.3	$ 20.2	$ 43.7	$ 61.1	$ 21.1
Reserve for other investments	3.0	—	—	—	3.0

Twelve months ended December 31, 2017

($ in millions)	Balance Jan. 1, 2017	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [1]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2017
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 23.3	$ 14.8	$ 39.1	$ 58.9	$ 18.3
Reserve for other investments	3.0	—	—	—	3.0

Twelve months ended December 31, 2016

($ in millions)	Balance Jan. 1, 2016	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [1]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2016
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 20.3	$ 19.7	$ 48.5	$ 65.2	$ 23.3
Reserve for other investments	3.0	—	—	—	3.0

[1] Charged to Other Accounts reflects the deferral of bad debt expense to a regulatory asset.

NISOURCE INC.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our chief executive officer and chief financial officer are responsible for evaluating the effectiveness of disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)). Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by the Company in reports that are filed or submitted under the Exchange Act are accumulated and communicated to management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our chief executive officer and chief financial officer concluded that, as of the end of the period covered by this report, disclosure controls and procedures were effective to provide reasonable assurance that financial information was processed, recorded and reported accurately.

Management’s Annual Report on Internal Control over Financial Reporting

Our management, including our chief executive officer and chief financial officer, are responsible for establishing and maintaining internal control over financial reporting, as such term is defined under Rule 13a-15(f) or Rule 15d-15(f) promulgated under the Exchange Act. However, management would note that a control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our management has adopted the 2013 framework set forth in the Committee of Sponsoring Organizations of the Treadway Commission report, Internal Control - Integrated Framework, the most commonly used and understood framework for evaluating internal control over financial reporting, as its framework for evaluating the reliability and effectiveness of internal control over financial reporting. During 2018, we conducted an evaluation of our internal control over financial reporting. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of the end of the period covered by this annual report.

Deloitte & Touche LLP, our independent registered public accounting firm, issued an attestation report on our internal controls over financial reporting which is contained in Item 8, “Financial Statements and Supplementary Data.”

Changes in Internal Controls

There have been no changes in our internal control over financial reporting during the most recently completed quarter covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Except for the information required by this item with respect to our executive officers included at the end of Part I of this report on Form 10-K, the information required by this Item 10 is incorporated herein by reference to the discussion in "Proposal 1 Election of Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance," of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2019.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item 11 is incorporated herein by reference to the discussion in "Corporate Governance - Compensation Committee Interlocks and Insider Participation," "Director Compensation," "Executive Compensation," and "Executive Compensation - Compensation Committee Report," of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2019.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item 12 is incorporated herein by reference to the discussion in "Security Ownership of Certain Beneficial Owners and Management" and "Equity Compensation Plan Information" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2019.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item 13 is incorporated herein by reference to the discussion in "Corporate Governance - Policies and Procedures with Respect to Transactions with Related Persons" and "Corporate Governance - Director Independence" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2019.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item 14 is incorporated herein by reference to the discussion in "Independent Auditor Fees" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 7, 2019.

PART IV

NISOURCE INC.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

Financial Statements and Financial Statement Schedules

The following financial statements and financial statement schedules filed as a part of the Annual Report on Form 10-K are included in Item 8, "Financial Statements and Supplementary Data."

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Report of Independent Registered Public Accounting Firm	46
Statements of Consolidated Income (Loss)	48
Statements of Consolidated Comprehensive Income (Loss)	49
Consolidated Balance Sheets	50
Statements of Consolidated Cash Flows	52
Statements of Consolidated Stockholders' Equity	53
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Exhibits

The exhibits filed herewith as a part of this report on Form 10-K are listed on the Exhibit Index below. Each management contract or compensatory plan or arrangement of ours, listed on the Exhibit Index, is separately identified by an asterisk.

Pursuant to Item 601(b), paragraph (4)(iii)(A) of Regulation S-K, certain instruments representing long-term debt of our subsidiaries have not been included as Exhibits because such debt does not exceed 10% of the total assets of ours and our subsidiaries on a consolidated basis. We agree to furnish a copy of any such instrument to the SEC upon request.

EXHIBIT NUMBER	DESCRIPTION OF ITEM
(1.1)	Form of Equity Distribution Agreement (incorporated by reference to Exhibit 1.1 to the NiSource Inc. Form 8-K filed on November 1, 2018).
(1.2)	Form of Master Forward Sale Confirmation (incorporated by reference to Exhibit 1.2 to the NiSource Inc. Form 8-K filed on November 1, 2018).
(2.1)	Separation and Distribution Agreement, dated as of June 30, 2015, by and between NiSource Inc. and Columbia Pipeline Group, Inc. (incorporated by reference to Exhibit 2.1 to the NiSource Inc. Form 8-K filed on July 2, 2015).
(3.1)	Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the NiSource Inc. Form 8-K filed on January 26, 2018).
(3.2)	Bylaws of NiSource Inc., as amended and restated through January 26, 2018 (incorporated by reference to Exhibit 3.1 to the NiSource Inc. Form 8-K filed on January 26, 2018).
(3.3)	Certificate of Designations of 5.65% Series A Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on June 12, 2018).
(3.4)	Form of Certificate of Designations of 6.50% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on November 29, 2018).
(3.5)	Certificate of Designations of 6.50% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on December 6, 2018).
(3.6)	Certificate of Designations of Series B-1 Preferred Stock (incorporated by reference to Exhibit 3.1 to the NiSource Inc. Form 8-K filed on December 27, 2018).
(4.1)	Indenture, dated as of March 1, 1988, by and between Northern Indiana Public Service Company ("NIPSCO") and Manufacturers Hanover Trust Company, as Trustee (incorporated by reference to Exhibit 4 to the NIPSCO Registration Statement (Registration No. 33-44193)).

(4.2)	First Supplemental Indenture, dated as of December 1, 1991, by and between Northern Indiana Public Service Company and Manufacturers Hanover Trust Company, as Trustee (incorporated by reference to Exhibit 4.1 to the NIPSCO Registration Statement (Registration No. 33-63870)).
(4.3)	Indenture Agreement, dated as of February 14, 1997, by and between NIPSCO Industries, Inc., NIPSCO Capital Markets, Inc. and Chase Manhattan Bank as trustee (incorporated by reference to Exhibit 4.1 to the NIPSCO Industries, Inc. Registration Statement (Registration No. 333-22347)).
(4.4)	Second Supplemental Indenture, dated as of November 1, 2000, by and among NiSource Capital Markets, Inc., NiSource Inc., New NiSource Inc., and The Chase Manhattan Bank, as trustee (incorporated by reference to Exhibit 4.45 to the NiSource Inc. Form 10-K for the period ended December 31, 2000).
(4.5)	Indenture, dated November 14, 2000, among NiSource Finance Corp., NiSource Inc., as guarantor, and The Chase Manhattan Bank, as Trustee (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form S-3, dated November 17, 2000 (Registration No. 333-49330)).
(4.6)	Form of 3.490% Notes due 2027 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on May 17, 2017).
(4.7)	Form of 4.375% Notes due 2047 (incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on May 17, 2017).
(4.8)	Form of 3.950% Notes due 2048 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on September 8, 2017).
(4.9)	Form of 2.650% Notes due 2022 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on November 14, 2017).
(4.10)	Second Supplemental Indenture, dated as of November 30, 2017, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.4 to Post-Effective Amendment No. 1 to Form S-3 filed November 30, 2017 (Registration No. 333-214360)).
(4.11)	Third Supplemental Indenture, dated as of November 30, 2017, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on December 1, 2017).
(4.12)	Second Supplemental Indenture, dated as of February 12, 2018, between Northern Indiana Public Service Company and The Bank of New York Mellon, solely as successor trustee under the Indenture dated as of March 1, 1988 between the Company and Manufacturers Hanover Trust Company, as original trustee. (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 10-Q filed on May 2, 2018).
(4.13)	Third Supplemental Indenture, dated as of June 11, 2018, by and between NiSource Inc. and The Bank of New York Mellon, as trustee (including form of 3.650% Notes due 2023) (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on June 12, 2018).
(4.14)	Deposit Agreement, dated as of December 5, 2018, among NiSource, Inc., Computershare Inc. and Computershare Trust Company, N.A., acting jointly as depositary, and the holders from time to time of the depositary receipts described therein (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on December 6, 2018).
(4.15)	Form of Depositary Receipt (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on December 6, 2018).
(4.16)	Amended and Restated Deposit Agreement, dated as of December 27, 2018, among NiSource, Inc., Computershare Inc. and Computershare Trust Company, N.A., acting jointly as depositary, and the holders from time to time of the depositary receipts described therein (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on December 27, 2018).
(4.17)	Form of Depositary Receipt (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on December 27, 2018).
(10.1)	2010 Omnibus Incentive Plan (incorporated by reference to Exhibit B to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting held on May 11, 2010, filed on April 2, 2010).*

(10.2) First Amendment to the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 10-K filed on February 18, 2014.)*

(10.3) 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit C to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting held on May 12, 2015, filed on April 7, 2015).*

(10.4)	Second Amendment to the NiSource Inc. 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 8-K filed October 23, 2015.)*
(10.5)	Form of Performance Share Award Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on April 30, 2014.)*
(10.6)	Form of Amended and Restated 2013 Performance Share Agreement effective on implementation of the spin-off on July 1, 2015, (under the 2010 Omnibus Incentive Plan)(incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on November 3, 2015).*
(10.7)	Form of Amended and Restated 2014 Performance Share Agreement effective on the implementation of the spin-off on July 1, 2015, (under the 2010 Omnibus Incentive Plan)(incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 10-Q filed on November 3, 2015).*
(10.8)	Form of Amendment to Restricted Stock Unit Award Agreement related to Vested but Unpaid NiSource Restricted Stock Unit Awards for Nonemployee Directors of NiSource entered into as of July 13, 2015 (incorporated by reference to Exhibit 10.3 to the NiSource Inc. Form 10-Q filed on November 3, 2015).*
(10.9)	NiSource Inc. Nonemployee Director Retirement Plan, as amended and restated effective May 13, 2008 (incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 10-K filed on February 27, 2009).*
(10.10)	Supplemental Life Insurance Plan effective January 1, 1991, as amended, (incorporated by reference to Exhibit 2 to the NIPSCO Industries, Inc. Form 8-K filed on March 25, 1992).*
(10.11)	Form of Change in Control and Termination Agreement (incorporated by reference to Exhibit 99.1 to the NiSource Inc. Form 8-K filed January 6, 2014).*
(10.12)	Revised Form of Change in Control and Termination Agreement (incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 8-K filed on October 23, 2015.)*
(10.13)	Form of Restricted Stock Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.18 to the NiSource Inc. Form 10-K filed on February 28, 2011).*
(10.14)	Form of Restricted Stock Unit Award Agreement for Non-employee directors under the Non-employee Director Stock Incentive Plan (incorporated by reference to Exhibit 10.19 to the NiSource Inc. Form 10-K filed on February 28, 2011).*
(10.15)	Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 to NiSource Inc. Form 10-Q filed on August 2, 2011).*
(10.16)	Form of Performance Share Award Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.3 to the NiSource Inc. Form 10-Q filed on May 3, 2016).*
(10.17)	Form of Restricted Stock Unit Award Agreement under the 2010 Omnibus Incentive Plan.* (incorporated by reference to Exhibit 10.17 to the NiSource Inc. Form 10-K filed on February 22, 2017)
(10.18)	Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2010 Omnibus Incentive Plan. (incorporated by reference to Exhibit 10.18 to the NiSource Inc. Form 10-K filed on February 22, 2017) *
(10.19)	Amended and Restated NiSource Inc. Supplemental Executive Retirement Plan effective May 13, 2011 (incorporated by reference to Exhibit 10.3 to NiSource Inc. Form 10-Q filed on October 28, 2011).*
(10.20)	Amended and Restated Pension Restoration Plan for NiSource Inc. and Affiliates effective May 13, 2011 (incorporated by reference to Exhibit 10.4 to NiSource Inc. Form 10-Q filed on October 28, 2011).*
(10.21)	Amended Restated Savings Restoration Plan for NiSource Inc. and Affiliates effective October 22, 2012 (incorporated by reference to Exhibit 10.20 to the NiSource Inc. Form 10-K filed on February 19, 2013).*
(10.22)	Amended and Restated NiSource Inc. Executive Deferred Compensation Plan effective November 1, 2012 (incorporated by reference to Exhibit 10.21 to the NiSource Inc. Form 10-K filed on February 19, 2013).*
(10.23)	NiSource Inc. Executive Severance Policy, as amended and restated, effective January 1, 2015 (incorporated by reference to Exhibit 10.21 to the NiSource Inc. Form 10-K filed on February 18, 2015).*

(10.24) Fourth Amended and Restated Revolving Credit Agreement, dated as of November 28, 2016, among NiSource Finance Corp., as Borrower, NiSource Inc., the Lenders party thereto, Barclays Bank PLC, as Administrative Agent, JPMorgan Chase Bank, N.A. and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Syndication Agents, Citibank, N.A., Credit Suisse AG, Cayman Islands Branch and Wells Fargo Bank, National Association, as Co-Documentation Agents, and Barclays Bank PLC, JPMorgan Chase Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd., Credit Suisse Securities (USA) LLC, Citigroup Global Markets, Inc. and Wells Fargo Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 8-K filed on November 28, 2016).

(10.25) Note Purchase Agreement, dated as of August 23, 2005, by and among NiSource Finance Corp., as issuer, NiSource Inc., as guarantor, and the purchasers named therein (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Current Report on Form 8-K filed on August 26, 2005).

(10.26) Amendment No. 1, dated as of November 10, 2008, to the Note Purchase Agreement by and among NiSource Finance Corp., as issuer, NiSource Inc., as guarantor, and the purchasers whose names appear on the signature page thereto (incorporated by reference to Exhibit 10.30 to the NiSource Inc. Form 10-K filed on February 27, 2009).

(10.27) Term Loan Agreement, dated as of March 31, 2016, by and among NiSource Finance Corp., as Borrower, NiSource Inc., as Guarantor, the Lenders party thereto, and PNC Bank, National Association, as Administrative Agent, JP Morgan Chase Bank, N.A., as Syndication Agent, and Mizuho Bank, Ltd., as Documentation Agent (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on May 3, 2016).

(10.28) Letter Agreement, dated as of March 17, 2015, by and between NiSource Inc. and Donald Brown. (incorporated by reference Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on April 30, 2015).*

(10.29) Letter Agreement, dated as of February 23, 2016, by and between NiSource Inc. and Pablo A. Vegas. (incorporated by reference Exhibit 10.29 to the NiSource Inc. Form 10-K filed on February 22, 2017).*

(10.30) Tax Allocation Agreement, dated as of June 30, 2015, by and between NiSource Inc. and Columbia Pipeline Group, Inc. (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on July 2, 2015).

(10.31) Employee Matters Agreement, dated as of June 30, 2015, by and between NiSource Inc. and Columbia Pipeline Group, Inc. (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on July 2, 2015).

(10.32) Form of Change in Control and Termination Agreement (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on August 2, 2017).

(10.33) Form of Performance Share Award Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.33 to the NiSource Form 10-K filed on February 20, 2018).*

(10.34) Form of Restricted Stock Unit Award Agreement under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.34 to the NiSource Form 10-K filed on February 20, 2018).*

(10.35) Term Loan Agreement dated as of April 18, 2018 among NiSource Inc., as borrower, the lenders party thereto and MUFG Bank, Ltd., as administrative agent and as sole lead arranger and sole bookrunner (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on April 19, 2018).

(10.36) Common Stock Subscription Agreement, dated as of May 2, 2018, by and among NiSource Inc. and the purchasers named therein (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on May 2, 2018).

(10.37) Registration Rights Agreement, dated as of May 2, 2018, by and among NiSource Inc. and the purchasers named therein (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on May 2, 2018).

(10.38) Purchase Agreement, dated as of June 6, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 5.650% Series A Preferred Stock (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on June 12, 2018).

(10.39) Purchase Agreement, dated as of June 6, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 3.650% Notes due 2023 (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on June 12, 2018).

(10.40) Registration Rights Agreement, dated as of June 11, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 5.650% Series A Preferred Stock (incorporated by reference to Exhibit 10.3 of the NiSource Inc. Form 8-K filed on June 12, 2018).

(10.41)	Registration Rights Agreement, dated as of June 11, 2018, by and among NiSource Inc. and Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and MUFG Securities Americas Inc., as representatives, relating to the 3.650% Notes due 2023 (incorporated by reference to Exhibit 10.4 of the NiSource Inc. Form 8-K filed on June 12, 2018).
(10.42)	Amended and Restated NiSource Inc. Supplemental Executive Retirement Plan effective August 10, 2017 (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 10-Q filed on November 1, 2018).
(10.43)	Amended and Restated Pension Restoration Plan for NiSource Inc. and Affiliates effective August 10, 2017 (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 10-Q filed on November 1, 2018).
(10.44)	Amended Restated Savings Restoration Plan for NiSource Inc. and Affiliates effective August 10, 2017 (incorporated by reference to Exhibit 10.3 of the NiSource Inc. Form 10-Q filed on November 1, 2018).
(10.45)	Form of 2019 Performance Share Award Agreement under the 2010 Omnibus Incentive Plan.* **
(21)	List of Subsidiaries.**
(23)	Consent of Deloitte & Touche LLP.**
(31.1)	Certification of Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.**
(31.2)	Certification of Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.**
(32.1)	Certification of Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).**
(32.2)	Certification of Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).**
(101.INS)	XBRL Instance Document.**
(101.SCH)	XBRL Schema Document.**
(101.CAL)	XBRL Calculation Linkbase Document.**
(101.LAB)	XBRL Labels Linkbase Document.**
(101.PRE)	XBRL Presentation Linkbase Document.**
(101.DEF)	XBRL Definition Linkbase Document.**

* Management contract or compensatory plan or arrangement of NiSource Inc.

** Exhibit filed herewith.

References made to NIPSCO filings can be found at Commission File Number 001-04125. References made to NiSource Inc. filings made prior to November 1, 2000 can be found at Commission File Number 001-09779.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

NiSource Inc.
(Registrant)

Date: February 20, 2019

By: /s/ JOSEPH HAMROCK
Joseph Hamrock
President, Chief Executive Officer and Director
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ JOSEPH HAMROCK Joseph Hamrock	President, Chief Executive Officer and Director (Principal Executive Officer)	Date: February 20, 2019
/s/ DONALD E. BROWN Donald E. Brown	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	Date: February 20, 2019
/s/ JOSEPH W. MULPAS Joseph W. Mulpas	Vice President and Chief Accounting Officer (Principal Accounting Officer)	Date: February 20, 2019
/s/ RICHARD L. THOMPSON Richard L. Thompson	Chairman and Director	Date: February 20, 2019
/s/ PETER A. ALTABEF Peter A. Altabef	Director	Date: February 20, 2019
/s/ THEODORE H. BUNTING, JR. Theodore H. Bunting	Director	Date: February 20, 2019
/s/ ERIC L. BUTLER Eric L. Butler	Director	Date: February 20, 2019
/s/ ARISTIDES S. CANDRIS Aristides S. Candris	Director	Date: February 20, 2019
/s/ WAYNE S. DEVEYDT Wayne S. DeVeydt	Director	Date: February 20, 2019
/s/ DEBORAH A. HENRETTA Deborah A. Henretta	Director	Date: February 20, 2019
/s/ MICHAEL E. JESANIS Michael E. Jesanis	Director	Date: February 20, 2019
/s/ KEVIN T. KABAT Kevin T. Kabat	Director	Date: February 20, 2019
/s/ CAROLYN Y. WOO Carolyn Y. Woo	Director	Date: February 20, 2019

Exhibit 10.45

NiSource Inc.

2010 Omnibus Incentive Plan

Performance Share Award Agreement

This Performance Share Award Agreement (the "Agreement") is made and entered into as of _______________ (the "Grant Date"), by and between NiSource Inc., a Delaware corporation (the "Company"), and __________________ an Employee of the Company (the "Grantee"), pursuant to the terms of the NiSource Inc. 2010 Omnibus Incentive Plan, as amended (the "Plan"). Any term capitalized but not defined in this Agreement shall have the meaning set forth in the Plan.

Section 1. Performance Share Award. The Company hereby grants to the Grantee, on the terms and conditions hereinafter set forth, a target award of ______________Performance Shares (the "Performance Shares"). The Performance Shares shall be represented by a bookkeeping entry with respect to the Grantee (the "Performance Share Account") of the Company, and each Performance Share shall be settled with one Share, to the extent provided under this Agreement and the Plan. This Agreement and the award shall be null and void unless the Grantee accepts this Agreement electronically within the Grantee's stock plan account with the Company's stock plan administrator according to the procedures then in effect.

Section 2. Performance-Based Vesting Conditions.

(a) General. Subject to the remainder of this Agreement, the Performance Shares shall vest pursuant to the terms of this Agreement and the Plan based on the achievement of the performance goals set forth in this Section 2 over the performance period beginning on _________________ and ending on _________________ (the "Performance Period"), provided (i) that that the Grantee remains in continuous Service through _________________ (the "Vesting Date") and (ii) the Company achieves the threshold cumulative NOEPS goal set forth in Section 2(b). Attainment of the performance goals shall be determined and certified by the Compensation Committee of the Board of Directors of the Company (the "Committee") prior to the settlement of the Performance Shares.

(b) Financial Performance Goal. Subject to the terms of this Agreement and the Plan, _________________shall be eligible to vest based on the Company's achievement of cumulative NOEPS during the Performance Period, as follows:

Performance Level(1)	Cumulative NOEPS	Percentage of Performance Shares that Shall Vest(2)
Threshold	$________	____________
Target	$________	____________
Maximum	$_______and above	____________

(1) The vesting percentage for performance between performance levels shall be determined based on linear interpolation.

(2) The number of Performance Shares that shall vest based on the Company's cumulative NOEPS performance shall be subject to a performance modifier of +/- 25% based on the Company's RTSR over the Performance Period, with such Performance Shares (i) increasing by 25% if the Company's RTSR is in the top quartile of the TSR Peer Group, (ii) decreasing by 25% if the Company's RTSR is in the bottom quartile of the TSR Peer Group, and (iii) remaining the same if the Company's RTSR is in the second or third quartiles of the TSR Peer Group. No other adjustment shall be made based on the Company's RTSR.

(c) Customer Framework Performance Goals. Subject to the terms of this Agreement and the Plan, ________________shall be eligible to vest based on the achievement of the Customer Framework Goals set forth below, with each goal equally weighted:

Performance Measure	Goal(1)
National Safety Council Barometer Survey	________________
JD Power Gas and Electric Utility Residential Customer Satisfaction Studies	________________
Operations and Maintenance Financial Plan	________________
Organizational Health Index	________________
Greenhouse Gas Emissions	________________

(1) If the Company fails to achieve the applicable performance goal, then the Performance Shares allocated to such performance goal shall not be eligible to vest.

(d) Definitions.

(i) "cumulative NOEPS" means the Company's cumulative net operating earnings per share performance as certified by the Committee following the Performance Period.

(ii) "RTSR" means the annualized growth in the dividends and share price of a Share, calculated using a 20 day trading average of the Company's closing price beginning on __________________ and ending ________________ compared to the TSR performance of the TSR Peer Group. The starting and ending share prices for the computation of RTSR will equal the average closing price of each company's common stock over the 20 trading days immediately preceding the first and last day of the performance period.

(iii) "TSR Peer Group" means the peer group of companies determined by the Committee at its meeting on _________________.

Section 3. Termination of Employment.

(a) Termination of Service Prior to Vesting Date. Except as set forth below, if the Grantee's Service is terminated for any reason prior to the Vesting Date, then the Grantee shall forfeit the Performance Shares credited to the Grantee's Performance Share Account.

(b) Retirement, Disability or Death.

(i) Notwithstanding the foregoing, in the event that the Grantee's Service terminates prior to the Vesting Date and on or within 12 months prior to the end of the Performance Period as a result of the Grantee's (i) Retirement, (ii) Disability; or (iii) death, then the Grantee (or the Grantee's beneficiary or estate in the case of the Grantee's death) shall vest in a pro rata portion of the Performance Shares, based on the actual performance results for the Performance Period. Such pro rata portion of the Performance Shares shall be determined by multiplying the number of Performance Shares earned based on actual performance by a fraction, where the numerator shall equal the number of calendar months (including partial calendar months) that have elapsed from the Grant Date through the date of the Grantee's termination of Service, and the denominator shall be the number of calendar months (including partial calendar months) that have elapsed between the Grant Date and __________________.

(ii) If the Grantee terminates Service due to death prior to the Vesting Date and with more than 12 months remaining in the Performance Period, then the Grantee's beneficiary or estate shall vest, on the date of termination, in a pro rata portion of the target Performance

Shares. Such pro rata portion of the Performance Shares shall be determined by multiplying the number of target Performance Shares by a fraction, where the numerator shall equal the number of calendar months (including partial calendar months) that have elapsed from the Grant Date through the date of the Grantee's termination of Service, and the denominator shall be the number of calendar months (including partial calendar months) that have elapsed between the Grant Date and _______________.

(iii) "Retirement" means the Grantee's termination from Service at or after attainment of age 55 and completing at least ten years of service (within the meaning of the Company's tax-qualified pension plan, as in effect on the Grant Date, regardless of whether the Grantee is eligible for such plan).

(c) Change in Control. Notwithstanding the foregoing provisions, in the event of a Change in Control, the Performance Shares under this Agreement shall be subject to Article XVI of the Plan. In the event of any conflict between Article XVI of the Plan and this Agreement, Article XVI shall control. Notwithstanding any other agreement between the Company and the Grantee, the "Good Reason" definition set forth in Section 16.1 of the Plan shall govern this award.

Section 4. Delivery of Shares. Subject to the terms of this Agreement and except as otherwise provided for herein, the Company shall convert the Performance Shares in the Grantee's Performance Share Account into Shares and issue or deliver the total number of Shares due to the Grantee as soon as administratively practicable after the Vesting Date (but in no event later than _________________) or, if earlier, within 30 days following the Grantee's death in accordance with Section 3(b)(ii), Grantee's termination of Service without Cause or due to Good Reason in accordance with Section 16.1(a) of the Plan or a Change in Control in accordance with Section 16.1(b) of the Plan. The delivery of the Shares shall be subject to payment of the applicable withholding tax liability and the forfeiture provisions of this Agreement. If the Grantee dies before the Company has issued or distributed the vested Performance Shares, the Company shall transfer any Shares with respect to the vested Performance Shares in accordance with the Grantee's written beneficiary designation or to the Grantee's estate if no written beneficiary designation is provided. The issuance or deliver of the Shares hereunder shall be evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company. The Company shall pay all original issue or transfer taxes and all fees and expenses incident to such issuance or delivery, except as otherwise provided in Section 5.

Section 5. Withholding of Taxes. As a condition precedent to the delivery to Grantee of any Shares upon vesting of the Performance Shares, Grantee shall, upon request by the Company, pay to the Company such amount of cash as the Company may be required, under all applicable federal, state, local or other laws or regulations, to withhold and pay over as income or other withholding taxes (the "Required Tax Payments") with respect to the Performance Shares. If Grantee shall fail to advance the Required Tax Payments after request by the Company, the Company may, in its discretion, deduct any Required Tax Payments from any amount then or thereafter payable by the Company to Grantee or withhold Shares. Grantee may elect to satisfy his or her obligation to advance the Required Tax Payments by any of the following means: (a) a cash payment to the Company; (b) delivery to the Company (either actual delivery or by attestation procedures established by the Company) of previously owned whole Shares having a Fair Market Value, determined as of the date the obligation to withhold or pay taxes first arises in connection with the Performance Shares (the "Tax Date"), equal to the Required Tax Payments; (c) authorizing the Company to withhold from the Shares otherwise to be delivered to Grantee upon the vesting of the Performance Shares, a number of whole Shares having a Fair Market Value, determined as of the Tax Date, equal to the Required Tax Payments; or (d) any combination of (a), (b) and (c). Shares to be delivered or withheld may not have a Fair Market Value in excess of the minimum amount of the Required Tax Payments. Any fraction of a Share which would be required to satisfy such an obligation shall be disregarded and the remaining amount due shall be paid in cash by Grantee. No Shares shall be delivered until the Required Tax Payments have been satisfied in full.

Section 6. Compliance with Applicable Law. Notwithstanding anything contained herein to the contrary, the Company's obligation to issue or deliver certificates evidencing the Performance Shares shall be subject to all applicable laws, rules and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required. The delivery of all or any Shares that relate to the Performance Shares shall be effective only at such time that the issuance of such Shares shall not violate any state or federal securities or other laws. The Company is under no obligation to effect any registration of Shares under the Securities Act of 1933 or to effect any state registration or qualification of the Shares that may be issued under this Agreement. Subject to Section 409A of the Code (the "Section 409A"), the Company may, in its sole discretion, delay the delivery of Shares or place restrictive legends on Shares in order to ensure that the issuance of any Shares shall be in compliance with federal or state securities laws and the rules of any exchange upon which the Company's Shares are traded. If the Company delays the delivery of Shares in order to ensure compliance with any state or federal securities or other laws, the Company shall deliver the Shares at the earliest date at which the Company reasonably believes that such delivery shall not cause such violation, or at such later date that may be permitted under Section 409A.

Section 7. Restriction on Transferability. Except as otherwise provided under the Plan, until the Performance Shares have vested under this Agreement, the Performance Shares granted herein and the rights and privileges conferred hereby may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated (by operation of law or otherwise), other than by will or the laws of descent and distribution. Any attempted transfer in violation of the provisions of this paragraph shall be void, and the purported transferee shall obtain no rights with respect to such Performance Shares.

Section 8. Grantee's Rights Unsecured. The right of the Grantee or his or her beneficiary to receive a distribution hereunder shall be an unsecured claim against the general assets of the Company, and neither the Grantee nor his or her beneficiary shall have any rights in or against any amounts credited to the Grantee's Performance Share Account, any Shares or any other specific assets of the Company. All amounts credited to the Grantee's Performance Share Account shall constitute general assets of the Company and may be disposed of by the Company at such time and for such purposes as it may deem appropriate.

Section 9. No Rights as Stockholder or Employee. The Grantee shall not have any privileges of a stockholder of the Company (including, without limitation, any voting rights or rights to receive dividends) with respect to the Performance Shares subject to this Agreement. Furthermore, nothing in this Agreement shall confer upon the Grantee any right to continue as an Employee of the Company or any Affiliate or to interfere in any way with the right of the Company or any Affiliate to terminate the Grantee's Service at any time.

Section 10. Adjustments. If at any time while the award is outstanding, the number of outstanding Performance Shares is changed by reason of a reorganization, recapitalization, stock split or any of the other events described in the Plan, the number and kind of Performance Shares and the performance goals, as applicable, shall be adjusted in accordance with the provisions of the Plan.

Section 11. Notices. Any notice hereunder by the Grantee shall be given to the Company in writing, and such notice shall be deemed duly given only upon receipt thereof at the following address: Corporate Secretary, NiSource Inc., 801 East 86th Avenue, Merrillville, IN 46410-6271 (or at such other address as the Company may designate by notice to the Grantee). Any notice hereunder by the Company shall be given to the Grantee in writing, and such notice shall be deemed duly given only upon receipt thereof at such address as the Grantee may have on file with the Company.

Section 12. Administration. The administration of this Agreement, including the interpretation and amendment or termination of this Agreement, shall be performed in accordance with the Plan. All determinations and decisions made by the Committee, the Board, or any delegate of the Committee as to the provisions of this Agreement shall be conclusive, final, and binding on all persons. Notwithstanding the foregoing, if subsequent guidance is issued under Section 409A that would impose additional taxes, penalties, or interest to either the Company or the Grantee, the Company may administer this Agreement in accordance with such guidance and amend this Agreement without the consent of the Grantee to the extent such actions, in the reasonable judgment of the Company, are considered necessary to avoid the imposition of such additional taxes, penalties, or interest.

Section 13. Governing Law. This Agreement shall be construed and enforced in accordance with the laws of the State of Indiana, without giving effect to the choice of law principles thereof.

Section 14. Entire Agreement; Agreement Subject to Plan. This Agreement and the Plan contain all of the terms and conditions with respect to the subject matter hereof and supersede any previous agreements, written or oral, relating to the subject matter hereof. This Agreement is subject to the provisions of the Plan and shall be interpreted in accordance therewith. In the event that the provisions of this Agreement and the Plan conflict, the Plan shall control. The Grantee hereby acknowledges receipt of a copy of the Plan.

Section 15. Section 409A Compliance. This Agreement and the Performance Shares granted hereunder are intended to be exempt from Section 409A to the maximum extent possible, and shall be interpreted and construed accordingly.

[SIGNATURE PAGE TO FOLLOW]

IN WITNESS WHEREOF, the Company has caused the Performance Shares subject to this Agreement to be granted, and the Grantee has accepted the Performance Shares subject to the terms of the Agreement, as of the date first above written.

NiSource Inc.

____
By: ___________________
Its: ___________________

GRANTEE

By: ____
____

Exhibit 21

SUBSIDIARIES OF NISOURCE

as of December 31, 2018

Segment/Subsidiary

GAS DISTRIBUTION OPERATIONS	**State of Incorporation**
Bay State Gas Company d/b/a Columbia Gas of Massachusetts	Massachusetts
Central Kentucky Transmission Company	Delaware
Columbia Gas of Kentucky, Inc.	Kentucky
Columbia Gas of Maryland, Inc.	Delaware
Columbia Gas of Ohio, Inc.	Ohio
Columbia Gas of Pennsylvania, Inc.	Pennsylvania
Columbia Gas of Virginia, Inc.	Virginia
NiSource Gas Distribution Group, Inc.	Delaware
ELECTRIC OPERATIONS	
Northern Indiana Public Service Company LLC*	Indiana
CORPORATE AND OTHER OPERATIONS	
Columbia Gas of Ohio Receivables Corporation	Delaware
Columbia Gas of Pennsylvania Receivables Corporation	Delaware
NIPSCO Accounts Receivable Corporation	Indiana
NiSource Corporate Group, LLC	Delaware
NiSource Corporate Services Company	Delaware
NiSource Development Company, Inc.	Indiana
NiSource Energy Technologies, Inc.	Indiana
NiSource Strategic Sourcing Inc.	Ohio
NiSource Insurance Corporation, Inc.	Utah
Lake Erie Land Company	Indiana
RoseWater Wind Generation LLC	Indiana
NiSource Retail Services, Inc.	Delaware (Inactive)
EnergyUSA-TPC, Inc.	Indiana (Inactive)

* Reported under Gas Distribution Operations and Electric Operations.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-107743, 333-166888, 333-170706, 333-204168 and 333-228102 on Form S-8, 333-214360 on Form S-3, 333-228791, 333-228790 and 333-228791 on Form S-4 of our reports dated February 20, 2019, relating to the consolidated financial statements and financial statement schedule of NiSource Inc. and subsidiaries (the "Company") and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of NiSource Inc. for the year ended December 31, 2018.

/s/ DELOITTE & TOUCHE LLP
Columbus, Ohio
February 20, 2019

Exhibit 31.1

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Joseph Hamrock, certify that:

1. I have reviewed this Annual Report on Form 10-K of NiSource Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2019

By: /s/ Joseph Hamrock

Joseph Hamrock
President and Chief Executive Officer

Exhibit 31.2

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Donald E. Brown, certify that:

1. I have reviewed this Annual Report on Form 10-K of NiSource Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2019

By: /s/ Donald E. Brown

Donald E. Brown

Executive Vice President and Chief Financial Officer

Exhibit 32.1

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of NiSource Inc. (the "Company") on Form 10-K for the year ending December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Joseph Hamrock, Chief Executive Officer of the Company, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Joseph Hamrock

Joseph Hamrock
President and Chief Executive Officer

Date: February 20, 2019

Exhibit 32.2

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of NiSource Inc. (the "Company") on Form 10-K for the year ending December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Donald E. Brown, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Donald E. Brown

Donald E. Brown
Executive Vice President and Chief Financial Officer

Date: February 20, 2019

STOCKHOLDER INFORMATION

FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of federal securities laws. Investors and prospective investors should understand that many factors govern whether any forward-looking statement contained herein will be or can be realized. Any one of those factors could cause actual results to differ materially from those projected. Examples of forward-looking statements in this report include statements and expectations regarding NiSource's or any of its subsidiaries' business, performance, growth, commitments, investment opportunities, and planned, identified, infrastructure or utility investments. All forward-looking statements are based on assumptions that management believes to be reasonable; however, there can be no assurance that actual results will not differ materially. Factors that could cause actual results to differ materially from the projections, forecasts, estimates, plans, expectations and strategy discussed in this report include, among other things, NiSource's debt obligations; any changes in NiSource's credit rating; NiSource's ability to execute its growth strategy; changes in general economic, capital and commodity market conditions; pension funding obligations; economic regulation and the impact of regulatory rate reviews; NiSource's ability to obtain expected financial or regulatory outcomes; NiSource's ability to adapt to, and manage costs related to, advances in technology; any changes in our assumptions regarding the financial implications of the Greater Lawrence Incident; potential incidents and other operating risks associated with our business; our ability to obtain sufficient insurance coverage; the outcome of legal and regulatory proceedings, investigations, inquiries, claims and litigation; any damage to NiSource's reputation, including in connection with the Greater Lawrence Incident; compliance with environmental laws and the costs of associated liabilities; fluctuations in demand from residential and commercial customers; economic conditions of certain industries; the success of NIPSCO's electric generation strategy; the price of energy commodities and related transportation costs or an inability to obtain an adequate, reliable and cost-effective fuel supply to meet customer demands; the reliability of customers and suppliers to fulfill their payment and contractual obligations; potential impairments of goodwill or definite-lived intangible assets; changes in taxation and accounting principles; the impact of an aging infrastructure; the impact of climate change; potential cyber-attacks; construction risks and natural gas costs and supply risks; extreme weather conditions; the attraction and retention of a qualified work force; the ability of NiSource's subsidiaries to generate cash; tax liabilities associated with the separation of Columbia Pipeline Group, Inc.; NiSource's ability to manage new initiatives and organizational changes; the performance of third-party suppliers and service providers; and other matters set forth in Item 1A, "Risk Factors" section of NiSource's Annual Report on Form 10-K for the fiscal year ended December 31, 2018, and in other filings with the Securities and Exchange Commission. A credit rating is not a recommendation to buy, sell or hold securities, and may be subject to revision or withdrawal at any time by the assigning rating organization. In addition, dividends are subject to board approval. NiSource expressly disclaims any duty to update, supplement or amend any of its forward-looking statements contained in this report, whether as a result of new information, subsequent events or otherwise, except as required by applicable law.

REGULATION G DISCLOSURE STATEMENT

This report includes financial results and guidance for NiSource with respect to net operating earnings, which is a non-GAAP financial measure as defined by the SEC's Regulation G. The company includes this measure because management believes it permits investors to view the company's performance using the same tools that management uses and to better evaluate the company's ongoing business performance. With respect to such guidance, it should be noted that there will likely be a difference between this measure and its GAAP equivalent due to various factors, including, but not limited to, fluctuations in weather, the impact of asset sales and impairments, and other items included in GAAP results. The company is not able to estimate the impact of such factors on GAAP earnings and, as such, is not providing earnings guidance on a GAAP basis.

ANTICIPATED DIVIDEND RECORD & PAYMENT DATES - NI COMMON STOCK

RECORD DATE	PAYMENT DATE
02/11/19	02/20/19
04/30/19	05/20/19
07/31/19	08/20/19
10/31/19	11/20/19
02/11/20	02/20/20

COMMON STOCK DIVIDEND DECLARED

On February 20, 2019, the company paid a quarterly dividend of $0.20 per share, equivalent to $0.80 per share on an annual basis.

INVESTOR & FINANCIAL INFORMATION

Financial analysts and investment professionals should direct written and telephone inquiries to NiSource Investor Relations at 801 E. 86th Avenue, Merrillville, IN 46410 or (614) 460-4789.

Copies of NiSource's financial reports are available by writing or calling the Investor Relations department at the address or phone number listed above. The materials are also available at NiSource.com.

STOCKHOLDER SERVICES

Questions about stockholder accounts, stock certificates, transfer of shares, dividend payments, automatic dividend reinvestment and stock purchase plan, and electronic deposit may be directed to Computershare at the following:

Computershare
c/o Shareholder Services
P. O. Box 505000
Louisville, KY 40233-5000
or
c/o Shareholder Services
462 South 4th Street, Suite 1600
Louisville, KY 40202

(888) 884-7790

TDD for Hearing Impaired: (800) 231-5469

Foreign Stockholders: (201) 680-6578

TDD Foreign Stockholders: (201) 680-6610

computershare.com/investor

STOCKHOLDER INQUIRIES
Computershare
Shareowner Services
(888) 884-7790

ANALYST INQUIRIES
Investor
Relations
(614) 460-4789

MEDIA INQUIRIES
Corporate
Communications
(614) 460-5544

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