COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	
	)	

COLUMBIA GAS OF KENTUCKY, INC.'S
RESPONSES TO COMMISSION STAFF'S THIRD REQUEST FOR INFORMATION

FILED: August 25, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183

VERIFICATION OF DAVID ROY

COMMONWEALTH OF KENTUCKY	)
	)
COUNTY OF FAYETTE	)

David Roy, Vice President of Operations and Construction of Columbia Gas of Kentucky, Inc., being duly sworn, states that he has supervised the preparation of certain responses to Commission Staff's Request for Information in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

David Roy
David Roy

The foregoing Verification was signed, acknowledged and sworn to before me this 24th day of August, 2021, by David Roy.

Evelyn Long Durr

EVELYN LONG DURR
Notary Public
Commonwealth of Kentucky
Commission Number 600778
My Commission Expires May 15, 2022

Notary Commission No. 600778

Commission expiration: May 15, 2022

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:)
)
THE ELECTRONIC APPLICATION OF)
COLUMBIA GAS OF KENTUCKY, INC. FOR AN)
ADJUSTMENT OF RATES; APPROVAL OF)
DEPRECIATION STUDY; APPROVAL OF TARIFF) Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF)
PUBLIC CONVENIENCE AND NECESSITY; AND)
OTHER RELIEF)

VERIFICATION OF CHUN-YI LAI

STATE OF OHIO)
)
COUNTY OF FRANKLIN)

Chun-Yi Lai, Financial Planning Manager for NiSource Corporate Services Company, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of certain responses to Commission Staff's Request for Information in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Chun-Yi Lai

The foregoing Verification was signed, acknowledged and sworn to before me this 20 day of August, 2021, by Chun-Yi Lai.

MICHAEL SHUMATE
Notary Public, State of Ohio
My Commission Expires
January 24, 2024

Notary Commission No. 2019-RE-765767

Commission expiration: 1-24-2024

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	

VERIFICATION OF JEFFERY GORE

STATE OF OHIO	)
	)
COUNTY OF FRANKLIN	)

Jeffery Gore, Regulatory Manager for NiSource Corporate Services Company, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that he has supervised the preparation of certain response to Commission Staff's Request for Information in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Jeffery Gore

The foregoing Verification was signed, acknowledged and sworn to before me this 13th day of August, 2021, by Jeffery Gore.

John R Ryan III
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

Notary Commission No. N/A

Commission expiration: N/A

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	

VERIFICATION OF JENNIFER HARDING

STATE OF OHIO	)
	)
COUNTY OF FRANKLIN	)

Jennifer Harding, Director, Income Tax Operations for NiSource Corporate Services Company, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of certain responses to Commission Staff's Request for Information in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Jennifer Harding

The foregoing Verification was signed, acknowledged and sworn to before me this 18th day of August, 2021, by Jennifer Harding.

NOTARIAL SEAL STATE OF OHIO

John R Ryan III
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

Notary Commission No. N/A

Commission expiration: N/A

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	
	)	

VERIFICATION OF JOHN SPANOS

COMMONWEALTH OF PENNSYLVANIA	)
	)
COUNTY OF CUMBERLAND	)

John Spanos, President of Gannett Fleming Valuation and Rate Consultants, LLC, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that he has supervised the preparation of certain responses to Commission Staff's Request for Information in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

John J. Spanos

John Spanos

The foregoing Verification was signed, acknowledged and sworn to before me this 16th day of August, 2021, by John Spanos.

Commonwealth of Pennsylvania - Notary Seal
MEGAN LYNN ECKRICH - Notary Public
Cumberland County
My Commission Expires Sep 16, 2023
Commission Number 1264513

Megan Lynn Eckrich

Notary Commission No. 1264513

Commission expiration: ~~1264513~~ Sep. 16, 2023

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:)
)
THE ELECTRONIC APPLICATION OF)
COLUMBIA GAS OF KENTUCKY, INC. FOR AN)
ADJUSTMENT OF RATES; APPROVAL OF)
DEPRECIATION STUDY; APPROVAL OF TARIFF) Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF)
PUBLIC CONVENIENCE AND NECESSITY; AND)
OTHER RELIEF)

VERIFICATION OF JUDITH SIEGLER

STATE OF INDIANA)
)
COUNTY OF LAKE)

Judith Siegler, Lead Regulatory Studies Analyst for NiSource Corporate Services Company, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of certain responses to Commission Staff's Request for Information in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Judith Siegler

Judith Siegler

The foregoing Verification was signed, acknowledged and sworn to before me this 24 day of August, 2021, by Judith Siegler.

Cynthia A. Schmied

Notary Commission No. 0643096

Commission expiration: March 21. 2029

NOTARY PUBLIC SEAL STATE OF INDIANA
CYNTHIA A. SCHMIED
Commission Number 0643096
My Commission Expires
March 21, 2029

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183

VERIFICATION OF KEVIN JOHNSON

STATE OF OHIO	)
	)
COUNTY OF FRANKLIN	)

Kevin Johnson, Lead Regulatory Analyst for NiSource Corporate Services Company, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that he has supervised the preparation of certain responses to Commission Staff's Request for Information in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Ken Johnson

Kevin Johnson

The foregoing Verification was signed, acknowledged and sworn to before me this 20th day of August, 2021, by Kevin Johnson.

Samantha Wynn

SAMANTHA C WYNN
Notary Public State of Ohio
My Comm. Expires April 18, 2026

Notary Commission No. n/a

Commission expiration: 18 April 2026

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183

VERIFICATION OF KIMBERLY CARTELLA

STATE OF OHIO	)
	)
COUNTY OF LORAIN	)

Kimberly Cartella, Director Compensation for NiSource Corporate Services Company, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of certain responses to Commission Staff's Request for Information in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Kimberly Cartella

Kimberly Cartella

The foregoing Verification was signed, acknowledged and sworn to before me this 24th day of August, 2021, by Kimberly Cartella.

Emily L. Brady

Notary Commission No. ______

Emily L. Brady, Attorney at Law
Resident Summit County
Notary Public, State of Ohio
My Commission Has No Expiration Date
Sec 147.03 RC

Commission expiration: NO EXP.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	

VERIFICATION OF MELISSA BARTOS

STATE OF MASSACHUSETTS	)
	)
COUNTY OF MIDDLESEX	)

Melissa Bartos, Vice President for Concentric Energy Advisors, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of certain responses to Commission Staff's Request for Information in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Melissa Bartos

The foregoing Verification was signed, acknowledged and sworn to before me this 16th day of August, 2021, by Melissa Bartos.

KRISTINA D. BRUCE
Notary Public
Commonwealth of Massachusetts
My Commission Expires
November 4, 2027

Notary Commission No. ____________

Commission expiration: November 4, 2027

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF		

VERIFICATION OF SUSAN TAYLOR

STATE OF OHIO	)
	)
COUNTY OF FRANKLIN	)

Susan Taylor, Director of Financial Planning for NiSource Corporate Services Company, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of certain responses to Commission Staff's Request for Information in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Susan Taylor

Susan Taylor

The foregoing Verification was signed, acknowledged and sworn to before me this 18th day of August, 2021, by Susan Taylor.

NOTARIAL SEAL STATE OF OHIO

John R Ryan III
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

Notary Commission No. N/A

Commission expiration: N/A

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183

VERIFICATION OF SUZANNE K. SURFACE

STATE OF OHIO	)
	)
COUNTY OF FRANKLIN	)

Suzanne K. Surface, Senior Vice President for NiSource Corporate Services Company, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of certain responses to Commission Staff's Request for Information in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Suzanne K. Surface

The foregoing Verification was signed, acknowledged and sworn to before me this 17th day of August, 2021, by Suzanne K. Surface.

Notary Commission No. 2021-RE-830293

Commission expiration: 04/22/2026

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183
	)	

VERIFICATION OF VINCENT REA

STATE OF NORTH CAROLINA)
)
COUNTY OF MOORE)

Vincent Rea, Managing Director of Regulatory Finance Associates, LLC, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that he has supervised the preparation of certain responses to Commission Staff's Request for Information in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Vincent Rea

The foregoing Verification was signed, acknowledged and sworn to before me this 16 day of August, 2021, by Vincent Rea.

STEPHEN W SIKES
Notary Public, North Carolina
Moore County
My Commission Expires
October 21, 2023

Notary Commission No.

____

Commission expiration:
10-21-23

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183
	)	

VERIFICATION OF JUDY COOPER

COMMONWEALTH OF KENTUCKY	)
	)
COUNTY OF FAYETTE	)

Judy Cooper, Director of Regulatory Affairs of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of certain responses to Commission Staff's Request for Information in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Judy M Cooper

Judy Cooper

The foregoing Verification was signed, acknowledged and sworn to before me this 24th day of August, 2021, by Judy Cooper.

Evelyn Long Durr

EVELYN LONG DURR
Notary Public
Commonwealth of Kentucky
Commission Number 600778
My Commission Expires May 15, 2022

Notary Commission No. 600778

Commission expiration: May 15, 2022

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	
	)	

VERIFICATION OF KIMRA COLE

COMMONWEALTH OF KENTUCKY	)
	)
COUNTY OF FAYETTE	)

Kimra Cole, President of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised certain responses to Commission Staff's Request for Information in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Kimra Cole

Kimra Cole

The foregoing Verification was signed, acknowledged and sworn to before me this 24th day of August, 2021, by Kimra Cole.

Evelyn Long Durr

EVELYN LONG DURR
Notary Public
Commonwealth of Kentucky
Commission Number 600778
My Commission Expires May 15, 2022

Notary Commission No. 600778

Commission expiration: May 15, 2022

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

1. Refer to the Direct Testimony of Melissa Bartos (Bartos Testimony), page 16, Table 1 – Forecasted Customer Counts, and Table 2 - Forecasted Annual Volume. The annual average usage per residential customer (residential sales volumes/residential sales customers) increases from 673 Ccf/customer in 2021 to 663 Ccf/ customer in 2022 to 685 Ccf/customer in 2023. Explain why the average annual use per residential customer is increasing annually between 2021 and 2023

Response:

As a preliminary note, the annual average use per residential sales customer *decreases* from 673 Ccf/customer in 2021 to 663 Ccf/customer in 2022, but then increases to 685 Ccf/customer in 2023. The increase in annual average use per residential customer from 2022 to 2023 is due to the forecasted decrease in natural gas prices from 2022 to 2023. The natural gas price forecast was derived from the U.S. Energy Information Administration ("EIA").

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

2. Refer to the Direct Testimony of David A. Roy (Roy Testimony), page 12, line 2.

a. Provide the number of Type-1 leaks found on the Columbia Kentucky's first generation plastic pipe system and the number of leaks per mile for the first generation plastic pipe system for the past three years.

b. Provide the number of Type-1 leaks found on the Columbia Kentucky bare steel pipe system and the number of leaks per mile for the bare steel pipe system for the past three years

Response:

The following table presents the data requested. The table provided contains only Grade 1 leaks, for all causes, inclusive of mains & services. The basis used to determine the leaks per mile calculation was only the mileage of mains for each type since service lengths are unknown.

Grade 1 Leaks		2018	2019	2020
First Gen Plastic	Found	29	19	14
	Leaks/Mile	0.12	0.08	0.06
Bare Steel	Found	316	248	162
	Leaks/Mile	0.88	0.73	0.50

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

3. Refer to the Roy Testimony, pages 46–52, regarding Columbia Kentucky's Safety Modernization and Replacement Program (SMRP).

a. Columbia Kentucky's 2020 Annual Report to PHMSA reported four miles of cast/wrought iron were remaining on the system. Confirm the total miles remaining and provide the location, including miles of pipe for each location.

b. Refer to the Roy Testimony, page 11, line 6, where Mr. Roy states that "Columbia expects cast iron will be completely eliminated from use within its system by the end of 2022." For the locations provided in previous request, provide the planned projects to support this statement.

c. Explain whether Columbia Kentucky would commit to provide the Commission with monthly or quarterly filings of the miles of cast iron replacement projects completed and to include miles of cast iron eliminated and miles of cast iron remaining.

d. Columbia Kentucky's 2020 Annual Report to PHMSA reported 316.2 miles of bare, unprotected steel pipe remaining on the system, and on page 11, line 17, of Mr. Roy's testimony, he states that bare steel is on track to be eliminated by -4- Case No. 2021-00183 2037. If Aldyl-A is approved to be included in SMRP, explain what effect this additional pipe removal efforts would have on Columbia Kentucky's timeline to meet the 2037 date for bare steel removal.

e. The projected SMRP costs are $40.0 million in 2021, $40.0 million in 2022, and $41.6 million in 2023. Provide support for this forecasted $121.6 million projected capital spend.

Response:

a. Columbia confirms that the 2020 annual report to PHMSA indicated 4 miles of cast/wrought iron were remaining in the system at year end. For the locations of the remaining cast / wrought iron, Columbia utilized its Geographic Information System ("GIS") to generate the list shown in Attachment A. It should be noted that since the beginning of 2021 and as of 8/18/21, Columbia has retired approximately 0.62 miles of cast iron. KY PSC Case No. 2021-00183, Staff 3-3, Attachment A identifies cast iron segments that remain in service as of this date.

b. KY PSC Case No. 2021-00183, Staff 3-3, Attachment A identifies the locations of the cast and wrought iron pipe segments and the year the pipe is forecasted to be retired. Columbia is still designing the projects intended to replace the remaining cast iron pipe in 2022. The planned projects are not available at this time, but will include all pipe segments included within Attachment A assigned for 2022.

c. Columbia would commit to quarterly filings that specify the locations and miles of cast iron retired, as well as, the locations and miles of cast iron remaining during the 2022 calendar year.

d. Should the Commission approve Columbia's request to allow the inclusion of first generation plastic pipe (including Aldyl-A) within Columbia's SMRP, Columbia would still plan on retiring all bare steel pipe by the end of 2037 from its' distribution system.

e. The project list for the 2021 SMRP is shown in KY PSC Case No. 2021-00183, Staff 3-3, Attachment B. The list of SMRP projects for 2022 and 2023 are not available. Columbia is still in the process of developing the project list for the 2022 and won't have that completed for a few more weeks. The SMRP project list for 2023 will likely not be developed until the fall of 2022.

ATTACHMENTS ARE EXCEL SPREADSHEETS AND UPLOADED SEPARATELY

Proposed 2021 SMRP Projects

Project Name	Project ID	Location (Streets)	City	Facility to Install	Size(s) to Install (in)	Install Footage	Stations Retired	Proposed Material To Be Removed	Customer Service Replacements	Start Month	Completion Month	Safety Issue addressed	Main Cost	Service Replacement Cost	Proposed Blanket Estimate	Total Project Cost
Highland Avenue High Pressure SMRP Optimain 2615117 18-0267767-00	18-53312	Highland Ave & East-West Connector ROW	Frankfort	Coated Steel High Pressure	8	3,401	0	3401' of bare steel pipe	0	July	November	This project addresses and eliminates high pressure bare steel pipe with mechanically jointed short barrel couplings located in proximity to other structures and a railroad crossing.	$765,225	$0		$ 765,225
Martin Luther King Cast Iron SMRP OP# 2610568 JOB# 18-0268433-00 (LP PHASE) 20-0269812-00 (MP PHASE)	18-58813	ML King, 3rd St, 2nd St, Noble, Spruce	Lexington	Plastic medium density	2"/6"/8"	4,300	0	1632' bare steel 1713' cast iron 530' coated steel 463' plastic	32	January	July	This project eliminates cast iron pipe for the reasons stated in Columbia Case No. 2009-00141 & the reasons and commitments made in Columbia Case No. 2016-00162 as well as the guidance provided by PHMSA Advisory Bulletin ADB 2012-005.	$1,204,000	$135,648		$ 1,339,648
South Limestone Cast Iron SMRP Optimain No. 2610571 JOB# 20-0269513-00	20-72224	S LIMESTONE ST, COLFAX, MOUNTMULLIN, PRALL	Lexington	Plastic medium density	2	6,400	0	1343' cast iron 1221' bare steel 1578' plastic 133' other 1578' plastic 3741' coated steel	41	February	September	This project eliminates cast iron pipe for the reasons stated in Columbia Case No. 2009-00141 & the reasons and commitments made in Columbia Case No. 2016-00162 as well as the guidance provided by PHMSA Advisory Bulletin ADB 2012-005.	$992,000	$173,799		$ 1,165,799
SMRP - Walnut St., Maysville Optimain combo 2609686 JO# 20-0269730-00	20-74375	Forrest Ave., Commerce St., Reynolds Dr., Poplar St., Walnut St., Third St., Union St.	Maysville	Plastic medium density	2", 4"	10,500	2	4375' cast iron 4282' bare steel 295' wrought iron 38' other 2736' coated steel 1496' of plastic	145	March	November	This project eliminates cast iron pipe and two regulator stations for the reasons stated in Columbia Case No. 2009-00141 & the reasons and commitments made in Columbia Case No. 2016-00162 as well as the guidance provided by PHMSA Advisory Bulletin ADB 2012-005.	$1,627,500	$614,655		$ 2,242,155
Maysville, 3rd St. Cast Iron Optimain Project 2610649 JO# 20-0269737-00 & 20-0269740-00	20-74435	3rd St., 4th st., Bridge St., Limestone St., Cherry Ally, Market St., Bugle Ally, Lexington Pk., Maddox Ave.	Maysville	Plastic medium density	2", 4", 8"	6,500	0	2898' bare steel 1867' cast iron 2149' plastic 1434' coated steel	125	January	August	This project eliminates cast iron pipe for the reasons stated in Columbia Case No. 2009-00141 & the reasons and commitments made in Columbia Case No. 2016-00162 as well as the guidance provided by PHMSA Advisory Bulletin ADB 2012-005.	$1,007,500	$529,875		$ 1,537,375
South Ashland Ave. Cast Iron SMRP Optimain No. 2610585 JOB# 20-0269518-00	20-72245	S ASHLAND AVE	Lexington	Plastic medium density	2"	2,050	0	572' cast iron 1441' 1st generation plastic	49	February	April	This project eliminates cast iron pipe for the reasons stated in Columbia Case No. 2009-00141 & the reasons and commitments made in Columbia Case No. 2016-00162 as well as the guidance provided by PHMSA Advisory Bulletin ADB 2012-005.	$389,500	$207,711		$ 597,211
Whittland Drive SMRP OP# 1625841 JOB# 20-0269711-00	20-74112	Whittland Drive, N Limestone, Glenn Place	Lexington	Plastic medium density	2"/4"	3,300	0	2477' Bare Steel 258' Plastic 34' Other	72	April	July	This project addresses an emerging problem for operations with corrosion on bare steel pipe that is reported to range in condition from fair to poor with a range of surface pitting. This project addresses leakage that has spread within dead vegetation.	$511,500	$305,208		$ 816,708
Wallace SMRP 2532267 20-0269537-00	20-72361	Wallace Ave, Montgomery St, Hoge Ave, Chinn St, Adair St,Virginia St, Owenton Ave, Collins St , Murrel St, Wright St, Holmes St	Frankfort	Plastic medium density	2"/6"	9,560	1	4497' bare steel 1895' coated steel 1873' plastic	162	January	August	This project addresses a high Optimain risk concentration with historic leaks reported to be mostly in poor condition and having deep pits often requiring multiple repair clamps. This project also eliminates one regulator station and pipe that has a propensity for Grade 1 and 2+ leaks.	$1,481,800	$686,718		$ 2,168,518
Frankfort on Walnut from Plaza to Elkhorn-1634294 / 2610666 - 6688228F 20-0269539-00 20-0269540-00	20-72362	Walnut St, Grandview Dr, Elkhorn Dr, Greenhill Av, Thompson St, Versailles Rd	Frankfort	Plastic medium density	2,4	5,627	1	425 bare steel 2014 coated steel 3102' plastic	80	March	November	This project addresses the 7th highest area of risk concentration in Kentucky and eliminates poor performing pipe and one district regulator station.	$872,185	$339,120		$ 1,211,305
Bath Ave SMRP - AORC Base 1626892 JO# 20-0269773-00	20-74824	29th St, 30th St, Bath Av, Broom St, Carter Av, Central Av, Hill St, Hermann Av, Chatteroi St	Ashland	Plastic medium density	2,4	15,300	0	3989' bare steel 3573' coated steel 8510' plastic	213	January	December	This project eliminates bare steel pipe that has a high concentration of leaks. It also has a relatively high area of risk concentration maximum risk score.	$2,371,500	$902,907		$ 3,274,407
Frankfort 2nd Street Relocation 19-0268568-00	1960737	Battle, Bridge, Capitol, Conway, Ewing, Logan, Riverview, Second, Shaw, State, Third, and Webber	Frankfort	Plastic medium density	2,4	3,659	0	2663' bare steel 859' coated steel 2003' plastic	42	January	April	This project is being worked in conjunction with a public improvement project to eliminate bare steel pipe having a high concentration of leaks. This project contains the third and fourth highest areas of risk concentration in the state.	$567,145	$178,038		$ 745,183
Newtown Nanner Horse Farm Replacement 19-0268985-00	19-66929	Right of Way	Versailles	Coated Steel High Pressure	12	5,800	0	5800 feet of bare steel pipe	3	May	September	This replacement project addresses mechanically coupled high pressure, bare steel pipe installed in the 1920s. The leak repair reports indicate the pipe is in poor condition and has deep pits.	$1,592,100	$12,717		$ 1,604,817
Blue Grass Ave. SMRP 1721689		Bluegrass Av, Highlawn AVE	Lexington	Plastic medium density	2	2,100	0	2100' Bare Steel		June	August	This project addresses a high risk single Optimain project that will be worked in conjunction with an LFUCG public improvement project. The project has the nineteenth highest area of risk concentration in the state.	$325,500	$0		$ 325,500
Lick Branch Rd SMRP - 2610445 20-0269800-00	20-75034	Main St/HWY 40, Lick Branch Road	Inez	Medium Density plastic pipe	2"	600	0	600' Bare Steel	12			This project addresses corrosion issues on pipe that is under hard surface with some of the pipe located in proximity to buildings. The pipe has a history of Grade 1 leaks and the leak repairs interfere with access to businesses.	$93,000	$50,868		$ 143,868
South Shore SMRP 2610306 Combo 2539827	2074025	West 2nd Ave, 4th, Center, Fifth, First, Fullerton, Hauser, Main, Riverside, Third	South Shore	Plastic medium density	2 & 4	7,000	0	4238' Bare Steel 3985 coated steel 1276 plastic	34	January	October	This project addresses an emerging problem with an increased number of main line leaks often resulting in emergency repairs.	$1,085,000	$144,126		$ 1,229,126

Proposed 2021 SMRP Projects

Project Name	Project ID	Location (Streets)	City	Facility to Install	Size(s) to Install (in)	Install Footage	Stations Retired	Proposed Material To Be Removed	Customer Service Replacements	Start Month	Completion Month	Safety Issue addressed	Main Cost	Service Replacement Cost	Proposed Blanket Estimate	Total Project Cost
Chenault Road SMRP OP# 2610569 JOB# 20-0269763-00	20-74695	Chenault, Cross, Hart, Romany, Louisiana	Lexington	Medium Density plastic pipe	4,2	6,000	0	8191' bare steel 925' plastic 10' coated steel	150	March	October	This project addresses the fourth highest area of risk concentration in the state. The pipe has a history of water infiltration and freeze offs.	$930,000	$635,850		$ 1,565,850
Louisa on Lackey from Sycamore ST to Carter-1722573 & 2434522: COMBO 2610708	19-68538	Lackey Ave, Hwy 23.	Louisa	Medium Density plastic pipe	4	1,344	0	2795 bare steel 1879 coated steel 680 plastic	20	April	June	This project addresses poor performing pipe under hard surface in proximity to a railroad. The project area has experienced water infiltration issues.	$208,320	$84,780		$ 293,100
Clays Mill Road Phase III; COMBO 2608045	20-69446	Clays Mill Rd fm Stratford to Harrodsburg Rd + Blue Ash, Reed, & Woodbine and portions of Rosemont Garden, Lane Allen, Southland Dr, and Lafayette Parkway	Lexington	Medium density plastic and coated steel	8, 6, 4, 2	18,500	1	12654' bare steel 575' coated steel 2593' plastic	175	January	December	This project addresses bare steel pipe with a high concentration of leaks in a very busy traffic corridor. It is being worked in conjunction with a public improvement project.	$2,867,500			$ 3,500,000
Dyasrd Hill SMRP - AORC Base 1869082: Combo 2598445	19-63196	Dysard Hill Dr, Prospect Ave	Ashland	Medium Density plastic pipe	2 & 4	1,200	0	653' Bare Steel 282' plastic 421 coated steel	6	April	June	This project addresses the tenth highest area of risk concentration in Optimain with the bare steel pipe reported to be in poor condition and having deep pits in the surface of the pipe. This project addresses leakage and the resulting migration of gas. This project contains pipe installed in the 1920s in proximity to structures.	$186,000	$25,434		$ 211,434
Lexington on Tremont from Ashland to Beaumont - 1636357 Job Order No. 20-0269771-00	20-74813	Eldemere, Kastle Rd, Melrose, Tremont Av, Mt. Vernon	Lexington	Medium Density plastic pipe	4,2	7,100	0	9142' Bare 1350' coated steel 731' plastic 34' other	150	April	November	This project will allow future retirement of the Marquis And Cooper pit regulator stations while also eliminating the bare steel medium pressure pipe located on the UK practice facility.	$1,100,500	$635,850		$ 1,736,350
Colby RD HP SMRP JOB# 20-0269641-00	20-73598	Colby Road	Winchester	Coated Steel High Pressure	12	1,500	0	1500' of bare steel pipe	9	January	March	This project addresses 1920's vintage mechanically joined high pressure bare steel pipe.	$285,000	$38,151		$ 323,152
Ashland on Frederick from Blackburn to North - 1629113 JO# 20-0269775-00	20-74825	Blackburn, North, Frederick St	Ashland	Medium Density plastic pipe	4,6,8	4,850	0	3782' bare steel 421' coated steel 282' plastic	43	May	November	This project addresses the 32 highest area of risk concentration around Blackburn Avenue.	$751,750	$182,277		$ 934,027
Ashland on Harrison from 6TH to Craft -1620324 JO# 20-0269781-00	20-74850	McGuire St., Cedar St., Cherry St., 6th St., Barbar Rd., Long St., Harrison St., Perry St., Pollard Rd.	Ashland	Medium Density plastic pipe	2,4	9,150	0	2549' bare steel 5880' plastic	80	March	November	This project eliminates poor performing pipelines and addresses the 35th highest area of risk concentration in the state.	$1,418,250	$339,120		$ 1,757,370
Hindman on Owens Branch from Short Branch to Owens Branch & Stewart Fork-1621622 JO# 19-0268829-00	19-65023	Hwy 80, Short Branch & Owens Branch	Hindman	Medium Density plastic pipe	2,4	10,400	0	7544' bare steel 2457' coated steel 1331' plastic	50	March	November	This project addresses bare steel pipe and the 59th highest area of risk concentration in the state.	$1,612,000	$211,950		$ 1,823,950
Manhattan Drive SMRP Optimain No. 1638839 Job Order No. 20-0269752-00	20-74609	MANHATTAN DRIVE, BRYAN STATION	Lexington	Medium Density plastic pipe	4	3,100	0	1820' bare steel	40	April	June	This project addresses bare steel pipe whose replacement is necessary to facilitate a future retirement of a regulator station with access and age and condition issues. The leak repair reports indicate the pipe is mostly in poor condition with a propensity to Grade 1 and 2+ leaks requiring multiple repair clamps.	$480,500	$169,560		$ 650,061
Main St Irvine SMRP - 2610566 20-0269816-00	20-75191	Carhartt, Main, Park, Covey, Collins,	Irvine	Medium Density plastic pipe	6,4,2	8,500	2	4779' bare steel 152' galvanized 4307' coated steel 5586' plastic	115	February	November	This project addresses bare steel pipe whose leak repair reports indicate the pipe has deep pits and generalized corrosion affecting the servicability of the pipe. Water infiltration has been a historic problem that will be eliminated in this area with this work.	$1,317,500	$487,485		$ 1,804,985
Paris Cast Iron - 2610525 20-0269806-00	20-75121	Walkers, Williams, 8th Street, Cypress, Henderson, and Higgins	Paris	Medium Density Plastic Pipe	2,6	18,000	4	5268 cast iron 12651 bare steel 4358 coated steel 5064 plastic	321	January	December	This project eliminates cast iron pipe and four regulator stations for the reasons stated in Columbia Case No. 2009-00141 & the reasons and commitments made in Columbia Case No. 2016-00162 as well as the guidance provided by PHMSA Advisory Bulletin ADB 2012-005.	$2,790,000	$1,360,719		$ 4,150,719
High Street Relocation - 2590287 20-0269473-00	20-71641	High St	Paris	Medium Density Plastic Pipe	2	5,000	0	Cast Iron and Bare Steel	66	January	August	This project eliminates cast iron pipe for the reasons stated in Columbia Case No. 2009-00141 & the reasons and commitments made in Columbia Case No. 2016-00162 as well as the guidance provided by PHMSA Advisory Bulletin ADB 2012-005. It will also be worked in conjunction with a public improvement project.	$775,000	$279,774		$ 1,054,774
East Main Street SMRP 2615106 20-0269499-00	20-72092	East Main Street	Mount Sterling	Medium Density Plastic Pipe	4	1,100	0	916' bare steel	4	January	March	This project addresses an unrepairable leak under a bridge and brings a new medium pressure trunk line into town so that future bare steel low-pressure replacements may be achieved with smaller diameter higher pressure pipe.	$170,500	$16,956		$ 187,456
Southland Drive Replacement		Southland Drive	Lexington	Medium Density plastic pipe	4	1,200	0	1200' bare steel		February	April	This project is necessary to address water infiltration into the main and service interruptions.	$186,000	$0		$ 186,000
Devonia Replacement		Devonia	Lexington	Medium Density plastic pipe	4	1,200	0	1200' bare steel		April	June	This project is necessary to address water infiltration into the main and service interruptions.	$185,807	$0		$ 185,807
Scattered Services	Multiple	Multiple	Multiple	Medium Density Plastic Pipe				Leaking bare steel service lines	80	January	December	This project addresses leaking bare steel services to eliminate migration of gas in proximity to structures.		$339,120		$ 339,120
579 - Blanket Meter Install Replacement	Multiple	Multiple	Multiple	Meter Attachments	NA	0		Retired Meter Setting Components	NA	January	December	Necessary for the customer to be connected to the new main			$59,000	$ 59,000

Proposed 2021 SMRP Projects

Project Name	Project ID	Location (Streets)	City	Facility to Install	Size(s) to Install (in)	Install Footage	Stations Retired	Proposed Material To Be Removed	Customer Service Replacements	Start Month	Completion Month	Safety Issue addressed	Main Cost	Service Replacement Cost	Proposed Blanket Estimate	Total Project Cost
581 - House Regulators Replacement	Multiple	Multi	Multiple	Service Regulators	Na	NA	0	Retired House Regulators	NA	January	December	Necessary for the customer to be connected to the new main			$70,000	$ 70,000
Last Line - Do not Enter Data																
Sub Totals:																$ 40,000,000

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

4. Refer Roy Testimony, page 56, concerning the benefit of modifying Line DE for In-line Inspection (ILI).

a. Provide the number of miles and locations for all high consequence area and medium consequence area segments identified on the Line DE ILI project route.

b. Provide a copy of the technical analysis to show the evaluation of all options considered by Columbia Kentucky to support the use of ILI technology to meet the requirements of 49 C.F.R. 192.937(c) for the Line DE ILI project.

c. Provide a copy of all studies indicating that using ILI in lieu of other assessment methods available to meet the requirements of 49 C.F.R. 192.937(c) is the most cost-effective

Response:

a. There are currently a total of five high consequence areas ("HCA's") and twelve moderate consequence areas ("MCA's") associated with Line DE. Please see KY PSC Case No. 2021-00183, Staff 3-4, Attachment A for a list of the HCA's and

MCA's, as well as, their stationing location and their associated lengths in feet. See CONFIDENTIAL KY PSC Case No. 2021-00183, Staff 3-4, Attachment B for a high level map showing a visual of the different HCA and MCA locations along Line DE's route.

b. 49 C.F.R. 192.937(c) provides assessment methods that may be used by an operator to assess threats identified on a given segment of pipe as specified in 192.917. 192.917 outlines the expectation an operator has to identify threats on their system. More specifically, PHMSA promulgated a pipeline safety improvement in the recent Gas Transmission Rule regulation ("Mega-Rule" – October 1, 2019) identified in 192.917 and is directly referenced below:

> **§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**
>
> *(a) Threat identification. An operator must identify and evaluate <u>all potential threats to each covered pipeline segment</u>. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 2, which are grouped under the following four categories:*
>
> > *(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;*

(2) Static or resident threats, such as fabrication or construction defects;

(3) Time independent threats such as third party damage, mechanical damage, incorrect operational procedure, weather related and outside force damage to include consideration of seismicity, geology, and soil stability of the area; and

(4) Human error.

This updated code requirement asks operators to evaluate all potential threats. Past practice had operators evaluating the most likely threats and determine the amount of changes in that threat from baseline assessment to re-assessments. These threats were typically time dependent and classified as a form of corrosion. This would generally be accomplished with over the ground assessment techniques (Direct Assessment) applied within the high consequence area.

These new requirements will require operators who do not use In-Line Inspection ("ILI") to use a combination of the Direct Assessment methods, referred to previously, along with Pressure Testing in order to accomplish the assessment of all threats. Because of this and other customer driven concerns, Columbia elected to move forward with ILI.

c. Please see KY PSC Case No. 2021-00183, Staff 3-4, Attachment C for a high level overview of the cost differences for various assessment methods.

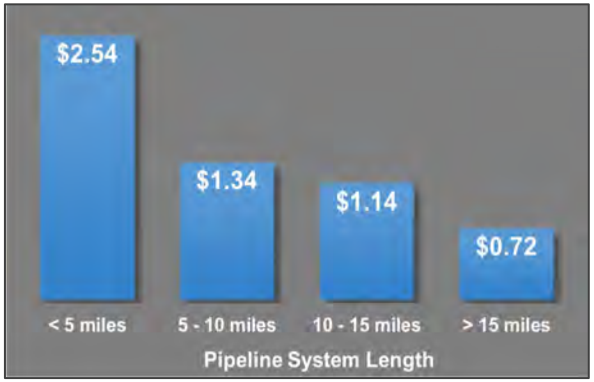
HCA/MCA DE ILI Project Route

PIPELINE ID	STATUS	BEGIN	END	HCA or MCA	LENGTH
32010170-1	Current	162271.18	164081.47	MCA	1786.218419
32010170-3	Current	25433.52	26859.56	MCA	1440.98695
32010170-2	Current	34834.91	38094.87	MCA	3313.070144
32010170-1-020	Current	0	4	MCA	4.000017
32010170-1	Current	66768.94	67389.93	MCA	625.613195
32010170-2	Current	19459.47	22575.45	HCA	3182.73215
32010170-1-021	Current	0	4	MCA	4.000148
32010170-1-019	Current	0	2	MCA	2.000008
32010170-2	Current	24035.84	25581.86	HCA	1528.363593
32010170-2	Current	32192.25	34834.91	HCA	2510.128012
32010170-3	Current	65796.52	65925.34	MCA	130.17494
32010170-1-018	Current	0	14.33	MCA	14.333211
32010170-1	Current	159520.05	161381.89	HCA	1900.265934
32010170-1	Current	166994.13	169100	MCA	2092.697488
32010170-2-001	Current	0	4	MCA	4.000148
32010170-2	Current	0	5262.92	MCA	5447.011698
32010170-3	Current	65925.34	69608	HCA	3819.818717

ATTACHMENT FILED UNDER SEAL PURSUANT TO A MOTION FOR CONFIDENTIAL TREATMENT

Prioritization Considerations

Assessment Method Comparison



Assessment Methods


Direct Assessment (DA)


Pressure Test (PT)


Inline Inspection (ILI)

	Criteria	DA	PT	ILI
Benefits	Capable of detecting sub-critical flaws	O	X	O
	Allows for a comprehensive assessment of the entire pipeline	X	O	O
	Valid assessment method for corrosion	O	Δ	O
	Valid assessment method for mechanical damage	Δ	O	O
	Valid assessment method for material flaws	X	O	O

	NiSource Integrity Assessment Average Cost per Mile ($K/mile)	DA	PT	ILI
Costs	< 5 miles long	**$56.5**	**$241.3**	**$89.6**
	5 to < 10 miles long	**$20.8**	**$69.8**	**$35.2**
	10 to < 15 miles long	**$14.8**	**$41.3**	**$30.4**
	≥ 15 miles long	**$12.4**	**$29.5**	**$14.7**

Key: O: Good; Δ: Marginal, X: Poor or NA

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

5. Refer to Columbia Kentucky's Response to Staff's First Request, Item 3. In response to Staff asking why Columbia Kentucky did not fully develop detailed engineering plans and specifications for the proposed CPCN, did not defer the CPCN request until more information was available, Columbia Kentucky responded that it did not want to incur significant engineering costs. Refer to the final Order in Case No. 2020- 00174,[1] page 80. Here, the Commission found that the proposed CPCN should be denied because Kentucky Power did not provide adequate support for either the costs of its proposal or the alternative, nor did Kentucky Power provide sufficient evidence that the proposal was the most reasonable least-cost alternative. Provide documentation that will permit review of the proposed project using the Commission's standard of review under KRS 278.020(1), demonstrating the proposed facility is the most reasonable, least-cost alternative, supporting a need for such facilities, and an absence of wasteful duplication.

[1] Case No. 2020-00174, *Electronic Application of Kentucky Power Company for (1) a General Adjustment of Its Rates for Electric Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) Approval of a Certificate of Public Convenience and Necessity; and (5) All Other Required Approvals and Relief*, (Ky. PSC Ja. 13, 2021).

Response: Columbia notes the Commission's Order on August 24, 2021 denying the deviation request filed in in conjunction with this case. The Order, which is currently being reviewed by the Company, may have an impact on the response to this request. Columbia will promptly supplement this response.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

6. Refer to Columbia Kentucky's response to Staff's First Request, Item 9. Provide the total costs of the Picarro project, if adopted.

Response:

Please refer to the below costs, which were also provided in Columbia's response to the Attorney General's First set of Requests for Information, No. 15, part c.

Unit Costs

1. $1,200,000 one-time capital cost
2. $60,000 O&M per year of service charge
3. $4,000 per year for vehicle lease
4. $1,000 per year for annual vehicle maintenance costs

Driver - $100,000 per unit, per useful year of operation

Analysis - $22,500 per year

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

7. Refer to Columbia Kentucky's response to Commission Staff's Second Request for Information (Staff's Second Request), Item 1.

a. Confirm that it would be more accurate to forecast the in-service date of a specific major capital project for the purpose of determining when plant additions would occur based on the actual projected in-service date for the project as opposed to an in-service curve, and if Columbia Kentucky is not able to confirm, explain each basis why it is not able to confirm.

b. Provide a spreadsheet showing the months in which Columbia Kentucky included projected spending on the major construction projects, or any portion thereof, in plant in service for the purpose of determining the revenue requirement in this matter.

c. Provide the effect on rate base in the forecasted period and the effect on the revenue requirement in the forecasted period of including the major construction projects as additions to plant in service on the in-service dates shown for each project at Tab 35 of the Application.

Response:

a.

The method of using specific in-service dates for large projects when projecting plant balances in the forecasted test year would provide a more precise rate base calculation – but may not provide a more accurate estimate of plant in service balances for the forecasted test year. The 2022 project plans are in the very preliminary scheduling phase and the timing of spend and in-service will very likely change as it gets closer to the 2022 construction season. Additionally, major projects are often separated into sub-projects that can be completed and in-service at different times during the year. The timing/scheduling of these 2022 sub-projects has not yet been developed. While providing a more precise calculation, the underlying in-service timing for 2022 capital projects is likely to be very different than what will occur.

Refer to PSC Case No. 2021-00183, Staff 3-7, Attachment A, which provides the budgeted activity in Construction Work in Progress ("CWIP") for 2021 and 2022. This roll-forward schedule tracks the budgeted capital expenditure spend and the budgeted additions to plant-in-service.

The 2021 total Spend (Column C) in this CWIP roll-forward is higher than the Capital Construction budget (Line 37 & 38) due to an adjustment in the IT spend category as described in the testimony of Witness Gore. The 2021 total Additions to Plant-in-Service

Spend is higher than the 2021 total Spend reflecting the budget for the balance of CWIP that is expected to be lower at the end of the 2021 calendar year by $2,578,792. The December 2020 CWIP balance was higher than expected as work done in 2020 did not get closed to Plant in Service. Further supporting this expectation is the actual results for January 2021 (Line 2). The January 2021 Additions to Plant were approximately $5.5 million compared to a fully budgeted January 2022 Additions to Plant of approximately $1.7 million. Additionally, the Additions to Plant exceed the actual month spend by approximately $2.2 million as items in CWIP at December 2020 were moved into service.

The 2022 total Spend (Column C) in this CWIP roll-forward is higher than the 2022 Capital Construction budget (Lines 42-47) due to addition of the training facility investment that was not in the capital budget partially offset by an adjustment in the IT spend category. These differences from budget were described in the testimony of Witness Gore. The 2022 total Additions to Plant-in-Service Spend is aligned with the 2022 total Spend reflecting the expectation that the CWIP balance will be unchanged from December 2021 and December 2022.

The 2021 and 2022 monthly spend patterns reflect slightly higher spend in the prime construction season (mid-late-March through end of October) versus the winter months. As the monthly Spend is a debit to CWIP and not to plant-in-service, the spending patterns do not impact the calculation of rate base.

The 2021 and 2022 Additions to Plant in Service do impact the calculation of rate base. The methodology of spreading the Additions to Plant in Service was done in three categories:

- IT software projects in-service timing was aligned with the updated project information as discussed in Witness Gore's testimony. The in-service timing is detailed by project in WPB-2.2a.
- All other budgeted capital investments in-service timing was based on a 3-year historic view of the monthly in-service additions. The monthly spread is as follows:

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2.64%	6.45%	6.89%	5.40%	4.87%	5.49%	6.18%	9.00%	6.63%	10.63%	16.46%	19.36%

  This monthly spread results in 68% of the additions going into service in the last 6 months of the year and 46% of the additions going into service in the last 3 months of the year.

- The training facility investment of $5.59 million was put in service in November 2022 additions.

The methodology used to forecast the 2022 Additions to Plant in Service provides a reasonable result and reflects the historic trends at the Company. The use of specific in-service dates for large projects that will most assuredly change is likely to create false precision and is not considered a reasonable methodology. Additionally, the historic periods used to create the in-service curve would also have had large projects that were likely to be put into service late in the year, so the historic curve is a reasonable basis to project the forecasted test year.

b. and c.

The company did not include specific in-service dates for any project in the budget. Rather, the historic monthly spread was used for all budgeted non-IT software investments. Refer to KY PSC Case No. 2021-00183, Staff 3-7, Attachment B for a comparison on the revenue requirement in the forecasted test year for the two projects (1) Westwood Point of Delivery Station, and (2) Line DE In-Line Inspection. Page 1 of the attachment compares the revenue requirements based on in-service as planned versus in-service as filed. Pages 2 -5 provide details on the rate base and depreciation expense impact.

The calculated difference in the revenue requirement is $120,623 and the following are items of note within the calculation:

- The Westwood Point of Delivery Station work is shown as going into service at month end October as this work would be done prior to the beginning of the winter heating season.

- The Line DE In-Line Inspection would be done in at least two phases and also fully completed and in-service by the end of October, prior to the beginning of winter heating season.
- The returns and depreciation rate reflect the as-filed for amounts.

ATTACHMENTS
ARE EXCEL
SPREADSHEETS
AND UPLOADED
SEPARATELY

Line #		Revenue Requirement - As filed		Revenue Requirement - Estimated Project In Service	
1	Rate Base				
2	Westwood Point of Delivery	1,298,236		805,084	
3	Line DEI In-Line Inspection	2,596,475		2,144,343	
4	Total Rate Base		3,894,711		2,949,427
5					
6	Filed For Rate of Return		7.48%		7.48%
7					
8	Return on Rate Base		291,324		220,617
9					
10	Depreciation				
11	Westwood Point of Delivery	22,858		12,980	
12	Line DEI In-Line Inspection	45,716		36,342	
13	Total Depreciation		68,574		49,322
14					
15					
16	Operating Income Required		359,898		269,939
17					
18	Gross Revenue Conversion Factor		1.340866		1.340866
19					
20	Revneue Requirement		$ 482,575		$ 361,952
21					
22	**Difference**			$ 120,623	

Westwood Point of Delivery - As Filed

Line #			December	January	February	March	April	May	June	July	August	September	October	November	December	13-Month Average
1	Plant in Service		0	2.64%	6.45%	6.89%	5.40%	4.87%	5.49%	6.18%	9.00%	6.63%	10.63%	16.46%	19.36%	
2																
3	37600 Beginning Month		-	-	92,548	318,206	559,466	748,407	918,758	1,110,760	1,327,007	1,642,023	1,874,235	2,246,290	2,822,407	
4	Additions - $3,500,000		-	92,548	225,658	241,260	188,941	170,351	192,002	216,247	315,016	232,212	372,055	576,117	677,593	
5	Ending Month		-	92,548	318,206	559,466	748,407	918,758	1,110,760	1,327,007	1,642,023	1,874,235	2,246,290	2,822,407	3,500,000	
6																
7	Total Plant in Service		-	92,548	318,206	559,466	748,407	918,758	1,110,760	1,327,007	1,642,023	1,874,235	2,246,290	2,822,407	3,500,000	1,320,008
8																
9	Total Accumulated Depreciation															
10																
11	37600 Beginning Month		-	-	(69)	(374)	(1,025)	(1,995)	(3,231)	(4,736)	(6,544)	(8,746)	(11,354)	(14,410)	(18,169)	
12	Depreciation		-	(69)	(305)	(651)	(970)	(1,236)	(1,505)	(1,808)	(2,202)	(2,608)	(3,056)	(3,759)	(4,689)	
13	End of Month		-	(69)	(374)	(1,025)	(1,995)	(3,231)	(4,736)	(6,544)	(8,746)	(11,354)	(14,410)	(18,169)	(22,858)	
14																
15	Total Accumlated Depreciation		-	(69)	(374)	(1,025)	(1,995)	(3,231)	(4,736)	(6,544)	(8,746)	(11,354)	(14,410)	(18,169)	(22,858)	(7,193)
16																
17	Deferred Income Tax															
18	Beginning Month			-	(2,712)	(5,364)	(7,931)	(10,418)	(12,838)	(15,192)	(17,470)	(19,649)	(21,727)	(23,694)	(25,485)	
19	Depreciation			(2,712)	(2,653)	(2,566)	(2,487)	(2,421)	(2,353)	(2,278)	(2,180)	(2,078)	(1,966)	(1,791)	(1,559)	
20	End of Month		-	(2,712)	(5,364)	(7,931)	(10,418)	(12,838)	(15,192)	(17,470)	(19,649)	(21,727)	(23,694)	(25,485)	(27,044)	(14,579)
21																
22	Total Rate Base															1,298,236
23																
24	Depreciation															
25																2022 Expense
26	37600	1.78%	-	69	305	651	970	1,236	1,505	1,808	2,202	2,608	3,056	3,759	4,689	
27																
28	Total Depreciation		-	69	305	651	970	1,236	1,505	1,808	2,202	2,608	3,056	3,759	4,689	22,858

Westwood Point of Delivery - Estimated Project In-Service Date

Line #			December	January	February	March	April	May	June	July	August	Septembe	October	November	December	13-Month Average
1	Plant in Service															
2																
3	37600 Beginning Month		-	-	-	-	-	-	-	-	-	-	-	3,500,000	3,500,000	
4	Additions												3,500,000	-		
5	Ending Month		-	-	-	-	-	-	-	-	-	-	3,500,000	3,500,000	3,500,000	
6																
7	Total Plant in Service		-	-	-	-	-	-	-	-	-	-	3,500,000	3,500,000	3,500,000	807,692
8																
9	Total Accumulated Depreciation															
10																
11	37600 Beginning Month		-	-	-	-	-	-	-	-	-	-	-	(2,596)	(7,788)	
12	Depreciation		-	-	-	-	-	-	-	-	-	-	(2,596)	(5,192)	(5,192)	
13	End of Month		-	-	-	-	-	-	-	-	-	-	(2,596)	(7,788)	(12,980)	
14																
15	Total Accumlated Depreciation		-	-	-	-	-	-	-	-	-	-	(2,596)	(7,788)	(12,980)	(1,797)
16																
17	Deferred Income Tax															
18	Beginning Month		-	-	-	-	-	-	-	-	-	-	-	(2,081)	(3,515)	
19	Depreciation			-	-	-	-	-	-	-	-	-	(2,081)	(1,434)	(1,434)	
20	End of Month		-	-	-	-	-	-	-	-	-	-	(2,081)	(3,515)	(4,948)	(811)
21																
22	Total Rate Base															805,084
23																
24	Depreciation															2022 Expense
25																
26	37600	1.78%	-	-	-	-	-	-	-	-	-	-	2,596	5,192	5,192	
27																
28	Total Depreciation		-	-	-	-	-	-	-	-	-	-	2,596	5,192	5,192	12,980

Line DE In-Line Inspection - As Filed

Line #			December	January	February	March	April	May	June	July	August	September	October	November	December	13-Month Average
1	Plant in Service			2.64%	6.45%	6.89%	5.40%	4.87%	5.49%	6.18%	9.00%	6.63%	10.63%	16.46%	19.36%	
2																
3	37600 Beginning Month		-	-	185,096	636,412	1,118,932	1,496,815	1,837,518	2,221,522	2,654,016	3,284,048	3,748,473	4,492,584	5,644,819	
4	Additions - $7,000,000		-	185,096	451,316	482,520	377,883	340,703	384,004	432,494	630,032	464,425	744,111	1,152,235	1,355,184	
5	Ending Month		-	185,096	636,412	1,118,932	1,496,815	1,837,518	2,221,522	2,654,016	3,284,048	3,748,473	4,492,584	5,644,819	7,000,003	
6																
7	Total Plant in Service		-	185,096	636,412	1,118,932	1,496,815	1,837,518	2,221,522	2,654,016	3,284,048	3,748,473	4,492,584	5,644,819	7,000,003	2,640,018
8																
9	Total Accumulated Depreciation															
10																
11	37600 Beginning Month		-	-	(137)	(746)	(2,048)	(3,988)	(6,461)	(9,471)	(13,087)	(17,491)	(22,707)	(28,819)	(36,338)	
12	Depreciation		-	(137)	(609)	(1,302)	(1,940)	(2,473)	(3,010)	(3,616)	(4,404)	(5,216)	(6,112)	(7,519)	(9,378)	
13	End of Month		-	(137)	(746)	(2,048)	(3,988)	(6,461)	(9,471)	(13,087)	(17,491)	(22,707)	(28,819)	(36,338)	(45,716)	
14																
15	Total Accumlated Depreciation		-	(137)	(746)	(2,048)	(3,988)	(6,461)	(9,471)	(13,087)	(17,491)	(22,707)	(28,819)	(36,338)	(45,716)	(14,385)
16																
17	Deferred Income Tax															
18	Beginning Month		-	-	(5,424)	(10,730)	(15,862)	(20,836)	(25,677)	(30,384)	(34,939)	(39,299)	(43,455)	(47,388)	(50,970)	
19	Depreciation			(5,424)	(5,306)	(5,133)	(4,974)	(4,841)	(4,707)	(4,556)	(4,359)	(4,156)	(3,933)	(3,582)	(3,118)	
20	End of Month		-	(5,424)	(10,730)	(15,862)	(20,836)	(25,677)	(30,384)	(34,939)	(39,299)	(43,455)	(47,388)	(50,970)	(54,088)	(29,158)
21																
22	Total Rate Base															2,596,475
23																
24	Depreciation															2022 Expense
25																
26	37600	1.78%	-	137	609	1,302	1,940	2,473	3,010	3,616	4,404	5,216	6,112	7,519	9,378	
27																
28	Total Depreciation		-	137	609	1,302	1,940	2,473	3,010	3,616	4,404	5,216	6,112	7,519	9,378	45,716

Line DE In-Line Inspection - Estimated Project In-Servcie Dates

Line #			December	January	February	March	April	May	June	July	August	September	October	November	December	13-Month Average
1	Plant in Service															
2																
3	37600 Beginning Month		-	-	-	-	-	-	-	-	-	3,500,000	3,500,000	7,000,000	7,000,000	
4	Additions										3,500,000		3,500,000	-		
5	Ending Month		-	-	-	-	-	-	-	-	3,500,000	3,500,000	7,000,000	7,000,000	7,000,000	
6																
7	Total Plant in Service		-	-	-	-	-	-	-	-	3,500,000	3,500,000	7,000,000	7,000,000	7,000,000	2,153,846
8																
9	Total Accumulated Depreciation															
10																
11	37600 Beginning Month		-	-	-	-	-	-	-	-	-	(2,596)	(7,788)	(15,576)	(25,959)	
12	Depreciation		-	-	-	-	-	-	-	-	(2,596)	(5,192)	(7,788)	(10,383)	(10,383)	
13	End of Month		-	-	-	-	-	-	-	-	(2,596)	(7,788)	(15,576)	(25,959)	(36,342)	
14																
15	Total Accumlated Depreciation		-	-	-	-	-	-	-	-	(2,596)	(7,788)	(15,576)	(25,959)	(36,342)	(6,789)
16																
17	Deferred Income Tax															
18	Beginning Month		-	-	-	-	-	-	-	-	-	(2,081)	(3,515)	(7,029)	(9,897)	
19	Depreciation			-	-	-	-	-	-	-	(2,081)	(1,434)	(3,515)	(2,867)	(2,867)	
20	End of Month		-	-	-	-	-	-	-	-	(2,081)	(3,515)	(7,029)	(9,897)	(12,764)	(2,714)
21																
22	Total Rate Base															2,144,343
23																
24	Depreciation															2022 Expense
25																
26	37600	1.78%	-	-	-	-	-	-	-	-	2,596	5,192	7,788	10,383	10,383	
27																
28	Total Depreciation		-	-	-	-	-	-	-	-	2,596	5,192	7,788	10,383	10,383	36,342

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

8. Refer to Columbia Kentucky's response to Staff's Second Request, Item 16.

a. Explain Columbia Kentucky's plans for beginning to accept Renewable Natural Gas.

b. Explain the potential advantages and disadvantages of beginning to accept Renewable Natural Gas

Response:

a. With the approval of the gas quality standards for Renewable Natural Gas ("RNG"), Columbia will be ready to accept RNG. Should the Company want to purchase RNG, or an RNG supplier approach the Company to transport RNG, or should one of our transportation customers request the ability to have RNG delivered by a natural gas supplier the gas quality standards will provide the guidelines of what must be met in order for the gas to be accepted. At this point, Columbia does not have any current requests from any party to deliver RNG, nor are they actively soliciting to purchase RNG. However, given the growing attention on carbon emissions and sustainability, the Company expects RNG to become more prevalent in the future. Establishing gas quality standards for RNG is the necessary first step, as it will provide potential suppliers of RNG with the minimum standard that is required to bring RNG onto the Company's system. This will enable customers and suppliers to proactively seek opportunities to bring the benefits of RNG to Columbia's system.

b. Columbia does not see any disadvantages of accepting RNG as long as that RNG meets its minimum gas quality standards. The advantages of accepting RNG are twofold. First, accepting RNG will provide the opportunity to lower the carbon fuel mix for Columbia's customers. More specifically, it would provide Columbia's transportation customers an option to secure a low carbon fuel for customers who wish to lower their carbon emissions. Second, accepting RNG will encourage more production of RNG which will increase the supply of a low carbon fuel. Whether that gas is used by Columbia's customers or others, it will serve to lower emissions.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

9. Refer to Columbia Kentucky's response to Staff's First Request, Item 18. Provide documentation that supports the statement that typically an increase of 1.5 to 2.0 times the system average increase is considered to be the maximum range and at the same time support the concept of gradualism.

Response:

As noted in the response to Staff Data Request 2-18, the Company noted "there is no hard and fast rule with respect to applying the concept of gradualism in developing a revenue distribution. American Gas Association's Gas Rate Fundamentals fourth addition states on page 155 "Stability leads to a policy of gradualism in rate changes if substantial increases (or decreases) are called for in the context of a single rate case. Changes in gas utility pricing policy should be imposed gradually so that customers can adjust and any adverse impacts on the customers' operations are minimized." NARUC's "Gas Distribution Rate Design Manual" published in June 1989 states on page 56 "Even when there is convincing evidence that major changes are needed, Commissions will often utilize the concept of gradualism to make a series of small incremental changes rather than large revolutionary change."

As noted in the response to Staff Data Request 2-18, the Company limited increases to no more than 1.0 percent above the total company increase for any one rate class. The 1.5 to 2.0 times the system average increase maximum range is based on NiSource's experience filing gas distribution rate cases in the six states it serves.[1] It is important to note that Columbia has not seen the need for a more aggressive movement toward parity in this case and therefore did not propose a more aggressive movement (1.5 to 2.0 times system average) that has been seen in other jurisdictions.

[1] Case no. R-2020-3018835 Pennsylvania Public Utility Commission dated February 19, 2021 page 233 of the opinion and order.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

10. Refer to Columbia Kentucky's response to Staff's First Request, Item 22.

a. If completed, provide the zero-intercept study.

b. Recently, the Commission expressed its concern about the demand/customer expenses allocation for distribution plant classifications and the Commission's preference for the zero-intercept method.[1] Although this concern has been expressed in electric rate cases, the same concept applies to natural gas in that if the zero-intercept analysis does not provide reasonable results, then this indicates little relationship between the number or cost and the number of customers, and therefore increasing the customer charge based on an arbitrary allocation is unreasonable. Provide an update to the filed cost of service study where the calculation of the distribution mains where the minimum system was applied is 100 percent demand.

[1] See Case No. 2020-00131, *Electronic Application of Meade County Rural Electric Cooperative Corporation for an Adjustment in Rate* (Ky. PSC Sept 16, 2020), Order at 12

Response:

a. As noted in Staff's data request Staff 2-022, Columbia Kentucky retained an outside consultant to perform a zero-intercept study. KY PSC Case No. 2021-00183, Staff 3-010, Attachment A provide the results of Columbia's zero-intercept study which was performed by Black & Veatch Management Consulting, LLC (Black & Veatch).

b. KY PSC Case No. 2021-00183, Staff 3-010, Attachment B provides a 100% Demand study to show mains costs treated as 100% Demand related and 0% Customer related. As discussed in Witness Johnson's testimony, the Company submitted three Allocated Cost of Service studies with its application. Attachment KLJ-ACOS-1 to Witness Johnson's testimony is a Customer/Demand study that identified approximately 75% of mains costs as being customer related. Attachment KLJ-ACOS-2 to Witness Johnson's testimony is a Demand/Commodity study where the demand component for each class was used to allocate 50% of the cost of mains with total throughput used to allocate the remaining 50%. Attachment KLJ-ACOS-3 to Witness Johnson's testimony is an Average study where mains are allocated based on a simple average of the mains allocation factors produced from the Customer/Demand and Demand/Commodity studies. The Company's rates in this case were designed based on the Average study which identified approximately 37.7% of mains costs as being customer related. With the completion of Columbia's zero-intercept study by Black & Veatch, the results show there is a statistically valid customer cost component of mains that supports the use of the Company's Customer/Demand Study in deriving its Average Study for purposes of designing the Company's rates.

DRAFT

ZERO INTERCEPT ANALYSIS

For Distribution Mains

Case No. 2021-00183

BV PROJECT NO. 409508

PREPARED FOR

Columbia Gas of Kentucky, Inc.

18 AUGUST 2021

BLACK & VEATCH

Table of Contents

LIST OF TABLES

LIST OF FIGURES

Executive Summary

In a Class Cost of Service Study (CCOSS), the distribution systems costs are classified as either "Demand" or "Customer" related. Demand-related costs are those costs associated with serving increasing peak demand. In contrast, customer-related costs are those costs associated with serving a customer regardless of customer demand.

One of the two commonly accepted approaches to estimating the classification of costs of distribution mains for a natural gas utility is the Zero Intercept Approach (ZIA). The ZIA uses regression analysis to determine the customer-related portion of the costs of distribution mains by fitting a curve to the gas utility's distribution mains data. The intercept of the fitted equation is the Zero Intercept and represents the theoretical cost of distribution mains to serve zero loads (i.e., the cost of connecting a customer to the gas distribution system). The ZIA is the preferred approach of the Kentucky Public Service Commission (the Commission).[1]

Black & Veatch Management Consulting, LLC (Black & Veatch) was retained by Columbia Gas of Kentucky, Inc. (CKY) to perform a Zero Intercept analysis. ZIA for its natural gas distribution mains. Based upon Black & Veatch's base case analysis and alternative scenarios, the results support a customer-related cost component for CKY's gas distribution mains of between 43.49 percent and 43.69 percent.

[1] Commonwealth of Kentucky Public Service Commission, Case No. 2020-00174

Description of the Zero Intercept Approach

The ZIA is a commonly used methodology for determining the customer cost component of distribution mains. Two of the more commonly accepted literary references relied upon when preparing CCOSS are the Electric Utility Cost Allocation Manual, by John J. Doran et al., National Association of Regulatory Utility Commissioners (NARUC) and Gas Rate Fundamentals, American Gas Association. Both these authorities describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities. In its publication, “Gas Distribution Rate Design Manual,” NARUC presents a section which describes the zero-intercept approach as a minimum system method to be used when identifying and quantifying a customer cost component of distribution mains investment.

In the case of a natural gas distribution utility, the ZIA uses distribution main data to fit a regression equation where the estimated dependent variable (y-hat) is the Unit Cost (i.e., the installed cost per foot) and the estimated independent variable (x-hat) is the diameter of the respective pipe sizes. In the case of distribution mains, the independent variable is commonly specified as the square of the diameter of each pipe size, reflecting that the capacity of pipelines does not increase in a linear function. The result is a linear regression equation. The intercept in the equation is the theoretical cost per foot of the distribution mains system constructed with a pipe diameter of zero and, therefore, is customer related.

The product of the estimated intercept (i.e., y-hat) and the number of feet of mains is that portion of the utility’s cost of distribution mains that is customer-related. The balance of the distribution-system cost is demand-related.

Estimating the Zero Intercept for CKY's Distribution Mains

CKY's distribution mains are composed of Steel, Plastic, and Cast-Iron. Each material type has unique cost characteristics. Therefore, the different cost characteristics of each material type requires that the size and cost data for each material be analyzed separately, capturing their unique cost structures. The cost to install distribution mains has changed over time, reflecting the overall inflation rate and other factors. Therefore, Black & Veatch used the Handy-Whitman Index (HWI) to adjust each year's investment to a constant dollar value in 2020. The HWI provides unique annual index values for each type of pipe material for each year, allowing for a consistent statement of costs. The HWI data used in this analysis is provided in Appendix A.

The total footage and cost of distribution mains for each material type are presented in Table 1 below.

Table 1 – Footage and Characterisitics of CKY's Distribution Mains

Material	Total Distribution Mains in Feet (Ft.)	Installed Cost in 2020 Dollars ($)	Cost per Foot in 2020 Dollars ($)
Steel	6,269,213	$445,460,940	$71.06
Plastic	7,692,500	$273,497,691	$35.55
Cast Iron	40,068	$1,707,130	$42.61

Regression Analyses

The cost to install distribution mains differs based upon the type of material used. Therefore, the resulting regression equation would be expected to differ for each material type. Black & Veatch prepared a ZIA based upon data for main size and installed cost per foot provided by CKY. The CKY distribution system consists of plastic, steel and cast iron mains with sizes ranging from 0.75 Inches to 24 Inches. Appendix B of this report details the raw data used in this analysis adjusted for inflation.

STEEL MAINS

The regression analysis for steel mains produced the following results.

Equation 1 ***Steel Mains Cost per Foot = $34.1517 + (0.86547 * Diameter^2)***

The resulting Y-intercept, $34.1517 per foot, is that portion of the average cost of steel distribution main, $71.06 per foot, which is customer-related, 48.06 percent of distribution mains.

PLASTIC MAINS

The regression analysis for plastic mains produced the following results.

Equation 2 ***Plastic Mains = $12.9241 + (2.4792 * Diameter^2)***

The resulting Y-intercept, $12.9241 per foot, is that portion of the average cost of plastic distribution main, $35.55 per foot, which is customer-related, 36.35 percent of distribution mains.

CAST IRON MAINS

The regression analysis for cast iron mains produced the following results.

Equation 3 *Cast Iron Mains = \$33.0993 + (0.2627 * Diameter^2)*

The resulting Y-intercept, \$33.0993 per foot, is that portion of the average cost of cast iron distribution main, \$42.61 per foot, is customer-related, which is 77.69 percent of distribution mains.

Customer-Related Cost Component of CKY's Distribution Mains

Black & Veatch calculated a weighted average of the different pipe materials (i.e., steel, plastic, and cast iron) based upon the above regression analyses to derive CKY's customer-related cost component of distribution mains. The weighted average calculation is based upon investment for each material adjusted to 2020 cost levels. Table 2 below details the results of the analysis.

Table 2 – Estimation of the Customer-Related Cost Component of Distribution Mains – Base Case

Type	Total Current Cost	Customer Cost Percentage	Customer Cost Component
Steel	\$445,460,940	48.06%	\$214,104,280
Plastic	\$273,497,691	36.35%	\$99,418,494
Cast Iron	\$1,707,130	77.69%	\$1,326,222
Total	**\$720,665,761**	**43.69%**	**\$314,848,996**

The ZIA results in a customer-related cost component of 43.69 percent. The demand-related cost component is 56.31 percent of the total cost of CKY's distribution mains.

Alternative Scenario Analysis

Black & Veatch performed two alternative scenario analyses to determine if using a different specification of the regression equations led to a statistically significant result. The scenarios performed are discussed below.

EXCLUSION OF CAST IRON MAINS

Cast iron mains are being retired from service by virtually all gas distribution utilities in North America. CKY only has approximately 40,000 feet of cast iron mains remaining in service, which is 0.3 percent of its total installed footage of mains. Black & Veatch re-estimated the customer-related cost component of distribution mains with cast iron mains excluded from the analysis by removing them from the weighted average calculation. The results are provided in Table 3 below.

Table 3 - Estimation of the Customer-Related Cost Component of Distribution Mains with Cast Iron Mains Excluded

Type	Total Current Cost	Customer Cost Percentage	Customer Cost Component
Steel	$445,460,940	48.06%	$214,104,280
Plastic	$273,497,691	36.35%	$99,418,494
Total	**$718,958,631**	**43.61%**	**$313,522,774**

The resulting customer-related cost component of mains decreased slightly from 43.69 percent to 43.61 percent.

ELIMINATION OF PIPE DIAMETERS WHICH ARE NOT COMMONLY USED

Most the distribution mains installed by CKY fall into a limited number of sizes. Therefore, Black & Veatch performed the regression analyses adopting the criteria to limit the sample to those sizes that are most commonly installed on CKY's system.

Steel Mains - The entire population of steel mains contains 22 different sizes (i.e., diameters). However, limiting the regression analysis mains with diameters which constituted at least 5 percent of the installed system, reduced the number of pipe sizes to 6 diameters, constituting 95.62% of the steel pipe installed by CKY. Figure 1 below provides an illustration of the percentage of each steel main by size and the relative portion of the total percentage of steel mains.

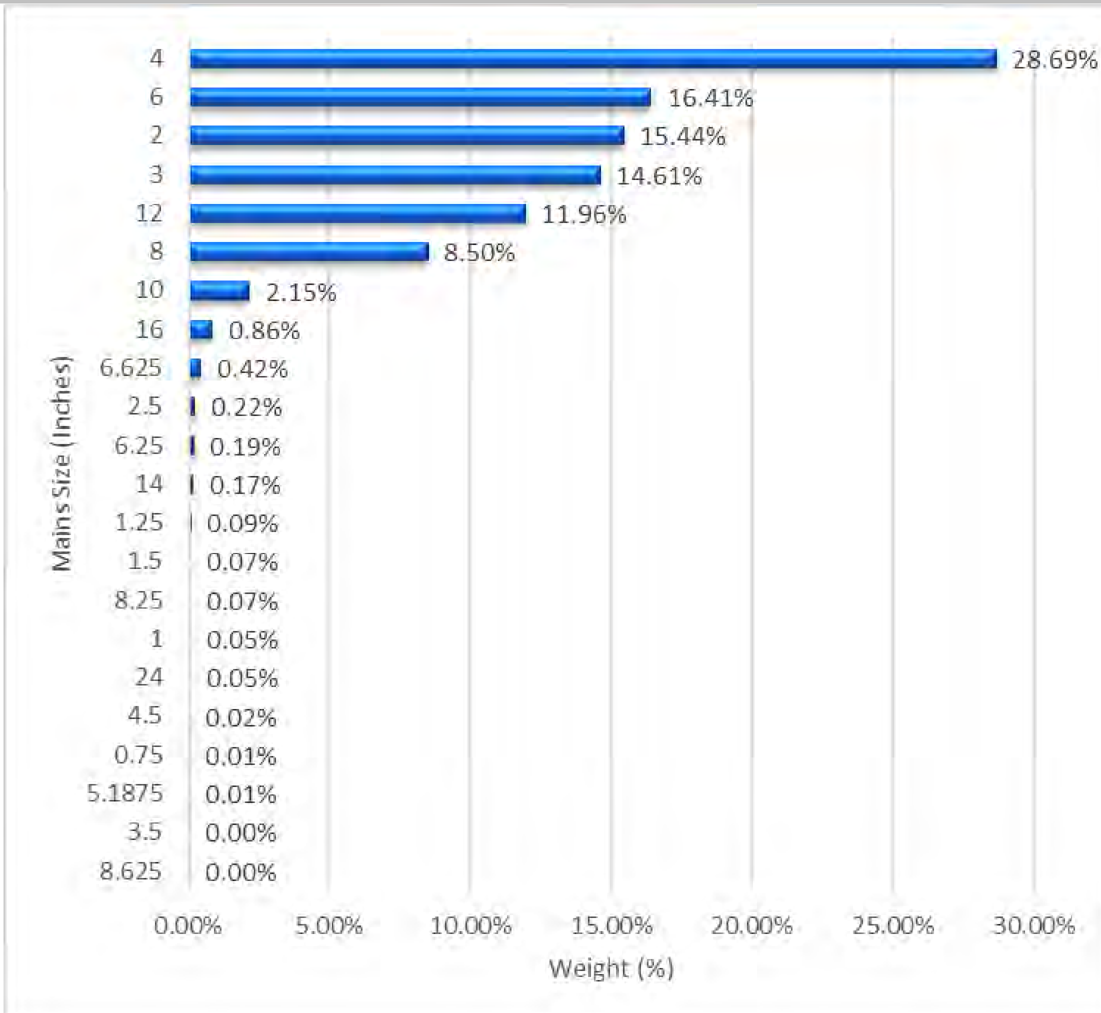


Figure 1 – Percentage of Steel Main Footage by Size

The regression analysis for steel mains excluding pipe diameters not commonly used by CKY produced the following results.

Equation 4 ***Steel Mains = \$31.0585+ (1.00324* Diameter²)***

The resulting Y-intercept, \$31.0585 per foot, is that portion of the average cost of cast iron distribution main, \$67.83 per foot, is customer-related, which is 45.79 percent of distribution mains.

<u>Plastic Mains</u> - The entire population of plastic mains contains ten different diameters of sizes (i.e., diameters). However, limiting the regression analysis mains with diameters which constituted at least 5 percent of the installed system, reduced the number of pipe sizes to 4 diameters, constituting 97.05% of the steel pipe installed by CKY. Figure 2 below provides an illustration of the percentage of each plastic main by size and its relative portion of the total percentage of plastic mains.

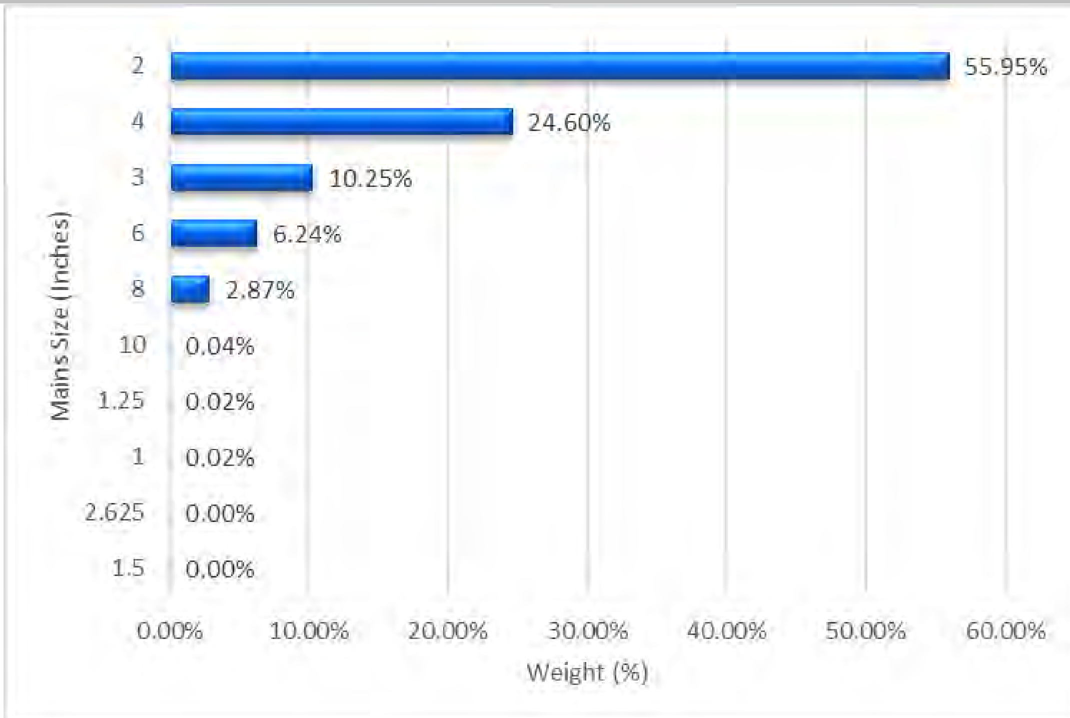


Figure 2 - Percentage of Plastic Main Footage by Size

The regression analysis for plastic mains excluding pipe diameters not commonly used by CKY produced the following results.

Equation 5 *Plastic Mains = \$13.6437 + (1.9453* Diameter^2)*

The resulting Y-intercept, \$13.6437 per foot, is that portion of the average cost of cast iron distribution main, \$34.24 per foot, is customer-related, which is 39.84 percent of distribution mains.

The results of the revised regression analysis are provided in Table 4 below. Elimination of pipe diameters that are not commonly used in the CKY system results in a customer cost component of mains of 43.49% of the total system.

Table 4 - Estimation of the Customer-Related Cost Component of Distributiion Mains – Only Common Pipe Sizes

Type	Total Current Cost	Customer Cost Percentage	Customer Cost Component
Steel	\$406,600,174	45.79%	\$186,176,977
Plastic	\$255,638,568	39.84%	\$101,853,651
Total	**\$662,238,742**	**43.49%**	**\$288,030,595**

Performing the ZIA using only commonly used pipe sizes slightly increased the percentage of distribution mains that are classified as customer-related from 43.69 percent to 43.49 percent.

CONCLUSION

Table 5 below compares the results of the base case and two alternative scenarios detailed in this report.

Table 5 – Sumamry of the Results of Each Scenario

Case Description	Percent of Distribution Mains Classified as Customer - Related
Base Case	43.69%
Exclude Cast Iron	43.61%
Only Common Pipeline Sizes	43.49%

The results of the three cases demonstrate very little difference in the overall results of the ZIA. The consistency of the results across the various scenarios supports a customer-related cost component of distribution mains for CKY of between 43.49 percent and 43.69 percent.

Appendix A. Handy Whitman Index (HWI)

Handy Whitman Index
(Atlantic South Region)

	1920	1921	1922	1923	1924	1925	1926	1927	1928	1929	1930	1931	1932	1933	1934	1935	1936	1937	1938	1939	1940
Index Value (2020 = 1.00)																					
Cast Iron	0.0258	0.0227	0.0206	0.0216	0.0227	0.0227	0.0227	0.0196	0.0186	0.0186	0.0186	0.0175	0.0155	0.0165	0.0196	0.0196	0.0196	0.0216	0.0216	0.0216	0.0227
Steel	0.0158	0.0147	0.0137	0.0147	0.0147	0.0158	0.0168	0.0158	0.0147	0.0158	0.0147	0.0147	0.0147	0.0126	0.0147	0.0147	0.0137	0.0147	0.0147	0.0158	0.0147
Plastic	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Handy Whitman Index
(Atlantic South Region)

	1940	1941	1942	1943	1944	1945	1946	1947	1948	1949	1950	1951	1952	1953	1954	1955	1956	1957	1958	1959	1960
Index Value (2020 = 1.00)																					
Cast Iron	0.0227	0.0247	0.0268	0.0278	0.0278	0.0299	0.0340	0.0412	0.0474	0.0485	0.0485	0.0526	0.0536	0.0557	0.0588	0.0619	0.0649	0.0691	0.0711	0.0742	0.0763
Steel	0.0147	0.0168	0.0189	0.0189	0.0200	0.0200	0.0231	0.0252	0.0294	0.0315	0.0326	0.0347	0.0368	0.0399	0.0410	0.0431	0.0462	0.0494	0.0515	0.0546	0.0567
Plastic	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Handy Whitman Index
(Atlantic South Region)

	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Index Value (2020 = 1.00)																					
Cast Iron	0.0763	0.0794	0.0814	0.0835	0.0856	0.0866	0.0876	0.0876	0.0897	0.0918	0.0948	0.0990	0.1021	0.1031	0.1443	0.1629	0.1670	0.1711	0.1825	0.1897	0.2072
Steel	0.0567	0.0588	0.0609	0.0630	0.0641	0.0662	0.0683	0.0714	0.0735	0.0798	0.0851	0.0924	0.1008	0.1050	0.1218	0.1366	0.1460	0.1576	0.1733	0.1880	0.2027
Plastic	0.0000	0.0000	0.1230	0.1248	0.1266	0.1266	0.1319	0.1355	0.1390	0.1444	0.1515	0.1622	0.1711	0.1783	0.1996	0.2264	0.2406	0.2567	0.2763	0.3012	0.3333

Handy Whitman Index
(Atlantic South Region)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Index Value (2020 = 1.00)																					
Cast Iron	0.2072	0.2258	0.2299	0.2474	0.2423	0.2546	0.2454	0.2515	0.2665	0.2812	0.2814	0.2804	0.2825	0.2884	0.2969	0.2889	0.2915	0.3013	0.3046	0.3093	0.3155
Steel	0.2027	0.2258	0.2395	0.2458	0.2521	0.2479	0.2353	0.2405	0.2592	0.2721	0.2765	0.2818	0.2855	0.2925	0.3146	0.3204	0.3214	0.3293	0.3361	0.3456	0.3629
Plastic	0.3333	0.3654	0.3868	0.4011	0.4082	0.4100	0.4135	0.4225	0.4443	0.4759	0.4884	0.4973	0.5000	0.5120	0.5214	0.5307	0.5414	0.5521	0.5646	0.5749	0.5860

Handy Whitman Index
(Atlantic South Region)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
					Jul.1	Jul.1	Jul.1	Jul.1	Jul.1	Jul.1	Jul.1	Jul.1	Jul.1	Jul.1	Jul.1	Jul.1	Jul.1	Jul.1	Jul.1	Jul.1	
Index Value (2020 = 1.00)																					
Cast Iron	0.3155	0.3229	0.3425	0.3487	0.3593	0.3835	0.4186	0.4640	0.5237	0.5835	0.6124	0.6031	0.7082	0.7309	0.8191	0.7887	0.7959	0.8577	0.9113	0.9526	1.0000
Steel	0.3629	0.3674	0.3747	0.3881	0.4785	0.5735	0.6229	0.5924	0.7090	0.6429	0.6744	0.7321	0.8267	0.8088	0.8109	0.7805	0.7542	0.8214	0.8845	0.9013	1.0000
Plastic	0.5860	0.5998	0.6132	0.6217	0.6480	0.6863	0.7201	0.7692	0.7897	0.8414	0.8075	0.8253	0.8717	0.8717	0.8717	0.8770	0.8859	0.9002	0.9091	0.9519	1.0000

Appendix B. Summary Data Used in the Regression Analyses

STEEL

Main Size (inches)	Main Size^2 (inches)	Cost Per Foot ($/Ft.)	Linear Feet	Total Current Cost
0.75	0.56	$18.89	869	$16,414
1.00	1.00	$28.66	3,174	$90,965
1.25	1.56	$21.82	5,948	$129,786
1.50	2.25	$53.00	4,198	$222,473
2.00	4.00	$26.70	967,986	$25,843,990
2.50	6.25	$32.67	14,006	$457,572
3.00	9.00	$38.29	915,769	$35,062,456
3.50	12.25	$105.85	207	$21,910
4.00	16.00	$49.89	1,798,418	$89,714,350
4.50	20.25	$61.86	1,394	$86,239
5.19	26.91	$50.33	604	$30,398
6.00	36.00	$70.21	1,029,020	$72,243,869
6.25	39.06	$43.38	11,771	$510,615
6.63	43.89	$64.82	26,309	$1,705,395
8.00	64.00	$104.42	533,103	$55,668,549
8.25	68.06	$68.07	4,131	$281,181
8.63	74.39	$78.30	74	$5,794
10.00	100.00	$145.61	134,643	$19,605,211
12.00	144.00	$170.73	750,099	$128,066,960
14.00	196.00	$234.64	10,723	$2,516,090
16.00	256.00	$214.46	53,654	$11,506,420
24.00	576.00	$537.84	3,113	$1,674,305

PLASTIC

Main Size (inches)	Main Size^2 (inches)	Cost Per Foot ($/Ft.)	Linear Feet	Total Current Cost
1.00	1	$21.86	1,436	$31,396.83
1.25	1.5625	$9.09	1,797	$16,340.16
1.50	2.25	$95.50	36	$3,437.84
2.00	4	$24.25	4,304,315	$104,384,293.74
2.63	6.890625	$12.54	180	$2,256.93
3.00	9	$25.17	788,572	$19,849,689.03
4.00	16	$48.32	1,892,515	$91,444,339.27
6.00	36	$83.28	479,847	$39,960,246.36
8.00	64	$76.27	220,893	$16,846,541.10
10.00	100	$329.72	2,909	$959,149.64

CAST IRON

Main Size (inches)	Main Size^2 (inches)	Cost Per Foot ($/Ft.)	Linear Feet	Total Current Cost
1.25	1.5625	$32.61	169	$5,511
1.5	2.25	$34.87	110	$3,836
2	4	$25.19	598	$15,064
3	9	$30.77	5,020	$154,485
4	16	$40.11	25,536	$1,024,269
6	36	$58.55	8,282	$484,927
10	100	$53.93	353	$19,036

Appendix C. Regression Results – Base Case

REGRESSION – STEEL

Number of Observations Read	22
Number of Observations Used	22

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	1	266801	266801	522.46	<.0001
Error	20	10213	511		
Corrected Total	21				

Root MSE	22.6	R-Square	0.9631
Dependent Mean	100.9282	Adj R-Sq	0.9613
Coeff Var	22.392156		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t value	Pr > |t|	Heteroscedasticity Consistent Standard Error	Heteroscedasticity Consistent t Value	Heteroscedasticity Consistent Pr > |t|
Intercept	1	34.1517	5.63442	6.061	<.0001	4.876622	7.0031	<.0001
Size ^2	1	0.86547	0.03786	22.857	<.0001	0.027807	31.124	0.22

Heteroscedasticity Consistent Covariance of		
Variable	Intercept	Size ^2
Intercept	23.781445	-0.04719589
Size ^2	-0.047196	0.000773237

Test of First and Second Moment		
DF	Chi-Square	Pr > ChiSq
1	0.040406	0.8407

REGRESSION – PLASTIC

Number of Observations Read	10
Number of Observations Used	10

Analysis of Variance					
Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	1	61509	61509	23.836	0.001221
Error	8	20644	2580		
Corrected Total	9				

Root MSE	50.8	R-Square	0.7487
Dependent Mean	72.59934	Adj R-Sq	0.7173
Coeff Var	69.973088		

Parameter Estimates

						Heteroscedasticity Consistent		
Variable	DF	Parameter Estimate	Standard Error	t value	Pr > |t|	Standard Error	t Value	Pr > |t|
Intercept	1	12.9241	20.1853	0.64	0.5399	13.52336	0.9557	0.367215
Size ^2	1	2.4792	0.5078	4.882	0.00122	0.66942	3.7035	0.006012

Heteroscedasticity Consistent Covariance		
Variable	Intercept	Size ^2
Intercept	182.8814	-4.903972
Size ^2	-4.903972	0.448129

Test of First and Second Moment		
DF	Chi-Square	Pr > ChiSq
1	3.5394	0.05993

REGRESSION – CAST IRON

Number of Observations Read	7
Number of Observations Used	7

Analysis of Variance					
Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	1	523.4	523.4	6.5784	0.05035
Error	5	397.81	79.56		
Corrected Total	6				

Root MSE	8.92	R-Square	0.5682
Dependent Mean	39.43408	Adj R-Sq	0.4818
Coeff Var	22.620028		

Parameter Estimates

						Heteroscedasticity Consistent		
Variable	DF	Parameter Estimate	Standard Error	t value	Pr > |t|	Standard Error	t Value	Pr > |t|
Intercept	1	33.0993	4.1793	7.92	0.000517	2.769552	11.9511	7.23E-05
Size ^2	1	0.2627	0.1024	2.565	0.05035	0.065341	4.0201	0.01012

Heteroscedasticity Consistent Covariance		
Variable	Intercept	Size ^2
Intercept	7.6704174	-0.042188
Size ^2	-0.042188	0.0042695

Test of First and Second Moment		
DF	Chi-Square	Pr > ChiSq
1	0.18943	0.6634

Appendix D. Regression Results by Common Pipe Size (Excluding Cast Iron)

REGRESSION – STEEL

Number of Observations Read	22
Number of Observations Used	6

Analysis of Variance					
Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	1	14150.7	14150.7	287.24	<.0001
Error	4	197.1	49.3		
Corrected Total	5				

Root MSE	7.019	R-Square	0.9863
Dependent Mean	76.70581	Adj R-Sq	0.9828
Coeff Var	9.1505454		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t value	Pr > |t|	Heteroscedasticity Consistent Standard Error	t Value	Pr > |t|
Intercept	1	31.05851	3.93253	7.898	0.00139	2.997974	10.36	0.00049
Size	1	1.00324	0.05919	16.948	<.0001	0.044076	22.762	<.0001

Heteroscedasticity Consistent Covariance of Estimates		
Variable	Intercept	Size
Intercept	8.9878482	-0.082812
Size	-0.0828125	0.0019427

Test of First and Second Moment Specification		
DF	Chi-Square	Pr > ChiSq
1	0.01536	0.9014

REGRESSION – PLASTIC

Number of Observations Read	10
Number of Observations Used	4

Analysis of Variance					
Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	1	2243.06	2243.06	79.389	0.01236
Error	2	56.51	28.25		
Corrected Total	3				

Root MSE	5.315	R-Square	0.9754
Dependent Mean	45.25469	Adj R-Sq	0.9631
Coeff Var	11.744639		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t value	Pr > |t|	Heteroscedasticity Consistent		
						Standard Error	t Value	Pr > |t|
Intercept	1	13.6437	4.4329	3.078	0.0913	3.284355	4.1541	0.053353
Size ^2	1	1.9453	0.2183	8.91	0.0124	0.094541	20.5763	0.002354

Heteroscedasticity Consistent Covariance		
Variable	Intercept	Size ^2
Intercept	10.786991	-0.29586
Size ^2	-0.295859	0.008938

Test of First and Second Moment		
DF	Chi-Square	Pr > ChiSq
1	1.2243	0.2685

ATTACHMENTS ARE EXCEL SPREADSHEETS AND UPLOADED SEPARATELY

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

11. Refer to Columbia Kentucky's response to Commission Staff's Second Request, Item 30. The response did not address the question. For each of the business risks enumerated on pages 11–12 of Vincent V. Rea's Direct Testimony (Rea Testimony), explain specifically how Columbia Kentucky has been affected.

Response:

Columbia's Response to Staff's Second Set of Requests for Information, No. 30 pointed to the Direct Testimony of Columbia witness Rea, wherein he identifies a number of business risks that are impacting gas utilities, and their valuations. Attempting too specifically link the identified risks to Columbia's operations would incorrectly account for their impact, as financial markets do not value gas utilities based solely on the experiences in one state nor on one utility in that state. Instead, these risks represent what the financial markets are currently weighing when weighing the investment risk of gas utility operations today.

Additionally, Columbia offers the following information to show impacts of these risks on Columbia and/or NiSource:

Decarbonization risks – While not viewed as an active issue currently in the Commonwealth of Kentucky, it has the potential to impact the cost of capital that Columbia can access, due to the pressures placed on the industry in other jurisdictions, by investors, or by decisions made by customers. Any such cost of capital impacts would ultimately flow through to customers in Kentucky. This example coupled with the more traditional risk factors continue to weigh on gas utility valuations, cost of capital, and utility credit ratings.

Gas throughput risks – Columbia's significantly higher allocation of gas throughput to commercial, industrial, and transport customers makes it more exposed to future economic downturns and potential system bypass. Continued exposure to this risk is a factor in the risk evaluation of NiSource by investors. Please see Columbia's Responses to the Attorney General's First Set of Requests for Information, No. 37 and Staff's Second Set of Requests for Information, No. 31 for additional confidential information related to this risk.

COVID risks – Columbia Witness Bartos discussed in her testimony (pages 11-15) the impacts of COVID on usage by customer class. Specifically, COVID-19 use per customer was lower than what would have otherwise been expected by approximately 7.3% and 6.6% for the 12-month period of March 2020 through February 2021 for residential and commercial customers respectively, as shown in the table below.

	A	B	C=A-B	D=B/C
Last 12 Months of History	Actual UPC (Dth/customer)	UPC Indicator Variables (Dth/customer)	Expected UPC Absent COVID Impact (Dth/customer)	Percent UPC Impact of COVID (%)
Residential Use Per Customer Analysis				
Mar-20	9.645		9.645	*
Apr-20	4.845	-0.7848	5.630	-13.9%
May-20	4.149	-0.8306	4.980	-16.7%
Jun-20	1.776		1.776	*
Jul-20	0.943		0.943	*
Aug-20	0.853		0.853	*
Sep-20	0.931		0.931	*
Oct-20	1.521	-0.7472	2.268	-32.9%
Nov-20	3.611		3.611	*
Dec-20	8.917	-0.8339	9.751	-8.6%
Jan-21	13.776	-0.8629	14.639	-5.9%
Feb-21	14.649	-1.1249	15.774	-7.1%
Residential Total	**65.615**	**-5.1843**	**70.7994**	**-7.3%**
Commercial Use Per Customer Analysis				
Mar-20	69.019	-5.9852	75.004	-8.0%
Apr-20	41.323	-5.6764	46.999	-12.1%
May-20	34.376	-9.586	43.962	-21.8%
Jun-20	23.850	-4.0126	27.863	-14.4%
Jul-20	20.419		20.419	*
Aug-20	20.760		20.760	*
Sep-20	22.053		22.053	*
Oct-20	28.564	-2.8626	31.427	-9.1%
Nov-20	40.869	-3.808	44.677	-8.5%
Dec-20	73.995	-3.5772	77.572	-4.6%
Jan-21	100.255	-5.2346	105.490	-5.0%
Feb-21	105.198		105.198	*
Commercial Total	**580.681**	**-40.7426**	**621.4236**	**-6.6%**
** Indicator variable not statistically significant in these months*				
Sources: AG-1-34a; AG-1-93 Attachment A				

Please also see Columbia's Response to the Attorney General's First Set of Requests for Information, No. 34. Additionally, lower throughput and lower revenues from COVID impacted NiSource. Please see KY PSC Case No. 2021-00183, Staff 3-11, Attachment A (NiSource 2020 10K at pages 34 and 36 of the PDF) and KY PSC Case No. 2021-00183, Staff 3-11, Attachment B (NiSource 2009 10Q at page 56 of the PDF). The COVID-19 Delta variant (and other variants) appear to be a credible threat to the U.S. economic recovery and a return to pre-pandemic normalcy.

Higher gas procurement costs risks – NiSource distribution utilities have experienced declining usage in part due to sensitivity to commodity prices. Please see KY PSC Case No. 2021-00183, Staff 3-11, Attachment B (at the bottom of page 70 of the PDF). And the volatility of gas commodity costs continues today. Please also see Columbia's recent approved Gas Cost Adjustment request in Case No. 2021-00308 showing a proposed rate of $5.4029 (increasing from current rate of $4.9177)

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, 2020
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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☑

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 $8,671,854,266 based upon the June 30, 2020, closing price of $22.74 on the New York Stock Exchange.

There were 391,859,711 shares of Common Stock outstanding as of February 9, 2021.

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 25, 2021.

CONTENTS

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
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
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)
COVID-19 ("the COVID-19 pandemic" or "the pandemic")	Novel Coronavirus 2019
DPA	Deferred prosecution agreement
DPU	Department of Public Utilities
DSIC	Distribution System Investment Charge
DSM	Demand Side Management
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
GAAP	Generally Accepted Accounting Principles
GCA	Gas cost adjustment
GHG	Greenhouse gas
GWh	Gigawatt hours

DEFINED TERMS

HLBV	Hypothetical Liquidation at Book Value
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 sold to, and liabilities 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
PPA	Power Purchase Agreement
PSC	Public Service Commission
PUC	Public Utility Commission
PUCO	Public Utilities Commission of Ohio
RCRA	Resource Conservation and Recovery Act
ROE	Return on Equity
Rosewater	Rosewater Wind Generation LLC
ROU	Right of use
SAVE	Steps to Advance Virginia's Energy Plan
SEC	Securities and Exchange Commission
SMRP	Safety Modification and Replacement Program
SMS	Safety Management System
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
TSA	Transition Service Agreement
U.S. Attorney's Office	U.S. Attorney's Office for the District of Massachusetts
VIE	Variable Interest Entity
VSCC	Virginia State Corporation Commission

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. Expressions of future goals and expectations and similar expressions, including "may," "will," "should," "could," "would," "aims," "seeks," "expects," "plans," "anticipates," "intends," "believes," "estimates," "predicts," "potential," "targets," "forecast," and "continue," reflecting something other than historical fact are intended to identify forward-looking statements. 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 ability to execute our business plan or growth strategy, including utility infrastructure investments; potential incidents and other operating risks associated with our business; our ability to adapt to, and manage costs related to, advances in technology; impacts related to our aging infrastructure; our ability to obtain sufficient insurance coverage and whether such coverage will protect us against significant losses; the success of our electric generation strategy; construction risks and natural gas costs and supply risks; fluctuations in demand from residential and commercial customers; fluctuations in 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 attraction and retention of a qualified workforce and ability to maintain good labor relations; our ability to manage new initiatives and organizational changes; the performance of third-party suppliers and service providers; potential cyber-attacks; any damage to our reputation; any remaining liabilities or impact related to the sale of Massachusetts Business; the impacts of natural disasters, potential terrorist attacks or other catastrophic events; the impacts of climate change and extreme weather conditions; our debt obligations; any changes to our credit rating or the credit rating of certain of our subsidiaries; adverse economic and capital market conditions or increases in interest rates; economic regulation and the impact of regulatory rate reviews; our ability to obtain expected financial or regulatory outcomes; continuing and potential future impacts from the COVID-19 pandemic; economic conditions in certain industries; the reliability of customers and suppliers to fulfill their payment and contractual obligations; the ability of our subsidiaries to generate cash; pension funding obligations; potential impairments of goodwill; changes in the method for determining LIBOR and the potential replacement of the LIBOR benchmark interest rate; the outcome of legal and regulatory proceedings, investigations, incidents, claims and litigation; potential remaining liabilities related to 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; compliance with applicable laws, regulations and tariffs; compliance with environmental laws and the costs of associated liabilities; changes in taxation; and other matters set forth in Item 1, "Business," Item 1A, "Risk Factors" and Part II. Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," of this report, some 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.

PART I

ITEM 1. BUSINESS

NISOURCE INC.

NiSource Inc. is an energy holding company under the Public Utility Holding Company Act of 2005 whose primary subsidiaries are fully regulated natural gas and electric utility companies, serving approximately 3.7 million customers in six 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'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 February 26, 2020, NiSource and Columbia of Massachusetts entered into an Asset Purchase Agreement with Eversource (the "Asset Purchase Agreement"). 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 (3) Eversource agreed to assume certain liabilities of Columbia of Massachusetts and its affiliates. The closing of the transaction occurred on October 9, 2020. Refer to Note 1-A, "Company Structure and Principles of Consolidation," Note 7, "Goodwill and Other Intangible Assets," Note 20-C. "Legal Proceedings," and Note 20-E. "Other Matters," in the Notes to Consolidated Financial Statements for more information.

The COVID-19 pandemic has had widespread effects, including impacts on the communities in which we serve as well as our business operations. NiSource has been pro-active in adjusting its operating procedures in response to the pandemic, including customer facing and field activities as well as our back-office support. Through 2020, we have not experienced material impacts to our ongoing or planned construction, replacement and maintenance activities as a result of the pandemic. Please refer to specific and potential impacts of the pandemic in Item 1A, "Risk Factors", Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and 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 24, "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 3.2 million customers in six states. We operate approximately 53,700 miles of distribution main pipeline plus the associated individual customer service lines and 1,700 miles of transmission main pipeline located in our service areas described below. Throughout our service areas we also have gate stations and other operations support facilities. Through our wholly-owned subsidiary NiSource Gas Distribution Group, Inc., we own five distribution subsidiaries that provide natural gas to approximately 2.4 million residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, and Maryland. Additionally, we distribute natural gas to approximately 848,000 customers in northern Indiana through our wholly-owned subsidiary NIPSCO.

Rates include provisions to adjust billings for fluctuations in the cost of natural gas. Revenues are adjusted for differences between actual costs, subject to reconciliation, and the amounts billed in current rates.

Electric Operations

We generate, transmit and distribute electricity through our subsidiary NIPSCO to approximately 479,000 customers in 20 counties in the northern part of Indiana and also engage in wholesale electric 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 (i) Sugar Creek, a CCGT plant located in West Terre Haute, IN with generating capacity of 571 MW; (ii) two gas-fired generating units located at R.M. Schahfer with a generating capacity of 155 MW; and (iii) 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 2,816 MW. NIPSCO is the managing partner in Rosewater Wind Generation LLC, a joint venture that owns and operates 102 MW of nameplate generating capacity in White County, IN. Refer to Note 4 "Variable Interest Entities" in the Notes to Consolidated Financial Statements for more information.

In May 2018, NIPSCO completed the retirement of two coal-burning units at Bailly Generating Station, located in Chesterton, IN. These units had a generating capacity of approximately 460 MW, which was replaced through various electric purchase agreements.

NIPSCO's transmission system, with voltages from 69,000 to 765,000 volts, consists of 3,009 circuit miles. NIPSCO is interconnected with eight neighboring electric utilities. During the year ended December 31, 2020, NIPSCO generated 68.8% and purchased 31.2% 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, Financial Transmission Rights 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 providing safe and reliable service through our core, rate-regulated asset-based utilities, which generate substantially all of our operating income. Our utilities continue to move forward on core safety, infrastructure and environmental investment programs supported by complementary regulatory and customer initiatives across all six states in which we operate. Our goal is to develop strategies that benefit all stakeholders as we (i) address changing customer conservation patterns, (ii) align our price structures with our cost structure, and (iii) embark on long-term investment programs. These strategies focus on improving safety and reliability, enhancing customer service, lowering customer bills and reducing emissions while generating sustainable returns.

The safety of our customers, communities and employees remains our top priority. The SMS transitioned in 2020 from an accelerated project launch to an established operating model within NiSource. With the continued support and advice from the Quality Review Board, a panel of third parties with safety operations expertise engaged by management to advise on safety matters, we are continuing to mature our SMS processes, capabilities and talent as we collaborate within and across industries to enhance safety and reduce operational risk.

In its 2018 Integrated Resource Plan submission to the IURC, NIPSCO laid out a plan to retire the R.M. Schahfer Generating Station by 2023 and Michigan City Generating Station by 2028. These units represent 72% of NIPSCO's remaining generation capacity. The current replacement plan includes renewable sources of energy, including wind, solar, and battery storage, to be obtained through a combination of NIPSCO investment and PPAs. Refer to Note 20-E, "Other Matters," in the Notes to Consolidated Financial Statements for further discussion of these plans.

Rate Case Actions

The following table describes current rate case actions as applicable in each of our jurisdictions net of tracker impacts. See "Cost Recovery and Trackers" below for further detail on trackers.

(in millions)

Company	Proposed ROE	Approved ROE	Requested Incremental Revenue	Approved Incremental Revenue	Filed	Status	Rates Effective
NIPSCO - Electric[1]	10.80 %	9.75 %	$ 21.4	$ (53.5)	October 31, 2018	Approved December 4, 2019	January 2020
Columbia of Pennsylvania[2]	9.86 %	N/A	$ 76.8	In process	April 24, 2020	Order Expected Q1 2021	January 2021
Columbia of Maryland	10.95 %	None specified[3]	$ 5.0	$ 2.0	May 15, 2020	Approved November 7, 2020	December 2020

[1]Rates were implemented in two steps, with implementation of step 1 rates effective on January 2, 2020 and step 2 rates effective on March 2, 2020.

[2]On December 4, 2020, a Recommended Decision was issued by the Administrative Law Judge (ALJ) for the PUC to "deny the Company's request in its entirety because it has not met its burden of providing, by substantial evidence, that the proposed base rate revenue increase will result in just and reasonable rates, as required by 66 Pa.C.S.A. § 1301 during the current Coronavirus-2019 pandemic." Columbia of Pennsylvania filed Exceptions to the ALJ's Recommended Decision on December 22, 2020 in which the Company proposed an increase of $76.8 million to be implemented in two steps: (1) an increase of $38.4 million to be effective January 23, 2021 through June 30, 2021, and defer revenue related to the remaining increase to regulatory assets during this phase, and (2) the remaining increase of $38.4 million to be implemented on July 1, 2021. Columbia of Pennsylvania proposed to recover the revenue deferred to a Regulatory Asset during the initial phase over a one-year period beginning January 1, 2022 and ending December 31, 2022. A Final Order from the PUC is expected during the first quarter of 2021 for rates effective retroactively on January 23, 2021.

[3]Columbia of Maryland's rate case resulted in a black box settlement, representing a settlement to a specific revenue increase but not a specified ROE. The settlement provides use of a 9.60% ROE for future Make Whole and Infrastructure Tracker filings.

ITEM 1. BUSINESS

NISOURCE INC.

Competition and Changes in the Regulatory Environment

The regulatory frameworks applicable to our operations, including environmental regulations, 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. We believe we are, in all material respects, in compliance with such laws and regulations and do not expect continued compliance to have a material impact on our capital expenditures, earnings, or competitive position. We continue to monitor existing and pending laws and regulations, and the impact of regulatory changes cannot be predicted with certainty. Refer to Note 20-D, "Environmental Matters" in the Notes to Consolidated Financial Statements for more information regarding environmental regulations that are applicable to our operations.

The Gas Distribution Operations utilities have pursued non-traditional revenue sources within the evolving natural gas marketplace. These efforts include (i) the sale of products and services upstream of the companies' service territory, (ii) the sale of products and services in the companies' service territories, and (iii) 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 utility 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 utility's system. The incentive mechanisms give the Gas Distribution Operations utilities 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. While historical 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 has adopted a decoupled rate design that closely links the recovery of fixed costs with fixed charges. Columbia of Maryland and Columbia of Virginia have regulatory approval for weather and revenue normalization adjustments for certain customer classes, which adjust monthly revenues that exceed or fall short of approved levels. Columbia of Pennsylvania continues to operate its pilot residential weather normalization adjustment. Columbia of Kentucky incorporates a weather normalization adjustment. In a prior gas base rate proceeding, NIPSCO implemented a higher fixed customer charge for residential and small customer classes moving toward recovering more of its fixed costs through a fixed recovery charge, but has no weather or usage protection mechanism.

Cost Recovery and Trackers. Comparability of our line item operating results are impacted by regulatory trackers that allow for the future recovery in rates of certain costs as described below. Increases in expenses that are the subject to approved regulatory tracker mechanisms generally lead to increased regulatory assets, which ultimately result in a corresponding increase in operating revenues and, therefore, have essentially no impact on total operating income results. Certain approved regulatory tracker mechanisms allow for abbreviated regulatory proceedings in order for the operating companies to quickly implement revised rates and recover associated 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 confirm the recovery of prudently incurred energy commodity costs supplied to 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, which is updated quarterly to reflect actual costs incurred to supply electricity to customers.

Natural Gas Competition. Open access to natural gas supplies over interstate pipelines and the deregulation of the gas supply has led to tremendous change in the energy markets. LDC customers can purchase gas directly from producers and marketers in an open, competitive market. This separation or "unbundling" of the transportation and other services offered by LDCs allows customers to purchase the commodity independent of services provided by LDCs. 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 (i) investor-owned, municipal, and cooperative electric utilities throughout its service areas, (ii) other regulated and unregulated natural gas intra and interstate pipelines and (iii) 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.

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 and cooling seasons, revenues from gas and electric sales, respectively, are more significant than in other months. The heating season is primarily from November through March, and the cooling season is primarily from June through September.

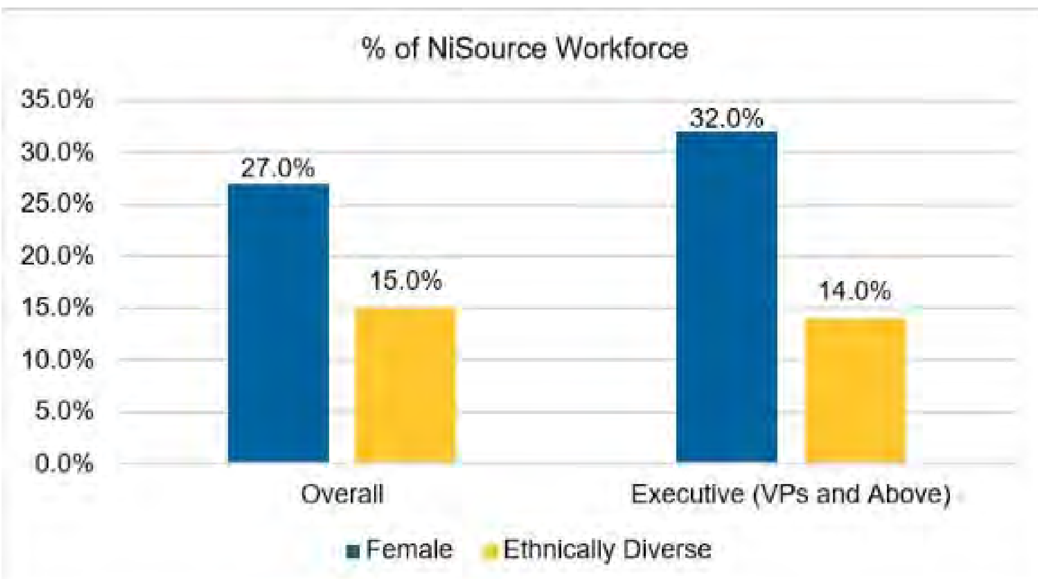
Human Capital

Human Capital Goals and Objectives. We have aligned our human capital goals to achieve the overall company objectives by driving an enhanced talent strategy, elevating support for front-line leaders, fostering a culture of rigor and accountability and strengthening our Human Resources function as a whole.

Workforce Composition. As of December 31, 2020, we had 7,301 full-time and 88 part-time employees. 2,728 employees were subject to collective bargaining agreements with various labor unions. Six of these agreements covering 527 employees are set to expire within one year.

Diversity. Our talent acquisition teams hired 612 external candidates in 2020 across all business segments. 35% of external hires were female and 18% were racially or ethnically diverse. In 2020, we engaged with community-based organizations, conducted career interest workshops in local schools, and focused our employee mentorship program on females. We also led a separate targeted development program for select employees to support the growth and development of female and ethnically diverse talent. We offered several employee resource groups ("ERGs") and hosted mostly virtual activities throughout 2020. We have ERGs set up to support African-American, LatinX, veterans, LGBTQ+, female and Asian employees, among others, and held several sponsored conversations between senior executives and the ERGs.

The following provides the diversity breakdown of NiSource as of December 31, 2020:



Talent Development. We offer leadership development programs to enhance the behaviors and skills of our existing and future leaders. In 2020, we had participation from employees of all levels. We also offer extensive technical and non-technical employee training programs. Additionally, we strive to provide promotion and advancement opportunities for employees. In 2020, 84% of all leadership positions at the supervisor and above level were filled internally. Succession planning is regularly conducted to ensure bench strength for leadership positions. We utilize retention bonuses and conduct stay conversations in order to retain talent. Retention at NiSource in 2020 was over 93%. Retention is calculated using the total number of terminations divided by the average headcount for the annual period, not including the impacts from the sale of the Massachusetts Business and voluntary separation programs.

Employee Safety and Wellness. We have a number of programs to support employees and their families' physical, mental, and financial well-being. These programs include a paid wellness day, telemedicine services, an Employee Assistance Program, Integrated Health Management navigation services, employee paid sick/disability leave and paid illness in family days, competitive medical, dental, vision, life and long term disability programs including employee health savings account company contributions and no cost registered financial planner counseling.

In response to COVID-19, we have implemented procedures designed to protect our employees who work in the field and who continue to work in operational and corporate facilities, including social distancing, wearing face coverings, temperature checks and more frequent cleaning of equipment and facilities. We have also implemented work-from-home policies and practices. We have minimized non-essential work that requires an employee to enter a customer premise and limited company vehicle occupancy to one person, where possible. We continue to employ physical and cybersecurity measures to ensure that our operational and support systems remain functional. Our actions to date have mitigated the spread of COVID-19 amongst our employees. We will continue to follow the Centers for Disease Control and Prevention ("CDC") guidance and implement safety measures intended to ensure employee and customer safety during the pandemic.

Other Relevant Business Information

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

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*. The information contained on our website is not included in, nor incorporated by reference into, this Annual Report on Form 10-K.

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.

OPERATIONAL RISKS

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, which includes investments related to natural gas pipeline modernization and investments related to our renewable energy projects and the build-transfer execution goals within our business plan. Our "NiSource Next" initiative, a comprehensive program designed to identify long-term sustainable capability enhancements and cost optimization improvements, may not be effective. 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. Environmental activist groups, investors and governmental entities may continue to oppose natural gas delivery and infrastructure investments in the jurisdictions where we operate 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. In addition, we consider acquisitions or dispositions of assets or businesses, joint ventures and mergers from time to time as we execute on our business plan and growth strategy. Any of these circumstances 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).

Our gas distribution and transmission 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 and transmission 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, excavation or vehicular damage to our infrastructure, 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, including regulator stations, liquefied natural gas and underground storage, 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.

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 includes generating power at central station power plants to achieve economies of scale and produce power at a competitive cost. We continue to research, plan for, and implement new technologies that produce reliable, cost-efficient power or reduce power consumption. These technologies include renewable energy, distributed generation, energy storage, and energy efficiency. Advances in technology, changes in laws or regulations (including subsidization) and other alternative methods of producing power are reducing the cost of electric generation from these sources to a level that is competitive with most central station power electric production. 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.

Our natural gas business model leverages widespread utilization of natural gas for space heating as a core driver of revenues. Alternative energy sources, new technologies or alternatives to natural gas space heating, including cold climate heat pumps and/or efficiency of other products, could reduce demand and increase customer attrition, which would impact our ability to recover on our investments in our gas distribution assets.

In addition, customers are increasingly expecting additional communications, increased access to information, and expanded electronic capabilities regarding their electric and natural gas services, which, in some cases, involves 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.

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 electric and gas infrastructure assets. These risks can be driven by threats such as, but not limited to, electrical faults, mechanical failure, internal corrosion, external corrosion, ground movement and stress corrosion and/or 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. 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 interruption of electric service, major component failure at generating facilities and electric substations, 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.

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 and underwriting considerations of insurers. For example, some insurers are moving away from underwriting certain energy related businesses such as those in the coal industry or those exposed to certain perils such as wildfires as well as gas explosion events or other infrastructure-related risks. The utility 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. 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 our operations, and we expect that they will continue to increase as a result of hardening in 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 exceeded the total amount of liability coverage available under our policies. Certain types of damages, expenses or claimed costs, such as fines and penalties, have been and in the future 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.

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

Our plan to replace 80% of our coal generation capacity by mid-2023 and all of our coal generation by the end of 2028 with primarily renewable resources may not progress as anticipated. 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 Integrated Resource Plan evaluated demand-side and supply-side resource alternatives to meet NIPSCO customers' future energy requirements over the ensuing 20 years.

The preferred option within the Integrated Resource Plan retires the R.M. Schahfer Generating Station by mid-2023 and the Michigan City Generating Station by the end of 2028. These stations 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. The current replacement plan includes renewable sources of energy, including wind, solar, and battery storage. In the second quarter of 2020, the MISO approved NIPSCO's plan to retire the R.M. Schahfer Generating Station in 2023. In February 2021, NIPSCO decided to submit modified Attachment Y Notices to MISO requesting accelerated retirement of two of the four units at R.M. Schahfer Generating Station. The two units are now expected to be retired by the end of 2021, with the remaining two units still scheduled to be retired in 2023. Refer to Note 20- E. "Other Matters - NIPSCO 2018 Integrated Resource Plan," in the Notes to Consolidated Financial Statements for additional information.

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. As required by statute, NIPSCO plans to submit a new Integrated Resource Plan to the IURC by November 1, 2021. This submission will again outline NIPSCO's short and long term plans for meeting the energy supply needs of its customers, taking into account current perspectives on a range of factors including, but not limited to, new state and federal policy, wholesale market rules, forecasted customer demand, and available resource alternatives.The analysis, conclusions and Preferred Plan in the 2021 Integrated Resource Plan may be different from the analysis, conclusions and Preferred Plan in the 2018 Integrated Resource Plan.

Our capital projects and programs subject us to construction risks and natural gas costs and supply risks, and are subject to regulatory oversight, including requirements for 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.

On May 1, 2020, former President Donald Trump issued an executive order (the "EO") prohibiting any transaction initiated after that day that (i) involves bulk-power system ("BPS") equipment designed, developed, manufactured or supplied by persons owned by, controlled by or subject to the jurisdiction or direction of a foreign adversary and (ii) poses an unacceptable risk to national security. Implementing regulations from the U.S. Secretary of Energy are still pending. The EO also requires the U.S. Secretary of Energy to review the risk of existing bulk-power system equipment sourced from foreign adversaries and to establish a task force to review and recommend federal procurement policies and procedures consistent with the considerations identified in the EO. On July 8, 2020, the U.S. Department of Energy issued a Request for Information ("RFI"), seeking input from industry stakeholders to "understand the energy industry's current practices to identify and mitigate vulnerabilities in the supply chain" for components of bulk-power system equipment. The RFI identifies the following governments as "foreign adversaries": China, Cuba, Iran, North Korea, Russia and Venezuela. The RFI notes that the U.S. Secretary of Energy retains authority to amend this list at any time and such countries have been identified only for the purposes of the EO. Pursuant to the EO, on December 17, 2020, the U.S. Department of Energy issued a Prohibition Order (the “Prohibition Order”) prohibiting the acquisition, importation, transfer, or installment of specified BPS equipment from China that directly serves critical defense facilities. While the implications of the Prohibition Order are still being assessed, it could impact our procurement processes for BPS equipment. In the future, certain bulk-power system equipment owned or operated by NiSource could possibly be considered to be sourced from a foreign adversary within the meaning of the EO. These regulations, if implemented, may impact our procurement processes for bulk-power system equipment.

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.

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.

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 current electric generating fleet is dependent on coal and natural gas for fuel, and our gas distribution operations purchase and resell a portion of the natural gas we deliver to our customers. These energy commodities are subject to price fluctuations and fluctuations in associated transportation costs. When appropriate, we use 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 selling energy to our customers. 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.

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.

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.

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, third-party software vulnerabilities and inadvertent disclosure of sensitive information), the utility industry faces evolving and increasingly complex cybersecurity risks associated with protecting sensitive and confidential customer and employee information, electric grid infrastructure, and natural gas infrastructure. Deployment of new business technologies, along with maintaining legacy technology, represents a large-scale opportunity for attacks on our information systems and confidential customer and employee 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 a cybersecurity incident.

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

ITEM 1A. RISK FACTORS

NISOURCE INC.

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.

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.

On October 9, 2020, we completed the sale of the Massachusetts Business to Eversource. The sale of the Massachusetts Business involves separation or carve-out activities and costs and possible disputes with Eversource. We have continued financial liabilities with respect to the business conducted by Columbia of Massachusetts, as we retain responsibility for, and have agreed to indemnify Eversource against, certain liabilities. This responsibility includes 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 occurred prior to the closing in connection with the 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.

Further, the sale of the Massachusetts Business may result in a dilutive impact to our future earnings if we are unable to offset the loss of revenue associated with the sale, which could have a material adverse effect on our results of operations and financial condition.

The impacts of natural disasters, acts of terrorism, acts of war, civil unrest, cyber-attacks, accidents, public health emergencies 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, acts of war, civil unrest, cyber-attack (as further detailed above), accident, public health emergency, pandemic, 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. Also, companies in our industry face a heightened risk of exposure to acts of terrorism and vandalism. 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.

Climate change has the potential to affect our business.

Our strategy may be impacted by policy and legal, technology, market, and reputational risks and opportunities that are associated with the transition to a lower-carbon economy, as disclosed in other risk factors in this section. In addition, climate change may exacerbate the risks to our physical infrastructure, including 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 transition to a lower carbon economy have the potential to affect our business by reducing our ability to serve customers, increasing the costs we incur in providing our products and services, impacting the demand for and consumption of our products and services (due to changes in costs, technology, reputation and weather patterns), and affecting the economic health of the regions in which we operate. Changes in policy to combat climate change, and technology advancement, each of which can also accelerate the implications of a transition to a lower carbon economy, may materially adversely impact our business, financial position, results of operations, and cash flows.

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.

FINANCIAL, ECONOMIC AND MARKET RISKS

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 $9,746.1 million outstanding as of December 31, 2020. 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 2020 and 2021, the impacts of the COVID-19 pandemic. 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 our credit ratings (including the standalone credit ratings of 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, 2020, the collateral requirement that would be required in the event of a downgrade below the ratings trigger levels would amount to approximately $53.9 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.

The novel coronavirus (COVID-19) pandemic adversely impacts our business, results of operations, financial condition, liquidity and cash flows.

ITEM 1A. RISK FACTORS

NISOURCE INC.

The continued spread of COVID-19 has resulted in widespread impacts on the global economy and financial markets and could lead to a prolonged reduction in economic activity, extended disruptions to supply chains and capital markets, and reduced labor availability and productivity. We have experienced lower revenues, higher expenses for personal protective equipment and supplies, and higher bad debt expense as a consequence of the pandemic, which has negatively impacted our results of operations as of December 31, 2020. Our future operating results and liquidity may continue to be impacted by the pandemic, but the extent of the impact remains uncertain. Such ongoing impact of the pandemic includes, but is not limited to:

- Lower revenue and cash flow, resulting from the decrease in commercial and industrial gas and electric demand as businesses comply with operating restrictions and re-opening plans in each state and as businesses experience negative economic impact from the pandemic, potentially offset by higher residential demand;
- Lower revenue and cash flow due to the continuing suspension of late payment and reconnection fees in some jurisdictions;
- A decline in revenue due to an increase in customer attrition rates, as well as lower revenue growth if customer additions slow due to a prolonged economic downturn;
- A continued increase in bad debt and a decrease in cash flows resulting from the suspension of shut-offs and the inability of our customers to pay for their gas and electric service due to job loss or other factors, partially offset by regulatory deferral;
- Lower revenues on a prolonged basis resulting from higher customer bankruptcies, predominately focused on commercial and industrial customers not able to sustain operations through the broader economic downturn;
- A continued delay in cash flows as customers utilize the more flexible payment plans we offer; and
- An increase in internal labor costs from higher overtime.

We also face the risk of not achieving operational compliance and/or customer requirements because of work restrictions or unavailable employees due to the pandemic. For more information regarding the items above and additional items related to the pandemic that we are evaluating and monitoring, please see our discussion of these topics in Part II., Item 7. "Management Discussion and Analysis of Financial Condition and Results of Operations - Executive Summary - Introduction - COVID-19" in this report and in our future filings with the Securities and Exchange Commission. To the extent the pandemic adversely affects our business, results of operations, financial condition, liquidity or cash flows, it may also have the effect of heightening many of the other Risk Factors described herein. The degree to which the pandemic will impact us will depend in part on future developments, including the continued severity and duration of the outbreak, actions that may be taken by governmental authorities, and to what extent and when normal economic and operating conditions can resume.

Adverse economic and market conditions, including as a result of the COVID-19 pandemic, or increases in interest rates could materially and adversely affect our business, results of operations, cash flows, financial condition and liquidity.

Deteriorating, sluggish or volatile 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 our revenue or growth rate and increase operating costs. The continued spread of COVID-19 has resulted in widespread impacts on the global economy and financial markets and could lead to a prolonged reduction in economic activity, disruptions to supply chains and capital markets, and reduced labor availability and productivity.

In connection with the pandemic, certain state regulatory commissions instituted disconnection moratoriums and the suspension of collection of late payment fees, deposits and reconnection fees, which impacted our ability to pursue our standard credit risk mitigation practices. Following the issuance of these moratoriums, certain of our regulated operations have been authorized to record a regulatory asset for bad debt expense above levels currently in rates. While several of these moratoriums remain in place, we have reinstated our common credit mitigation practices where moratoriums have expired. It is possible that such moratoriums will be extended or reinstated as the pandemic continues.

In addition, the pandemic has impacted our physical business operations, resulting in delays in conducting certain residential work and additional costs required to comply with pandemic-related health and safety protocols.

Further, 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, increased borrowing costs, and/or lower equity valuation levels could reduce future earnings per share and cash flows. Refer to Note 15, “Long-Term Debt,” in the Notes to Consolidated Financial Statements for information related to outstanding long-term debt and maturities of that debt. In addition, any rise in interest rates may lead to higher borrowing costs, which may adversely impact reported earnings, cost of capital and capital holdings.

If, in the future, we face limits to the credit and capital markets or experience significant increases in the cost of capital or are unable to access the capital markets, 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.

Most 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.

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. The COVID-19 pandemic is another factor that will continue to influence the regulatory process, such as the implementation of disconnection moratoriums as discussed above and the risk of not being able to recover costs and/or returns on invested capital through raising rates during a pandemic, which has disproportionately impacted vulnerable customers and communities.

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.

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 our businesses operate. In particular, sales to large industrial customers, such as those in the steel, oil refining, industrial gas and related industries, are impacted by economic downturns, including the downturn resulting from the COVID-19 pandemic; geographic or technological shifts in production or production methods; and consumer demand for environmentally friendly products and practices. The U.S. manufacturing industry continues to adjust to changing market conditions including international competition, increasing costs, and fluctuating demand for its products. In addition, our results of operations are negatively impacted by lower revenues resulting from higher bankruptcies, predominately focused on commercial and industrial customers not able to sustain operations through the economic disruptions related to the pandemic.

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 result in an increase in defaults by customers, suppliers and counterparties. As stated above, in connection with the COVID-19 pandemic, certain state regulatory commissions instituted regulatory moratoriums that have impacted our ability to pursue our standard credit risk mitigation practices.

ITEM 1A. RISK FACTORS

NISOURCE INC.

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.

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 12, "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 plan. 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 longer life expectancy assumptions, as well as voluntary early retirements. 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.

We have significant goodwill. Any future impairments of 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.

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, which requires us to maintain a debt to capitalization ratio that does not exceed 70%. As of December 31, 2020, the ratio was 62.5%.

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, 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. In November 2020, the Board of Governors of the U.S. Federal Reserve System, the Federal Deposit Insurance Corporation and the Office of the U.S. Comptroller of the Currency collectively issued a statement encouraging banks to stop entering into financial contracts that use LIBOR as a reference rate as soon as possible, and no later than December 31, 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.

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.

LITIGATION, REGULATORY AND LEGISLATIVE RISKS

The outcome of legal and regulatory proceedings, investigations, inquiries, claims and litigation related to our business operations 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 those related to the Greater Lawrence Incident, the most significant of which are summarized in Note 20, “Other Commitments and Contingencies” in the Notes to Consolidated Financial Statements. Our insurance does not cover all costs and expenses that we have incurred or that we may incur in the future relating to the Greater Lawrence Incident, and may not fully cover incidents that could 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.

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. We have been 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 further described in Note 7, "Goodwill and Other Intangible Assets," Note 20-C. "Legal Proceedings," and Note 20-E. "Other Matters" in the Notes to Consolidated Financial Statements.

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.

We may also incur additional costs associated with the Greater Lawrence Incident, beyond the amount currently anticipated, including in connection with the U.S. Attorney’s Office investigation 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 through the pending property insurance litigation related to this matter, or we incur a material amount of other costs, 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 or rules in connection with the operations or maintenance of our natural gas system, and we are ordered to pay additional amounts in 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, which was subsequently approved by the United States District Court for the District of Massachusetts (the "Court"). See Note 20-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.

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, injunctions to remedy the failure or harm, and the inability to operate facilities as designed.

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 increasing focus on both coal and natural gas. 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, increased sourcing of renewable energy, and priority pipeline replacement, energy efficiency programs, leak detection and repair, 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.

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, 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.

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, 2020.

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 20-C "Legal Proceedings" in the Notes to Consolidated Financial Statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

Table of Contents

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	57	President and Chief Executive Officer of NiSource since July 2015.
Donald E. Brown	49	Executive Vice President, Chief Financial Officer and President, NiSource Corporate Services.
		Executive Vice President of NiSource since May 2015.
		Chief Financial Officer of NiSource since July 2015.
		President, NiSource Corporate Services since June 2020.
		Treasurer of NiSource from July 2015 to June 2016.
Anne-Marie W. D'Angelo	44	Executive Vice President, General Counsel and Corporate Secretary.
		Executive Vice President of NiSource since January 2021.
		Corporate Secretary and General Counsel of NiSource since September 2019.
		Senior Vice President of NiSource from September 2019 to January 2021.
		General Counsel of Global Brass & Copper Inc. from May 2017 to August 2019.
		Assistant General Counsel of McDonald’s USA from January 2015 to May 2017.
Shawn Anderson	39	Senior Vice President and Chief Strategy and Risk Officer of NiSource since June 2020.
		Vice President, Strategy of NiSource from January 2019 to May 2020.
		Vice President of NiSource from May 2018 to December 2018.
		Treasurer and Chief Risk Officer of NiSource from June 2016 to May 2020.
		Vice President, Regulatory Affairs and Financial of Columbia of Ohio from July 2015 to June 2016.
Charles E. Shafer, II	51	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	59	Executive Vice President and Chief Experience Officer.
		Executive Vice President of NiSource since July 2015.
		Chief Experience Officer of NiSource since June 2020.
		President, NIPSCO of NiSource from July 2015 to May 2020.
Pablo A. Vegas	47	Executive Vice President, Chief Operating Officer and President, NiSource Utilities.
		Executive Vice President of NiSource since May 2016.
		Chief Operating Officer and President, NiSource Utilities of NiSource since June 2020.
		President, Gas Utilities of NiSource from January 2019 to May 2020.
		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.
		President, Columbia Gas Group, of NiSource 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.

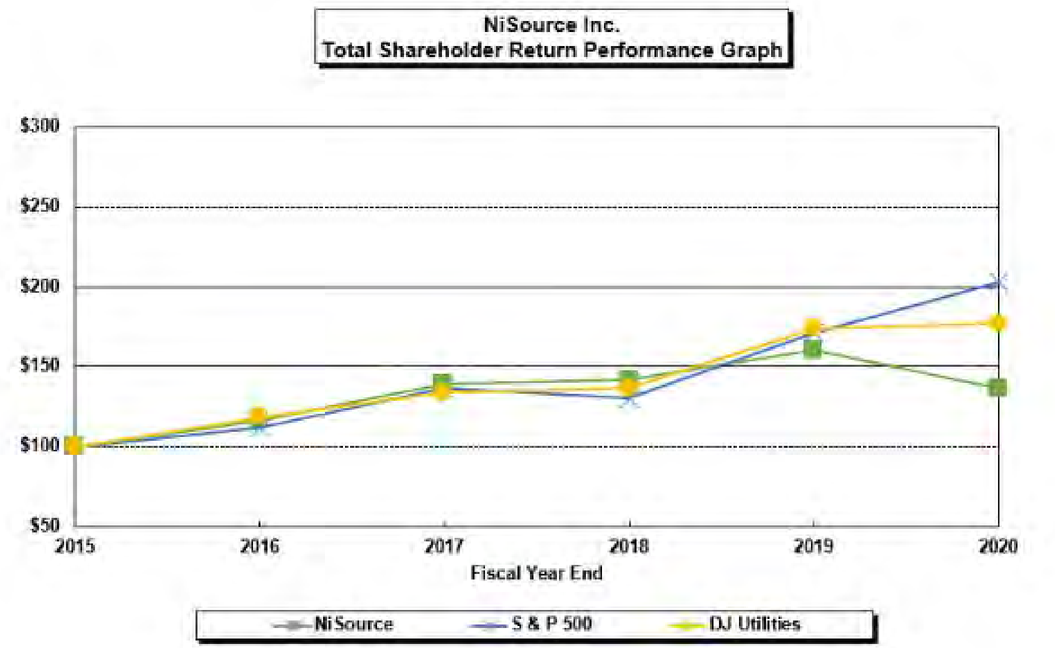
NiSource's common stock is listed and traded on the New York Stock Exchange under the symbol "NI."

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 27, 2021 meeting, the Board declared a quarterly common dividend of $0.22 per share, payable on February 19, 2021 to holders of record on February 9, 2021.

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 9, 2021, NiSource had 18,211 common stockholders of record and 391,859,711 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.



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.

Purchases of Equity Securities by Issuer and Affiliated Purchasers. For the three months ended December 31, 2020, no equity securities that are registered by NiSource Inc. pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our affiliated purchasers.

ITEM 6. SELECTED FINANCIAL DATA

NISOURCE INC.

None.

On November 19, 2020, the SEC issued amendments to streamline and enhance certain financial disclosure requirements in Regulation S-K. These changes are effective for annual filings for the first fiscal year ending on or after August 9, 2021. Early adoption is permitted for companies after February 10, 2021, and companies are permitted to selectively early adopt the provisions of the final rules, provided an amended item is adopted in its entirety. We early adopted the amendments to Item 301 in their entirety, which removed the requirement to furnish selected financial data for each of the last five fiscal years.

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

NISOURCE INC.

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 six 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 24, "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 (i) address changing customer conservation patterns, (ii) develop more contemporary pricing structures, and (iii) embark on long-term infrastructure investment and safety programs. These strategies focus on improving reliability and safety, enhancing customer service, lowering customer bills and reducing 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 *Electric Supply* section of our Electric Operations Segment discussion for additional information on our long term electric generation strategy.

Columbia of Massachusetts Asset Sale: On February 26, 2020, NiSource and Columbia of Massachusetts entered into an Asset Purchase Agreement with Eversource (the "Asset Purchase Agreement"). Upon the terms and subject to the conditions set forth in the Asset Purchase Agreement, we sold the Massachusetts Business to Eversource for net proceeds of approximately $1,113 million in cash, subject to adjustment for the final working capital amount. The sale was approved by the Massachusetts DPU on October 7, 2020, and closed on October 9, 2020. As a result of the sale, we have transitioned to executing a TSA with Eversource. See Note 1, "Nature of Operations and Summary of Significant Accounting Policies," in the Notes to Consolidated Financial Statements for additional information.

Your Energy, Your Future: Our plan to replace 80% of our coal generation capacity by the end of 2023 and all of our coal generation by the end of 2028 with primarily renewable resources is well underway. In October 2020, we executed three BTAs for 900 MW solar nameplate capacity and 135 MW of storage capacity. In December 2020, the formation of the Rosewater Wind Generation joint venture, one of our previously executed BTAs, was completed, and has begun operation. We executed in December 2020 a PPA for an additional 280 MW of solar nameplate capacity. These projects were selected following a comprehensive review of bids submitted through the RFP process that NIPSCO underwent in late 2019. The projects complement previously executed BTAs and PPAs with a combined nameplate capacity of 400 MW and 1,300 MW, respectively. For additional information, see Note 4 "Variable Interest Entities" and "Results and Discussion of Segment Operation - Electric Operations," in this Management's Discussion.

NiSource Next: We have launched a comprehensive, multi-year program designed to deliver long-term safety, sustainable capability enhancements and cost optimization improvements. This program will advance the high priority we place on safety and risk mitigation, further enable our safety management system ("SMS"), and enhance the customer experience. NiSource Next is designed to (i) leverage our current scale, (ii) utilize technology, (iii) define clear roles and accountability with our leaders and employees, and (iv) standardize our processes to focus on operational rigor, quality management and continuous improvement. An initial step in this program was the voluntary separation program announced in August 2020, with an expected total severance expense of approximately $38.0 million. The majority of these separation costs will be expensed in 2020 and approximately $21.2 million has been paid as of December 31, 2020. The NiSource Next initiative, along with the sale of the Massachusetts Business, is projected to achieve a reduction in ongoing operation and maintenance costs by approximately 8% in 2021 compared to 2020. For additional information, see Note 20-E, "Other Matters," in the Notes to Consolidated Financial Statements.

COVID-19: The safety of our employees and customers, while providing essential services during the COVID-19 pandemic, continues to be a key area of focus. Since March 2020, we have taken a proactive, coordinated approach intended to prevent, mitigate and respond to the pandemic, by utilizing our Incident Command System (ICS). The ICS includes members of our executive leadership team, a medical review professional, and members of functional teams from across our company. The ICS monitors state-by-state conditions and determines steps to conduct our operations safely for employees and customers.

We have implemented procedures designed to protect our employees who work in the field and who continue to work in operational and corporate facilities, including social distancing, wearing face coverings, temperature checks and more frequent cleaning of equipment and facilities. We have also implemented work-from-home policies and practices. We have minimized non-essential work that requires an employee to enter a customer premise and limited company vehicle occupancy to one person, where possible. We continue to employ physical and cybersecurity measures to ensure that our operational and support systems remain functional. Our actions to date have mitigated the spread of COVID-19 amongst our employees and principal field contractors. We will continue to follow CDC guidance and implement safety measures intended to ensure employee and customer safety during this pandemic. We are following all federal, state and local guidelines related to the COVID-19 vaccinations and will encourage employees to receive the vaccine when it is available to them.

Since the beginning of the pandemic, we have been helping our customers navigate this challenging time. We suspended disconnections soon after this outbreak began. As of December 2020, suspension of disconnections has been lifted in some, but not all, of our jurisdictions. We plan to continue our payment assistance programs across all of our operating territory to help customers deal with the impact of the pandemic. Additionally, we continue to have dialogue with the state regulatory commissions for each of our operating companies regarding the pandemic. Regulatory deferrals for certain costs have been allowed by all of our state regulatory commissions. Costs approved for deferral vary by state. For information on the state specific suspension of disconnections and COVID-19 regulatory filings, see Note 9, "Regulatory Matters," in the Notes to Consolidated Financial Statements. The CARES Act was enacted on March 27, 2020 and provides monetary-relief and financial aid to individuals, business, nonprofits, states and municipalities. The Coronavirus Relief Act was enacted on December 27, 2020 and extended or supplemented many of the programs from the CARES act. We are continuing to promote multiple resources available to customers including benefits from the CARES Act, such as additional funding for both the Low-Income Home Energy Assistance Program and the Community Services Block Grant to help support income-qualified customers. We are sharing energy efficiency tips to help customers save energy at home and promoting our budget plan program, which allows customers to pay about the same amount each month.

We have experienced lower revenue, higher expenses for personal protective equipment and supplies, and higher bad debt expense as a consequence of the pandemic, which has negatively impacted our results of operations through December 31, 2020. Refer to "Results and Discussion of Segment Operation" in this Management's Discussion for additional segment specific information. We did experience lower cash flows from operations for the year ended December 31, 2020 in comparison to the same period in 2019 due, in part, to slower collections of customer accounts receivable; however, we believe we have sufficient liquidity as a result of the issuance of $1.0 billion notes in April 2020, the remaining cash proceeds received from the sale of the Massachusetts Business in October 2020, the available capacity under our short-term revolving credit facility and accounts receivable securitization facilities, and our anticipated ability to access capital markets. Additionally, in the second quarter of 2020 we reduced our planned 2020 capital investments by $145 million. We did not make any other material changes to our capital construction programs or our renewable generation projects. While we have not experienced any significant issues in our supply chain, we are actively managing the materials, supplies, and contract services for our generation, transmission, distribution, and customer services functions.

Refer to Part I. Item 1A. "Risk Factors" for additional information related to the ongoing impact of the pandemic.

Greater Lawrence Incident: For the year ended December 31, 2020, we have incurred $17 million of third-party claims and other incident-related costs associated with the Greater Lawrence Incident. For additional information, see Note 20-C, "Legal Proceedings" and Note 20-E "Other Matters," in the Notes to Consolidated Financial Statements.

We invested approximately $258 million of capital spend for specific pipeline replacement work that was completed in 2019. We maintain property insurance for gas pipelines and other applicable property. In 2019, Columbia of Massachusetts filed a proof of loss with its property insurer for this pipeline replacement work. 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. See Note 1, "Nature of Operations and Summary of Significant Accounting Policies," in the Notes to Consolidated Financial Statements for additional information.

Refer to Note 20-C. "Legal Proceedings" and Note 20-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.

Summary of Consolidated Financial Results

A summary of our consolidated financial results for the years ended December 31, 2020, 2019 and 2018, are presented below:

Year Ended December 31, *(in millions, except per share amounts)*	**2020**	2019	2018	2020 vs. 2019	2019 vs. 2018
Operating Revenues	**$ 4,681.7**	$ 5,208.9	$ 5,114.5	$ (527.2)	$ 94.4
Operating Expenses					
Cost of energy	**1,109.3**	1,534.8	1,761.3	(425.5)	(226.5)
Other Operating Expenses	**3,021.6**	2,783.4	3,228.5	238.2	(445.1)
Total Operating Expenses	**4,130.9**	**4,318.2**	**4,989.8**	**(187.3)**	**(671.6)**
Operating Income	**550.8**	890.7	124.7	(339.9)	766.0
Total Other Deductions, Net	**(582.1)**	(384.1)	(355.3)	(198.0)	(28.8)
Income Taxes	**(17.1)**	123.5	(180.0)	(140.6)	303.5
Net Income (Loss)	**(14.2)**	383.1	(50.6)	(397.3)	433.7
Net income attributable to noncontrolling interest	**3.4**	—	—	3.4	—
Net Income (Loss) attributable to NiSource	**(17.6)**	383.1	(50.6)	(400.7)	433.7
Preferred dividends	**(55.1)**	(55.1)	(15.0)	—	(40.1)
Net Income (Loss) Available to Common Shareholders	**(72.7)**	328.0	(65.6)	(400.7)	393.6
Basic Earnings (Loss) Per Share	**$ (0.19)**	$ 0.88	$ (0.18)	$ (1.07)	$ 1.06
Basic Average Common Shares Outstanding	**384.3**	374.6	356.5	9.7	18.1

The majority of the costs of energy in both segments are tracked costs that are passed through directly to the customer, resulting in an equal and offsetting amount reflected in operating revenues.

On a consolidated basis, we reported a net loss available to common shareholders of $72.7 million or $0.19 per basic share for the twelve months ended December 31, 2020 compared to income to common shareholders of $328.0 million or $0.88 per basic share for the same period in 2019. Additionally, we reported operating income of $550.8 million for the twelve months ended December 31, 2020 compared to $890.7 million for the same period in 2019. The decrease in both net income available to common shareholders and operating income during 2020 was primarily due to lower operating revenue related to the sale of the Massachusetts Business, as well as higher operating expenses due to insurance recoveries recorded in 2019, net of third-party claims and other costs, related to the Greater Lawrence Incident. Additionally, the decrease to net income available to common shareholders was also impacted by the loss on early extinguishment of debt in 2020 as well as partially offset by a change from income tax expense in 2019 to an income tax benefit in 2020.

Other Deductions, Net

Other deductions, net reduced income by $582.1 million in 2020 compared to a reduction in income of $384.1 million in 2019. This change is primarily due to the loss on early extinguishment of debt in 2020.

Income Taxes

The decrease in income tax expense from 2019 to 2020 is primarily attributable to lower pre-tax income, resulting from the items discussed above in "Operating Income" and "Other Deductions, Net," state jurisdictional mix of pre-tax loss in 2020 tax effected at statutory tax rates and increased amortization of excess deferred federal income taxes in 2020 compared to 2019. These items are offset by increased deferred tax expense recognized on the sale of the Columbia of Massachusetts' regulatory liability, established due to TCJA in 2017, that would have otherwise been recognized over the amortization period, non-cash impairment of goodwill related to Columbia of Massachusetts in 2019 (see Note 7, "Goodwill and Other Intangible Assets" for additional information) and one-time adjustments to deferred tax balances.

Refer to Note 11, "Income Taxes," in the Notes to Consolidated Financial Statements for additional information on income taxes and the change in the effective tax rate.

RESULTS AND DISCUSSION OF OPERATIONS

Presentation of Segment Information

Our operations are divided into two primary reportable segments: Gas Distribution Operations and Electric Operations. The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as an operating segment, are presented as "Corporate and Other" within the Notes to the Consolidated Financial Statements and primarily are comprised of interest expense on holding company debt, and unallocated corporate costs and activities.

Gas Distribution Operations

Financial and operational data for the Gas Distribution Operations segment for the years ended December 31, 2020, 2019 and 2018, are presented below:

Year Ended December 31, *(in millions)*	**2020**	2019	2018	2020 vs. 2019	2019 vs. 2018
Operating Revenues	**$ 3,140.1**	$ 3,522.8	$ 3,419.5	$ (382.7)	$ 103.3
Operating Expenses					
Cost of energy	**794.2**	1,067.6	1,259.3	(273.4)	(191.7)
Operation and maintenance	**1,138.0**	935.7	1,908.1	202.3	(972.4)
Depreciation and amortization	**363.1**	403.2	301.0	(40.1)	102.2
Impairment of intangible assets	**—**	209.7	—	(209.7)	209.7
Loss on sale of fixed assets and impairments, net	**412.4**	0.1	0.2	412.3	(0.1)
Other taxes	**233.3**	231.1	205.0	2.2	26.1
Total Operating Expenses	**2,941.0**	2,847.4	3,673.6	93.6	(826.2)
Operating Income (Loss)	**$ 199.1**	$ 675.4	$ (254.1)	$ (476.3)	$ 929.5
Revenues					
Residential	**$ 2,110.6**	$ 2,317.2	$ 2,248.3	$ (206.6)	$ 68.9
Commercial	**679.7**	775.1	753.7	(95.4)	21.4
Industrial	**213.8**	245.8	228.6	(32.0)	17.2
Off-System	**41.0**	77.7	92.4	(36.7)	(14.7)
Other	**95.0**	107.0	96.5	(12.0)	10.5
Total	**$ 3,140.1**	$ 3,522.8	$ 3,419.5	$ (382.7)	$ 103.3
Sales and Transportation (MMDth)					
Residential	**249.5**	274.9	280.3	(25.4)	(5.4)
Commercial	**170.5**	189.6	187.6	(19.1)	2.0
Industrial	**538.1**	542.5	555.7	(4.4)	(13.2)
Off-System	**23.3**	32.9	30.0	(9.6)	2.9
Other	**0.3**	0.3	—	—	0.3
Total	**981.7**	1,040.2	1,053.6	(58.5)	(13.4)
Heating Degree Days	**5,097**	5,375	5,562	(278)	(187)
Normal Heating Degree Days	**5,485**	5,452	5,610	33	(158)
% Warmer than Normal	**(7)%**	(1)%	(2)%		
Gas Distribution Customers					
Residential	**2,954,478**	3,221,178	3,194,662	(266,700)	26,516
Commercial	**253,184**	282,778	281,517	(29,594)	1,261
Industrial	**4,968**	5,982	5,833	(1,014)	149
Other	**3**	3	3	—	—
Total	**3,212,633**	3,509,941	3,482,015	(297,308)	27,926

Cost of energy for the Gas Distribution Operations segment is principally comprised of the cost of natural gas used while providing transportation and distribution services to customers. These are tracked costs that are passed through directly to the customer resulting in an equal and offsetting amount reflected in operating revenue. In addition, comparability of operation and maintenance expenses, depreciation and amortization, and other taxes may be impacted by regulatory, depreciation and tax trackers that allow for the recovery in rates of certain costs. Therefore, increases in these tracked operating expenses are offset by increases in operating revenues and have essentially no impact on net income.

2020 vs. 2019 Operating Income
For 2020, Gas Distribution Operations reported operating income of $199.1 million, a decrease of $476.3 million from the comparable 2019 period.

Operating revenues for 2020 were $3,140.1 million, a decrease of $382.7 million from the same period in 2019. The change in operating revenues was primarily driven by:

- Lower cost of energy billed to customers, which is offset in operating expense, of $273.4 million.
- Lower revenues due to the sale of the Massachusetts Business of $102.2 million.
- Lower revenues from the effects of warmer weather in 2020 of $47.9 million.
- Lower regulatory, depreciation, and tax trackers, which are offset in operating expense, of $20.7 million.
- The effects of decreased commercial and industrial usage and decreased late and disconnection fees, both primarily related to the COVID-19 pandemic, of $11.3 million.

Partially offset by:

- New rates from base rate proceedings, infrastructure replacement programs and Columbia of Ohio's CEP of $57.1 million.
- The effects of increased residential usage primarily related to the pandemic of $5.0 million.

Operating expenses were $93.6 million higher in 2020 compared to 2019. This change was primarily driven by:

- Loss on sale of the Massachusetts Business of $412.4 million.
- Insurance recoveries recorded in 2019, net of third party claims and other costs, related to the Greater Lawrence Incident of $243.2 million.
- Severance and outside services expense related to NiSource Next initiative of $32.4 million.
- Increased expenses primarily due to the impact of the pandemic related to materials and supplies, outside services, and uncollectible expenses of $23.8 million, offset by $12.0 million of deferral of uncollectible and other expenses, net of benefits, related to the pandemic.
- Higher depreciation and amortization and property tax expense primarily due to higher capital expenditures placed in service of $24.3 million

Partially offset by:

- Lower cost of energy billed to customers, which is offset in operating revenue, of $273.4.
- Non-cash impairment of the Columbia of Massachusetts franchise rights of $209.7 million in 2019.
- Lower operation and maintenance and depreciation and amortization expenses due to the Massachusetts Business sale of $98.7 million.
- Lower employee and administrative expense of $28.9 million.
- Lower regulatory, depreciation, and tax trackers, which are offset in operating revenues, of $20.7 million.

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

Operating revenues for 2019 were $3,522.8 million, an increase of $103.3 million from the same period in 2018. The change in operating 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, 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.

Partially offset by:

- Lower cost of energy billed to customers, which is offset in operating expenses of $191.7 million.

Operating expenses were $826.2 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.
- Lower cost of energy billed to customers, which is offset in operating revenues of $191.7 million.

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 regulator 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 operating 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.

Weather
In general, we calculate the weather-related revenue variance based on changing customer demand driven by weather variance from normal heating degree days, net of weather normalization mechanisms. 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 operating revenues.

Weather in the Gas Distribution Operations service territories for 2020 was about 7% warmer than normal and about 5% warmer than 2019, leading to decreased operating revenues of $47.9 million for the year ended December 31, 2020 compared to 2019. The majority of these amounts were driven by NIPSCO and Columbia of Pennsylvania.

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 operating 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.

NISOURCE INC.
Gas Distribution Operations (continued)

Throughput
Total volumes sold and transported for the year ended December 31, 2020 were 981.7 MMDth, compared to 1,040.2 MMDth for 2019. This decrease is primarily attributable to warmer weather experienced in 2020 compared to 2019, the sale of the Massachusetts Business and decreased usage by commercial and industrial customers primarily due to the pandemic.

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.

Commodity Price Impact
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 operating income 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 20-C. "Legal Proceedings," and Note 20-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. This sale was completed on October 9, 2020. For additional information, see Note 1, “Nature of Operations and Summary of Significant Accounting Policies,” in the Notes to Consolidated Financial Statements.

Electric Operations

Financial and operational data for the Electric Operations segment for the years ended December 31, 2020, 2019 and 2018, are presented below:

Year Ended December 31, *(in millions)*	**2020**	2019	2018	2020 vs. 2019	2019 vs. 2018
Operating Revenues	**$ 1,536.6**	$ 1,699.2	$ 1,708.2	$ (162.6)	$ (9.0)
Operating Expenses					
Cost of energy	**315.2**	467.3	502.1	(152.1)	(34.8)
Operation and maintenance	**497.6**	495.0	500.0	2.6	(5.0)
Depreciation and amortization	**321.3**	277.3	262.9	44.0	14.4
Gain on sale of fixed assets and impairments, net	**—**	(0.1)	—	0.1	(0.1)
Other taxes	**53.7**	52.9	57.1	0.8	(4.2)
Total Operating Expenses	**1,187.8**	1,292.4	1,322.1	(104.6)	(29.7)
Operating Income	**$ 348.8**	$ 406.8	$ 386.1	$ (58.0)	$ 20.7
Revenues					
Residential	**$ 527.8**	$ 481.6	$ 494.7	$ 46.2	$ (13.1)
Commercial	**480.3**	486.7	492.6	(6.4)	(5.9)
Industrial	**412.9**	608.4	614.4	(195.5)	(6.0)
Wholesale	**12.3**	11.7	15.7	0.6	(4.0)
Other	**103.3**	110.8	90.8	(7.5)	20.0
Total	**$ 1,536.6**	$ 1,699.2	$ 1,708.2	$ (162.6)	$ (9.0)
Sales (Gigawatt Hours)					
Residential	**3,484.0**	3,369.5	3,535.2	114.5	(165.7)
Commercial	**3,550.0**	3,760.3	3,844.6	(210.3)	(84.3)
Industrial	**7,480.3**	8,466.1	8,829.5	(985.8)	(363.4)
Wholesale	**83.6**	8.2	114.3	75.4	(106.1)
Other	**106.0**	117.2	124.4	(11.2)	(7.2)
Total	**14,703.9**	15,721.3	16,448.0	(1,017.4)	(726.7)
Cooling Degree Days	**900**	962	1,180	(62)	(218)
Normal Cooling Degree Days	**803**	803	806	—	(3)
% Warmer than Normal	**12 %**	20 %	46 %		
Electric Customers					
Residential	**418,871**	415,534	412,267	3,337	3,267
Commercial	**57,435**	57,058	56,605	377	453
Industrial	**2,154**	2,256	2,284	(102)	(28)
Wholesale	**722**	726	735	(4)	(9)
Other	**2**	2	2	—	—
Total	**479,184**	475,576	471,893	3,608	3,683

Electric Operations (continued)

Cost of energy for the Electric Operations segment is principally comprised of the cost of coal, related handling costs, natural gas purchased for internal generation of electricity at NIPSCO, and the cost of power purchased from third-party generators of electricity. The majority of these are tracked costs that are passed through directly to the customer resulting in an equal and offsetting amount reflected in operating revenue. In addition, comparability of operation and maintenance expenses and depreciation and amortization may be impacted by regulatory and depreciation trackers that allow for the recovery in rates of certain costs. Therefore, increases in these tracked operating expenses are offset by increases in operating revenues and have essentially no impact on net income.

2020 vs. 2019 Operating Income
For 2020, Electric Operations reported operating income of $348.8 million, a decrease of $58.0 million from the comparable 2019 period.

Operating revenues for 2020 were $1,536.6 million, an decrease of $162.6 million from the same period in 2019. The change in operating revenues was primarily driven by:

- Lower cost of energy billed to customers, which is offset in operating expense, of $152.1 million.
- Lower regulatory and depreciation trackers, which are offset in operating expense, of $25.2 million.
- The effects of decreased commercial and industrial usage and decreased late and disconnection fees, both primarily related to the COVID-19 pandemic, of $24.9 million.

Partially offset by:

- Higher revenue from recent base rate proceedings of $22.5 million.
- The effects of increased residential usage primarily related to the pandemic of $13.5 million.
- The effects of customer growth of $4.0 million.

Operating expenses were $104.6 million lower in 2020 than 2019. This change was primarily driven by:

- Lower cost of energy billed to customers, which is offset in operating revenue, of $152.1 million.
- Lower regulatory and depreciation trackers, which are offset in operating revenues, of $25.2 million.
- Lower outside services costs of $16.0 million primarily related to lower generation-related maintenance.
- Lower employee and administrative costs of $8.1 million.

Partially offset by:

- Increased depreciation of $61.6 million primarily due to additional plant placed in service.
- Severance and outside services expenses related to the NiSource Next initiative of $13.0 million.
- Increased expenses primarily due to the impact of pandemic-related materials and supplies, outside services, uncollectible and sequestration expenses of $10.7 million, offset by a $5.3 million deferral of uncollectible and other expenses, related to the pandemic.
- Increased materials and supplies costs of $4.7 million
- Higher insurance expense of $2.7 million primarily driven by increased premiums.
- Increased environmental costs of $1.3 million.

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.

Operating revenues for 2019 were $1,699.2 million, a decrease of $9.0 million from the same period in 2018. The change in operating revenues was primarily driven by:

- Lower cost of energy billed to customers, which is offset in operating expense, of $34.8 million.
- Lower revenues from the effects of cooler weather of $15.1 million.

- Decreased residential, commercial and industrial usage of $10.8 million.

Partially offset 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.

Operating expenses were $29.7 million lower in 2019 than 2018. This change was primarily driven by:

- Lower cost of energy billed to customers, which is offset in operating revenue, of $34.8 million.
- 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.

Partially offset by:

- Higher regulatory and depreciation trackers, which are offset in operating revenues, of $8.4 million.
- Increased depreciation of $8.7 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 operating revenues.

Weather in the Electric Operations' territories for 2020 was 12% warmer than normal and 6% cooler than the same period in 2019, which had an immaterial impact on operating revenues for the year ended December 31, 2020 compared to 2019.

Weather in the Electric Operations' territories for 2019 was 20% warmer than normal and 18% cooler than the same period in 2018, decreasing operating revenues $15.1 million for the year ended December 31, 2019 compared to 2018.

Sales
Electric Operations sales were 14,703.9 GWh for 2020, a decrease of 1,017.4 GWh, or 6.5% compared to 2019. This decrease was primarily attributable to decreased usage by industrial and commercial customers due to the pandemic and higher self-generation by industrial customers, partially offset by increased usage by residential customers primarily due to the pandemic.

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.

Commodity Price Impact
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 operating 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 45.9% and 51.5% of the total industrial MWh sales for the years ended December 31, 2020 and 2019, respectively.

Electric Supply

NIPSCO 2018 Integrated Resource Plan. NIPSCO concluded 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 the R.M. Schahfer Generating Station by mid-2023 and the Michigan City Generating Station by the end of 2028. These stations represent 2,080 MW of generating capacity, equal to 72% of NIPSCO's remaining capacity and 100% of NIPSCO's remaining coal-fired generating capacity. In the second quarter of 2020, the MISO approved NIPSCO's plan to retire the R.M. Schahfer Generating Station in 2023. The planned replacement by the end of 2023 of approximately 1,400 MW of retiring coal-fired generation station could provide incremental capital investment opportunities of approximately $1.8 to $2.0 billion, primarily in 2022 and 2023. Refer to Note 6, "Property, Plant and Equipment" and Note 20-E, "Other Matters," in the Notes to Consolidated Financial Statements for further information. In February 2021, NIPSCO decided to submit modified Attachment Y Notices to MISO requesting accelerated retirement of two of the four coal fired units at R.M. Schahfer Generating Station. The two units are now expected to be retired by the end of 2021, with the remaining two units still scheduled to be retired in 2023. At retirement, the net book value of the retired units will be reclassified from "Non-Utility and Other property", to current and long-term "Regulatory Assets."

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. NIPSCO has executed several PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per MWh. Each facility supplying the energy will have an associated nameplate capacity, and payments under the PPAs will not begin until the associated generation facility is constructed by the owner/seller. NIPSCO has also executed several BTAs with developers to construct renewable generation facilities. The following table summarizes the executed PPAs and BTAs that have not yet been placed into service:

Project Name	Transaction Type	Technology	Nameplate Capacity (MW)	Storage Capacity (MW)	Submitted to IURC	IURC Approval	Estimated Construction Completion
Jordan Creek	20 year PPA	Wind	400	—	02/01/2019	6/05/2019	In Service (12/10/2020)
Rosewater[(1)]	BTA	Wind	100	—	02/01/2019	8/07/2019	In Service (12/29/2020)
Indiana Crossroads[(2)]	BTA	Wind	300	—	10/22/2019	2/19/2020	12/31/2021
Greensboro	20 year PPA	Solar & Storage	100	30	7/17/2020	1/27/2021	6/30/2023
Brickyard	20 year PPA	Solar	200	—	7/17/2020	1/27/2021	6/30/2023
Green River	20 year PPA	Solar	200	—	12/23/2020	Pending	6/30/2023
Cavalry[(2)]	BTA	Solar & Storage	200	60	11/30/2020	Pending	12/31/2023
Dunn's Bridge I[(2)]	BTA	Solar	265	—	11/30/2020	Pending	12/31/2022
Dunn's Bridge II[(2)]	BTA	Solar & Storage	435	75	11/30/2020	Pending	12/31/2023
Gibson	22 year PPA	Solar	280	—	01/29/2021	Pending	12/31/2023

(1) Ownership of the facility was transferred to a joint venture whose members include NIPSCO and an unrelated tax equity partner.

(2) Ownership of the facilities will be transferred to joint ventures whose members include NIPSCO and an unrelated tax equity partner.

We expect to secure additional agreements with counterparties and initiate regulatory compliance filings into 2021.

Liquidity and Capital Resources

We continually evaluate the availability of adequate financing to fund our ongoing business operations, working capital and core safety and infrastructure investment programs. Our financing is sourced through cash flow from operations and the issuance of debt and/or equity. External debt financing is provided primarily through the issuance of long-term debt, accounts receivable securitization programs and our $1.5 billion commercial paper program, which is backstopped by our committed revolving credit facility with a total availability from third-party lenders of $1.85 billion. The commercial paper program and credit facility provide cost-effective, short-term financing until it can be replaced with a balance of long-term debt and equity financing that achieves our desired capital structure. We have also utilized an at-the-market (ATM) equity sales program that allowed us to issue and sell shares of our common stock up to an aggregate offering price of $434.4 million. The program expired on December 31, 2020, but we expect to issue additional equity under ATM offerings from time to time.

We believe these sources provide adequate capital to fund our operating activities and capital expenditures in 2021 and beyond.

Greater Lawrence Incident. As discussed in the "Executive Summary", Part I, Item 1A “Risk Factors,” and in Note 20, “Other Commitments and Contingencies” in the Notes to Consolidated Financial Statements, due to the inherent uncertainty of litigation, there can be no assurance that the outcome or resolution of any particular claim related to the Greater Lawrence Incident will not continue to have an adverse impact on our cash flows. Through income generated from operating activities, amounts available under the short-term revolving credit facility, and our ability to access capital markets, we believe we have adequate capital available to settle remaining anticipated claims associated with the Greater Lawrence Incident. Previous costs in excess of insurance recoveries were primarily funded through short-term borrowings. The sale of the Massachusetts Business was completed on October 9, 2020. On October 14, 2020, we used a portion of the proceeds from the Massachusetts Business sale to pay down these short-term borrowings.

Operating Activities

Net cash from operating activities for the year ended December 31, 2020 was $1,104.0 million, a decrease of $479.3 million from 2019. This decrease was primarily driven by a year over year increase in net payments related to the Greater Lawrence Incident. During 2020, we paid approximately $227 million compared to net receipts of $289 million, representing insurance recoveries offset by payments, during 2019. Refer to Note 20, "Other Commitments and Contingencies" in the Notes to Consolidated Financial Statements for further information related to the Greater Lawrence Incident.

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. See below for further details of our capital expenditures and related regulatory programs. In 2020, our typical investing cash outflows were offset by $1,115.9 million of proceeds from the sale of assets, driven by the sale of the Massachusetts Business. Refer to Note 1 "Nature of Operations and Summary of Significant Accounting Policies" for more information.

Capital Expenditures. The table below reflects capital expenditures and certain other investing activities by segment for 2020, 2019 and 2018.

(in millions)	**2020**	2019	2018[3]
Gas Distribution Operations			
System Growth and Tracker	**$ 975.7**	$ 1,006.1	$ 897.5
Maintenance	**291.2**	374.3	417.8
Total Gas Distribution Operations	**1,266.9**	1,380.3	1,315.3
Electric Operations			
System Growth and Tracker	**222.1**	279.5	346.0
Maintenance	**200.7**	189.4	153.3
Total Electric Operations	**422.8**	468.9	499.3
Corporate and Other Operations - Maintenance[1]	**31.1**	18.6	—
Total[2]	**$ 1,720.8**	$ 1,867.8	$ 1,814.6

[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 2019 and 2020.
[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 2020, capital expenditures and certain other investing activities were $1,720.8 million, which was $147.0 million lower than the 2019 capital program. This decrease in spending is primarily due to the sale of the Massachusetts Business and impact of COVID 19.

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 2021, we project to invest approximately $1.9 to $2.1 billion in our capital program. This projected level of spend is an increase from our 2020 spend levels and supports continued investment in safety and reliability through modernizing gas and electric systems while meeting customer growth demands.

Regulatory Capital Improvement Programs. In 2020, 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. 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	Costs Covered[1]	Rates Effective
Columbia of Ohio	IRP - 2020	$	32.9	$	234.4	1/19-12/19	Replacement of (1) hazardous service lines, (2) cast iron, wrought iron, uncoated steel, and bare steel pipe, (3) natural gas risers prone to failure and installation of AMR devices.	May 2020
Columbia of Ohio	CEP - 2020	$	18.0	$	185.1	1/19-12/19	Assets not included in the IRP.	September 2020
NIPSCO - Gas	TDSIC 1	$	0.6	$	26.0	1/20-6/20	New or replacement projects undertaken for the purpose of safety, reliability, system modernization or economic development.	January 2021
NIPSCO - Gas	FMCA 5	$	4.8	$	42.3	4/20-9/20	Project costs to comply with federal mandates.	April 2021
Columbia of Pennsylvania	DSIC-Q4 2020[2]	$	0.8	$	25.0	9/20-11/20	Eligible project costs including piping, couplings, gas service lines, excess flow valves, risers, meter bars, meters, and other related capitalized cost, to improve the distribution system.	January 2021
Columbia of Virginia	SAVE - 2021	$	5.2	$	46.4	1/21-12/21	Replacement projects that (1) enhance system safety or reliability, or (2) reduce, or potentially reduce, greenhouse gas emissions.	January 2021
Columbia of Kentucky	SMRP - 2021[3]	$	5.8	$	50.0	1/21-12/21	Replacement of mains and inclusion of system safety investments.	Q2 2021
Columbia of Maryland	STRIDE - 2021	$	1.3	$	16.9	1/21-12/21	Pipeline upgrades designed to improve public safety or infrastructure reliability.	January 2021
NIPSCO - Electric	TDSIC - 7[4]	$	11.3	$	122.3	7/19-7/20	New or replacement projects undertaken for the purpose of safety, reliability, system modernization or economic development.	February 2021
NIPSCO - Electric	FMCA - 13[5][6]	$	(1.2)	$	—	9/19-2/20	Project costs to comply with federal mandates.	August 2020

[1]Programs do not include any costs already included in base rates.
[2]Due to a cap on the revenues permitted to flow through the DSIC, Columbia Gas of Pennsylvania is only able to request recovery of a portion of the capital investment for this period.
[3]On December 17, 2020, the Kentucky PSC issued an Order suspending the rates through May 30, 2021. An Order for approval can be received from the Commission prior to this date.
[4]Incremental capital and revenue are net of amounts included in the step 2 rates. See Part 1, Item 1. "Business" for additional information.
[5]Incremental revenue is inclusive of tracker eligible operations and maintenance expense.
[6]No eligible capital investments were made during the investment period.

Refer to Note 9, "Regulatory Matters" and Note 20-E, "Other Matters," in the Notes to Consolidated Financial Statements for a further discussion of regulatory developments during 2020.

Financing Activities

Short-term Debt. Refer to Note 16, "Short-Term Borrowings," in the Notes to Consolidated Financial Statements for information on short-term debt.

Long-term Debt. Refer to Note 15, "Long-Term Debt," in the Notes to Consolidated Financial Statements for information on long-term debt.

Net Available Liquidity. As of December 31, 2020, an aggregate of $1,721.6 million of net liquidity was available, including cash and credit available under the revolving credit facility and accounts receivable securitization programs.

Sources of Liquidity

The following table displays our liquidity position as of December 31, 2020 and 2019:

Year Ended December 31, *(in millions)*	2020	2019
Current Liquidity		
Revolving Credit Facility	**$ 1,850.0**	$ 1,850.0
Accounts Receivable Program[(1)]	**273.3**	353.2
Less:		
Commercial Paper	**503.0**	570.0
Accounts Receivable Programs Utilized	**—**	353.2
Letters of Credit Outstanding Under Credit Facility	**15.2**	10.2
Add:		
Cash and Cash Equivalents	**116.5**	139.3
Net Available Liquidity	**$ 1,721.6**	$ 1,409.1

[(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, which requires us to maintain a debt to capitalization ratio that does not exceed 70%. As of December 31, 2020, the ratio was 62.5%.

Sale of Trade Accounts Receivables. Refer to Note 19, "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, 2020. In February 2020, S&P changed our and certain of our subsidiaries' outlook from Negative to Stable. There were no other changes to the below credit ratings or outlooks since 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+	Stable	Baa2	Stable	BBB	Stable
NIPSCO	BBB+	Stable	Baa1	Stable	BBB	Stable
Columbia of Massachusetts	BBB+	Stable	Baa2	Stable	Not rated	Not rated
Commercial Paper	A-2	Stable	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, 2020, the collateral requirement that would be required in the event of a downgrade below the ratings trigger levels would amount to approximately $53.9 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, 2020, 391,760,051 shares of common stock and 440,000 shares of preferred stock were outstanding. For more information regarding our common and preferred stock, see Note 13, "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, 2020 and their maturities were:

(in millions)	Total	2021	2022	2023	2024	2025	After
Long-term debt [1]	$ 9,135.0	$ —	$ 30.0	$ —	$ —	$ 1,260.0	$ 7,845.0
Interest payments on long-term debt	6,046.3	336.3	335.7	334.1	334.1	334.1	4,372.0
Finance leases[2]	264.7	32.7	32.2	28.8	20.8	16.1	134.1
Operating leases[3]	48.0	11.7	5.2	4.7	4.5	3.7	18.2
Energy commodity contracts	42.1	42.1	—	—	—	—	—
Service obligations:							
Pipeline service obligations[4]	1,495.6	468.7	422.5	256.0	150.5	56.2	141.7
IT service obligations	240.3	74.9	74.0	38.1	30.5	22.8	—
Other service obligations[5]	12.6	12.6	—	—	—	—	—
Other liabilities[6]	116.9	26.0	0.8	90.1	—	—	—
Total contractual obligations	$ 17,401.5	$ 1,005.0	$ 900.4	$ 751.8	$ 540.4	$ 1,692.9	$ 12,511.0

(1) Long-term debt balance excludes unamortized issuance costs and discounts of $86.9 million.

(2) Finance lease payments shown above are inclusive of interest totaling $69.7 million.

(3) Operating lease payments shown above are inclusive of interest totaling $7.8 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 as they are renewed month-to-month after the first year. If we were to continue the fleet vehicle leases outstanding at December 31, 2020, payments would be $30.0 million in 2021, $27.7 million in 2022, $24.9 million in 2023, $22.0 million in 2024, $19.0 million in 2025 and $21.5 million thereafter.

(4) In February 2021, the demand rate increased for our pipeline service obligations, resulting in a total increase of $638.6 million in addition to our future pipeline service obligations shown above.

(5) On February 9, 2021, a rail transportation contract for the transportation of coal was fully executed between NIPSCO and a counterparty, replacing the prior agreement. The minimum coal tonnage shipment commitment for 2021 was eliminated under the new agreement, reducing our contractual obligation for 2021 by $12.1 million.

(6) Other liabilities shown above are inclusive of the Rosewater Developer payment due in 2023.

Our calculated estimated interest payments for long-term debt is based on the stated coupon and payment dates. For 2021, we project that we will be required to make interest payments of approximately $339.4 million, which includes $336.3 million of interest payments related to our long-term debt outstanding as of December 31, 2020. At December 31, 2020, we had $503.0 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 2021. Plan contributions beyond 2021 are dependent upon a number of factors, including actual returns on plan assets, which cannot be reliably estimated at this time. In 2021, we expect to make contributions of approximately $2.9 million to our pension plans and approximately $21.8 million to our postretirement medical and life plans. Refer to Note 12, "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, sales and use, and various other taxes and expect to make tax payments of approximately $253.4 million in 2021, 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 14, "Income Taxes," in the Notes to Consolidated Financial Statements for more information.

NIPSCO has executed several PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per MWh. Each facility supplying the energy will have an associated nameplate capacity, and payments under the PPAs will not begin until the associated generation facility is constructed by the owner/seller. NIPSCO has also executed several BTAs with developers to construct renewable generation facilities. NIPSCO's purchase requirement under the BTAs 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 and the tax equity partner are obligated to make cash contributions to the partnership at the date construction is substantially complete. Once the tax equity partner has earned their negotiated rate of return and we have reached the agreed upon contractual date, NIPSCO has the option to purchase at fair market value from the tax equity partner the remaining interest in the aforementioned joint venture. See Note 20-A, "Contractual Obligations," and Note 20-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 20, "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. We manage risk through 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 10, "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, 2020 and 2019.

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, accounts receivable programs and now-settled term loan, 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 $12.3 million and $19.0 million for 2020 and 2019, 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 10, "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, 2020 and 2019.

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.

Certain individual state regulatory commissions instituted regulatory moratoriums in connection with the COVID-19 pandemic that impacted our ability to pursue our credit risk mitigation practices for customer accounts receivable. Following the issuances of these moratoriums, certain of our regulated operations have been authorized to recognize a regulatory asset for bad debt costs above levels currently in rates. We have reinstated our common credit mitigation practices where moratoriums have expired. See the COVID-19 pandemic discussion in Part I. Item 1A, "Risk Factors" for risks that have been identified related to the pandemic and refer to Note 9, "Regulatory Matters" in the Notes to Consolidated Financial Statements for state specific regulatory moratoriums.

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 $1,930.5 million and $2,065.5 million at December 31, 2020, and $2,239.6 million and $2,512.2 million at December 31, 2019, respectively. For additional information, refer to Note 9, “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. If we determine that the amounts included as regulatory assets are no longer 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 9, "Regulatory Matters," and Note 11, "Income Taxes," in the Notes to Consolidated Financial Statements.

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 2021 net periodic benefit cost, we selected an expected pre-tax long-term rate of return of 5.20% and 5.50% 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 utilize a full yield curve approach to estimate the service and interest components of net periodic benefit cost for pension and other postretirement benefits 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 12, “Pension and Other Postretirement Benefits,” in the Notes to Consolidated Financial Statements.

Typically, 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. Due to the ongoing COVID-19 pandemic, we adjusted our mortality assumption through 2023 to reflect anticipated slow recovery.

The following tables illustrate the effects of changes in these actuarial assumptions while holding all other assumptions constant:

	Impact on December 31, 2020 Projected Benefit Obligation Increase/(Decrease)	
Change in Assumptions *(in millions)*	Pension Benefits	Other Postretirement Benefits
+50 basis points change in discount rate	$ (88.7)	$ (29.8)
-50 basis points change in discount rate	96.5	32.7

	Impact on 2020 Expense Increase/(Decrease)[1]	
Change in Assumptions *(in millions)*	Pension Benefits	Other Postretirement Benefits
+50 basis points change in discount rate	$ (2.0)	$ (0.8)
-50 basis points change in discount rate	1.6	0.9
+50 basis points change in expected long-term rate of return on plan assets	(9.8)	(1.3)
-50 basis points change in expected long-term rate of return on plan assets	9.8	1.3

[1]Before labor capitalization and regulatory deferrals.

Goodwill and Other Intangible Assets. We have six goodwill reporting units, comprised of the six state operating companies within the Gas Distribution Operations reportable segment. Our goodwill assets at December 31, 2020 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, 2020.

A quantitative ("step 1") test was completed on May 1, 2020 for all reporting units. Columbia of Massachusetts was not considered to be a reporting unit for the May 1, 2020 fair value measurement as the goodwill balance had been reduced to zero as of December 31, 2019. 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. 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 each of the reporting units exceeds their carrying value. As a result, no impairment charges were recorded.

We recorded impairment charges related to goodwill and other intangible assets in 2019. See Note 7, "Goodwill and Other Intangible Assets," in the Notes to Consolidated Financial Statements for information regarding our 2019 analyses and assumptions.

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 for additional information regarding our significant judgments and estimates related to revenue recognition.

Variable Interest Entities. A VIE is an entity in which the controlling interest is determined through means other than a majority voting interest. The primary beneficiary of a VIE is the business enterprise which has the power to direct the activities of the VIE that most significantly impact the VIE's economic performance. Also, the primary beneficiary either absorbs a significant amount of the VIE's losses or has the right to receive benefits that could be significant to the VIE. We consider these qualitative elements in determining whether we are the primary beneficiary of a VIE, and we consolidate those VIEs for which we are determined to be the primary beneficiary. As the managing member of a partnership, we would control decisions that are significant to the ongoing operations and economic results. Therefore, we have concluded that we are the primary beneficiary of Rosewater and have consolidated Rosewater even though we own less than 100% of the total equity membership interest.

We have determined that the use of HLBV accounting is reasonable and appropriate to attribute income and loss to the noncontrolling interest held by the tax equity partner. HLBV accounting was selected as the allocation of Rosewater's economic results to members differ from the members' relative ownership percentages. Using the HLBV method, our earnings are calculated based on how the partnership would distribute its cash if it were to hypothetically sell all of its assets for their carrying amounts and liquidate at each reporting period. Under HLBV, we calculate the liquidation value allocable to each partner at the beginning and end of each period based on the contractual liquidation waterfall and adjust our income for the period to reflect the change our associated book value. Refer to Note 4, "Variable Interest Entities" 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.

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.

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, 2020 and 2019, 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, 2020, 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, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 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, 2020, 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 17, 2021, 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 matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Impact of Rate Regulation on the Financial Statements - Refer to Note 9 to the consolidated financial statements

Critical Audit Matter Description

The Company’s subsidiaries are fully regulated natural gas and electric utility companies serving customers in six 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.

The Company’s subsidiaries’ rates are subject to regulatory rate-setting processes. Rates are determined and approved in regulatory proceedings based on an analysis of the subsidiaries’ costs to provide utility service and a return on, and recovery of, the subsidiaries’ investment in the utility business. Regulatory decisions can have an impact on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. The respective commissions' regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the commission in the future will impact the accounting for regulated operations, including

NISOURCE INC.
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the commission will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

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 and (2) the likelihood of refund of amounts previously collected from customers. 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 the 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; 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 the commissions for the Company, regulatory statutes, interpretations, procedural memorandums, 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 precedents of the commissions' treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.

• For regulatory matters in process, we inspected the Company's filings with the commissions and the filings with the commissions by intervenors that may impact the Company's future rates, 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. For assets that were abandoned, we inquired of management about their considerations regarding the abandonment. We inspected minutes of the board of directors and regulatory orders and other filings with the 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.

/s/ DELOITTE & TOUCHE LLP
Columbus, Ohio
February 17, 2021

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)*	**2020**	2019	2018
Operating Revenues			
Customer revenues	**$ 4,473.2**	$ 5,053.4	$ 4,991.1
Other revenues	**208.5**	155.5	123.4
Total Operating Revenues	**4,681.7**	5,208.9	5,114.5
Operating Expenses			
Cost of energy	**1,109.3**	1,534.8	1,761.3
Operation and maintenance	**1,585.9**	1,354.7	2,352.9
Depreciation and amortization	**725.9**	717.4	599.6
Impairment of goodwill and intangible assets	**—**	414.5	—
Loss on sale of assets, net	**410.6**	—	1.2
Other taxes	**299.2**	296.8	274.8
Total Operating Expenses	**4,130.9**	4,318.2	4,989.8
Operating Income	**550.8**	890.7	124.7
Other Income (Deductions)			
Interest expense, net	**(370.7)**	(378.9)	(353.3)
Other, net	**32.1**	(5.2)	43.5
Loss on early extinguishment of long-term debt	**(243.5)**	—	(45.5)
Total Other Deductions, Net	**(582.1)**	(384.1)	(355.3)
Income (Loss) before Income Taxes	**(31.3)**	506.6	(230.6)
Income Taxes	**(17.1)**	123.5	(180.0)
Net Income (Loss)	**(14.2)**	383.1	(50.6)
Net income attributable to noncontrolling interest	**3.4**	—	—
Net Income (Loss) attributable to NiSource	**(17.6)**	383.1	(50.6)
Preferred dividends	**(55.1)**	(55.1)	(15.0)
Net Income (Loss) Available to Common Shareholders	**(72.7)**	328.0	(65.6)
Earnings (Loss) Per Share			
Basic Earnings (Loss) Per Share	**$ (0.19)**	$ 0.88	$ (0.18)
Diluted Earnings (Loss) Per Share	**$ (0.19)**	$ 0.87	$ (0.18)
Basic Average Common Shares Outstanding	**384.3**	374.6	356.5
Diluted Average Common Shares	**384.3**	376.0	356.5

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)*	**2020**	2019	2018
Net Income (Loss)	**$ (14.2)**	$ 383.1	$ (50.6)
Other comprehensive income (loss):			
Net unrealized gain (loss) on available-for-sale securities[1]	**2.7**	5.7	(2.6)
Net unrealized gain (loss) on cash flow hedges[2]	**(70.7)**	(64.2)	22.7
Unrecognized pension and OPEB benefit (costs)[3]	**3.9**	3.1	(4.4)
Total other comprehensive income (loss)	**(64.1)**	(55.4)	15.7
Total Comprehensive Income (Loss)	**$ (78.3)**	$ 327.7	$ (34.9)

[1] Net unrealized gain (loss) on available-for-sale securities, net of $0.7 million tax expense, $1.5 million tax expense and $0.6 million tax benefit in 2020, 2019 and 2018, respectively.
[2] Net unrealized gain (loss) on derivatives qualifying as cash flow hedges, net of $23.4 million tax benefit, $21.2 million tax benefit and $7.5 million tax expense in 2020, 2019 and 2018, respectively.
[3] Unrecognized pension and OPEB benefit (costs), net of $0.1 million tax benefit, $1.6 million tax expense and $1.5 million tax benefit in 2020, 2019 and 2018, 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, 2020**		December 31, 2019
ASSETS				
Property, Plant and Equipment				
Plant	**$**	**24,179.9**	$	24,541.9
Accumulated depreciation and amortization		**(7,560.4)**		(7,629.7)
Net Property, Plant and Equipment[(1)]		**16,619.5**		16,912.2
Investments and Other Assets				
Unconsolidated affiliates		**—**		1.3
Available-for-sale debt securities (amortized cost of $163.9 and $150.1, allowance for credit losses of $0.5 and $0, respectively)		**170.9**		154.2
Other investments		**81.1**		74.7
Total Investments and Other Assets		**252.0**		230.2
Current Assets				
Cash and cash equivalents		**116.5**		139.3
Restricted cash		**9.1**		9.1
Accounts receivable		**843.6**		876.1
Allowance for credit losses		**(52.3)**		(19.2)
Accounts receivable, net		**791.3**		856.9
Gas inventory		**191.2**		250.9
Materials and supplies, at average cost		**141.5**		120.2
Electric production fuel, at average cost		**68.4**		53.6
Exchange gas receivable		**34.1**		48.5
Regulatory assets		**135.7**		225.7
Deferred property taxes		**85.6**		79.5
Prepayments and other		**86.0**		70.2
Total Current Assets[(1)]		**1,659.4**		1,853.9
Other Assets				
Regulatory assets		**1,794.8**		2,013.9
Goodwill		**1,485.9**		1,485.9
Deferred charges and other		**228.9**		163.7
Total Other Assets		**3,509.6**		3,663.5
Total Assets	**$**	**22,040.5**	$	22,659.8

[(1)]Includes $175.6 million of net property, plant and equipment assets and $1.7 million of current assets of a consolidated VIE that may be used only to settle obligations of the consolidated VIE. Refer to Note 4 "Variable Interest Entity" for additional information.

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, 2020	December 31, 2019
CAPITALIZATION AND LIABILITIES		
Capitalization		
Stockholders' Equity		
Common stock - $0.01 par value, 600,000,000 shares authorized; 391,760,051 and 382,135,680 shares outstanding, respectively	**$ 3.9**	$ 3.8
Preferred stock - $0.01 par value, 20,000,000 shares authorized; 440,000 shares outstanding	**880.0**	880.0
Treasury stock	**(99.9)**	(99.9)
Additional paid-in capital	**6,890.1**	6,666.2
Retained deficit	**(1,765.2)**	(1,370.8)
Accumulated other comprehensive loss	**(156.7)**	(92.6)
Total NiSource Stockholders' Equity	**5,752.2**	5,986.7
Noncontrolling interest in consolidated subsidiaries	**85.6**	—
Total Stockholders' Equity	**5,837.8**	5,986.7
Long-term debt, excluding amounts due within one year	**9,219.8**	7,856.2
Total Capitalization	**15,057.6**	13,842.9
Current Liabilities		
Current portion of long-term debt	**23.3**	13.4
Short-term borrowings	**503.0**	1,773.2
Accounts payable	**589.0**	666.0
Customer deposits and credits	**243.3**	256.4
Taxes accrued	**244.1**	231.6
Interest accrued	**104.7**	99.4
Risk management liabilities	**78.2**	12.6
Exchange gas payable	**48.5**	59.7
Regulatory liabilities	**161.3**	160.2
Accrued compensation and employee benefits	**141.8**	156.3
Claims accrued	**28.6**	165.4
Other accruals	**113.6**	151.6
Total Current Liabilities	**2,279.4**	3,745.8
Other Liabilities		
Risk management liabilities	**144.6**	134.0
Deferred income taxes	**1,470.6**	1,485.3
Accrued insurance liabilities	**84.8**	81.5
Accrued liability for postretirement and postemployment benefits	**336.1**	373.2
Regulatory liabilities	**1,904.2**	2,352.0
Asset retirement obligations	**477.1**	416.9
Other noncurrent liabilities	**286.1**	228.2
Total Other Liabilities	**4,703.5**	5,071.1
Commitments and Contingencies (Refer to Note 20, "Other Commitments and Contingencies")		
Total Capitalization and Liabilities	**$ 22,040.5**	$ 22,659.8

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)*	**2020**	2019	2018
Operating Activities			
Net Income (Loss)	$ **(14.2)**	$ 383.1	$ (50.6)
Adjustments to Reconcile Net Income (Loss) to Net Cash from Operating Activities:			
Loss on early extinguishment of debt	**243.5**	—	45.5
Depreciation and amortization	**725.9**	717.4	599.6
Deferred income taxes and investment tax credits	**(29.0)**	118.2	(188.2)
Stock compensation expense and 401(k) profit sharing contribution	**17.4**	25.9	28.6
Impairment of goodwill and intangible assets	—	414.5	—
Loss (gain) on sale of assets	**409.8**	(0.6)	1.3
Amortization of discount/premium on debt	**9.4**	8.2	7.5
AFUDC equity	**(9.9)**	(8.0)	(14.2)
Other adjustments	**0.2**	(0.3)	0.4
Changes in Assets and Liabilities:			
Accounts receivable	**(3.9)**	187.8	(186.2)
Inventories	**(1.5)**	(2.0)	41.4
Accounts payable	**(29.7)**	(299.9)	268.4
Customer deposits and credits	**10.0**	16.9	(25.4)
Taxes accrued	**28.4**	7.3	20.2
Interest accrued	**5.3**	8.8	(21.7)
Exchange gas receivable/payable	**(6.9)**	55.5	(21.5)
Other accruals	**(218.8)**	105.3	43.5
Prepayments and other current assets	**(5.9)**	(33.6)	(14.5)
Regulatory assets/liabilities	**70.8**	(85.6)	(53.2)
Postretirement and postemployment benefits	**(103.6)**	(21.1)	58.2
Deferred charges and other noncurrent assets	**(15.0)**	(76.1)	3.8
Other noncurrent liabilities	**21.7**	61.6	(2.8)
Net Cash Flows from Operating Activities	**1,104.0**	1,583.3	540.1
Investing Activities			
Capital expenditures	**(1,758.1)**	(1,802.4)	(1,818.2)
Cost of removal	**(138.2)**	(113.2)	(104.3)
Proceeds from disposition of assets	**1,115.9**	0.4	1.8
Purchases of available-for-sale securities	**(144.7)**	(140.4)	(90.0)
Sales of available-for-sale securities	**131.4**	132.1	82.3
Payment to renewable generation asset developer	**(85.3)**	—	—
Other investing activities	**(0.1)**	1.1	2.3
Net Cash Flows used for Investing Activities	**(879.1)**	(1,922.4)	(1,926.1)
Financing Activities			
Proceeds from issuance of long-term debt	**2,974.0**	750.0	350.0
Repayments of long-term debt and finance lease obligations	**(1,622.0)**	(51.6)	(1,046.1)
Issuance of short-term debt (maturity > 90 days)	**1,350.0**	600.0	950.0
Repayment of short-term debt (maturity > 90 days)	**(2,200.0)**	(700.0)	—
Change in short-term borrowings, net (maturity ≤ 90 days)	**(420.1)**	(104.0)	(178.5)
Issuance of common stock, net of issuance costs	**211.4**	244.4	848.2
Issuance of preferred stock, net of issuance costs	—	—	880.0
Equity costs, premiums and other debt related costs	**(246.5)**	(17.8)	(46.0)
Acquisition of treasury stock	—	—	(4.0)
Contributions from non-controlling interest, net of issuance costs	**82.2**	—	—
Dividends paid - common stock	**(321.6)**	(298.5)	(273.3)
Dividends paid - preferred stock	**(55.1)**	(56.1)	(11.6)
Net Cash Flows from Financing Activities	**(247.7)**	366.4	1,468.7
Change in cash, cash equivalents and restricted cash	**(22.8)**	27.3	82.7
Cash, cash equivalents and restricted cash at beginning of period	**148.4**	121.1	38.4
Cash, Cash Equivalents and Restricted Cash at End of Period	$ **125.6**	$ 148.4	$ 121.1

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[(1)]	Treasury Stock	Additional Paid-In Capital	Retained Deficit	Accumulated Other Comprehensive Loss	Noncontrolling Interest in Consolidated Subsidiaries	Total
Balance as of January 1, 2018	**$ 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 ($0.80 per share)	—	—	—	—	(298.5)	—	—	(298.5)
Preferred stock (See Note 13)	—	—	—	—	(56.1)	—	—	(56.1)
Stock issuances:								
Employee stock purchase plan	—	—	—	5.6	—	—	—	5.6
Long-term incentive plan	—	—	—	10.4	—	—	—	10.4
401(k) and profit sharing	—	—	—	17.6	—	—	—	17.6
ATM Program	—	—	—	229.1	—	—	—	229.1
Balance as of December 31, 2019	**$ 3.8**	**$ 880.0**	**$ (99.9)**	**$ 6,666.2**	**$ (1,370.8)**	**$ (92.6)**	**$ —**	**$ 5,986.7**
Comprehensive Loss:								
Net Income (Loss)	—	—	—	—	(17.6)	—	3.4	(14.2)
Other comprehensive loss, net of tax	—	—	—	—	—	(64.1)	—	(64.1)
Dividends:								
Common stock ($0.84 per share)	—	—	—	—	(321.7)	—	—	(321.7)
Preferred stock (See Note 13)	—	—	—	—	(55.1)	—	—	(55.1)
Contribution from noncontrolling interest	—	—	—	—	—	—	82.2	82.2
Stock issuances:								
Employee stock purchase plan	—	—	—	5.7	—	—	—	5.7
Long-term incentive plan	—	—	—	8.4	—	—	—	8.4
401(k) and profit sharing	—	—	—	13.4	—	—	—	13.4
ATM program	0.1	—	—	196.4	—	—	—	196.5
Balance as of December 31, 2020	**$ 3.9**	**$ 880.0**	**$ (99.9)**	**$ 6,890.1**	**$ (1,765.2)**	**$ (156.7)**	**$ 85.6**	**$ 5,837.8**

(1)Series A and Series B shares have an aggregate liquidation preference of $400M and $500M, respectively. See Note 13, "Equity" for additional information.

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 (continued)

	Preferred	Common		
(in thousands)	**Shares**	**Shares**	**Treasury**	**Outstanding**
Balance as of January 1, 2018	**—**	**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**
Issued:				
Employee stock purchase plan	—	236	—	236
Long-term incentive plan	—	385	—	385
401(k) and profit sharing plan	—	544	—	544
ATM program	—	8,459	—	8,459
Balance as of December 31, 2020	**440**	**395,723**	**(3,963)**	**391,760**

[1]See Note 13, "Equity," for additional information.

The 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 3.7 million customers in six states. We generate substantially all of our operating income through these rate-regulated businesses. The consolidated financial statements include the accounts of us, our majority-owned subsidiaries, and VIEs of which we are the primary beneficiary after the elimination of all intercompany accounts and transactions.

On February 26, 2020, NiSource and Columbia of Massachusetts entered into an Asset Purchase Agreement with Eversource (the "Asset Purchase Agreement"). On October 9, 2020, NiSource and Columbia of Massachusetts received net proceeds from the sale of approximately $1,113 million, which included, a $1,100 million purchase price, an estimate of Columbia of Massachusetts' net working capital, net of closing costs and a $56.0 million payment in lieu of penalties that NiSource agreed to make in full settlement of all of the pending and potential claims, lawsuits, investigations or proceedings settled by and released by a settlement agreement approved by the Massachusetts DPU. As of December 31, 2020, we have recorded a loss on the sale of $412.4 million based on asset and liability balances as of the close of the transaction on October 9, 2020, estimated net working capital and estimated transaction costs. This estimated pre-tax loss is presented as "Loss on sale of assets, net" on the Statements of Consolidated Income (Loss) and is subject to change based on the final net working capital determination.

The Massachusetts Business had the following pretax income (loss) for the twelve months ended December 31, 2020, 2019 and 2018:

	Twelve Months Ended December 31,		
(in millions)	**2020**	2019	2018
Pretax Income (Loss)	**($422.3)**	$36.8	($835.6)

We continue to monitor how the COVID-19 pandemic is affecting our workforce, customers, suppliers, operations, financial results and cash flow. See Note 3, "Revenue Recognition," Note 9, "Regulatory Matters," and Note 11, "Income Taxes," for information on the pandemic.

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, weather and reasonable and supportable forecasts. 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 $338.3 million and $350.5 million as of December 31, 2020 and 2019, 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, 2020, 2019 or 2018. Refer to Note 18, "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.

We continually evaluate whether or not our operations are within the scope of ASC 980 and rate regulations. As part of that analysis, we evaluate probability of recovery for our regulatory assets. In management’s opinion, our regulated subsidiaries will be subject to regulatory accounting for the foreseeable future. Refer to Note 9, "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. Our 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 includes renewable generation assets owned by a joint venture of which we are the primary beneficiary and is generally depreciated on a straight-line basis over the life of the associated asset. Refer to Note 6, "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 2.6% in 2020, 3.0% in 2019 and 3.5% in 2018.

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 gross amounts are classified as "Non-Utility and Other " as described in Note 6, "Property, Plant and Equipment." If the asset is no longer operating but still subject to recovery, 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 "Net 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 6, "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

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.

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. See Note 7, "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, 2020 and 2019 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 19, "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 9, "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 $42.3 million and $47.2 million at December 31, 2020 and 2019, 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 $19.6 million and $25.5 million at December 31, 2020 and 2019, respectively. Gas inventory valued using the weighted average cost methodology was $148.8 million at December 31, 2020 and $203.7 million at December 31, 2019.

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 10, "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, including expenditures related to asset retirement obligations and cost of removal, 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 “Other accruals” 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 8, "Asset Retirement Obligations," and Note 20, "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 20-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 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Statement* ASU 2021-01, *Reference Rate Reform (Topic 848): Scope*	This pronouncement provides temporary optional expedients and exceptions for applying GAAP principles to contract modifications and hedging relationships to ease the financial reporting burdens of the expected market transition from LIBOR and other interbank offered rates to alternative reference rates.	Upon issuance on March 12, 2020, and will apply though December 31, 2022.	We continue to evaluate the temporary expedients and options available under this guidance, and the effects of these pronouncements on our Consolidated Financial Statements and Notes to Consolidated Financial Statements. We are currently identifying and evaluating contracts that may be impacted. As of December 31, 2020, we have not applied any expedients and options available under this ASU.

Standard	Description	Effective Date	Effect on the financial statements or other significant matters
ASU 2020-06, *Debt with Conversion and Other Options (Subtopic 470-20) and Derivative and Hedging - Contracts in Entity's Own Equity (Subtopic 815-40): Accounting for Convertible Instruments and Contracts in an Entity's Own Equity*	This pronouncement simplifies the accounting for certain financial instruments with characteristics of liabilities and equity, including convertible instruments and contracts on an entity's own equity. Specifically, the ASU "simplifies accounting for convertible instruments by removing major separation models required under current GAAP." In addition, the ASU "removes certain settlement conditions that are required for equity contracts to qualify for it" and "simplifies the diluted earnings per share (EPS) calculations in certain areas."	Annual period beginning after December 15, 2021. Early adoption is permitted for annual period beginning after December 15, 2020.	This pronouncement does not impact any securities we currently have on our balance sheet. We will continue to evaluate the effects of this pronouncement on our Consolidated Financial Statements and Notes to Consolidated Financial Statements as it pertains to any relevant future activity. We expect to adopt this ASU on its effective date.

Recently Adopted Accounting Pronouncements

Standard	Adoption
ASU 2019-04, *Codification Improvements to Topic 326, Financial Instruments-Credit Losses, Topic 815, Derivatives and Hedging, and Topic 825, Financial Instruments* ASU 2016-13, *Financial Instruments-Credit Losses (Topic 326)*	In June 2016, the FASB issued ASU 2016-13, Measurement of Credit Losses on Financial Instruments (ASC 326). ASC 326 revised the GAAP guidance on the impairment of most financial assets and certain other instruments that are not measured at fair value through net income. ASC 326 introduces the current expected credit loss (CECL) model that is based on expected losses for instruments measured at amortized cost rather than incurred losses. It also requires entities to record an allowance 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 debt securities will be recognized immediately in earnings, instead of over-time as they would under historic guidance. In 2019, the FASB issued ASU 2019-04, Codification Improvements to Topic 326, Financial Instruments-Credit Losses, Topic 815, Derivative and Hedging, and Topic 825, Financial Instruments. This pronouncement clarified and improved certain areas of guidance related to the recently issued standards on credit losses, hedging, and recognition and measurement. We adopted ASC 326 effective January 1, 2020, using a modified retrospective method. Adoption of this standard did not have material impact on our Consolidated Financial Statements. No adjustments were made to the January 1, 2020 opening balances as a result of this adoption. As required under the modified retrospective method of adoption, results for the reporting periods beginning after January 1, 2020 are presented under ASC 326, while prior period amounts are not adjusted. See Note 3, "Revenue Recognition," and Note 18, "Fair Value," for our discussion of the implementing these standards.
ASU 2018-14, *Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20): Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans*	Issued in August 2018, 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 for fiscal years ending after December 15, 2020, and are applied on a retrospective basis to all periods presented. These disclosure requirements are reflected in the Note 12, "Pension and Postretirement Benefits."
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. We adopted the amendments of this pronouncement as of January 1, 2021 with no material impact to the Consolidated Financial Statements.

3. Revenue Recognition

Customer Revenues. Substantially all of our revenues are tariff-based. 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, which creates enforceable rights and obligations. 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 exceeds 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. Distribution revenues are generally considered daily or "at-will" contracts as customers may cancel their service at any time (subject to notification requirements), and revenue generally represents the amount we are entitled to bill customers.

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. We completed the sale of the Massachusetts Business on October 9, 2020. 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, 2020 (in millions)	Gas Distribution Operations	Electric Operations	Corporate and Other[2]	Total
Customer Revenues[1]				
Residential	$ 2,075.0	$ 527.8	$ —	$ 2,602.8
Commercial	670.5	480.3	—	1,150.8
Industrial	212.8	412.1	—	624.9
Off-system	41.0	—	—	41.0
Miscellaneous	32.7	20.2	0.8	53.7
Total Customer Revenues	$ 3,032.0	$ 1,440.4	$ 0.8	$ 4,473.2
Other Revenues	96.1	95.5	16.9	208.5
Total Operating Revenues	$ 3,128.1	$ 1,535.9	$ 17.7	$ 4,681.7

[1]Customer revenue amounts exclude intersegment revenues. See Note 24, "Segments of Business," for discussion of intersegment revenues.
[2]Other revenues related to the Transition Services Agreement entered into in connection with the sale of the Massachusetts Business.

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 24, "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 24, "Segments of Business," for discussion of intersegment revenues.

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 mechanisms that allow for the adjustment of billings and revenue for certain approved programs. 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.

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, 2020 and 2019 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, 2019	$	466.6	$	346.6
Balance as of December 31, 2020		400.0		327.2
Decrease	$	(66.6)	$	(19.4)

[1]Customer billed receivables decreased due to decreased natural gas costs and warmer weather in 2020 compared to 2019.

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. We maintain common utility credit risk mitigation practices, including requiring deposits and actively pursuing collection of past due amounts. Our regulated operations also utilize certain regulatory mechanisms that facilitate recovery of bad debt costs within tariff-based rates, which provides further evidence of collectibility. In connection with the COVID-19 pandemic, certain state regulatory commissions instituted regulatory moratoriums that impacted our ability to pursue our standard credit risk mitigation practices. Following the issuance of these moratoriums, certain of our regulated operations have been authorized to recognize a regulatory asset for bad debt costs above levels currently in rates. We have reinstated our common credit mitigation practices where moratoriums have expired (see Note 9, "Regulatory Matters," for additional information on regulatory moratoriums and regulatory assets). It is probable that substantially all of the consideration to which we are entitled from customers will be collected upon satisfaction of performance obligations.

Allowance for Credit Losses. We adopted ASC 326 effective January 1, 2020. See "Recently Adopted Accounting Pronouncements" in Note 2, "Recent Accounting Pronouncements," for more information about ASC 326.

Each of our business segments pool their customer accounts receivables based on similar risk characteristics, such as customer type, geography, payment terms, and related macro-economic risks. Expected credit loss exposure is evaluated separately for each of our accounts receivable pools. Expected credit losses are established using a model that considers historical collections experience, current information, and reasonable and supportable forecasts. Relevant and reliable internal and external inputs used in the model include, but are not limited to, energy consumption trends, revenue projections, actual charge-offs data, recoveries data, shut-off orders executed data, and final bill data. We continuously evaluate available reasonable and supportable information relevant to assessing collectibility of current and future receivables. We evaluate creditworthiness of specific customers periodically or when required by changes in facts and circumstances. When we become aware of a specific commercial or industrial customer's inability to pay, an allowance for expected credit losses is recorded for the relevant amount. We also monitor other circumstances that could affect our overall expected credit losses; these include, but are not limited to, creditworthiness of overall population in service territories, adverse conditions impacting an industry sector, and current economic conditions.

At each reporting period, we record expected credit losses using an allowance for credit losses account. When deemed to be uncollectible, customer accounts are written-off. A rollforward of our allowance for credit losses for the year ended December 31, 2020 are presented in the table below:

Year Ended December 31, 2020 (in millions)	Gas Distribution Operations	Electric Operations	Corporate and Other	Total
Beginning balance[1]	9.1	3.1	0.8	13.0
Current period provisions	45.3	9.3	—	54.6
Write-offs charged against allowance	(26.7)	(3.0)	—	(29.7)
Recoveries of amounts previously written off	14.1	0.3	—	14.4
Ending balance of the allowance for credit losses	41.8	9.7	0.8	52.3

[1]Total beginning balance differs from that presented in the Consolidated Balance Sheets as it excludes Columbia of Massachusetts. Columbia of Massachusetts' customer receivables and related allowance for credit losses were included in the sale of the Massachusetts Business that occurred on October 9, 2020.

As of December 31, 2020, we have also evaluated the adequacy of our allowance for credit losses in light of the suspension of shut-offs for nonpayment due to the COVID-19 pandemic that remain in effect for certain jurisdictions, as well as the economic downturn. Our evaluation included an analysis of customer payment trends in 2020, economic conditions, receivables aging, considerations of past economic downturns and the associated allowance for credit losses and customer account write-offs. In addition, we considered benefits available under governmental COVID-19 relief programs, the impact of unemployment benefits initiatives, and flexible payment plans being offered to customers affected by or experiencing hardship as a result of the pandemic, which could help to mitigate the potential for increasing customer account delinquencies. Based upon this evaluation, we have concluded that the allowance for credit losses as of December 31, 2020 adequately reflected the collection risk and net realizable value for our receivables. We will continue to monitor changing circumstances and will adjust our allowance for credit losses as additional information becomes available.

4. Variable Interest Entities

A VIE is an entity in which the controlling interest is determined through means other than a majority voting interest. The primary beneficiary of a VIE is the business enterprise which has the power to direct the activities of the VIE that most significantly impact the VIE’s economic performance. Also, the primary beneficiary either absorbs a significant amount of the VIE’s losses or has the right to receive benefits that could be significant to the VIE. We consider these qualitative elements in determining whether we are the primary beneficiary of a VIE, and we consolidate those VIEs for which we are determined to be the primary beneficiary.

Rosewater (a joint venture) owns and operates 102 MW of nameplate capacity wind generation assets. Members of the joint venture are NIPSCO (who is the managing member) and a tax equity partner. Earnings, tax attributes and cash flows are allocated to both NIPSCO and the tax equity partner in varying percentages by category and over the life of the partnership. Once the tax equity partner has earned their negotiated rate of return and we have reached the agreed upon contractual date, NIPSCO has the option to purchase at fair market value from the tax equity partner the remaining interest in the aforementioned joint venture. NIPSCO has an obligation to purchase, through a PPA at established market rates, 100% of the electricity generated by Rosewater.

As the managing member of Rosewater, we control decisions that are significant to its ongoing operations and economic results. Therefore, we have concluded that we are the primary beneficiary of Rosewater and have consolidated Rosewater even though we own less than 100% of the total equity membership interest.

We have determined that the use of HLBV accounting is reasonable and appropriate in order to attribute income and loss to the noncontrolling interest held by the tax equity partner. HLBV accounting was selected as the allocation of Rosewater's economic results to members differ from the members' relative ownership percentages. Using the HLBV method, our earnings are calculated based on how the partnership would distribute its cash if it were to hypothetically sell all of its assets for their carrying amounts and liquidate at each reporting period. Under HLBV, we calculate the liquidation value allocable to each partner at the beginning and end of each period based on the contractual terms of the related entity's operating agreement and adjust our income for the period to reflect the change our associated book value.

In December 2020, in exchange for their respective membership interests in Rosewater, NIPSCO contributed $0.7 million in cash, and the tax equity partner contributed $86.1 million in cash, the first of two contractual cash contributions for each partner, per the equity capital contribution agreement. NIPSCO's remaining economic interest was acquired by assuming an obligation of $69.7 million to the developer, which comes due in 2023 and is included in "Other noncurrent liabilities" in the Consolidated Balance Sheets. From the contributed funds, Rosewater paid $85.3 million to the developer of the wind generation assets. The developer of the facility is not a partner in the joint venture for federal income tax purposes and does not receive any share of earnings, tax attributes, or cash flows of Rosewater. Once asset construction is complete, NIPSCO and the tax equity partner will each make a second cash contribution of $0.1 million and $7.5 million, respectively, and NIPSCO will assume an additional obligation to the developer of $6.0 million, totaling contributions of $170.1 million for both partners. We did not provide any financial or other support during the year that was not previously contractually required, nor do we expect to provide such support in the future.

At December 31, 2020, $156.4 million in net assets (as detailed in the table below) related to Rosewater and the non-controlling interest attributable to the unrelated tax equity partner of $85.6 million were included in the Consolidated Balance Sheets. For the year ended December 31, 2020 $3.4 million was allocated to the tax equity partner and is included in "Net income attributable to non-controlling interest" on the Statements of Consolidated Income (Loss).

At December 31, 2020, our consolidated balance sheet included the following assets and liabilities associated with Rosewater:

(in millions)		
Net Property, Plant and Equipment	$	175.6
Current assets		1.7
Total assets[(1)]	$	177.3
Current liabilities	$	15.3
Asset retirement obligations		5.5
Other noncurrent liabilities		0.1
Total liabilities	$	20.9

[(1)]The assets of Rosewater represent assets of a consolidated VIE that can be used only to settle obligations of the consolidated VIE.

5. 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 years ended December 31, 2020 and 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 these periods, and any incremental shares would have had an anti-dilutive impact on EPS. The computation of diluted average common shares is as follows:

Year Ended December 31, *(in thousands)*	**2020**	2019	2018
Denominator			
Basic average common shares outstanding	**384,347**	374,650	356,491
Dilutive potential common shares:			
Shares contingently issuable under employee stock plans	—	929	—
Shares restricted under employee stock plans	—	154	—
Forward agreements	—	253	—
Diluted Average Common Shares	**384,347**	375,986	356,491

6. Property, Plant and Equipment

Our property, plant and equipment on the Consolidated Balance Sheets are classified as follows:

At December 31, *(in millions)*	**2020**	2019
Property, Plant and Equipment		
Gas Distribution Utility[1]	**$ 14,010.2**	$ 14,989.7
Electric Utility[1]	**6,478.0**	8,902.3
Corporate	**197.3**	153.3
Construction Work in Process	**572.6**	457.3
Renewable Generation Assets[2]	**175.7**	—
Non-Utility and Other[3]	**2,746.1**	39.3
Total Property, Plant and Equipment	**$ 24,179.9**	$ 24,541.9
Accumulated Depreciation and Amortization		
Gas Distribution Utility[1]	**$ (3,292.9)**	$ (3,556.0)
Electric Utility[1]	**(2,305.0)**	(3,973.8)
Corporate	**(109.3)**	(79.5)
Renewable Generation Assets[2]	**(0.1)**	—
Non-Utility and Other[3]	**(1,853.1)**	(20.4)
Total Accumulated Depreciation and Amortization	**$ (7,560.4)**	$ (7,629.7)
Net Property, Plant and Equipment	**$ 16,619.5**	$ 16,912.2

[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]Our renewable generation assets are part of our electric segment and represent Non-Utility Property, owned and operated by Rosewater Wind Generation LLC, a joint venture between NIPSCO and unrelated tax equity partner, and depreciated straight-line over 30 years. Refer to Note 4, "Variable Interest Entities" for additional information.
[3]Non-Utility and Other as of December 31, 2020 includes net book value of $903.8 million related to R.M. Schahfer Generating Station, which was reclassified from Electric Utility in the second quarter of 2020. Depreciation expense for the remaining net book value continues to be recorded at the composite depreciation rate approved by the IURC. See Note 20-E, "Other 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, 2020, 2019 and 2018 were as follows:

	2020	2019	2018
Electric Operations[1]	**3.4 %**	2.8 %	2.9 %
Gas Distribution Operations	**2.3 %**	2.5 %	2.2 %

[1]Increased rate beginning in 2020 primarily attributable to higher depreciation rates from the recent rate case proceeding.

We recognized depreciation expense of $655.6 million, $612.2 million and $503.4 million for the years ended 2020, 2019 and 2018, respectively.

Amortization of Software Costs. We amortized $56.7 million, $55.5 million and $54.1 million in 2020, 2019 and 2018, respectively, related to software costs. Our unamortized software balance was $136.4 million and $169.6 million at December 31, 2020 and 2019, respectively.

Amortization of Cloud Computing Costs. We amortized $3.4 million, $1.6 million and $0.1 million in 2020, 2019 and 2018, respectively, related to cloud computing costs. Our unamortized cloud computing balance was $12.7 million and $14.2 million at December 31, 2020 and 2019, respectively.

7. 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, 2020 and 2019:

(in millions)	**2020**	2019
Gas Distribution Operations	$ 1,485.9	$ 1,485.9
Electric Operations	—	—
Corporate and Other	—	—
Total	**$ 1,485.9**	$ 1,485.9

For our annual goodwill impairment analysis performed as of May 1, 2020, we completed a quantitative ("step 1") fair value measurement of our reporting units. 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 the most recent cash flow projections. The test indicated that the fair value of each of the reporting units that are allocated goodwill exceeded their carrying values, indicating that no impairment was necessary.

Columbia of Massachusetts was not considered to be a reporting unit for May 1, 2020 fair value measurement as the goodwill balance had been reduced to zero as of December 31, 2019. During the fourth quarter of 2019, in connection with the preparation of the year-end financial statements, we assessed the matters related to the then proposed sale of the Massachusetts Business and determined a new impairment analysis was required for our Columbia of Massachusetts reporting unit. The fair value of the Columbia of Massachusetts reporting unit was determined in the same manner as described above for our remaining reporting units. The 2019 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.

Intangible and Other Long-Lived Assets Impairment. 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. Prior to December 31, 2019, our intangible assets, apart from goodwill, consisted 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.

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. As a result, we performed a year-end impairment test of our 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. The 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 during the year ended December 31, 2019.

As of December 31, 2020 and 2019, the carrying amount of the franchise rights was zero. We recorded zero amortization expense in 2020 and $11.0 million in 2019 and 2018 related to our franchise rights intangible asset.

8. 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 an 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 2020 and 2019 are presented in the table below:

(in millions)	**2020**		2019	
Beginning Balance	**$ 416.9**		$ 352.0	
Accretion recorded as a regulatory asset/liability	**17.3**		15.7	
Additions	**5.5**		—	
Settlements	**(13.9)**		(5.4)	
Change in estimated cash flows	**86.0**	(1)	54.6	(2)
Other	**(16.2)**	(3)	—	
Ending Balance	**$ 495.6**		$ 416.9	

(1)The change in estimated cash flows for 2020 is primarily attributed to revisions to the estimated costs associated with refining the CCR compliance plan, changes in estimated costs for electric generating stations and the changes in estimated costs for retirement of gas mains. See Note 20-D. "Environmental Matters" for additional information on CCRs.
(2)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.
(3)Represents the Columbia of Massachusetts Asset Retirement Obligations that were included in the sale of the Massachusetts Business that occurred on October 9, 2020.

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.

9. 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 when the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates will 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. We assess the probability of collection for all of our regulatory assets each period.

Regulatory assets were comprised of the following items:

At December 31, *(in millions)*		2020		2019
Regulatory Assets				
Unrecognized pension and other postretirement benefit costs (see Note 12)	**$**	**583.3**	$	739.1
Deferred pension and other postretirement benefit costs (see Note 12)		**72.4**		91.3
Environmental costs (see Note 20-D)		**56.6**		73.4
Regulatory effects of accounting for income taxes (see Note 1-N and Note 11)		**194.5**		234.0
Under-recovered gas and fuel costs (see Note 1-J)		**8.0**		3.9
Depreciation		**192.6**		210.7
Post-in-service carrying charges		**228.6**		219.8
Safety activity costs		**146.0**		118.6
DSM programs		**37.8**		50.1
Bailly Generating Station		**204.7**		221.8
Losses on Commodity Price Risk Programs (See Note 10)		**54.7**		76.4
Deferred Property Taxes		**62.9**		60.3
Other		**88.4**		140.2
Total Regulatory Assets	**$**	**1,930.5**	$	2,239.6
Less: Current Portion		**135.7**		225.7
Total Noncurrent Regulatory Assets	**$**	**1,794.8**	$	2,013.9

Regulatory liabilities were comprised of the following items:

At December 31, *(in millions)*		2020		2019
Regulatory Liabilities				
Over-recovered gas and fuel costs (see Note 1-J)	**$**	**47.8**	$	42.6
Cost of removal (see Note 8)		**775.2**		1,047.5
Regulatory effects of accounting for income taxes (see Note 1-N and Note 11)		**1,105.1**		1,307.0
Deferred pension and other postretirement benefit costs (see Note 12)		**69.5**		64.7
Other		**67.9**		50.4
Total Regulatory Liabilities	**$**	**2,065.5**	$	2,512.2
Less: Current Portion		**161.3**		160.2
Total Noncurrent Regulatory Liabilities	**$**	**1,904.2**	$	2,352.0

Regulatory assets, including under-recovered gas and fuel costs and depreciation, of approximately $1,260.6 million and $1,524.3 million as of December 31, 2020 and 2019, respectively, are not earning a return on investment. These costs are recovered over a remaining life, the longest of which is 41 years.

Assets:

Unrecognized pension and other postretirement benefit costs. Represents the deferred 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 by certain subsidiaries that will ultimately be recovered through base rates.

Deferred pension and other postretirement benefit costs. Primarily relates to the difference between defined benefit plan expense recorded by certain subsidiaries due to regulatory orders and the corresponding expense that would otherwise be recorded in accordance with GAAP. The majority of these amounts are driven by Columbia of Ohio. The timeframe for the recovery of these costs will be addressed in the next base rate case, and the costs are expected to be collected through future base rates, revenue riders or tracking mechanisms.

Environmental costs. Includes certain recoverable costs related to gas plant sites, disposal sites or other sites onto which material may have migrated, the recovery of which is to be addressed in future base rates, billing riders or tracking mechanisms of certain of our subsidiaries.

Regulatory effects of accounting for income taxes. Represents the deferral and under collection of 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. The majority of this balance is driven by Columbia of Ohio's IRP and CEP deferrals. Recovery of these amounts is approved annually through the related riders.

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. The majority of this balance is driven by Columbia of Ohio's IRP and CEP deferrals.

Safety activity costs. Represents the difference between costs incurred by certain of our subsidiaries in eligible safety programs in compliance with PHMSA regulations in excess of those being recovered in rates.

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.

Losses on Commodity Price Risk Programs. Represents the unrealized losses related to certain of our subsidiary's commodity price risk programs. These programs help to protect against the volatility of commodity prices and these amounts are collected from customers through their inclusion in customer rates.

Property Taxes. Represents the deferral and under collection of property taxes in the rate making process for Columbia of Ohio and is driven by the IRP and CEP deferrals.

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 for utility assets that have been collected through depreciation rates 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. Balance includes excess deferred taxes recorded upon implementation of the TCJA in December 2017, net of amounts amortized through 2020.

Deferred pension and other postretirement benefit costs. Primarily represents cash contributions in excess of postretirement benefit expense that is deferred by certain subsidiaries.

COVID-19 Regulatory Filings
In response to the COVID-19 pandemic, we have engaged, or have received directives from, the regulatory commissions in the states in which we operate, as described below.

Columbia of Ohio filed a Deferral Application and a Transition Plan with the PUCO on May 29, 2020. The Deferral Application requested approval to record a regulatory asset for pandemic incremental costs, foregone revenue from late payment fees, and bad debt expense from certain classes of customers. An order approving the Deferral Application was received on July 15, 2020. The Transition Plan requested the resumption of activities that were suspended in March 2020, including resumption of disconnects due to non-payment and billing of late payment fees beginning with the August 2020 billing cycle. The PUCO approved the Transition Plan on June 17, 2020. As of December 31, 2020, $2.0 million of incremental pandemic-related costs were deferred to a regulatory asset.

NIPSCO received a COVID-19 pandemic order from the IURC on June 29, 2020. This order extended the disconnection moratorium and the suspension of collection of late payment fees, deposits and reconnection fees through August 14, 2020. The order requires utilities to offer payment arrangements of at least six months and requires NIPSCO to provide the IURC with information about NIPSCO’s communications with delinquent customers. On August 12, 2020, the IURC issued an order affirming the expiration of the disconnect moratorium after August 14, 2020, while requiring that six month payment plans be offered to all customers and extending the suspension for collection of late payment fees, deposits, and reconnection fees through October 12, 2020 for residential customers only. On October 7, 2020 the Office of Utility Consumer Counselor ("OUCC") filed a motion for the IURC to extend these temporary consumer protections for an additional 60 days. On October 27, the IURC issued a docket entry denying the OUCC's motion. The June 29, 2020 order also authorized NIPSCO to create a regulatory asset for pandemic-related incremental bad debt expense as well as the costs to implement the requirements of the order. As of December 31, 2020, $9.2 million of incremental bad debt expense and costs to implement the requirements of the order were deferred to a regulatory asset.

Columbia of Pennsylvania received a secretarial letter issued by the Pennsylvania PUC on May 13, 2020 authorizing Pennsylvania utilities to create a regulatory asset for incremental bad debt expense incurred since March 13, 2020, above levels currently in rates. While Columbia of Pennsylvania is not authorized to defer any other incremental costs, it is required to track extraordinary non-recurring costs, and any offsetting benefits received, in connection with the COVID-19 pandemic. On October 13, 2020, the Pennsylvania PUC entered an order modifying its March 13, 2020 emergency order that had established a moratorium on utility service terminations. As modified, the moratorium still applies to residential customers with incomes at or below 300% of the federal poverty income guidelines (“protected customers”). For all other customers, the moratorium was lifted on November 9, 2020, but utilities must comply with several notice requirements beyond those already in place in Pennsylvania in order to proceed with service terminations. For residential customers who are subject to termination under the revised moratorium, as of December 1, 2020, the standard winter service moratorium will be in effect until April 1, 2021, which will render service termination for delinquent accounts impractical during that period. Additionally, the October 13, 2020 order authorizes utilities to create a regulatory asset for any incremental expenses incurred above those embedded in rates resulting from the directives contained in the Order. As of December 31, 2020, $5.4 million of incremental bad debt expense was deferred to a regulatory asset.

On March 16, 2020, the VSCC ordered a moratorium on service disconnections for unpaid bills due to the effects of the COVID-19 pandemic. The order also suspended late payment fees, required utilities to offer payment plans of up to 12 months, and required utilities to provide certain information about customer accounts receivables to the VSCC. Columbia of Virginia received an order from the VSCC on April 29, 2020 authorizing Columbia of Virginia to create a regulatory asset for incremental bad debt expense, suspended late payment fees, reconnection costs, carrying costs and other incremental prudently incurred costs related to the pandemic. The VSCC moratorium expired on October 6, 2020; however, the directives requiring utilities to offer payment plans of up to 12 months and suspending service disconnections or charging of late payment fees to customers that are current on such payment plans remain in effect. On November 18, 2020, legislation was enacted that extended the moratorium on residential service disconnections and late payment fees until the Governor determines that the economic and public health conditions have improved such that the prohibition does not need to be in place, or until at least 60 days after such declared state of emergency ends, whichever is sooner. Recovery of any regulatory asset will be addressed in future base rate proceedings and is subject to an earnings test review.

On August 31, 2020, the Maryland PSC issued an emergency order that extended the Governor's order prohibiting residential service terminations through October 1, 2020. The emergency order also requires Maryland utilities that proceed with residential service terminations after that date to provide at least 45 days notice prior to terminating service; to offer structured payment plans to applicable residential customers with a minimum of 12 months to repay, or 24 months for certified low income customers; the requirement or collection of down payments or deposits as a condition of beginning a payment plan by any residential customer; and cannot refuse to negotiate or deny a payment plan to a residential customer due to such customer's failure to meet the terms and conditions of an alternate payment plan during the past 18 months. Columbia of Maryland received an order issued by the Maryland PSC on April 9, 2020, authorizing Maryland utilities to create a regulatory asset for incremental COVID-19 pandemic-related costs, including incremental bad debt expense, incurred to ensure that customers have essential utility service during the state of emergency in Maryland. Such incremental costs must be offset by any benefit received in connection with the pandemic. As of December 31, 2020, Columbia of Maryland has deferred $0.7 million of incremental bad debt expense and pandemic-related costs to a regulatory asset.

Columbia of Kentucky received an order from the Kentucky PSC on September 21, 2020 lifting the disconnection moratorium for all customers, effective October 20, 2020. The September 21, 2020 order also lifted the suspension of late payment and reconnection fees for non-residential customers as of October 20, 2020. For residential customers, the moratorium on late payment and reconnection fees is extended to December 31, 2020 and tracking of lost revenue is required. Residential customers with accumulated arrearages for service provided on or after March 16, 2020 through October 1, 2020 will be notified and placed on a default payment plan of equal installments for nine months beginning with the November 2020 billing cycle. Residential customers on a payment plan that default shall be offered another payment plan. Carrying charges may be applied to all arrearages arising during the default payment plan period at a rate no greater than the utility's long-term debt rate. The Kentucky PSC order allows Columbia of Kentucky to create a regulatory asset for carrying charges on all arrearages arising during the default payment plan period. As of December 31, 2020, an immaterial amount of carrying charges were deferred to a regulatory asset.

10. Risk Management Activities

We are exposed to certain risks related to our 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)*	**2020**	2019
Risk Management Assets - Current[(1)]		
Interest rate risk programs	**$ —**	$ —
Commodity price risk programs	**10.4**	0.6
Total	**$ 10.4**	$ 0.6
Risk Management Assets - Noncurrent[(2)]		
Interest rate risk programs	**$ —**	$ —
Commodity price risk programs	**2.8**	3.8
Total	**$ 2.8**	$ 3.8
Risk Management Liabilities - Current		
Interest rate risk programs	**$ 70.9**	$ —
Commodity price risk programs	**7.3**	12.6
Total	**$ 78.2**	$ 12.6
Risk Management Liabilities - Noncurrent		
Interest rate risk programs	**$ 99.5**	$ 76.2
Commodity price risk programs	**45.1**	57.8
Total	**$ 144.6**	$ 134.0

(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 10 years and is limited to 20% 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, 2020, we have two 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 gains and losses related to these swaps are recorded to AOCI and will be 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" in the Statements of Consolidated Income (Loss) as it became probable the forecasted borrowing transactions would no longer occur.

There were no amounts excluded from effectiveness testing for derivatives in cash flow hedging relationships at December 31, 2020, 2019 and 2018.

Our derivative instruments measured at fair value as of December 31, 2020 and 2019 do not contain any credit-risk-related contingent features.

11. Income Taxes

Income Tax Expense. The components of income tax expense (benefit) were as follows:

Year Ended December 31, *(in millions)*	**2020**	2019	2018
Income Taxes			
Current			
Federal	**$ 0.2**	$ —	$ —
State	**11.7**	5.2	8.2
Total Current	**11.9**	5.2	8.2
Deferred			
Federal	**(0.4)**	110.7	(209.4)
State	**(27.4)**	9.0	22.2
Total Deferred	**(27.8)**	119.7	(187.2)
Deferred Investment Credits	**(1.2)**	(1.4)	(1.0)
Income Taxes	**$ (17.1)**	$ 123.5	$ (180.0)

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)*	**2020**		2019		2018	
Book income (loss) before income taxes	**$ (31.3)**		$ 506.6		$ (230.6)	
Tax expense (benefit) at statutory federal income tax rate	**(6.6)**	**21.0 %**	106.5	21.0 %	(48.4)	21.0 %
Increases (reductions) in taxes resulting from:						
State income taxes, net of federal income tax benefit	**(11.7)**	**37.4**	10.1	2.0	24.7	(10.7)
Amortization of regulatory liabilities	**(38.4)**	**122.7**	(29.4)	(5.8)	(29.3)	12.7
Goodwill impairment	**—**	**—**	43.0	8.5	—	—
Fines and penalties	**11.8**	**(37.7)**	11.5	2.3	0.2	(0.1)
Charitable contribution carryover	**—**	**—**	(2.5)	(0.5)	—	—
State regulatory proceedings	**—**	**—**	(9.5)	(1.9)	(127.8)	55.4
Employee stock ownership plan dividends and other compensation	**(1.3)**	**4.2**	(2.0)	(0.4)	(2.2)	1.0
Deferred taxes on TCJA regulatory liability divested	**23.3**	**(74.5)**	—	—	—	—
Tax accrual adjustments	**8.9**	**(28.4)**	—	—	—	—
Federal tax credits	**(2.5)**	**8.0**	—	—	—	—
Other adjustments	**(0.6)**	**1.9**	(4.2)	(0.8)	2.8	(1.2)
Income Taxes	**$ (17.1)**	**54.6 %**	$ 123.5	24.4 %	$ (180.0)	78.1 %

The effective income tax rates were 54.6%, 24.4% and 78.1% in 2020, 2019 and 2018, respectively. The difference in tax expense year-over-year has a relative impact on the effective tax rate proportional to pretax income or loss. The 30.2% increase in effective tax rate in 2020 versus 2019 was primarily the result of lower pre-tax income, state jurisdictional mix of pre-tax loss in 2020 tax effected at statutory tax rates and increased amortization of excess deferred federal income taxes in 2020 compared to 2019. These items were offset by increased deferred tax expense recognized on the sale of Columbia of Massachusetts' regulatory liability, established due to TCJA in 2017, that would have otherwise been recognized over the amortization period, non-deductible penalties as described in Note 1, "Company Structure and Principles of Consolidation" and non-cash impairment of goodwill related to Columbia of Massachusetts in 2019 (see Note 7, "Goodwill and Other Intangible Assets" for additional information), and one-time tax accrual adjustments.

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 7, "Goodwill and Other Intangible Assets" for additional information) and non-deductible fines and penalties related to the Greater Lawrence Incident (see Note 20, "Legal Proceedings" for additional information). The rate is also impacted by the relative impact of permanent differences on higher pre-tax income.

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)*	**2020**	2019
Deferred tax liabilities		
Accelerated depreciation and other property differences	**$ 2,339.3**	$ 2,516.9
Other regulatory assets	**331.8**	381.5
Total Deferred Tax Liabilities	**2,671.1**	2,898.4
Deferred tax assets		
Other regulatory liabilities and deferred investment tax credits (including TCJA)	**287.8**	336.1
Pension and other postretirement/postemployment benefits	**118.1**	152.1
Net operating loss carryforward and AMT credit carryforward	**602.1**	765.9
Environmental liabilities	**22.6**	25.4
Other accrued liabilities	**41.5**	35.3
Other, net	**128.4**	98.3
Total Deferred Tax Assets	**1,200.5**	1,413.1
Net Deferred Tax Liabilities	**$ 1,470.6**	$ 1,485.3

At December 31, 2020, we have federal net operating loss carryforwards of $520.8 million. The federal net operating loss carryforwards are available to offset taxable income and will begin to expire in 2037. In addition, we have $7.8 million in charitable contribution carryforwards to offset future taxable income, which begin to expire in 2023. We believe it is more likely than not that we will realize the benefit from the federal net operating loss carryforwards.

We also have $81.4 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 a portion of the benefit from certain state NOL carryforwards will not be realized. In recognition of this risk, we have provided a valuation allowance of $6.4 million (net) on the deferred tax assets related to sale of Massachusetts Business assets (see Note 1, "Company Structure and Principles of Consolidation" for additional information) reflected in the state net operating loss carryforward presented above.

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)*	**2020**	2019	2018
Unrecognized Tax Benefits - Opening Balance	**$ 23.2**	$ 1.2	$ 1.4
Gross decreases - tax positions in prior period	**(1.5)**	(0.6)	(0.4)
Gross increases - current period tax positions	**—**	22.6	0.2
Unrecognized Tax Benefits - Ending Balance	**$ 21.7**	$ 23.2	$ 1.2
Offset for net operating loss carryforwards	**(21.7)**	(22.6)	—
Balance - Less Net Operating Loss Carryforwards	**$ —**	$ 0.6	$ 1.2

In 2020, we resolved prior unrecognized tax benefits of $1.5 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, 2020, 2019 and 2018, and there were no balances for accrued penalties recorded on the Consolidated Balance Sheets as of December 31, 2020 and 2019.

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, 2020, tax years through 2019 have been audited and are effectively closed to further assessment. The audit of tax year 2020 under the CAP program is expected to be completed in 2021.

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, 2020, there were no state income tax audits in progress that would have a material impact on the consolidated financial statements.

12. 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. The Board has delegated oversight of the pension and other postretirement benefit plans' assets to an Administrative & Investment Management Committee ("the Committee"). The Committee has adopted investment policy statements for the pension and other postretirement benefit plans' assets. For the pension plans, we employ a liability-driven investing strategy. A total return approach is utilized for the other postretirement benefit plans' assets. A mix of diversified investments are used to maximize the long-term return of plan assets and hedge the liabilities at a prudent level of risk. The investment portfolio includes U.S. and non-U.S. equities, real estate, long-term and intermediate-term fixed income and alternative investments. Risk tolerance is established through careful consideration of plan liabilities, funded status, and asset class volatility. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

In determining the expected long-term rate of return on plan assets, historical markets are studied, relationships between equities and fixed income are analyzed and current market factors, such as inflation and interest rates are evaluated with consideration of diversification and rebalancing. Our expected long-term rate of return on assets is based on assumptions regarding target asset allocations and corresponding long-term capital market assumptions for each asset class. The pension plans' investment 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.

As of December 31, 2020, 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%
Private Equity	0%	5%	0%	0%
Short-Term Investments	0%	10%	0%	10%

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 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%
Private Equity	0%	5%	0%	0%
Short-Term Investments	0%	10%	0%	10%

Pension Plan and Postretirement Plan Asset Mix at December 31, 2020 and December 31, 2019:

	Defined Benefit Pension Assets	December 31, 2020	Postretirement Benefit Plan Assets	December 31, 2020
Asset Class *(in millions)*	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	$ 446.3	21.0 %	$ 108.8	38.0 %
International Equities	230.1	10.9 %	48.2	16.8 %
Fixed Income	1,291.2	61.0 %	122.0	42.6 %
Real Estate	52.9	2.5 %	—	—
Cash/Other	97.2	4.6 %	7.4	2.6 %
Total	$ 2,117.7	100.0 %	$ 286.4	100.0 %

	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 %

The categorization of investments into the asset classes in the tables 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 pension and other postretirement benefits investment assets at fair value as of December 31, 2020 and 2019. Assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. There were no investment assets in the pension and other postretirement benefits trusts classified within Level 3 for the years ended December 31, 2020 and 2019.

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, 2020, there were no significant changes to valuation techniques to determine the fair value of our pension and other postretirement benefits' assets.

Fair Value Measurements at December 31, 2020:

(in millions)	December 31, 2020	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	$ 11.9	$ 11.9	$ —	$ —
Equity securities				
U.S. equities	2.4	2.4	—	—
Fixed income securities				
Government	243.4	—	243.4	—
Corporate	692.6	—	692.6	—
Mutual Funds				
U.S. multi-strategy	161.3	161.3	—	—
International equities	55.4	55.4	—	—
Fixed income	0.1	0.1	—	—
Private equity limited partnerships(3)				
U.S. multi-strategy(1)	10.9	—	—	—
International multi-strategy(2)	6.6	—	—	—
Distressed opportunities	0.3	—	—	—
Real estate	52.9	—	—	—
Commingled funds(3)				
Short-term money markets	78.8	—	—	—
U.S. equities	279.7	—	—	—
International equities	176.8	—	—	—
Fixed income	337.6	—	—	—
Pension plan assets subtotal	2,110.7	231.1	936.0	—
Other postretirement benefit plan assets:				
Mutual funds				
U.S. multi-strategy	94.8	94.8	—	—
International equities	24.1	24.1	—	—
Fixed income	121.8	121.8	—	—
Commingled funds(3)				
Short-term money markets	7.6	—	—	—
U.S. equities	14.0	—	—	—
International equities	24.1	—	—	—
Other postretirement benefit plan assets subtotal	286.4	240.7	—	—
Due to brokers, net(4)	(1.6)	—	(1.6)	—
Accrued income/dividends	8.6	8.6	—	—
Total pension and other postretirement benefit plan assets	$ 2,404.1	$ 480.4	$ 934.4	$ —

(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 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, 2020:

(in millions)	Fair Value	Redemption Frequency	Redemption Notice Period
Commingled Funds			
Short-term money markets	$ 86.4	Daily	1 day
U.S. equities	293.7	Daily	1-5 days
International equities	200.9	Monthly	10-30 days
Fixed income	337.6	Daily	3 days
Total	$ 918.6		

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)	—
Distress opportunities	2.4	(2.4)	—
Real estate	52.7	(52.7)	—
Total	$ 86.1	$ (86.1)	$ —

[1]Level 3 assets from 2018 were reclassified in the 2019 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	3 days
International equities	168.2	Monthly	10-30 days
Fixed income	351.8	Daily	3 days
Total	$ 860.5		

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)	**2020**	2019	**2020**	2019
Change in projected benefit obligation[(1)]				
Benefit obligation at beginning of year	**$ 2,130.5**	$ 1,981.3	**$ 576.5**	$ 492.5
Service cost	**32.0**	29.2	**6.6**	5.1
Interest cost	**51.6**	72.3	**15.4**	19.2
Plan participants' contributions	**—**	—	**4.1**	4.8
Plan amendments	**—**	—	**—**	5.1
Actuarial loss[(2)]	**140.1**	204.3	**24.8**	88.8
Benefits paid	**(174.5)**	(156.6)	**(37.0)**	(39.5)
Estimated benefits paid by incurred subsidy	**—**	—	**0.4**	0.5
Spinoff to Eversource	**(121.3)**	—	**—**	—
Projected benefit obligation at end of year	**$ 2,058.4**	$ 2,130.5	**$ 590.8**	$ 576.5
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 2,080.9**	$ 1,867.7	**$ 261.4**	$ 216.3
Actual return on plan assets	**329.9**	366.8	**36.3**	56.9
Employer contributions	**2.9**	2.9	**21.6**	23.0
Plan participants' contributions	**—**	—	**4.1**	4.7
Benefits paid	**(174.6)**	(156.5)	**(37.0)**	(39.5)
Spinoff to Eversource	**(121.4)**	—	**—**	—
Fair value of plan assets at end of year	**$ 2,117.7**	$ 2,080.9	**$ 286.4**	$ 261.4
Funded Status at end of year	**$ 59.3**	$ (49.6)	**$ (304.4)**	$ (315.1)
Amounts recognized in the statement of financial position consist of:				
Noncurrent assets	**91.4**	8.2	**—**	—
Current liabilities	**(2.9)**	(3.0)	**(0.9)**	(0.8)
Noncurrent liabilities	**(29.2)**	(54.8)	**(303.5)**	(314.3)
Net amount recognized at end of year[(3)]	**$ 59.3**	$ (49.6)	**$ (304.4)**	$ (315.1)
Amounts recognized in accumulated other comprehensive income or regulatory asset/liability[(4)]				
Unrecognized prior service credit	**$ 0.3**	$ 3.0	**$ (10.1)**	$ (10.7)
Unrecognized actuarial loss	**497.2**	652.8	**116.4**	118.4
Net amount recognized at end of year	**$ 497.5**	$ 655.8	**$ 106.3**	$ 107.7

[(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)]The pension actuarial loss was primarily driven by the decrease in the discount rate, offset by the change in mortality assumptions. The other postretirement benefits loss was also primarily driven by a decrease in discount rates, offset by favorable claims experienced and a change in the mortality assumptions.
[(3)]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 $583.3 million and zero, respectively, as of December 31, 2020, and $739.1 million and $0.1 million, respectively, as of December 31, 2019 that would otherwise have been recorded to accumulated other comprehensive loss.

Our accumulated benefit obligation for our pension plans was $2,036.8 million and $2,111.5 million as of December 31, 2020 and 2019, respectively. The accumulated benefit obligation at each 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 our 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,	
	2020[(1)]	2019
Accumulated Benefit Obligation	**$ 32.1**	$ 1,473.9
Funded Status		
Projected Benefit Obligation	**32.1**	1,492.9
Fair Value of Plan Assets	**—**	1,435.1
Funded Status of Underfunded Pension Plans at End of Year	**$ (32.1)**	$ (57.8)

(1)As of December 31, 2020, only our nonqualified plans were underfunded. These plans have no assets as they are not funded until benefits are paid.

Information for pension plans with plan assets in excess of the projected benefit obligation:

	December 31,	
	2020	2019
Accumulated Benefit Obligation	**$ 2,004.7**	$ 637.6
Funded Status		
Projected Benefit Obligation	**2,026.3**	637.6
Fair Value of Plan Assets	**2,117.7**	645.8
Funded Status of Overfunded Pension Plans at End of Year	**$ 91.4**	$ 8.2

Our pension plans were overfunded, in aggregate, by $59.3 million at December 31, 2020 compared to being underfunded by $49.6 million at December 31, 2019. 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 2020 and 2019.

Our other postretirement benefit plans were underfunded by $304.4 million at December 31, 2020 compared to being underfunded by $315.1 million at December 31, 2019. The change in funded status was primarily due to favorable asset returns offset by a decrease in discount rates. We contributed $21.6 million and $23.0 million to our other postretirement benefit plans in 2020 and 2019, respectively.

In 2020 and 2019, 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 $10.5 million and $9.5 million in 2020 and 2019, respectively. Net periodic pension benefit cost for 2020 was decreased by $1.4 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	
	2020	2019	**2020**	2019
Weighted-average assumptions to Determine Benefit Obligation				
Discount Rate	**2.38 %**	3.12 %	**2.49 %**	3.21 %
Rate of Compensation Increases	**4.00 %**	4.00 %	**—**	—
Interest Crediting Rates	**4.00 %**	4.00 %	**—**	—
Health Care Trend Rates				
Trend for Next Year	**—**	—	**6.69 %**	6.68 %
Ultimate Trend	**—**	—	**4.50 %**	4.50 %
Year Ultimate Trend Reached	**—**	—	**2029**	2028

We expect to make contributions of approximately $2.9 million to our pension plans and approximately $21.8 million to our postretirement medical and life plans in 2021.

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)			
2021	$ 218.8	$ 38.4	$ 0.4
2022	154.5	37.8	0.4
2023	149.2	37.3	0.4
2024	145.9	37.0	0.4
2025	141.3	36.6	0.3
2026-2030	621.9	172.1	1.2

The following table provides the components of the plans' actuarially determined net periodic benefits cost for each of the three years ended December 31, 2020, 2019 and 2018:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2020**	2019	2018	**2020**	2019	2018
Components of Net Periodic Benefit Cost[(1)]						
Service cost	**$ 32.0**	$ 29.2	$ 31.3	**$ 6.6**	$ 5.1	$ 5.0
Interest cost	**51.6**	72.3	67.1	**15.4**	19.2	17.6
Expected return on assets	**(111.6)**	(108.8)	(142.3)	**(14.4)**	(13.1)	(14.9)
Amortization of prior service cost (credit)	**0.7**	0.2	(0.4)	**(2.1)**	(3.2)	(4.0)
Recognized actuarial loss	**33.8**	45.2	40.6	**4.9**	2.0	3.8
Settlement/curtailment loss	**10.5**	9.5	18.5	**1.5**	—	—
Total Net Periodic Benefits Cost	**$ 17.0**	$ 47.6	$ 14.8	**$ 11.9**	$ 10.0	$ 7.5

(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		
	2020	2019	2018	**2020**	2019	2018
Weighted-average Assumptions to Determine Net Periodic Benefit Cost						
Discount rate - service cost	**3.39 %**	4.48 %	3.79 %	**3.52 %**	4.59 %	3.89 %
Discount rate - interest cost	**2.65 %**	3.84 %	3.15 %	**2.76 %**	3.94 %	3.27 %
Expected Long-Term Rate of Return on Plan Assets	**5.70 %**	6.10 %	7.00 %	**5.67 %**	5.83 %	5.80 %
Rate of Compensation Increases	**4.00 %**	4.00 %	4.00 %	**—**	—	—
Interest Crediting Rates	**4.00 %**	4.00 %	4.00 %	**—**	—	—

We assumed a 5.70% and 5.67% rate of return on pension and other postretirement plan assets, respectively, for our calculation of 2020 pension benefits cost. These rates were primarily based on asset mix and historical rates of return and were adjusted in 2020 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)	**2020**	2019	**2020**	2019
Other Changes in Plan Assets and Projected Benefit Obligations Recognized in Other Comprehensive Income or Regulatory Asset or Liability				
Net prior service cost	**$ —**	$ —	**$ —**	$ 5.1
Net actuarial loss (gain)	**(78.2)**	(53.8)	**2.9**	45.1
Settlements/curtailments	**(10.5)**	(9.5)	**(1.5)**	—
Less: amortization of prior service cost	**(0.7)**	(0.2)	**2.1**	3.2
Less: amortization of net actuarial loss	**(33.8)**	(45.2)	**(4.9)**	(2.0)
Less: gain attributable to spinoff to Eversource	**(33.1)**	—	**—**	—
Less: prior service cost attributable to spinoff to Eversource	**(2.0)**	—	**—**	—
Total Recognized in Other Comprehensive Income or Regulatory Asset or Liability	**$ (158.3)**	$ (108.7)	**$ (1.4)**	$ 51.4
Amount Recognized in Net Periodic Benefits Cost and Other Comprehensive Income or Regulatory Asset or Liability	**$ (141.3)**	$ (61.1)	**$ 10.5**	$ 61.4

13. Equity

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 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 15, "Long-Term Debt," for more information. As of December 31, 2020, 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 2020, 2019 and 2018 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 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.

On August 6, 2020, 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 August 7, 2020 to September 3, 2020, 2,809,029 shares were borrowed from third parties and sold by the dealer at a weighted average price of $23.25 per share. On December 15, 2020, the forward agreement was settled for $22.77 per share, resulting in $64.0 million of net proceeds.

On September 4, 2020, 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 September 4, 2020 to September 16, 2020, 1,452,102 shares were borrowed from third parties and sold by the dealer at a weighted average price of $22.28 per share. On December 15, 2020, the forward agreement was settled for $21.82 per share, resulting in $31.7 million of net proceeds.

The equity distribution agreements entered into on November 1, 2018 and amended on August 1, 2019 expired December 31, 2020.

The following table summarizes our activity under the ATM program:

Year Ending December 31,		**2020**		2019		2018
Number of shares issued		**8,459,430**		8,422,498		8,883,014
Average price per share	**$**	**23.60**	$	27.75	$	26.85
Proceeds, net of fees (*in millions*)	**$**	**196.5**	$	229.1	$	232.5

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.

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, 2020 and 2019, 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, 2020 and 2019, Series B Preferred Stock had $1.4 million of cumulative preferred dividends in arrears, or $72.23 per share.

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,
			2020	2019	2018	2020	2019
(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	$ 56.50	$ 28.88	$ 393.9	$ 393.9
6.500% Series B	$ 25,000.00	20,000	$ 1,625.00	$ 1,674.65	$ —	$ 486.1	$ 486.1

Noncontrolling Interest in Consolidated Subsidiaries. In December 2020, NIPSCO and a tax equity partner completed their initial cash contributions into the Rosewater joint venture. Earnings, tax attributes and cash flows are allocated to both NIPSCO and the tax equity partner in varying percentages by category and over the life of the partnership. The tax equity partner's contributions, net of these allocations, is represented as a noncontrolling interest within total equity on the Consolidated Balance Sheets. Refer to Note 4, "Variable Interest Entities," for more information.

14. Share-Based Compensation

Prior to May 19, 2020 we issued share-based compensation to employees and non-employee directors under the NiSource Inc. 2010 Omnibus Plan ("2010 Omnibus Plan"), which was most recently approved by stockholders at the Annual Meeting of Stockholders held on May 12, 2015. The 2010 Omnibus Plan provided 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 superseded the Director Stock Incentive Plan (“Director Plan”) with respect to grants made after the effective date of the 2010 Omnibus Plan.

The stockholders approved and adopted the NiSource Inc. 2020 Omnibus Incentive Plan ("2020 Omnibus Plan") at the Annual Meeting of Stockholders held on May 19, 2020. The 2020 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 2010 Omnibus Plan with respect to grants made after the effective date of the 2020 Omnibus Plan.

The 2020 Omnibus Plan provides that the number of shares of common stock of NiSource available for awards is 10,000,000 plus the number of shares subject to outstanding awards that expire or terminate for any reason that were granted under the 2020 Omnibus Plan, the 2010 Omnibus Plan or any other equity plan under which awards were outstanding as of May 19, 2020. At December 31, 2020, there were 10,007,832 shares available for future awards under the 2020 Omnibus Plan.

We recognized stock-based employee compensation expense of $13.5 million, $16.3 million and $15.2 million, during 2020, 2019 and 2018, respectively, as well as related tax benefits of $3.3 million, $4.0 million and $3.7 million, respectively. We recognized related excess tax expense from the distribution of vested share-based employee compensation of $0.4 million in 2020 and excess tax benefits of $0.8 million and $1.0 million in 2019 and 2018, respectively.

As of December 31, 2020, the total remaining unrecognized compensation cost related to non-vested awards amounted to $19.1 million, which will be amortized over the weighted-average remaining requisite service period of 1.9 years.

Restricted Stock Units and Restricted Stock. We granted 235,100, 166,031, and 158,689 restricted stock units and shares of restricted stock to employees, subject to service conditions in 2020, 2019, and 2018, respectively. The total grant date fair value of the restricted stock units and shares of restricted stock during 2020, 2019, and 2018, respectively, was $6.1 million, $4.1 million, and $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, 2020, 223,724, 135,170, and 119,333 non-vested restricted stock units and shares of restricted stock granted in 2020, 2019, and 2018, respectively.

If an employee terminates employment before the service conditions lapse under the 2018, 2019 or 2020 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.

A summary of our restricted stock unit award transactions for the year ended December 31, 2020 is as follows:

(shares)	Restricted Stock Units	Weighted Average Award Date Fair Value Per Unit ($)
Non-vested at December 31, 2019	302,606	23.49
Granted	235,100	25.77
Forfeited	(38,220)	24.18
Vested	(21,259)	24.68
Non-vested at December 31, 2020	**478,227**	**24.51**

Employee Performance Shares. We granted 528,729 and 552,389 performance shares subject to service, performance and market-based vesting conditions in 2020 and 2019, respectively. We awarded 514,338 performance shares subject to similar service, performance and market conditions in 2018. The performance conditions are based on the achievement of one non-GAAP financial measure, relative total shareholder return 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 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-based vesting 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 over the performance period, approximately) 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 the market-based vesting condition. The grant date fair value of the NOEPS shares is 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. See table below for further details on these awards.

If a threshold level of cumulative NOEPS financial performance is achieved, additional operational measures, which we refer to as the customer value framework and which consists of equally weighted areas of focus, apply. Each area of focus represents an equal portion of the customer value framework shares, and the targets for all areas of focus must be met for the customer value framework shares to vest at 100%. The grant date fair value of the customer value framework shares is 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 for those customer value framework shares that are granted. See table below for further details on these awards.

For the 2020 awards, the customer value framework consists of four equally weighted areas of focus including safety, customer satisfaction, culture and environmental, each representing 25% of the customer value framework shares. For the 2019 and 2018 awards, the customer value framework consists of five equally weighted areas of focus including financial and all those noted for the 2020 awards, each representing 20% of the customer value framework shares.

For the 2018 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 is 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.

The following table presents details of the performance awards described above.

Award Year	Service Conditions Lapse date	Performance Period	Award Conditions	Shares outstanding at 12/31/2020 *(shares)*	Grant Date Fair Value *(in millions)*
2020	02/28/23	01/01/2020-12/31/2022	Non-GAAP Financial Measure	392,619	$ 11.7
			Operational Measures	90,604	$ 2.6
2019	02/28/22	01/01/2019-12/31/2021	Non-GAAP Financial Measure	384,680	$ 11.7
			Operational Measures	88,769	$ 2.5
2018	02/26/21	01/01/2018-12/31/2020	Non-GAAP Financial Measure	347,479	$ 9.2
			Operational Measures[1]	80,185	$ 2.4

[1] Grant date fair value amount represents the service inception date fair value of these awards as they are not yet granted.

A summary of our performance award transactions for the year ended December 31, 2020 is as follows:

(shares)	Performance Awards	Weighted Average Grant Date Fair Value Per Unit ($)[1]
Non-vested at December 31, 2019	1,503,251	22.74
Granted	528,729	27.01
Forfeited	(118,716)	25.63
Vested	(528,928)	28.30
Non-vested at December 31, 2020	**1,384,336**	**25.09**

[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 19, 2020, awards to non-employee directors may be made only under the 2020 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 deferral election. Certain restricted stock units remain outstanding from the 2010 Omnibus Plan and 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, 2020, 210,273 restricted stock units are outstanding to non-employee directors under either the 2020 Omnibus Plan, the 2010 Omnibus Plan or the Director Plan. Of this amount, 67,806 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, 2020, 2019 and 2018, we recognized 401(k) match, profit sharing and non-elective contribution expense of $37.8 million, $37.5 million and $37.6 million, respectively.

15. Long-Term Debt

Our long-term debt as of December 31, 2020 and 2019 is as follows:

Long-term debt type	Maturity as of December 31, 2020	Weighted average interest rate (%)	Outstanding balance as of December 31, *(in millions)* 2020	2019
Senior notes:				
NiSource	December 2021	4.45 %	—	63.6
NiSource	November 2022	2.65 %	—	500.0
NiSource	February 2023	3.85 %	—	250.0
NiSource	June 2023	3.65 %	—	350.0
NiSource	August 2025	0.95 %	**1,250.0**	—
NiSource	November 2025	5.89 %	—	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**	750.0
NiSource	May 2030	3.60 %	**1,000.0**	—
NiSource	February 2031	1.70 %	**750.0**	—
NiSource	December 2040	6.25 %	**152.6**	250.0
NiSource	June 2041	5.95 %	**347.4**	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			**$ 9,003.0**	$ 7,581.6
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[(1)]	December 2025 to February 2028	6.37 %	**15.0**	40.0
Total medium term notes			**$ 132.0**	$ 157.0
Finance leases:				
NiSource Corporate Services	April 2022 to January 2025	2.19 %	**49.4**	22.3
NIPSCO	November 2028	1.79 %	**16.0**	—
Columbia of Ohio	October 2021 to March 2044	6.16 %	**91.2**	94.8
Columbia of Virginia	July 2029 to November 2039	6.30 %	**18.4**	19.1
Columbia of Kentucky	May 2027	3.79 %	**0.3**	0.3
Columbia of Pennsylvania	August 2027 to May 2035	5.65 %	**19.7**	20.7
Columbia of Massachusetts	N/A	— %	—	44.3
Total finance leases			**195.0**	201.5
Unamortized issuance costs and discounts			**$ (86.9)**	$ (70.5)
Total Long-Term Debt			**$ 9,243.1**	$ 7,869.6

(1) Rate increased from 6.30% in 2019 to 6.37% in 2020 in connection with debt redemptions described below.

Details of our 2020 long-term debt related activity are summarized below:

- On April 13, 2020, we completed the issuance and sale of $1.0 billion of 3.60% senior unsecured notes maturing in 2030, which resulted in approximately $987.8 million of net proceeds after deducting commissions and expenses.
- On August 18, 2020, we completed the issuance and sale of $1.25 billion of 0.95% senior unsecured notes maturing in 2025 and $750.0 million of 1.70% senior unsecured notes maturing in 2031, which resulted in approximately $1,980.4 million of net proceeds after deducting commissions and expenses.
- In August 2020, we executed tender offers for $969.3 million of outstanding notes consisting of a combination of our 4.45% notes due 2021, 2.65% notes due 2022, 3.85% notes due 2023, 3.65% notes due 2023, 6.25% notes due 2040, and 5.95% notes due 2041. In August and September 2020, we redeemed $609.3 million of outstanding notes representing the remainder of our 4.45% notes due 2021, 2.65% notes due 2022, 3.85% notes due 2023, and 3.65% notes due 2023 and all of our 5.89% notes due 2025. In conjunction with the debt retired, we recorded a $231.8 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums.
- In September 2020, Columbia of Massachusetts redeemed $25.0 million of its outstanding 6.26% notes due 2028. In conjunction with the debt retired, Columbia of Massachusetts recorded an $11.7 million loss on early extinguishment of long-term debt, primarily attributable to early redemption premiums. Under the terms of the Asset Purchase Agreement, Columbia of Massachusetts' net working capital at the closing of the sale of the Massachusetts Business was increased by 50% of the debt extinguishment costs, which was approximately $5.3 million.

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 completed the issuance and sale 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.

See Note 20-A, "Contractual Obligations," for the outstanding long-term debt maturities at December 31, 2020.

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%. As of December 31, 2020, the ratio was 62.5%.

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.

16. Short-Term Borrowings

We generate short-term borrowings from our revolving credit facility, commercial paper program, accounts receivable transfer programs and now-settled 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, 2020 and 2019, 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 $503.0 million and $570.0 million of commercial paper outstanding as of December 31, 2020 and 2019, 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 no transfers as of December 31, 2020 and $353.2 million in transfers as of December 31, 2019, respectively. Refer to Note 19, "Transfers of Financial Assets," for additional information.

On April 1, 2020, we terminated and repaid in full our existing $850.0 million term loan agreement with a syndicate of banks led by MUFG Bank, Ltd. and entered into a new $850.0 million term loan agreement with a syndicate of banks led by KeyBank National Association. Any and all outstanding borrowings under the term loan agreement were due by March 31, 2021. Interest charged on borrowings depended on the variable rate structure we elected at the time of each borrowing. The available variable rate structures from which we could choose were defined in the term loan agreement. Under the agreement, we borrowed $850.0 million on April 1, 2020 with an interest rate of LIBOR plus 75 basis points. On October 14, 2020, we terminated and repaid in full our $850.0 million term loan agreement with proceeds from the sale of the Massachusetts Business.

Short-term borrowings were as follows:

At December 31, *(in millions)*	**2020**	2019
Commercial Paper weighted-average interest rate of 0.27% and 2.03% at December 31, 2020 and 2019, respectively	**$ 503.0**	$ 570.0
Accounts receivable securitization facility borrowings	—	353.2
Term loan interest rate of 2.40% at December 31, 2019	—	$ 850.0
Total Short-Term Borrowings	**$ 503.0**	$ 1,773.2

Other than for the term loan, revolving credit facility 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.

17. Leases

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 are reported in accordance with ASC 840. 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. Adoption of this 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 23 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 2 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.

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 years ended December 31, 2020 and 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	**2020**	2019
Finance lease cost			
Amortization of right-of-use assets	Depreciation and amortization	**$ 23.4**	$ 15.5
Interest on lease liabilities	Interest expense, net	**11.1**	11.3
Total finance lease cost		**34.5**	26.8
Operating lease cost	Operation and maintenance	**20.3**	17.9
Short-term lease cost	Operation and maintenance	**—**	1.0
Total lease cost		**$ 54.8**	$ 45.7

Our right-of-use assets and liabilities are presented in the following lines on the Consolidated Balance Sheets:

At December 31, *(in millions)*	Balance Sheet Classification	**2020**	2019
Assets			
Finance leases	Net Property, Plant and Equipment	**$ 176.8**	$ 179.5
Operating leases	Deferred charges and other	**39.9**	64.2
Total leased assets		**216.7**	243.7
Liabilities			
Current			
Finance leases	Current portion of long-term debt	**23.3**	13.4
Operating leases	Other accruals	**10.3**	13.2
Noncurrent			
Finance leases	Long-term debt, excluding amounts due within one year	**171.7**	188.1
Operating leases	Other noncurrent liabilities	**29.9**	51.6
Total lease liabilities		**$ 235.2**	$ 266.3

Other pertinent information related to leases was as follows:

Year Ended December 31, *(in millions)*		**2020**		2019
Cash paid for amounts included in the measurement of lease liabilities				
Operating cash flows used for finance leases	**$**	**11.1**	$	11.3
Operating cash flows used for operating leases		**20.2**		17.9
Financing cash flows used for finance leases		**18.4**		10.6
Right-of-use assets obtained in exchange for lease obligations				
Finance leases		**59.3**		26.4
Operating leases	**$**	**10.9**	$	13.4

	December 31, 2020	December 31, 2019
Weighted-average remaining lease term (years)		
Finance leases	**11.2**	14.8
Operating leases	**8.0**	9.2
Weighted-average discount rate		
Finance leases	**5.1 %**	5.9 %
Operating leases	**4.0 %**	4.3 %

Maturities of our lease liabilities as of December 31, 2020 were as follows:

As of December 31, 2020, *(in millions)*		Total		Finance Leases		Operating Leases
2021	$	44.4	$	32.7	$	11.7
2022		37.4		32.2		5.2
2023		33.5		28.8		4.7
2024		25.3		20.8		4.5
2025		19.8		16.1		3.7
Thereafter		152.3		134.1		18.2
Total lease payments		312.7		264.7		48.0
Less: Imputed interest		(77.5)		(69.7)		(7.8)
Total		235.2		195.0		40.2
Reported as of December 31, 2020						
Short-term lease liabilities		33.6		23.3		10.3
Long-term lease liabilities		201.6		171.7		29.9
Total lease liabilities	$	235.2	$	195.0	$	40.2

There were no leases signed but not yet commenced as of December 31, 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 were primarily charged to operation and maintenance expense as incurred.

18. 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, 2020 and December 31, 2019:

Recurring Fair Value Measurements December 31, 2020 (*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, 2020
Assets				
Risk management assets	$ —	$ 13.2	$ —	$ 13.2
Available-for-sale securities	—	170.9	—	170.9
Total	**$ —**	**$ 184.1**	**$ —**	**$ 184.1**
Liabilities				
Risk management liabilities	$ —	$ 222.8	$ —	$ 222.8
Total	**$ —**	**$ 222.8**	**$ —**	**$ 222.8**

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**

Risk Management Assets and Liabilities. 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 that reduce exposures. As of December 31, 2020 and 2019, 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.

Credit risk is considered in the fair value calculation of each of our forward-starting interest rate swaps, as described in Note 10, "Risk Management Activities." 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.

NIPSCO has entered into long-term forward natural gas purchase instruments 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 10, “Risk Management Activities.”

Available-for-Sale Debt Securities. Available-for-sale debt securities are investments pledged as collateral for trust accounts related to our wholly-owned insurance company. 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.

We adopted ASC 326 effective January 1, 2020. See "Recently Adopted Accounting Pronouncements" in Note 2, "Recent Accounting Pronouncements," for more information about ASC 326. Upon adoption of ASC 326, our available-for-sale debt securities impairments are recognized periodically using an allowance approach instead of an 'other than temporary' impairment model. At each reporting date, we utilize a quantitative and qualitative review process to assess the impairment of available-for-sale debt securities at the individual security level. For securities in a loss position, we evaluate our intent to sell or whether it is more-likely-than-not that we will be required to sell the security prior to the recovery of its amortized cost. If either criteria is met, the loss is recognized in earnings immediately, with the offsetting entry to the carrying value of the security. If both criteria are not met, we perform an analysis to determine whether the unrealized loss is related to credit factors. The analysis focuses on a variety of factors that include, but are not limited to, downgrade on ratings of the security, defaults in the current reporting period or projected defaults in the future, the security's yield spread over treasuries, and other relevant market data. If the unrealized loss is not related to credit factors, it is included in other comprehensive income. If the unrealized loss is related to credit factors, the loss is recognized as credit loss expense in earnings during the period, with an offsetting entry to the allowance for credit losses. The amount of the credit loss recorded to the allowance account is limited by the amount at which security's fair value is less than its amortized cost basis. If the credit losses in the allowance for credit losses are deemed uncollectible, the allowance on the uncollectible portion will be charged off, with an offsetting entry to the carrying value of the security. Subsequent improvements to the estimated credit losses of available-for-sale debt securities will be recognized immediately in earnings instead of over-time as they would under historic guidance. During the year ended December 31, 2020, we recorded $0.5 million as an allowance for credit losses on available-for-sale debt securities as a result of the analysis described above. Continuous credit monitoring and portfolio credit balancing mitigates our risk of credit losses on our available-for-sale debt securities.

The amortized cost, gross unrealized gains and losses, allowance for credit losses, and fair value of available-for-sale securities at December 31, 2020 and 2019 were:

December 31, 2020 *(in millions)*	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses[1]	Allowance for Credit Losses	Fair Value
Available-for-sale debt securities					
U.S. Treasury debt securities	$ 33.7	$ 0.3	$ —	$ —	$ 34.0
Corporate/Other debt securities	130.2	7.7	(0.5)	(0.5)	136.9
Total	**$ 163.9**	**$ 8.0**	**$ (0.5)**	**$ (0.5)**	**$ 170.9**

December 31, 2019 *(in millions)*	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses[2]	Allowance for Credit Losses	Fair Value
Available-for-sale debt 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**

[1] Fair value of U.S. Treasury debt securities and Corporate/Other debt securities in an unrealized loss position without an allowance for credit losses is $0 and $13.2 million, respectively, at December 31, 2020.
[2] Fair value of U.S. Treasury debt securities and Corporate/Other debt securities in an unrealized loss position without an allowance for credit losses is $17.2 million and $12.2 million, respectively, at December 31, 2019.

Realized gains and losses on available-for-sale securities were immaterial for the year-ended December 31, 2020 and 2019.

The cost of maturities sold is based upon specific identification. At December 31, 2020, approximately $4.9 million of U.S. Treasury debt securities and approximately $4.3 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, 2020 and 2019.

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.

The sale of the Massachusetts Business occurred on October 9, 2020, and the assets and liabilities of the Massachusetts Business were measured at fair value, less costs to sell. Our estimated total pre-tax loss for the year ended December 31, 2020 is $412.4 million.

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 7, "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, 2020 and 2019, 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 2020**	**Estimated Fair Value 2020**	Carrying Amount 2019	Estimated Fair Value 2019
Long-term debt (including current portion)	**$ 9,243.1**	**$ 11,034.2**	$ 7,869.6	$ 8,764.4

19. 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 2021 and October 2021 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, 2020, the maximum amount of debt that could be recognized related to our accounts receivable programs is $380.0 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, 2020 and 2019:

At December 31, *(in millions)*	**2020**	2019
Gross receivables	**$ 607.7**	$ 569.1
Less: receivables not transferred	**607.7**	215.9
Net receivables transferred	**$ —**	$ 353.2
Short-term debt due to asset securitization	**$ —**	$ 353.2

During 2020 and 2019, $353.2 million and $46.0 million, respectively, was recorded as cash flows used for financing activities related to the change in short-term borrowings due to securitization transactions. Fees associated with the securitization transactions were $2.6 million for the years ended December 31, 2020, 2019 and 2018. 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.

20. 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, 2020 and their maturities were:

(in millions)	Total	2021	2022	2023	2024	2025	After
Long-term debt [1]	$ 9,135.0	$ —	$ 30.0	$ —	$ —	$ 1,260.0	$ 7,845.0
Interest payments on long-term debt	6,046.3	336.3	335.7	334.1	334.1	334.1	4,372.0
Finance leases[2]	264.7	32.7	32.2	28.8	20.8	16.1	134.1
Operating leases[3]	48.0	11.7	5.2	4.7	4.5	3.7	18.2
Energy commodity contracts	42.1	42.1	—	—	—	—	—
Service obligations:							
Pipeline service obligations[4]	1,495.6	468.7	422.5	256.0	150.5	56.2	141.7
IT service obligations	240.3	74.9	74.0	38.1	30.5	22.8	—
Other service obligations[5]	12.6	12.6	—	—	—	—	—
Other liabilities[6]	116.9	26.0	0.8	90.1	—	—	—
Total contractual obligations	$ 17,401.5	$ 1,005.0	$ 900.4	$ 751.8	$ 540.4	$ 1,692.9	$ 12,511.0

[1] Long-term debt balance excludes unamortized issuance costs and discounts of $86.9 million.
[2] Finance lease payments shown above are inclusive of interest totaling $69.7 million.
[3] Operating lease payments shown above are inclusive of interest totaling $7.8 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 as they are renewed month-to-month after the first year. If we were to continue the fleet vehicle leases outstanding at December 31, 2020, payments would be $30.0 million in 2021, $27.7 million in 2022, $24.9 million in 2023, $22.0 million in 2024, $19.0 million in 2025 and $21.5 million thereafter.
[4]In February 2021, the demand rate increased for our pipeline service obligations, resulting in a total increase of $638.6 million in addition to our future pipeline service obligations shown above.
[5]On February 9, 2021, a rail transportation contract for the transportation of coal was fully executed between NIPSCO and a counterparty, replacing the prior agreement. The minimum coal tonnage shipment commitment for 2021 was eliminated under the new agreement, reducing our contractual obligation for 2021 by $12.1 million.
[6]Other liabilities shown above are inclusive of the Rosewater Developer payment due in 2023.

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 the minimum quantity 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, 2020.

NIPSCO has power purchase arrangements representing a total of 500 MW of wind power, with contracts expiring between between 2024 and 2040. 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 early termination of one of these agreements by NIPSCO for any reason (other than material breach by the counterparties), 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.

We have pipeline service agreements that provide for pipeline capacity, transportation and storage services. These agreements, which have expiration dates ranging from 2021 to 2038, 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 2025.

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, 2020 and 2019, we had issued stand-by letters of credit of $15.2 million and $10.2 million , respectively, for the benefit of third parties.

We have provided guarantees related to our future performance under BTAs for our renewable generation projects. At December 31, 2020, our guarantees for the Rosewater and Indiana Crossroads BTAs totaled $40.7 million. The amount of each guaranty will decrease upon the substantial completion of the construction of the facilities. See "- E. Other Matters - NIPSCO 2018 Integrated Resource Plan," below for more information.

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. On September 1, 2020, the Massachusetts Governor terminated the state of emergency declared following the Greater Lawrence Incident.

We have been subject to state and federal 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. On February 26, 2020, the Company and Columbia of Massachusetts entered into agreements with the U.S. Attorney's Office for the District of Massachusetts to resolve the U.S. Attorney's Office's investigation relating to the Greater Lawrence Incident, as described below. The Company and Columbia of Massachusetts entered into an agreement with the Massachusetts Attorney General's Office (among other parties) to resolve the Massachusetts DPU and the Massachusetts Attorney General's Office investigations, that was approved by the Massachusetts DPU on October 7, 2020 as part of the sale of the Massachusetts Business to Eversource.

NTSB Investigation. As previously disclosed, the NTSB concluded its investigation into the Greater Lawrence Incident. On November 24, 2020, the NTSB closed NiSource's one remaining open safety recommendation.

U.S. Department of Justice Investigation. 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 Deferred Prosecution Agreement (the "DPA").

On March 9, 2020, Columbia of Massachusetts entered its guilty plea pursuant to the Plea Agreement, which the Court accepted. Subsequently, Columbia of Massachusetts and the U.S. Attorney's Office modified the Plea Agreement. On June 23, 2020, the Court sentenced Columbia of Massachusetts in accordance with the terms of the modified Plea Agreement. Under the modified Plea Agreement, Columbia of Massachusetts is subject to the following terms, among others: (i) a criminal fine in the amount of $53,030,116, which has been paid; (ii) a three year probationary period that will terminate early 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, but in no event before the end of the one-year mandatory period of probation; (iii) compliance with each of the NTSB recommendations stemming from the Greater Lawrence Incident; and (iv) employment of an in-house monitor until the end of the term of probation or until the sale of Columbia of Massachusetts or its gas distribution business, whichever is earlier. On October 13, 2020, the Court, upon agreement of the U.S. Attorney's Office and Columbia Gas of Massachusetts, modified the terms of probation by ending the term of the in-house monitor.

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 of Massachusetts or its gas distribution business, a fine equal to the total amount of the profit or gain, if any, 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 withdraws its plea for any reason, if the Court rejects any aspect of the Plea Agreement, 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. The sale of the Massachusetts Business was completed on October 9, 2020. The Company was not required to forfeit or pay any funds because the Company did not realize a profit or gain from the sale as provided in the DPA.

U.S. Federal Government Activity. On December 27, 2020, the Protecting Our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2020 was signed into law reauthorizing funding for federal pipeline safety programs through September 30, 2023. Among other things, the PIPES Act requires that PHMSA revise the pipeline safety regulations to require operators to update, as needed, their existing distribution integrity management plans, emergency response plans, and O&M plans. The PIPES Act also requires PHMSA to adopt new requirements for managing records and updating, as necessary existing district regulator stations to eliminate common modes of failure that can lead to overpressurization. PHMSA must also require that operators implement leak detection and repair programs that meet safety needs and consider the environment, require the use of advance leak detection practices and technologies, and require operators to be able to locate and categorize all leaks that are hazardous to human safety or the environment, or that can become hazardous. Natural gas companies, including the Company, may see increased costs depending on how PHMSA implements the new mandates resulting from the PIPES Act.

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.

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 Court granted final approval of the settlement on March 12, 2020.

With respect to claims not included in the consolidated class action, many of the asserted wrongful death and bodily injury claims have settled, and we continue to discuss potential settlements with remaining claimants. The outcomes and impacts of such private actions are uncertain at this time.

Shareholder Derivative Lawsuit. On April 28, 2020, a shareholder derivative lawsuit was filed by the City of Detroit Police and Fire Retirement System in the United States District Court for the District of Delaware against certain of our current and former directors, alleging breaches of fiduciary duty with respect to the pipeline safety management systems relating to the distribution of natural gas prior to the Greater Lawrence Incident and also including claims related to our proxy statement disclosures regarding our safety systems. The remedies sought include damages for the alleged breaches of fiduciary duty, corporate governance reforms, and restitution of any unjust enrichment. The defendants have filed a motion to dismiss the lawsuit. The motion to dismiss is fully briefed. On January 5, 2021, the judge set the defendants' motion to dismiss for oral argument on March 2, 2021. Because of the preliminary nature of this lawsuit, we are not able to estimate a loss or range of loss, if any, that may be incurred in connection with this matter at this time.

Financial Impact. Since the Greater Lawrence Incident, we have recorded expenses of approximately $1,036 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 $1,036 million to $1,050 million, depending on the number, nature, final outcome and value of third-party claims. 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. These costs also do not include non-claims related and government investigation-related legal expenses resulting from the incident, the capital cost of the pipeline replacement and the payment in lieu of penalties, which are set forth in " - D. Other Matters - Greater Lawrence Incident Restoration," "- Greater Lawrence Incident Pipeline Replacement," and Note 1-A, "Company Structure and Principles of Consolidation," respectively.

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, 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 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 we are, in all material respects, in 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, 2020 and 2019, we had recorded a liability of $92.6 million and $104.4 million, respectively, to cover environmental remediation at various sites. The current portion of this liability is included in "Other Accruals" 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 U.S. Court of Appeals for the D.C. Circuit vacated and remanded the rule on January 19, 2021. NIPSCO will continue to monitor this matter.

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 54 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, 2020. Our total estimated liability related to the facilities subject to remediation was $85.0 million and $102.2 million at December 31, 2020 and 2019, 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 in 2019 to modify its infrastructure and manage CCRs. 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 will also continue to work with EPA and the Indiana Department of Environmental Management to obtain administrative approvals associated with the CCR rule. In the event that the approvals are not obtained, future operations could be impacted. We believe the possibility of such an outcome is remote.

E. Other Matters.

NIPSCO 2018 Integrated Resource Plan. NIPSCO concluded 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 the R.M. Schahfer Generating Station by mid-2023 and the Michigan City Generating Station by the end of 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. NIPSCO will refresh its 2018 Integrated Resource Plan in 2021.

In the second quarter of 2020, the MISO approved NIPSCO's plan to retire the R.M. Schahfer Generating Station in 2023. In accordance with ASC 980-360, the net book value of certain plant and equipment for the R.M. Schahfer Generating Station was reclassified as "Non-Utility and Other" as described in Note 6, "Property, Plant and Equipment." The December 2019, NIPSCO electric rate case order included approval to create a regulatory asset upon the retirement of the R.M. Schahfer Generating Station. The order allows for the recovery of and on the net book value of the station by the end of 2032. Refer to Note 6, "Property, Plant and Equipment" for further information.

In connection with the MISO's approval of NIPSCO's planned retirement of the R.M. Schahfer Generating Station, we recorded $4.6 million of plant retirement-related charges in the second quarter of 2020. These charges are presented within "Operation and maintenance" and were comprised of write downs of certain capital projects that have been cancelled and materials and supplies inventory balances deemed obsolete due to the planned retirement. As more information becomes available, the retirement date of the R.M. Schahfer Generating Station will be finalized, and additional plant retirement-related charges may be incurred. In February 2021, NIPSCO decided to submit modified Attachment Y Notices to MISO requesting accelerated retirement of two of the four coal fired units at R.M. Schahfer Generating Station. The two units are now expected to be retired by the end of 2021, with the remaining two units still scheduled to be retired in 2023. At retirement, the net book value of the retired units will be reclassified from "Non-Utility and Other property", to current and long-term "Regulatory Assets," as described above.

In connection with the planned retirement of the Schahfer Generating Station and the Michigan City Generating Station, the current capacity replacement plan includes lower-cost, reliable, cleaner energy resources to be obtained through a combination of NIPSCO ownership and PPAs. To this effect, NIPSCO has entered into a number of agreements with counterparties.

NIPSCO has executed several PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per MWh. Each facility supplying the energy will have an associated nameplate capacity, and payments under the PPAs will not begin until the associated generation facility is constructed by the owner/seller. NIPSCO has also executed several BTAs with developers to construct renewable generation facilities. NIPSCO's purchase requirement under the BTAs 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 and the tax equity partner are obligated to make cash contributions to the partnership at the date construction is substantially complete. Once the tax equity partner has earned their negotiated rate of return and we have reached the agreed upon contractual date, NIPSCO has the option to purchase at fair market value from the tax equity partner the remaining interest in the aforementioned joint venture.

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, we have recorded expenses for other incident-related costs. 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. These amounts do not include the capital cost of the pipeline replacement, which is set forth below.

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)	Total Costs Incurred through December 31, 2019	**Year Ended December 31, 2020**	Incident to Date
Third-party claims and government fines, penalties and settlements	$ 1,041	**$ (5)**	$ 1,036
Other incident-related costs	420	**22**	442
Total	1,461	**17**	1,478
Insurance recoveries recorded	(800)	**—**	(800)
Total costs incurred	$ 661	**$ 17**	$ 678

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. While we collected the entire $800 million, expenses related to the incident exceeded the total amount of insurance coverage available under our policies.

The following table summarizes the total estimated incident-related expenses.

(in millions)	**Current Total Estimated Amount**
Third-party claims and government fines, penalties and settlements	$1,036 - $1,050
Other incident-related costs	$445 - $450

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 pipeline system. We 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 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. Refer to Note 1-A, "Company Structure and Principles of Consolidation," for more information.

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 issued a denial during the first quarter of 2020. We filed an application for abatement in the second quarter of 2020, resulting in a hearing with the MA DOR during the fourth quarter of 2020. We believe it is reasonably possible that an alternative method will be proposed by the MA DOR during the first half of 2021.

Voluntary Separation Program. On August 5, 2020, we commenced a voluntary separation program for certain employees. Expense for the voluntary separation program was predominantly recognized in the third quarter of 2020, when the employees accepted the offer, absent a retention period. For employees that have a retention period, expense will be recognized over the remaining service period. Employee acceptance under the voluntary separation program was determined by management based on facts and circumstances of the benefits being offered. The total severance expense for employees who were accepted under the voluntary separation program offered in August 2020 is approximately $38 million, which will be recognized over the remaining service period of the applicable employees. A rollforward of the voluntary separation program accrual for the year ended December 31, 2020 is presented below:

(in millions)	**Balance as of January 1, 2020**	**Changes Attributable to Costs Incurred[(1)]**	**Costs Paid**	**Adjustments**	**Balance as of December 31, 2020[(2)]**
Voluntary Separation Program	$ —	33.5	$ (21.2)	(1.2)	$ 11.1

[(1)]This activity is presented within "Operation and maintenance" in our Statements of Consolidated Income (Loss).
[(2)]This activity is presented within "Accrued compensation and employee benefits" in our Consolidated Balance Sheets.

21. 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, 2018	**$ 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)**
Other comprehensive income (loss) before reclassifications	3.3	(70.8)	2.9	(64.6)
Amounts reclassified from accumulated other comprehensive loss	(0.6)	0.1	1.0	0.5
Net current-period other comprehensive income (loss)	2.7	(70.7)	3.9	(64.1)
Balance as of December 31, 2020	**$ 6.0**	**$ (147.9)**	**$ (14.8)**	**$ (156.7)**

[1]All amounts are net of tax. Amounts in parentheses indicate debits.

22. Other, Net

Year Ended December 31, *(in millions)*	**2020**	2019	2018
Interest income	**$ 5.5**	$ 7.7	$ 6.6
AFUDC equity	**9.9**	8.0	14.2
Charitable contributions[1]	**(1.5)**	(5.1)	(45.3)
Pension and other postretirement non-service cost[2]	**9.3**	(16.5)	18.0
Sale of emission reduction credits	**4.6**	—	—
Interest rate swap settlement gain[3]	—	—	46.2
Miscellaneous	**4.3**	0.7	3.8
Total Other, net	**$ 32.1**	$ (5.2)	$ 43.5

[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 20, "Other Commitments and Contingencies" for additional information on the Greater Lawrence Incident.
[2] See Note 12, "Pension and Other Postretirement Benefits" for additional information.
[3] See Note 10, "Risk Management Activities" for additional information.

23. Interest Expense, Net

Year Ended December 31, *(in millions)*	**2020**	2019	2018
Interest on long-term debt	**$ 354.2**	$ 327.7	$ 342.2
Interest on short-term borrowings	**14.7**	50.8	31.8
Debt discount/cost amortization	**9.1**	8.3	7.7
Accounts receivable securitization fees	**2.6**	2.6	2.6
Allowance for borrowed funds used and interest capitalized during construction	**(7.0)**	(7.5)	(9.1)
Debt-based post-in-service carrying charges	**(14.6)**	(18.7)	(35.0)
Other	**11.7**	15.7	13.1
Total Interest Expense, net	**$ 370.7**	$ 378.9	$ 353.3

24. Segments of Business

At December 31, 2020, our operations are divided into two primary reportable segments, the Gas Distribution Operations and the Electric Operations segment. The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as an operating segment, are presented as "Corporate and Other" and primarily are comprised of interest expense on holding company debt, and unallocated corporate costs and activities. Refer to Note 3, "Revenue Recognition," for additional information on our segments and their sources of revenues. 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)*	**2020**	2019	2018
Operating Revenues			
Gas Distribution Operations			
Unaffiliated	**$ 3,128.1**	$ 3,509.7	$ 3,406.4
Intersegment	**12.1**	13.1	13.1
Total	**3,140.2**	3,522.8	3,419.5
Electric Operations			
Unaffiliated	**1,535.9**	1,698.4	1,707.4
Intersegment	**0.7**	0.8	0.8
Total	**1,536.6**	1,699.2	1,708.2
Corporate and Other			
Unaffiliated	**17.7**	0.8	0.7
Intersegment	**449.8**	468.1	517.6
Total	**467.5**	468.9	518.3
Eliminations	**(462.6)**	(482.0)	(531.5)
Consolidated Operating Revenues	**$ 4,681.7**	$ 5,208.9	$ 5,114.5

Year Ended December 31, *(in millions)*		**2020**		2019		2018
Operating Income (Loss)						
Gas Distribution Operations(1)	**$**	**199.1**	$	675.4	$	(254.1)
Electric Operations		**348.8**		406.8		386.1
Corporate and Other(2)		**2.9**		(191.5)		(7.3)
Consolidated Operating Income	**$**	**550.8**	$	890.7	$	124.7
Depreciation and Amortization						
Gas Distribution Operations	**$**	**363.1**	$	403.2	$	301.0
Electric Operations		**321.3**		277.3		262.9
Corporate and Other		**41.5**		36.9		35.7
Consolidated Depreciation and Amortization	**$**	**725.9**	$	717.4	$	599.6
Assets						
Gas Distribution Operations	**$**	**13,433.0**	$	14,224.5	$	13,527.0
Electric Operations		**6,443.1**		6,027.6		5,735.2
Corporate and Other		**2,164.4**		2,407.7		2,541.8
Consolidated Assets	**$**	**22,040.5**	$	22,659.8	$	21,804.0
Capital Expenditures(3)						
Gas Distribution Operations	**$**	**1,266.9**	$	1,380.3	$	1,315.3
Electric Operations		**422.8**		468.9		499.3
Corporate and Other		**31.1**		18.6		—
Consolidated Capital Expenditures	**$**	**1,720.8**	$	1,867.8	$	1,814.6

(1)In 2020, Gas Distribution Operations reflects the loss of $412.4 million on the sale of the Massachusetts Business. For additional information, see Note 1, "Nature of Operations and Summary of Significant Accounting Policies".
(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 7, "Goodwill and Other Intangible Assets."
(3)Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the inclusion of capital expenditures in current liabilities, the capitalized portion of the Corporate Incentive Plan payout, and AFUDC Equity.

25. 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)
2020				
Operating Revenues	$ 1,605.5	$ 962.7	$ 902.5	$ 1,211.0
Operating Income	148.2	91.7	92.8	218.1
Net Income (Loss)	75.6	(4.7)	(172.9)	87.8
Net income attributable to noncontrolling interest	—	—	—	3.4
Net Income (Loss) attributable to NiSource	75.6	(4.7)	(172.9)	84.4
Preferred Dividends	(13.8)	(13.8)	(13.8)	(13.7)
Net Income (Loss) Available to Common Shareholders	61.8	(18.5)	(186.7)	70.7
Earnings (Loss) Per Share				
Basic Earnings (Loss) Per Share	$ 0.16	$ (0.05)	$ (0.49)	$ 0.18
Diluted Earnings (Loss) Per Share	$ 0.16	$ (0.05)	$ (0.49)	$ 0.18
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)

(1) Net income for the first quarter of 2020 was impacted by $280.2 million loss on sale of the Massachusetts Business. 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 1, "Company Structure and Principles of Consolidation" and Note 20-E, "Other Matters" for additional information.
(2) Net income for the second quarter of 2020 was impacted by an additional $84.4 million loss on sale of the Massachusetts Business. 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 1, "Company Structure and Principles of Consolidation" and Note 20-E, "Other Matters" for additional information.
(3) Net loss for the third quarter of 2020 was impacted by $243.4 million loss on early extinguishments of long-term debt. See Note 15, "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 7, "Goodwill and Other Intangible Assets."

26. Supplemental Cash Flow Information

The following table provides additional information regarding our Consolidated Statements of Cash Flows for the years ended December 31, 2020, 2019 and 2018:

Year Ended December 31, *(in millions)*	**2020**	2019	2018
Supplemental Disclosures of Cash Flow Information			
Non-cash transactions:			
Capital expenditures included in current liabilities	**$ 170.4**	$ 223.6	$ 152.0
Assets acquired under a finance lease	**59.3**	26.4	54.6
Assets acquired under an operating lease	**10.9**	13.4	—
Reclassification of other property to regulatory assets[1]	**—**	—	245.3
Assets recorded for asset retirement obligations[2]	**91.5**	54.6	78.1
Obligation to developer at formation of joint venture[3]	**69.7**	—	—
Schedule of interest and income taxes paid:			
Cash paid for interest, net of interest capitalized amounts	**$ 349.0**	$ 349.7	$ 354.2
Cash paid for income taxes, net of refunds[4]	**(1.0)**	10.8	3.3

(1)See Note 9 "Regulatory Matters" for additional information.
(2)See Note 8 "Asset Retirement Obligations" for additional information.
(3)Represents investing non-cash activity. See Note 4 "Variable Interest Entities" for additional information.
(4)Amount of refunds in 2020 was greater than the amount of tax payments due to overpayments in 2019.

NISOURCE INC.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS

Twelve months ended December 31, 2020

($ in millions)	Balance Jan. 1, 2020	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [(1)]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2020
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 19.2	$ 31.6	$ 33.0	$ 31.5	$ 52.3
Reserve for other investments	3.0	—	—	3.0	—

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

(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 2020, 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 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, 2020, 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, 2020, 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, 2020, of the Company and our report dated February 17, 2021, 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 17, 2021

ITEM 9B. OTHER INFORMATION

NISOURCE INC.

Not applicable.

PART III

NISOURCE INC.

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 "Delinquent Section 16(a) Reports"" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 25, 2021.

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 25, 2021.

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 25, 2021.

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 25, 2021.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item 14 is incorporated herein by reference to the discussion in "Independent Registered Public Accounting Firm Fees" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 25, 2021.

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."

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. (incorporated by reference to Exhibit 4.20 of the NiSource Form 10-K filed on February 28, 2020)
(4.21)	Form of 3.600% Notes due 2030 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on April 8, 2020).
(4.22)	Form of 0.950% Notes due 2025 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on August 18, 2020).
(4.23)	Form of 1.700% Notes due 2031(incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on August 18, 2020).
(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)	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).*

(10.33)	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).
(10.34)	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).
(10.35)	Form of Performance Share Award Agreement (incorporated by reference to Exhibit 10.39 of the NiSource Form 10-K filed on February 28, 2020).*
(10.36)	Form of Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.40 of the NiSource Form 10-K filed on February 28, 2020). *
(10.37)	Form of Cash-Based Award Agreement (incorporated by reference to Exhibit 10.41 of the NiSource Form 10-K filed on February 28, 2020). *
(10.38)	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).
(10.39)	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).
(10.40)	Term Loan Agreement, dated as of April 1, 2020, among NiSource Inc., as Borrower, the lenders party thereto, and KeyBank National Association, as Administrative Agent, and KeyBank National Association, PNC Bank, National Association and U.S. Bank National Association, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on April 1, 2020).
(10.41)	2020 Omnibus Incentive Plan (incorporated by reference to Exhibit A to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting held on May 19, 2020, filed on April 13, 2020).*
(10.42)	Settlement Agreement, dated July 2, 2020, by and among Bay State Gas Company d/b/a Columbia Gas of Massachusetts, NiSource Inc., Eversource Gas Company of Massachusetts, Eversource Energy, the Massachusetts Attorney General's Office, the Massachusetts Department of Energy Resources the Low-Income Weatherization and Fuel Assistance Program Network (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on July 6, 2020).
(10.43)	Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2020 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 10-Q filed on August 5, 2020).*
(10.44)	Addendum to Plea Agreement filed on or about June 21, 2020 in the United States District Court for the District of Massachusetts (incorporated by reference to Exhibit 10.4 of the NiSource Inc. Form 10-Q filed on August 5, 2020).
(10.45)	Letter Agreement by and among NiSource Inc., Bay State Gas Company d/b/a Columbia Gas of Massachusetts and Eversource Energy Relating to Asset Purchase Agreement, dated October 9, 2020 (incorporated by reference to Exhibit 10.3 to the NiSource Inc. Form 10-Q filed on November 2, 2020).***
(10.46)	NiSource Inc. Supplemental Executive Retirement Plan, as amended and restated effective November 1, 2020 (incorporated by reference to Exhibit 10.4 to the NiSource Inc. Form 10-Q filed on November 2, 2020).*
(10.47)	Pension Restoration Plan for NiSource Inc. and Affiliates, as amended and restated effective November 1, 2020 (incorporated by reference to Exhibit 10.5 to the NiSource Inc. Form 10-Q filed on November 2, 2020).
(10.48)	Savings Restoration Plan for NiSource Inc. and Affiliates, as amended and restated effective November 1, 2020 (incorporated by reference to Exhibit 10.6 to the NiSource Inc. Form 10-Q filed on November 2, 2020).*
(10.49)	NiSource Inc. Executive Severance Policy, as amended and restated effective October 19, 2020 (incorporated by reference to Exhibit 10.7 to the NiSource Inc. Form 10-Q filed on November 2, 2020).*
(10.50)	NiSource Next Voluntary Separation Program, effective as of August 5, 2020 (incorporated by reference to Exhibit 10.8 to the NiSource Inc. Form 10-Q filed on November 2, 2020).*

(10.51)	Letter Agreement dated October 19, 2020 by and between NiSource Inc. and Carrie Hightman (incorporated by reference to Exhibit 10.9 to the NiSource Inc. Form 10-Q filed on November 2, 2020).*
(10.52)	Amendment to Settlement Agreement by and among Bay State Gas Company d/b/a Columbia Gas of Massachusetts, NiSource Inc., Eversource Gas Company of Massachusetts, Eversource Energy, the Massachusetts Attorney General's Office, the Massachusetts Department of Energy Resources and the Low-Income Weatherization and Fuel Assistance Program Network, dated September 29, 2020 (incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 10-Q filed on November 2, 2020).
(10.53)	Form of Restricted Stock Unit Award Agreement.* **
(10.54)	Form of Performance Share Unit Award Agreement.* **
(10.55)	Form of Special Performance Share Unit Award Agreement.* **
(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.

ITEM 16. FORM 10-K SUMMARY

None

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 17, 2021

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 17, 2021
/s/ DONALD E. BROWN Donald E. Brown	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	Date: February 17, 2021
/s/ GUNNAR J. GODE Gunnar J. Gode	Vice President and Chief Accounting Officer (Principal Accounting Officer)	Date: February 17, 2021
/s/ KEVIN T. KABAT Kevin T. Kabat	Chairman of the Board	Date: February 17, 2021
/s/ PETER A. ALTABEF Peter A. Altabef	Director	Date: February 17, 2021
/s/ THEODORE H. BUNTING, JR. Theodore H. Bunting, Jr.	Director	Date: February 17, 2021
/s/ ERIC L. BUTLER Eric L. Butler	Director	Date: February 17, 2021
/s/ ARISTIDES S. CANDRIS Aristides S. Candris	Director	Date: February 17, 2021
/s/ WAYNE S. DEVEYDT Wayne S. DeVeydt	Director	Date: February 17, 2021
/s/ DEBORAH A. HENRETTA Deborah A. Henretta	Director	Date: February 17, 2021
/s/ DEBORAH A.P. HERSMAN Deborah A. P. Hersman	Director	Date: February 17, 2021
/s/ MICHAEL E. JESANIS Michael E. Jesanis	Director	Date: February 17, 2021
/s/ CAROLYN Y. WOO Carolyn Y. Woo	Director	Date: February 17, 2021
/s/ LLOYD M. YATES Lloyd M. Yates	Director	Date: February 17, 2021

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 "Grant Date"), by and between NiSource Inc., a Delaware corporation (the "Company"), and [________], an Employee of the Company or an Affiliate (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. 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 shall 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 rata* 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 Grant Date and the date the Grantee terminates Service, and the denominator shall be the number of full or partial calendar months between the Grant Date and the Vesting Date. For purposes of this Agreement, "Retirement" means the Grantee's termination from Service at or after attainment of age 55 and completion of at least 10 years of continuous

Service measured from the Grantee's most recent date of hire with the Company or an Affiliate.

(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 any other agreement between the Company and the Grantee, the "Good Reason" definition set forth in the Plan shall govern this award. 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 shall convert the Restricted Stock Units in the Grantee's RSU Account into Shares and issue or 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 shall 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. As a condition precedent to the delivery to Grantee of any Shares upon vesting of the Restricted Stock Units, 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 Restricted Stock Units. 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 Restricted Stock Units (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 Restricted Stock Units, 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 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. The delivery of all or any Shares that relate to the Restricted Stock Units 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 Code 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 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 Restricted Stock Units may be replaced by Alternative 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, 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 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. 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 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. To the extent a conflict exists between this Agreement and the Plan, the provisions of the Plan shall govern. This Agreement is pursuant to the terms of the Plan.

Section 15. Code Section 409A Compliance. 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 FOLLOWS]

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:

NiSource Inc.

20__ Omnibus Incentive Plan

20__ Performance Share Unit Award Agreement

This Performance Share Unit 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 or an Affiliate (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 Unit Award.** The Company hereby grants to the Grantee, on the terms and conditions hereinafter set forth, a target award of [TOTAL TARGET NUMBER] Performance Share Units. The Performance Share Units shall be represented by a bookkeeping entry with respect to the Grantee (the "PSU Account"), and each Performance Share Unit 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 Share Units 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 that that the Grantee remains in continuous Service through _________________ (the "Vesting Date"). 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 Share Units.

(b) Financial Performance Goal. Subject to the terms of this Agreement and the Plan, [INSERT TARGET NUMBER OF NOEPS SHARES] of the Performance Share Units 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 Share Units Eligible for Vesting(2)
Trigger	$________	_____________
Target	$________	_____________
Stretch	$_______and above	_____________

(1) The vesting percentage for performance between performance levels shall be determined based on linear interpolation.

(2) The number of Performance Share Units that shall vest based on the Company's cumulative NOEPS performance shall be subject to a performance magnifier as described below.

(3) Performance Magnifier. Subject to the terms of this Agreement and the Plan, the number of Performance Share Units eligible for vesting pursuant to Section 2(b) shall be adjusted based on the following schedule:

Performance Measure	Goal(1)	Magnifier(2)

(1) The vesting percentage for performance between performance levels shall be determined based on linear interpolation.

(2) Based on whether the Company achieves or fails to achieve the applicable performance goal, Performance Share Units eligible for vesting pursuant to Sections 2(b) shall be increased or decreased in accordance with the percentages noted above.

(c) RTSR Performance Goal. Subject to the terms of this Agreement and the Plan, [INSERT TARGET NUMBER OF RTSR SHARES] of the Performance Share Units shall be eligible to vest based on the Company's achievement of RTSR during the Performance Period, as follows:

Performance Level(1)	RTSR Percentile Ranking	Percentage of Performance Share Units Eligible for Vesting(2)
Trigger	________	_____________
Target	________	_____________
Stretch	_______and above	_____________

(1) The vesting percentage for performance between performance levels shall be determined based on linear interpolation.

(2) The number of Performance Share Units that shall vest based on the Company's RTSR performance shall be subject to a performance magnifier as described below.

(3) Performance Magnifier. Subject to the terms of this Agreement and the Plan, the number of Performance Share Units eligible for vesting pursuant to Section 2(c) shall be adjusted based on the following schedule:

Performance Measure	Goal(1)	Magnifier(2)

(1) The vesting percentage for performance between performance levels shall be determined based on linear interpolation.

(2) Based on whether the Company achieves or fails to achieve the applicable performance goal, Performance Share Units eligible for vesting pursuant to Section 2(c) shall be increased or decreased in accordance with the percentages noted above.

(d) Maximum Vesting Level. Notwithstanding anything herein to the contrary, including performance determined under Sections 2(b)(3) and 2(c)(3), the maximum vesting level under this Award shall be capped at 200% of the target Performance Share Units.

(e) 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 the Company's disclosure thresholds; (y) pending transactions as a result of requirements to present operations as "held for sale" under Accounting Standard Codification 205; and (z) changes in law or accounting principles, in each case, as determined by the Committee.

(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 shall 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 approved by the Committee at its meeting on _________________, as adjusted to reflect corporate transactions with respect to peer group companies as approved by the Committee at such meeting.

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 Share Units credited to the Grantee's PSU 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 Share Units, based on the actual performance results for the Performance Period. Such *pro rata* portion of the Performance Share Units shall be determined by multiplying the number of Performance Share Units 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 Share Units. Such *pro rata* portion of the Performance Share Units shall be determined by multiplying the number of target Performance Share Units 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 completion of at least 10 years of continuous Service measured from the Grantee's most recent date of hire with the Company or an Affiliate.

(c) Change in Control. Notwithstanding the foregoing provisions, in the event of a Change in Control, the Performance Share 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 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 Share Units in the Grantee's PSU 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 Share Units 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 Share Units 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 Share Units, the Company shall transfer any Shares with respect to the vested Performance Share Units 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 Share Units, 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 Share Units. 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 Share Units (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 Share Units, 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 Share 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. The delivery of all or any Shares that relate to the Performance Share Units 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 Code 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 Code Section 409A.

Section 7. Restriction on Transferability. Except as otherwise provided under the Plan, until the Performance Share Units have vested under this Agreement, the Performance Share 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 Performance Share 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 PSU Account, any Shares or any other specific assets of the Company. All amounts credited to the Grantee's PSU 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 Performance Share Units subject to this Agreement, nor shall the Company have any obligation to issue any dividend or otherwise afford any rights to which Shares are entitled with respect to any such Performance Share 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 Performance Share Units is changed by reason of a reorganization, recapitalization, stock split or any of the other events described in the Plan (in each case as determined by the Committee), the number and kind of Performance Share Units and the performance goals, as applicable, 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 Performance Share Units may be replaced by Alternative Awards or forfeited in exchange for payment of cash in accordance with the Change in Control procedures and provisions of the Plan, as determined by the Committee.

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 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. 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. Code Section 409A Compliance. This Agreement and the Performance Share Units granted hereunder are intended to be exempt from Code Section 409A to the maximum extent possible, and shall be interpreted and construed accordingly.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF, the Company has caused the Performance Share Units subject to this Agreement to be granted, and the Grantee has accepted the Performance Share Units subject to the terms of the Agreement, as of the date first above written.

NiSource Inc.

____

By: __________________

Its: __________________

NiSource Inc.

20__ Omnibus Incentive Plan

20__ Performance Share Unit Award Agreement

This Performance Share Unit 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 or an Affiliate (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 Unit Award.** The Company hereby grants to the Grantee, on the terms and conditions hereinafter set forth, a target award of [TOTAL TARGET NUMBER] Performance Share Units. The Performance Share Units shall be represented by a bookkeeping entry with respect to the Grantee (the "PSU Account"), and each Performance Share Unit 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 and the Grantee remaining in continuous Service through the 28th day of February that follows each applicable Performance Period (each, a "Vesting Date"), the Performance Share Units shall vest in accordance with the schedule set forth below, based on the Company's RTSR performance over the _______ through ________ performance period (the "3-Year Performance Period"); provided, however, that the vesting of a portion of the Performance Share Units may be accelerated based on the Company's RTSR performance over the __________ through _______ performance period (the "2-Year Performance Period" and, together with the 3-Year Performance Period, the "Performance Periods") in accordance with the schedule set forth below. Notwithstanding the foregoing, the number of Performance Share Units eligible for vesting based on performance during the 2-Year Performance Period shall be limited to the product of: 67% multiplied by the target Performance Share Units multiplied by the vesting percentage determined based on the schedule below (the "2-Year Cap"). The number of Performance Share Units eligible for vesting based on the Company's RTSR performance during the 3-Year Performance Period shall be reduced by the number of Performance Share Units that vested and were settled with respect to the 2-Year Performance Period. For the avoidance of doubt, any Performance Share Units that vested and were settled with respect to the 2-Year Performance Period shall not, subject to Section 20.10 of the Plan, be reduced based on performance during the 3-Year Performance Period.

(b)

Performance Level(1)	**RTSR Percentile Ranking**	**Percentage of Performance Share Units Eligible for Vesting(2)**
Trigger	________	____________
Target	________	____________
Stretch	_______and above	____________

(1) The vesting level for performance between performance levels shall be determined based on linear interpolation.
(2) The number of Performance Share Units that shall vest based on the Company's RTSR performance shall be subject to (a) a performance magnifier as described in Section 2(b) below and (b) with respect to Performance Share Units that vest during the 2-Year Performance Period, the 2-Year Cap.

(c) Performance Magnifier. Subject to the terms of this Agreement and the Plan, the number of Performance Share Units eligible for vesting pursuant to Section 2(a) shall be adjusted based on the following schedule based on performance during the applicable Performance Period:

Performance Measure	**Goal(1)**	**Magnifier(2)**

(1) The vesting level for performance between performance levels shall be determined based on linear interpolation.

(2) Based on whether the Company achieves or fails to achieve the applicable performance goal, Performance Share Units eligible for vesting pursuant to Section 2(a) shall be increased or decreased in accordance with the percentages noted above, with any increase with respect to the 2-Year Performance Period, subject to the 2-Year Cap.

(d) Maximum Vesting Level. Notwithstanding anything herein to the contrary, including performance determined under Section 2(b), the maximum vesting level under this Award shall be capped at 200% of the target Performance Share Units.

(e) Definitions.

(i) "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 shall 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.

(ii) "TSR Peer Group" means the peer group of companies approved by the Committee at its meeting on _________________, as adjusted to reflect corporate transactions with respect to peer group companies as approved by the Committee at such meeting.

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 unvested Performance Share Units credited to the Grantee's PSU 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 Share Units, based on the actual performance results for the applicable Performance Period. Such *pro rata* portion of the Performance Share Units with respect to each Performance Period shall be determined by multiplying the number of Performance Share Units 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 from the Grant Date and the applicable Vesting Date, with any Performance Share Units vesting with respect to the 2-Year Performance Period pursuant to this Section 3(b)(i) subject to the 2-Year Cap.

(ii) If the Grantee terminates Service due to death prior to the Vesting Date and with more than 12 months remaining in the 3-Year 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 Share Units. Such *pro rata* portion of the Performance Share Units shall be determined by multiplying the number of target Performance Share Units 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 completion of at least 10 years of continuous Service measured from the Grantee's most recent date of hire with the Company or an Affiliate.

(c) Change in Control. Notwithstanding the foregoing provisions, in the event of a Change in Control, the Performance Share 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 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 Share Units in the Grantee's PSU Account into Shares and issue or deliver the total number of Shares due to the Grantee within 60 days following the applicable 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 Share Units 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 Share Units 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 Share Units, the Company shall transfer any Shares with respect to the vested Performance Share Units 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 Share Units, 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 Share Units. 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 Share Units (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 Share Units, 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 Share 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. The delivery of all or any Shares that relate to the Performance Share Units 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 Code 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 Code Section 409A.

Section 7. Restriction on Transferability. Except as otherwise provided under the Plan, until the Performance Share Units have vested under this Agreement, the Performance Share 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 Performance Share 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 PSU Account, any Shares or any other specific assets of the Company. All amounts credited to the Grantee's PSU 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 Performance Share Units subject to this Agreement, nor shall the Company have any obligation to issue any dividend or otherwise afford any rights to which Shares are entitled with respect to any such Performance Share 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 Performance Share Units is changed by reason of a reorganization, recapitalization, stock split or any of the other events described in the Plan (in each case as determined by the Committee), the number and kind of Performance Share Units and the performance goals, as applicable, 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 Performance Share Units may be replaced by Alternative Awards or forfeited in exchange for payment of cash in accordance with the Change in Control procedures and provisions of the Plan, as determined by the Committee.

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 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. 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. Code Section 409A Compliance. This Agreement and the Performance Share Units granted hereunder are intended to be exempt from Code Section 409A to the maximum extent possible, and shall be interpreted and construed accordingly.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF, the Company has caused the Performance Share Units subject to this Agreement to be granted, and the Grantee has accepted the Performance Share Units subject to the terms of the Agreement, as of the date first above written.

NiSource Inc.

____

By: __________________

Its: __________________

Exhibit 21

SUBSIDIARIES OF NISOURCE

as of December 31, 2020

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
RoseWater Wind Generation LLC	Indiana
RoseWater Wind Farm LLC	Delaware
Indiana Crossroads Wind Generation LLC	Indiana
Dunn's Bridge I Solar Generation LLC	Delaware
Dunn's Bridge II Solar Generation LLC	Delaware
Cavalry Solar Generation LLC	Delaware
Elliot Solar Generation LLC	Delaware
Fairbanks Solar Generation LLC	Delaware
Indiana Crossroads Solar Generation LLC	Delaware
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
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, 333-228102, 333-233382, 333-238501, 333-248405 on Form S-8, and Registration Statement Nos. 333-228790 and 333-228791 on Form S-4 of our reports dated February 17, 2021, relating to the consolidated 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, 2020.

/s/ DELOITTE & TOUCHE LLP
Columbus, Ohio
February 17, 2021

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 17, 2021	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 17, 2021	By:	/s/ Donald E. Brown
			Donald E. Brown
			Executive Vice President, Chief Financial Officer, and President of NiSource Corporate Services

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, 2020 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 17, 2021

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, 2020 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, Chief Financial Officer, and President of NiSource Corporate Services

Date: February 17, 2021

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

FORM 10-Q

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2009

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)

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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files.)
Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐

Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: Common Stock, $0.01 Par Value: 275,338,872 shares outstanding at July 31, 2009.

NISOURCE INC.
FORM 10-Q QUARTERLY REPORT
FOR THE QUARTER ENDED JUNE 30, 2009

Table of Contents

Table of Contents

DEFINED TERMS

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

NiSource Subsidiaries and Affiliates	
Bay State	Bay State Gas Company
Capital Markets	NiSource Capital Markets, Inc.
CER	Columbia Energy Resources, Inc.
CNR	Columbia Natural Resources, Inc.
Columbia	Columbia Energy Group
Columbia Energy Services	Columbia Energy Services Corporation
Columbia Gulf	Columbia Gulf Transmission Company
Columbia of Kentucky	Columbia Gas of Kentucky, Inc.
Columbia of Maryland	Columbia Gas of Maryland, Inc.
Columbia of Ohio	Columbia Gas of Ohio, Inc.
Columbia of Pennsylvania	Columbia Gas of Pennsylvania, Inc.
Columbia of Virginia	Columbia Gas of Virginia, Inc.
Columbia Transmission	Columbia Gas Transmission LLC
CORC	Columbia of Ohio Receivables Corporation
Crossroads Pipeline	Crossroads Pipeline Company
Granite State Gas	Granite State Gas Transmission, Inc.
Hardy Storage	Hardy Storage Company, L.L.C.
Kokomo Gas	Kokomo Gas and Fuel Company
Lake Erie Land	Lake Erie Land Company
Millennium	Millennium Pipeline Company, L.L.C.
NDC Douglas Properties	NDC Douglas Properties, Inc.
NiSource	NiSource Inc.
NiSource Corporate Services	NiSource Corporate Services Company
NiSource Development Company	NiSource Development Company, Inc.
NiSource Finance	NiSource Finance Corp.
Northern Indiana	Northern Indiana Public Service Company
Northern Indiana Fuel and Light	Northern Indiana Fuel and Light Company
Northern Utilities	Northern Utilities, Inc.
NRC	NIPSCO Receivables Corporation
PEI	PEI Holdings, Inc.
Whiting Clean Energy	Whiting Clean Energy, Inc.
Abbreviations	
AFUDC	Allowance for funds used during construction
Ameren	Ameren Services Company
AOC	Administrative Order by Consent
AOCI	Accumulated other comprehensive income
ARRs	Auction Revenue Rights
ASM	Ancillary Services Market
BART	Best Alternative Retrofit Technology
BBA	British Banker Association
Bcf	Billion cubic feet
Board	Board of Directors
BPAE	BP Alternative Energy North America Inc
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CARE	Conservation and Ratemaking Efficiency
CCGT	Combined Cycle Gas Turbine
CERCLA	Comprehensive Environmental Response Compensation and Liability Act (also known as Superfund)
Chesapeake	Chesapeake Appalachia, L.L.C.
CPCN	Certificate of Public Convenience and Necessity

DEFINED TERMS (continued)

Day 2	Began April 1, 2005 and refers to the operational control of the energy markets by MISO, including the dispatching of wholesale electricity and generation, managing transmission constraints, and managing the day-ahead, real-time and financial transmission rights markets
DOT	United States Department of Transportation
DSM	Demand Side Management
Dth	Dekatherm
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
ECR	Environmental Cost Recovery
ECRM	Environmental Cost Recovery Mechanism
ECT	Environmental cost tracker
EER	Environmental Expense Recovery
EERM	Environmental Expense Recovery Mechanism
EPA	United States Environmental Protection Agency
EPS	Earnings per share
FAC	Fuel adjustment clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN 47	FASB Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations”
FIN 48	FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes”
FSP	FASB Staff Position
FSP FAS 107-1 and APB 28-1	FASB Staff Position FAS 107-1 and APB 28-1: Interim Disclosures about Fair Value of Financial Instruments
FSP FAS 115-2 and FAS 124-2	FASB Staff Position FAS 115-2 and FAS 124-2: Recognition and Presentation of Other-Than-Temporary Impairments
FSP FAS 132(R)-1	FASB Staff Position FAS 132 (R)-1: Employers’ Disclosures About Postretirement Benefit Plan Assets
FSP FAS 140-4 and FIN 46(R)-8	FASB Staff Position FAS 140-4 and FASB Interpretation No. 46(R): Disclosures about Transfers of Financial Assets and Interests in Variable Interest Entities
FSP FAS 141(R)-1	FASB Staff Position FAS 141(R)-1: Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies
FSP FAS 157-2	FASB Staff Position FAS 157-2: Effective Date of FASB Statement No. 157
FSP FAS 157-3	FASB Staff Position FAS 157-3: Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active
FSP FAS 157-4	FASB Staff Position FAS 157-4: Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly
FTRs	Financial Transmission Rights
GAAP	U.S. Generally Accepted Accounting Principles
gwh	Gigawatt hours
hp	Horsepower
IDEM	Indiana Department of Environmental Management
IURC	Indiana Utility Regulatory Commission
LDCs	Local distribution companies
LIBOR	London InterBank Offered Rate
LIFO	Last-in, first-out
MGP	Manufactured gas plant
MISO	Midwest Independent Transmission System Operator
MMDth	Million dekatherms

Table of Contents

DEFINED TERMS (continued)

mw	Megawatts
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NOx	Nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income (Loss)
OPEB	Other postretirement benefits
OUCC	Indiana Office of Utility Consumer Counselor
PADEP	Pennsylvania Department of Environmental Protection
PCB	Polychlorinated biphenyls
Piedmont	Piedmont Natural Gas Company, Inc.
PIPP	Percentage of Income Plan
PPUC	Pennsylvania Public Utility Commission
PSC	Public Service Commission
PUCO	Public Utilities Commission of Ohio
RCRA	Resource Conservation and Recovery Act
RSG	Revenue Sufficiency Guarantee
SAB No. 92	Staff Accounting Bulletin No. 92, “Accounting and Disclosures Relating to Loss Contingencies”
SEC	Securities and Exchange Commission
SFAS No. 5	Statement of Financial Accounting Standards No. 5, “Accounting for Contingencies”
SFAS No. 71	Statement of Financial Accounting Standards No. 71, “Accounting for the Effects of Certain Types of Regulation”
SFAS No. 109	Statement of Financial Accounting Standards No. 109, “Accounting for Income Taxes”
SFAS No. 131	Statement of Financial Accounting Standards No. 131, “Disclosures about Segments of an Enterprise and Related Information”
SFAS No. 132(R)	Statement of Financial Accounting Standards No. 132(R), “Employers’ Disclosures about Pensions and Other Postretirement Benefits — an amendment of FASB No. 87, 88, and 106”
SFAS No. 133	Statement of Financial Accounting Standards No. 133, “Accounting for Derivative Instruments and Hedging Activities,” as amended
SFAS No. 140	Statement of Financial Accounting Standards No. 140, “Accounting for Transfers and Servicing of Financial Asset and Extinguishments of Liabilities”
SFAS No. 141R	Statement of Financial Accounting Standards No. 141R, “Business Combinations”
SFAS No. 142	Statement of Financial Accounting Standards No. 142, “Goodwill and Other Intangible Assets”
SFAS No. 143	Statement of Financial Accounting Standards No. 143, “Accounting for Asset Retirement Obligations”
SFAS No. 157	Statement of Financial Accounting Standards No. 157, “Fair Value Measurement”
SFAS No. 160	Statement of Financial Accounting Standards No. 160, “Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB No. 51”
SFAS No. 161	Statement of Financial Accounting Standards No. 161, “Disclosures about Derivative Instruments and Hedging — an amendment of SFAS No. 133”
SFAS No. 165	Statement of Financial Accounting Standards No. 165, “Subsequent Events”

DEFINED TERMS (continued)

SFAS No. 166	Statement of Financial Accounting Standards No. 166, "Accounting for Transfers of Financial Assets an amendment of FASB Statement No. 140"
SFAS No. 167	Statement of Financial Accounting Standards No. 167, "Amendments to FASB Interpretation No. 46(R)"
SFAS No. 168	Statement of Financial Accounting Standards No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles a replacement of FASB Statement No. 162"
SIP	State Implementation Plan
SO2	Sulfur dioxide
SOP 96-1	Statement of Position 96-1, "Environmental Remediation Liabilities"
VaR	Value-at-risk and instrument sensitivity to market factors
VSCC	Virginia State Corporation Commission

PART I

ITEM 1. FINANCIAL STATEMENTS

NISOURCE INC.
Condensed Statements of Consolidated Income (Loss) (unaudited)

(in millions, except per share amounts)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Net Revenues				
Gas Distribution	**$ 448.8**	$ 928.1	**$ 2,171.7**	$ 3,164.9
Gas Transportation and Storage	**260.9**	236.1	**657.5**	594.3
Electric	**285.4**	339.9	**582.2**	671.7
Other	**14.1**	53.1	**36.4**	105.1
Gross Revenues	**1,009.2**	1,557.2	**3,447.8**	4,536.0
Cost of Sales (excluding depreciation and amortization)	**338.2**	892.0	**1,713.1**	2,833.8
Total Net Revenues	**671.0**	665.2	**1,734.7**	1,702.2
Operating Expenses				
Operation and maintenance	**363.7**	343.5	**841.8**	752.9
Depreciation and amortization	**148.2**	147.6	**291.9**	283.1
Impairment and (gain)/loss on sale of assets, net	**-**	(0.9)	**(2.0)**	(2.4)
Other taxes	**52.6**	62.2	**154.7**	164.3
Total Operating Expenses	**564.5**	552.4	**1,286.4**	1,197.9
Equity Earnings (Loss) in Unconsolidated Affiliates	**(2.6)**	1.6	**3.8**	3.6
Operating Income	**103.9**	114.4	**452.1**	507.9
Other Income (Deductions)				
Interest expense, net	**(105.3)**	(87.4)	**(195.8)**	(179.2)
Gain (Loss) on early extinguishment of long-term debt	**(0.7)**	-	**2.5**	-
Other, net	**(0.5)**	1.3	**(4.7)**	(0.4)
Total Other Income (Deductions)	**(106.5)**	(86.1)	**(198.0)**	(179.6)
Income (Loss) From Continuing Operations Before Income Taxes	**(2.6)**	28.3	**254.1**	328.3
Income Taxes	**6.1**	8.6	**103.5**	120.0
Income (Loss) from Continuing Operations	**(8.7)**	19.7	**150.6**	208.3
Income (Loss) from Discontinued Operations - net of taxes	**12.7**	(219.2)	**2.0**	(212.4)
Loss on Disposition of Discontinued Operations - net of taxes	**(8.8)**	(2.8)	**(9.0)**	(98.9)
Net Income (Loss)	**$ (4.8)**	$ (202.3)	**$ 143.6**	$ (103.0)
Basic Earnings (Loss) Per Share				
Continuing operations	**$ (0.03)**	$ 0.07	**$ 0.55**	$ 0.76
Discontinued operations	**0.01**	(0.81)	**(0.03)**	(1.14)
Basic Earnings (Loss) Per Share	**$ (0.02)**	$ (0.74)	**$ 0.52**	$ (0.38)
Diluted Earnings (Loss) Per Share				
Continuing operations	**$ (0.03)**	$ 0.07	**$ 0.54**	$ 0.76
Discontinued operations	**0.01**	(0.80)	**(0.02)**	(1.13)
Diluted Earnings (Loss) Per Share	**$ (0.02)**	$ (0.73)	**$ 0.52**	$ (0.37)
Dividends Declared Per Common Share	**$ 0.23**	$ 0.23	**$ 0.69**	$ 0.69
Basic Average Common Shares Outstanding	**274.7**	274.0	**274.4**	273.9
Diluted Average Common Shares	**274.7**	275.4	**277.0**	275.4

The accompanying Notes to Condensed Consolidated Financial Statements (unaudited) are an integral part of these statements.

ITEM 1. FINANCIAL STATEMENTS (continued)

NISOURCE INC.
Condensed Consolidated Balance Sheets (unaudited)

(in millions)	**June 30, 2009**	December 31, 2008
ASSETS		
Property, Plant and Equipment		
Utility Plant	**$ 18,664.8**	$ 18,356.8
Accumulated depreciation and amortization	**(8,232.9)**	(8,080.8)
Net utility plant	**10,431.9**	10,276.0
Other property, at cost, less accumulated depreciation	**111.2**	112.1
Net Property, Plant and Equipment	**10,543.1**	10,388.1
Investments and Other Assets		
Assets of discontinued operations and assets held for sale	**180.3**	178.3
Unconsolidated affiliates	**146.4**	86.8
Other investments	**111.6**	117.9
Total Investments and Other Assets	**438.3**	383.0
Current Assets		
Cash and cash equivalents	**248.9**	20.6
Restricted cash	**64.2**	79.9
Accounts receivable (less reserve of $59.0 and $43.9, respectively)	**544.7**	1,027.0
Gas inventory	**247.0**	511.8
Underrecovered gas and fuel costs	**1.8**	180.2
Materials and supplies, at average cost	**98.4**	95.1
Electric production fuel, at average cost	**81.2**	63.7
Price risk management assets	**24.5**	118.3
Exchange gas receivable	**163.7**	371.6
Regulatory assets	**286.3**	314.9
Assets of discontinued operations and assets held for sale	**495.7**	416.8
Prepayments and other	**180.3**	217.7
Total Current Assets	**2,436.7**	3,417.6
Other Assets		
Price risk management assets	**70.7**	95.7
Regulatory assets	**1,597.3**	1,640.4
Goodwill	**3,677.3**	3,677.3
Intangible assets	**325.1**	330.6
Postretirement and postemployment benefits assets	**9.2**	10.3
Deferred charges and other	**125.6**	123.5
Total Other Assets	**5,805.2**	5,877.8
Total Assets	**$ 19,223.3**	$ 20,066.5

The accompanying Notes to Condensed Consolidated Financial Statements (unaudited) are an integral part of these statements.

ITEM 1. FINANCIAL STATEMENTS (continued)

NISOURCE INC.
Condensed Consolidated Balance Sheets (unaudited) (continued)

(in millions, except share amounts)	**2009**	2008
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common Stockholders' Equity		
Common stock - $0.01 par value, 400,000,000 shares authorized; 275,148,454 and 274,261,799 shares issued and outstanding, respectively	**$ 2.8**	$ 2.7
Additional paid-in capital	**4,032.7**	4,020.3
Retained earnings	**855.1**	901.1
Accumulated other comprehensive loss	**(74.0)**	(172.0)
Treasury stock	**(24.2)**	(23.3)
Total Common Stockholders' Equity	**4,792.4**	4,728.8
Long-term debt, excluding amounts due within one year	**6,564.4**	5,943.9
Total Capitalization	**11,356.8**	10,672.7
Current Liabilities		
Current portion of long-term debt	**424.0**	469.3
Short-term borrowings	**-**	1,163.5
Accounts payable	**240.9**	606.9
Dividends declared	**63.3**	-
Customer deposits	**125.4**	125.6
Taxes accrued	**209.1**	206.5
Interest accrued	**125.4**	120.1
Overrecovered gas and fuel costs	**424.4**	35.9
Price risk management liabilities	**101.1**	237.5
Exchange gas payable	**319.4**	555.5
Deferred revenue	**20.2**	4.3
Regulatory liabilities	**35.1**	40.4
Accrued liability for postretirement and postemployment benefits	**7.1**	6.4
Liabilities of discontinued operations and liabilities held for sale	**261.2**	158.1
Temporary LIFO liquidation credit	**8.3**	-
Legal and environmental reserves	**328.3**	375.1
Other accruals	**249.2**	486.1
Total Current Liabilities	**2,942.4**	4,591.2
Other Liabilities and Deferred Credits		
Price risk management liabilities	**5.1**	17.9
Deferred income taxes	**1,672.1**	1,576.4
Deferred investment tax credits	**42.9**	46.1
Deferred credits	**73.0**	76.7
Deferred revenue	**7.3**	6.2
Accrued liability for postretirement and postemployment benefits	**1,254.4**	1,238.5
Liabilities of discontinued operations and liabilities held for sale	**163.6**	174.9
Regulatory liabilities and other removal costs	**1,413.4**	1,386.1
Asset retirement obligations	**127.5**	126.0
Other noncurrent liabilities	**164.8**	153.8
Total Other Liabilities and Deferred Credits	**4,924.1**	4,802.6
Commitments and Contingencies (Refer to Note 17)	**-**	-
Total Capitalization and Liabilities	**$ 19,223.3**	$ 20,066.5

The accompanying Notes to Condensed Consolidated Financial Statements (unaudited) are an integral part of these statements.

ITEM 1. FINANCIAL STATEMENTS (continued)

NISOURCE INC.
Condensed Statements of Consolidated Cash Flows (unaudited)

Six Months Ended June 30, *(in millions)*	**2009**	2008
Operating Activities		
Net Income	**$ 143.6**	$ (103.0)
Adjustments to Reconcile Net Income to Net Cash from Continuing Operations:		
Gain on Early Extinguishment of Debt	**(2.5)**	-
Depreciation and Amortization	**291.9**	283.1
Net Changes in Price Risk Management Assets and Liabilities	**1.7**	19.4
Deferred Income Taxes and Investment Tax Credits	**34.1**	52.2
Deferred Revenue	**15.9**	(16.7)
Stock Compensation Expense	**4.9**	4.5
Gain on Sale of Assets	**(2.0)**	(4.1)
Loss on Impairment of Assets	**-**	1.6
Income from Unconsolidated Affiliates	**(3.8)**	(1.1)
Loss on Disposition of Discontinued Operations - Net of Taxes	**9.0**	98.9
Loss (Income) from Discontinued Operations - Net of Taxes	**(2.0)**	212.4
Amortization of Discount/Premium on Debt	**6.2**	3.7
AFUDC Equity	**-**	(4.1)
Changes in Assets and Liabilities:		
Accounts Receivable	**413.2**	207.1
Inventories	**219.3**	361.9
Accounts Payable	**(327.1)**	(49.8)
Customer Deposits	**(0.2)**	(0.4)
Taxes Accrued	**81.9**	10.8
Interest Accrued	**5.3**	0.6
(Under) Overrecovered Gas and Fuel Costs	**566.8**	(195.9)
Exchange Gas Receivable/Payable	**(22.4)**	15.0
Other Accruals	**(213.3)**	(149.0)
Prepayments and Other Current Assets	**20.7**	11.0
Regulatory Assets/Liabilities	**52.2**	(53.7)
Postretirement and Postemployment Benefits	**19.0**	5.0
Deferred Credits	**(7.7)**	1.7
Deferred Charges and Other NonCurrent Assets	**0.7**	(11.2)
Other NonCurrent Liabilities	**11.8**	(30.6)
Net Operating Activities from Continuing Operations	**1,317.2**	669.3
Net Operating Activities used for Discontinued Operations	**(77.0)**	(30.9)
Net Cash Flows from Operating Activities	**1,240.2**	638.4
Investing Activities		
Capital Expenditures	**(385.6)**	(448.7)
Sugar Creek purchase	**-**	(329.7)
Insurance Recoveries	**54.6**	25.9
Proceeds from Disposition of Assets	**2.1**	229.6
Restricted Cash	**15.7**	90.1
Other Investing Activities	**(29.4)**	(2.1)
Net Investing Activities used for Continuing Operations	**(342.6)**	(434.9)
Net Investing Activities from Discontinued Operations	**22.7**	47.3
Net Cash Flows used for Investing Activities	**(319.9)**	(387.6)
Financing Activities		
Issuance of Long-Term Debt	**963.5**	706.0
Retirement of Long-Term Debt	**(364.9)**	(12.0)
Repurchase of Long-Term Debt	**-**	(254.0)
Change in Short-Term Debt, Net	**(1,163.5)**	(555.0)
Issuance of Common Stock	**0.4**	0.8
Acquisition of Treasury Stock	**(0.9)**	(0.2)
Dividends Paid - Common Stock	**(126.2)**	(126.1)
Net Cash Flows used for Financing Activities	**(691.6)**	(240.5)
Increase in cash and cash equivalents from continuing operations	**283.0**	(6.1)
Cash (contributions to) receipts from discontinued operations	**(54.7)**	17.4
Cash and cash equivalents at beginning of period	**20.6**	34.6
Cash and Cash Equivalents at End of Period	**$ 248.9**	$ 45.9

The accompanying Notes to Condensed Consolidated Financial Statements (unaudited) are an integral part of these statements.

ITEM 1. FINANCIAL STATEMENTS (continued)

NISOURCE INC.
Condensed Statements of Consolidated Comprehensive Income (Loss) (unaudited)

(in millions, net of taxes)	Three Months Ended June 30, **2009**	Three Months Ended June 30, 2008	Six Months Ended June, 30 **2009**	Six Months Ended June, 30 2008
Net Income (Loss)	**$ (4.8)**	$ (202.3)	**$ 143.6**	$ (103.0)
Other comprehensive income				
Net gain (loss) on available for sale securities (a)	**1.5**	(0.7)	**0.2**	(2.0)
Net unrealized gains on cash flow hedges (b)	**111.1**	10.0	**96.6**	27.3
Unrecognized pension benefit and OPEB costs (c)	**0.6**	0.6	**1.2**	(3.0)
Total other comprehensive income	**113.2**	9.9	**98.0**	22.3
Total Comprehensive Income (Loss)	**$ 108.4**	$ (192.4)	**$ 241.6**	$ (80.7)

(a) Net unrealized gain (loss) on available for sale securities, net of $1.1 million tax expense and $0.5 million tax benefit in the second quarter of 2009 and 2008, respectively, and $0.3 million tax expense and $1.3 million tax benefit for the first six months of 2009 and 2008, respectively.

(b) Net unrealized gain on derivatives qualifying as cash flow hedges, net of $74.9 million and $6.8 million tax expense in second quarter of 2009 and 2008, respectively, and $64.7 million and $18.7 million tax expense for the first six months of 2009 and 2008, respectively.

(c) Unrecognized pension benefit and OPEB costs recorded to accumulated other comprehensive income, net of $0.4 million and $0.8 tax expense in second quarter of 2009 and 2008, respectively, and $0.7 million tax expense and $1.8 million tax benefit for the first six months of 2009 and 2008, respectively.

The accompanying Notes to Condensed Consolidated Financial Statements (unaudited) are an integral part of these statements.

ITEM 1. FINANCIAL STATEMENTS (continued)

NISOURCE INC.
Notes to Condensed Consolidated Financial Statements (unaudited)

1. Basis of Accounting Presentation

The accompanying unaudited condensed consolidated financial statements for NiSource reflect all normal recurring adjustments that are necessary, in the opinion of management, to present fairly the results of operations in accordance with GAAP in the United States of America.

The accompanying financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in NiSource's Annual Report on Form 10-K for the fiscal year ended December 31, 2008. Income for interim periods may not be indicative of results for the calendar year due to weather variations and other factors.

The following unaudited condensed consolidated financial statements have been prepared pursuant to the rules and regulations of the SEC. Certain information and note disclosures normally included in annual financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to those rules and regulations, although NiSource believes that the disclosures made are adequate to make the information not misleading.

NiSource's management has performed an evaluation of subsequent events through August 4, 2009, which is the date the financial statements were issued.

2. Recent Accounting Pronouncements

Recently Adopted Accounting Pronouncements

SFAS No. 165 – Subsequent Events. In May 2009, the FASB issued SFAS No. 165. The standard does not require significant changes regarding recognition or disclosure of subsequent events, but does require disclosure of the date through which subsequent events have been evaluated for purposes of disclosure and accounting recognition. The standard was effective for financial statements issued after June 15, 2009. The adoption of this standard on April 1, 2009 did not have a material impact on the Condensed Consolidated Financial Statements (unaudited).

SFAS No. 161 – Disclosures about Derivative Instruments and Hedging — an amendment of SFAS No. 133. In March 2008, the FASB issued SFAS No. 161 to amend and expand the disclosure requirements of SFAS No. 133 with the intent to provide users of the financial statements with an enhanced understanding of how and why an entity uses derivative instruments, how these derivatives are accounted for and how the respective reporting entity's financial statements are affected. SFAS No. 161 is effective for fiscal years and interim periods beginning after November 15, 2008, and earlier application is encouraged. NiSource adopted this standard on January 1, 2009. Refer to Note 9, "Risk Management Activities," in the Notes to Condensed Consolidated Financial Statements (unaudited) for additional information.

SFAS No. 160 - Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB No. 51. In December 2007, the FASB issued SFAS No. 160 to improve the relevance, comparability, and transparency of the financial information that a reporting entity provides in its consolidated financial statements regarding non-controlling ownership interests in a business and for the deconsolidation of a subsidiary. This Statement was effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 and earlier adoption is prohibited. The adoption of this standard on January 1, 2009 did not have a material impact on the Condensed Consolidated Financial Statements (unaudited).

SFAS No. 157 – Fair Value Measurements. In September 2006, the FASB issued SFAS No. 157 to define fair value, establish a framework for measuring fair value and to expand disclosures about fair value measurements. SFAS No. 157 does not change the requirements to apply fair value in existing accounting standards.

Under SFAS No. 157, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts.

NISOURCE INC.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

The standard clarifies that fair value should be based on the assumptions market participants would use when pricing the asset or liability.

The adoption of SFAS No. 157 did not have an impact on NiSource's January 1, 2008 balance of retained earnings.

In February 2008, the FASB issued FSP FAS 157-2, which delayed the effective date of SFAS No. 157 for all nonrecurring fair value measurements of non-financial assets and liabilities until fiscal years beginning after November 15, 2008.

In October 2008, the FASB issued FSP FAS 157-3, which clarified the application of SFAS No. 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. The FSP was effective upon issuance, including prior periods for which financial statements have not been issued.

In April 2009, the FASB issued FSP FAS 157-4 to provide additional guidance for estimating fair value when the volume and level of activity for the asset or liability have significantly decreased. This FSP is effective for interim reporting periods ending after June 15, 2009, with early adoption permitted. NiSource adopted this FSP on April 1, 2009.

Refer to Note 10, "Fair Value Assets and Liabilities," in the Notes to Condensed Consolidated Financial Statements (unaudited) for additional information regarding the adoption of SFAS No. 157.

SFAS No. 141R – Business Combinations. In December 2007, the FASB issued SFAS No. 141R to improve the relevance, representational faithfulness, and comparability of information that a reporting entity provides in its financial reports regarding business combinations and its effects, including recognition of assets and liabilities, the measurement of goodwill and required disclosures. This Statement was effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 and earlier adoption is prohibited. The adoption of this standard on January 1, 2009 did not have a material impact on the Condensed Consolidated Financial Statements (unaudited).

In April 2009, the FASB issued FSP FAS 141(R)-1, which amends and clarifies SFAS No. 141 to address application issues on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This FSP was effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008.

FSP FAS 140-4 and FIN 46(R)-8 – FASB Staff Position Amendment of FASB Statement No. 140 and FASB Interpretation No. 46(R). In December 2008, the FASB issued FSP FAS 140-4 and FIN 46(R)-8 to require public entities to provide additional disclosures about transfers of financial assets and to provide additional disclosures related to an entity's involvement with variable interest entities. This FSP was effective for the first reporting period ending after December 15, 2008, with early application encouraged. The adoption of this FSP on January 1, 2009 did not have a material impact on the Condensed Consolidated Financial Statements (unaudited). Refer to Note 11, "Transfers of Financial Assets," in the Notes to Condensed Consolidated Financial Statements (unaudited) for additional information regarding FSP FAS 140-4.

FSP FAS 115-2 and FAS 124-2 – FASB Staff Position Amendment of FASB Statement No. 115 and FASB Statement No. 124. In April 2009, the FASB issued FSP FAS 115-2 and FAS 124-2 to amend the other-than-temporary impairment guidance in GAAP for debt securities to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. This FSP is effective for interim reporting periods ending after June 15, 2009, with early adoption permitted. The adoption of this FSP on April 1, 2009 did not have a material impact on the Condensed Consolidated Financial Statements (unaudited).

FSP FAS 107-1 and APB 28-1 – FASB Staff Position Amendment of FASB Statement No. 107 and APB Opinion No. 28. In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1 to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as annual financial statements. This FSP is effective for interim reporting periods ending after June 15, 2009, with early adoption permitted. NiSource adopted this FSP on April 1, 2009. As this FSP provides only disclosure requirements, the application of this standard did not have a material impact on the Condensed Consolidated Financial Statements (unaudited). Refer to Note 10, "Fair Value Assets and Liabilities," in the Notes to Condensed Consolidated Financial Statements (unaudited) for additional information regarding FSP FAS 107-1.

Recently Issued Accounting Pronouncements

SFAS No. 168 – The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles a replacement of FASB Statement No. 162. In June 2009, the FASB issued SFAS No. 168 to address the new authoritative GAAP recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. On the effective date of this Statement, the Codification will supersede all then-existing non-SEC accounting and reporting standards. All other non-grandfathered non-SEC accounting literature not included in the Codification will become non-authoritative. Following this Statement, the FASB will not issue new standards in the form of Statements, FASB Staff Positions, or Emerging Issues Task Force Abstracts; rather, it will issue Accounting Standards Updates. This Statement is effective for financial statements issued for interim and annual periods ending after September 15, 2009. This Statement does not change GAAP and will not have a material impact on NiSource.

SFAS No. 167 – Amendments to FASB Interpretation No. 46(R). In June 2009, the FASB issued SFAS No. 167 to amend certain requirements of FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities, to improve financial reporting by enterprises involved with variable interest entities and to provide more relevant and reliable information to users of financial statements. This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on the first fiscal year that begins after November 15, 2009 with early adoption prohibited. NiSource is currently reviewing the additional requirements to determine the impact on the Condensed Consolidated Financial Statements (unaudited) and Notes to Condensed Consolidated Financial Statements.

SFAS No. 166 – Accounting for Transfers of Financial Assets an amendment of FASB Statement No. 140. In June 2009, the FASB issued SFAS No. 166 to amend the derecognition guidance in Statement 140 to improve the relevance, representational faithfulness, and comparability of the information that a reporting entity provides in its financial statements about a transfer of financial assets; the effects of a transfer on its financial position, financial performance, and cash flows; and a transferor's continuing involvement, if any, in transferred financial assets. This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on the first fiscal year that begins after November 15, 2009 with early adoption prohibited. NiSource is currently reviewing the accounting and additional disclosure requirements to determine the impact on the Condensed Consolidated Financial Statements (unaudited) and Notes to Condensed Consolidated Financial Statements. This Statement may require sales of accounts receivable, under the accounts receivable program discussed in Note 11, "Transfers of Financial Assets," in the Notes to Condensed Consolidated Financial Statements (unaudited) to be recorded as debt on the Consolidated Balance Sheets effective January 1, 2010.

FSP FAS 132(R)-1 - FASB Staff Position Amendment of FASB Statement No. 132(R)-1. In December 2008, the FASB issued FSP FAS 132 (R)-1 to amend SFAS No. 132(R), to provide guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan. FSP FAS 132(R)-1 is effective for fiscal years ending after December 15, 2009 with earlier adoption permitted. NiSource is currently reviewing the additional disclosure requirements to determine the impact on the Condensed Consolidated Financial Statements (unaudited) and Notes to Condensed Consolidated Financial Statements.

ITEM 1. FINANCIAL STATEMENTS (continued)

NISOURCE INC.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

3. Earnings Per Share

Basic EPS is computed by dividing income available to common stockholders by the weighted-average number of shares of common stock outstanding for the period. The weighted average shares outstanding for diluted EPS include the incremental effects of the various long-term incentive compensation plans. The numerator in calculating both basic and diluted EPS for each period is reported net income. The computation for the three months ended June 30, 2009 is not presented since NiSource had a loss from continuing operations and net loss on the Condensed Statements of Consolidated Income (Loss) (unaudited) during that period. The computation of diluted average common shares follows:

(in thousands)	Three Months Ended June 30, 2008	Six Months Ended June 30, **2009**	Six Months Ended June 30, 2008
Denominator			
Basic average common shares outstanding	273,973	**274,446**	273,947
Dilutive potential common shares			
Shares contingently issuable under employee stock plans	1,230	**2,400**	1,230
Shares restricted under employee stock plans	192	**108**	180
Diluted Average Common Shares	275,395	**276,954**	275,357

4. Restructuring Activities

In response to the current economic conditions, in February 2009, NiSource announced an organizational restructuring of the Gas Transmission and Storage Operations segment. NiSource is eliminating positions across the 16 state operating territory of Gas Transmission and Storage. The reductions will occur through voluntary programs and involuntary separations. In addition to employee reductions, the Gas Transmission and Storage Operations segment will take steps to achieve additional cost savings by efficiently managing its various business locations, reducing its fleet operations, creating alliances with third party service providers, and implementing other changes in line with its strategic plan for growth and maximizing value of existing assets. During the first half of 2009, NiSource recorded a pre-tax restructuring charge, net of adjustments, of $19.8 million to “Operation and maintenance” expense on the Condensed Statement of Consolidated Income (Loss) (unaudited), which primarily includes costs related to severance and other employee related costs for approximately 360 employees. As of June 30, 2009, 246 employees had been severed from employment. NiSource expects this restructuring initiative to be substantially complete by the end of 2009.

Restructuring reserve by restructuring initiative:

(in millions)	Balance at December 31, 2008	Additions	Benefits Paid	Adjustments	Balance at June 30, 2009
Gas Transmission and Storage initiative	$ -	$ 20.4	$ (14.1)	$ (0.6)	**$ 5.7**
Total	$ -	$ 20.4	$ (14.1)	$ (0.6)	**$ 5.7**

5. Gas in Storage

Gas Distribution Operations prices natural gas storage injections at the average of the costs of natural gas supply purchased during the year. For interim periods, the difference between current projected replacement cost and the LIFO cost for quantities of gas temporarily withdrawn from storage is recorded as a temporary LIFO liquidation credit or debit within the Condensed Consolidated Balance Sheets (unaudited). Due to seasonality requirements, NiSource expects interim variances in LIFO layers to be replenished by year-end. Changes between the temporary LIFO liquidation credits in the amounts of $8.3 million and $174.8 million during the first six months of 2009 and

NiSource Inc.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

2008, respectively, are considered a non-cash activity for the Condensed Statements of Consolidated Cash Flow (unaudited). In addition to the temporary LIFO liquidation credit described above NiSource also has a temporary LIFO liquidation debit of $31.4 million recorded for the first six months of 2009 for certain gas distribution companies recorded within, "Prepayments and other," on the Condensed Consolidated Balance Sheets (unaudited).

6. Discontinued Operations and Assets and Liabilities Held for Sale

The assets and liabilities of discontinued operations and held for sale on the Condensed Consolidated Balance Sheet (unaudited) at June 30, 2009 were:

(in millions)

Assets of discontinued operations and held for sale:	Property, plant and equipment, net	Accounts receivable, net	Price Risk assets	Restricted cash	Other assets	**Total**
Unregulated Natural Gas Marketing	$ 0.7	$ 39.1	$ 397.0	$ 191.2	$ 22.5	**$ 650.5**
Lake Erie Land	11.9	-	-	-	-	**11.9**
NiSource Corporate Services	6.2	-	-	-	-	**6.2**
NDC Douglas Properties	3.6	-	-	-	1.2	**4.8**
Columbia Transmission	2.6	-	-	-	-	**2.6**
Total	**$ 25.0**	**$ 39.1**	**$ 397.0**	**$ 191.2**	**$ 23.7**	**$ 676.0**

Liabilities of discontinued operations and held for sale:	Debt	Accounts payable	Price risk liabilities	Tax liabilities	Other liabilities	**Total**
Unregulated Natural Gas Marketing	$ -	$ 32.1	$ 376.2	$ 8.4	$ 2.6	**$ 419.3**
NDC Douglas Properties	4.9	0.4	-	-	0.2	**5.5**
Total	**$ 4.9**	**$ 32.5**	**$ 376.2**	**$ 8.4**	**$ 2.8**	**$ 424.8**

The assets and liabilities of discontinued operations and held for sale on the Consolidated Balance Sheet at December 31, 2008 were:

(in millions)

Assets of discontinued operations and held for sale:	Property, plant and equipment, net	Accounts receivable, net	Price risk assets	Restricted cash	Other assets	**Total**
Unregulated Natural Gas Marketing	$ 0.6	$ 123.7	$ 137.1	$ 206.7	$ 80.4	**$ 548.5**
Bay State Gas Company	20.8	-	-	-	-	**20.8**
Lake Erie Land	11.9	-	-	-	-	**11.9**
NiSource Corporate Services	6.2	-	-	-	-	**6.2**
NDC Douglas Properties	4.1	-	-	-	1.0	**5.1**
Columbia Transmission	2.6	-	-	-	-	**2.6**
Total	**$ 46.2**	**$ 123.7**	**$ 137.1**	**$ 206.7**	**$ 81.4**	**$ 595.1**

Liabilities of discontinued operations and held for sale:	Debt	Accounts payable	Price risk liabilities	Tax liabilities	Other liabilities	**Total**
Unregulated Natural Gas Marketing	$ -	$ 94.6	$ 219.6	$ -	$ 13.5	**$ 327.7**
NDC Douglas Properties	4.9	0.2	-	-	0.2	**5.3**
Total	**$ 4.9**	**$ 94.8**	**$ 219.6**	**$ -**	**$ 13.7**	**$ 333.0**

Assets classified as discontinued operations or held for sale are no longer depreciated.

NiSource is engaged in a process to sell its unregulated natural gas marketing business. Net assets for the unregulated natural gas marketing business of $231.2 million have been accounted for as assets and liabilities of discontinued operations and the results of operations and cash flows of the unregulated natural gas marketing business were classified as discontinued operations for all periods presented. As a result of the letter of intent signed during the second quarter of 2009, an impairment loss of $8.8 million, net of tax, was recognized during the second quarter of 2009.

Lake Erie Land, which is wholly-owned by NiSource, is in the process of selling real estate to a private real estate development group. NiSource accounts for the assets expected to be sold to the private developer during the next twelve months as assets held for sale. In the second quarter of 2009, the developer was unable to meet certain contractual obligations under the sale agreement, specifically the payment of an $11 million note receivable that was due on June 13, 2009. NiSource granted a limited extension for the payment of the note and began negotiations with another potential party to replace the original developer. In July 2009, NiSource signed a Letter of Intent with the new potential party. Based on the most probable scenarios as of June 30, 2009, the Lake Erie Land assets continue to meet criteria for assets held for sale.

NiSource Corporate Services is continuing to work with several potential buyers to sell its Marble Cliff facility. A third party appraisal was performed in December 2008 with an estimated market value of the property of $6.2 million, which equals the book value. NiSource has accounted for this facility as assets held for sale.

NDC Douglas Properties, a subsidiary of NiSource Development Company, is in the process of exiting some of its low income housing investments. NiSource has accounted for the investments to be sold as assets and liabilities of discontinued operations and held for sale.

On June 18, 2009, Columbia Transmission received approval from the FERC to abandon by sale to an unaffiliated third party its Line R System in West Virginia, which includes certain natural gas pipeline and compression facilities. These assets held for sale have a net book value of $2.4 million. The sale transaction is expected to close sometime during the second half of 2009. Columbia Transmission continues to pursue FERC approval on the sale of certain other non-core assets.

On June 30, 2008, NiSource sold Whiting Clean Energy to BPAE for $216.7 million, which included $16.1 million in working capital. In the first quarter of 2008, NiSource began accounting for the operations of Whiting Clean Energy as discontinued operations. For the six months ended June 30, 2008, an after tax loss of $31.9 million was included in Loss on Disposition of Discontinued Operations in the Condensed Statements of Consolidated Income (Loss) (unaudited).

On December 1, 2008, NiSource sold NiSource subsidiaries Northern Utilities and Granite State Gas to Unitil Corporation. The final sale amount was $209.1 million which included $49.1 million in working capital. Under the terms of the transaction, Unitil Corporation acquired Northern Utilities, a local gas distribution company serving 52 thousand customers in 44 communities in Maine and New Hampshire and Granite State Gas, an 86-mile FERC regulated gas transmission pipeline primarily located in Maine and New Hampshire. For the three and six months ended June 30, 2008, an after tax loss of $3.4 million and $66.9 million, respectively, was included in Loss on Disposition of Discontinued Operations in the Condensed Statements of Consolidated Income (Loss) (unaudited).

During the second quarter of 2008, Bay State signed a letter of intent to sell certain assets, including water heater rentals and other service agreements. During April 2009, negotiations with a potential buyer were terminated. NiSource has determined that it is no longer probable that the property will be sold within twelve months and therefore, reclassified the assets from assets held for sale to assets held and used during the quarter.

NiSource Retail Services, a wholly-owned subsidiary of NiSource, had been engaged in a process to sell certain assets. During April 2009 negotiations with a potential buyer were terminated. NiSource has determined that it is no longer probable that the property will be sold within twelve months and therefore, reclassified the assets from assets held for sale to assets held and used during the quarter.

ITEM 1. FINANCIAL STATEMENTS (continued)

NISOURCE INC.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

Results from discontinued operations from Whiting Clean Energy, Granite State Gas, Northern Utilities, NDC Douglas Properties low income housing investments, the unregulated natural gas marketing business, and reserve changes for NiSource's former exploration and production subsidiary, CER, are provided in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	**2009**	2008	**2009**	2008
Revenues from Discontinued Operations	**$ 126.5**	$ 306.2	**$ 423.8**	$ 738.6
Income (Loss) from discontinued operations	**21.4**	(335.7)	**4.1**	(324.0)
Income tax (benefit) expense	**8.7**	(116.5)	**2.1**	(111.6)
Income (Loss) from Discontinued Operations - net of taxes	**$ 12.7**	$ (219.2)	**$ 2.0**	$ (212.4)
Loss on Disposition of Discontinued Operations - net of taxes	**$ (8.8)**	**$ (2.8)**	**$ (9.0)**	$ (98.9)

The $8.8 million after-tax loss on the disposition of discontinued operations in the second quarter of 2009 related to NiSource's decision to sell its unregulated natural gas marketing business. The loss on disposition of discontinued operations for the six months ended June 30, 2008 include the after tax loss on disposition related to the sales of Whiting Clean Energy, Northern Utilities and Granite State Gas of $31.9 million, $52.0 million and $14.9 million, respectively.

7. Asset Retirement Obligations

NiSource accounts for its asset retirement obligations in accordance with SFAS No. 143 and FIN 47. Certain costs of removal that have been, and continue to be, included in depreciation rates and collected in the service rates of the rate-regulated subsidiaries are classified as regulatory liabilities and other removal costs on the Condensed Consolidated Balance Sheets (unaudited).

Changes in NiSource's liability for asset retirement obligations for the first six months of 2009 and 2008 are presented in the table below:

(in millions)	**2009**	2008
Balance as of January 1,	**$ 126.0**	$ 128.1
Accretion expense	**0.3**	0.4
Accretion recorded as a regulatory asset	**3.6**	2.8
Settlements	**(2.4)**	(3.2)
Balance as of June 30,	**$ 127.5**	$ 128.1

8. Regulatory Matters

Gas Distribution Operations Regulatory Matters

Significant Rate Developments. Columbia of Ohio filed a base rate case with the PUCO on March 3, 2008, and a settlement agreement was filed on October 24, 2008. In the base rate case, Columbia of Ohio sought recovery of increased infrastructure rehabilitation costs, as well as the stabilization of revenues and cost recovery through rate design. The agreement included an annual revenue increase of $47.1 million, and also provides for recovery of costs associated with Columbia of Ohio's infrastructure rehabilitation program. On December 3, 2008, the PUCO approved the settlement agreement in all material respects, and approved Columbia of Ohio's proposed rate design.

On April 30, 2009, Columbia of Ohio filed an application with the PUCO to defer pension and other postretirement benefits expenses above those currently subject to collection in rates effective January 1, 2009. On July 8, 2009, the PUCO issued an Order approving Columbia of Ohio's application, although the deferred balances shall not accrue carrying charges and Columbia of Ohio shall not seek recovery of pension and other postretirement benefits deferrals in a base rate proceeding for a period of five years. The amount deferred will be approximately $13.0 million for 2009, which will be reflected in the results for the third and fourth quarters of 2009.

On April 23, 2009, Columbia of Kentucky filed an application with the Kentucky PSC to defer pension and other postretirement benefits expenses above those currently subject to collection in rates. If approved, the amount deferred would be approximately $1.2 million for 2009. This matter is currently pending.

On January 15, 2009, Columbia of Ohio filed an application with the PUCO requesting authority to increase Columbia of Ohio’s PIPP rider rate in order to collect $82 million in PIPP arrearages. On March 3, 2009, Columbia of Ohio’s proposal was approved and became effective.

On January 28, 2008, Columbia of Pennsylvania filed a base rate case with the PPUC seeking recovery of costs associated with its significant infrastructure rehabilitation program, as well as stabilization of revenues through modifications to rate design. On July 2, 2008, Columbia of Pennsylvania and all interested parties filed a unanimous settlement and on October 23, 2008, the PPUC issued an Order approving the settlement as filed, increasing annual revenues by $41.5 million.

On April 16, 2009, Bay State filed a base rate case with the Massachusetts Department of Public Utilities, requesting an increase of $34.6 million. In its filing, Bay State is seeking revenue decoupling, as well as an expedited mechanism for the recovery of costs associated with the rehabilitation of the company’s infrastructure. This matter is currently pending and expected to be resolved with new rates taking effect in the fourth quarter 2009.

On May 1, 2009, Columbia of Kentucky filed a base rate case with the Kentucky PSC, requesting an annual increase of $11.6 million. In its initial filing, Columbia of Kentucky is seeking enhancements to rate design, as well as an expedited mechanism for the recovery of costs associated with the rehabilitation of the company’s infrastructure. This matter is currently pending.

On June 8, 2009, Columbia of Virginia filed an Application with the VSCC for approval of a CARE Plan for a three-year period beginning January 1, 2010. The CARE Plan includes incentives for residential and small general service customers to actively pursue conservation and energy conservation measures, a surcharge designed to recover the costs of such measures on a real-time basis, and a performance-based incentive for the delivery of conservation and energy efficiency benefits. The CARE Plan also includes a rate decoupling mechanism designed to mitigate the impact of declining customer usage. The VSCC scheduled the matter for hearing on October 19, 2009.

On October 1, 2008, Columbia of Maryland filed a base rate case with the Maryland PSC. On February 20, 2009, Columbia of Maryland and all interested parties filed a unanimous settlement in the case, recommending an annual revenue increase of $1.2 million. On March 27, 2009, the settlement was approved as filed.

On November 24, 2008, Northern Indiana filed Supplemental Testimony in its annual gas cost recovery proceeding seeking a cost recovery mechanism for Unaccounted for Gas at current gas prices. Historically, in Indiana, Unaccounted for Gas recovery mechanisms are determined within a base rate proceeding. Intervenors have filed testimony, opposing recovery of Unaccounted for Gas in the gas cost adjustment proceeding and disputing the calculation of Unaccounted for Gas. Evidentiary hearings were held on April 20 and 21, 2009. An order is expected in the third quarter of 2009.

In March 2009, Indiana Governor Daniels signed Senate Bill 423 into law giving the Indiana Finance Authority the authority to contract, on behalf of gas customers in the state of Indiana, with developers capable of building facilities that manufacture Substitute Natural Gas from coal. The Indiana Finance Authority is seeking bids to initiate a Substitute Natural Gas plant in Southern Indiana under a 30 year contract. It is expected that all Indiana gas utilities including Northern Indiana will be delivering a portion of Substitute Natural Gas from this facility. The IURC must approve the final contract.

Cost Recovery and Trackers. A significant portion of the distribution companies' revenue is related to the recovery of gas costs, the review and recovery of which occurs via standard regulatory proceedings. All states 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. NiSource distribution companies have historically been found prudent in the procurement of gas supplies to serve customers.

Certain operating costs of the NiSource distribution companies are significant, recurring in nature, and generally outside the control of the distribution companies. Some states allow the recovery of such costs via cost tracking mechanisms. Such tracking mechanisms allow for abbreviated regulatory proceedings in order for the distribution 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 gas cost recovery adjustment mechanisms, tax riders, and bad debt recovery mechanisms.

Comparability of Gas Distribution Operations line item operating results is impacted by these regulatory trackers that allow for the recovery in rates of certain costs such as bad debt expenses. Increases in the expenses that are the subject of trackers result in a corresponding increase in net revenues and therefore have essentially no impact on total operating income results.

Certain of the NiSource distribution companies have completed rate proceedings involving infrastructure replacement or are embarking upon regulatory initiatives to replace significant portions of their operating systems that are nearing the end of their useful lives. Each LDC's approach to cost recovery may be unique, given the different laws, regulations and precedent that exist in each jurisdiction. On February 27, 2009, Columbia of Ohio filed an application to adjust its Infrastructure Replacement Program Rider to recover costs for risers and accelerated main replacements. On June 24, 2009, the PUCO approved a stipulation allowing Columbia of Ohio to implement the new rider rate July 1, 2009, resulting in an annual revenue increase of approximately $14 million.

On December 28, 2007, Columbia of Ohio entered into a stipulation with the Ohio Consumers' Counsel and PUCO Staff and other stakeholders resolving litigation concerning a pending Gas Cost Recovery audit of Columbia of Ohio. The stipulation calls for an accelerated pass back to customers of $36.6 million, occurring from January 31, 2008 through January 31, 2009, generated through off-system sales and capacity release programs, the development of new energy efficiency programs for introduction in 2009, and the development of a wholesale auction process for customer supply to take effect in 2010. The entire requirement of the stipulation was passed back through January 31, 2009. The stipulation also resolves issues related to pending and future Gas Cost Recovery Management Performance audits through 2008. The PUCO approved this agreement on January 23, 2008.

Gas Transmission and Storage Operations Regulatory Matters

Eastern Market Expansion Project. On January 14, 2008, the FERC issued an order which granted a certificate to construct the project. The project allows Columbia Transmission to expand its facilities to provide additional storage and transportation services and to replace certain existing facilities. The Eastern Market Expansion is adding 97,000 Dth per day of storage and transportation deliverability and is fully subscribed on a 15-year contracted firm basis. Construction of the facilities is complete and was placed in service April 1, 2009.

Appalachian Expansion Project. On August 22, 2008, the FERC issued an order to Columbia Transmission, which granted a certificate to construct the project. The project includes building a new 9,470 hp compressor station in West Virginia. The Appalachian Expansion Project added 100,000 Dth per day of transportation capacity and is fully subscribed on a 15-year contracted firm basis. Construction is complete and the project was placed in service on July 1, 2009.

Ohio Storage Project. On June 24, 2008, Columbia Transmission filed an application before the FERC for approval to expand two of its Ohio storage fields for additional capacity of nearly 7 Bcf and 103,400 Dth per day of daily deliverability. Approval was granted in March 2009 and construction of the facilities began in April 2009. Partial service related to this expansion was available beginning May 2009 and the remainder will be available no later than the fourth quarter of 2009. The expansion capacity is 58% contracted on a long-term, firm basis, with the FERC authorized market-based rates for these services.

Electric Operations Regulatory Matters

Significant Rate Developments. Northern Indiana filed a petition for new electric base rates and charges on June 27, 2008. The case-in-chief was originally filed on August 29, 2008, and amended on December 19, 2008 after the Sugar Creek facility was successfully dispatched into MISO. The filing requested an increase in base rates calculated to produce additional annual gross margin of $85.7 million. Evidentiary hearings on Northern Indiana's direct case commenced on January 12, 2009 and concluded on February 6, 2009. Several stakeholder groups have intervened in the case, representing customer groups and various counties and towns within Northern Indiana's electric service territory. Field hearings to record customer testimonies were held on March 3, 2009 and July 15, 2009. The OUCC and intervenors filed their cases-in-chief on May 8, 2009. Northern Indiana filed its rebuttal testimony on June 26, 2009. Northern Indiana made several minor changes to its revenue requirement, and, as a result the margin requirement in the rebuttal filing is $6 million less than the original request. Final hearings began on July 27, 2009. The case is expected to be resolved, and new electric rates effective during early 2010.

During 2002, Northern Indiana settled certain regulatory matters related to an electric rate review. On September 23, 2002, the IURC issued an Order adopting most aspects of the settlement. The Order approving the settlement provides that certain electric customers of Northern Indiana will receive bill credits of approximately $55.1 million each year. The credits will continue at approximately the same annual level and per the same methodology, until the IURC enters a base rate order that approves revised Northern Indiana electric rates. The order included a rate moratorium that expired on July 31, 2006. The order also provides that 60% of any future earnings beyond a specified earnings level will be retained by Northern Indiana. The billing factor used to distribute the revenue credit to customers is based on historical electric usage, therefore, in times of higher usage and revenues the amount credited may exceed $55.1 million annually, but would be offset in a subsequent period. Credits amounting to $26.3 million and $25.1 million were recognized for electric customers for the first half of 2009 and 2008, respectively.

MISO. As part of Northern Indiana's participation in the MISO transmission service and wholesale energy market, certain administrative fees and non-fuel costs have been incurred. IURC orders have been issued authorizing the deferral for consideration in a future rate case proceeding of the administrative fees and certain non-fuel related costs incurred after Northern Indiana's rate moratorium, which expired on July 31, 2006. During the first half of 2009, non-fuel cost credits of $3.7 million were deferred in accordance with the aforementioned orders. In addition, administrative, FERC and other fees of $3.5 million were deferred. In total, for the first half of 2009 and 2008, net MISO credits of $0.2 million and costs of $4.9 million, respectively, were deferred. In its base rate case, Northern Indiana proposes recovery over a four year amortization period of the cumulative amount of charges that were deferred as of December 31, 2008, and to recover, through a tracker, charges deferred between December 31, 2008 and the date of effective rates in this case. The aforementioned tracker is also proposed for recovery of these charges on an ongoing basis. As noted below, as part of MISO's initiation of an ASM, Northern Indiana will also incur non-fuel administrative costs associated with this market. The IURC authorized Northern Indiana to defer the costs associated with participating in the ASM subject to a final determination in a subsequent phase of the same proceeding. On June 30, 2009, the IURC issued an Order in the subsequent phase of the ASM proceeding confirming that Northern Indiana is permitted to continue deferring non-fuel administrative costs.

Northern Indiana was an active stakeholder in the process used in designing, testing and implementing the ASM and in developing the surrounding business practices. On January 18, 2008, Northern Indiana as part of a Joint Petition among several other Indiana utilities, "Joint Petitioners," filed a request to the IURC to participate in ASM and seek approval of timely cost recovery for the associated costs of participating. On August 13, 2008, the IURC issued a Phase I order, authorizing the Joint Petitioners authority to transfer additional balancing authority functions and to implement the operational changes necessary to participate in the ASM and to seek recovery of modified MISO charge-types via the FAC and to defer certain other MISO charge-types, pending a final determination on the issue of cost recovery in Phase II. This order also created a subdocket for the purpose of further consideration of whether a cost-benefit analysis of participation in MISO or the MISO ASM should be required. Phase II of this proceeding deals with how the Joint Petitioners will approach the ASM, specifically related to cost recovery. The evidentiary hearing for Phase II concluded on February 9, 2009 and on June 30, 2009, the IURC issued an Order authorizing Northern Indiana to recover fuel-related ASM charges in its FAC and to defer non-fuel charges. The market began on January 6, 2009. The impact of ASM will not have a material effect on cash flows or earnings.

NISOURCE INC.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

On November 7, 2008, the FERC issued an Order clarifying the RSG First Pass calculation and requiring the MISO to resettle the RSG market using the correct calculation and to pay refunds, or assess surcharges, to market participants, as appropriate, to correct a misinterpretation of an order issued by FERC in April 2006. Northern Indiana believes that it would have been entitled to a refund, with the amount subject to calculation by MISO. On June 12, 2009, however, FERC issued an order on rehearing in which it affirmed its prior order clarifying the method to calculate the RSG First Pass rate, but reversed its ruling requiring the MISO to pay refunds, and collect surcharges, on equitable grounds. Northern Indiana has asked FERC to reconsider its decision to deny refunds and that request remains pending.

MISO's implementation of FERC's April 2006 Order on the RSG First Pass calculation resulted in several million dollars of surcharges to Northern Indiana through market resettlements implemented during the summer of 2007. As a result, Northern Indiana and Ameren jointly filed a complaint with FERC on August, 10, 2007, contending that the RSG rates in effect were unjust and unreasonable. On November 10, 2008, the FERC issued an Order granting these complaints and ordering the MISO to calculate refunds and surcharges, as appropriate, back to the date of the complaint filed by Northern Indiana and Ameren, as authorized by Section 206 of the Federal Power Act. On May 6, 2009, however, the FERC issued an Order that upheld its decision granting the complaint, but largely reversed its directive requiring MISO to pay refunds, and collect surcharges, on equitable grounds. The FERC affirmed the refund and surcharge requirement only for those transactions that occurred after the date of the November 10, 2008 Order, instead of August 10, 2007, as it had previously required. Northern Indiana and Ameren have requested rehearing of the FERC's May 6, 2009 Order, and that request remains pending.

Cost Recovery and Trackers. A significant portion of Northern Indiana's 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 standard, quarterly, "summary" regulatory proceeding in Indiana. Various intervenors, including the OUCC, have taken issue with the allocation of costs included in Northern Indiana's FAC-80, FAC-81 and FAC-82, which cover the reconciliation of April – December 2008. The IURC has granted a sub-docket to consider such issues in those filings. The intervening parties and Northern Indiana are discussing procedures to eliminate these concerns and to resolve them for the historical periods. There is no procedural schedule established for this sub-docket. Northern Indiana recorded an accrual for this matter in accordance with SFAS No. 5.

The IURC issued an order on May 28, 2008 approving the purchase of Sugar Creek, and on May 30, 2008 Northern Indiana purchased the 535 mw CCGT for $330 million in order to help meet capacity needs. The IURC, on February 18, 2009, issued an order approving a settlement agreement filed in this proceeding allowing Northern Indiana to begin deferring carrying costs and depreciation on Sugar Creek effective on December 1, 2008, when Sugar Creek was dispatched into MISO, at the agreed to carrying cost rate of 6.5%, less $4.5 million annually, the annual depreciation on the Mitchell plant, pursuant to the FAC-71 settlement. The terms of recovery of the deferral will be resolved in Northern Indiana's current rate proceeding. On March 19, 2009, LaPorte County filed a notice of appeal regarding the IURC's decision. On July 21, 2009, the Indiana Court of Appeals granted LaPorte County's Motion to Dismiss the appeal filed with the court on July 16, 2009.

As part of a settlement agreement which resolved issues surrounding purchased power costs, Northern Indiana implemented a new "benchmarking standard," that became effective in October 2007, which defines the price above which purchased power costs must be absorbed by Northern Indiana and are not permitted to be passed on to ratepayers. The benchmark is based upon the costs of power generated by a hypothetical natural gas fired unit using gas purchased and delivered to Northern Indiana and a set sharing mechanism. During the first six months of 2009 and 2008, the amount of purchased power costs exceeding the benchmark amounted to $1.0 million and $6.5 million, respectively, which was recognized as a net reduction of revenues. The agreement also contemplated Northern Indiana adding generating capacity to its existing portfolio by providing for the benchmark to be adjusted as new capacity is added. The dispatch of Sugar Creek into MISO on December 1, 2008 triggered a change in the benchmark, whereby the first 500 mw tier of the benchmark provision was eliminated.

Northern Indiana has approval from the IURC to recover certain environmental related costs through an ECT. Under the ECT, Northern Indiana is permitted to recover (1) AFUDC and a return on the capital investment expended by Northern Indiana to implement IDEM's NOx SIP through an ECRM and (2) related operation and maintenance and depreciation expenses once the environmental facilities become operational through an EERM.

NISOURCE INC.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

Under the IURC's November 26, 2002 order, Northern Indiana is permitted to submit filings on a semi-annual basis for the ECRM and on an annual basis for the EERM. In addition, Northern Indiana received an IURC order issuing a CPCN for the CAIR and CAMR Phase I Compliance Plan Projects, estimated to cost approximately $23 million. Northern Indiana includes the CAIR and CAMR Phase I Compliance Plan costs to be recovered in the semi-annual ECRM and annual EERM filing six months after construction costs begin. On October 23, 2008, Northern Indiana filed for approval of a revised cost estimate to meet the NOx and SO2 and mercury emissions environmental standards. Northern Indiana anticipates a total capital investment of approximately $368 million. This revised cost estimate was approved by the IURC on January 14, 2009. On October 1, 2008, the IURC approved ECR-12 for capital expenditures (net of accumulated depreciation) of $267.7 million. Northern Indiana filed ECR-13 and EER-6 in February 2009, for net capital expenditures and expense of $268.1 million and $18.7 million, respectively. The Order was issued April 29, 2009. In the electric base rate case, Northern Indiana has proposed that the frequency of the EERM be changed from annual to semi-annual, consistent with the filing of the ECRM. In addition, Northern Indiana proposed that the EERM be used to pass through to ratepayers the cost of any emission allowance purchases and the proceeds of any emission allowance sales.

9. Risk Management Activities

NiSource is exposed to certain risks relating to its ongoing business operations. The primary risks managed by using derivative instruments are commodity price risk and interest rate risk. Derivative natural gas contracts are entered into to manage the price risk associated with natural gas price volatility and to secure forward natural gas prices. Interest rate swaps are entered into to manage interest rate risk associated with NiSource's fixed-rate borrowings. In accordance with SFAS No. 133, NiSource designates many of its commodity forward contracts as cash flow hedges of forecasted purchases of commodities and designates its interest rate swaps as fair value hedges of fixed-rate borrowings. Additionally, certain NiSource subsidiaries enter into forward physical contracts with various third parties to procure natural gas or power for its operational needs. These forward physical contracts are derivatives which qualify for the normal purchase normal sales exception under SFAS No. 133 and do not require mark-to-market accounting. In the second quarter of 2009, NiSource engaged in a process to sell its unregulated natural gas marketing business. As a result of this decision, it became probable that certain forecasted transactions are no longer probable of occurring from a consolidated NiSource perspective, which triggered the mark-to-market of certain forward sales contracts that were previously exempt under the normal purchase and sale exception. In addition, the mark-to-market gains and losses deferred in accumulated other comprehensive income (loss) related to certain financial derivatives accounted for as a cash flow hedge were also recognized in income from discontinued operations during the quarter. NiSource adopted SFAS No. 161 on January 1, 2009, an amendment to SFAS No. 133, and the disclosures contained in this note regarding NiSource's use of derivatives are pursuant to the requirement of SFAS No. 133, as amended.

Accounting Policy for Derivative Instruments. SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities. SFAS No. 133 requires an entity to recognize all derivatives as either assets or liabilities on the Consolidated Balance Sheets at fair value, unless such contracts are exempted such as a normal purchase normal sale contract 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.

NiSource uses a variety of derivative instruments (exchange traded futures and options, physical forwards and options, basis contracts, financial commodity swaps, and interest rate swaps) to effectively manage its commodity price risk and interest rate risk exposure. If certain conditions are met, a derivative may be specifically designated as (a) a hedge of the exposure to changes in the fair value of a recognized asset or liability or an unrecognized firm commitment, or (b) a hedge of the exposure to variable cash flows of a forecasted transaction. In order for a derivative contract to be designated as a hedge, the relationship between the hedging instrument and the hedged item or transaction must be highly effective. The effectiveness test is performed at the inception of the hedge and each reporting period thereafter, throughout the period that the hedge is designated. Any amounts determined to be ineffective are recognized currently in earnings. For derivative contracts that qualify for the normal purchase normal sale exception under SFAS No. 133, a contract's fair value is not recognized in the Consolidated Financial Statements until the contract is settled.

NiSource Inc.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

Unrealized and realized gains and losses are recognized each period as components of accumulated other comprehensive income (loss), regulatory assets and liabilities or earnings depending on the designation of the derivative instrument. For subsidiaries that utilize derivatives for cash flow hedges, the effective portions of the gains and losses are recorded to accumulated other comprehensive income (loss) and are recognized in earnings concurrent with the disposition of the hedged risks. If a forecasted transaction corresponding to a cash flow hedge is no longer probable to occur, the accumulated gains or losses on the derivative are recognized currently in earnings. For fair value hedges, the gains and losses are recorded in earnings each period together with the change in the fair value of the hedged item. As a result of the rate-making process, the rate-regulated subsidiaries generally record gains and losses as regulatory liabilities or assets and recognize such gains or losses in earnings when both the contracts settle and the physical commodity flows. These gains and losses recognized in earnings are then subsequently recovered or passed back to customers in revenues through rates. When gains and losses are recognized in earnings, they are recognized in cost of sales for derivatives that correspond to commodity risk activities and are recognized in interest expense for derivatives that correspond to interest-rate risk activities.

Commodity Price Risk Programs. NiSource and NiSource's utility customers are exposed to variability in cash flows associated with natural gas purchases and volatility in natural gas prices. NiSource purchases natural gas for sale and delivery to its 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 NiSource's utility subsidiaries offer programs where variability in the market price of gas is assumed by the respective utility. The objective of NiSource's commodity price risk programs is to mitigate this gas cost variability, for NiSource or on behalf of its customers, associated with natural gas purchases by economically hedging the various gas cost components by using a combination of futures, options, forward physical contracts, basis swap contracts or other derivative contract. Northern Indiana also uses derivative contracts to minimize risk associated with power price volatility. These commodity price risk programs and their respective accounting treatment are described below.

Northern Indiana, Northern Indiana Fuel and Light, Kokomo Gas, Columbia of Pennsylvania, Columbia of Kentucky, Columbia of Maryland and Columbia of Virginia use NYMEX derivative contracts to minimize risk associated with gas price volatility. These derivative programs must be marked to fair value, but because these derivatives are used within the framework of the companies' gas cost recovery mechanism, regulatory assets or liabilities are recorded to offset the change in the fair value of these derivatives.

Northern Indiana, Columbia of Virginia and Columbia of Pennsylvania offer a fixed price program as an alternative to the standard gas cost recovery mechanism. These services provide customers with the opportunity to either lock in their gas cost or place a cap on the gas costs that would be charged in future months. In order to hedge the anticipated physical purchases associated with these obligations, forward physical contracts, NYMEX futures and NYMEX options are used to secure forward gas prices. The accounting treatment elected for these contracts is varied whereby certain of these contracts are accounted for as cash flow hedges while some contracts are not. The normal purchase normal sale exception under SFAS No. 133 is elected for forward physical contracts associated with these programs whereby delivery of the commodity is probable to occur.

Northern Indiana also offers a DependaBill program to its customers as an alternative to the standard tariff rate that is charged to residential customers. The program allows Northern Indiana customers to fix their total monthly bill in future months at a flat rate regardless of gas usage or commodity cost. In order to hedge the anticipated physical purchases associated with these obligations, forward physical contracts, NYMEX futures and NYMEX options are used to secure forward gas prices. The accounting treatment elected for these contracts is varied whereby certain of these contracts are accounted for as cash flow hedges while some contracts are not. The normal purchase normal sale exception under SFAS No. 133 is elected for forward physical contracts associated with these programs whereby delivery of the commodity is probable to occur.

For regulatory incentive purposes, Northern Indiana enters into gas purchase contracts at first of the month prices that give counterparties the daily option to either sell an additional package of gas at first of the month prices or recall the original volume to be delivered. Northern Indiana charges a fee for this option. The changes in the fair value of these options are primarily due to the changing expectations of the future intra-month volatility of gas prices. These written options are derivative instruments, must be marked to fair value and do not meet the

ITEM 1. FINANCIAL STATEMENTS (continued)

NISOURCE INC.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

requirement for hedge accounting treatment. However, in accordance with SFAS No. 71, Northern Indiana records the related gains and losses associated with these transactions as a regulatory asset or liability.

For regulatory incentive purposes, Columbia of Kentucky, Columbia of Ohio, Columbia of Pennsylvania, and Columbia of Maryland (collectively, the "Columbia LDCs") enter into contracts that allow counterparties the option to sell gas to Columbia LDCs at first of the month prices for a particular month of delivery. Columbia LDCs charge the counterparties a fee for this option. The changes in the fair value of the options are primarily due to the changing expectations of the future intra-month volatility of gas prices. These Columbia LDCs defer a portion of the change in the fair value of the options as either a regulatory asset or liability in accordance with SFAS No. 71 based on the regulatory customer sharing mechanisms in place, with the remaining changes in fair value recognized currently in earnings.

As part of the MISO Day 2 initiative, Northern Indiana was allocated and has purchased FTRs. These FTRs help Northern Indiana offset congestion costs due to the MISO Day 2 activity. The FTRs are marked to fair value and do not qualify for hedge accounting treatment, but since congestion costs are recoverable through the fuel cost recovery mechanism, the related gains and losses associated with marking these derivatives to market are recorded as a regulatory asset or liability in accordance with SFAS No. 71. In the second quarter of 2008, MISO changed its allocation procedures from an allocation of FTRs to an allocation of ARRs, whereby Northern Indiana was allocated ARRs based on its historical use of the MISO administered transmission system. ARRs entitle the holder to a stream of revenues or charges based on the price of the associated FTR in the FTR auction. Northern Indiana converted the ARRs that were received in the second quarter of 2008 into FTRs.

NiSource is also involved in commercial and industrial gas sales, whereby gas derivatives are utilized to hedge expected future gas purchases. These derivatives associated with commercial and industrial gas sales have generally been accounted for as cash flow hedges. NiSource also has corresponding forward physical sales contracts of natural gas with customers. These forward physical sales contracts are derivatives, which have generally qualified for, and for which NiSource has elected the normal purchase normal sales exception under SFAS No. 133, and which do not require mark-to-market accounting. In the second quarter of 2009, NiSource has engaged in a process to sell its unregulated natural gas marketing business. As a result of this decision, certain forecasted transactions are no longer probable to occur, which triggered the mark-to-market treatment of certain forward sales contracts that were previously exempt under the normal purchase and sale election. In addition, the mark-to-market gains and losses deferred in accumulated other comprehensive income (loss) related to certain financial derivatives accounted for as a cash flow hedge were also recognized in income from discontinued operations during the quarter. The physical sales contracts marked-to-market had a fair value pre-tax gain of approximately $149.9 million at June 30, 2009, while the financial cash flow hedge contracts recognized to income from discontinued operations in the same period had a fair value pre-tax loss of $126.4 million.

Commodity price risk program derivative contracted gross volumes are as follows:

	June 30, 2009	December 31, 2008
Commodity Price Risk Program:		
Gas price volatility program derivatives (MMDth)	**28.8**	31.2
PPS program derivatives (MMDth)	**1.6**	1.9
DependaBill program derivatives (MMDth)	**0.5**	0.3
Regulatory incentive program derivatives (MMDth)	**6.6**	2.9
Gas marketing program derivatives (MMDth) (a)	**83.2**	84.4
Gas marketing forward physical derivatives (MMDth) (b)	**93.9**	-
Electric energy program FTR derivatives (mw)	**2,753**	8,068

(a) Basis contract volumes not included in the above table were 93.2 MMDth and 83.5 MMDth as of June 30, 2009 and December 31, 2008,

NiSource Inc.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

respectively.

(b) Gas marketing forward physical derivatives at December 31, 2008 received the normal purchase normal sales exception under SFAS No. 133 and did not require mark-to-market accounting.

Interest Rate Risk Activities. NiSource recognizes that the prudent and selective use of derivatives may help it to lower its cost of debt capital and manage its interest rate exposure. NiSource Finance has entered into various "receive fixed" and "pay floating" interest rate swap agreements which modify the interest rate characteristics of its outstanding long-term debt from fixed to variable rate. These interest rate swaps also serve to hedge the fair market value of NiSource Finance's outstanding debt portfolio. As of June 30, 2009, NiSource had $7.0 billion of outstanding debt, of which $1.1 billion is subject to fluctuations in interest rates as a result of the fixed-to-variable interest rate swap transactions. These interest rate swaps are designated as fair value hedges. The effectiveness of the interest rate swaps in offsetting the exposure to changes in the debt's fair value is measured pursuant to SFAS No. 133. NiSource had no net gain or loss recognized in earnings due to hedging ineffectiveness from prior years.

On May 12, 2004, NiSource Finance entered into fixed-to-variable interest rate swap agreements in a notional amount of $660 million with six counterparties having a 6 1/2-year term. NiSource Finance will receive payments based upon a fixed 7.875% interest rate and pay a floating interest amount based on U.S. 6-month BBA LIBOR plus an average of 3.08% per annum. There was no exchange of premium at the initial date of the swaps. On September 15, 2008, NiSource Finance terminated a fixed-to-variable interest rate swap agreement with Lehman Brothers having a notional amount of $110 million.

On July 22, 2003, NiSource Finance entered into fixed-to-variable interest rate swap agreements in a notional amount of $500 million with four counterparties with an 11-year term. NiSource Finance will receive payments based upon a fixed 5.40% interest rate and pay a floating interest amount based on U.S. 6-month BBA LIBOR plus an average of 0.78% per annum. There was no exchange of premium at the initial date of the swaps. In addition, each party has the right to cancel the swaps on July 15, 2013.

As stated above, on September 15, 2008, NiSource Finance terminated a fixed-to-variable interest rate swap agreement with Lehman Brothers having a notional amount of $110 million. NiSource Finance elected to terminate the swap when Lehman Holdings Inc., guarantor under the applicable International Swaps and Derivatives Association agreement, filed for Chapter 11 bankruptcy protection on September 14, 2008, which constituted an event of default under the swap agreement between NiSource Finance and Lehman Brothers Special Financing Inc. The mark-to-market close-out value of this swap at the September 15, 2008 termination date was determined to be $4.8 million and was fully reserved in the third quarter of 2008. The termination of this swap did not impact NiSource's ability to assert hedge accounting for its remaining fixed-to-variable interest rate swap agreements.

Contemporaneously with the issuance on September 16, 2005 of the 5.25% and 5.45% notes, NiSource Finance settled $900 million of forward starting interest rate swap agreements with six counterparties. NiSource paid an aggregate settlement payment of $35.5 million which is being amortized from accumulated other comprehensive loss to interest expense over the term of the underlying debt, resulting in an effective interest rate of 5.67% and 5.88%, respectively. As of June 30 2009, $15.2 million is in accumulated other comprehensive loss related to forward starting interest rate swap settlement.

ITEM 1. FINANCIAL STATEMENTS (continued)

NISOURCE INC.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

NiSource's location and fair value of derivative instruments on the Condensed Consolidated Balance Sheets (unaudited) were:

Asset Derivatives *(in millions)*	**June 30, 2009**		December 31, 2008	
Balance Sheet Location	**Fair Value**		Fair Value	
Derivatives designated as hedging instruments under SFAS No. 133				
Commodity price risk programs				
Price risk management assets (current)	**$**	**21.7**	$	111.4
Price risk management assets (noncurrent)		-		(0.1)
Assets of discontinued operations and assets held for sale (current)		-		32.1
Assets of discontinued operations and assets held for sale (noncurrent)		-		105.0
Interest rate risk activities				
Price risk management assets (noncurrent)		**70.7**		95.8
Total derivatives designated as hedging instruments under SFAS No. 133	**$**	**92.4**	$	344.2
Derivatives not designated as hedging instruments under SFAS No. 133				
Commodity price risk programs				
Price risk management assets (current)	**$**	**2.8**	$	6.9
Price risk management assets (noncurrent)		-		-
Assets of discontinued operations and assets held for sale (current)		**230.0**		-
Assets of discontinued operations and assets held for sale (noncurrent)		**167.0**		-
Total derivatives not designated as hedging instruments under SFAS No. 133	**$**	**399.8**	$	6.9
Total Asset Derivatives	**$**	**492.2**	$	351.1

Liability Derivatives *(in millions)*	**June 30, 2009**		December 31, 2008	
Balance Sheet Location	**Fair Value**		Fair Value	
Derivatives designated as hedging instruments under SFAS No. 133				
Commodity price risk programs				
Price risk management liabilities (current)	**$**	**52.6**	$	184.6
Price risk management liabilities (noncurrent)		**0.6**		0.8
Price risk management liabilities (current)				-
Liabilities of discontinued operations and liabilities held for sale (current)		-		49.0
Liabilities of discontinued operations and liabilities held for sale (noncurrent)				170.6
Interest rate risk activities				
Price risk management liabilities (noncurrent)		-		-
Total derivatives designated as hedging instruments under SFAS No. 133	**$**	**53.2**	$	405.0
Derivatives not designated as hedging instruments under SFAS No. 133				
Commodity price risk programs				
Price risk management liabilities (current)	**$**	**48.5**	$	52.9
Price risk management liabilities (noncurrent)		**4.5**		17.1
Liabilities of discontinued operations and liabilities held for sale (current)		**221.7**		-
Liabilities of discontinued operations and liabilities held for sale (noncurrent)		**154.5**		-
Total derivatives not designated as hedging instruments under SFAS No. 133	**$**	**429.2**	$	70.0
Total Liability Derivatives	**$**	**482.4**	$	475.0

Table of Contents

ITEM 1. FINANCIAL STATEMENTS (continued)

NiSource Inc.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

The effect of derivative instruments on the Condensed Statements of Consolidated Income (Loss) (unaudited) were:

Derivatives in Cash Flow Hedging Relationships

Three Months Ended, *(in millions)*

Derivatives in SFAS No. 133 Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in OCI on Derivative (Effective Portion)		Location of Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	
	June 30, 2009	June 30, 2008		**June 30, 2009**	June 30, 2008
Commodity price risk programs	**$ 110.7**	$ 9.6	Cost of Sales	**$ 19.0**	$ 16.3
Interest rate risk activities	**0.4**	0.4	Interest expense, net	**(0.4)**	-
Total	**$ 111.1**	$ 10.0		**$ 18.6**	$ 16.3

Six Months Ended, *(in millions)*

Derivatives in SFAS No. 133 Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in OCI on Derivative (Effective Portion)		Location of Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	
	June 30, 2009	June 30, 2008		**June 30, 2009**	June 30, 2008
Commodity price risk programs	**$ 95.8**	$ 26.5	Cost of Sales	**$ (24.8)**	$ 25.4
Interest rate risk activities	**0.8**	0.8	Interest expense, net	**(0.8)**	-
Total	**$ 96.6**	$ 27.3		**$ (25.6)**	$ 25.4

Three Months Ended, *(in millions)*

Derivatives in SFAS No. 133 Cash Flow Hedging Relationships	Location of Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectivness Testing)	Amount of Gain (Loss) Recognized in Income of Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	
		June 30, 2009	June 30, 2008
Commodity price risk programs	Cost of Sales	**$ -**	$ (0.2)
Interest rate risk activities	Interest expense, net	**-**	-
Total		**$ -**	$ (0.2)

NiSource Inc.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

Six Months Ended, *(in millions)*

Derivatives in SFAS No. 133 Cash Flow Hedging Relationships	Location of Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectivness Testing)	Amount of Gain (Loss) Recognized in Income of Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	
		June 30, 2009	June 30, 2008
Commodity price risk programs	Cost of Sales	**$ -**	$ (0.3)
Interest rate risk activities	Interest expense, net	**-**	-
Total		**$ -**	$ (0.3)

Derivatives in Fair Value Hedging Relationships

Three Months Ended, *(in millions)*

Derivatives in SFAS No. 133 Fair Value Hedging Relationships	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives	
		June 30, 2009	June 30, 2008
Interest rate risk activites	Interest expense, net	**$ 8.2**	$ 2.0
Total		**$ 8.2**	$ 2.0

Six Months Ended, *(in millions)*

Derivatives in SFAS No. 133 Fair Value Hedging Relationships	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives	
		June 30, 2009	June 30, 2008
Interest rate risk activites	Interest expense, net	**$ 15.3**	$ 2.3
Total		**$ 15.3**	$ 2.3

Three Months Ended, *(in millions)*

Hedged Item in SFAS No. 133 Fair Value Hedge Relationships	Location of Gain (Loss) Recognized in Income on Related Hedged Item	Amount of Gain (Loss) Recognized in Income on Related Hedged Items	
		June 30, 2009	June 30, 2008
Fixed-rate debt	Interest expense, net	**$ (8.2)**	$ (2.0)
Total		**$ (8.2)**	$ (2.0)

Six Months Ended, *(in millions)*

Hedged Item in SFAS No. 133 Fair Value Hedge Relationships	Location of Gain (Loss) Recognized in Income on Related Hedged Item	Amount of Gain (Loss) Recognized in Income on Related Hedged Items	
		June 30, 2009	June 30, 2008
Fixed-rate debt	Interest expense, net	**$ (15.3)**	$ (2.3)
Total		**$ (15.3)**	$ (2.3)

ITEM 1. FINANCIAL STATEMENTS (continued)

NiSource Inc.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

Derivatives not designated as hedging instruments under SFAS No. 133

Three Months Ended, *(in millions)*

Derivatives Not Designated as Hedging Instruments under SFAS No. 133	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Realized/Unrealized Gain (Loss) Recognized in Income on Derivatives *	
		June 30, 2009	June 30, 2008
Commodity price risk programs	Gas Distribution revenues	**$ (0.1)**	$ 5.5
Commodity price risk programs	Cost of Sales	**0.4**	0.3
Commodity price risk programs	Income (Loss) from Discontinued Operations - net of taxes	**20.8**	-
Total		**$ 21.1**	$ 5.9

* For the amounts of realized/unrealized gain (loss) recognized in income on derivatives disclosed in the table above, gains of $0.1 million and $5.6 million for the second quarter of 2009 and 2008, respectively, were deferred per regulatory orders. These amounts will be amortized to income over future periods per regulatory order up to twelve-months.

Six Months Ended, *(in millions)*

Derivatives Not Designated as Hedging Instruments under SFAS No. 133	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Realized/Unrealized Gain (Loss) Recognized in Income on Derivatives *	
		June 30, 2009	June 30, 2008
Commodity price risk programs	Gas Distribution revenues	**$ (46.0)**	$ 2.7
Commodity price risk programs	Cost of Sales	**(1.0)**	1.2
Commodity price risk programs	Income (Loss) from Discontinued Operations - net of taxes	**20.8**	-
Total		**$ (26.2)**	**$ 3.9**

* For the amounts of realized/unrealized gain (loss) recognized in income on derivatives disclosed in the table above, a loss of $47.4 million and gain of $4.4 million for the first half of 2009 and 2008, respectively, were deferred per regulatory orders. These amounts will be amortized to income over future periods per regulatory order up to twelve-months.

During second quarter of 2009, NiSource reclassified $126.4 million ($75.1 million, net of tax) related to its cash flow hedges from accumulated other comprehensive loss to income (loss) from discontinued operations due to the probability that certain forecasted transactions would not occur related to the unregulated natural gas marketing business that NiSource plans to sell. No amounts were reclassified in the second quarter of 2008. It is anticipated that during the next twelve months the expiration and settlement of cash flow hedge contracts will result in income statement recognition of amounts currently classified in accumulated other comprehensive loss of approximately $60.0 million of loss, net of taxes.

NiSource's derivative instruments measured at fair value under SFAS No. 133 as of June 30, 2009 do not contain any credit-risk-related contingent features.

Certain NiSource affiliates have physical commodity purchase agreements that meet the definition of a derivative for which NiSource has elected the normal purchase normal sale exception. These agreements are exempt from the requirement of SFAS No. 133 and are not measured at fair value. Certain of these agreements do contain "ratings triggers"

NiSource Inc.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

that require increases in collateral if the credit rating of NiSource or certain of its affiliates are rated below BBB- by Standard and Poor's or below Baa3 by Moody's. The collateral requirement from a downgrade for these normal purchase normal sale agreements below the ratings trigger levels would amount to approximately $2.1 million as of June 30, 2009.

NiSource had approximately $63.9 million and $78.8 million of cash on deposit with brokers for margin requirements associated with open derivative positions reflected within, "Restricted cash," on the Condensed Consolidated Balance Sheets (unaudited) as of June 30, 2009 and December 31, 2008, respectively.

10. Fair Value Disclosures

A. SFAS 157 Fair Value Measurements. NiSource adopted the provisions of SFAS No. 157 for financial assets and liabilities on January 1, 2008 and the effective date provision for non-financial assets and liabilities delayed by the issuance of FSP FAS 157-2 on January 1, 2009. There was no impact on retained earnings as a result of the adoption.

Recurring Fair Value Measurements. The following table presents financial assets and liabilities measured and recorded at fair value on NiSource's Condensed Consolidated Balance Sheet (unaudited) on a recurring basis and their level within the fair value hierarchy as of June 30, 2009:

Recurring Fair Value Measurements *(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 June 30, 2009**
Assets				
Price risk management assets	$ 19.7	$ 72.6	$ 2.9	**$ 95.2**
Price risk management assets (discontinued operations)	233.9	163.1	-	**397.0**
Available-for-sale securities	26.3	34.6	-	**60.9**
Total	**$ 279.9**	**$ 270.3**	**$ 2.9**	**$ 553.1**
Liabilities				
Price risk management liabilities	$ 101.1	$ 4.2	$ 0.9	**$ 106.2**
Price risk management liabilities (discontinued operations)	350.9	25.3	-	**376.2**
Total	**$ 452.0**	**$ 29.5**	**$ 0.9**	**$ 482.4**

Price risk management assets and liabilities include commodity exchange-traded and non-exchange-based derivative contracts. Exchange-traded derivative contracts are generally 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. The company uses 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 in 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 in 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.

Price risk management assets also include fixed-to-floating interest-rate swaps, which are designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. NiSource uses a calculation of future cash inflows and estimated future outflows related to the swap agreements, which are discounted and netted to determine the current fair value. Additional inputs to the present value calculation include the contract terms, as well as market parameters such as current and projected interest rates and volatility. As they are based on observable data and valuations of similar instruments, the interest-rate swaps are categorized in Level 2 in the fair value hierarchy. Credit risk is considered in the fair value calculation of the interest rate swap.

As of June 30, 2009, price risk management assets and liabilities classified as an asset or liability of a discontinued operation also includes certain forward physical gas sales contracts that no longer qualify for the normal purchase and sale exemption. The fair value of these contracts is determined primarily from Level 1 and Level 2 inputs, and is reflected in the table above as Level 2.

Available-for-sale securities are investments pledged as collateral for trust accounts related to NiSource's wholly-owned insurance company. Available-for-sale securities are included within "Other investments" in the Condensed Consolidated Balance Sheets (unaudited). Securities classified within Level 1 include U.S. Treasury debt securities which are highly liquid and are actively traded in over-the-counter markets. NiSource values corporate and mortgage-backed debt securities using a matrix pricing model that incorporates market-based information. These securities trade less frequently and are classified within Level 2. 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 debt securities at June 30, 2009 and December 31, 2008 were:

(in millions)	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
Available-for-sale debt securities, June 30, 2009				
U.S. Treasury securities	$ 26.1	$ 0.4	$ (0.2)	$ 26.3
Corporate/Other bonds	33.8	1.5	(0.7)	34.6
Total Available-for-sale debt securities, June 30, 2009	**$ 59.9**	**$ 1.9**	**$ (0.9)**	**$ 60.9**

(in millions)	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
Available-for-sale debt securities, December 31, 2008				
U.S. Treasury securities	$ 34.9	$ 2.2	$ (0.2)	$ 36.9
Corporate/Other bonds	34.0	1.2	(1.1)	34.1
Total Available-for-sale debt securities, December 31, 2008	**$ 68.9**	**$ 3.4**	**$ (1.3)**	**$ 71.0**

ITEM 1. FINANCIAL STATEMENTS (continued)

NISOURCE INC.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis for the three and six months ended June 30, 2009:

Three Months Ended June 30, 2009 *(in millions)*	Financial Transmission Rights	Other Derivatives	Total
Balance as of March 31, 2009	$ 0.9	$ (0.2)	$ 0.7
Total gains or losses (unrealized/realized)			
Included in regulatory assets/liabilities	(0.3)	0.2	(0.1)
Purchases, issuances and settlements (net)	2.1	(0.7)	1.4
Balance as of June 30, 2009	**$ 2.7**	**$ (0.7)**	**$ 2.0**
Change in unrealized gains/(losses) relating to instruments still held as of June 30, 2009	**$ -**	**$ 0.4**	**$ 0.4**

Six Months Ended June 30, 2009 *(in millions)*	Financial Transmission Rights	Other Derivatives	Total
Balance as of January 1, 2009	$ 2.6	$ 1.6	$ 4.2
Total gains or losses (unrealized/realized)			
Included in regulatory assets/liabilities	(0.3)	0.4	0.1
Purchases, issuances and settlements (net)	0.4	(2.7)	(2.3)
Balance as of June 30, 2009	**$ 2.7**	**$ (0.7)**	**$ 2.0**
Change in unrealized gains/(losses) relating to instruments still held as of June 30, 2009	**$ -**	**$ 0.4**	**$ 0.4**

As part of the MISO Day 2 initiative, Northern Indiana was allocated and has purchased FTRs. These rights help Northern Indiana offset congestion costs due to the MISO Day 2 activity. These instruments are considered derivatives and are valued utilizing forecasted congestion source and sink prices in the Day Ahead market. They are classified as Level 3 and reflected in the table above. The FTRs do not qualify for hedge accounting treatment, but since congestion costs are recoverable through the fuel cost recovery mechanism, the related gains and losses associated with marking these derivatives to market are recorded as a regulatory asset or liability, in accordance with SFAS No. 71. Northern Indiana also writes options for regulatory incentive purposes which are also considered Level 3 valuations and accounted for in accordance with SFAS No. 71. Realized gains and losses for these Level 3 recurring items are included in income within "Cost of Sales" on the Condensed Statements of Consolidated Income (Loss) (unaudited). Unrealized gains and losses from Level 3 recurring items are included within, Regulatory assets or Regulatory liabilities, on the Condensed Consolidated Balance Sheets (unaudited).

Non-recurring Fair Value Measurements. NiSource is engaged in a process to sell its unregulated natural gas marketing business. Net assets for the unregulated natural gas marketing business have been accounted for as assets of discontinued operations and the results of operations and cash flows of the unregulated natural gas marketing business were classified as discontinued operations for all periods presented. As a result of the letter of intent signed during the second quarter of 2009, other assets were recorded at fair value and a pre-tax impairment loss of $6.9 million was recognized during the second quarter in accordance with the provisions of SFAS No. 144. The other assets of the unregulated natural gas marketing business were valued based on the anticipated adjusted purchase price included in the letter of intent which is an unobservable input and is considered a Level 3 valuation. The following table presents financial assets measured and recorded at fair value on NiSource's Condensed Consolidated Balance Sheet (unaudited) on a non-recurring basis and their level within the fair value hierarchy as of June 30, 2009:

Non-Recurring Fair Value Measurements *(in millions)*	Balance as of June 30, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Gains (Losses)
Assets					
Long-lived net assets held for sale	$ 22.5	$ -	$ -	$ 22.5	$ (6.9)
Total	**$ 22.5**	**$ -**	**$ -**	**$** 22.5	**$ (6.9)**

B. SFAS 107 Fair Value Measurements. In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1 to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as annual financial statements. This FSP is effective for interim reporting periods ending after June 15, 2009, with early adoption permitted. NiSource adopted this FSP on April 1, 2009 and therefore has included the following SFAS 107 disclosures.

NiSource has certain financial instruments that are not measured at fair value on a recurring basis but nevertheless are recorded at amounts that approximate fair value due to their liquid or short-term nature, including cash and cash equivalents, restricted cash, accounts receivable, accounts payable, customer deposits and short-term borrowings. The company's long-term borrowings are recorded at historical amounts unless designated as a hedged item in a fair value hedge under SFAS No. 133.

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate fair value.

Investments. NiSource has corporate owned life insurance which is accounted for in accordance with FTB 85-4 and recorded at cash surrender value. NiSource's investments in corporate owned life insurance at June 30, 2009 and December 31, 2008 were $20.9 million and $17.7 million, respectively.

Long-term Debt. The fair values of these securities are estimated based on the quoted market prices for the same or similar issues or on the rates offered for securities of the same remaining maturities. Certain premium costs associated with the early settlement of long-term debt are not taken into consideration in determining fair value.

The carrying amount and estimated fair values of financial instruments were as follows:

At December 31, *(in millions)*	**Carrying Amount June 30, 2009**	**Estimated Fair Value June 30, 2009**	Carrying Amount Dec. 31, 2008	Estimated Fair Value Dec. 31, 2008
Long-term investments	**$ 21.9**	**$ 21.9**	$ 18.9	$ 18.9
Long-term debt (including current portion)	**6,988.4**	**6,691.0**	6,413.2	4,929.1

11. Transfers of Financial Assets

On May 14, 2004, Columbia of Ohio entered into an agreement to sell, without recourse, substantially all of its trade receivables, as they originate, to CORC, a wholly-owned subsidiary of Columbia of Ohio. CORC, in turn, is party to an agreement with Dresdner Bank AG, also dated May 14, 2004, under the terms of which it sells an undivided percentage ownership interest in the accounts receivable to a commercial paper conduit. On July 1, 2006, the agreement was amended to increase the seasonal program limit from $300 million to $350 million. On June 16, 2009, the agreement was extended through September 30, 2009. As of June 30, 2009, $100.0 million of accounts receivable had been sold by CORC compared to $236.5 million as of December 31, 2008.

Under the agreement, Columbia of Ohio acts as administrative agent, performing record keeping and cash collection functions for the accounts receivable sold. Columbia of Ohio receives a fee, which provides adequate compensation for such services. No servicing asset or liability is recorded since the servicing fee paid to Columbia of Ohio approximates a market rate.

On December 30, 2003, Northern Indiana entered into an agreement to sell, without recourse, all of its trade receivables, as they originated, to NRC, a wholly-owned subsidiary of Northern Indiana. NRC, in turn, was party to an agreement with Citibank, N.A. under the terms of which it sold an undivided percentage ownership interest in the accounts receivable to a commercial paper conduit. On May 20, 2009, NRC terminated its agreement with Citibank, North America, Inc., while Northern Indiana concurrently terminated its agreement with NRC. Northern Indiana plans on establishing a new accounts receivable program with another bank conduit sponsor prior to September 30, 2009.

NiSource's accounts receivable programs qualify for sale accounting based upon the conditions met in SFAS No. 140. In the agreements, all transferred assets have been isolated from the transferor and put presumptively beyond the reach of the transferor and its creditors. The transferors do not retain any interest in the sold receivables.

All accounts receivables sold to the commercial paper conduits are valued at face value, which approximate fair value due to its short-term nature. The accounts receivable sold are net of required loss reserves under the agreements.

The following tables reflect the gross and net receivables sold as of June 30, 2009 and December 31, 2008 as well as the retained interests, net receivables derecognized, and cash flows during the three and six months ended June 30, 2009 for Columbia of Ohio and Northern Indiana:

(in millions)	**June 30, 2009**	December 31, 2008
Receivables interest	$ 169.3	$ 657.8
Less: Retained interest	69.3	302.2
Net receivables derecognized	$ 100.0	$ 355.6

(in millions)	**Three Months Ended June 30, 2009**	**Six Months Ended June 30, 2009**
Operating cash flow		
Proceeds from receivables sold	$ 593.6	$ 1,689.8
Collections remitted to commercial paper conduit	(1,043.6)	(1,945.4)
Net cash flows used for operations	$ (450.0)	$ (255.6)
Receivables repurchased	$ 65.3	$ 65.3
Other, net expense — fees paid	$ 3.4	$ 7.6

12. Goodwill Assets

In accordance with the provisions of Statement SFAS No. 142 , NiSource tests its goodwill for impairment annually as of June 30 each year unless indicators, events, or circumstances would require an immediate review. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit, which generally is an operating segment or a component of an operating segment as defined in paragraph 10 of SFAS No. 131 and paragraph 30 of SFAS No. 142. In accordance with paragraph 30 of SFAS No. 142, certain components of an operating segment with similar economic characteristics are aggregated and deemed a single reporting unit. Goodwill amounts are generally allocated to the reporting units based upon the amounts allocated at the time of their respective acquisition. The goodwill impairment test is a two-step process which requires NiSource to make estimates regarding the fair value of the reporting unit. The first step of the goodwill impairment test, used to identify potential impairment, compares the fair value of the reporting unit with its carrying value, including goodwill. If the fair value of the reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not impaired, thus the second step of the impairment test is not required. However, if the carrying amount of the reporting unit exceeds its fair value, the second step of the goodwill impairment test is performed to measure the amount of impairment loss (if any), which compares the implied fair value of reporting unit goodwill with the carrying amount of that goodwill. If the carrying amount of reporting unit goodwill exceeds the implied fair value, an impairment loss is recognized in an amount equal to that excess.

NiSource has four reporting units that carry or are allocated goodwill. NiSource's goodwill assets at June 30, 2009 were $3,677.3 million pertaining primarily to the acquisition of Columbia on November 1, 2000. Of this amount, approximately $1,975.5 million is allocated to Columbia Transmission Operations (which is comprised of Columbia Transmission and Columbia Gulf) and $1,683.0 million is allocated to Columbia Distribution Operations (which is comprised of Columbia of Kentucky, Columbia of Maryland, Columbia of Ohio, Columbia of Pennsylvania and Columbia of Virginia). In addition, the goodwill balances at June 30, 2009 for Northern Indiana Fuel and Light and Kokomo Gas were $13.3 million and $5.5 million, respectively.

In estimating the fair value of the Columbia Transmission Operations and Columbia Distribution Operations reporting units for the June 30, 2009 test, NiSource used a weighted average of the income and market approach. Under the income approach, NiSource utilized a valuation technique based on discounted cash flows that incorporates internal projections of expected future cash flows and operating results to estimate a fair value of each reporting unit. Under the market approach, NiSource utilized three market-based models to estimate the fair value of the reporting units: (i) the comparable company multiples method, which estimated fair value of each reporting unit by analyzing EBITDA multiples of a peer group of publicly traded companies and applying that multiple to the reporting units EBITDA (ii) the comparable transactions method, which valued the reporting unit based on observed EBITDA multiples from completed transactions of peer companies and applying that multiple to the reporting unit's EBITDA and (iii) the market capitalization method, which used the NiSource share price and allocated NiSource's total market capitalization among both the goodwill and non-goodwill reporting units based on the relative EBITDA, revenues and operating income of each reporting unit. Each of the three market approaches were calculated with the assistance of a third party valuation firm, using multiples and assumptions inherent in today's market. The degree of judgment involved and reliability of inputs into each model were considered in weighting the various approaches. The resulting estimate of fair value of the reporting units, using the weighted average of the income and market approaches, exceeded their carrying values, indicating that no impairment exists, under Step 1 of the annual impairment test.

Certain key assumptions used in determining the fair values of the reporting units included planned operating results, discount rates and the long-term outlook for growth. NiSource used discount rates of 5.68% and 6.04% for Columbia Transmission Operations and Columbia Distribution Operations, respectively. Management also performed a sensitivity analysis using discount rates of 6.55% and 6.91% for Columbia Transmission Operations and Columbia Distribution Operations, respectively. Using the discount rates of 5.68% and 6.04% for Columbia Transmission Operations and Columbia Distribution Operations, respectively, the excess fair values were approximately $1,500 million for each reporting unit. If the discount rates were increased to 6.55% and 6.91% for Columbia Transmission Operations and Columbia Distribution Operations, respectively, the excess fair value would be approximately $700 million and approximately $500 million, respectively. Under either discount rate scenario, the impairment test indicated that a write-down of goodwill was not required.

Goodwill related to the acquisition of Northern Indiana Fuel and Light and Kokomo Gas of $13.3 million and $5.5 million, respectively, was also tested for impairment as of June 30, 2009 using an income approach to determine the fair value of each of these reporting units. A discount rate range of 6.04% to 6.91% and growth rates, factoring in the regulatory environment and growth initiatives, for each reporting unit were the significant assumptions used in determining the fair values using the income approach. The step 1 goodwill impairment test resulted in the fair value of each of these reporting units exceeding the carrying value.

13. Income Taxes

NiSource's interim effective tax rates reflect the estimated annual effective tax rates for 2009 and 2008, respectively, adjusted for tax expense associated with certain discrete items. The effective tax rate for the quarter ended June 30, 2009 was negative due to reasons mentioned below, and for the quarter ended June 30, 2008 was 30.4%. The effective tax rates for the six months ended June 30, 2009 and June 30, 2008 were 40.7% and 36.6%, respectively. These effective tax rates differ from the federal tax rate of 35% primarily due to the effects of tax credits, state income taxes, utility rate-making, and other permanent book-to-tax differences such as the electric production tax deduction provided under Internal Revenue Code Section 199.

The second quarter of 2009 effective tax rate is significantly impacted by an adjustment that increased deferred state income taxes as a result of the transfer of unregulated natural gas marketing business assets to assets and liabilities of discontinued operations, as well as by an increase in tax expense due to certain non-deductible expenses recorded in the quarter. The effective tax rate for the six months ended June 30, 2009 versus the six months ended June 30, 2008 increased by 4.1% due primarily to a reduction in estimated Section 199 deductions as a result of lower projected taxable income for 2009, an increase in tax expense related to AFUDC-Equity and certain depreciation differences, as well as the impact of the deferred state income tax increase and non-deductible expenses discussed above.

On July 3, 2008, the Governor of Massachusetts signed into law a bill that significantly changed the Massachusetts corporate income tax regime. Under the new law, which became effective for tax years beginning on or after January 1, 2009, NiSource calculates its Massachusetts income tax liability on a unitary basis, meaning that the income tax obligation to the Commonwealth of Massachusetts is determined based on an apportioned share of all of NiSource’s income, rather than just the income of NiSource’s subsidiaries doing business in Massachusetts. Because of NiSource’s substantial operations outside of Massachusetts, the new law had the impact of reducing the deferred income tax liability to Massachusetts. In accordance with SFAS No. 109, NiSource recognized the impact of this tax law change in the third quarter of 2008. Second quarter and six months ended 2009 income tax expense reflects the impact of the new law on a going forward basis.

There have been no material changes in 2009 to NiSource’s FIN 48 liabilities since December 31, 2008.

14. Pension and Other Postretirement Benefits

NiSource provides defined contribution plans and noncontributory defined benefit retirement plans that cover its employees. Benefits under the defined benefit retirement plans reflect the employees’ compensation, years of service and age at retirement. Additionally, NiSource provides 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 NiSource. 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.

NiSource expects to make contributions of approximately $104.2 million to its pension plans and approximately $52.9 million to its postretirement medical and life plans in 2009, which could change depending on market conditions. Through June 30, 2009, NiSource has contributed $11.3 million to its pension plans and $23.4 million to its other postretirement benefit plans.

NiSource Inc.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

The following table provides the components of the plans' net periodic benefits cost for the second quarter and six months ended June 30, 2009 and 2008:

	Pension Benefits		**Other Postretirement Benefits**	
Three Months Ended June 30, *(in millions)*	**2009**	2008	**2009**	2008
Components of Net Periodic Benefit Cost				
Service cost	**$ 9.0**	$ 9.4	**$ 2.2**	$ 2.3
Interest cost	**35.8**	33.1	**11.9**	11.9
Expected return on assets	**(30.4)**	(48.5)	**(4.2)**	(6.3)
Amortization of transitional obligation	**-**	-	**2.0**	2.0
Amortization of prior service cost	**1.0**	1.0	**0.3**	0.2
Recognized actuarial loss	**16.4**	0.3	**1.9**	1.0
Total Net Periodic Benefits Cost	**$ 31.8**	$ (4.7)	**$ 14.1**	$ 11.1

	Pension Benefits		**Other Postretirement Benefits**	
Six Months Ended June 30, *(in millions)*	**2009**	2008	**2009**	2008
Components of Net Periodic Benefit Cost				
Service cost	**$ 18.0**	$ 18.7	**$ 4.4**	$ 4.7
Interest cost	**71.6**	66.2	**23.8**	23.8
Expected return on assets	**(60.9)**	(97.0)	**(8.4)**	(12.6)
Amortization of transitional obligation	**-**	-	**4.0**	4.0
Amortization of prior service cost	**2.0**	2.1	**0.6**	0.4
Recognized actuarial loss	**32.8**	0.6	**3.8**	2.0
Total Net Periodic Benefits Cost	**$ 63.5**	$ (9.4)	**$ 28.2**	$ 22.3

The significant increase in pension cost for 2009 is due to a $797.7 million, or 35.6%, reduction in pension plan assets in 2008 due to a 30.3% negative return on assets for the year resulting from the overall market decline and benefit payments of $165.9 million made during 2008. For the quarters ended June 30, 2009 and 2008, pension and other postretirement benefit cost of approximately $12.3 million and income of $1.5 million, respectively, was capitalized as a component of plant or recognized as a regulatory asset or liability consistent with regulatory orders for certain of NiSource's regulated businesses. For the six months ended June 30, 2009 and 2008, pension and other postretirement benefit cost of approximately $24.6 million and income of $2.6 million, respectively, was capitalized as a component of plant or recognized as a regulatory asset or liability consistent with regulatory orders for certain of NiSource's regulated businesses.

15. Long-Term Debt

On April 9, 2009, NiSource Finance announced the final closing of a $385 million senior unsecured two-year bank term loan with a syndicate of banks maturing February 11, 2011. Borrowings under the bank term loan have an effective cost of LIBOR plus 538 basis points. On February 16, 2009, NiSource announced the initial closing of the bank term loan at the level of $265 million. Under an accordion feature, NiSource was able to increase the loan by $120 million prior to final closing.

On March 31, 2009, NiSource Finance announced that it was commencing a cash tender offer for up to $300 million aggregate principal amount of its outstanding 7.875% Notes due 2010. On April 28, 2009, NiSource Finance announced that $250.6 million of these notes were successfully tendered.

On March 9, 2009, NiSource Finance issued $600.0 million of 10.75% unsecured notes that mature March 15, 2016.

During January 2009, NiSource repurchased $32.4 million of the $450.0 million floating rate notes scheduled to mature in November 2009 and $67.6 million of the $1.0 billion 7.875% unsecured notes scheduled to mature in November 2010.

16. Share-Based Compensation

NiSource currently issues long-term incentive grants to key management employees under a long-term incentive plan approved by stockholders on April 13, 1994 (1994 Plan). The 1994 Plan, as amended and restated, permits the following types of grants, separately or in combination: nonqualified stock options, incentive stock options, restricted stock awards, stock appreciation rights, restricted stock units, contingent stock units and dividend equivalents payable on grants of options, performance units and contingent stock awards.

At June 30, 2009, there were 27,288,739 shares reserved for future awards under the amended and restated 1994 Plan.

NiSource recognized stock-based employee compensation expense of $4.9 million and $4.5 million and related tax benefits of $2.0 million and $1.7 million during the first six months of 2009 and 2008, respectively.

As of June 30, 2009, the total remaining unrecognized compensation cost related to nonvested awards amounted to $17.2 million, which will be amortized over the weighted-average remaining requisite service period of 2.1 years.

Stock Options. As of June 30, 2009, approximately 4.6 million options were outstanding and exercisable with a weighted average strike price of $22.60.

Restricted Awards. On March 24, 2009, 308,496 restricted stock units subject to service conditions were granted. The grant date fair-value of the restricted units was $3.0 million, based on the average market price of NiSource's common stock at the date of grant of $10.15, which will be expensed net of forfeitures ratably over the three year requisite service period. The service conditions lapse on January 31, 2012 when 100% of the shares vest. If the employee terminates employment before January 31, 2012 (1) due to retirement, having attained age 55 and completed ten years of service, or (2) due to death or disability, the employment conditions will lapse with respect to a pro rata portion of the restricted units on the date of termination. Termination due to any other reason will result in all restricted units awarded being forfeited effective the employee's date of termination. Employees will be entitled to receive dividends upon vesting. As of June 30, 2009, 539,493 nonvested restricted stock units were granted and outstanding.

Contingent Stock Units. On March 24, 2009, 925,490 contingent stock units subject to performance conditions were granted. The grant date fair-value of the award was $9.1 million, based on the average market price of NiSource's common stock at the date of grant of $10.15 which will be expensed net of forfeitures over the three year requisite service period. The performance conditions are based on achievement of non-GAAP financial measures: cumulative net operating earnings, that NiSource defines as income from continuing operations adjusted for certain items; cumulative funds from operations that NiSource defines as net operating cash flows provided by continuing operations; and total debt that NiSource defines as total debt adjusted for significant movement in natural gas prices and other adjustments determined by the Board. The service conditions lapse on January 31, 2012 when 100% of the shares vest. If the employee terminates employment before January 31, 2012 (1) due to retirement, having attained age 55 and completed ten years of service, or (2) due to death or disability, the employment conditions will lapse with respect to a pro rata portion of the contingent units on the date of termination. Termination due to any other reason will result in all contingent units awarded being forfeited effective the employee's date of termination. Employees will be entitled to receive dividends upon vesting. As of June 30, 2009, 1,695,626 nonvested contingent stock units were granted and outstanding.

Time-accelerated Awards. NiSource awarded restricted shares and restricted stock units that contain provisions for time-accelerated vesting to key executives under the 1994 Plan in January 2004. The total shareholder return measures established were not met; therefore these grants do not have an accelerated vesting period. At June 30, 2009, NiSource had 270,785 awards outstanding which contained the time-accelerated provisions.

Non-employee Director Awards. The Amended and Restated Non-employee Director Stock Incentive Plan provides for awards of restricted stock, stock options and restricted stock units, which vest immediately. The plan requires that restricted stock units be distributed to the directors after their separation from the Board. As of June 30, 2009, 89,860 restricted shares and 274,136 restricted stock units had been issued under the Plan.

NiSource Inc.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

17. Other Commitments and Contingencies

A. Guarantees and Indemnities. As a part of normal business, NiSource and certain 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. 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. The total commercial commitments in existence at June 30, 2009 and the years in which they expire were:

(in millions)	Total	2009	2010	2011	2012	2013	After
Guarantees of subsidiaries debt	$ 6,438.4	$ 417.6	$ 681.8	$ 385.0	$ 315.0	$ 545.0	$ 4,094.0
Guarantees supporting commodity transactions of subsidiaries	446.7	213.1	228.2				5.4
Letters of credit	275.3	1.3	272.9	0.1			1.0
Other guarantees	783.4	61.7	2.9		15.2	225.2	478.4
Total commercial commitments	$ 7,943.8	$ 693.7	$ 1,185.8	$ 385.1	$ 330.2	$ 770.2	$ 4,578.8

Guarantees of Subsidiaries Debt. NiSource has guaranteed the payment of $6.4 billion of debt for various wholly-owned subsidiaries including NiSource Finance, and through a support agreement, Capital Markets, which is reflected on NiSource's Condensed Consolidated Balance Sheet (unaudited) as of June 30, 2009. The subsidiaries are required to comply with certain financial covenants under the debt instruments and in the event of default, NiSource would be obligated to pay the debt's principal and related interest. NiSource does not anticipate its subsidiaries will have any difficulty maintaining compliance.

Guarantees Supporting Commodity Transactions of Subsidiaries. NiSource has issued guarantees, which support up to approximately $446.7 million of commodity-related payments for its current subsidiaries involved in energy marketing and trading and those satisfying requirements under forward gas sales agreements of current and former subsidiaries. These guarantees were provided to counterparties in order to facilitate physical and financial transactions involving natural gas and electricity. To the extent liabilities exist under the commodity-related contracts subject to these guarantees, such liabilities are included in the Condensed Consolidated Balance Sheets (unaudited).

Lines and Letters of Credit. NiSource Finance maintains a $1.5 billion five-year revolving credit facility with a syndicate of banks which has a termination date of July 7, 2011. This facility provides a reasonable cushion of short-term liquidity for general corporate purposes including meeting cash requirements driven by volatility in natural gas prices, as well as provides for the issuance of letters of credit. During September 2008, NiSource Finance entered into a new $500 million six-month revolving credit agreement with a syndicate of banks led by Barclays Capital that was originally due to expire on March 23, 2009. However, on February 13, 2009, the six-month credit facility was terminated in conjunction with the closing of a new two-year bank term loan. At June 30, 2009, NiSource had no short-term borrowings outstanding under its credit facility and has issued stand-by letters of credit of approximately $275.3 million for the benefit of third parties.

Other Guarantees or Obligations. On June 30, 2008, NiSource sold Whiting Clean Energy to BPAE for $216.7 million which included $16.1 million in working capital. The agreement with BPAE contains representations, warranties, covenants and closing conditions. NiSource has executed purchase and sales agreement guarantees totaling $220 million which guarantee performance of PEI's covenants, agreements, obligations, liabilities, representations and warranties under the agreement with BPAE. No amounts related to the purchase and sales agreement guarantees are reflected in the Condensed Consolidated Balance Sheet (unaudited) as of June 30, 2009.

NiSource has additional purchase and sales agreement guarantees totaling $30.0 million, which guarantee performance of the seller's covenants, agreements, obligations, liabilities, representations and warranties under the agreements. No amounts related to the purchase and sales agreement guarantees are reflected in the Condensed Consolidated Balance Sheets. Management believes that the likelihood NiSource would be required to perform or otherwise incur any significant losses associated with any of the aforementioned guarantees is remote.

NISOURCE INC.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

On August 29, 2007, Millennium entered into a bank credit agreement to finance the construction of the Millennium pipeline project. As a condition precedent to the credit agreement, NiSource issued a guarantee securing payment for 47.5%, its indirect ownership interest percentage, of amounts borrowed under the credit agreement up until such time as the amounts payable under the agreement are paid in full. As of June 30, 2009, Millennium owed $798.9 million under the financing agreements, of which NiSource guaranteed $379.5 million. NiSource recorded an accrued liability of approximately $7.6 million related to the fair value of this guarantee. The permanent financing for Millennium is expected to be completed when debt capital market conditions improve. In the interim, Millennium will continue to be funded by the $800 million credit agreement, which extends through August 2010.

On June 29, 2006, Columbia Transmission, Piedmont, and Hardy Storage entered into multiple agreements to finance the construction of the Hardy Storage project, which is accounted for by NiSource as an equity investment. Under the financing agreement, Columbia Transmission issued guarantees securing payment for 50% of any amounts issued in connection with Hardy Storage up until such time as the project is placed in service and operated within certain specified parameters. As of June 30, 2009, Hardy Storage owed $123.4 million under the financing agreement, for which Columbia Transmission recorded an accrued liability of approximately $1.2 million related to the fair value of its guarantee securing payment for $61.7 million which is 50% of the amount borrowed.

NiSource has issued other guarantees supporting derivative related payments associated with interest rate swap agreements issued by NiSource Finance, operating leases for many of its subsidiaries and for other agreements entered into by its current and former subsidiaries.

B. Other Legal Proceedings. In the normal course of its business, NiSource and its subsidiaries have been named as defendants in various legal proceedings. In the opinion of management, the ultimate disposition of these currently asserted claims will not have a material adverse impact on NiSource's consolidated financial position.

In the case of Tawney, et al. v. Columbia Natural Resources, Inc., the Plaintiffs, who are West Virginia landowners, filed a lawsuit in early 2003 against CNR alleging that CNR underpaid royalties on gas produced on their land by improperly deducting post-production costs and not paying a fair value for the gas. In December 2004, the court granted plaintiffs' motion to add NiSource and Columbia as defendants. Plaintiffs also claimed that the defendants fraudulently concealed the deduction of post-production charges. The court certified the case as a class action that includes any person who, after July 31, 1990, received or is due royalties from CNR (and its predecessors or successors) on lands lying within the boundary of the state of West Virginia. All claims by the government of the United States are excluded from the class. Although NiSource sold CNR in 2003, NiSource remains obligated to manage this litigation and for the majority of any damages ultimately awarded to the plaintiffs. On January 27, 2007, the jury hearing the case returned a verdict against all defendants in the amount of $404.3 million; this is comprised of $134.3 million in compensatory damages and $270 million in punitive damages. In January 2008, the Defendants filed their petition for appeal, and on March 24, 2008, the Defendants filed their amended petition for appeal with the West Virginia Supreme Court of Appeals. On May 22, 2008, the West Virginia Supreme Court of Appeals refused the defendants petition for appeal. On August 22, 2008, Defendants filed their petitions to the United States Supreme Court for writ of certiorari. The Plaintiffs filed their response on September 22, 2008. On September 19, 2008, the West Virginia Supreme Court issued an order extending the stay of the judgment until proceedings before the United States Supreme Court are fully concluded. Given the West Virginia Court's refusal of the appeal, NiSource adjusted its reserve in the second quarter of 2008 to reflect the portion of the trial court judgment for which NiSource would be responsible, inclusive of interest. This amount was included in "Legal and environmental reserves," on the Consolidated Balance Sheet as of December 31, 2008. On October 24, 2008, the West Virginia Circuit Court for Roane County, West Virginia, preliminarily approved a settlement agreement with a total settlement amount of $380 million. The settlement received final approval by the Court on November 22, 2008. NiSource's share of the settlement liability is up to $338.8 million. NiSource has complied with its obligations under the settlement agreement to fund $85.5 million in the qualified settlement fund by January 13, 2009. Additionally, NiSource provided a letter of credit on January 13, 2009 in the amount of $254 million and thereby complied with its obligation to secure the unpaid portion of the settlement. The trial court entered its order discharging the judgment on January 20, 2009. The Court is supervising the administration of the settlement proceeds. NiSource will be required to make additional payments, pursuant to the settlement, upon notice from the Class Administrator.

C. Environmental Matters.

General. The operations of NiSource are subject to extensive and evolving Federal, state and local environmental laws and regulations intended to protect the public health and the environment. Such environmental laws and regulations affect operations as they relate to impacts on air, water and land.

A reserve of $76.9 million and $73.1 million has been recorded as of June 30, 2009 and December 31, 2008, respectively, to cover probable corrective actions at sites where NiSource has environmental remediation liability. Regulatory assets have been recorded to the extent environmental expenditures are expected to be recovered in rates. NiSource accrues 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 many factors including currently enacted laws and regulations, existing technology and estimated site-specific costs whereby 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. NiSource's estimated environmental remediation liability will be refined as events in the remediation process occur. Actual remediation costs may differ materially from NiSource's estimates due to the dependence on the factors listed above.

On June 26, 2009, the United States House of Representatives passed a climate change bill, titled the *American Clean Energy and Security Act of 2009* ("ACES"). The comprehensive bill proposes a multi-sector, market-based greenhouse gas cap and trade system starting in 2012 for electrical suppliers and 2016 for natural gas suppliers. ACES would allocate gas and electric suppliers a certain number of allowances without charge, but these allocations would decrease over time, phasing out entirely by 2030, while gas pipeline companies are not allowed any emission allowances under ACES, they would fall under the greenhouse gas cap in 2014. ACES also contains Renewable Energy Standards, which would require retail electric suppliers to provide specified portions of their power from renewable sources by targeted dates. The Senate is considering its own renewable energy standard and has announced that it will consider separate legislation regulating green house gases later this year.

If ACES or other Federal comprehensive climate change bills were to pass both Houses of Congress and be enacted into law, the actual impact on NiSource's financial performance would depend on a number of factors, including the overall level of greenhouse gas reductions and amount of renewable energy required under the final legislation, the degree to which offsets may be used for compliance, the amount of recovery allowed from customers, and the extent to which NiSource would be entitled to receive CO_2 allowances without having to purchase them in an auction or on an open market. ACES or other Federal legislation could result in additional expense or compliance costs that may not be fully recoverable from customers and, as such, could materially impact NiSource's financial results. A full and accurate cost estimate cannot be made at the time.

On April 2, 2007, in Massachusetts v. EPA, the Supreme Court ruled that the EPA does have authority under the CAA to regulate emissions of greenhouse gases if it is determined that greenhouse gases have a negative impact on human health or the environment. On April 17, 2009, the EPA issued a proposed rule, which would make the following findings: (a) that greenhouse gases in the atmosphere endanger the public health and welfare within the meaning of the CAA and (b) that emissions of carbon dioxide and other greenhouse gases from new motor vehicles contribute to the mix of greenhouse gases in the atmosphere. The EPA accepted public comments on this new rule, which could become final in 2009. Although the EPA's proposed findings deal only with new motor vehicles, the proposed rule could be a precursor for the regulation of other greenhouse gas sources by the EPA under the CAA. The cost impact of any future regulation cannot be determined at this time.

The EPA proposed a mandatory greenhouse gas reporting rule on March 10, 2009, that would require reporting of greenhouse gas emissions from large sources. The emission information collected would be used by the EPA to develop comprehensive and accurate data relevant to future climate policy decisions, including potential future regulation of greenhouse gases. According to the proposal, data collection would begin January 1, 2010, with first reports due to the EPA on March 31, 2011. NiSource will continue to monitor development of this rule.

On February 25, 2009, the EPA proposed national emission standards for hazardous air pollutants for stationary reciprocating internal combustion engines that are not already covered by earlier EPA regulation. The proposed rule would impact smaller engines and impose a variety of additional requirements depending on the size and type of engine. In accordance with a consent decree, the proposed rule is scheduled to be finalized by February 10, 2010, with compliance generally required three years later. NiSource will continue to closely monitor developments in this matter and cannot estimate the cost of compliance at this time.

Implementation of the ozone and fine particulate matter NAAQS may require imposition of additional controls on boilers, engines and turbines. On April 15, 2004, the EPA finalized the eight-hour ozone nonattainment area designations under the 1997 eight-hour ozone NAAQS. After designation, the CAA provides for a process for promulgation of rules specifying compliance level, compliance deadline, and necessary controls to be implemented within designated areas over the next few years. In addition, on March 12, 2008, the EPA announced the tightening of the eight-hour ozone NAAQS. The number of areas that do not meet the new standard could significantly increase across the country, thus requiring additional Federal and state attainment planning and rulemaking. Resulting Federal and state rules could require additional reductions in NOx emissions from facilities owned by electric generation and gas transmission and storage operations.

On March 29, 2007, the EPA signed a rule to govern implementation of the NAAQS for particulate matter (PM2.5) that the EPA promulgated in 1997. The rule addresses a wide range of issues, including state rulemaking requirements as well as attainment demonstration requirements and deadlines. States must evaluate potential reduction measures for the emission of particulate matter and its precursors such as SO2 and NOx. The rule includes a conditional presumption that, for power plants subject to the CAIR, compliance with CAIR would satisfy Reasonably Available Control Measures and Reasonably Available Control Technology requirements for SO2 and NOx. States were required to submit attainment SIPs in April 2008. Also, on September 21, 2006, the EPA issued revisions to the NAAQS for particulate matter. The final rule increased the stringency of the current fine particulate (PM2.5) standard, added a new standard for inhalable coarse particulate (particulate matter between 10 and 2.5 microns in diameter), and revoked the annual PM10 standards while retaining the 24-hour PM10 standards. The EPA rule designating areas not meeting the new fine particulate matter standards was signed December 22, 2008, and is expected to be effective in 2009. The SIPs detailing how states will reduce emissions to meet the NAAQS will be due three years later in order to meet attainment by 2014 with a possible five year extension to 2019. On February 24, 2009, the D.C. Circuit struck down the primary annual and secondary PM2.5 NAAQS promulgated by the EPA in 2006 (American Farm Bureau Federation, et al. v. EPA). These standards have been remanded to the EPA for reconsideration. The Court denied the petitions to review the primary daily and annual standards for PM10. These standards are not vacated (i.e., they are still in effect, but must be reconsidered by the EPA). These actions could require further reductions in NOx emissions from various emission sources in and near nonattainment areas, including reductions from Gas Transmission and Storage Operations. NiSource will continue to closely monitor developments in these matters and cannot estimate the timing or cost of emission controls at this time.

Gas Distribution Operations. Several Gas Distribution Operations subsidiaries are potentially responsible parties at waste disposal sites under the CERCLA (commonly known as Superfund) and similar state laws, as well as at MGP sites, which such subsidiaries, or their corporate predecessors, own or previously owned or operated. Gas Distribution Operations subsidiaries may be required to share in the cost of cleanup of such sites. In addition, some Gas Distribution Operations subsidiaries have responsibility for corrective action under the RCRA for closure and cleanup costs associated with underground storage tanks and under the Toxic Substances Control Act for cleanup of PCBs. The final costs of cleanup have not yet been determined. As site investigations and cleanup proceed and as additional information becomes available reserves are adjusted.

A program has been instituted to identify and investigate former MGP sites where Gas Distribution Operations subsidiaries or predecessors are the current or former owner. The program has identified up to 84 such sites and initial investigations have been conducted at 52 sites. Additional investigation activities have been completed or are in progress at 50 sites and remedial measures have been implemented or completed at 30 sites. This effort includes the sites contained in the January 2004 Indiana Voluntary Remediation Program agreements between the IDEM and Northern Indiana, Kokomo Gas, and other Indiana utilities. Only those site investigation, characterization and remediation costs currently known and determinable can be considered “probable and reasonably estimable” under SFAS No. 5. As costs become probable and reasonably estimable, reserves will be adjusted. As reserves are recorded, regulatory assets are recorded to the extent environmental expenditures are expected to be recovered through rates. NiSource is unable, at this time, to estimate the time frame and potential costs of the entire program. Management expects that, as characterization is completed, additional remediation work is performed and more facts become available, NiSource will be able to develop a probable and reasonable estimate for the entire program or a major portion thereof consistent with the SEC's SAB No. 92, SFAS No. 5 and SOP 96-1.

Gas Transmission and Storage Operations. Columbia Transmission continues to conduct characterization and remediation activities at specific sites under a 1995 EPA AOC. The 1995 AOC covered 245 facilities, approximately 13,000 liquid removal points, approximately 2,200 mercury measurement stations and about 3,700 storage well locations. Field characterization has been performed at all sites. Site characterization reports and remediation plans, which must be submitted to the EPA for approval, are in various stages of development and completion. Remediation has been completed at the mercury measurement stations, liquid removal point sites, storage well locations and all but 48 of the 245 facilities. The AOC was amended in 2008 to facilitate payment of EPA oversight costs and to remove all but the remaining 48 facilities from the AOC.

One of the facilities subject to the AOC is the Majorsville Operations Center, which was remediated under an EPA approved Remedial Action Work Plan in summer 2008. Pursuant to the Remedial Action Work Plan, Columbia Transmission completed a project that stabilized residual oil contained in soils at the site and in sediments in an adjacent stream. On April 23, 2009, however, PADEP issued an NOV to Columbia Transmission, alleging that the remediation was not effective. The NOV asserts violations of the Pennsylvania Clean Streams Law and the Pennsylvania Solid Waste Management Act and contains a settlement demand in the amount of $1 million. On May 27, 2009, Columbia Transmission filed an appeal of the NOV to the Pennsylvania Environmental Hearing Board. Columbia Transmission is unable to estimate the likelihood or cost of potential penalties or additional remediation at this time.

Columbia Transmission and Columbia Gulf are potentially responsible parties at several waste disposal sites under CERCLA and similar state laws. The potential liability is believed to be de minimis. However, the final allocation of cleanup costs has yet to be determined. As site investigations and cleanups proceed and as additional information becomes available reserves will be adjusted.

Electric Operations.
Air. In December 2001, the EPA approved regulations developed by the State of Indiana to comply with the EPA's NOx SIP call. The NOx SIP call requires certain states, including Indiana, to reduce NOx levels from several sources, including industrial and utility boilers, to lower regional transport of ozone. Compliance with the NOx limits contained in these rules was required by May 31, 2004. To comply with the rule, Northern Indiana developed a NOx compliance plan, which included the installation of Selective Catalytic Reduction and combustion control NOx reduction technology at its active generating stations and is currently in compliance with the NOx requirements. In implementing the NOx compliance plan, Northern Indiana has expended approximately $316.2 million as of June 30, 2009.

Implementation of the fine particulate matter and ozone NAAQS has the potential to require imposition of additional controls on coal-fired boilers. On April 15, 2004, the EPA finalized the eight-hour ozone nonattainment area designations for the 1997 eight-hour ozone NAAQS and designated Lake, Porter, and LaPorte counties as nonattainment of the standard. This triggered a multi-year process for development of rules specifying compliance level, compliance deadline, and necessary controls to be implemented within nonattainment areas. Local ozone air quality improved in these three counties, and LaPorte County was redesignated to attainment of the eight-hour ozone NAAQS effective January 28, 2008. IDEM is also recommending Lake and Porter counties be redesignated to attainment with the 1997 standard because of improved air quality during the most recent averaging period. However, the March 12, 2008 EPA tightening of the eight-hour ozone NAAQS may result in Lake, Porter and LaPorte counties again being designated as nonattainment of the new 2008 ozone NAAQS. As discussed above under "General," the EPA ozone NAAQS revision could lead to additional emission reductions of NOx, an ozone precursor, from facilities owned by Northern Indiana. Northern Indiana will closely monitor developments in these matters and cannot at this time estimate the timing or cost of emission controls that may eventually be required.

Also, in 2005 Lake and Porter counties were designated nonattainment for fine particulate matter. Similar to ozone, local particulate matter air quality improved and IDEM submitted an attainment SIP that is awaiting EPA approval. Northern Indiana will continue to closely monitor developments in these matters and cannot predict the outcome or impact of the EPA action at this time.

NISOURCE INC.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

On September 21, 2006, the EPA issued revisions to the NAAQS for particulate matter. The EPA rule designating areas not meeting the new (2006) fine particulate matter standards was signed December 22, 2008, and expected to be effective in 2009. The SIPs detailing how states will reduce emissions to meet the NAAQS in these areas will be due three years later with attainment due by 2014 and a possible five year extension to 2019. The SIPs developed to meet this standard could impact the emission control requirements for coal-fired boilers including Northern Indiana's electric generating stations. Northern Indiana will continue to closely monitor developments in these matters and cannot estimate the impact, timing or cost of emission controls at this time.

On October 15, 2008, the EPA announced its first strengthening of the NAAQS for lead in 30 years by tightening the standards from the current 1.5 micrograms per cubic meter to 0.15 micrograms per cubic meter and changing both the calculation method and averaging time. Also included are provisions for the EPA to improve the existing lead monitoring network by requiring placement of monitors in areas with industrial facilities that emit one or more tons per year of lead. Designations of whether or not areas meet the standards are to be finalized by January 2012 with the state plans for reducing emissions to meet the standards due in June 2013 and compliance by January 2017. Northern Indiana is unable to predict the outcome of this action at this time.

On March 10, 2005, the EPA issued the CAIR final regulations. The rule establishes phased reductions of NOx and SO2 from 28 Eastern states, including electric utilities in Indiana, by establishing an annual emissions cap for NOx and SO2 and an additional cap on NOx emissions during the ozone control season. On March 15, 2006, the EPA signed three related rulemakings providing final regulatory decisions on implementing the CAIR. The EPA, in one of the rulings, denied several petitions for reconsideration of various aspects of the CAIR, including requests by Northern Indiana to reconsider SO2 and NOx allocations. As an affected state, Indiana structured, and preliminarily adopted in June 2006, a draft rule to meet the EPA abbreviated CAIR SIP requirements and adopted the final rules on November 1, 2006. The CAIR rules became effective in Indiana on February 25, 2007. In a petition filed with the IURC in December 2006, Northern Indiana provided plans for the first phase of the emission control construction required to address the Phase I CAIR requirements and a request for appropriate cost treatment and recovery. Northern Indiana's plan includes the upgrade of existing emission controls on three generating units for an estimated cost of $45.4 million and anticipates that these expenses are recoverable.

On July 11, 2008, the D.C. Court of Appeals vacated the CAIR in its entirety, and remanded the rule back to the EPA to develop a rule consistent with the Court's opinion. On September 24, 2008, four petitions were submitted seeking rehearing by the original panel and the full panel (en banc). Among the petitioners were the EPA as well as industry and environmental groups. On December 23, 2008, the Court decided to remand the CAIR without vacatur to EPA in order to remedy the CAIR's flaws in accordance with the Court's July 11, 2008 opinion in this case. Consequently, the Federal CAIR remains in effect. Northern Indiana will continue to monitor this matter and can not predict the outcome or impact of EPA action at this time.

In anticipation of the issuance of the Court's mandate to vacate CAIR upon the conclusion of legal proceedings, on October 23, 2008, the IDEM took the initial step to develop a new state rule to replace CAIR and obtain the emission reductions it would have achieved. As a result of the Court's December 23, 2008 action, the Indiana CAIR remains in effect and the IDEM suspended its replacement rulemaking activity based on the expectation that the EPA will develop a replacement rule. Northern Indiana will continue to monitor IDEM activity in this matter.

On October 3, 2007, the Indiana Air Pollution Control Board adopted, with minor changes from the EPA CAMR, the state rule to implement EPA's CAMR. The rule became effective on February 3, 2008, with compliance required in 2010. On February 8, 2008, the United States Court of Appeals for the District of Columbia Circuit vacated two EPA rules addressing utility mercury emissions that are the stimulus for the Indiana Air Pollution Control Board's CAMR. The first is the EPA's rule delisting coal and oil-fired electric generating units from the list of sources whose emissions are regulated under section 112 of the CAA, 42 U.S.C. § 7412. *Revision of December 2000 Regulatory Finding* ("Delisting Rule"), 70 Fed. Reg. 15,994 (March 29, 2005). The second is the EPA's rule that set performance standards for new coal-fired electric generating units and established total mercury emission limits for states along with a cap-and-trade program for new and existing coal-fired electric generating units. *Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units* ("CAMR"), 70 Fed. Reg. 28,606 (May 18, 2005). In response to the vacatur, the EPA is pursuing a new Section 112 rulemaking to establish Maximum Achievable Control Technology standards for electric utilities. On July 2, 2009, the EPA provided a notification and opportunity for comment on a new information request to obtain industry data that will be used to develop the National Emission Standards for Hazardous Air Pollutants for coal- and oil-fired electric steam generating units. The data collected and EPA’s response to this decision will affect the implementation and timing of the installation of controls to address potential reduction obligations for mercury and other pollutants subject to the section 112 rulemaking. Northern Indiana will closely monitor developments regarding any further action by the EPA and subsequent regulatory developments from the EPA and/or the Indiana Air Pollution Control Board in this matter.

On October 3, 2007, the Indiana Air Pollution Control Board adopted, with some minor modifications, a rule to implement the EPA BART requirements for reduction of regional haze. The rule became effective February 22, 2008, with compliance with any required BART controls within five years (2013). The language of the final rule relies upon the provisions of the Indiana CAIR to meet requirements for NOx and SO2 and does not impose any additional control requirements on coal-fired generation emissions, including those of Northern Indiana. As part of the BART analysis process, the IDEM evaluated the potential impact of particulate matter from electric generating units and found no significant impacts on Class I areas.

In late 1999, the EPA initiated a New Source Review enforcement action against several industries, including the electric utility industry, concerning rule interpretations that have been the subject of recent (prospective) reform regulations. On September 29, 2004, the EPA issued an NOV to Northern Indiana for alleged violations of the CAA and the Indiana SIP. The NOV alleges that modifications were made to certain boiler units at three of Northern Indiana’s generating stations between the years 1985 and 1995 without obtaining appropriate air permits for the modifications. The ultimate resolution could require additional capital expenditures and operations and maintenance costs, as well as payment of substantial penalties and development of supplemental environmental projects. Northern Indiana is currently in discussions with the EPA regarding possible resolutions to this NOV.

Water. The Great Lakes Water Quality Initiative program added new water quality standards for facilities that discharge into the Great Lakes watershed, including Northern Indiana’s three electric generating stations located on Lake Michigan. The State of Indiana has promulgated its regulations for this water discharge permit program and has received final EPA approval.

The IDEM issued a renewed NPDES Permit for Northern Indiana’s Michigan City Generating Station in 2006. The permit requires that the facility meet the Great Lakes Initiative discharge limits for copper. The Michigan City Generating Station originally had a four year compliance schedule to meet these limits, but on December 20, 2008, was granted a one year extension due to challenges with meeting the new limit. The new date of compliance with the new copper limits ends on April 2011 with the expiration of the current NPDES permit. Northern Indiana currently is evaluating and implementing various alternatives for treating copper in wastewater at the Michigan City Generating Station.

Great Lakes Initiative-based discharge limits for mercury have also been set for both the Bailly and the Michigan City Generating Stations. Northern Indiana will collect data, develop and implement pollution reduction program plans, to demonstrate progress in reducing mercury discharge. Streamlined Mercury Variance applications will be submitted for both stations in 2009.

On February 16, 2004, the EPA Administrator signed the Phase II Rule of the Clean Water Act Section 316(b) which requires all large existing steam electric generating stations meet certain performance standards to reduce the effects on aquatic organisms at their cooling water intake structures. The rule became effective on September 7, 2004. Under this rule, stations will either have to demonstrate that the performance of their existing fish protection systems meet the new standards or develop new systems, such as a closed-cycle cooling tower. On January 25, 2007, the Second Circuit in a Court decision on the Phase II 316(b) Rule remanded for EPA reconsideration the options providing flexibility for meeting the requirements of the rule. On March 20, 2007, the EPA issued a guidance memorandum advising its Regional Administrators that the Agency considers the Phase II 316(b) Rule governing cooling water withdrawals suspended. On July 5, 2007, the Second Circuit Court of appeals denied the petitions for rehearing that had asked the Court to reconsider its remand of the Phase II 316(b) Rule. On July 9, 2007, the EPA published a notice in the Federal Register suspending the Phase II Rule. The notice explained that the EPA is not accepting comments on the suspension and notes that "best professional judgment" is to be used in making 316(b) decisions.

Various parties submitted petitions for a *writ of certiorari* to the U.S. Supreme Court in early November 2007 seeking to reverse the Second Circuit Court's decision. On April 1, 2009, the Supreme Court issued their ruling reversing and remanding the Second Circuit's ruling. The case, *Entergy Corp. v. Riverkeeper, Inc.* , determined that the EPA did not overstep its authority when it adopted national performance standards utilizing cost-benefit analyses. The matter was remanded back to the 2 nd Circuit U.S. Court of Appeals for further proceedings. The EPA will propose a revised 316(b) rule and provide guidance to address the impact of the Court decision. The Bailly Generating Station is the only Northern Indiana generating station that does not utilize closed cycle cooling and the NPDES permit contains permit conditions that will require Bailly to address the 316(b) rules. Northern Indiana will continue to closely monitor this activity and cannot estimate the costs associated with the ultimate outcome at this time.

Remediation. Northern Indiana is a potentially responsible party under the CERCLA and similar state laws at two waste disposal sites and shares in the cost of their cleanup with other potentially responsible parties. At one site, the Remedial Investigation and Feasibility Study was submitted to the EPA in 2007. The EPA issued a Record of Decision in 2008 to conduct additional remedial activities at the site. At the second site, Northern Indiana has agreed to conduct a Remedial Investigation and Feasibility Study in the vicinity of the third party, state-permitted landfill where Northern Indiana contracted for fly ash disposal. In addition, Northern Indiana has corrective action liability under the RCRA for three facilities that historically stored hazardous waste.

On March 31, 2005, the EPA and Northern Indiana entered into an AOC under the authority of Section 3008(h) of the RCRA for the Bailly Station. The order requires Northern Indiana to identify the nature and extent of releases of hazardous waste and hazardous constituents from the facility. Northern Indiana must also remediate any release of hazardous constituents that present an unacceptable risk to human health or the environment. The process to complete investigation and select appropriate remediation activities is ongoing. A reserve has been established to fund the remedial measures proposed to the EPA. The final costs of cleanup could change based on EPA review.

On September 13, 2006, IDEM advised Northern Indiana that further investigation of historic releases from two previously removed underground storage tanks at the Schahfer Generating Station would need to be investigated. Northern Indiana completed an investigation of potentially impacted soils and groundwater and submitted results to the IDEM Leaking Underground Storage Tank section.

Coal Combustion Products. The Federal government continues to show interest in developing regulations covering coal combustion waste products. Subsequent to the December 22, 2008 dike collapse at a Tennessee Valley Authority ash pond, congressional hearings were held on the issue. Legislation regulating coal ash pursuant to the Surface Mining Control and Reclamation Act was introduced and the EPA is reviewing its previous determination that Federal regulation of coal ash as a RCRA Subtitle C hazardous waste is not appropriate. NiSource will monitor future regulatory actions and cannot estimate the potential financial impact at this time.

ITEM 1. FINANCIAL STATEMENTS (continued)

NISOURCE INC.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

18. Accumulated Other Comprehensive Loss

The following table displays the components of Accumulated Other Comprehensive Loss, which is included in "Common Stockholders' Equity," on the Condensed Consolidated Balance Sheets (unaudited).

(in millions)		**June 30, 2009**		December 31, 2008
Other comprehensive loss, before taxes:				
Unrealized gains on securities	**$**	**0.9**		0.4
Tax (expense) benefit on unrealized gains on securities		**(0.3)**		-
Unrealized losses on cash flow hedges		**(70.8)**		(232.1)
Tax benefit on unrealized gains on cash flow hedges		**27.6**		92.3
Unrecognized pension benefit and OPEB costs		**(50.8)**		(52.7)
Tax benefit on unrecognized pension benefit and OPEB costs		**19.4**		20.1
Total Accumulated Other Comprehensive Loss, net of taxes	**$**	**(74.0)**	$	(172.0)

Millennium, in which Columbia Transmission has an equity investment, entered into three interest rate swap agreements with a notional amount totaling $420 million with seven counterparties. In accordance with paragraph 121 of SFAS No. 130, Columbia Transmission recorded an unrecognized loss of $9.3 million as a decrease in its investment in Millennium and a corresponding decrease in accumulated other comprehensive income (loss), representing its ownership portion of the fair value of these swaps as of June 30, 2009.

19. Business Segment Information

Operating segments are components of an enterprise for which separate financial information is available that is evaluated regularly by the chief operating decision maker in deciding how to allocate resources and in assessing performance. The NiSource Chief Executive Officer is the chief operating decision maker.

NiSource's operations are divided into four primary business 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 Gas Transmission and Storage Operations segment offers gas transportation and storage services for LDCs, marketers and industrial and commercial customers located in northeastern, mid-Atlantic, midwestern and southern states and the District of Columbia. The Electric Operations segment provides electric service in 20 counties in the northern part of Indiana. The Other Operations segment primarily includes ventures focused on distributed power generation technologies, including fuel cells and storage systems.

The following table provides information about business segments. NiSource uses operating income as its primary measurement for each of the reported segments and makes 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.

ITEM 1. FINANCIAL STATEMENTS (continued)

NiSource Inc.
Notes to Condensed Consolidated Financial Statements (unaudited) (continued)

(in millions)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
REVENUES				
Gas Distribution Operations				
Unaffiliated	**$ 557.5**	$ 1,026.5	**$ 2,512.8**	$ 3,474.0
Intersegment	**-**	2.9	**-**	2.9
Total	**557.5**	1,029.4	**2,512.8**	3,476.9
Gas Transmission and Storage Operations				
Unaffiliated	**164.2**	151.8	**346.9**	321.0
Intersegment	**44.9**	44.2	**104.5**	106.3
Total	**209.1**	196.0	**451.4**	427.3
Electric Operations				
Unaffiliated	**286.7**	341.1	**584.9**	673.9
Intersegment	**0.2**	0.2	**0.4**	0.4
Total	**286.9**	341.3	**585.3**	674.3
Other Operations (a)				
Unaffiliated	**1.1**	32.2	**2.6**	59.0
Intersegment	**1.1**	1.2	**2.2**	2.2
Total	**2.2**	33.4	**4.8**	61.2
Adjustments and eliminations	**(46.5)**	(42.9)	**(106.5)**	(103.7)
Consolidated Revenues	**$ 1,009.2**	$ 1,557.2	**$ 3,447.8**	$ 4,536.0
Operating Income (Loss)				
Gas Distribution Operations	**$ 3.9**	$ (10.0)	**$ 247.1**	$ 244.9
Gas Transmission and Storage Operations	**79.6**	77.9	**172.5**	182.7
Electric Operations	**23.0**	50.7	**40.3**	89.1
Other Operations	**(1.7)**	(1.5)	**(3.1)**	(3.3)
Corporate	**(0.9)**	(2.7)	**(4.7)**	(5.5)
Consolidated Operating Income	**$ 103.9**	$ 114.4	**$ 452.1**	$ 507.9

(a) Other Operations gross revenues in 2008 included gas marketing activities to three municipalities in the United States associated with Columbia Energy Services. Obligations under these contracts were completed by December 2008.

20. Supplemental Cash Flow Information

The following table provides additional information regarding NiSource's Condensed Statements of Consolidated Cash Flows (unaudited) for the six months ended June 30, 2009 and 2008:

Six Months Ended June 30, *(in millions)*	2009	2008
Supplemental Disclosures of Cash Flow Information		
Non-cash transactions		
Changes in accrued plant in service and other items	**$ (8.0)**	$ 23.2
Change in equity investments related to unrealized gains (losses)	**34.2**	-
Schedule of interest and income taxes paid		
Cash paid for interest	**186.1**	188.0
Interest capitalized	**1.8**	12.4
Cash paid for income taxes	**-**	38.3

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITIONS AND RESULTS OF OPERATIONS

NISOURCE INC.

Note regarding forward-looking statements
The Management's Discussion and Analysis, including statements regarding market risk sensitive instruments, contains "forward-looking statements," within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. 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 NiSource's plans, objectives, expected performance, expenditures and 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. From time to time, NiSource may publish or otherwise make available forward-looking statements of this nature. All such subsequent forward-looking statements, whether written or oral and whether made by or on behalf of NiSource, are also expressly qualified by these cautionary statements. 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.

Realization of NiSource's objectives and expected performance is subject to a wide range of risks and can be adversely affected by, among other things, weather, fluctuations in supply and demand for energy commodities, growth opportunities for NiSource's businesses, increased competition in deregulated energy markets, the success of regulatory and commercial initiatives, dealings with third parties over whom NiSource has no control, the effectiveness of NiSource's restructured outsourcing agreement, actual operating experience of NiSource's assets, the regulatory process, regulatory and legislative changes, the impact of potential new environmental laws or regulations, the results of material litigation, changes in pension funding requirements, changes in general economic, capital and commodity market conditions, and counterparty credit risk, many of which risks are beyond the control of NiSource. In addition, the relative contributions to profitability by each segment, and the assumptions underlying the forward-looking statements relating thereto, may change over time. NiSource expressly disclaims a duty to update any of the forward-looking statements contained in this report.

The following Management's Discussion and Analysis should be read in conjunction with NiSource's Annual Report on Form 10-K for the fiscal year ended December 31, 2008.

CONSOLIDATED REVIEW

Executive Summary

NiSource is an energy holding company under the Public Utility Holding Company Act of 2005 whose subsidiaries are engaged in the transmission, storage and distribution of natural gas in the high-demand energy corridor stretching from the Gulf Coast through the Midwest to New England and the generation, transmission and distribution of electricity in Indiana. NiSource generates virtually 100% of its operating income through these rate-regulated businesses. A significant portion of NiSource's operations is subject to seasonal fluctuations in sales. During the heating season, which is primarily from November through March, net revenues from gas sales are more significant, and during the cooling season, which is primarily from June through September, net revenues from electric sales and transportation services are more significant than in other months.

For the six months ended June 30, 2009, NiSource reported income from continuing operations of $150.6 million, or $0.55 per basic share, a decrease of $57.7 million, or $0.21 per basic share reported for the same period in 2008.

Decreases in income from continuing operations were due primarily to the following items:

- Employee and administrative expenses increased $40.0 million across NiSource's business segments resulting from increased pension expense of approximately $49.2 million. The increase in pension expense for 2009 is primarily due to a $797.7 million reduction in pension plan assets in 2008. Pension plan assets declined as a result of a 30.3% negative return on assets for the year due to the overall market decline and benefit payments of $165.9 million made during 2008.

- Electric Operations net revenues were $26.9 million lower primarily due to lower industrial usage and off-system sales. Industrial volumes are down approximately 23% in the first six months of 2009 when compared to the same 2008 period.

- NiSource's Gas Transmission and Storage Operations segment recorded a $19.8 million restructuring charge in the first quarter of 2009.

- Interest expense increased $16.6 million primarily due to incremental interest expense associated with the issuance of $700 million of long-term debt in May of 2008 and $600 million of long-term debt in March of 2009, partially offset by the open market debt repurchase of $100 million in January 2009, the $250.6 million tender offer debt repurchase in April 2009 and lower short-term interest rates.

Decreases in income from continuing operations were partially offset due to the following items:

- Gas Distribution Operations' net revenues increased by $39.4 million due primarily to increased revenues of $47.6 million from regulatory initiatives including impacts from rate proceedings.

- Gas Transmission and Storage Operations' net revenues increased by $24.1 million due primarily to increases in firm capacity reservation fees and shorter term transportation and storage services. The increase in firm capacity reservation fees was the result of higher revenue for storage services, new Appalachian Supply interconnects, and incremental revenue from transportation agreements.

These factors and other impacts to the financial results are discussed in more detail within the following discussions of "Results of Operations" and "Results and Discussion of Segment Operations."

Four-Point Platform for Growth

NiSource's four-part business plan will continue to center on commercial and regulatory initiatives; commercial growth and expansion of the gas transmission and storage business; financial management of the balance sheet; and process and expense management.

Commercial and Regulatory Initiatives

Rate Development and Other Regulatory Matters. NiSource is moving forward on regulatory initiatives across several distribution company markets and progress continues with Northern Indiana's electric base rate case. Whether through full rate case filings or other approaches, NiSource's goal is to develop strategies that benefit all stakeholders as it addresses changing customer conservation patterns, develops more contemporary pricing structures, and embarks on long-term investment programs to enhance its infrastructure.

Northern Indiana filed a petition for new electric base rates and charges on June 27, 2008. The case-in-chief was originally filed on August 29, 2008, and amended on December 19, 2008 after the Sugar Creek facility was successfully dispatched into MISO. The filing requested an increase in base rates calculated to produce additional annual gross margin of $85.7 million. Evidentiary hearings on Northern Indiana's direct case commenced on January 12, 2009 and concluded on February 6, 2009. Several stakeholder groups have intervened in the case, representing customer groups and various counties and towns within Northern Indiana's electric service territory. Field hearings to record customer testimonies were held on March 3, 2009 and July 15, 2009. The OUCC and intervenors filed their cases-in-chief on May 8, 2009. Northern Indiana filed its rebuttal testimony on June 26, 2009. Northern Indiana made several minor changes to its revenue requirement, and, as a result the margin requirement in the rebuttal filing is $6 million less than the original request. Final hearings began on July 27, 2009. The case is expected to be resolved, and new electric rates effective during early 2010.

Columbia of Ohio received authority on July 8, 2009 from the PUCO to defer the difference between actual pension and other postretirement benefits expenses and the levels reflected in Columbia of Ohio's base rates effective January 1, 2009. The financial impact of the deferral, which is expected to positively impact 2009 operating income by approximately $13.0 million, will be reflected in the company's results for the third and fourth quarters.

On April 16, 2009, Bay State filed a base rate case with the Massachusetts Department of Public Utilities, requesting an increase of $34.6 million. In its initial filing, Bay State is seeking revenue decoupling, as well as an expedited mechanism for the recovery of costs associated with the rehabilitation of the company's infrastructure. This matter is currently pending and expected to be resolved with new rates taking effect in the fourth quarter 2009.

On May 1, 2009, Columbia of Kentucky filed a base rate case with the Kentucky PSC, requesting an annual increase of $11.6 million. In its initial filing, Columbia of Kentucky is seeking enhancements to rate design, as well as an expedited mechanism for the recovery of costs associated with the rehabilitation of the company's infrastructure. This matter is currently pending.

Northern Indiana received a favorable regulatory order on February 18, 2009 related to its actions to increase its electric generating capacity and advance its electric rate case. Acting on a settlement reached among Northern Indiana and its regulatory stakeholders, the IURC ruled that Northern Indiana's Sugar Creek electric generating plant was "in service" for ratemaking purposes as of December 1, 2008. The IURC also approved the deferral of depreciation expenses and carrying costs associated with the $330 million Sugar Creek investment. Northern Indiana purchased Sugar Creek on May 30, 2008 and effective December 1, 2008, Sugar Creek was accepted as an internal designated network resource within the MISO.

On January 15, 2009, Columbia of Ohio filed an application with the PUCO requesting authority to increase Columbia of Ohio's PIPP rider rate in order to collect $82.2 million in PIPP arrearages over a three year period. On March 3, 2009, Columbia of Ohio's proposal was deemed approved and became effective.

On October 1, 2008, Columbia of Maryland filed a base rate case with the Maryland PSC. On February 20, 2009, Columbia of Maryland and all interested parties filed a unanimous settlement in the case, recommending an annual revenue increase of $1.2 million. On March 27, 2009, the settlement was approved as filed.

Refer to the "Results and Discussion of Segment Operations" for a complete discussion of regulatory matters.

Bear Garden Station. Columbia of Virginia has entered into an agreement with Dominion Virginia Power to install facilities to serve a 585 mw combined cycle generating station in Buckingham County, VA, known as the Bear Garden station. The project requires approximately 13.3 miles of 24-inch steel pipeline and associated facilities to serve the station. In March 2009, the VSCC approved Dominion Virginia Power Company's planned Bear Garden station with service expected to begin by the summer of 2011.

Commercial Growth and Expansion of the Gas Transmission and Storage Business

Hardy Storage Project. The first two phases of Hardy Storage are in service, receiving customer injections and withdrawing natural gas from its new underground natural gas storage facility in West Virginia. When the third and final Phase is fully operational in November 2009, the field will have a working storage capacity of 12 Bcf, and the ability to deliver 176,000 Dth of natural gas per day. Hardy Storage is a joint venture of subsidiaries of Columbia Transmission and Piedmont.

Line 1570 Project. In October 2008, Columbia Transmission entered into a Precedent Agreement to gather and transport phased in volumes of up to 150,000 Dth per day of gas in the Waynesburg, PA area along Line 1570. The first two phases of this project were available for service in October 2008 and March 2009. Additional volumes will be phased in later in 2009 and during 2010. Facilities are expected to be completed in fourth quarter of 2009.

Millennium Pipeline Project. The Millennium pipeline was substantially completed in the fourth quarter of 2008 and the pipeline commenced service on December 22, 2008, with the capability to transport up to 525,400 Dth per day of natural gas to markets along its route, as well as to the New York City market through its pipeline interconnections. The Millennium partnership is currently comprised of interest from Columbia Transmission (47.5%), DTE Millennium Company (26.25%), and National Grid Millennium LLC (26.25%) with Columbia Transmission acting as operator.

Columbia Penn Project. In September 2008, Columbia Transmission announced its intention to develop additional natural gas transmission, gathering and processing services along and around its existing pipeline corridor between Waynesburg, PA and Renovo, PA, referred to as the "Columbia Penn" corridor. This two-phase development will provide access to pipeline capacity in conjunction with production increases in the Marcellus Shale formation which underlies Columbia Transmission's transmission and storage network in the region. Phase I was placed into service in February 2009 and Phase II should be available by the end of 2009.

Eastern Market Expansion Project . The project allows Columbia Transmission to expand its facilities to provide additional storage and transportation services and to replace certain existing facilities. The Eastern Market Expansion is adding 97,000 Dth per day of storage and transportation deliverability and is fully subscribed on a 15-year contracted firm basis. Construction of the facilities is complete and was placed in service April 1, 2009.

Ohio Storage Project. On June 24, 2008, Columbia Transmission filed an application before the FERC for approval to expand two of its Ohio storage fields for additional capacity of nearly 7 Bcf and 103,400 Dth per day of daily deliverability. Approval was granted in March 2009 and construction of the facilities began in April 2009. Partial service related to this expansion was available beginning May 2009 and the remainder will be available no later than the fourth quarter of 2009. The expansion capacity is 58% contracted on a long-term, firm basis, with the FERC authorized market-based rates for these services.

Appalachian Expansion Project. On August 22, 2008, the FERC issued an order to Columbia Transmission, which granted a certificate to construct the project. The project includes building a new 9,470 hp compressor station in West Virginia. The Appalachian Expansion Project added 100,000 Dth per day of transportation capacity and is fully subscribed on a 15-year contracted firm basis. Construction is complete and the project was placed in service on July 1, 2009.

Easton Compressor Station. On March 30, 2009, Columbia Transmission announced a binding open season for capacity into premium East Coast markets resulting from modifications made to the company's Easton Compressor Station. The modifications will increase delivery capacity from the Wagoner interconnection point between the Columbia Transmission and Millennium pipeline systems. Through the open season, which closed on April 3, 2009, Columbia Transmission received 30,000 Dth per day of binding bids. Construction is under way and service is expected to commence in the fourth quarter of 2009.

Centerville Expansion Project. An open season to solicit interest and receive bids for expanded capacity on Columbia Gulf's system for delivery to Southern Natural Gas and the Louisiana intrastate pipeline market was held during the first quarter of 2008, and bids for 60,000 Dth per day of capacity were submitted. The remaining 175,000 Dth per day of capacity is being reviewed in conjunction with other market opportunities on the East Lateral in South Louisiana. The project is expected to be placed into service in late 2010.

Cobb Compressor Station Expansion. Shippers have also executed precedent agreements for a total of approximately 25,500 Dth per day of long-term firm transportation service associated with a facility expansion at Cobb Compressor Station in Kanawha County, West Virginia. The Cobb Expansion is expected to be in service April 1, 2010.

Financial Management of the Balance Sheet

NiSource has been closely monitoring developments relative to the financial crisis and has executed on its plan to effectively manage through this period. During the past several months, NiSource has successfully executed against its financing and liquidity plan through the following actions:

- On June 25, 2009, Columbia of Virginia received approval from the VSCC for the issuance of external long-term debt of up to $75 million of either external long-term debt or long-term inter-company notes. Northern Indiana is also seeking to amend its financing petition to allow for the issuance of $120 million of either external long-term debt or long-term inter-company notes.

- On April 9, 2009, NiSource Finance announced the final closing of a $385 million senior unsecured two-year bank term loan with a syndicate of banks maturing February 11, 2011. Borrowings under the bank term loan have an effective cost of LIBOR plus 538 basis points. On February 16, 2009, NiSource announced the initial closing of the bank term loan at the level of $265 million. Under an accordion feature, NiSource was able to increase the loan by $120 million prior to final closing.

NISOURCE INC.

- On March 31, 2009, NiSource Finance announced that it was commencing a cash tender offer for up to $300 million aggregate principal amount of its outstanding 7.875% Notes due 2010. On April 28, 2009, NiSource Finance announced that $250.6 million of these notes were successfully tendered.

- On March 9, 2009, NiSource Finance issued $600 million of senior unsecured notes in an underwritten offering. NiSource will use the proceeds from the issuance to complete the refinancing of outstanding debt scheduled to mature in November 2009 and for general corporate purposes, including refinancing a portion of outstanding debt scheduled to mature in November 2010.

During the third quarter of 2009, NiSource also expects to file a petition to add an accounts receivable securitization facility for Columbia of Pennsylvania and is in the process of executing new facilities at Columbia of Ohio and Northern Indiana. Total capacity of these facilities is expected to be approximately $525 million with opportunities for annual renewal and capacity increases as required.

NiSource's overall liquidity strategy, including the recent financial and optimization initiatives, not only fully addresses the company's 2009 debt refinancing requirements but also places the company well on the way toward meeting the remaining 2010 refinancing needs. NiSource estimates that its remaining financing requirements through 2010 will be less than $500 million. NiSource will continue to closely monitor events in the credit markets, as well as overall economic conditions in the nation and the markets it serves. Maintaining financial flexibility will remain a key priority for NiSource.

Credit Ratings. On March 5, 2009, Standard and Poor's affirmed its senior unsecured ratings for NiSource and its subsidiaries at BBB-, and revised the outlook to stable from negative. On July 29, 2009, Moody's Investors Service affirmed the senior unsecured ratings for NiSource at Baa3, and the existing ratings of all other subsidiaries. Moody's outlook for NiSource and its subsidiaries is negative. On February 4, 2009, Fitch lowered its senior unsecured ratings for NiSource to BBB- and for Northern Indiana to BBB. Fitch's outlook for NiSource and all of its subsidiaries is stable. Although all ratings continue to be investment grade, an additional downgrade by Standard and Poor's, Moody's or Fitch would result in a rating that is below investment grade.

Process and Expense Management

In February 2009, NiSource announced an organizational restructuring of the Gas Transmission and Storage Operations segment. NiSource is eliminating positions across the 16 state operating territory of Gas Transmission and Storage Operations. The reductions will occur through normal attrition as well as through voluntary programs and involuntary separations. In addition to employee reductions, the Gas Transmission and Storage Operations segment will take steps to achieve additional cost savings by efficiently managing its various business locations, reducing its fleet operations, creating alliances with third party service providers, and implementing other changes in line with its strategic plan for growth and in response to current economic conditions. During the first half of 2009, NiSource recorded a pre-tax restructuring charge, net of adjustments, of $19.8 million to "Operation and maintenance" expense on the Condensed Statement of Consolidated Income (Loss) (unaudited), which primarily includes costs related to severance and other employee related costs for approximately 360 employees. As of June 30, 2009, 246 employees had been severed from employment bringing the restructuring liability balance for this initiative to $5.7 million. NiSource expects this restructuring initiative to be substantially complete by the end of 2009. Refer to Note 4, "Restructuring Activities," in the Notes to Condensed Consolidated Financial Statements (unaudited) for additional information regarding restructuring initiatives.

In the second quarter of 2009, Northern Indiana and representatives of the United Steelworkers union reached five-year collective bargaining agreements covering approximately 1,900 Northern Indiana employees. The parties' new labor agreements are scheduled to expire May 31, 2014.

Ethics and Controls

NiSource has had a long term commitment to providing accurate and complete financial reporting as well as high standards for ethical behavior by its employees. NiSource's senior management takes an active role in the development of this Form 10-Q and the monitoring of the company's internal control structure and performance. In addition, NiSource will continue its mandatory ethics training program in which employees at every level throughout the organization participate.

Refer to "Controls and Procedures" included in Item 4.

Results of Operations
Quarter Ended June 30, 2009

Net Income
NiSource reported a net loss of $4.8 million, or $0.02 loss per basic share, for the three months ended June 30, 2009, compared to a net loss of $202.3 million, or $0.74 loss per basic share, for the second quarter 2008. The loss from continuing operations was $8.7 million, or $0.03 loss per basic share, for the three months ended June 30, 2009, compared to income of $19.7 million, or $0.07 per basic share, for the second quarter 2008. Operating income was $103.9 million, a decrease of $10.5 million from the same period in 2008. All per share amounts are basic earnings per share. Basic average shares of common stock outstanding at June 30, 2009 were 274.7 million compared to 274.0 million at June 30, 2008.

Comparability of line item operating results was impacted by regulatory and tax trackers that allow for the recovery in rates of certain costs such as bad debt expenses. Therefore, increases in these tracked operating expenses are offset by increases in net revenues and had essentially no impact on income from continuing operations. A net increase in operating expenses of $2.2 million for the second quarter of 2009 was offset by a corresponding net increase to net revenues reflecting recovery of these tracked costs.

Net Revenues
Total consolidated net revenues (gross revenues less cost of sales) for the three months ended June 30, 2009, were $671.0 million, a $5.8 million increase from the same period last year. This increase in net revenues was primarily due to increased Gas Distribution Operations' net revenues of $17.8 million and increased Gas Transmission and Storage Operations' net revenues of $13.1 million, partially offset by lower Electric Operations' net revenues of $21.9 million. Gas Distribution Operations' net revenues increased due to increased revenues of $28.7 million from regulatory initiatives including impacts from rate proceedings, partially offset by decreased usage from residential and industrial customers. Within Gas Transmission and Storage Operations, net revenues increased due primarily to increases in firm capacity reservation fees and shorter term transportation and storage services of $12.9 million. The increase in firm capacity reservation fees was the result of higher revenue for storage services, new Appalachian Supply interconnects, and incremental revenue from transportation agreements. Electric Operations' net revenues decreased due to lower industrial usage, which was significantly impacted by steel and steel-related companies. The major steel companies were operating at close to full capacity in early 2008 and are now operating at about half capacity.

Expenses
Operating expenses for the second quarter 2009 were $564.5 million, an increase of $12.1 million from the 2008 period. This increase was primarily due to higher pension expense of approximately $25 million, increased legal reserves of $6.4 million and $5.0 million higher electric generation and maintenance costs, partially offset by lower employee and administrative expenses, excluding pension, of $15.3 million across NiSource's business segments and decreased other taxes of $9.6 million. The increase in pension expense for 2009 is due to a $797.7 million reduction in pension plan assets in 2008 from a 30.3% negative return on assets for the year due to the overall market decline and benefit payments of $165.9 million made during 2008.

Other Income (Deductions)
Interest expense increased by $17.9 million primarily due to incremental interest expense associated with the issuance of $700 million of long-term debt in May of 2008 and $600 million of long-term debt in March of 2009, partially offset by the open market debt repurchase of $100 million in January 2009, the $250.6 million tender offer debt repurchase in April 2009 and lower short-term interest rates. Other, net was a loss of $0.5 million compared to income of $1.3 million for the second quarter of 2008 as a result of lower interest income.

Income Taxes
Income taxes for the second quarter of 2009 were $6.1 million, a decrease of $2.5 million compared to the second quarter of 2008. The effective tax rate was negative for the quarter ended June 30, 2009 compared to 30.4% for the comparable period last year. These effective tax rates differ from the federal tax rate of 35% primarily due to the effects of tax credits, state income taxes, utility rate-making, and other permanent book-to-tax differences such as the electric production tax deduction provided under Internal Revenue Code Section 199. The second quarter of 2009 effective tax rate is significantly impacted by an adjustment that increased deferred state income taxes as a result of NiSource’s decision to sell its unregulated natural gas marketing business, as well as by an increase in tax expense due to certain non-deductible expenses recorded in the quarter.

Discontinued Operations
Discontinued operations reflected income of $12.7 million in the second quarter of 2009, compared to a loss of $219.2 million in the second quarter of 2008. Income for 2009 is primarily attributable to NiSource’s unregulated natural gas marketing business. The loss in 2008 is primarily attributable to an adjustment to the reserve for the Tawney litigation. The $8.8 million after-tax loss on the disposition of discontinued operations in the second quarter of 2009 related to NiSource’s decision to sell its unregulated natural gas marketing business. In the second quarter of 2008, NiSource recorded an estimated after-tax loss adjustment of $2.8 million for the disposition of Northern Utilities, Granite State Gas and Whiting Clean Energy.

Results of Operations
Six Months Ended June 30, 2009

Net Income
NiSource reported net income of $143.6 million, or $0.52 per basic share, for the six months ended June 30, 2009, compared to a net loss of $103.0 million, or $0.38 loss per basic share, for the first six months 2008. Income from continuing operations was $150.6 million, or $0.55 per basic share, for the six months ended June 30, 2009, compared to $208.3 million, or $0.76 per basic share, for the comparable 2008 period. Operating income was $452.1 million, a decrease of $55.8 million from the same period in 2008. All per share amounts are basic earnings per share. Basic average shares of common stock outstanding at June 30, 2009 were 274.4 million compared to 273.9 million at June 30, 2008.

Comparability of line item operating results was impacted by regulatory and tax trackers that allow for the recovery in rates of certain costs such as bad debt expenses. Therefore, increases in these tracked operating expenses are offset by increases in net revenues and had essentially no impact on income from continuing operations. A net increase in operating expenses of $14.7 million for 2009 was offset by a corresponding net increase to net revenues reflecting recovery of these tracked costs.

Net Revenues
Total consolidated net revenues (gross revenues less cost of sales) for the six months ended June 30, 2009, were $1,734.7 million, a $32.5 million increase from the same period last year. Net revenues increased primarily due to increased Gas Distribution Operations’ net revenues of $39.4 million and increased Gas Transmission and Storage Operations’ net revenues of $24.1 million, partially offset by lower Electric Operations’ net revenues of $26.9 million. Gas Distribution Operations’ net revenues increased due to increased revenues of $47.6 million from regulatory initiatives including impacts from rate proceedings, increased net regulatory and tax trackers of $9.0 million offset in expense and colder weather of approximately $7 million, partially offset by decreased customer usage of $17.0 million and a $9.0 million decrease in off-system sales. Within Gas Transmission and Storage Operations, net revenues increased due to increases in firm capacity reservation fees and shorter term transportation and storage services of $19.3 million. The increase in firm capacity reservation fees was the result of higher revenue for storage services, new Appalachian Supply interconnects, and incremental revenue from transportation agreements. Electric Operations’ net revenues decreased due to lower industrial usage, which was significantly impacted by steel and steel-related companies, and lower off-system sales. The major steel companies were operating at close to full capacity in early 2008 and are now operating at about half capacity.

Expenses
Operating expenses for the first six months of 2009 were $1,286.4 million, an increase of $88.5 million from the comparable 2008 period. This increase was primarily due to higher pension expense of approximately $49.2 million, a restructuring charge in Gas Transmission and Storage Operations of $19.8 million, higher net regulatory and tax trackers of $14.7 million offset in net revenues described above, and an $8.8 million increase in depreciation and amortization expense. These increases are partially offset by lower employee and administrative expenses, excluding pension, of $9.2 million.

Other Income (Deductions)
Interest expense increased by $16.6 million primarily due to incremental interest expense associated with the issuance of $700 million of long-term debt in May of 2008 and $600 million of long-term debt in March of 2009, partially offset by the open market debt repurchase of $100 million in January 2009, the $250.6 million tender offer debt repurchase in April 2009 and lower short-term interest rates. Other, net was a loss of $4.7 million compared to a loss of $0.4 million for the second quarter of 2008 as a result of lower interest income.

Income Taxes
Income tax for the first six months of 2009 was $103.5 million, a decrease of $16.5 million compared to the first six months of 2008 due primarily to lower pretax book income, partially offset by a higher effective tax rate. The effective tax rate for the first six months of 2009 was 40.7% compared to 36.6% for the comparable period last year. These effective tax rates differ from the federal tax rate of 35% due to the effects of tax credits, state income taxes, utility rate-making, and other permanent book-to-tax differences such as the electric production tax deduction provided under Internal Revenue Code Section 199. The effective tax rate was higher in 2009 primarily due to a reduction in estimated Section 199 deductions as a result of lower projected taxable income for 2009, an increase in tax expense related to AFUDC-Equity and certain depreciation differences, as well as the impact of the deferred state income tax increase and non-deductible expenses discussed above.

Discontinued Operations
For the six months ended June 30, 2009, NiSource recognized income of $2.0 million from discontinued operations compared to a loss of $212.4 million in the comparable 2008 period. Income for 2009 is primarily attributable to NiSource's intent to sell its unregulated natural gas marketing business in the second quarter of 2009. The loss in 2008 is primarily attributable to an adjustment to the reserve for the Tawney litigation. In addition, in 2008, NiSource began accounting for the operations of Northern Utilities, Granite State Gas and Whiting Clean Energy as discontinued operations. As such, net income of $4.6 million from continuing operations was classified to net income (loss) from discontinued operations for the six months ended June 30, 2008. The $9.0 million after-tax loss on the disposition of discontinued operations in the second quarter of 2009 is primarily related to NiSource's decision to sell its unregulated natural gas marketing business. For the six months ended June 30, 2008, NiSource recorded an estimated after-tax loss of $98.9 million for the dispositions of Northern Utilities, Granite State Gas and Whiting Clean Energy.

Liquidity and Capital Resources

A significant portion of NiSource's operations, most notably in the gas distribution, gas transportation and electric distribution businesses, are subject to seasonal fluctuations in cash flow. During the heating season, which is primarily from November through March, cash receipts from gas sales and transportation services typically exceed cash requirements. During the summer months, cash on hand, together with the seasonal increase in cash flows from the electric business during the summer cooling season and external short-term and long-term financing, is used to purchase gas to place in storage for heating season deliveries and perform necessary maintenance of facilities.

Operating Activities
Net cash from operating activities for the six months ended June 30, 2009 was $1,240.2 million, an increase of $601.8 million compared to the first six months of 2008. Gas price changes significantly impacted working capital when comparing the two periods. During the first six months of 2009 gas prices dropped dramatically resulting in a

$566.8 million over-recovery of gas cost. During the first six months of 2008 gas prices actually increased resulting in a $195.9 million under recovery of gas costs.

Tawney Settlement. In the first quarter of 2009, NiSource funded $60.5 million in compliance with the settlement agreement in addition to $25.0 million that was funded in the fourth quarter of 2008. No additional payments were made through June 30, 2009. NiSource expects to make the remaining payments in 2009 up to the total settlement amount of $338.8 million. A letter of credit of $254 million was issued on January 13, 2009 to cover these remaining payments. Refer to Part II, Item 1, "Legal Proceedings," for additional information.

Pension and Other Postretirement Plan Funding. NiSource expects to make contributions of approximately $104.2 million to its pension plans and approximately $52.9 million to its postretirement medical and life plans in 2009, which could change depending on market conditions. Through June 30, 2009, NiSource has contributed $11.3 million to its pension plans and $23.4 million to its other postretirement benefit plans.

Investing Activities
NiSource's capital expenditures for the six months ended June 30, 2009 were $385.6 million, compared to $448.7 million for the first six months of 2008. NiSource continues to project capital expenditures for the year to be approximately $800 million.

Restricted cash was $64.2 million and $79.9 million as of June 30, 2009 and December 31, 2008, respectively. The decrease in restricted cash was due primarily to the change in forward gas prices which resulted in decreased net margin deposits on open derivative contracts used within NiSource's risk management and energy marketing activities.

NiSource received insurance proceeds for capital repairs of $54.6 million and $25.9 million for the first six months of 2009 and 2008, respectively, related to hurricanes and other items.

Financing Activities
Long-term Debt. NiSource's 2009 financing requirement includes the refinancing of outstanding debt scheduled to mature in November 2009, as well as payments associated with the Tawney settlement. During the first half of 2009, NiSource has successfully executed against its previously announced financing and liquidity plan through the following activities:

- On April 9, 2009, NiSource Finance announced the final closing of a $385 million senior unsecured two-year bank term loan with a syndicate of banks maturing February 11, 2011. Borrowings under the bank term loan have an effective cost of LIBOR plus 538 basis points. On February 16, 2009, NiSource announced the initial closing of the bank term loan at the level of $265 million. Under an accordion feature, NiSource was able to increase the loan by $120 million prior to final closing.

- On March 31, 2009, NiSource Finance announced that it was commencing a cash tender offer for up to $300 million aggregate principal amount of its outstanding 7.875% Notes due 2010. On April 28, 2009, NiSource Finance announced that $250.6 million of these notes were successfully tendered.

- On March 9, 2009, NiSource Finance issued $600.0 million of 10.75% unsecured notes that mature March 15, 2016.

- During January 2009, NiSource repurchased $32.4 million of the $450.0 million floating rate notes scheduled to mature in November 2009 and $67.6 million of the $1.0 billion 7.875% unsecured notes scheduled to mature in November 2010.

In addition to the items listed above, Columbia of Virginia on June 25, 2009 received approval from the VSCC for the issuance of external long-term debt of up to $75 million of either external long-term debt or long-term inter-company notes. Northern Indiana is also seeking to amend its financing petition to allow for the issuance of $120 million of either external long-term debt or long-term inter-company notes.

During July 2008, Northern Indiana redeemed $24.0 million of its medium-term notes, with an average interest rate of 6.80%.

On May 15, 2008, NiSource Finance issued $500.0 million of 6.80% unsecured notes that mature January 15, 2019 and $200.0 million of 6.15% unsecured notes that mature on March 1, 2013. The notes due in 2013 constitute a further issuance of the $345.0 million 6.15% notes issued February 19, 2003, and will form a single series having an aggregate principal amount outstanding of $545.0 million.

Jasper County Pollution Control Bonds **.** Northern Indiana has seven series of Jasper County Pollution Control Bonds with a total principal value of $254 million currently outstanding. Prior to March 25, 2008, each of the series bore interest at rates established through auctions that took place at either 7, 28, or 35 day intervals. Between February 13, 2008 and March 5, 2008, Northern Indiana received notice that six separate market auctions of four series of the Jasper County Pollution Control Bonds had failed. As a result, those series representing an aggregate principal amount of $112 million of the Jasper County Pollution Control Bonds bore interest at default rates equal to 15% or 18% per annum. Subsequent auctions were successful, but resulted in interest rates between 5.13% and 11.0%, which were in excess of historical market rates. These auction failures were attributable to the lack of liquidity in the auction rate securities market, largely driven by the turmoil in the bond insurance market. The Jasper County Pollution Control Bonds are insured by either Ambac Assurance Corporation or MBIA Insurance Corporation.

Northern Indiana converted all seven series of Jasper County Pollution Control Bonds from the auction rate mode to a variable rate demand bond mode between March 25, 2008 and April 11, 2008 and repurchased the bonds as part of the conversion process, of which $199.0 million had been repurchased as of March 31, 2008. Between April 11, 2008 and August 24, 2008, all of the Jasper County Pollution Control Bonds were held in Northern Indiana's treasury. On August 25, 2008, Northern Indiana converted all of the Jasper County Pollution Control Bonds from a variable rate demand mode to a fixed rate mode, and reoffered the bonds to external investors. As a result of the fixed rate conversion and reoffering process, the weighted average interest rate is now fixed at 5.58%.

Northern Indiana reflected the Jasper County Pollution Control Bonds held in treasury as an offset to long-term debt within the Condensed Consolidated Balance Sheet (unaudited) as of March 31, 2008 and June 30, 2008 upon repurchase and the debt was considered extinguished per SFAS No. 140. As such, unamortized debt expense of $4.6 million previously recorded under deferred charges and other was reclassified to a regulatory asset. The Consolidated Balance Sheet as of December 31, 2008 reflects the reissuance of the long-term debt. The repurchase of these bonds are included under, "Financing Activities," in the Condensed Statement of Consolidated Cash Flow (unaudited).

Credit Facilities. NiSource Finance maintains a $1.5 billion five-year revolving credit facility with a syndicate of banks which has a termination date of July 7, 2011. This facility provides a reasonable cushion of short-term liquidity for general corporate purposes including meeting cash requirements driven by volatility in natural gas prices, as well as provides for the issuance of letters of credit. During September 2008, NiSource Finance entered into a new $500 million six-month revolving credit agreement with a syndicate of banks led by Barclays Capital that was originally due to expire on March 23, 2009. However, on February 13, 2009, the six-month credit facility was terminated in conjunction with the closing of a new two-year bank term loan.

NiSource Finance had no outstanding credit facility borrowings at June 30, 2009, and had borrowings of $1,163.5 million at December 31, 2008, at a weighted average interest rate of 1.09%.

As of June 30, 2009 and December 31, 2008, NiSource Finance had $275.3 million and $87.3 million of stand-by letters of credit outstanding, respectively. A letter of credit of $254 million was issued on January 13, 2009 to cover the remaining payments related to the Tawney settlement.

As of June 30, 2009, an aggregate of $1,227.4 million of credit was available under the credit facility.

Sale of Trade Accounts Receivables. On May 14, 2004, Columbia of Ohio entered into an agreement to sell, without recourse, substantially all of its trade receivables, as they originate, to CORC, a wholly-owned subsidiary of

Columbia of Ohio. CORC, in turn, is party to an agreement with Dresdner Bank AG, also dated May 14, 2004, under the terms of which it sells an undivided percentage ownership interest in the accounts receivable to a commercial paper conduit. On July 1, 2006, the agreement was amended to increase the seasonal program limit from $300 million to $350 million. On June 16, 2009, the agreement was extended through September 30, 2009, at which time Columbia of Ohio anticipates that the accounts receivable program will be transitioned to a new bank conduit sponsor. As of June 30, 2009, $100.0 million of accounts receivable had been sold by CORC compared to $236.5 million as of December 31, 2008.

Under the agreement, Columbia of Ohio acts as administrative agent, by performing record keeping and cash collection functions for the accounts receivable sold by CORC. Columbia of Ohio receives a fee, which provides adequate compensation, for such services.

On December 30, 2003, Northern Indiana entered into an agreement to sell, without recourse, all of its trade receivables, as they originated, to NRC, a wholly-owned subsidiary of Northern Indiana. NRC, in turn, was party to an agreement with Citibank, N.A. under the terms of which it sold an undivided percentage ownership interest in the accounts receivable to a commercial paper conduit. On May 20, 2009, NRC terminated its agreement with Citibank, North America, Inc., while Northern Indiana concurrently terminated its agreement with NRC. Northern Indiana plans on establishing a new accounts receivable program with another bank conduit sponsor prior to September 30, 2009.

Credit Ratings. On March 5, 2009, Standard and Poor's affirmed its senior unsecured ratings for NiSource and its subsidiaries at BBB-, and revised the outlook to stable from negative. On July 29, 2009, Moody's Investors Services affirmed the senior unsecured ratings for NiSource at Baa3, and the existing ratings of all other subsidiaries. Moody's outlook for NiSource and its subsidiaries is negative. On February 4, 2009, Fitch lowered its senior unsecured ratings for NiSource to BBB- and for Northern Indiana to BBB. Fitch's outlook for NiSource and all of its subsidiaries is stable. Although all ratings continue to be investment grade, an additional downgrade by Standard and Poor's, Moody's or Fitch would result in a rating that is below investment grade.

Certain NiSource affiliates have agreements that contain "ratings triggers" that require increased collateral if the credit ratings of NiSource or certain of its subsidiaries are rated below BBB- by Standard and Poor's or Baa3 by Moody's. These agreements are primarily for insurance purposes and for the physical purchase or sale of power. The collateral requirement from a downgrade below the ratings trigger levels would amount to approximately $25 million. In addition to agreements with ratings triggers, there are other agreements that contain "adequate assurance" or "material adverse change" provisions that could result in additional credit support such as letters of credit and cash collateral to transact business.

Contractual Obligations. As of June 30, 2009, NiSource has $3.9 million of estimated federal and state income tax liabilities, including interest, recorded on its books in accordance with FIN 48. If or when such amounts may be settled is uncertain and cannot be estimated at this time. NiSource does not anticipate any significant changes to its liability for unrecognized tax benefits over the next twelve months.

Market Risk Disclosures

Risk is an inherent part of NiSource's energy businesses. The extent to which NiSource properly and effectively identifies, assesses, monitors and manages each of the various types of risk involved in its businesses is critical to its profitability. NiSource seeks to identify, assess, monitor and manage, in accordance with defined policies and procedures, the following principal risks that are involved in NiSource's energy businesses: commodity market risk, interest rate risk and credit risk. Risk management at NiSource is a multi-faceted process with oversight by the Risk Management Committee that requires constant communication, judgment and knowledge of specialized products and markets. NiSource's 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. In recognition of the increasingly varied and complex nature of the energy business, NiSource's risk management policies and procedures continue to evolve and are subject to ongoing review and modification.

NISOURCE INC.

Various analytical techniques are employed to measure and monitor NiSource's market and credit risks, including VaR. VaR represents the potential loss or gain for an instrument or portfolio from changes in market factors, for a specified time period and at a specified confidence level.

Commodity Price Risk

NiSource is exposed to commodity price risk as a result of its subsidiaries' operations involving natural gas and power. To manage this market risk, NiSource's subsidiaries use derivatives, including commodity futures contracts, swaps and options. NiSource is not involved in speculative energy trading activity.

Commodity price risk resulting from derivative activities at NiSource's 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. Some of NiSource's rate-regulated utility subsidiaries offer commodity price risk products to its customers for which derivatives are used to hedge forecasted customer usage under such products. These subsidiaries do not have regulatory recovery orders for these products and are subject to gains and losses recognized in earnings due to hedge ineffectiveness.

Interest Rate Risk

NiSource is exposed to interest rate risk as a result of changes in interest rates on borrowings under its revolving credit agreement and floating rate notes, which have interest rates that are indexed to short-term market interest rates. NiSource is also exposed to interest rate risk due to changes in interest rates on fixed-to-variable interest rate swaps that hedge the fair value of long-term debt. 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 $4.5 million and $10.0 million for the quarter and six months ended June 30, 2009, respectively, and $5.2 million and $11.6 million for the quarter and six months ended June 30, 2008, respectively.

Credit Risk

Due to the nature of the industry, credit risk is embedded in many of NiSource's business activities. NiSource's 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 Corporate Credit Risk 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 NiSource 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, letters of credit and qualified guarantees of support.

As a result of the ongoing credit crisis in the financial markets, NiSource has been closely monitoring the financial status of its banking credit providers and interest rate swap counterparties. NiSource continues to evaluate the financial status of its banking partners through the use of market-based metrics such as credit default swap pricing levels, and also through traditional credit ratings provided by the major credit rating agencies.

The parent company of one of NiSource's interest rate swap counterparties, Lehman Brothers Holdings Inc., filed for Chapter 11 bankruptcy protection on September 14, 2008, which constituted an event of default under the swap agreement between NiSource Finance and Lehman Brothers Special Financing Inc. As a result, on September 15, 2008, NiSource Finance terminated the fixed-to-variable interest rate swap agreement with Lehman Brothers having a notional value of $110 million. The mark-to-market close-out value of this swap at the September 15, 2008 termination date was determined to be $4.8 million and was fully reserved in the third quarter of 2008.

NiSource also reviewed its exposure to all other counterparties including the other interest rate swap counterparties and concluded there was no significant risk associated with these counterparties. NiSource will continue to closely monitor events in the credit markets, as well as overall economic conditions in the nation and the markets it serves.

NISOURCE INC.

Fair Value Measurement

NiSource measures fair value in accordance with SFAS No. 157 for its financial assets and liabilities. The level of the fair value hierarchy disclosed is based on the lowest level of input that is significant to the fair value measurement. NiSource's financial assets and liabilities include price risk assets and liabilities, available-for-sale securities and a deferred compensation plan obligation.

Exchange-traded derivative contracts are generally 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. The company uses 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 in 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 in 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.

Price risk management assets also include fixed-to-floating interest-rate swaps, which are designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. NiSource uses a calculation of future cash inflows and estimated future outflows related to the swap agreements, which are discounted and netted to determine the current fair value. Additional inputs to the present value calculation include the contract terms, as well as market parameters such as current and projected interest rates and volatility. As they are based on observable data and valuations of similar instruments, the interest-rate swaps are categorized in Level 2 in the fair value hierarchy. Credit risk is considered in the fair value calculation of the interest rate swap.

Refer to Note 10, "Fair Value Assets and Liabilities," in the Notes to the Condensed Consolidated Financial Statements for additional information on NiSource's fair value measurements.

Market Risk Measurement

Market risk refers to the risk that a change in the level of one or more market prices, rates, indices, volatilities, correlations or other market factors, such as liquidity, will result in losses for a specified position or portfolio. NiSource calculates a one-day VaR at a 95% confidence level for the gas marketing group that utilizes a variance/covariance methodology. The daily market exposure for the gas marketing portfolio on an average, high and low basis was $0.2 million, $0.4 million and zero for the second quarter of 2009, respectively. Prospectively, management has set the VaR limit at $0.8 million for gas marketing. Exceeding this limit would result in management actions to reduce portfolio risk.

Refer to "Critical Accounting Policies" included in this Item 7 and Note 9, "Risk Management Activities," in the Notes to Condensed Consolidated Financial Statements for further discussion of NiSource's risk management.

Off Balance Sheet Arrangements

As a part of normal business, NiSource and certain 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.

NiSource has issued guarantees that support up to approximately $446.7 million of commodity-related payments for its current subsidiaries involved in energy commodity contracts and to satisfy requirements under forward gas sales agreements. These guarantees were provided to counterparties in order to facilitate physical and financial transactions involving natural gas and electricity. To the extent liabilities exist under the commodity-related contracts subject to these guarantees, such liabilities are included in the Consolidated Balance Sheets.

NiSource has purchase and sales agreement guarantees totaling $253.0 million, which guarantee performance of the seller's covenants, agreements, obligations, liabilities, representations and warranties under the agreements. No amounts related to the purchase and sales agreement guarantees are reflected in the Consolidated Balance Sheets. Management believes that the likelihood NiSource would be required to perform or otherwise incur any significant losses associated with any of the aforementioned guarantees is remote.

NiSource has other guarantees outstanding. Refer to Note 17-A, "Guarantees and Indemnities," in the Notes to Condensed Consolidated Financial Statements for additional information about NiSource's off balance sheet arrangements.

Other Information

Critical Accounting Policies

Goodwill. NiSource's goodwill assets at June 30, 2009 were $3,677.3 million, most of which resulted from the acquisition of Columbia on November 1, 2000. The goodwill balance also includes $13.3 million for Northern Indiana Fuel and Light and $5.5 million for Kokomo Gas. As required, NiSource tests for impairment of goodwill on an annual basis and on an interim basis when events or circumstances indicate that a potential impairment may exist. NiSource's annual goodwill test takes place in the second quarter of each year and was most recently finalized as of June 30, 2009. The goodwill test utilized both an income approach and a market approach. In performing the goodwill test, NiSource made certain required key assumptions, such as long-term growth rates, discount rates and fair market values.

These key assumptions required significant judgment by management which are subjective and forward-looking in nature. To assist in making these judgments, NiSource utilized third-party valuation specialists in both determining and testing key assumptions used in the analysis. NiSource based its assumptions on projected financial information that it believes is reasonable; however, actual results may differ materially from those projections. For example, with regard to NiSource's discount rate assumptions used in the June 30, 2009 test results, a 1% change in the discount rate would change the fair value of the Columbia Distribution Operations and Columbia Transmission Operations reporting units by approximately $1.0 billion and $800 million, respectively.

Although there was no goodwill asset impairment as of June 30, 2009, an interim impairment test could be triggered by the following: actual earnings results that are materially lower than expected, significant adverse changes in the operating environment, an increase in the discount rate, changes in other key assumptions which require judgment and are forward looking in nature, or if NiSource's market capitalization continues to stay below book value for an extended period of time.

Refer to Note 12, "Goodwill," in the Notes to Condensed Consolidated Financial Statements (unaudited) for additional information concerning NiSource's annual goodwill test.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITIONS AND RESULTS OF OPERATIONS (continued)

NISOURCE INC.

Recently Adopted Accounting Pronouncements

SFAS No. 165 – Subsequent Events. In May 2009, the FASB issued SFAS No. 165. The standard does not require significant changes regarding recognition or disclosure of subsequent events, but does require disclosure of the date through which subsequent events have been evaluated for purposes of disclosure and accounting recognition. The standard was effective for financial statements issued after June 15, 2009. The adoption of this standard on April 1, 2009 did not have a material impact on the Condensed Consolidated Financial Statements (unaudited).

SFAS No. 161 – Disclosures about Derivative Instruments and Hedging — an amendment of SFAS No. 133. In March 2008, the FASB issued SFAS No. 161 to amend and expand the disclosure requirements of SFAS No. 133 with the intent to provide users of the financial statements with an enhanced understanding of how and why an entity uses derivative instruments, how these derivatives are accounted for and how the respective reporting entity's financial statements are affected. SFAS No. 161 is effective for fiscal years and interim periods beginning after November 15, 2008, and earlier application is encouraged. NiSource adopted this standard on January 1, 2009. Refer to Note 9, "Risk Management Activities," in the Notes to Condensed Consolidated Financial Statements (unaudited) for additional information.

SFAS No. 160 – Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB No. 51. In December 2007, the FASB issued SFAS No. 160 to improve the relevance, comparability, and transparency of the financial information that a reporting entity provides in its consolidated financial statements regarding non-controlling ownership interests in a business and for the deconsolidation of a subsidiary. This Statement was effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 and earlier adoption is prohibited. The adoption of this standard on January 1, 2009 did not have a material impact on the Condensed Consolidated Financial Statements (unaudited).

SFAS No. 157 – Fair Value Measurements. In September 2006, the FASB issued SFAS No. 157 to define fair value, establish a framework for measuring fair value and to expand disclosures about fair value measurements. SFAS No. 157 does not change the requirements to apply fair value in existing accounting standards.

Under SFAS No. 157, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts. The standard clarifies that fair value should be based on the assumptions market participants would use when pricing the asset or liability.

The adoption of SFAS No. 157 did not have an impact on NiSource's January 1, 2008 balance of retained earnings.

In February 2008, the FASB issued FSP FAS 157-2, which delayed the effective date of SFAS No. 157 for all nonrecurring fair value measurements of non-financial assets and liabilities until fiscal years beginning after November 15, 2008.

In October 2008, the FASB issued FSP FAS 157-3, which clarified the application of SFAS No. 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. The FSP was effective upon issuance, including prior periods for which financial statements have not been issued.

In April 2009, the FASB issued FSP FAS 157-4 to provide additional guidance for estimating fair value when the volume and level of activity for the asset or liability have significantly decreased. This FSP is effective for interim reporting periods ending after June 15, 2009, with early adoption permitted. NiSource adopted this FSP on April 1, 2009.

Refer to Note 10, "Fair Value Assets and Liabilities," in the Notes to Condensed Consolidated Financial Statements (unaudited) for additional information regarding the adoption of SFAS No. 157.

SFAS No. 141R – Business Combinations. In December 2007, the FASB issued SFAS No. 141R to improve the relevance, representational faithfulness, and comparability of information that a reporting entity provides in its financial reports regarding business combinations and its effects, including recognition of assets and liabilities, the measurement of goodwill and required disclosures. This Statement was effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 and earlier adoption is prohibited. The adoption of this standard on January 1, 2009 did not have a material impact on the Condensed Consolidated Financial Statements (unaudited).

In April 2009, the FASB issued FSP FAS 141(R)-1, which amends and clarifies SFAS No. 141 to address application issues on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This FSP was effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008.

FSP FAS 140-4 and FIN 46(R)-8 – FASB Staff Position Amendment of FASB Statement No. 140 and FASB Interpretation No. 46(R). In December 2008, the FASB issued FSP FAS 140-4 and FIN 46(R)-8 to require public entities to provide additional disclosures about transfers of financial assets and to provide additional disclosures related to an entity's involvement with variable interest entities. This FSP was effective for the first reporting period ending after December 15, 2008, with early application encouraged. The adoption of this FSP on January 1, 2009 did not have a material impact on the Condensed Consolidated Financial Statements (unaudited). Refer to Note 11, "Transfers of Financial Assets," in the Notes to Condensed Consolidated Financial Statements (unaudited) for additional information regarding FSP FAS 140-4.

FSP FAS 115-2 and FAS 124-2 – FASB Staff Position Amendment of FASB Statement No. 115 and FASB Statement No. 124. In April 2009, the FASB issued FSP FAS 115-2 and FAS 124-2 to amend the other-than-temporary impairment guidance in GAAP for debt securities to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. This FSP is effective for interim reporting periods ending after June 15, 2009, with early adoption permitted. The adoption of this FSP on April 1, 2009 did not have a material impact on the Condensed Consolidated Financial Statements (unaudited).

FSP FAS 107-1 and APB 28-1 – FASB Staff Position Amendment of FASB Statement No. 107 and APB Opinion No. 28. In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1 to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as annual financial statements. This FSP is effective for interim reporting periods ending after June 15, 2009, with early adoption permitted. NiSource adopted this FSP on April 1, 2009. As this FSP provides only disclosure requirements, the application of this standard did not have a material impact on the Condensed Consolidated Financial Statements (unaudited). Refer to Note 10, "Fair Value Assets and Liabilities," in the Notes to Condensed Consolidated Financial Statements (unaudited) for additional information regarding FSP FAS 107-1.

Recently Issued Accounting Pronouncements

SFAS No. 168 – The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles a replacement of FASB Statement No. 162. In June 2009, the FASB issued SFAS No. 168 to address the new authoritative GAAP recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. On the effective date of this Statement, the Codification will supersede all then-existing non-SEC accounting and reporting standards. All other non-grandfathered non-SEC accounting literature not included in the Codification will become non-authoritative. Following this Statement, the FASB will not issue new standards in the form of Statements, FASB Staff Positions, or Emerging Issues Task Force Abstracts; rather, it will issue Accounting Standards Updates. This Statement is effective for financial statements issued for interim and annual periods ending after September 15, 2009. This Statement does not change GAAP and will not have a material impact on NiSource.

SFAS No. 167 – Amendments to FASB Interpretation No. 46(R). In June 2009, the FASB issued SFAS No. 167 to amend certain requirements of FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities, to improve financial reporting by enterprises involved with variable interest entities and to provide more relevant and reliable information to users of financial statements. This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on the first fiscal year that begins after November 15, 2009 with early adoption prohibited. NiSource is currently reviewing the additional requirements to determine the impact on the Condensed Consolidated Financial Statements (unaudited) and Notes to Condensed Consolidated Financial Statements.

SFAS No. 166 – Accounting for Transfers of Financial Assets an amendment of FASB Statement No. 140. In June 2009, the FASB issued SFAS No. 166 to amend the derecognition guidance in Statement 140 to improve the relevance, representational faithfulness, and comparability of the information that a reporting entity provides in its financial statements about a transfer of financial assets; the effects of a transfer on its financial position, financial performance, and cash flows; and a transferor's continuing involvement, if any, in transferred financial assets. This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on the first fiscal year that begins after November 15, 2009 with early adoption prohibited. NiSource is currently reviewing the accounting and additional disclosure requirements to determine the impact on the Condensed Consolidated Financial Statements (unaudited) and Notes to Condensed Consolidated Financial Statements. This Statement may require sales of accounts receivable, under the accounts receivable program discussed in Note 11, "Transfers of Financial Assets," in the Notes to Condensed Consolidated Financial Statements (unaudited) to be recorded as debt on the Consolidated Balance Sheets effective January 1, 2010.

FSP FAS 132(R)-1 – FASB Staff Position Amendment of FASB Statement No. 132(R)-1. In December 2008, the FASB issued FSP FAS 132 (R)-1 to amend SFAS No. 132(R), to provide guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan. FSP FAS 132(R)-1 is effective for fiscal years ending after December 15, 2009 with earlier adoption permitted. NiSource is currently reviewing the additional disclosure requirements to determine the impact on the Condensed Consolidated Financial Statements (unaudited) and Notes to Condensed Consolidated Financial Statements.

RESULTS AND DISCUSSION OF SEGMENT OPERATIONS

Presentation of Segment Information

NiSource's operations are divided into four primary business segments; Gas Distribution Operations, Gas Transmission and Storage Operations, Electric Operations, and Other Operations.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

NISOURCE INC.
Gas Distribution Operations

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	**2009**	2008	**2009**	2008
Net Revenues				
Sales Revenues	**$ 557.5**	$ 1,029.4	**$ 2,512.8**	$ 3,476.9
Less: Cost of gas sold (excluding depreciation and amortization)	**275.6**	765.3	**1,590.4**	2,593.9
Net Revenues	**281.9**	264.1	**922.4**	883.0
Operating Expenses				
Operation and maintenance	**187.4**	182.7	**456.7**	422.5
Depreciation and amortization	**62.9**	57.6	**123.3**	114.3
Gain on sale of assets	**-**	2.1	**-**	-
Other taxes	**27.7**	31.7	**95.3**	101.3
Total Operating Expenses	**278.0**	274.1	**675.3**	638.1
Operating Income	**$ 3.9**	$ (10.0)	**$ 247.1**	$ 244.9
Revenues ($ in Millions)				
Residential	**337.7**	490.7	**1,753.1**	1,919.5
Commercial	**112.4**	173.4	**610.8**	670.0
Industrial	**44.8**	69.1	**144.1**	171.4
Off System	**55.9**	275.9	**131.3**	609.9
Other	**6.7**	20.3	**(126.5)**	106.1
Total	**557.5**	1,029.4	**2,512.8**	3,476.9
Sales and Transportation (MMDth)				
Residential	**32.6**	33.7	**165.2**	171.1
Commercial	**23.4**	26.5	**101.4**	104.5
Industrial	**74.0**	89.3	**170.6**	192.5
Off System	**13.9**	23.0	**30.1**	60.4
Other	**0.2**	0.2	**0.5**	0.7
Total	**144.1**	172.7	**467.8**	529.2
Heating Degree Days	**443**	448	**3,126**	3,124
Normal Heating Degree Days	**472**	472	**3,105**	3,133
% Colder (Warmer) than Normal	**(6%)**	(5%)	**1%**	0%
Customers				
Residential			**2,987,144**	2,990,223
Commercial			**274,871**	275,937
Industrial			**7,861**	8,019
Other			**80**	72
Total			**3,269,956**	3,274,251

NiSource's natural gas distribution operations serve approximately 3.3 million customers in seven states: Ohio, Indiana, Pennsylvania, Massachusetts, Virginia, Kentucky and Maryland. The regulated subsidiaries offer both traditional bundled services as well as transportation only for customers that purchase gas from alternative suppliers. The operating results reflect the temperature-sensitive nature of customer demand with 73% of annual residential and commercial throughput affected by seasonality. As a result, segment operating income is higher in the first and fourth quarters reflecting the heating demand during the winter season.

NISOURCE INC.
Gas Distribution Operations (continued)

Bear Garden Station
Columbia of Virginia has entered into an agreement with Dominion Virginia Power to install facilities to serve a 585 mw combined cycle generating station in Buckingham County, VA, known as the Bear Garden station. The project requires approximately 13.3 miles of 24-inch steel pipeline and associated facilities to serve the station. In March 2009, the VSCC approved Dominion Virginia Power Company's planned Bear Garden station with service expected to begin by the summer of 2011.

Regulatory Matters
Significant Rate Developments. Columbia of Ohio filed a base rate case with the PUCO on March 3, 2008, and a settlement agreement was filed on October 24, 2008. In the base rate case, Columbia of Ohio sought recovery of increased infrastructure rehabilitation costs, as well as the stabilization of revenues and cost recovery through rate design. The agreement included an annual revenue increase of $47.1 million, and also provides for recovery of costs associated with Columbia of Ohio's infrastructure rehabilitation program. On December 3, 2008, the PUCO approved the settlement agreement in all material respects, and approved Columbia of Ohio's proposed rate design.

On January 15, 2009, Columbia of Ohio filed an application with the PUCO requesting authority to increase Columbia of Ohio's PIPP rider rate in order to collect $82.2 million in PIPP arrearages over a three year period. On March 3, 2009, Columbia of Ohio's proposal was approved and became effective.

On January 28, 2008, Columbia of Pennsylvania filed a base rate case with the PPUC seeking recovery of costs associated with its significant infrastructure rehabilitation program, as well as stabilization of revenues through modifications to rate design. On July 2, 2008, Columbia of Pennsylvania and all interested parties filed a unanimous settlement and on October 23, 2008, the PPUC issued an Order approving the settlement as filed, increasing annual revenues by $41.5 million.

On April 16, 2009, Bay State filed a base rate case with the Massachusetts Department of Public Utilities, requesting an increase of $34.6 million. In its filing, Bay State is seeking revenue decoupling, as well as an expedited mechanism for the recovery of costs associated with the rehabilitation of the company's infrastructure. This matter is currently pending and expected to be resolved with new rates taking effect in the fourth quarter 2009.

On May 1, 2009, Columbia of Kentucky filed a base rate case with the Kentucky PSC, requesting an annual increase of $11.6 million. In its initial filing, Columbia of Kentucky is seeking enhancements to rate design, as well as an expedited mechanism for the recovery of costs associated with the rehabilitation of the company's infrastructure. This matter is currently pending.

On June 8, 2009, Columbia of Virginia filed an Application with the VSCC for approval of a CARE Plan for a three-year period beginning January 1, 2010. The CARE Plan includes incentives for residential and small general service customers to actively pursue conservation and energy conservation measures, a surcharge designed to recover the costs of such measures on a real-time basis, and a performance-based incentive for the delivery of conservation and energy efficiency benefits. The CARE Plan also includes a rate decoupling mechanism designed to mitigate the impact of declining customer usage. The VSCC scheduled the matter for hearing on October 19, 2009.

On October 1, 2008, Columbia of Maryland filed a base rate case with the Maryland PSC. On February 20, 2009, Columbia of Maryland and all interested parties filed a unanimous settlement in the case, recommending an annual revenue increase of $1.2 million. On March 27, 2009, the settlement was approved as filed.

On November 24, 2008, Northern Indiana filed Supplemental Testimony in its annual gas cost recovery proceeding seeking a cost recovery mechanism for Unaccounted for Gas at current gas prices. Historically, in Indiana, Unaccounted for Gas recovery mechanisms are determined within a base rate proceeding. Intervenors have filed testimony, opposing recovery of Unaccounted for Gas in the gas cost adjustment proceeding and disputing the calculation of Unaccounted for Gas. Evidentiary hearings were held on April 20 and 21, 2009. An order is expected in the third quarter of 2009.

NISOURCE INC.
Gas Distribution Operations (continued)

In March 2009, Indiana Governor Daniels signed Senate Bill 423 into law giving the Indiana Finance Authority the authority to contract, on behalf of gas customers in the state of Indiana, with developers capable of building facilities that manufacture Substitute Natural Gas from coal. The Indiana Finance Authority is seeking bids to initiate a Substitute Natural Gas plant in Southern Indiana under a 30 year contract. It is expected that all Indiana gas utilities including Northern Indiana will be delivering a portion of Substitute Natural Gas from this facility. The IURC must approve the final contract.

Cost Recovery and Trackers. A significant portion of the distribution companies' revenue is related to the recovery of gas costs, the review and recovery of which occurs via standard regulatory proceedings. All states 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. NiSource distribution companies have historically been found prudent in the procurement of gas supplies to serve customers.

Certain operating costs of the NiSource distribution companies are significant, recurring in nature, and generally outside the control of the distribution companies. Some states allow the recovery of such costs via cost tracking mechanisms. Such tracking mechanisms allow for abbreviated regulatory proceedings in order for the distribution 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 gas cost recovery adjustment mechanisms, tax riders, and bad debt recovery mechanisms.

Comparability of Gas Distribution Operations line item operating results is impacted by these regulatory trackers that allow for the recovery in rates of certain costs such as bad debt expenses. Increases in the expenses that are the subject of trackers result in a corresponding increase in net revenues and therefore have essentially no impact on total operating income results.

Certain of the NiSource distribution companies have completed rate proceedings involving infrastructure replacement or are embarking upon regulatory initiatives to replace significant portions of their operating systems that are nearing the end of their useful lives. Each LDC's approach to cost recovery may be unique, given the different laws, regulations and precedent that exist in each jurisdiction. On February 27, 2009, Columbia of Ohio filed an application to adjust its Infrastructure Replacement Program Rider to recover costs for risers and accelerated main replacements. On June 24, 2009, the PUCO approved a stipulation allowing Columbia of Ohio to implement the new rider rate July 1, 2009, resulting in an annual revenue increase of approximately $14 million.

On December 28, 2007, Columbia of Ohio entered into a stipulation with the Ohio Consumers' Counsel and PUCO Staff and other stakeholders resolving litigation concerning a pending Gas Cost Recovery audit of Columbia of Ohio. The stipulation calls for an accelerated pass back to customers of $36.6 million, occurring from January 31, 2008 through January 31, 2009, generated through off-system sales and capacity release programs, the development of new energy efficiency programs for introduction in 2009, and the development of a wholesale auction process for customer supply to take effect in 2010. The entire requirement of the stipulation was passed back through January 31, 2009. The stipulation also resolves issues related to pending and future Gas Cost Recovery Management Performance audits through 2008. The PUCO approved this agreement on January 23, 2008.

On April 30, 2009, Columbia of Ohio filed an application with the PUCO to defer pension and other postretirement benefits expenses above those currently subject to collection in rates effective January 1, 2009. On July 8, 2009, the PUCO issued an Order approving Columbia of Ohio's application, although the deferred balances shall not accrue carrying charges and Columbia of Ohio shall not seek recovery of pension and other postretirement benefits deferrals in a base rate proceeding for a period of five years. The amount deferred will be approximately $13.0 million for 2009, which will be reflected in the results for the third and fourth quarters of 2009.

On April 23, 2009, Columbia of Kentucky filed an application with the Kentucky PSC to defer pension and other postretirement benefits expenses above those currently subject to collection in rates. If approved, the amount deferred would be approximately $1.2 million for 2009. This matter is currently pending.

Customer Usage. The NiSource distribution companies have experienced declining usage by customers, due in large part to the sensitivity of sales to volatility in commodity prices, as well as general economic conditions. A

Gas Distribution Operations (continued)

significant portion of the LDCs' operating costs are fixed in nature. 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. Columbia of Ohio has restructured its rate design through a base rate proceeding and has moved towards a "de-coupled" rate design which more closely links the recovery of fixed costs with fixed charges. Each of the states in which the NiSource LDCs operate have different requirements regarding the procedure for establishing such changes and NiSource is seeking similar changes through regulatory proceedings for its other gas distribution utilities.

Environmental Matters

Various environmental matters occasionally impact the Gas Distribution Operations segment. As of June 30, 2009, a reserve has been recorded to cover probable environmental response actions. Refer to Note 17-C, "Environmental Matters," in the Notes to Condensed Consolidated Financial Statements (unaudited) for additional information regarding environmental matters for the Gas Distribution Operations segment.

Weather

In general, NiSource calculates the weather related revenue variance based on changing customer demand driven by weather variance from normal heating degree-days. Normal is evaluated using heating degree days across the NiSource distribution region. While the temperature base for measuring heating degree-days (i.e. the estimated average daily temperature at which heating load begins) varies slightly across the region, the NiSource composite measurement is based on 62 degrees. NiSource 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 the aggregated NiSource composite heating degree-day comparison.

Weather in the Gas Distribution Operation's territories for the second quarter of 2009 was 6% warmer than normal and comparable to the second quarter in 2008.

Weather in the Gas Distribution Operation's territories for the first six months of 2009 was 1% colder than normal and comparable to the same period in 2008.

Throughput

Total volumes sold and transported of 144.1 MMDth for the second quarter of 2009 decreased by 28.6 MMDth from the same period last year. This decrease was mainly due to lower off-system sales volumes resulting primarily from decreased market opportunities, and lower customer usage.

Total volumes sold and transported of 467.8 MMDth for the first six months of 2009 decreased 61.4 MMDth from the same period last year. This decrease in volume was primarily due to lower off-system sales volumes resulting primarily from decreased market opportunities, and lower customer usage. The continuous decrease in gas prices in first half of 2009 presented less of an opportunity to sell gas to non-traditional customers.

Net Revenues

Net revenues for the second quarter of 2009 were $281.9 million, an increase of $17.8 million from the same period in 2008, due primarily to increased revenues of $28.7 million from regulatory and service programs including impacts from rate cases at various utilities, partially offset by decreased usage of approximately $7.4 million primarily from residential and industrial customers.

At Northern Indiana, sales revenues and customer billings are adjusted for amounts related to under and over-recovered purchased gas costs from prior periods per regulatory order. These amounts are primarily reflected in the "Other" gross revenues statistic provided at the beginning of this segment discussion. The adjustment to Other gross revenues for the three and six months ended June 30, 2009 was a revenue reduction of $26.6 million and $209.0 million, respectively, compared to a decrease of $14.7 million and increase of $9.1 million for the three months and six ended June 30, 2008, respectively, primarily due to the significant decline in gas prices experienced over the past twelve months.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

NISOURCE INC.
Gas Distribution Operations (continued)

Net revenues for the six months ended June 30, 2009 were $922.4 million, an increase of $39.4 million from the same period in 2008, due primarily to increased revenues of $47.6 million from regulatory and service programs including impacts from rate cases at various utilities, increases in net regulatory and tax trackers of $9.0 million offset in expense and the impact of slightly colder weather of approximately $7 million, partially offset by decreased usage of approximately $17.0 million primarily from residential and industrial customers and a $9.0 decrease in off-system sales.

Operating Income
For the second quarter of 2009, Gas Distribution Operations reported operating income of $3.9 million compared to an operating loss of $10.0 million compared to the same period in 2008. The increase in operating income was primarily attributable to higher net revenues discussed above, partially offset by higher operating expenses of $3.9 million. Operating expenses increased due to higher pension expense of $10.6 million, increased depreciation expense of $5.3 million and increased maintenance costs of $2.8 million, partially offset by lower employer and administrative costs, excluding pension, of $7.1 million and lower other taxes of $4.0 million.

For the first six months of 2009, Gas Distribution Operations reported operating income of $247.1 million, an increase of $2.2 million for the same period in 2008. The increase in operating income was primarily attributable to higher net revenues discussed above, mostly offset by increased operating expenses of $37.2 million. Operating expenses increased due to higher pension expense of $20.9 million, increased depreciation expense of $9.0 million and increased maintenance costs of $5.6 million.

Table of Contents

NISOURCE INC.
Gas Transmission and Storage Operations

(in millions)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Operating Revenues				
Transportation revenues	**$ 159.8**	$ 150.8	**$ 354.3**	$ 335.6
Storage revenues	**48.2**	44.5	**93.4**	90.1
Other revenues	**1.1**	0.7	**3.7**	1.6
Total Operating Revenues	**209.1**	196.0	**451.4**	427.3
Operating Expenses				
Operation and maintenance	**82.8**	78.8	**195.3**	163.6
Depreciation and amortization	**30.2**	29.4	**59.6**	58.7
Gain on sale of assets	**-**	(3.0)	**(2.0)**	(4.0)
Other taxes	**13.9**	14.5	**29.8**	29.9
Total Operating Expenses	**126.9**	119.7	**282.7**	248.2
Equity Earnings in Unconsolidated Affiliates	**(2.6)**	1.6	**3.8**	3.6
Operating Income	**$ 79.6**	$ 77.9	**$ 172.5**	$ 182.7
Throughput (MMDth)				
Columbia Transmission	**170.1**	166.8	**578.5**	553.2
Columbia Gulf	**244.7**	237.2	**507.8**	472.1
Crossroads Gas Pipeline	**8.8**	9.0	**17.4**	19.1
Intrasegment eliminations	**(156.4)**	(137.3)	**(326.9)**	(269.3)
Total	**267.2**	275.7	**776.8**	775.1

NiSource's Gas Transmission and Storage Operations segment consists of the operations of Columbia Transmission, Columbia Gulf, Crossroads Pipeline, and Central Kentucky Transmission. In total, NiSource owns a pipeline network of approximately 16 thousand miles extending from offshore in the Gulf of Mexico to New York and the eastern seaboard. The pipeline network serves customers in 16 northeastern, mid-Atlantic, midwestern and southern states, as well as the District of Columbia. In addition, the Gas Transmission and Storage Operations segment operates one of the nation's largest underground natural gas storage systems.

Hardy Storage Project
The first two phases of Hardy Storage are in service, receiving customer injections and withdrawing natural gas from its new underground natural gas storage facility in West Virginia. When the third and final Phase is fully operational in November 2009, the field will have a working storage capacity of 12 Bcf, and the ability to deliver 176,000 Dth of natural gas per day. Hardy Storage is a joint venture of subsidiaries of Columbia Transmission and Piedmont.

Line 1570 Project
In October 2008, Columbia Transmission entered into a Precedent Agreement to gather and transport phased in volumes of up to 150,000 Dth per day of gas in the Waynesburg, PA area along Line 1570. The first two phases of this project were available for service in October 2008 and March 2009. Additional volumes will be phased in later in 2009 and during 2010. Facilities are expected to be completed in fourth quarter of 2009.

NISOURCE INC.
Gas Transmission and Storage Operations (continued)

Millennium Pipeline Project
The Millennium pipeline was substantially completed in the fourth quarter of 2008 and the pipeline commenced service on December 22, 2008, with the capability to transport up to 525,400 Dth per day of natural gas to markets along its route, as well as to the New York City market through its pipeline interconnections. At this time clean-up along the construction spreads is underway and is expected to be completed in the third quarter of 2009.

On August 29, 2007, Millennium entered into a bank credit agreement to finance the construction of the Millennium pipeline project. As a condition precedent to the credit agreement, NiSource issued a guarantee securing payment for its indirect ownership interest percentage of amounts borrowed under the financing agreement up until such time as the amounts payable under the agreement are paid in full. The permanent financing for Millennium is expected to be completed when debt capital market conditions improve. As of June 30, 2009, Millennium borrowed $798.9 million under the interim bank credit agreement, which extends through August 2010. The Millennium partnership is currently comprised of interest from Columbia Transmission (47.5%), DTE Millennium Company (26.25%), and National Grid Millennium LLC (26.25%) with Columbia Transmission acting as operator. Additional information on this guarantee is provided in Note 17-A, "Guarantees and Indemnities," in the Notes to Condensed Consolidated Financial Statements (unaudited).

Columbia Penn Project
In September 2008, Columbia Transmission announced its intention to develop additional natural gas transmission, gathering and processing services along and around its existing pipeline corridor between Waynesburg, PA and Renovo, PA, referred to as the "Columbia Penn" corridor. This two-phase development will provide access to pipeline capacity in conjunction with production increases in the Marcellus Shale formation which underlies Columbia Transmission's transmission and storage network in the region. Phase I was placed into service in February 2009 and Phase II should be available by the end of 2009.

Eastern Market Expansion Project
On January 14, 2008, the FERC issued an order which granted a certificate to construct the project. The project allows Columbia Transmission to expand its facilities to provide additional storage and transportation services and to replace certain existing facilities. The Eastern Market Expansion is adding 97,000 Dth per day of storage and transportation deliverability and is fully subscribed on a 15-year contracted firm basis. Construction of the facilities is complete and was placed in service April 1, 2009.

Ohio Storage Project
On June 24, 2008, Columbia Transmission filed an application before the FERC for approval to expand two of its Ohio storage fields for additional capacity of nearly 7 Bcf and 103,400 Dth per day of daily deliverability. Approval was granted in March 2009 and construction of the facilities began in April 2009. Partial service related to this expansion was available beginning May 2009 and the remainder will be available no later than the fourth quarter of 2009. The expansion capacity is 58% contracted on a long-term, firm basis, with the FERC authorized market-based rates for these services.

Appalachian Expansion Project
On August 22, 2008, the FERC issued an order to Columbia Transmission, which granted a certificate to construct the project. The project includes building a new 9,470 hp compressor station in West Virginia. The Appalachian Expansion Project added 100,000 Dth per day of transportation capacity and is fully subscribed on a 15-year contracted firm basis. Construction is complete and the project was placed in service on July 1, 2009.

Easton Compressor Station Project
On March 30, 2009, Columbia Transmission announced a binding open season for capacity into premium East Coast markets resulting from modifications made to the company's Easton Compressor Station. The modifications will increase delivery capacity from the Wagoner interconnection point between the Columbia Transmission and Millennium pipeline systems. Through the open season, which closed on April 3, 2009, Columbia Transmission received 30,000 Dth per day of binding bids. Construction is under way and service is expected to commence in the fourth quarter of 2009.

Gas Transmission and Storage Operations (continued)

Centerville Expansion Project

An open season to solicit interest and receive bids for expanded capacity on Columbia Gulf's system for delivery to Southern Natural Gas and the Louisiana intrastate pipeline market was held during the first quarter of 2008, and bids for 60,000 Dth per day of capacity were submitted. The remaining 175,000 Dth per day of capacity is being reviewed in conjunction with other market opportunities on the East Lateral in South Louisiana. The project is expected to be placed into service in late 2010.

Cobb Compressor Station Expansion

Shippers have also executed precedent agreements for a total of approximately 25,500 Dth per day of long-term firm transportation service associated with a facility expansion at Cobb Compressor Station in Kanawha County, West Virginia. The Cobb Expansion is expected to be in service April 1, 2010.

Sales and Percentage of Physical Capacity Sold

Columbia Transmission and Columbia Gulf compete for transportation customers based on the type of service a customer needs, operating flexibility, available capacity and price. Columbia Gulf and Columbia Transmission provide a significant portion of total transportation services under firm contracts and derive a smaller portion of revenues through interruptible contracts, with management seeking to maximize the portion of physical capacity sold under firm contracts.

Firm service contracts require pipeline capacity to be reserved for a given customer between certain receipt and delivery points. Firm customers generally pay a "capacity reservation" fee based on the amount of capacity being reserved regardless of whether the capacity is used, plus an incremental usage fee when the capacity is used. Annual capacity reservation revenues derived from firm service contracts generally remain constant over the life of the contract because the revenues are based upon capacity reserved and not whether the capacity is actually used. The high percentage of revenue derived from capacity reservation fees mitigates the risk of revenue fluctuations within the Gas Transmission and Storage Operations segment due to changes in near-term supply and demand conditions. For the six months ended June 30, 2009, approximately 89.7% of the transportation revenues were derived from capacity reservation fees paid under firm contracts and 4.8% of the transportation revenues were derived from usage fees under firm contracts. This is compared to approximately 90.4% of the transportation revenues derived from capacity reservation fees paid under firm contracts and 4.6% of transportation revenues derived from usage fees under firm contracts for the six months ended June 30, 2008.

Interruptible transportation service is typically short term in nature and is generally used by customers that either do not need firm service or have been unable to contract for firm service. These customers pay a usage fee only for the volume of gas actually transported. The ability to provide this service is limited to available capacity not otherwise used by firm customers, and customers receiving services under interruptible contracts are not assured capacity in the pipeline facilities. Gas Transmission and Storage Operations provides interruptible service at competitive prices in order to capture short term market opportunities as they occur and interruptible service is viewed by management as an important strategy to optimize revenues from the gas transmission assets. For the six months ended June 30, 2009 and 2008, approximately 5.5% and 5.0%, respectively, of the transportation revenues were derived from interruptible contracts.

Hartsville and Delhi Compressor Stations

In February 2008, tornados struck Columbia Gulf's Hartsville Compressor Station in Macon County, Tennessee. The damage to the facility forced Columbia Gulf to declare force majeure because no gas was flowing through this portion of the pipeline system while a facility assessment was being performed and the current contractual transportation agreements could not be met. Since that time, Columbia Gulf has constructed both temporary and permanent facilities at Hartsville. In July 2008, the station completed the installation of temporary horsepower and restored capacity. During the next five to seven months, the temporary facilities that were constructed to restore system capabilities will be replaced with a permanent solution.

In December 2007, Columbia Gulf's Line 100 ruptured approximately two miles north of its Delhi Compressor Station in Louisiana. The damage to the pipeline forced Columbia Gulf to declare force majeure because no gas was flowing through this portion of the pipeline system on Lines 100, 200 and 300 while a facility assessment was performed. Lines 200 and 300 were returned to service and gas flow was restored one day after the rupture. Later

NISOURCE INC.
Gas Transmission and Storage Operations (continued)

that same month, the DOT issued a Corrective Action Order. The Order required Columbia Gulf to develop a remedial work plan to restore Line 100 pipeline's pressure and capacity. Between December 2007 and June 2008, the Line 100 pipeline operated at less than full pressure and full capacity. On July 1, 2008, Columbia Gulf received permission from the DOT to restore full pressure and full capacity on the Line 100 pipeline. Columbia Gulf continues to operate under this Order.

During the first quarter of 2009, NiSource settled its receivables for insurance claims. NiSource received claim proceeds of $52.0 million for capital losses, $4.3 million for operation and maintenance losses and $2.7 million for business interruption and fuel costs.

In April 2009, NiSource settled remaining insurance claims on the Line 100 rupture for a total of $2.6 million, net of all deductibles. This remaining insurance claim involves recovery for excess fuel and other losses.

Environmental Matters
Various environmental matters occasionally impact the Gas Transmission and Storage Operations segment. As of June 30, 2009, a reserve has been recorded to cover probable environmental response actions. Refer to Note 17-C, "Environmental Matters," in the Notes to Condensed Consolidated Financial Statements (unaudited) for additional information regarding environmental matters for the Gas Transmission and Storage Operations segment.

Restructuring
In response to the current economic conditions, in February 2009, NiSource announced an organizational restructuring of the Gas Transmission and Storage Operations segment. NiSource is eliminating positions across the 16 state operating territory of Gas Transmission and Storage. The reductions will occur through voluntary programs and involuntary separations. In addition to employee reductions, the Gas Transmission and Storage Operations segment will take steps to achieve additional cost savings by efficiently managing its various business locations, reducing its fleet operations, creating alliances with third party service providers, and implementing other changes in line with its strategic plan for growth and maximizing value of existing assets. During the first half of 2009, NiSource recorded a pre-tax restructuring charge, net of adjustments, of $19.8 million to "Operation and maintenance" expense on the Condensed Statement of Consolidated Income (Loss) (unaudited), which primarily includes costs related to severance and other employee related costs for approximately 360 employees. As of June 30, 2009, 246 employees had been severed from employment bringing the restructuring liability balance for this initiative to $5.7 million. NiSource expects this restructuring initiative to be substantially complete by the end of 2009. Refer to Note 4, "Restructuring Activities," in the Notes to Condensed Consolidated Financial Statements (unaudited) for additional information regarding restructuring initiatives.

Throughput
Throughput for the Gas Transmission and Storage Operations segment totaled 267.2 MMDth for the second quarter of 2009, compared to 275.7 MMDth for the same period in 2008. The decrease of 8.5 MMDth for the three-month period was primarily due to lower Columbia Gulf deliveries off of its mainline to other interconnecting parties.

Throughput for the Gas Transmission and Storage Operations segment totaled 776.8 MMDth for the first six months of 2009, compared to 775.1 MMDth for the same period in 2008. The slight increase of 1.7 MMDth is due primarily to incremental volumes transported from new Columbia Transmission interconnects partially offset by lower Columbia Gulf deliveries off of its mainline to other interconnecting parties.

Net Revenues
Net revenues were $209.1 million for the second quarter of 2009, an increase of $13.1 million from the same period in 2008, primarily due to increases in firm capacity reservation fees and shorter term transportation and storage services of $12.9 million, partially offset by $2.0 million of lower commodity margin revenues. The increase in firm capacity reservation fees was the result of higher revenue for storage services, new Appalachian Supply interconnects, and incremental revenue from transportation agreements.

Net revenues were $451.4 million for the first six months of 2009, an increase of $24.1 million from the same period in 2008, primarily due to increases in firm capacity reservation fees and shorter term transportation and storage services $19.3 million, the impact of regulatory trackers of $5.7 million which are primarily offset in expense and

NISOURCE INC.
Gas Transmission and Storage Operations (continued)

$2.6 million attributable to a new contract for the subleasing of production rights to storage fields in Ohio, partly offset by $2.4 million of lower commodity margin revenues. The reasons for the increase in firm capacity reservation fees for the six month period is consistent with those disclosed for the second quarter.

Operating Income
Operating income was $79.6 million for the second quarter of 2009, an increase of $1.7 million from the second quarter of 2008, primarily due to higher net revenues discussed above partially offset by higher operating expenses of $7.2 million and lower equity earnings. Operating expenses increased primarily due to the impact of a $2.9 million gain recognized in the second quarter of 2008 on the sale of certain Columbia Gulf offshore assets and $2.7 million of increased pension expense. Equity earnings decreased by $4.2 million primarily resulting from a $7.9 million charge for the ineffective portion of the cash flow hedges associated with forward starting interest rate swaps resulting from Millennium's decision to delay permanent financing until 2010 from June 2009 as was originally intended, partially offset by higher earnings on Millennium.

Operating income was $172.5 million for the first six months of 2009, a $10.2 million decrease from the comparable period in 2008. Operating income decreased as a result of higher operating expenses of $34.5 million partially offset by increased net revenue discussed above. Operating expenses increased primarily due to restructuring charges of $19.8 million, increased regulatory trackers of $6.0 million, which are primarily offset in revenues, higher pension expense of $5.2 million, increased environmental costs of $2.7 million, $2.6 million from Millennium capacity net lease costs, and lower gains recognized on sales of assets as 2008 included sales of non-core assets located in Ohio and certain offshore assets noted above. These increases were partially offset by lower expenses for maintenance costs of $3.2 million, materials and supplies of $2.7 million, and corporate insurance of $1.7 million due partially from lower offshore asset levels. Equity earnings increased by $0.2 million primarily resulting from higher earnings on Millennium, which went into service late in 2008, offset almost entirely by a $7.9 million charge for the ineffective portion of the cash flow hedges discussed above.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

NISOURCE INC.
Electric Operations

(in millions)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Net Revenues				
Sales revenues	**$ 286.9**	$ 341.3	**$ 585.3**	$ 674.3
Less: Cost of sales (excluding depreciation and amortization)	**107.4**	139.9	**227.4**	289.5
Net Revenues	**179.5**	201.4	**357.9**	384.8
Operating Expenses				
Operation and maintenance	**96.2**	78.1	**191.0**	161.1
Depreciation and amortization	**51.2**	58.4	**101.6**	105.8
Other taxes	**9.1**	14.2	**25.0**	28.8
Total Operating Expenses	**156.5**	150.7	**317.6**	295.7
Operating Income	**$ 23.0**	$ 50.7	**$ 40.3**	$ 89.1
Revenues ($ in millions)				
Residential	**85.6**	80.4	**180.7**	167.3
Commercial	**90.7**	88.7	**185.9**	167.1
Industrial	**104.7**	126.6	**221.6**	269.6
Wholesale	**3.8**	17.9	**6.0**	26.8
Other	**2.1**	27.7	**(8.9)**	43.5
Total	**286.9**	341.3	**585.3**	674.3
Sales (Gigawatt Hours)				
Residential	**758.8**	745.8	**1,601.6**	1,552.6
Commercial	**934.5**	952.5	**1,903.1**	1,896.5
Industrial	**1,789.9**	2,376.2	**3,778.9**	4,890.2
Wholesale	**118.7**	185.2	**176.3**	329.9
Other	**44.0**	29.8	**79.1**	64.6
Total	**3,645.9**	4,289.5	**7,539.0**	8,733.8
Cooling Degree Days	**197**	201	**197**	201
Normal Cooling Degree Days	**230**	230	**230**	230
% Warmer (Colder) than Normal	**(14%)**	(13%)	**(14%)**	(13%)
Electric Customers				
Residential			**398,097**	399,276
Commercial			**53,386**	53,095
Industrial			**2,452**	2,498
Wholesale			**11**	6
Other			**752**	754
Total			**454,698**	455,629

NiSource generates and distributes electricity, through its subsidiary Northern Indiana, to approximately 455 thousand customers in 20 counties in the northern part of Indiana. The operating results reflect the temperature-sensitive nature of customer demand with annual sales affected by temperatures in the northern part of Indiana. As a result, segment operating income is generally higher in the second and third quarters, reflecting cooling demand during the summer season.

Electric Supply
On October 24, 2008, Northern Indiana issued two requests for proposals to secure additional new sources of electric power to meet the future needs of its residential, commercial and industrial customers. The first request

NISOURCE INC.
Electric Operations (continued)

seeks capacity and energy proposals for up to 300 mw of electricity to address Northern Indiana's projected electricity supply needs during the 2011 to 2016 time period. The second request seeks up to 300 mw of electricity generated from renewable sources and/or DSM technologies to address Northern Indiana's projected electricity supply needs beginning in 2011.

On July 24, 2008, the IURC issued an order approving Northern Indiana's proposed purchase power agreements with subsidiaries of Iberdrola Renewables for wind-generated power from Iowa and South Dakota. Under these agreements Northern Indiana purchases up to approximately 100 mw of wind power. Northern Indiana began purchasing wind power in April of 2009. Although a state or federal renewable portfolio standard is not yet established, Northern Indiana expects that its wind power purchase agreements would qualify as eligible purchases under any such standard.

Regulatory Matters
Significant Rate Developments. Northern Indiana filed a petition for new electric base rates and charges on June 27, 2008. The case-in-chief was originally filed on August 29, 2008, and amended on December 19, 2008 after the Sugar Creek facility was successfully dispatched into MISO. The filing requested an increase in base rates calculated to produce additional annual gross margin of $85.7 million. Evidentiary hearings on Northern Indiana's direct case commenced on January 12, 2009 and concluded on February 6, 2009. Several stakeholder groups have intervened in the case, representing customer groups and various counties and towns within Northern Indiana's electric service territory. Field hearings to record customer testimonies were held on March 3, 2009 and July 15, 2009. The OUCC and intervenors filed their cases-in-chief on May 8, 2009. Northern Indiana filed its rebuttal testimony on June 26, 2009. Northern Indiana made several minor changes to its revenue requirement, and, as a result the margin requirement in the rebuttal filing is $6 million less than the original request. Final hearings began on July 27, 2009. The case is expected to be resolved, and new electric rates effective during early 2010.

During 2002, Northern Indiana settled certain regulatory matters related to an electric rate review. On September 23, 2002, the IURC issued an Order adopting most aspects of the settlement. The Order approving the settlement provides that certain electric customers of Northern Indiana will receive bill credits of approximately $55.1 million each year. The credits will continue at approximately the same annual level and per the same methodology, until the IURC enters a base rate order that approves revised Northern Indiana electric rates. The order included a rate moratorium that expired on July 31, 2006. The order also provides that 60% of any future earnings beyond a specified earnings level will be retained by Northern Indiana. The billing factor used to distribute the revenue credit to customers is based on historical electric usage, therefore, in times of higher usage and revenues the amount credited may exceed $55.1 million annually, but would be offset in a subsequent period. Credits amounting to $26.3 million and $25.1 million were recognized for electric customers for the first half of 2009 and 2008, respectively.

MISO. As part of Northern Indiana's participation in the MISO transmission service and wholesale energy market, certain administrative fees and non-fuel costs have been incurred. IURC orders have been issued authorizing the deferral for consideration in a future rate case proceeding of the administrative fees and certain non-fuel related costs incurred after Northern Indiana's rate moratorium, which expired on July 31, 2006. During the first half of 2009, non-fuel costs credit of $3.7 million were deferred in accordance with the aforementioned orders. In addition, administrative, FERC and other fees of $3.5 million were deferred. In total, for the first half of 2009 and 2008, net MISO credits of $0.2 million and costs of $4.9 million, respectively, were deferred. In its base rate case, Northern Indiana proposes recovery over a four year amortization period of the cumulative amount of charges that were deferred as of December 31, 2008, and to recover, through a tracker, charges deferred between December 31, 2008 and the date of effective rates in this case. The aforementioned tracker is also proposed for recovery of these charges on an ongoing basis. As noted below, as part of MISO's initiation of an ASM, Northern Indiana will also incur non-fuel administrative costs associated with this market. The IURC authorized Northern Indiana to defer the costs associated with participating in the ASM subject to a final determination in a subsequent phase of the same proceeding. On June 30, 2009, the IURC issued an Order in the subsequent phase of the ASM proceeding confirming that Northern Indiana is permitted to continue deferring non-fuel administrative costs.

Northern Indiana was an active stakeholder in the process used in designing, testing and implementing the ASM and in developing the surrounding business practices. On January 18, 2008, Northern Indiana as part of a Joint Petition among several other Indiana utilities, "Joint Petitioners," filed a request to the IURC to participate in ASM and seek

NiSource Inc.
Electric Operations (continued)

approval of timely cost recovery for the associated costs of participating. On August 13, 2008, the IURC issued a Phase I order, authorizing the Joint Petitioners authority to transfer additional balancing authority functions and to implement the operational changes necessary to participate in the ASM and to seek recovery of modified MISO charge-types via the FAC and to defer certain other MISO charge-types, pending a final determination on the issue of cost recovery in Phase II. This order also created a subdocket for the purpose of further consideration of whether a cost-benefit analysis of participation in MISO or the MISO ASM should be required. Phase II of this proceeding deals with how the Joint Petitioners will approach the ASM, specifically related to cost recovery. The evidentiary hearing for Phase II concluded on February 9, 2009 and on June 30, 2009, the IURC issued an Order authorizing Northern Indiana to recover fuel-related ASM charges in its FAC and to defer non-fuel charges. The market began on January 6, 2009. The impact of ASM will not have a material effect on cash flows or earnings.

On November 7, 2008, the FERC issued an Order clarifying the RSG First Pass calculation and requiring the MISO to resettle the RSG market using the correct calculation and to pay refunds, or assess surcharges, to market participants, as appropriate, to correct a misinterpretation of an order issued by FERC in April 2006. Northern Indiana believes that it would have been entitled to a refund, with the amount subject to calculation by MISO. On June 12, 2009, however, FERC issued an order on rehearing in which it affirmed its prior order clarifying the method to calculate the RSG First Pass rate, but reversed its ruling requiring the MISO to pay refunds, and collect surcharges, on equitable grounds. Northern Indiana has asked FERC to reconsider its decision to deny refunds and that request remains pending.

MISO's implementation of FERC's April 2006 Order on the RSG First Pass calculation resulted in several million dollars of surcharges to Northern Indiana through market resettlements implemented during the summer of 2007. As a result, Northern Indiana and Ameren jointly filed a complaint with FERC on August, 10, 2007, contending that the RSG rates in effect were unjust and unreasonable. On November 10, 2008, the FERC issued an Order granting these complaints and ordering the MISO to calculate refunds and surcharges, as appropriate, back to the date of the complaint filed by Northern Indiana and Ameren, as authorized by Section 206 of the Federal Power Act. On May 6, 2009, however, the FERC issued an Order that upheld its decision granting the complaint, but largely reversed its directive requiring MISO to pay refunds, and collect surcharges, on equitable grounds. The FERC affirmed the refund and surcharge requirement only for those transactions that occurred after the date of the November 10, 2008 Order, instead of August 10, 2007, as it had previously required. Northern Indiana and Ameren have requested rehearing of the FERC's May 6, 2009 Order, and that request remains pending.

Cost Recovery and Trackers. A significant portion of Northern Indiana's 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 standard, quarterly, "summary" regulatory proceeding in Indiana. Various intervenors, including the OUCC, have taken issue with the allocation of costs included in Northern Indiana's FAC-80, FAC-81 and FAC-82, which cover the reconciliation of April - December 2008. The IURC has granted a sub-docket to consider such issues in those filings. The intervening parties and Northern Indiana are discussing procedures to eliminate these concerns and to resolve them for the historical periods. There is no procedural schedule established for this sub-docket. Northern Indiana recorded an accrual for this matter in accordance with SFAS No. 5.

The IURC issued an order on May 28, 2008 approving the purchase of Sugar Creek, and on May 30, 2008 Northern Indiana purchased the 535 mw CCGT for $330 million in order to help meet capacity needs. The IURC, on February 18, 2009, issued an order approving a settlement agreement filed in this proceeding allowing Northern Indiana to begin deferring carrying costs and depreciation on Sugar Creek effective on December 1, 2008, when Sugar Creek was dispatched into MISO, at the agreed to carrying cost rate of 6.5%, less $4.5 million annually, the annual depreciation on the Mitchell plant, pursuant to the FAC-71 settlement. The terms of recovery of the deferral will be resolved in Northern Indiana's current rate proceeding. On March 19, 2009, LaPorte County filed a notice of appeal regarding the IURC's decision. On July 21, 2009, the Indiana Court of Appeals granted LaPorte County's Motion to Dismiss the appeal filed with the court on July 16, 2009.

As part of a settlement agreement which resolved issues surrounding purchased power costs, Northern Indiana implemented a new "benchmarking standard," that became effective in October 2007, which defines the price above which purchased power costs must be absorbed by Northern Indiana and are not permitted to be passed on to ratepayers. The benchmark is based upon the costs of power generated by a hypothetical natural gas fired unit using

NISOURCE INC.
Electric Operations (continued)

gas purchased and delivered to Northern Indiana and a set sharing mechanism. During the first six months of 2009 and 2008, the amount of purchased power costs exceeding the benchmark amounted to $1.0 million and $6.5 million, respectively, which was recognized as a net reduction of revenues. The agreement also contemplated Northern Indiana adding generating capacity to its existing portfolio by providing for the benchmark to be adjusted as new capacity is added. The dispatch of Sugar Creek into MISO on December 1, 2008 triggered a change in the benchmark, whereby the first 500 mw tier of the benchmark provision was eliminated.

Northern Indiana has approval from the IURC to recover certain environmental related costs through an ECT. Under the ECT, Northern Indiana is permitted to recover (1) AFUDC and a return on the capital investment expended by Northern Indiana to implement IDEM's NOx SIP through an ECRM and (2) related operation and maintenance and depreciation expenses once the environmental facilities become operational through an EERM. Under the IURC's November 26, 2002 order, Northern Indiana is permitted to submit filings on a semi-annual basis for the ECRM and on an annual basis for the EERM. In addition, Northern Indiana received an IURC order issuing a CPCN for the CAIR and CAMR Phase I Compliance Plan Projects, estimated to cost approximately $23 million. Northern Indiana includes the CAIR and CAMR Phase I Compliance Plan costs to be recovered in the semi-annual ECRM and annual EERM filing six months after construction costs begin. On October 23, 2008, Northern Indiana filed for approval of a revised cost estimate to meet the NOx and SO2 and mercury emissions environmental standards. Northern Indiana anticipates a total capital investment of approximately $368 million. This revised cost estimate was approved by the IURC on January 14, 2009. On October 1, 2008, the IURC approved ECR-12 for capital expenditures (net of accumulated depreciation) of $267.7 million. Northern Indiana filed ECR-13 and EER-6 in February 2009, for net capital expenditures and expense of $268.1 million and $18.7 million, respectively. The Order was issued on April 20, 2009. In the electric base rate case, Northern Indiana has proposed that the frequency of the EERM be changed from annual to semi-annual, consistent with the filing of the ECRM. In addition, Northern Indiana proposed that the EERM be used to pass through to ratepayers the cost of any emission allowance purchases and the proceeds of any emission allowance sales.

Environmental Matters

Various environmental matters occasionally impact the Electric Operations segment. As of June 30, 2009, a reserve has been recorded to cover probable environmental response actions. Refer to Note 17-C, "Environmental Matters," in the Notes to Condensed Consolidated Financial Statements (unaudited) for additional information regarding environmental matters for the Electric Operations segment.

Sales

Electric Operations sales quantities for the second quarter of 2009 were 3,645.9 gwh, a decrease of 643.6 gwh compared to the second quarter of 2008. The decrease was due to lower industrial and wholesale volumes compared to the same period last year. The lower industrial and wholesale volumes in these areas were primarily the result of the economic downturn and the impact to the major steel companies, which were operating at close to full capacity in early 2008 and are now operating at about half capacity.

Electric Operations sales quantities for the first half of 2009 were 7,539.0 gwh, compared to 8,733.8 gwh in the first half of 2008. The decrease was due to lower industrial and wholesale volumes compared to the same period last year partially offset by higher residential and commercial volumes. The lower industrial and wholesale volumes in these areas were primarily the result of the economic downturn and the impact to the major steel companies, which were operating at close to full capacity in early 2008 and are now operating at about half capacity.

On July 8th, 2009, a discounted power sales agreement terminated with one of Northern Indiana's large industrial customers. On July 9th, 2009, a full tariff power sales agreement commenced with that customer.

Net Revenues

In the second quarter of 2009, Electric Operations net revenues of $179.5 million decreased by $21.9 million from the comparable 2008 period. This decrease was due to lower industrial and commercial usage of $14.5 million due to current economic conditions and lower off-system sales of $5.6 million.

At Northern Indiana, sales revenues and customer billings are adjusted for amounts related to under and over-recovered purchased fuel costs from prior periods per regulatory order. These amounts are primarily reflected in the

NISOURCE INC.
Electric Operations (continued)

"Other" gross revenues statistic provided at the beginning of this segment discussion. The adjustment to Other gross revenues for the three and six months ended June 30, 2009 was a revenue reduction of $9.0 million and $21.9 million, respectively, compared to a reduction of $1.5 million and $7.8 million for the three and six months ended June 30, 2008, respectively, due to a decline in the average cost of purchased and produced power subsequent to the establishment of estimated rates and volumes used for setting recovery factors.

In the first half of 2009, Electric Operations net revenues of $357.9 million decreased by $26.9 million from the comparable 2008 period. This decrease was due to lower industrial usage of $21.7 million due to current economic conditions and lower off-system sales of $10.2 million, partially offset by $5.5 million lower non-recoverable purchased power.

Operating Income

Operating income for the second quarter of 2009 was $23.0 million, a decrease of $27.7 million from the same period in 2008 due to lower net revenues discussed above and a $5.8 million increase in operating expenses. The increase in operating expenses was primarily due to higher pension expense of $10.5 million and electric generation and maintenance costs of $5.0 million, partially offset by $7.2 million of lower depreciation and a $5.1 million decrease in other taxes. The decrease in depreciation expense is due to the impact of an $8.3 million adjustment recorded by Northern Indiana during the second quarter of 2008.

Operating income for the first half of 2009 was $40.3 million, a decrease of $48.8 million from the same period in 2008 due to lower net revenues discussed above and a $21.9 million increase in operating expenses. The decrease in operating income was due to higher pension expense of $21.0 million and electric generation and maintenance expenses of $5.9 million, partially offset by lower environmental expenses of $4.7 million, depreciation expenses of $4.2 million and other taxes of $3.8 million. The decrease in depreciation expense is due to the impact of an $8.3 million adjustment recorded by Northern Indiana during the second quarter of 2008.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

NISOURCE INC.
O ther Operations

(in millions)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Net Revenues				
Products and services revenue	**$ 2.2**	$ 33.4	**$ 4.8**	$ 61.2
Less: Cost of products purchased (excluding depreciation and amortization)	**-**	30.9	**-**	56.0
Net Revenues	**2.2**	2.5	**4.8**	5.2
Operating Expenses				
Operation and maintenance	**2.8**	3.3	**6.1**	7.0
Depreciation and amortization	**0.9**	0.5	**1.4**	1.1
Other taxes	**0.2**	0.2	**0.4**	0.4
Total Operating Expenses	**3.9**	4.0	**7.9**	8.5
Operating Loss	**$ (1.7)**	$ (1.5)	**$ (3.1)**	$ (3.3)

The Other Operations segment participates in energy-related services and ventures focused on distributed power generation technologies, including fuel cells and storage systems. Additionally, the Other Operations segment is involved in real estate and other businesses.

In the second quarter of 2009, NiSource signed a letter of intent to sell its unregulated natural gas marketing business. These operations have been removed from NiSource's Other Operations business segment and are now being accounted for as discontinued operations. As such, net income of $13.5 million was classified as net income from discontinued operations for both the three months and six months ended June 30, 2009, and $1.4 million and $2.2 million was reclassified to discontinued operations for the three months and six months ended June 20, 2008, respectively. NiSource also recorded a net loss on sale of discontinued operations of $8.8 million in June 2009, related to the proposed sale of the business.

Lake Erie Land Company, Inc.
Lake Erie Land, which is wholly-owned by NiSource, is in the process of selling real estate to a private real estate development group. NiSource accounts for the assets expected to be sold to the private developer during the next twelve months as assets held for sale. In the second quarter of 2009, the developer was unable to meet certain contractual obligations under the sale agreement, specifically the payment of the $11 million note receivable that was due on June 13, 2009. NiSource granted a limited extension for the payment of the note and began negotiations with another potential party to replace the original developer. In July 2009, NiSource signed a Letter of Intent with the new potential party. Based on the most probable scenarios as of June 30, 2009, the Lake Erie Land assets continue to meet criteria for assets held for sale.

NDC Douglas Properties, Inc.
NDC Douglas Properties, a subsidiary of NiSource Development Company, is in the process of exiting some of its low income housing investments. NiSource has accounted for the investments to be sold as assets and liabilities of discontinued operations and held for sale. The remaining low income housing investments are consolidated as held and used.

Net Revenues
Net revenues of $2.2 million for the second quarter of 2009 decreased by $0.3 million from the second quarter of 2008. Net revenues for the Other Operations segment are primarily associated with energy-related ventures and the NDC Douglas Properties. Net revenues in 2008 included gas marketing activities to three municipalities in the United States associated with Columbia Energy Services. Obligations under these contracts were completed by December 2008.

Net revenues of $4.8 million for the first half of 2009 decreased by $0.4 million from the first half of 2008. Net revenues for the Other Operations segment are primarily related to energy-related ventures and the NDC Douglas

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

NISOURCE INC.
O ther Operations

Properties. Net revenues in 2008 included gas marketing activities to three municipalities in the United States associated with Columbia Energy Services. Obligations under these contracts were completed by December 2008.

Operating Loss
Other Operations reported an operating loss of $1.7 million for the second quarter of 2009, versus an operating loss of $1.5 million for the comparable 2008 period. The slight decrease in operating income resulted primarily from lower net revenues described above.

Other Operations reported an operating loss of $3.1 million for the first half of 2009, versus an operating loss of $3.3 million for the comparable 2008 period. The slight increase in operating income resulted primarily from decreased operating expense due mostly to lower employee and administrative expense of $0.7 million, partially offset by lower net revenues described above.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

NISOURCE INC.

For a discussion regarding quantitative and qualitative disclosures about market risk see “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Market Risk Disclosures.”

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

NiSource’s chief executive officer and its principal financial officer, after evaluating the effectiveness of NiSource’s disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)), have concluded based on the evaluation required by paragraph (b) of Exchange Act Rules 13a-15 and 15d-15 that, as of the end of the period covered by this report, NiSource’s disclosure controls and procedures are considered effective.

Changes in Internal Controls

There have been no changes in NiSource’s internal control over financial reporting during the fiscal period covered by this report that has materially affected, or is reasonably likely to affect, NiSource’s internal control over financial reporting.

PART II

ITEM 1. LEGAL PROCEEDINGS

NISOURCE INC.

1. Stand Energy Corporation, et al. v. Columbia Gas Transmission Corporation, et al., Kanawha County Court, West Virginia

On July 14, 2004, Stand Energy Corporation filed a complaint in Kanawha County Court in West Virginia. The complaint contains allegations against various NiSource companies, including Columbia Transmission and Columbia Gulf, and asserts that those companies and certain "select shippers" engaged in an "illegal gas scheme" that constituted a breach of contract and violated state law. The "illegal gas scheme" complained of by the plaintiffs relates to the Columbia Transmission and Columbia Gulf gas imbalance transactions that were the subject of the FERC enforcement staff investigation and subsequent settlement approved in October 2000. Columbia Transmission and Columbia Gulf filed a Motion to Dismiss on September 10, 2004. In October 2004, however, the plaintiffs filed their Second Amended Complaint, which clarified the identity of some of the "select shipper" defendants and added a federal antitrust cause of action. To address the issues raised in the Second Amended Complaint, the Columbia companies revised their briefs in support of the previously filed motions to dismiss. In June 2005, the Court granted in part and denied in part the Columbia companies' motion to dismiss the Second Amended Complaint. The Columbia companies have filed an answer to the Second Amended Complaint. On December 1, 2005, Plaintiffs filed a motion to certify this case as a class action. The Columbia companies filed their opposition to this motion in March 2008. On August 19, 2008, the Court denied the Motion for Class Certification. In late December 2008, the lead plaintiff, Stand Energy Corporation, reached a settlement agreement of all claims with all Defendants. Stand Energy Corporation was dismissed from the case on December 31, 2008, leaving Energy Marketing Services, Inc., AGF, Inc., Advantage Energy Marketing, Inc. and 1564 East Lancaster Avenue Business Trust as the remaining named plaintiffs. Columbia companies reached settlement with Energy Marketing Services, Inc. in late April 2009. Columbia companies' motion for summary judgment was granted on July 2, 2009 resulting in the dismissal of one plaintiff, Advantage Energy Marketing, Inc. from the case. Pretrial Conference was held on August 3, 2009 and the Trial with the remaining two plaintiffs, (AGF, Inc. and 1564 East Lancaster Avenue Business Trust) is scheduled for August 4, 2009.

2. United States of America ex rel. Jack J. Grynberg v. Columbia Gas Transmission Corporation, et al., U.S. District Court, Wyoming

The plaintiff filed a complaint in 1995, under the False Claims Act, on behalf of the United States of America, against approximately seventy pipelines, including Columbia Gulf and Columbia Transmission. The plaintiff claimed that the defendants had submitted false royalty reports to the government by mismeasuring natural gas produced on Federal land and Indian lands. The Plaintiff's original complaint was dismissed without prejudice for misjoinder of parties and for failing to plead fraud with specificity. In 1997, the plaintiff filed over sixty-five new False Claims Act complaints against over 330 defendants in numerous Federal courts. One of those complaints was filed in the Federal District Court for the Eastern District of Louisiana against Columbia and thirteen affiliated entities (collectively, the "Columbia defendants"). This complaint repeats the mismeasurement claims previously made and adds valuation claims alleging that the defendants undervalued natural gas for royalty purposes in various ways, including sales to affiliated entities at artificially low prices. This case was transferred, along with other new Grynberg cases, to Federal District Court in Wyoming in 1999.

On October 20, 2006, the Federal District Court issued an Order granting the Columbia defendants' motion to dismiss for lack of subject matter jurisdiction. Plaintiff appealed the dismissal of the Columbia defendants to the United States Court of Appeals for the Tenth Circuit, but the Court affirmed the dismissal in March 2009 and then denied plaintiff's motion to reconsider in May 2009.

3. Tawney, et al. v. Columbia Natural Resources, Inc., Roane County, WV Circuit Court

The Plaintiffs, who are West Virginia landowners, filed a lawsuit in early 2003 against CNR alleging that CNR underpaid royalties on gas produced on their land by improperly deducting post-production costs and not paying a fair value for the gas. In December 2004, the court granted plaintiffs' motion to add NiSource and Columbia as defendants. Plaintiffs also claimed that the defendants fraudulently concealed the deduction of post-production charges. The court certified the case as a class action that includes any person who, after July 31, 1990, received or is due royalties from CNR (and its predecessors or successors) on lands lying within the boundary of the state of West Virginia. All claims by the government of the United States are excluded from the class. Although NiSource sold CNR in 2003, NiSource remains obligated to manage this litigation and for the majority of any damages ultimately awarded to the plaintiffs. On January 27, 2007, the jury hearing the case returned a verdict against all defendants in the amount of $404.3 million; this is comprised of $134.3 million in compensatory damages and $270 million in punitive damages. In January 2008, the Defendants filed their petition for appeal, and on March 24, 2008, the Defendants filed their amended petition for appeal with the West Virginia Supreme Court of Appeals. On May 22, 2008, the West Virginia Supreme Court of Appeals refused the defendants petition for appeal. On August 22, 2008, Defendants filed their petitions to the United States Supreme Court for writ of certiorari. The Plaintiffs filed their response on September 22, 2008. On September 19, 2008, the West Virginia Supreme Court issued an order extending the stay of the judgment until proceedings before the United States Supreme Court are fully concluded. Given the West Virginia Court's refusal of the appeal, NiSource adjusted its reserve in the second quarter of 2008 to reflect the portion of the trial court judgment for which NiSource would be responsible, inclusive of interest. This amount was included in "Legal and environmental reserves," on the Consolidated Balance Sheet as of December 31, 2008. On October 24, 2008, the West Virginia Circuit Court for Roane County, West Virginia, preliminarily approved a settlement agreement with a total settlement amount of $380 million. The settlement received final approval by the Court on November 22, 2008. NiSource's share of the settlement liability is up to $338.8 million. NiSource has complied with its obligations under the settlement agreement to fund $85.5 million in the qualified settlement fund by January 13, 2009. Additionally, NiSource provided a letter of credit on January 13, 2009 in the amount of $254 million and thereby complied with its obligation to secure the unpaid portion of the settlement. The trial court entered its order discharging the judgment on January 20, 2009. The Court is supervising the administration of the settlement proceeds. NiSource will be required to make additional payments, pursuant to the settlement, upon notice from the Class Administrator.

4. John Thacker, et al. v. Chesapeake Appalachia, L.L.C., U.S. District Court, E.D. Kentucky Poplar Creek Development Company v. Chesapeake Appalachia, L.L.C., U.S. District Court, E.D. Kentucky

On February 8, 2007, Plaintiff filed the Thacker case, a purported class action alleging that Chesapeake has failed to pay royalty owners the correct amounts pursuant to the provisions of their oil and gas leases covering real property located within the state of Kentucky. Columbia has assumed the defense of Chesapeake in this matter pursuant to the provisions of the Stock Purchase Agreement dated July 3, 2003, among Columbia, NiSource, and Triana Energy Holding, Inc., Chesapeake's predecessor in interest ("Stock Purchase Agreement"). Plaintiffs filed an amended complaint on March 19, 2007, which, among other things, added NiSource and Columbia as defendants. On March 31, 2008, the Court denied the Defendants' Motions to Dismiss; the Defendants filed their answers to the complaint on April 25, 2008. On June 3, 2008, the Plaintiffs moved to certify a class consisting of all persons entitled to payment of royalty by Chesapeake under leases operated by Chesapeake at any point after February 5, 1992, on real property in Kentucky. The motion for class certification has been fully briefed, but has not yet been decided.

In June 2009, the parties to the Thacker litigation presented a settlement agreement to the Court for preliminary approval. Plaintiffs requested that the Court order that the settlement agreement, which is contingent upon court approval, is fair, reasonable and adequate, that the class proposed is preliminarily certified, that plaintiffs counsel be conditionally appointed as class counsel, that the proposed form and manner of notice be approved and that dates be set for requested exclusions, objections and a formal fairness hearing. The Court has taken plaintiff's motion under advisement and a ruling is expected shortly.

On October 9, 2008, Chesapeake tendered the Poplar Creek case to Columbia and Columbia subsequently assumed the defense of this matter pursuant to the provisions of the Stock Purchase Agreement. Poplar Creek also purports to be a class action covering royalty owners in the state of Kentucky and alleges that Chesapeake has improperly deducted costs from the royalty payments; there is thus some overlap of parties and issues between the Poplar Creek and Thacker cases. Plaintiffs filed an amended complaint on October 12, 2008. Chesapeake filed a motion for judgment on the pleadings in December 2008 which was granted on July 2, 2009. An Order of Dismissal has been entered in favor of the defendants. On July 30, 2009, plaintiffs filed a Notice of Appeal of the Order of Dismissal.

ITEM 1. LEGAL PROCEEDINGS (continued)

NISOURCE INC.

5. Environmental Protection Agency Notice of Violation

On September 29, 2004, the EPA issued an NOV to Northern Indiana for alleged violations of the CAA and the Indiana SIP. The NOV alleges that modifications were made to certain boiler units at three of Northern Indiana's generating stations between the years 1985 and 1995 without obtaining appropriate air permits for the modifications. The ultimate resolution could require additional capital expenditures and operations and maintenance costs as well as payment of substantial penalties and development of supplemental environmental projects. Northern Indiana is currently in discussions with the EPA regarding possible resolutions to this NOV.

6. Majorsville Operations Center — PADEP Notice of Violation

In 1995, Columbia Transmission entered into an AOC with the EPA that requires Columbia Transmission characterize and remediate environmental contamination at thousands of locations along Columbia Transmission's pipeline system. One of the facilities subject to the AOC is the Majorsville Operations Center, which was remediated under an EPA approved Remedial Action Work Plan in summer 2008. Pursuant to the Remedial Action Work Plan, Columbia Transmission completed a project that stabilized residual oil contained in soils at the site and in sediments in an adjacent stream.

On April 23, 2009, however, PADEP issued Columbia Transmission an NOV, alleging that the remediation was not effective. The NOV asserts violations of the Pennsylvania Clean Streams Law and the Pennsylvania Solid Waste Management Act and contains a settlement demand in the amount of $1 million. On May 27, 2009, Columbia Transmission filed an appeal of the NOV to the Pennsylvania Environmental Hearing Board. Columbia Transmission is unable to estimate the likelihood or cost of potential penalties or additional remediation at this time.

ITEM 1A. RISK FACTORS

There are many factors that could have a material adverse effect on NiSource's operating results, financial condition and cash flows. New risks may emerge at any time, and NiSource cannot predict those risks or estimate the extent to which they may affect financial performance. In addition to the risks listed in the "Risk Factors" section of NiSource's 2008 Form 10-K filed with the SEC on February 27, 2009, the risks described below could adversely impact the value of NiSource's securities.

Continued adverse economic and market conditions or increases in interest rates could reduce net revenue growth, increase costs, decrease future net income and cash flows and impact capital resources and liquidity needs.

The credit markets and the general economy have been experiencing a period of large-scale turmoil and upheaval characterized by the bankruptcy, failure, collapse or sale of various financial institutions and an unprecedented level of intervention from the United States federal government. While the ultimate outcome of these events cannot be predicted, it may have an adverse material effect on NiSource. A continued decline in the economy impacting NiSource's operating jurisdictions could further adversely affect NiSource's ability to grow its customer base and collect revenues from customers, which could reduce net revenue growth and increase operating costs. An increase in the interest rates NiSource pays would adversely affect future net income and cash flows. In addition, NiSource depends on debt to finance its operations, including both working capital and capital expenditures, and would be adversely affected by increases in interest rates. The current economic downturn and tightening of access to credit markets, coupled with NiSource's current credit ratings, could impact NiSource's ability to raise additional capital or refinance debt at a reasonable cost. Refer to Note 15, "Long-Term Debt," of the Consolidated Financial statements for information related to outstanding long-term debt and maturities of that debt.

Table of Contents

ITEM 1A. RISK FACTORS (continued)

NiSource Inc.

NiSource is 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.

NiSource's 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. Credit risk exposure is monitored by obtaining credit reports and updated financial information for customers and suppliers, and by evaluating the financial status of its banking partners and other counterparties through the use of market-based metrics such as credit default swap pricing levels, and also through traditional credit ratings provided by the major credit rating agencies. Continued adverse economic conditions could increase credit risk and could result in a material adverse effect on NiSource.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

On May 12, 2009, NiSource held its annual meeting of stockholders. On March 17, 2009, there were 274,305,532 shares of common stock outstanding and entitled to vote in person or by proxy at the meeting.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS (continued)

NISOURCE INC.

The number and percentage of votes received for, and the number of votes withheld, from each nominee for director are set forth below:

Nominee	Number of Votes FOR	Votes FOR as a percentage of Votes Cast	Number of votes AGAINST	Votes AGAINST as a percentage of Votes Cast
Richard A. Abdoo	223,245,609	97.36	6,060,155	2.64
Steven C. Beering	220,878,448	96.32	8,168,153	3.56
Dennis E. Foster	222,640,066	97.09	6,353,536	2.77
Michael E. Jesanis	223,359,996	97.41	5,681,535	2.48
Marty R. Kittrell	214,556,365	93.57	14,489,797	6.32
W. Lee Nutter	222,874,808	97.20	6,170,850	2.69
Deborah S. Parker	223,008,950	97.25	6,038,978	2.63
Ian M. Rolland	220,965,102	96.36	8,081,150	3.52
Robert C. Skaggs, Jr.	222,166,207	96.89	6,873,706	3.00
Richard L. Thompson	223,071,024	97.28	5,974,894	2.61
Carolyn Y. Woo	221,289,298	96.50	7,755,807	3.38

Accordingly, each of the nominees for director were elected to serve as director for a term of one year until 2010.

The number and percentage of votes received for, the number of votes against, and the number of votes abstained in conjunction with the ratification of Deloitte & Touche LLP as the Corporation's independent public accountants for the year 2009 are set forth below:

Number of votes FOR	Votes For as a percentage of Votes present a the meeting	Number of votes AGAINST	Number of votes ABSTAINED
225,337,197	98.27	2,977,466	991,100

Accordingly, the ratification to appoint Deloitte & Touche LLP as the Company's independent public accountants for the year 2009 was approved.

The number and percentage of votes received for, the number of votes against and the number of votes abstained in conjunction with the proposal to permit holders of 10% of outstanding common stock (or the lowest percentage allowed by law above 10%) the power to call special shareholder meetings is set forth below:

Number of votes FOR	Votes FOR as a percentage of shares outstanding	Number of votes AGAINST	Number of votes ABSTAINED
127,721,397	55.7	69,082,703	2,036,709

Accordingly, the advisory proposal regarding special shareholder meetings was approved.

ITEM 5. OTHER INFORMATION

NISOURCE INC.

None

ITEM 6. EXHIBITS

(31.1) Certification of Robert C. Skaggs, Jr., Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. *

(31.2) Certification of Stephen P. Smith, Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. *

(32.1) Certification of Robert C. Skaggs, Jr., Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).

(32.2) Certification of Stephen P. Smith, Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).

* Exhibit attached hereto.

Pursuant to Item 601(b)(4)(iii) of Regulation S-K, NiSource hereby agrees to furnish the SEC, upon request, any instrument defining the rights of holders of long-term debt of NiSource not filed as an exhibit herein. No such instrument authorizes long-term debt securities in excess of 10% of the total assets of NiSource and its subsidiaries on a consolidated basis.

Table of Contents

SIGNATURE

NISOURCE INC.

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

NiSource Inc.
(Registrant)

Date: August 4, 2009

By: /s/ Jeffrey W. Grossman
Jeffrey W. Grossman
Vice President and Controller
(Principal Accounting Officer
and Duly Authorized Officer)

Exhibit 31.1

Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Robert C. Skaggs, Jr., certify that:

1. I have reviewed this Quarterly Report of NiSource Inc. on Form 10-Q for the quarter ended June 30, 2009;

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(s) 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: August 4, 2009

By: /s/ Robert C. Skaggs, Jr.
Robert C. Skaggs, Jr.
Chief Executive Officer

Exhibit 31.2

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Stephen P. Smith, certify that:

1. I have reviewed this Quarterly Report of NiSource Inc. on Form 10-Q for the quarter ended June 30, 2009;

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(s) 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: August 4, 2009

By: /s/ Stephen P. Smith
Stephen P. Smith
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 Quarterly Report of NiSource Inc. (the “Company”) on Form 10-Q for the quarter ending June 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert C. Skaggs, Jr., 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/ Robert C. Skaggs, Jr.
Robert C. Skaggs, Jr.
Chief Executive Officer

Date: August 4, 2009

Exhibit 32.2

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Quarterly Report of NiSource Inc. (the "Company") on Form 10-Q for the quarter ending June 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Stephen P. Smith, 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/ Stephen P. Smith

Stephen P. Smith
Executive Vice President and Chief Financial Officer

Date: August 4, 2009

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

12. Refer to Columbia Kentucky's Response to Staff's Second Request, Item 35. Explain the basis for the weights applied to the various growth rates for the DCF calculations.

Response:

As discussed in Columbia's Response to Staff's Second Set of Requests for Information No. 35, Mr. Rea placed the greatest emphasis on the EPS growth estimates of equity analysts, as the finance literature has demonstrated that EPS growth estimates are a primary driver of stock valuations. Therefore, in accordance with the academic literature, Mr. Rea assigned the heaviest weighting to equity analyst EPS growth estimates, with a 2/3rd overall weighting being an appropriate weighting in Mr. Rea's judgment. The 2/3rd weighting amount is consistent with the approach previously taken by the Federal Energy Regulatory Commission (FERC), which now places an 80 percent weighting[1] on the EPS consensus growth estimates of equity analysts for purposes of applying the

[1] See, *FERC Opinion 569-B*, Docket No. EL14-12-015 (November 19, 2020) at P. 86.

constant growth DCF model. Considering that both sell-side equity analysts[2] and Value Line's investment analysts provide EPS growth rate estimates that are relied upon by the investment community, Mr. Rea believes it is reasonable to place equal emphasis on these two sources of EPS growth estimates. This is the basis of Mr. Rea's decision to apply a 1/3rd weighting to the EPS growth estimates of sell-side equity analysts, and a 1/3rd weighting to Value Line's EPS growth estimates.

As further noted in Columbia's Response to Staff's Second Set of Requests for Information No. 35, Mr. Rea applied the remaining 1/3rd overall weighting equally between historical EPS growth rates and retention growth rate forecasts. While the finance literature strongly suggests that these alternative growth rate measures have less of an impact on stock valuations and the investment decisions of equity investors, it is nonetheless reasonable to assume that they do have some degree of impact on investors, and therefore should be given some consideration. For this reason, in Mr. Rea's judgment, it is reasonable to apply a one-sixth weighting to the historical EPS growth rates reported by Value Line; and a one-sixth weighting to the retention growth rate forecasts published by Value Line.

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[2] Mr. Rea referenced the consensus EPS growth estimates of sell-side equity analysts, as reported by Yahoo Finance and Zacks.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

13. Refer to the Rea Testimony, page 22. Water distribution utilities have many similar operating characteristics to gas distribution utilities. Explain why it is not appropriate to include water utilities in the LDC proxy group or in the alternative, to consider them as a separate group as the company did with the combination utility group.

Response:

In developing the utility proxy groups to support his cost of capital evaluation, Mr. Rea's objective was to identify a group of gas utility holding companies that most closely reflected the operating characteristics of Columbia. In this regard, the Gas LDC Group identified by Mr. Rea, which consists of seven gas utility holding companies, provides the best representation of the Company's gas utility operations. This approach is the typical approach taken in gas utility rate proceedings, and therefore better facilitates a direct comparison of the cost of equity recommendations of opposing witnesses in the proceeding, since the opposing witnesses representing intervening parties will also typically present a "pure-play" gas utility proxy group. Although Mr. Rea agrees that water distribution utilities share many of the same operating characteristics that apply to gas distribution utilities, Mr. Rea has not included water utilities in his "pure-play" gas utility proxy group simply because gas utilities provide a better representation of Columbia's gas utility operations.

With respect to the Combination Utility Group referenced by Mr. Rea, which is comprised of nine combination gas and electric utility holding companies, it should be noted that, on average, approximately 30 percent of the consolidated revenues of these holding companies are attributable to gas utility operations. For this reason, the Combination Utility Group is a suitable complementary proxy group for purposes of the instant proceeding, since it reflects substantial gas distribution operations.

While Mr. Rea would have also given strong consideration to forming a complementary proxy group of combination gas and water utilities, there are very few publicly-traded holding companies that own both gas and water operating utilities. For example, Value Line provides investment research on a total of seven water utility holding companies, but only one of these holding companies, Essential Utilities (formerly Aqua America, Inc.), also owns and operates a gas utility subsidiary. For this reason, relying upon a proxy group of combination gas and electric utilities (as a complementary proxy group to the Gas LDC Group) provides a better representation of Columbia's utility operations.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

14. Refer to the Rea Testimony, Appendix B, pages 6–8, and to Attachment VVR-9.

a. Explain whether FERC's determination (proxy group companies with DCF estimates in excess of 17.7 percent and/or growth estimates in excess of 13.3 percent should be excluded from DCF analyses) applies to both historical and projected growth rates.

b. Explain to what extent this method was utilized to screen against high-end outlier DCF estimates.

c. Some of the projected and historical growth rates in attachments VVR-9 exceed the 13.3 limit set forth in FERC's previous high-end outlier methodology (ISO New England), but were not removed for the analysis. Explain why the growth rates in excess of 13.3 were not removed.

Response:

a. Considering that the FERC's constant growth DCF model approach only references the consensus EPS growth estimates of "sell-side" equity analysts as reported by the Institutional Brokers' Estimate System (IBES), which are forward-looking EPS growth estimates, it would appear that FERC's previous application of the 17.7 percent and 13.3 percent threshold tests was intended to apply to projected growth rates and projected cost of equity estimates only. However, the FERC's previous high-end outlier threshold tests as outlined above have now been superseded by the FERC's new high-end outlier methodology, as prescribed in FERC *Opinion No. 569-A* and *Opinion No. 569-B*. These FERC decisions are discussed at length in Appendix B to Mr. Rea's direct testimony.

b. For purposes of identifying high-end outlier estimates under the DCF method, Mr. Rea relied primarily upon the FERC's newer high-end outlier test, as prescribed in FERC *Opinion No. 569-A* and *Opinion No. 569-B*. Again, these decisions are further discussed in Appendix B to Mr. Rea's direct testimony. This approach essentially involves eliminating DCF estimates that are in excess of 200 percent of the median value for the initial proxy group results. However, as an additional reasonableness test, Mr. Rea also considered the FERC's previous 17.7 percent high-end outlier threshold for the cost of equity estimates yielded under the DCF method.

c. As noted in (b) above, Mr. Rea has relied primary on the FERC's newer high-end outlier test as prescribed in FERC *Opinion No. 569-A* and *Opinion No. 569-B*. This newer methodology supersedes the FERC's previous methodology prescribed in *ISO New England* (please see Appendix B to Mr. Rea's direct testimony for a further discussion of the *ISO New England* proceeding). Therefore, in applying a *secondary* reasonableness test to the DCF results yielded by Mr. Rea's cost of capital evaluation, he strictly referenced only the 17.7 percent high-end outlier threshold established in *ISO New England,* as this allowed him to further evaluate the reasonableness of the *overall* cost of equity estimates yielded by his DCF analyses.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

15. Refer to Columbia Kentucky's response to Staff's Second Request for Information, Item 50.a.

a. Provide a detailed breakdown of the amount listed as overheads and vehicle charges.

b. Confirm that when including labor, the total cost to disconnect and reconnect one customer is approximately $112.36 and that Columbia Kentucky is only recovering $25 of that amount.

Response:

a. The $10.08 amount listed as overheads and vehicle charges breaks down into vehicle costs of $10.013 and overheads of $0.062. These amounts were determined as an average of actual costs for the calendar years 2018, 2019 and 2020.

b. Yes, the total cost to disconnect and reconnect one customer is more than four (4) times the amount that is recovered directly from that one customer via the reconnect charge. The opportunity for Columbia to recover the remainder of the cost is embedded in the overall revenue requirement and base rate charges to all customers.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

16. Refer to Columbia Kentucky's response to Staff's Second Request, Item 50b. Confirm that, should the Commission approve a change to the minimum bill amounts, the seasonal reconnect fee will need to be updated to reflect that revision.

Response: Yes, as stated on Sheet No. 70 of Columbia's tariff. If service is discontinued at the request of customer, the Company may refuse service to such Customer, at the same premise within eight (8) months unless a reconnect fee is paid. The reconnect fee for residential and commercial customers is determined as the current applicable minimum charge times eight months.

**COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021**

17. Refer to Columbia Kentucky's response to Staff's Second Request, Item 51. The response provided does not answer the request for information. Provide a full response to the previous request of Staff's Second Request, Item 51.

Response:

Columbia has identified the following costs associated with late payments from customers.

Printing and mailing cost of reminder notice = $0.454
Printing and mailing cost of termination notice= $0.454
Third party outbound call to customer= $0.24
Columbia Customer Representative cost per inbound call = $6.73
Operational cost for collection premise visit = $13.75* (contractor) and $47 (company)
*Contract collectors are not available in some locations.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

18. Refer to Columbia Kentucky's response to Staff's Second Request, Item 52. The response provided does not answer the request for information. Provide a full response to the previous request of Staff's Second Request, Item 52.

Response: Columbia's cost for returned payments per item is as follows:

Bank Charge	$13.08
Company cost to generate and mail notice to customer	$ 0. 45
Company processing/handling labor cost	$ 4.20
Total	$17.73

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

19. Refer to Columbia Kentucky's current tariff on file with the Commission, P.S.C. Ky. No. 5, Original Sheet No. 60, Application for Service.

a. Provide the personal information requested of each new potential customer, explain why each item is needed, and for each one, indicate whether the information is required in order for the customer to receive service or if it is optional for the customer to provide.

b. If Columbia Kentucky has a standard Application for Service that a potential customer must fill out, provide a copy.

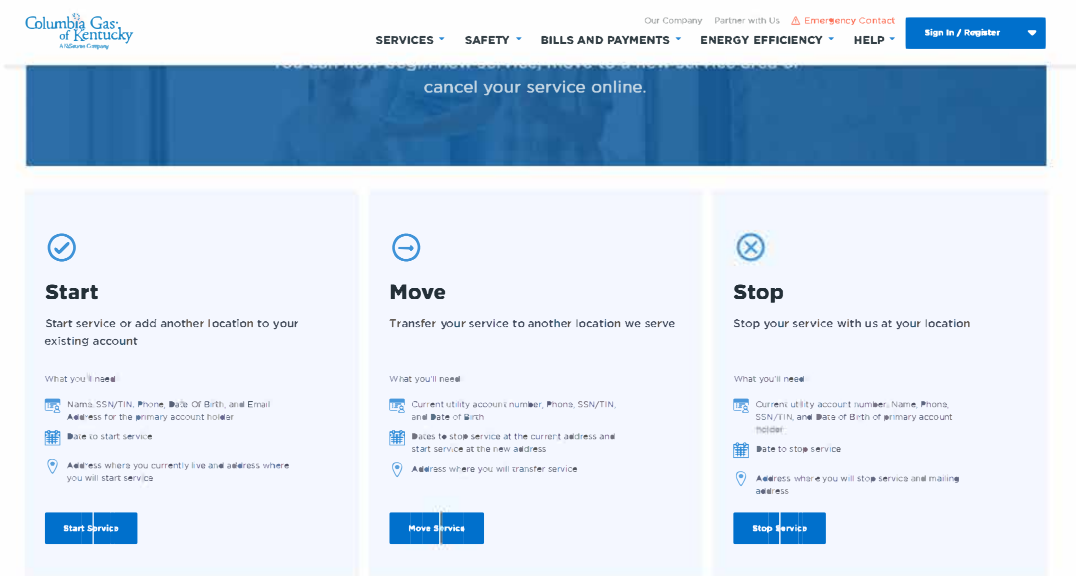
Response:

a. and b. Please see KY PSC Case No. 2021-00183, PSC Staff 3-19, Attachment A which contains screenshots of Columbia's standard Application for Service. The application notes whether the information is required in order for the customer to receive service or if it is optional for the customer to provide.

Columbia gathers the personal information that is required of a new residential customer to verify identity and to process a credit check via Equifax. The returned credit score reflects the applicant's credit worthiness and determines if a security deposit should be requested.

Information related to a new commercial connect is requested in order to verify the business entity. All new commercial customers are required to submit a security deposit. Columbia offers applicants the option of either an online application or the ability to speak with a customer representative. The same information is requested for either option.

Residential Start Service



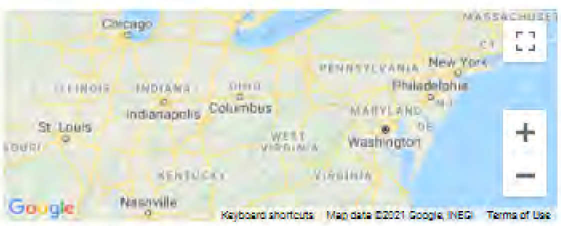
Columbia Gas of Kentucky

Start Service

Step 1 of 5: Find your property

Where do you want to start service?

Enter street address



What is your mailing address?

☐ Is your mailing address the same as your service address?

New Mailing Address

Address

Address Line 1

Address Line 2

City

State/Province

Zip Code/Postal Code

Country

What service do you need?

☐ Gas

CANCEL

NEXT

We're here for you.

Use this self-service process to start your service. Based on the information provided, your payment history or status of the service address, you may need to reach out to our Customer Service Representatives for help. If you can't proceed with your service order, we will be happy to assist in any way we can.

Moving From Address and all optional information is not required but helpful to validate your identity and determine credit eligibility.

If you're unable to complete your transaction online, please call us at **1-800-432-9345** Monday - Friday from 7 a.m. to 7 p.m.

Columbia Gas of Kentucky

Start Service

Step 2 of 5: Account Information

Enter your information

Residential | Business

Name (as it should appear on bill)

First Name

Last Name

SSN

Although providing your SSN is optional, it is helpful in verifying your identity and determining credit eligibility.

Date of Birth

Month | Day | Year

Phone Number

(E.G. 555-555-5555)

Email Address

Emergency Contact Full Name (Optional)

Emergency Contact Phone Number (Optional)

(E.G. 555-555-5555)

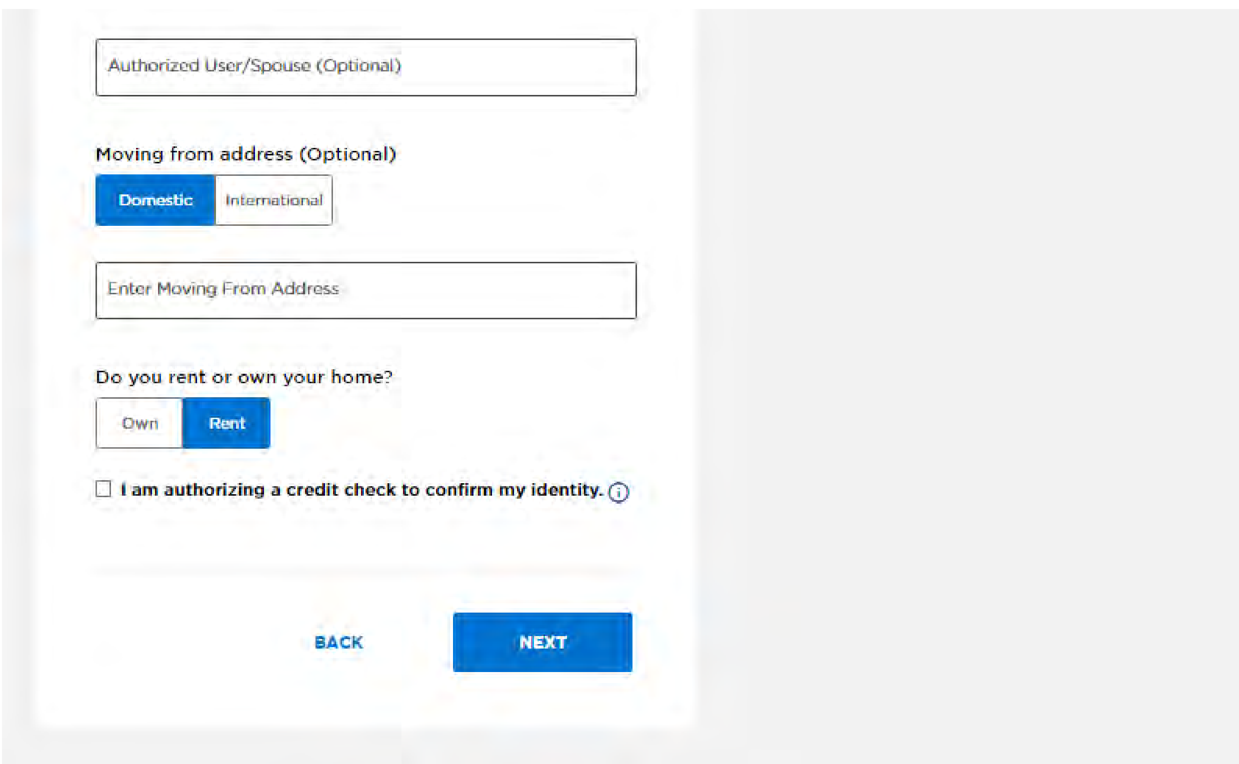
We're here for you.

Use this self-service process to start your service. Based on the information provided, your payment history or status of the service address, you may need to reach out to our Customer Service Representatives for help. If you can't proceed with your service order, we will be happy to assist in any way we can.

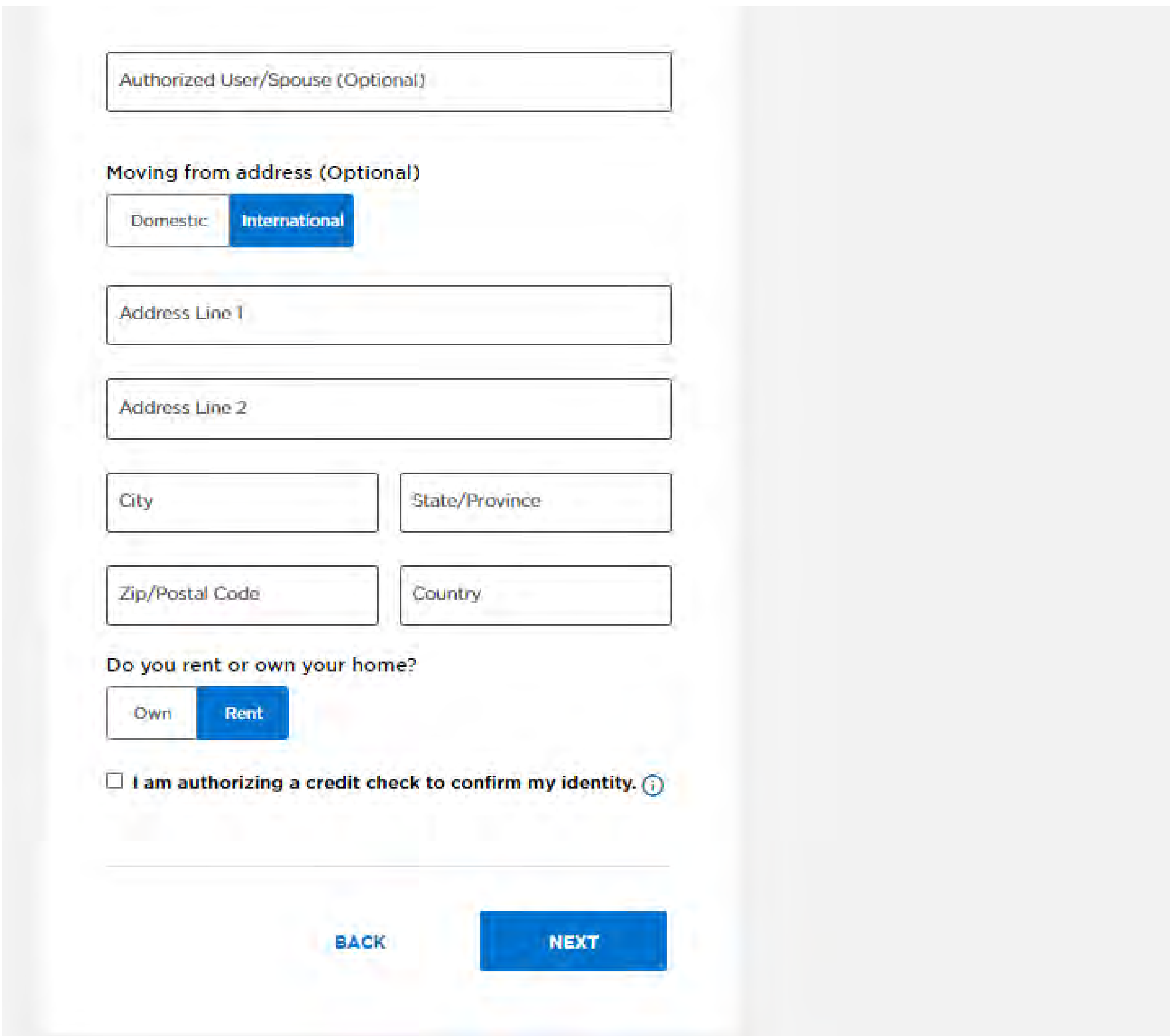
Moving From Address and all optional information is not required but helpful to validate your identity and determine credit eligibility.

If you're unable to complete your transaction online, please call us at **1-800-432-9345** Monday - Friday from 7 a.m. to 7 p.m.

- **Continuation of step 2 screenshot below.**



- **Switching from Domestic to International will prompt customer for more information. See next screenshot.**



Authorized User/Spouse (Optional)

Moving from address (Optional)

Domestic | International

Address Line 1

Address Line 2

City

State/Province

Zip/Postal Code

Country

Do you rent or own your home?

Own | Rent

☐ **I am authorizing a credit check to confirm my identity.** ⓘ

BACK

NEXT

Columbia Gas of Kentucky

Start Service

Step 3 of 5: Deposit Information

A security deposit is required.

A security deposit in the amount of 265.00 will be billed to you in 4 installment payments over the next months.

First Month Bill Overview

Deposit Dollar Amount:	$265.00
Number of Installments:	4 Installments
Total due today:	$0.00

If no amount is due today, the deposit installment will be added to your monthly bill

☐ Agree to Deposit

BACK NEXT

- **Sample deposit quote above**
- **Step 3 of the Residential application is automated. For new Residential applicants Columbia performs a credit check via Equifax utilizing the applicants personal information provided in step 2. The returned credit score reflects the applicants credit worthiness based on their established payment history. This step determines whether Columbia will request a security deposit. If one is required it is reflected on the customer's initial bill.**
- **For existing customers starting service at a new location, a deposit is based on an internal NiSource payment review.**
- **Applicants who choose not to provide their social security number in step 2 are by default requested to pay a security deposit.**

Columbia Gas of Kentucky

Start Service

Step 4 of 5: Start Service Date

When do you want to start service?

The first available start service date is **Aug 19, 2021**.

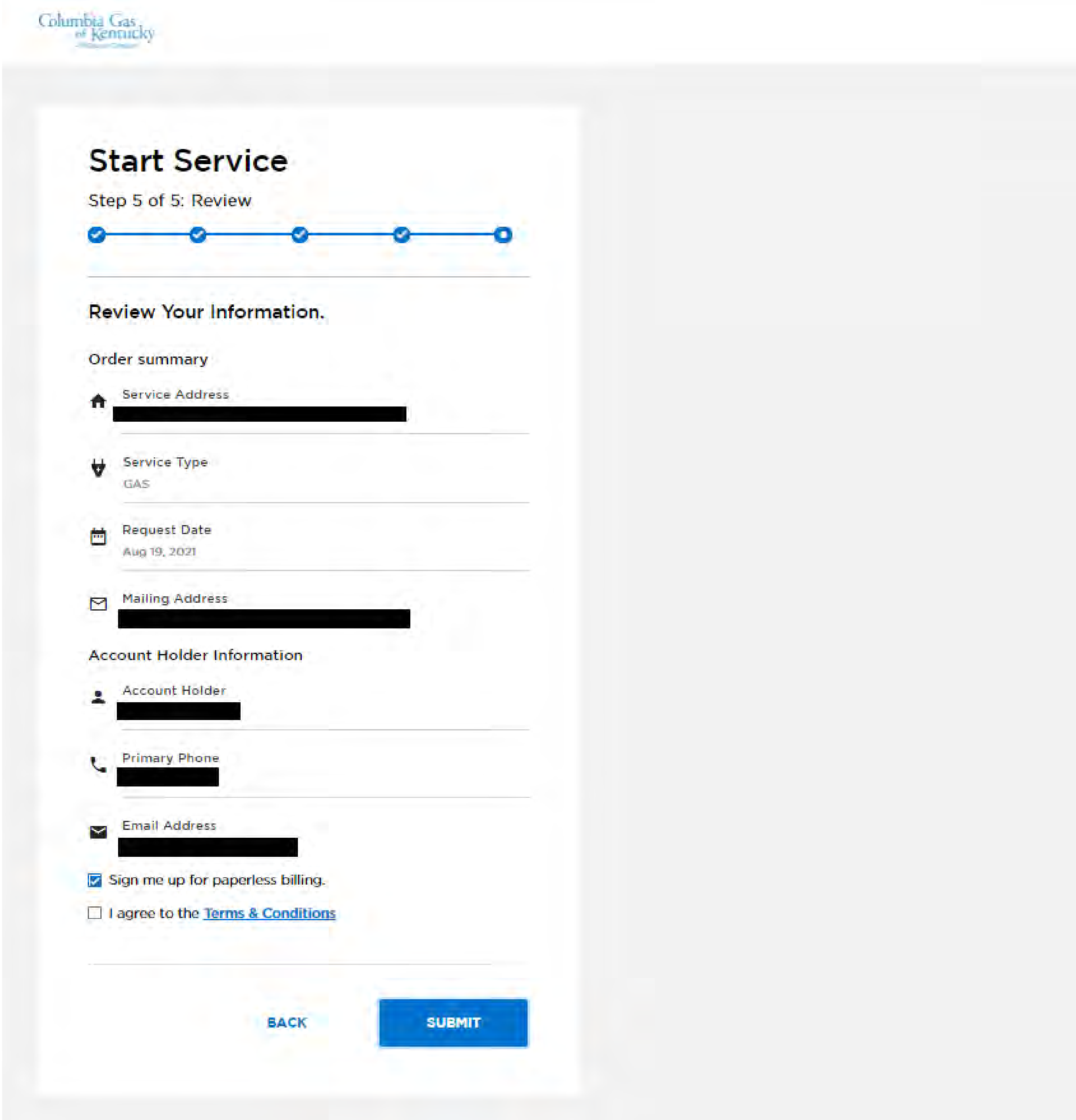
August 2021 »

Su	Mo	Tu	We	Th	Fr	Sa
25	26	27	28	29	30	31
1	2	3	4	5	6	7
8	9	10	11	12	13	14
15	16	17	18	19	20	21
22	23	24	25	26	27	28
29	30	31	1	2	3	4

Key: # - Available Dates
- Currently Selected Date
- Unavailable Dates

BACK NEXT

Your available date options may be limited due to the presence of a pending order at the service address selected. If the recommended dates do not meet your needs, and you need to discuss additional scheduling opportunities please call us at **1-800-432-9345**



Columbia Gas of Kentucky

Start Service

Step 5 of 5: Review

Review Your Information.

Order summary

Service Address
[redacted]

Service Type
GAS

Request Date
Aug 19, 2021

Mailing Address
[redacted]

Account Holder Information

Account Holder
[redacted]

Primary Phone
[redacted]

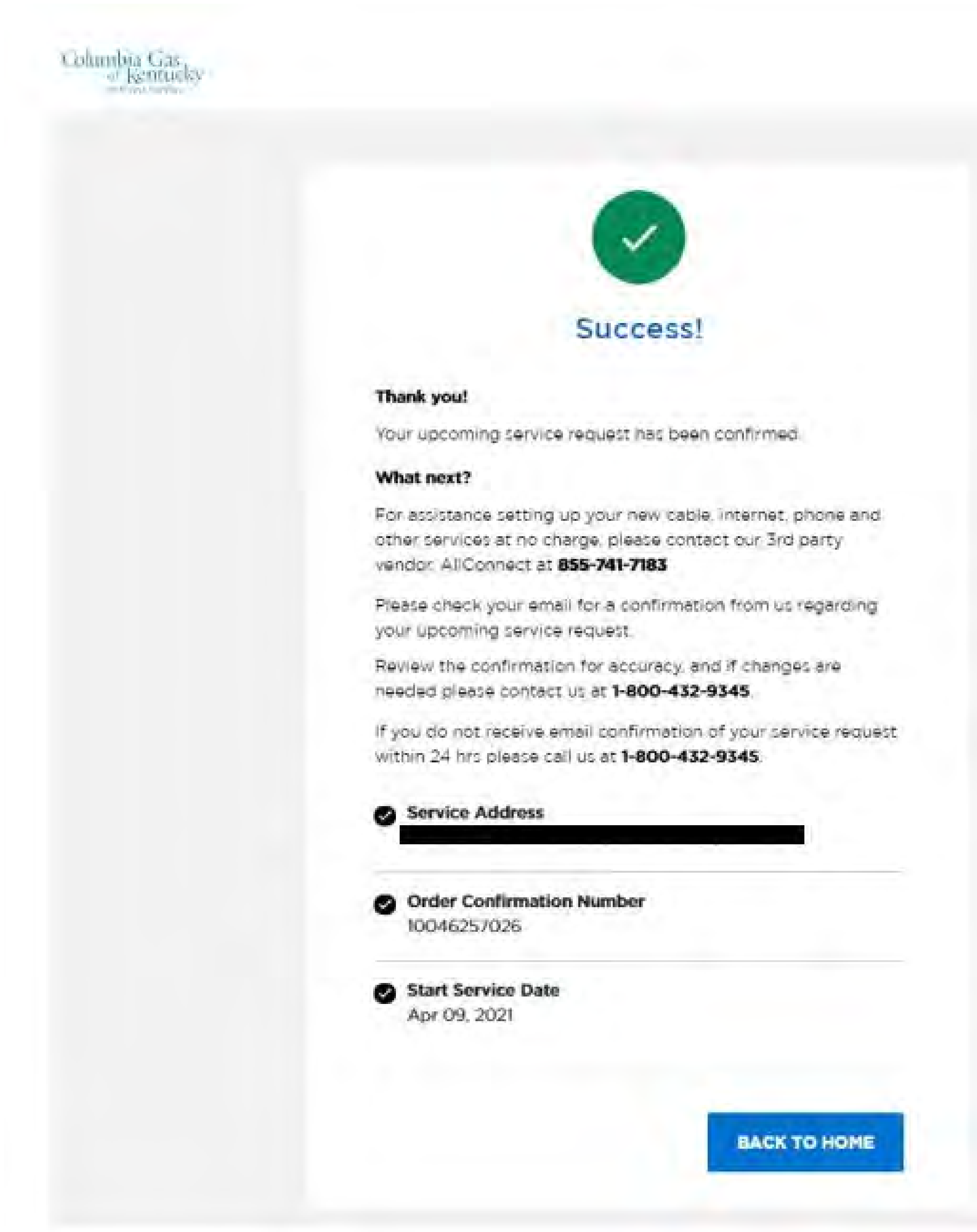
Email Address
[redacted]

☑ Sign me up for paperless billing.

☐ I agree to the Terms & Conditions

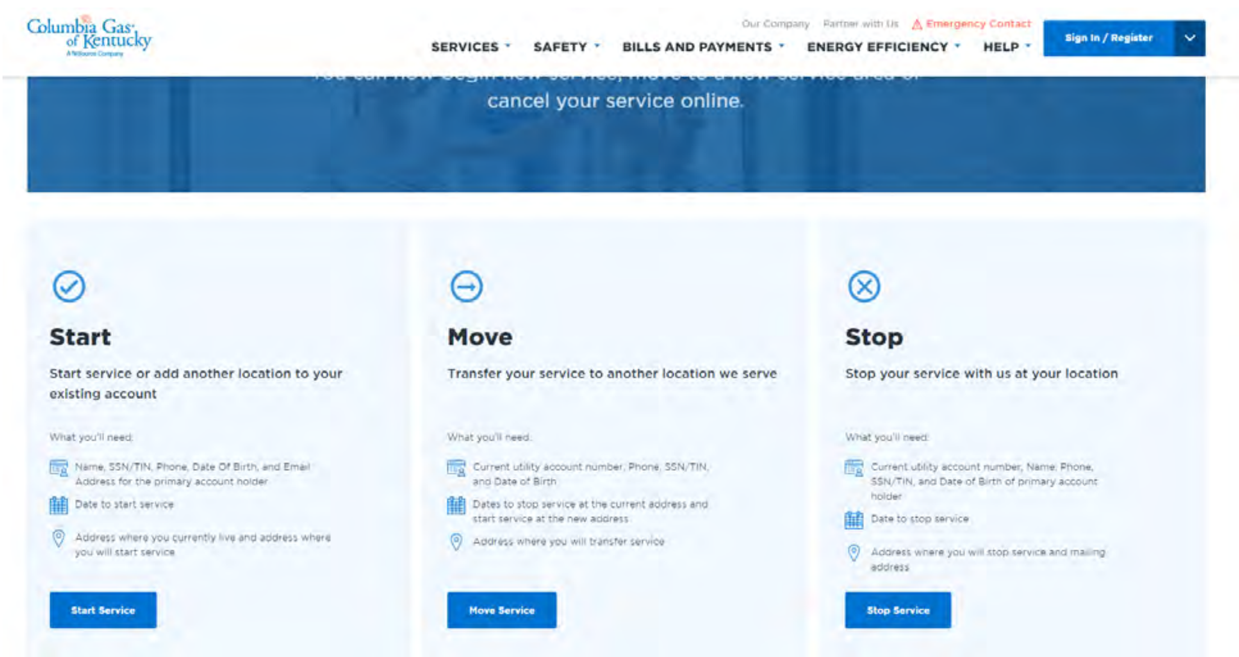
BACK SUBMIT

- **Link to Terms & Conditions:** https://www.columbiagasky.com/our-site/terms-of-use



- **Sample confirmation screen.**

Commercial Start Service



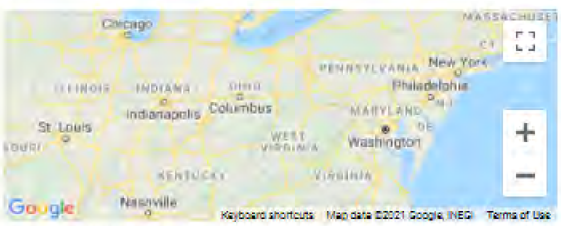
Columbia Gas of Kentucky

Start Service

Step 1 of 5: Find your property

Where do you want to start service?

Enter street address



What is your mailing address?

☐ Is your mailing address the same as your service address?

New Mailing Address

Address

Address Line 1

Address Line 2

City | State/Province

Zip Code/Postal Code | Country

What service do you need?

☐ Gas

CANCEL | NEXT

We're here for you.

Use this self-service process to start your service. Based on the information provided, your payment history or status of the service address, you may need to reach out to our Customer Service Representatives for help. If you can't proceed with your service order, we will be happy to assist in any way we can.

Moving From Address and all optional information is not required but helpful to validate your identity and determine credit eligibility.

If you're unable to complete your transaction online, please call us at **1-800-432-9345** Monday - Friday from 7 a.m. to 7 p.m.

Columbia Gas of Kentucky

Start Service

Step 2 of 5: Account Information

Enter your information

Residential | **Business**

Business Name

TIN

(E.G. 000-00-0000)

Primary Email Address

Primary Phone Number

(E.G. 555-555-5555)

Authorized User/Spouse (Optional)

BACK NEXT

We're here for you.

Use this self-service process to start your service. Based on the information provided, your payment history or status of the service address, you may need to reach out to our Customer Service Representatives for help. If you can't proceed with your service order, we will be happy to assist in any way we can.

Moving From Address and all optional information is not required but helpful to validate your identity and determine credit eligibility.

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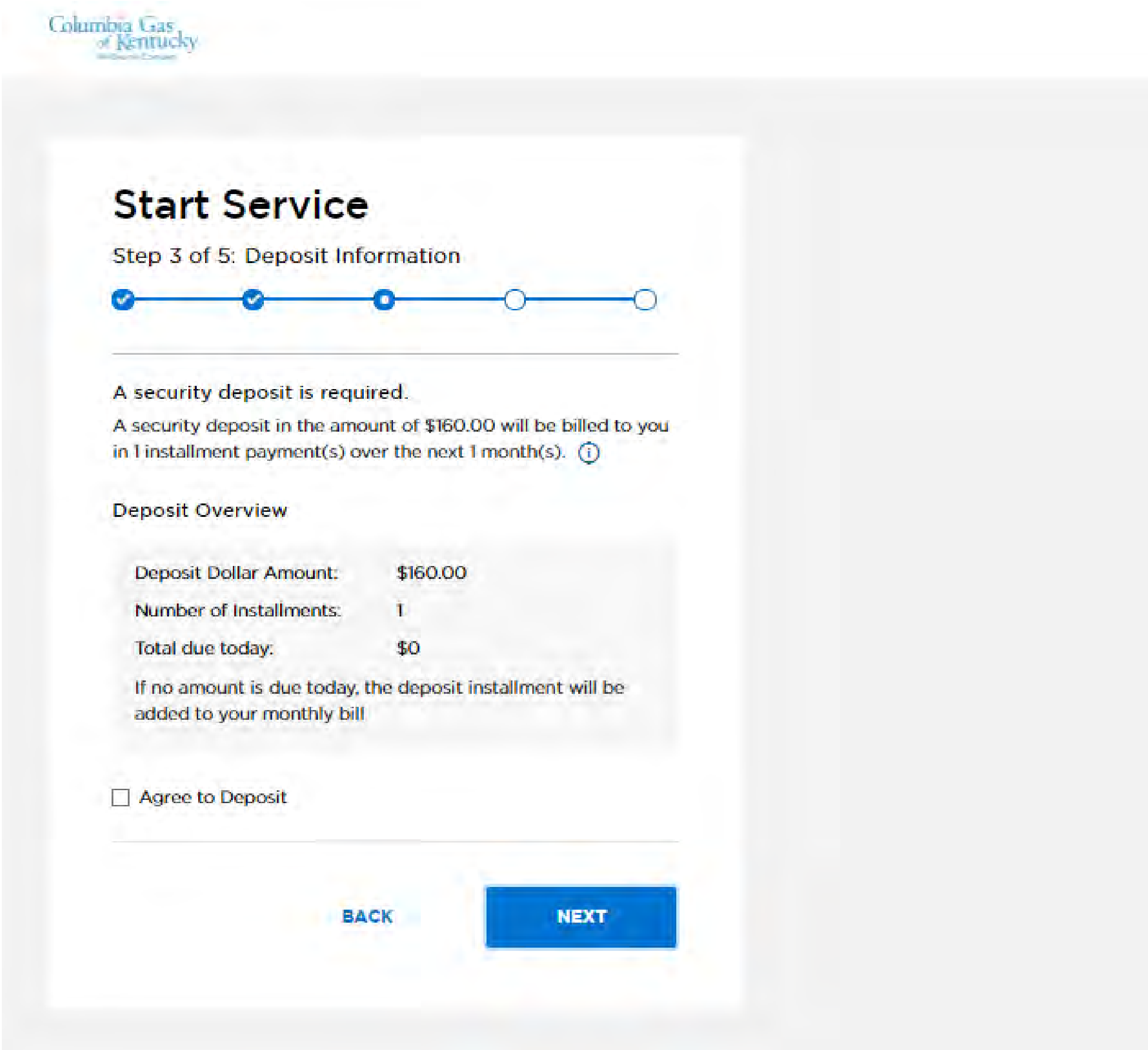


Columbia Gas of Kentucky

Start Service

Step 3 of 5: Deposit Information

A security deposit is required.

A security deposit in the amount of $160.00 will be billed to you in 1 installment payment(s) over the next 1 month(s).

Deposit Overview

Deposit Dollar Amount:	$160.00
Number of Installments:	1
Total due today:	$0

If no amount is due today, the deposit installment will be added to your monthly bill

☐ Agree to Deposit

BACK NEXT

- **Sample deposit quote above**
- **All new business accounts require a deposit.**
- **Deposit is calculated based on historical usage at the premise. The deposit quote will be the same regardless of the applicants method of application, online or by phone.**

Columbia Gas of Kentucky

Start Service

Step 4 of 5: Start Service Date

When do you want to start service?

The first available start service date is **Aug 19, 2021**.

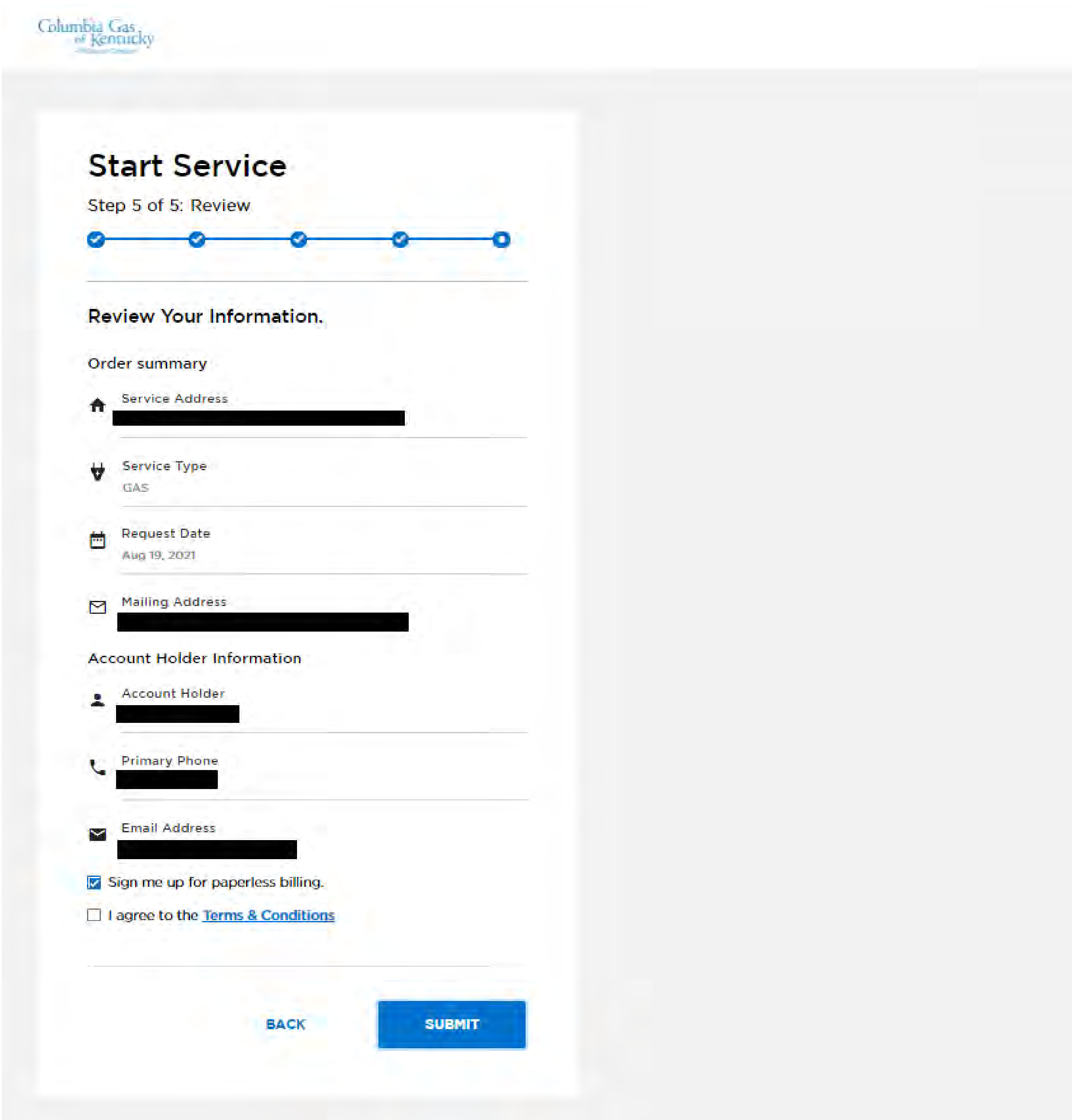
August 2021 »

Su	Mo	Tu	We	Th	Fr	Sa
25	26	27	28	29	30	31
1	2	3	4	5	6	7
8	9	10	11	12	13	14
15	16	17	18	19	20	21
22	23	24	25	26	27	28
29	30	31	1	2	3	4

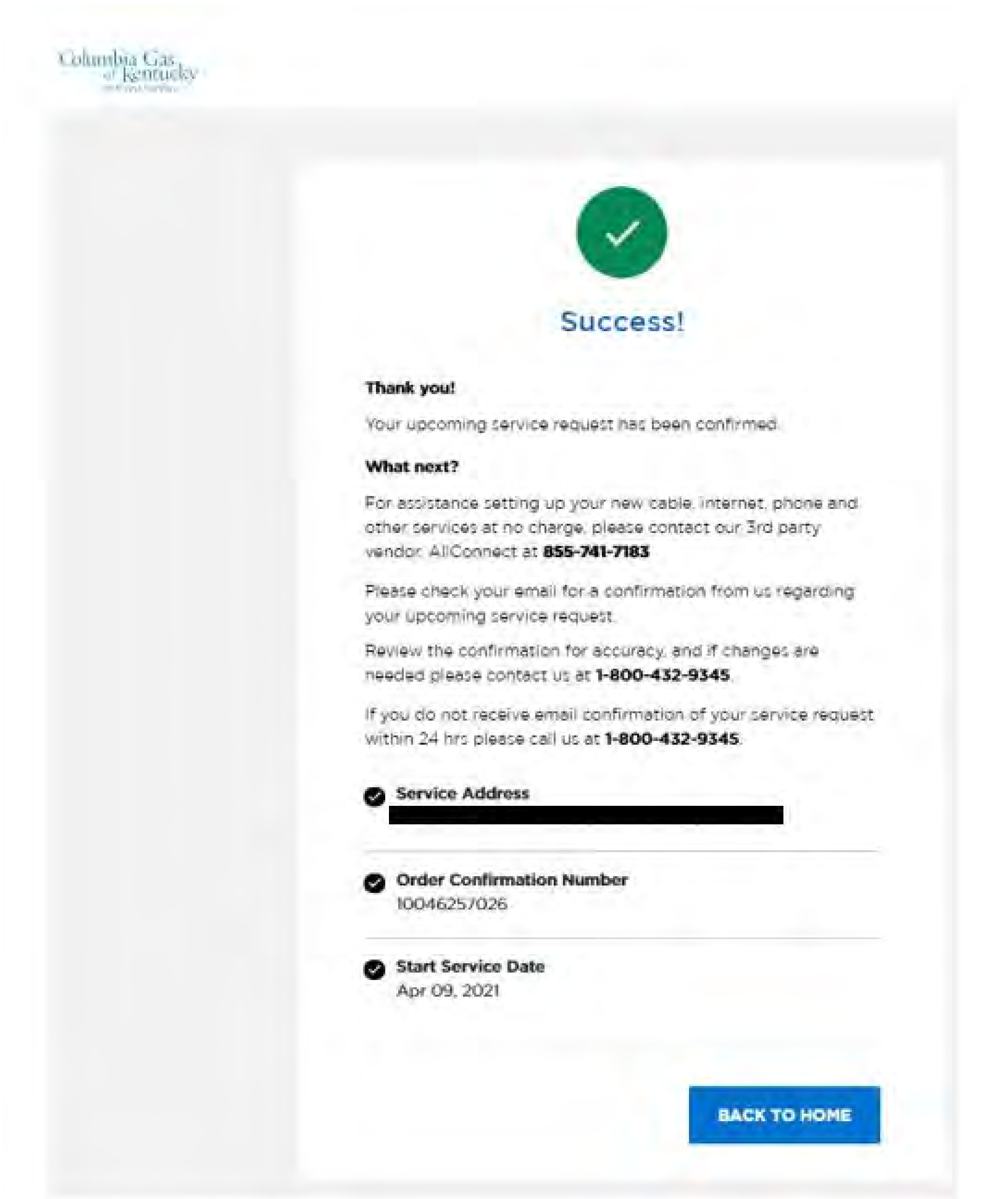
Key: # - Available Dates
- Currently Selected Date
- Unavailable Dates

BACK NEXT

Your available date options may be limited due to the presence of a pending order at the service address selected. If the recommended dates do not meet your needs, and you need to discuss additional scheduling opportunities please call us at **1-800-432-9345**



- **Link to Terms & Conditions: https://www.columbiagasky.com/our-site/terms-of-use**



- **Sample confirmation page.**

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

20. Refer to Columbia Kentucky's response to the Attorney General's First Request for Information, Item 110.

a. Explain generally how Columbia Kentucky contends that the group company tax sharing agreement requires net operating loss carryforwards to be assigned to members of the Consolidated Group with reference to the relevant provisions of the agreement.

b. Explain why Columbia Kentucky contends that the treatment of net operating loss carryforwards in the group company tax sharing agreement is reasonable.

c. State whether Columbia Kentucky contends that it is in a net operating loss position for federal tax purposes in the forecasted test period, and explain each basis for Columbia Kentucky's position.

Response:

a. The tax sharing agreement does not assign net operating loss (NOL) carryforwards (NOLC) to members of the consolidated group. It is based on each member's standalone income tax liability. For group members that have standalone taxable income, utilization of the NOL is based on the percentage of the standalone group member NOLC beginning balance divided by the consolidated group NOLC beginning balance.[1] For group members that have standalone taxable loss, the liability is recognized as zero generating a NOLC for the entire amount of the standalone member taxable loss.[2]

b. The treatment of net operating loss carryforwards in the group company tax sharing agreement is reasonable due to the fact that is based on the group members standalone income tax liability position.

c. Columbia Kentucky does not generate a net operating loss for the future text period ending December 31, 2022 AFTER adjustments at proposed rates. The Federal taxable income of $14,717,901 is depicted on Schedule E-1.1, Column 10, Line 17.

[1] Section 2.1(f)
[2] Section 2.1(b)

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

21. Refer to Columbia Kentucky's response to Staff's Second Request, Item 48 in which it indicated that the ADIT balance in Account 190 did not change because it does not forecast the change in the balance for capitalized inventory or customer advances captured in Account 190. Explain whether Columbia Kentucky forecasted any change in its net operating loss position during the forecasted period, and if so, explain where that change is reflected in the revenue model and why it is reflected in that manner.

Response:

The Company did forecast a change in the net operating loss carryforward during the forecasted period that represents utilization of the NOL based on the Federal taxable income multiplied by the Company's beginning balance NOL divided by the consolidated group beginning balance NOL in accordance with the tax sharing agreement.

Federal Taxable Income at Proposed Rates $14,717,901[1]

[1] KY PSC Case No. 2021-00183, Staff 1-54, Attachment A, Schedule E-1.1, Column 10,Line 17

2021 Columbia Kentucky NOLC/Group NOLC	.5961%
2022 NOL Utilized	87,736[2]
Tax Effected at 21%	18,425

[2] KY PSC Case No. 2021-00183, AG 1-110, Attachment A, Page 1, Column 11, Line 1

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

22. Provide an itemized explanation of the total expected capital cost of the large in-line inspection project for Line DE, including any engineering costs and any costs to obtain necessary rights in real property.

Response:

Please see KY PSC Case No. 2021-00183, Staff 3-22, Attachment A depicting a cost breakdown of the Line DE project for 2021 and 2022. An additional tab has been added to provide explanations for what each line item covers the cost of.

ATTACHMENTS
ARE EXCEL
SPREADSHEETS
AND UPLOADED
SEPARATELY

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

23. Identify each alternative to the large in-line inspection project for Line DE that was explored to address the needs for which Columbia Kentucky is proposing the project. Explain why Columbia Kentucky chose its current proposal over those alternatives, and if no alternatives were explored, explain why they were not.

Response:

There are only two methods to assess pipelines that fully comply with the new DOT §192.917 requirements. An operator can either use in-line inspection ("ILI") to assess the entire pipeline system or a combination of pressure testing ("PT") and direct assessment ("DA") typically assessing the High Consequence Area (HCA) only. Columbia chose ILI for several reasons. First, Line DE is one of the most important lines in Columbia's system. It supports Frankfort, Georgetown, Toyota Manufacturing, Jim Beam and Buffalo Trace, amongst many other entities. Due to Line DE's diverse customer base, reliability of service for this line is paramount. Any sustained interruption to Line DE at virtually any point on the line would create material customer interruptions, especially in the heating season.

Second, Columbia believes that it is important to assess the whole line and not just the required HCA's. The combination of PT and DA could help determine whether there are any current fatal flaws in the pipelines' ability to transport gas by code, but PT only gives you fatal moment in time information; whereas, ILI provides data that helps operators assess threats that have not yet developed into fatal flaws, but could well do so over time. Beyond these primary considerations, once Line DE is made piggable, it is very inexpensive, relatively speaking, to reassess the line on future inspection cycles. Pressure testing is very expensive on a cost per mile basis and requires customer outages for up a week for each segment being tested. In order to maintain service to some of these customers during pressure testing, Columbia would need to build bypass pipelines in parallel to the existing one.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

24. Provide all cost-benefit analyses, if any, performed by or on behalf of Columbia Kentucky to assess the proposed large in-line inspection project for Line DE and potential alternatives.

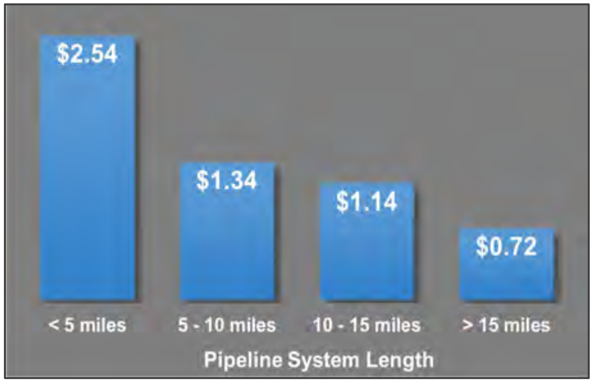
Response:

Please see KY PSC Case No. 2021-00183, Staff 3-24, Attachment A for some high level cost comparisons for pipeline assessment methods.

Prioritization Considerations

Assessment Method Comparison

Pipeline Retrofit Cost ($MM/mile)



Assessment Methods


Direct Assessment (DA)


Pressure Test (PT)


Inline Inspection (ILI)

Benefits

Criteria	DA	PT	ILI
Capable of detecting sub-critical flaws	O	X	O
Allows for a comprehensive assessment of the entire pipeline	X	O	O
Valid assessment method for corrosion	O	Δ	O
Valid assessment method for mechanical damage	Δ	O	O
Valid assessment method for material flaws	X	O	O

Costs

NiSource Integrity Assessment Average Cost per Mile ($K/mile)			
< 5 miles long	**$56.5**	**$241.3**	**$89.6**
5 to < 10 miles long	**$20.8**	**$69.8**	**$35.2**
10 to < 15 miles long	**$14.8**	**$41.3**	**$30.4**
≥ 15 miles long	**$12.4**	**$29.5**	**$14.7**

Key: O: Good; Δ: Marginal, X: Poor or NA

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

25. Identify all parties to which Columbia Kentucky sent a request for a bid or a request for proposal to complete the proposed large in-line inspection project for Line DE; provide a copy of any such request for a bid or request for proposal; and provide any responses to such a request for a bid or proposal.

Response:

CONFIDENTIAL KY PSC Case No. 2021-00183, Staff 3-25, Attachment A indicates the contractors bidding on the project. The request for bid and the responses can be found in CONFIDENTIAL KY PSC Case No. 2021-00183, Staff 3-25, Attachment B, Sets 1 and 2.

ATTACHMENT FILED UNDER SEAL PURSUANT TO A MOTION FOR CONFIDENTIAL TREATMENT

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

26. Provide, in Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible, the average monthly bill impact for each customer class based on current and proposed base rates and not including any riders, roll-in of the SMRP Rider, TAAF, and the gas cost adjustment.

Response:

The revenue requirement increase in this case is made up of five components as shown below:

Base Rate Revenue Increase	$38,217,184
Elimination of Tax Adjustment Credit	$3,572,349
Net Base Rate Revenue Increase	$41,789,533
Elimination of SMRP Charge	($15,165,106)
Net Gas Service Revenue Increase	$26,624,427
Late Payment Charge Increase	$70,560
Total Revenue Requirement Increase	$26,694,987

a. Please see KY PSC Case No. 2021-00183, Staff 3-26, Attachments A and B for the average monthly bill impact for each customer class based on current and proposed base rates and not including any riders, roll-in of the SMRP Rider, TAAF, and the gas cost adjustment. Attachments A and B are the average bill impact for the change in base rates only and matches the base rates that produce the base rate revenue increase of $38,217,184 shown above.

b. Please see KY Case No. 2021-00183, Staff 3-26, Attachments C and D for the average monthly bill impact for each customer class based on current and proposed base rates and not including any riders, roll-in of the SMRP Rider, and the gas cost adjustment. Attachments C and D are the average bill impact for the change in base rates plus the impact of eliminating the Tax Adjustment Credit and matches the rates that produce the Net Base Rate Revenue Increase of $41,789,533 shown above.

ATTACHMENTS ARE EXCEL SPREADSHEETS AND UPLOADED SEPARATELY

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

27. Refer to the Application, paragraph 23. Provide a breakdown of the SMRP revenue requirement that is included in the Columbia Kentucky's revenue requirement for the base and forecast period by the type of pipe and any associated costs with each type.

Response:

Forecasted Test Period

Refer to 2021-00183 Staff Set 3 No 27 Attachment A for the SMRP revenue requirement included in the forecasted test year revenue requirement. The Gas Plant Account detail is summarized on Page 5 of 21.

As the methodology of calculating SMRP was recently changed to a 13 month average balance, the various schedules included in Attachment A are still in development stage and the naming conventions are not fully vetted.

The revenue requirement calculation includes several assumptions that are provided below to ensure clarity:

- The December 31, 2020 rate base related balances (plant, accumulated depreciation, ADIT) were inserted based on the analysis included in 2021-00183 DR AG Set 2 No 84 Attachment D which reflect the restated 2021 SMRP revenue requirement with updated information that matches the rate case data.
- The 2022 SMRP investment levels were adjusted to remove the Line DE In-Line Inspection project. Additionally, the investments were placed in service based on the in-service curve as described in 2021-00183 Staff Set 3 No 7.
- The 2022 depreciation rates match the updated depreciation rates per the new deprecation study and as used to develop the forecasted test year depreciation expense.
- The rate of return was updated to match the filed for return from the rate case.
- The O&M savings were assumed to be the same as used in 2021-00183 DR AG Set 2 No 84 Attachment D.

<u>Base Period</u>

Refer to 2021-00183 Staff Set 3 No 27 Attachment B for the SMRP revenue requirement included in the base period revenue requirement. The by month detail was not maintained in a manner to create this analysis in a manner similar to the forecasted test year. Additionally, with the 12 month period crossing calendar years, the tax calculations are not set up to handle this period. The revenue requirement was developed using some trending techniques for some items as noted in Footnote B. Refer to 2021-00183 Staff Set 3 No 27 Attachment C for August plant detail by Gas Plant Account.

ATTACHMENTS
ARE EXCEL
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COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

28. Refer to the Application, Tab 36. Provide explanation for how Columbia Kentucky projects its capital expenditure and include any supporting workpapers.

Response:

With reference to Tab 36 of the Application, Columbia used the capital budget numbers from its multi-year budget as the basis for the response and deducted out any projects with an expected capital cost greater than 5% of the proposed annual capital budget. For outer year capital projections, Columbia uses a combination of risk assessment data, customer addition projections, known public improvement projects and historical averages. Beyond the next calendar year, most of the projections are generally historically based and get trued up as additional information becomes known. Please see CONFIDENTIAL KY PSC Case No. 2021-00183, Staff 3-28, Attachment A for spreadsheets delineating Columbia's process to project capital spend. Please note that the Attachment includes estimated budget amounts for years outside the forecasted test year of this case, which represent rough forecasts that are subject to and will change.

ATTACHMENT
FILED UNDER SEAL
PURSUANT TO A
MOTION FOR
CONFIDENTIAL
TREATMENT

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

29. Refer to Columbia Kentucky's Response to Staff's First Request for Information, Item 25.

a. Using the data provided in Schedule I1, calculate the annual "Slippage Factor" associated with any construction projects associated with Columbia Kentucky's SMRP.

b. Using the data provided in Schedule I1, calculate the annual "Slippage Factor" associated with any construction projects not associated with Columbia Kentucky's SMRP.

Response:

Please see Kentucky PSC 2021-00183, Staff 3-29, Attachment A. Please note that in Columbia's response to Set One No 25, Columbia discusses the installation of non-design facilities that represent a considerable portion of Columbia's overall budget. While it is possible to aggregate these dollars with the cumulative SMRP and non-SMRP spend, the data is not readily available to separate those two items. As a result, Columbia presents the slippage factor calculations based on SMRP design capital projects and non-SMRP design capital projects that are shown in the attachment identified above.

Slippage by Year (Data adapted from Schedule I1)

Installation Year	SMRP Design Capital Construction Project Budget	SMRP Variance	Non-SMRP Design Capital Construction Project Budget	Non-SMRP Variance	SMRP	Non-SMRP
2016	$13,068,470	-$917,629	$8,337,627	$1,028,399	-7.02%	12.33%
2017	$13,916,310	-$11,677	$14,681,133	-$5,360,693	-0.08%	-36.51%
2018	$17,306,832	$229,310	$6,547,888	$631,308	1.32%	9.64%
2019	$26,385,233	$3,604,711	$11,365,325	$665,070	13.66%	5.85%
2020	$25,102,716	$1,131,767	$13,340,541	$141,225	4.51%	1.06%

Note: As discussed in the response to Staff Set 1 No. 25, blanket budgets do not have and estimate and are not included in this analysis.

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2016 Non SMRP Construction Projects

Project No.	Project Title/Description	Total Budget Project Cost	Variance in Dollars
13026478400	INSTALL 2 NEW FISHER 627 REGS	$13,101.93	($7,017.73)
14026521900	INSTALL 230'-6" WTHP & 10'-12"	$162,626.42	$9,451.56
14026548701	INSTALL 11500' OF 4"/6" PMMP	$987,245.95	$740,429.02
14026558201	REPLACE GMB SETTING	$28,475.39	$13,118.32
15026560901	INSTALL 200' OF 2" PMIP	$60,650.62	($8,647.25)
15026569300	INSTALL WIRELESS EFC	$10,858.09	($3,460.47)
15026570100	INSTALL 1600' OF 2"PMMP MAIN	$41,816.93	$22,767.03
15026571400	INSTALL NEW REG STRUCTURE	$64,363.13	($10,089.41)
15026574300	INSTALL 1633' OF 2" PMMP	$41,595.16	($6,362.64)
15026578400	INSTALL 100' OF 12" CSHP	$135,287.49	$42,917.70
15026578600	INSTALL 1500' OF 2" PMMP	$61,244.23	($8,890.64)
15026582700	INSTALL 2795' - 4" & 2" PMMP	$233,068.41	($55,764.23)
15026584401	INSTALL 2050'-4" PMMP	$62,170.24	($13,200.97)
15026587801	INSTALL 2600' OF 2"/4"PMMP	$149,112.25	$73,486.34
15026588901	INSTALL 1150' OF 4" PMMP	$187,499.39	$6,660.52
15026591100	INSTALL 5025' OF 2"PMMP MAIN	$93,216.79	$6,271.84
15026597600	INSTALL EFC	$3,979.37	$10,766.80
15026598200	INSTALL FENCE FOR R-1217	$4,459.86	$1,416.47
15026599200	INSTALL 400' OF 4"PMMP	$48,946.01	($10,128.63)
15026599800	INSTALL 1125' OF 2"PMMP MAIN	$21,575.97	($351.72)
15026600301	INSTALL 425' OF 2"PMMP	$41,832.29	($18,385.39)
15026600500	INSTALL 250' OF 2"PMMP	$9,443.13	$3,933.87
15026601700	NSTALL GROUNDBED	$9,757.06	$9,705.73
15026602000	INSTALL NEW FENCE FOR R-1439	$5,664.86	($39.10)
15026604700	INSTALL 182' - 2" PM	$28,604.29	$4,031.08
15026604800	INSTALL 192' - 2" PM	$28,596.29	($519.48)
15026605000	INSTALL NEW GMB SETTING	$56,153.69	$42,989.70
15026606100	INSTALL RECORDING GAUGE	$5,959.40	($3,357.00)
15026607800	INSTALL 250' - 2" PM	$21,457.54	$1,085.58
15026609000	INSTALL 100' OF 2" PMIP	$21,145.05	$22,095.19
15026611400	INSTALL R-1860	$78,119.96	$10,182.10

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2016 Non SMRP Construction Projects

15026613100	INSTALL 30' - 4" PMMP	$15,032.87	($6,024.96)
15026613700	INSTALL 750' OF 2"PMMP	$20,886.67	($3,620.60)
15026614100	INSTALL 60' - 12" CS-HP	$191,112.40	$104,598.14
15026614400	INSTALL 50' OF 6" PMMP BYPASS	$14,830.84	$16,476.97
15026616401	INSTALL MI MINI-AT EFC W/MODEM	$10,774.73	($2,962.00)
15026616700	INSTALL CATALYTIC HEATER	$5,466.45	($1,438.98)
15026616901	INSTALL 292' - 2" PM	$50,631.27	$2,152.81
15026617202	INSTALL 1628'-2"&4" PMMP	$281,307.04	($31,919.91)
15026618800	INSTALL RECTIFIER & DEEP WELL	$67,884.57	$1,793.69
15026619100	INSTALL 125' OF 2" PMMP	$21,872.30	($13,522.51)
15026621300	INSTALL 128' OF 2" PMMP	$10,601.58	($2,430.36)
15026622500	INSTALL CATALYTIC HEATER	$4,604.72	($1,652.35)
15026623201	INSTALL 550'-4" PMMP	$59,234.84	$7,853.65
15026623500	INSTALL 3000' OF 4"PMMP	$115,368.50	$25,902.53
15026624700	INSTALL MI MINI-AT EFC W/MODEM	$3,473.30	$10,664.07
15026624901	INSTALL 225' OF 4"PMLP	$55,397.12	$16,037.09
16026626500	INSTALL 217' OF 2"PMMP	$5,562.76	($1,965.33)
16026626700	INSTALL 92' OF 2"PMIP	$13,243.61	$1,023.50
16026627000	INSTALL 1100'-2" PMMP	$51,250.67	($25,516.47)
16026627100	INSTALL 2"SS FITTING	$3,072.36	($1,473.65)
16026627400	INSTALL 100' OF 2" PMMP	$29,645.33	($23,026.08)
16026628700	INSTALL 24'-4" PM&CS	$61,397.22	$19,503.42
16026629400	INSTALL 900' OF 2" PMMP	$82,776.04	($56,524.95)
16026629501	INSTALL 1850' OF 2"PMMP	$63,641.92	($9,239.13)
16026629900	INSTALL 140'-4"&6" PMMP	$85,795.96	$681.83
16026630301	INSTALL 325' OF 2"PMMP	$52,823.24	($5,001.25)
16026630600	INSTALL 770' OF 2"PMMP	$56,907.18	$45,390.25
16026630800	INSTALL MI-WIRELESS	$21,366.20	($21,247.15)
16026631100	INSTALL 770'-6" CSHP	$603,927.83	($4,746.47)
16026631300	INSTALL 3300'-2",4",6" PMMP	$481,639.36	$86,196.79
16026631500	INSTALL 150'-4"PMMP	$9,921.91	$9,616.04
16026631700	INSTALL MI WIRELESS	$21,366.20	($11,935.66)
16026632100	INSTALL 2" BYPASS VALVE	$2,141.39	$1,975.68
16026632901	INSTALL 425' OF 2" PMMP	$52,546.55	$9,769.54
16026633900	INSTALL SPITFIRE RELITER	$9,543.23	$5,065.41
16026634000	INSTALL SPITFIRE RELITER	$9,578.33	$4,808.69
16026634700	INSTALL 105' OF 2" PMMP	$14,375.82	$22,721.87
16026635400	INSTALL 250' OF 2" PMMP	$21,570.36	$7,122.08
16026635500	INSTALL 160'-4" PMMP	$16,468.03	$4,083.93
16026635700	INSTALL 1275' - 2" PMIP	$57,323.41	$64,751.78

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2016 Non SMRP Construction Projects

16026637001	INSTALL 350' OF 4" PMMP	$64,218.31	$14,917.88
16026637400	INSTALL 300' OF 2"PMMP	$41,438.42	$8,067.02
16026637800	INSTALL ERX FOR R-1274	$24,466.55	($11,371.84)
16026637900	INSTALL 485' OF 2"PMMP	$23,557.33	($9,834.22)
16026638200	INSTALL 75' - 4" PMLP	$36,369.75	($16,167.55)
16026638700	INSTALL MI WIRELESS/EFC	$11,497.17	$5,817.80
16026638900	INSERT 100' OF 2"PMLP	$20,136.33	$2,218.94
16026639100	INSTALL 300' OF 2"PMMP	$19,642.33	$15,077.68
16026639500	INSTAL NEW RECTIFIER & GB	$67,085.49	($7,935.07)
16026639701	INSTALL NEW SKID REG STATION	$119,269.33	$6,997.19
16026639801	INSTALL 5615' OF 6"/4"/2"PMMP	$241,632.23	$37,798.93
16026640600	INSTALL 522 OF 4"PMMP	$44,238.76	$2,484.54
16026641200	INSTALL 40' OF 2" PMMP	$11,363.77	($6,174.12)
16026641400	INSTALL NEW REG SETTING VALVES	$16,686.93	$7,093.05
16026641900	INSTALL 100' - 2" PM	$14,860.51	($1,132.80)
16026642000	INSTALL 200' - 2" PM	$3,525.82	$4,867.14
16026642400	INSTALL MI WIRELESS	$14,387.75	($3,409.13)
16026644600	INSTALL 10' - 3" WTMP & 4" VLV	$46,961.17	($8,646.94)
16026645800	INSTALL 175' OF 4"PMIP	$12,625.83	($1,125.57)
16026646000	INSTAL VALVES & FITTINGS	$3,131.07	($289.75)
16026646101	INSTALL FITTINGS	$44,992.04	($778.44)
16026646200	REPLACE VALVE C-10;INOPERABLE	$27,510.10	$16,322.90
16026647100	INSTALL 285' - 2" PMMP	$23,214.03	($2,073.13)
16026648000	INSTALL 650' OF 2"PMMP	$30,744.71	($15,282.02)
16026648100	INSTALL 500' OF 2"PMMP	$19,210.36	$1,325.74
16026648200	INSTALL 35' OF 4"PMMP	$27,698.27	($5,816.96)
16026648400	INSTALL 700' OF 2"PMMP	$21,811.04	($3,720.04)
16026648501	INSTALL 133'-2" PMMP	$35,305.19	($18,820.12)
16026649101	INSTALL 600' OF 2"PMMP	$24,598.77	($720.92)
16026649400	INSTALL 150' OF 2"PMMP	$13,288.60	$2,081.88
16026649600	INSTALL 501' - 2" PMMP	$42,901.52	($12,927.21)
16026650800	INSTALL 100' OF 2" PMMP	$11,873.54	($5,096.01)
16026651400	INSTALL 460' OF 6"CSHP	$120,193.35	$33,374.32
16026652100	INSTALL 10' - 4" PMMP	$10,199.77	($445.35)
16026653401	INSTALL MI MINI-AT EFC	$10,150.73	($4,618.90)
16026653700	INSTALL 10'-6" PMMP & VALVE	$11,082.05	$899.75
16026655400	INSTALL 4" SST AT R-1403	$4,639.29	($3,266.00)
16026655700	INSTALL NEW EFC'S	$7,767.01	($753.15)
16026657200	INSTALL 500' OF 4" PMMP	$129,286.34	($35,086.49)
16026659500	INSTALL 20'-4"&6" PMMP	$4,701.04	($4,446.36)

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2016 Non SMRP Construction Projects

16026659700	INSTALL EFC	$364.25	($364.25)
16026660100	INSTALL 40' OF 6" PMLP	$47,183.82	($26,195.61)
16026660300	INSTALL 300' OF 2"PMMP	$24,635.91	($5,180.43)
16026661800	INSTALL 800' OF 2"PMMP	$28,272.41	($11,159.75)
16026661900	INSTALL 300' OF 2"PMMP	$15,832.53	($1,067.59)
16026662000	INSTALL REGULATOR	$920.90	($633.41)
16026662800	INSTALL 10' OF 4"PMMP	$2,494.45	($45.93)
16026663000	INSTALL 90'-2" PMMP PVT R/W	$12,853.88	($991.54)
16026664900	INSTALL 350' OF 2"PMMP	$21,842.47	($3,964.42)
16026665200	INSTALL 4" SETTING VALVES	$13,548.90	($3,742.12)
16026665400	MAVITY - INSTALL 8" SS FITTING	$14,539.73	($4,069.02)
16026666600	INSTALL GMB SETTING	$11,625.66	($996.67)
16026666900	INSTALL 120' OF 2" PMMP	$14,869.54	($2,039.33)
16026668200	INSTALL 300' OF 2"PMMP	$14,300.37	$26,421.42
16026669500	INSTALL 350' OF 2"PMMP	$19,892.37	($1,754.36)
16026670400	INSTALL MI WIRELESS EFC	$11,853.27	($4,065.76)
16026671400	INSTALL 350' OF 2"PMMP	$17,461.76	($3,326.77)
16026671700	INSTALL 240' OF 2"PMMP	$14,513.01	($2,374.89)
16026673400	INSTALL PRIVACY FENCE	$6,158.50	($1,497.56)
16026675200	INSTALL EFC & MI WIRELESS	$17,908.56	($14,635.75)
16026675400	INSTALL 240' - 4" PMMP	$15,110.22	($4,308.14)
16026676600	INSTALL 336' - 2" PMIP	$14,702.67	($334.13)
16026678100	INSTALL BUS ASSEMBLY BLDG	$10,342.56	($1,165.03)
16026678500	INSTALL NEW ODORIZER	$1,696.78	($1,498.21)
17026684100	INSTALL METAL BUILDING	$23,649.11	($1,054.22)
	2016 Non SMRP Construction Projects	**$8,337,627**	**$1,028,399**

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2017 Non SMRP Construction Projects

Project No.	Project Title/Description	Total Budget Project Cost	Variance in Dollars
15026580902	INSTALL 900'OF 8"/12" CSHP	$406,599.01	$6,892.22
15026581701	INSTALL 2400'-4" PMMP	$303,011.79	$38,442.20
15026594800	NEW BUILDING FOR REG SITE	$66,807.01	($70,841.46)
15026595002	INSTALL 260'-4"-CS/PMMP	$94,831.23	($25,772.65)
15026598602	INSTALL 740' - 2"/4" PMIP	$59,728.13	$4,179.85
15026610900	INSTALL REGS & HEATER	$5,013.84	$3,919.35
15026623601	INSTALL 2,200' OF 6" & 2" PMMP	$382,171.61	$205,295.42
16026631900	INSTALL CHAIN LINK FENCE	$15,948.30	($7,250.30)
16026633101	INSTALL 425' OF 2"PMMP MAIN	$38,135.18	($5,817.59)
16026633401	INSTALL 750' OF 4" PMIP	$175,821.35	($22,827.50)
16026637601	INSTALL 20'-8" CSHP	$225,383.98	$14,574.50
16026641600	INSTALL 375'-4"PMLP	$71,594.55	($26,157.07)
16026643500	INSTALL 2" VALVES	$24,215.24	($23,172.71)
16026646402	INSTALL NEW WATER BATH HEATER	$82,741.95	($12,264.15)
16026647500	INSTALL 1200' - 2" PMMP	$29,478.27	($689.48)
16026649702	INSTALL 930'-2"&4" PMMP	$192,331.96	$12,138.11
16026655000	PM RELOCATE 5600'-12"CSHP (TC)	$4,499,999.61	($4,204,511.27)
16026657500	INSTALL 3" MOONEY CONTROL REG	$6,149.01	($735.65)
16026658200	INSTALL 6" PCF	$6,440.75	$1,888.79
16026659000	INSTALL 350' OF 2" PMMP	$17,535.68	($6,735.49)
16026663201	INSTALL 2100' OF 2" PMMP	$125,703.49	($1,995.56)
16026666700	RELOCATE 12" HP MAIN	$120,312.04	$42,298.36
16026667300	ACQUIRE ESMT - EARLYMEADE FARM	$16,071.00	$1,639.18
16026667801	INSTALL 50'-6" PMMP	$134,221.11	($23,458.28)
16026668801	INSTALL TWO 2" SS - FITTINGS	$53,972.09	$18,170.63
16026671500	INSTALL 1626' - 2" PMMP	$97,571.86	($26,812.31)
16026674401	PM INSTALL 26,000'-6"/8" HDPE	$2,985,687.07	($740,255.42)
16026674700	INSTALL 675' - 2" PMMP	$95,497.78	$31,246.87
16026674800	INSTALL 500'-2" PMMP	$212,345.67	($112,691.36)
16026675000	INSTALL 200' - 2" PMMP	$21,436.67	$11,495.04
16026675900	INSTALL 2850' OF 2"/4"PMMP	$68,731.95	($3,279.31)
16026676100	INSTALL NEW GMB SETTING	$48,263.45	($9,843.44)
16026676300	INSTALL METAL BUILDING	$48,767.22	$910.97

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2017 Non SMRP Construction Projects

16026677000	INSTALL 100' - 4" PMLP MAIN	$15,690.67	$1,701.28
16026677200	INSTALL 400' - 2" PMMP	$30,602.33	$12,744.72
16026677700	INSTALL 165' OF 2"PMMP	$12,723.68	($1,023.70)
16026678400	INSTALL 115' - 2" PMIP	$6,882.44	$12,323.64
16026678800	INSTALL 1400'-4" CSHP	$181,476.00	($33,781.01)
16026679200	INSTALL 1500'-2" PMMP	$54,417.39	($10,785.35)
16026680300	INSTALL NEW GMB W/EFC	$83,331.79	$7,382.90
16026680600	INSTALL 475' OF 2"PMIP MAIN	$25,656.47	($4,197.18)
16026681800	INSTALL 200' OF 2"PMMP	$12,283.29	$640.92
16026682101	INSTALL 1025' OF 2"PMMP	$44,106.47	($24,533.20)
16026682500	INSTALL 950' OF 2"PMMP	$23,304.24	$731.18
16026683300	RELOCATE 50'-2" PMMP	$20,529.23	($17,117.48)
16026683700	INSTALL 150' - 2" PMMP	$11,221.08	($2,848.38)
16026683800	INSTALL 100' - 2" PMMP	$8,044.59	($4,761.75)
17026684200	INSTALL 500' - 2" PMMP	$52,559.77	($26,894.21)
17026684900	INSTALL 9X8X7 CHAIN LINK FENCE	$14,032.24	($2,228.24)
17026685100	INSTALL 230'-2" PMLP	$48,357.31	($6,260.24)
17026685600	INSTALL 520' OF 4"PMLP	$45,721.73	($2,103.77)
17026686300	INSTALL 600' OF 4"PMMP	$38,541.24	($6,386.36)
17026686700	INSTALL NON-PRIMARY RELIEF	$2,295.35	($1,410.84)
17026687100	INSTALL 2700' OF 2"/4"PMMP	$68,305.75	($7,365.92)
17026687300	INSTALL 900' OF 2"PMMP	$21,790.24	($5,713.46)
17026687400	INSTALL 2550' OF 2"/4" PMIP	$100,949.49	($4,630.86)
17026687900	INSTALL 1850' - 2" PMMP	$77,940.93	($2,189.73)
17026688300	INSTALL NEW RV-50 4G MODEM	$5,921.22	($2,461.13)
17026689400	INSTALL 10' - 2" PMMP	$4,460.29	($3,987.74)
17026693000	INSTALL 800'-2" PMMP	$45,114.48	($5,832.80)
17026693300	INSTALL NEW CHAIN LINK FENCE	$19,185.12	($9,806.86)
17026693500	INSTALL REG STATION FENCE	$11,814.94	($1,998.77)
17026693800	INSTALL CHAIN LINK FENCE	$24,081.12	($17,724.15)
17026694101	INSTALL 3400' - 4" PMIP	$219,406.65	($47,962.42)
17026694200	INSTALL 125' OF 2"PMMP	$9,731.47	($1,618.06)
17026694500	INSTALL MI WIRELESS	$13,082.45	($9,114.75)
17026695400	INSTALL NEW PAPER GAUGE	$908.50	($786.46)
17026697000	INSTALL 100' OF 2"PMMP	$7,933.24	($2,752.05)
17026697200	INSTALL 20' - 4" PMIP	$16,017.96	($7,811.22)
17026697500	INSTALL 5000' OF 2"/4"PMMP	$123,953.92	($65,644.00)
17026697600	INSTALL 400' - 2" PMMP	$41,766.99	($22,508.36)
17026697800	INSTALL 200' - 2" PMMP	$10,221.50	$4,987.62
17026698000	PM MIDWAY INTALL REG STATION	$367,126.16	($76,139.76)
17026698200	PM WOODFORD RESERVE MIDWAY	$101,156.71	($51,377.59)
17026698300	PM MIDWAY GMB FENCING	$26,767.00	($25,222.67)

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2017 Non SMRP Construction Projects

17026698700	INSTALL NEW REGULATOR & ORIFIC	$3,227.99	$3,649.86
17026699200	INSTALL CRITICAL VALVE	$14,881.46	$56.26
17026699700	INSTALL 215' OF 2"PMIP	$20,111.97	($6,163.95)
17026700600	INSTALL 250' OF 4"PMMP MAIN	$19,721.31	($4,527.83)
17026700900	INSTAL MI WIRELESS	$12,405.08	($3,260.83)
17026701300	REPLACE FI 630W/ FI 627	$618.87	$824.35
17026701500	REPLACE FI 630 W/ FI 627	$1,206.87	($288.00)
17026701700	REPLACE FI 630 W/ FI 627	$1,793.87	($168.77)
17026702200	REPLACE FI 630 W/ FI 627	$1,793.87	($93.78)
17026703600	INSTALL 100' OF 2"PMIP	$17,117.54	$5,487.12
17026705001	INSTALL 340' - 4" PMLP	$26,493.13	$27,823.26
17026705900	INSTALL 160' OF 2"PMMP	$17,619.88	($5,283.80)
17026707500	INSTALL CWT HEATER & INSTR.	$292,410.55	$66,456.13
17026708001	REPLACE SETTING VALVES	$12,811.74	$8,196.09
17026708801	INSTALL 220'- 2" PMMP	$15,643.56	($11,480.20)
17026710701	INSTALL 300' OF 2"PMMP	$24,493.77	($4,083.51)
17026710801	INSTALL 15'-10" CSMP	$146,302.22	($52,897.89)
17026711200	INSTALL 3500' OF 2"/4"PMMP	$72,064.25	$11,798.09
17026711400	INSTALL 200'-2" PMIP	$31,262.90	$15,417.18
17026711501	INSTALL 1200' - 2" PMMP	$88,897.33	$5,057.57
17026711801	INSTALL 2200' OF 2"/4"PMMP	$53,791.66	($3,262.31)
17026711900	INSTALL 215' OF 2"PMMP MAIN	$13,768.29	($3,272.00)
17026712800	INSTALL NEW SKID GMB SETTING	$75,608.25	($34,881.85)
17026712900	INSTALL 1575' 4"/6" PMMP	$181,779.76	$18,933.50
17026713600	INSTALL 625' OF 2"PMMP	$24,176.89	$2,243.08
17026713700	INSTALL CONTROLLS	$273,377.04	($55,180.84)
17026714200	INSTALL 300' - 2" PMMP	$18,413.91	$469.65
17026714400	INSTALL 1100' - 2" PMMP	$62,676.17	($23,916.78)
17026714800	INSTALL 212'-4" PMIP	$27,227.59	($12,432.99)
17026716600	INSTALL 90' OF 2"PMMP MAIN	$10,790.48	($5,614.67)
17026716800	INSTALL 180'-2" PMIP	$14,116.63	($1,649.48)
17026717600	INSTALL PRESSURE RELIEF VALVE	$1,195.98	($1,130.07)
17026717800	INSTALL GMB SETTING	$99,765.00	$55,102.73
17026718100	INSTALL 100' - 4" PMMP	$23,282.91	$1,733.32
17026718200	INSTALL 175' - 2" PMMP	$16,047.94	($13,194.78)
17026718400	INSTALL 175' OF 2"PMMP	$11,350.21	$11,490.29
17026719300	INSTALL 250' OF 2"PMMP	$17,006.88	($2,606.94)
17026720300	INSTALL 275'-2" PMMP	$18,240.46	($6,841.11)
17026721401	INSTALL 275' OF 2"PMMP	$13,134.63	$2,144.21
17026724400	INSTALL EFC	$313.64	($269.96)
17026725400	INSTALL FISHER 627 REGULATORS	$3,074.28	($1,154.23)
17026727700	INSTALL 30' OF 2"PMMP MAIN	$4,311.47	$2,306.11

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2017 Non SMRP Construction Projects

17026729700	INSTALL 475' OF 2"PMIP MAIN	$23,295.01	$2,963.46
17026729800	PM HP INLET PIPE - MIDWAY PROJ	$0.00	$3,069.07
17026731900	INSTALL 2 FISHER 627S	$2,596.18	($2,596.18)
17026735300	INSTALL 625' OF 2"PMMP MAIN	$15,553.71	($2,012.94)
17026736900	INSTALL NEW MI EFC	$10,065.22	$2,975.73
17026737700	INSTALL 275' OF 2"PMMP MAIN	$15,276.75	$5,869.76
17026738800	PM INSTALL FENCING AT POD	$0.00	$0.00
17026739900	INSTALL NEW RELIEF VALVE	$8,756.65	($4,366.19)
17026740000	INSTALL 210'-2" PMMP	$22,421.85	$18,372.82
17026741700	INSTALL 3-4" VALVES METER RUN	$8,182.55	$34,177.76
18026772100	INSTALL 5' OF 2"PMMP MAIN	$8,723.74	$3,809.43
	2017 Non SMRP Construction Projects	**$14,681,133.26**	**($5,360,692.85)**

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2018 Non SMRP Construction Projects

Project No.	Project Title/Description	Total Budget Project Cost	Variance in Dollars
13026486800	INSTALL 250'-12" CSHP	$486,540.74	$25,767.51
15026569503	PM INSTALL POD HUNTINGTON ALLO	$935,721.00	$619,190.10
15026569602	PM INSTALL GMB HUNINGTON ALLOY	$304,013.00	($142,949.89)
15026578201	INSTALL 600'-4" PMMP	$62,361.09	($2,419.52)
15026584901	INSTALL 15'-6" PMMP	$31,539.16	$2,794.12
15026603702	INSTALL 15' OF 2" PMMP	$14,665.26	($1,632.76)
16026634401	INSTALL 475'-4" & 6" PMMP	$121,107.41	$6,117.06
16026635100	INSTALL NEW METER AND SETTING	$69,280.62	($26,780.15)
17026684300	INSTALL 250'-2" PMMP	$31,690.13	$1,795.08
17026684601	INSTALL 5700' OF 2"/4"PMMP	$213,351.28	$5,301.49
17026690700	INSTALL 2"-IP & LP DUAL RUN RS	$89,150.40	($10,713.40)
17026691100	INSTALL STRUCTURE; R-1317 RELO	$91,119.13	($9,137.34)
17026710101	INSTALL 6,605' - 2" PHHP	$158,619.41	$36,171.44
17026713900	INSTALL 9X9X7 CHAIN LINK FENCE	$11,969.54	($2,448.64)
17026719001	INSTALL 2600' - 2" PMMP	$40,148.63	($1,935.47)
17026719501	INSTALL 8" SS	$64,412.82	$11,108.02
17026719900	INSTALL 100'-4" PMLP	$26,581.46	$7,452.13
17026721700	INSTALL 8760' OF 2"/4"PMMP	$220,888.33	($31,811.37)
17026722300	INSTALL 1000' OF 2"PMMP MAIN	$39,965.62	($2,077.69)
17026723400	INSTALL 1800' - 2/4" PMMP	$72,180.82	$15,576.90
17026723800	INSTALL 523'-4" PMMP	$28,994.43	($4,846.22)
17026723900	CONVERT CAB TO GMB	$18,863.56	($5,578.01)
17026725100	INSTALL 530' - 2" PMMP	$13,849.02	($439.87)
17026725200	INSTALL 20' OF 2"PMIP MAIN	$5,010.35	$4,240.29
17026729000	INSTALL 500' OF 2"/4"PMMP	$37,050.02	$14,060.50
17026730201	INSTALL 1100' OF 2"/6"PMMP MN	$45,252.12	($4,126.59)
17026734001	INSTALL 3425' OF 2"PMMP MAIN	$75,105.14	($3,100.17)
17026735900	INSTALL BYPASS VALVE	$3,946.70	$730.24
17026736800	INSTALL 800' - 2" PMMP	$37,639.65	$4,178.63
17026737200	INSTALL 605' - 2" PMMP	$55,506.09	$6,533.02
17026737400	INSTALL 100' -2" PMMP	$11,562.78	($4,799.56)

17026738000	INSTALL 180'-2" PMIP	$21,131.65	($4,437.29)
17026738200	INSTALL 425' OF 2"PMMP MAIN	$18,453.40	$2,766.89
17026739201	INSTALL 400' OF 2"PMMP MAIN	$43,805.10	($3,110.47)
17026740400	INSTALL 250'-2" PHHP	$33,763.00	($6,798.27)
17026741200	INSTALL 160' OF 2"PMMP MAIN	$12,264.20	$7,336.37
18026744400	INSTALL 2800' OF 6"PMMP MAIN	$150,928.00	($19,986.38)
18026745200	INSTALL 120' OF 4"PMMP MAIN	$10,847.20	$34,094.06
18026746100	INSTALL 2100' - 2" PMMP MAIN	$49,200.58	($5,979.60)
18026746200	INSERT 15' - 3" PMMP	$2,923.06	($2,923.06)
18026747700	INSTALL 1300' - 4" PMLP	$45,983.74	$36,144.97
18026747800	INSTALL GROUND BED	$6,720.61	($2,428.12)
18026748100	INSTALL 105'-2" PMMP	$21,179.75	($6,880.68)
18026748400	INSTALL 270'-2" PMMP	$20,348.75	($7,912.91)
18026748701	INSTALL 975' OF 2"PMMP MAIN	$43,685.28	$1,304.60
18026749800	INSTALL 100'-6" PMLP	$20,270.23	$670.64
18026750000	INSTALL 125' OF 2"PMMP MAIN	$12,809.21	$13,376.27
18026750100	INSTALL 1200' OF 2"PMMP MAIN	$29,326.46	($4,663.86)
18026750500	INSTALL EFC & MI WIRELESS	$19,542.30	($8,177.96)
18026750800	INSTALL 20'-2" PMMP	$8,838.58	($1,730.99)
18026751000	INSTALL 750' - 2" PMMP	$36,154.04	($5,314.60)
18026751100	INSTALL 7'-3" WTHP	$26,572.19	($5,861.02)
18026751701	INSTALL 750' - 6" PMMP	$160,937.40	($25,594.89)
18026752100	PM - GMB STATION FENCE	$83.59	($83.59)
18026752200	PM - INSTALL POD FENCING	$83.59	($83.59)
18026752500	INSTALL VRG PILOT FOR MONITOR	$5,590.65	$341.40
18026752900	INSTALL 3 VRG PILOTS	$27,587.33	$8,740.68
18026753100	INSTALL 2 VRG PILOTS	$10,099.33	$6,849.48
18026753800	INSTALL 525' OF 2"PMIP	$23,575.53	($3,749.15)
18026753900	INSTALL 50' - 2" PMMP	$12,804.75	($968.06)
18026754400	ACQUIRE ESMT FOR R-1380 EXP'N	$14,342.00	($1,300.07)
18026755300	INSTALL 275' OF 2"PMMP MAIN	$16,234.46	$5,198.73
18026756500	INSTALL 127'-2" PMLP	$80,593.26	($47,716.38)
18026757100	INSTALL NEW MI EFC	$9,933.51	$607.31
18026757400	INSTALL INLET/OUTLET VALVES	$1,490.75	$621.57
18026757600	ACQUIRE RECTIFIER SITE	$6,477.04	$3,618.04
18026758400	INSTALL 120'-2" PMMP	$18,116.06	($5,516.91)
18026758700	INSTALL MI WIRELESS W/SOLAR	$11,647.59	($2,681.58)
18026761500	INSTALL 1100' OF 2"PMMP MAIN	$22,277.67	$941.70
18026761900	INSTALL 20'-2" PMP	$27,540.21	$81,933.74
18026762200	INSTALL 400'-2" PMIP	$25,803.73	$7,239.38
18026762400	LAND FOR RECIFITIER SITE	$13,255.59	($4,027.19)
18026763400	INSTALL 700'-2" PMMP	$31,042.55	($880.69)
18026763700	INSTALL 130'-2" PMIP MAIN	$17,234.76	$7,799.13
18026763800	INSTALL 334' 4/2" PMMP (EMERG)	$34,743.70	($2,849.71)
18026764600	INSTALL 175' - 4" PMMP	$14,145.76	$6,952.24
18026765100	INSTALL 2825' - 2"PMMP	$62,925.07	$6,017.58

18026765600	INSTALL 175' - 4" PMLP	$30,187.60	$64,842.03
18026766000	INSTALL 185' OF 2"PMMP MAIN	$17,973.68	($2,481.57)
18026766100	NEW LAND AND EASEMENT	$7,515.19	$174.98
18026766700	INSTALL 660'-2" PMMP	$196,978.28	($23,903.02)
18026767400	ACQUIRE SITE FOR NEW REG STA	$35,632.00	($4,523.00)
18026767900	INSTALL NEW REGULATOR/HEATER	$10,394.68	($6,197.00)
18026768100	SET UP EASEMENT FACILITY	$10,206.19	$1,905.22
18026768200	INSTALL 475' OF 2"PMMP MAIN	$22,495.60	$324.31
18026769000	INSTALL 50' - 3" PMLP	$13,730.21	($4,489.12)
18026769300	INSTALL GROUND BED RECTIFIER	$39,677.78	($20,111.71)
18026769700	INSTALL 700' OF 2"PMMP MAIN	$30,298.42	$5,772.08
18026769900	INSTALL 3100' OF 2"PMMP MAIN	$113,279.91	$29,639.60
18026770300	INSTALL EFC	$11,518.69	($483.91)
18026770500	INSTALL EFC	$11,518.69	($565.42)
18026771000	INSTALL CHAIN LINK FENCE	$8,178.74	($3,228.55)
18026771400	INSTALL 2300' OF 2"PMMP MAIN	$63,530.25	$8,638.23
18026771601	INSTALL 800' OF 2"PMMP MAIN	$36,097.95	($4,391.74)
18026771900	INSTALL NEW MON/CON REGULATORS	$139,764.08	$124,497.34
18026772400	INSTALL 2" BALON B-P VALVES	$10,291.00	($1,358.47)
18026773500	INSTALL 205'-2" PMMP	$13,911.46	$14,369.60
18026773700	INSTALL 20' OF 3"PMMP MAIN	$22,530.02	($13,775.30)
18026775100	INSTALL 35' - 2" PMMP	$4,816.01	($4,138.26)
18026775500	INSTALL 1500'-2" PHHP	$48,705.91	($424.67)
18026775600	INSTALL 370'-4" PMIP	$41,665.28	($26,956.88)
18026775900	INSTALL EFC - MI WIRELESS UNIT	$10,110.28	($1,262.12)
18026777400	INSTALL 4000' OF 2"PMMP MAIN	$133,000.39	($31,258.99)
18026777500	INSTALL 300' OF 2"PMMP MAIN	$22,749.86	$13,799.45
18026781400	INSTALL 500' - 2" PMMP	$23,908.26	($2,508.13)
18026781600	INSTALL 900' OF 2"PMMP MAIN	$37,549.31	$19,033.08
18026782000	INSTALL 100'-2" PMIP	$15,360.65	($6,418.56)
18026782401	INSTALL 150' - 4" PMLP	$16,688.72	$2,054.45
18026782500	INSTALL 200' - 2" PMMP	$12,261.96	($6,999.58)
18026782800	INSTALL NEW EFC W/MI WIRELESS	$12,899.92	($4,944.77)
18026782900	INSTALL NEW EFC W/MI WIRELESS	$12,899.92	($4,754.14)
18026784800	INSTALL 1650' OF 2"PMMP MAIN	$31,155.33	($2,171.42)
18026784900	INSTALL 400'-2" PMHP	$22,702.09	$81.20
18026785000	INSTALL NEW CONTROL REGULATOR	$2,388.83	($2,028.64)
18026785300	INSTALL 24'-4" PMIP	$28,413.21	$21,709.76
18026785500	INSTALL EFC	$14,797.46	($2,689.99)
18026786900	INSTALL 120'-2" PMMP	$14,588.31	($7,948.20)
18026787600	INSTALL NEW RECTIFIER	$6,423.48	$59.82
18026788000	INSTALL 70' - 2" PMMP	$10,233.72	($5,961.15)
18026788500	INSTALL 1500'-2"PMMP	$65,744.84	($34,487.43)
18026788900	INSTALL 400' - 2" PMMP	$23,846.51	$879.96
18026789400	INSTALL 600'-2" PMIP	$26,849.41	($9,289.88)
18026789800	INSTALL 525' OF 2"PMMP MAIN	$25,393.48	($3,596.66)

18026790700	INSTALL SS FITTING	$20,483.54	($6,994.19)
18026790800	INSTALL 250' - 2" PMMP	$14,776.48	($537.14)
18026791000	INSTALL 140' OF 2"PMMP MAIN	$11,571.86	$1,805.30
18026791300	INSTALL 535' OF 2"PMMP MAIN	$22,934.10	$4,386.49
18026791400	INSTALL 375' - 2" PMMP	$50,710.68	($31,626.92)
18026791800	INSTALL 175' - 2" PMMP	$12,672.55	($883.14)
18026792200	INSTALL BYPASS & OUTLET VALVES	$6,123.97	$3,935.75
18026792600	INSTALL 100' OF 2"PMIP MAIN	$11,234.55	($2,717.35)
18026792700	INSTALL 4" BP VALVE	$5,690.69	($1,990.36)
18026792900	INSTALL 500' OF 2"PMMP MAIN	$24,897.10	$296.44
18026795101	INSTALL 210'-2" PMMP	$48,760.31	($4,819.42)
18026795300	REPLACE MONITOR/CONTROL REGS	$1,655.62	($1,587.01)
18026797000	INSTALL 175' OF 2"PMMP MAIN	$17,539.34	($6,736.82)
18026841600	INSTALL 185'-4" PMLP	$12,772.86	$53,085.29
18026842300	INSTALL 50'-4" PMLP	$13,072.86	$5,338.39
18026845200	INSTALL 10'-4" PMMP	$4,025.44	$402.53
18026845400	INSTALL EFC UNIT	$5,528.91	$321.25
18026846000	INSTALL 100' OF 2"PMMP MAIN	$7,443.86	$3,799.39
18026846600	INSTALL 225' OF 2"PMMP MAIN	$13,144.89	$2,717.37
18026848200	INSTALL 200' OF 4"PMMP MAIN	$7,492.96	$11,530.75
18026848400	INSTALL 80'-2" PMMP	$23,093.19	($19,968.85)
	2018 Non SMRP Construction Projects	**$6,547,888.25**	**$631,308.21**

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2019 Non SMRP Construction Projects

Project No.	Project Title/Description	Total Budget Project Cost	Variance in Dollars
15026619300	INSTALL NEW 2" BYPASS REGS	$1,699.75	($1,057.45)
16026683601	INSTALL 800' OF 2"/4"PMMP MAIN	$46,066.60	$19,581.59
17026705600	INSTALL 2"GV-10' 2"CSHP MAIN	$47,831.14	$9,044.98
17026723100	INSTALL TEMP REG STATION	$3,792.98	$12,713.39
17026725301	INSTALL 3300' OF 4"PMMP MAIN	$202,202.01	$10,916.49
17026733101	INSTALL 6075' OF 2"/4"PMMP	$394,597.42	($30,028.95)
17026740501	INSTALL 4,450' - 6/4/2" PMMP	$450,558.92	$28,687.35
18026746400	INSTALL 115'-6" PHHP/CSHP	$29,746.88	$4,479.73
18026746900	INSTALL 1700' 12" CSHP	$1,088,739.32	($119,728.13)
18026749200	INSTALL 1170'-4"/2" PMMP	$206,432.48	($21,156.89)
18026754200	INSTALL RECTIFIER	$14,431.61	$7,335.57
18026754700	INSTALL 640'-4"PMLP	$64,602.71	($29,928.55)
18026755802	INSTALL 70'-6" PMLP	$147,474.23	$2,798.51
18026756300	INSTALL 550' OF 2"PMMP MAIN	$23,888.40	($1,771.03)
18026761600	INSTALL 4" PIF	$21,889.89	$8,584.43
18026763500	R-1238 INSTALL CWT HEATER	$974,892.35	$291,176.74
18026767000	ACQUIRE LAND FOR SCADA BUILD.	$10,852.00	$4,664.89
18026767601	INSTALL 420'-4"&6" PMMP	$103,809.98	$35,662.03
18026772800	INSTALL 250' OF 2"PMMP	$17,789.21	($2,336.98)
18026772900	INSTALL 575' OF 2"PMMP MAIN	$27,269.89	($3,831.80)
18026774100	INSTALL 25'-4" PMIP	$48,783.42	$1,858.80
18026775701	INSTALL 1,490' - 2"/6" PMIP	$156,681.16	$17,546.45
18026775800	INSTALL 215'-2" PMIP	$38,240.22	($10,737.84)
18026777900	INSTALL 20'-6" CSHP-LEAKAGE	$60,097.63	$57,583.18
18026778601	INSTALL 3100' - 2"/4" PMMP	$99,496.04	$12,782.31
18026779000	R-1133 INSTALL NEW REG SETTING	$90,267.25	($24,736.72)
18026779200	R-1133 INSTALL NEW 19X24 FENCE	$16,030.75	($6,438.05)
18026780700	INSTALL NEW REG STA R-1222	$56,249.17	($22,308.70)
18026780900	R-1222 INSTALL NEW 20X20 FENCE	$16,537.96	$1,981.33
18026781000	R-1222 ACQUIRE 25X25 REG SITE	$28,537.00	($9,719.89)
18026781300	INSTALL 750' OF 4"PMLP MAIN	$21,512.70	$2,796.28

18026781901	INSTALL 1000' OF 6"PMMP MAIN	$215,170.03	($3,922.58)
18026783401	INSTALL 5,400' - 2"/4" PMMP	$230,334.92	$20,427.17
18026783800	INSTALL 320'-8" PMLP	$186,541.45	$45,020.07
18026784001	INSTALL 1385'-6" PMMP	$471,729.66	($44,399.33)
18026786201	INSTALL 3,250' - 2" PMMP	$142,507.14	$26,319.05
18026786300	NEW EASEMENT FOR REG STATION	$8,647.12	$8,522.88
18026789202	INSTALL 350' OF 2"PMMP MAIN	$22,611.67	$1,636.88
18026790300	INSTALL 350' OF 2"PMMP MAIN	$14,329.86	$3,764.88
18026791701	INSTALL 5400' OF 2"/4"PMMP	$204,633.99	($25,446.55)
18026794800	INSTALL 2200' OF 4"PMMP MAIN	$69,179.25	($403.77)
18026798100	INSTALL 2" SS FITTING	$7,049.90	$1,856.44
18026798900	INSTALL 625' OF 2"PMMP MAIN	$24,146.89	$9,585.25
18026799501	INSTALL 4" PV	$14,476.08	$747.23
18026799700	INSTALL 6" PV	$10,736.13	$1,512.97
18026800402	INSTALL 9000' OF 2"PMMP MAIN	$597,234.66	$4,367.34
18026800500	INSTALL 150'-2" PMLP	$30,813.85	$33,197.60
18026845900	INSTALL 110'- 4"CSHP INLET MN	$42,605.05	$16,266.24
18026846900	INSTALL 200'-2" PMIP	$14,331.16	$32,847.70
18026847801	INSTALL 925' OF 2"/4"PMMP MAIN	$93,860.03	$10,099.98
18026848300	INSTALL 100' OF 2"PMMP MAIN	$15,477.13	($2,349.03)
18026848501	INSTALL 7400' OF 2"/4"/6"PMMP	$499,644.97	$74,231.30
18026848800	INSTALL MI WIRELESS UNIT	$10,197.57	$500.60
18026849000	INSTALL MI WIRELESS UNIT	$6,384.57	$940.14
18026849700	INSTALL 825' OF 2"PMMP MAIN	$24,468.70	$19,418.83
18026849900	INSTALL REG #1863 DUAL RUN	$93,915.87	($4,334.53)
18026850000	REPLACE VALVE	$7,869.45	$4,369.83
19026850600	INSTALL 375' OF 4"PMMP MAIN	$23,051.38	$631.88
19026850701	INSTALL 675' OF 2"PMMP MAIN	$105,956.05	($22,062.90)
19026855100	INSTALL 50' - 2" PMMP	$7,788.26	$27.95
19026855900	INSTALL NON-PRIMARY RELIEF	$1,903.75	$4,003.87
19026856200	INSTALL 630'-2" PMMP	$44,437.99	$27,016.46
19026857100	INSTALL 40'-4" PMIP	$25,566.33	($6,302.86)
19026857400	INSTALL 80' OF 2"PMMP MAIN	$7,770.18	($2,517.05)
19026857500	INSTALL 400' OF 2"PMMP MAIN	$23,797.38	($1,896.66)
19026858000	INSTALL 400' OF 4"PMLP MAIN	$23,897.51	$18,619.27
19026858200	INSTALL 300' OF 2" PMMP MAIN	$16,963.21	$3,173.15
19026858300	INSTALL 3100' OF 2"PMMP MAIN	$69,931.54	($10,961.35)
19026858401	INSTALL 1020'-2" PMMP	$120,785.73	$414.04
19026859200	INSTALL 3250' OF 2"PMMP MAIN	$151,407.47	$11,188.76
19026860100	INSTALL EFC	$7,262.67	($1,701.97)
19026860200	INSTALL 1025' OF 2"PMMP MAIN	$44,639.74	($8,995.08)
19026860701	INSTALL INLET/OUTLET PIPING	$153,225.02	$12,135.18
19026860900	RELOCATE REG STATION #1684	$24,955.72	($691.17)
19026861200	INSTALL 80'-2" PMMP	$7,543.66	($3,083.36)
19026861600	INSTALL 97'-3" PMMP	$45,857.16	$13,656.01
19026861800	INSTALL HEATER	$4,140.03	$510.55

19026861900	INSTALL 250' OF 2"/4"PMMP	$17,824.62	$1,111.52
19026863100	INSTALL NEW CHAIN LINK FENCE	$12,912.80	($6,045.43)
19026863200	INSTALL 1600' OF 2"PMIP MAIN	$63,001.67	$41,818.71
19026863500	INSTALL 850' OF 2"PMMP MAIN	$33,977.87	($2,785.30)
19026863900	INSTALL 1450'-2" PMMP	$52,175.91	$1,164.08
19026864000	INSTALL 200' OF 2"PMMP MAIN	$13,477.92	$6,039.16
19026864100	INSTALL 485' OF 2"PMMP MAIN	$22,646.87	$4,221.79
19026864600	INSTALL 435' OF 2"PMMP MAIN	$20,756.36	$16,643.26
19026865100	ACQUIRE ESMT OVER CARMAN PROPY	$170,919.00	($40,779.91)
19026865400	INSTALL 4'-3" PMMP	$10,175.68	($4,504.93)
19026866100	INSTALL 450' OF 2"PMMP	$35,637.95	$21,442.55
19026866200	INSTALL TWO 2" SS	$27,449.49	$14,263.39
19026866500	INSTALL VRG CONTROLLER	$15,490.75	$11,454.95
19026867701	INSTALL 2100' OF 2"PMMP MAIN	$146,669.74	$12,739.98
19026868001	INSTALL 1050' OF 2"PMMP MAIN	$94,155.59	$7,252.31
19026868200	INSTALL MI WIRELESS EFC	$11,104.55	($6,623.48)
19026868301	INSTALL 450' OF 2"PMMP MAIN	$72,806.60	($17,181.50)
19026868400	INSTALL 70'-2" CSHP TO R-1222	$21,448.11	$22,227.41
19026868801	INSTALL 393'-4" CS/PMMP	$88,186.62	$10,236.41
19026869100	INSTALL 150' - 4" PMMP	$30,279.26	$27,920.88
19026869300	INSTALL 10'-3" PMLP	$7,452.84	($7,452.84)
19026869500	INSTALL 265' OF 2"PMMP MAIN	$16,744.87	$684.83
19026869900	INSTALL 225' OF 2"PMMP MAIN	$14,833.85	($1,972.11)
19026870200	INSTALL 100' OF 2"PMMP MAIN	$10,252.96	$6,633.47
19026870300	INSTALL 35' OF 2"PMMP MAIN	$4,141.42	($3.36)
19026870400	INSTALL 60' OF 2"PMMP MAIN	$7,261.68	$130.99
19026870901	INSTALL 15'-2" PMMP	$25,434.54	($4,448.53)
19026871100	INSTALL 40' OF 4"PMMP MAIN	$6,260.68	($1,134.53)
19026871300	INSTAL 100'-2" PMMP	$10,670.63	$10,064.47
19026872200	INSTALL 225' 2" PMMP	$65,634.42	$903.95
19026872900	INSTALL 378' 4" & 10' 3" PMMP	$98,659.18	($22,413.86)
19026873100	INSTALL 60' OF 2"CSHP MAIN	$21,475.24	$29,552.76
19026873300	INSTALL 4000' OF 2"PMMP MAIN	$133,806.59	$53,069.55
19026873400	INSTALL 2'-2" PMMP	$4,522.90	($4,339.28)
19026873600	INSTALL 24'-4" PMIP	$15,596.72	$7,329.34
19026874700	INSTALL 700' OF 2"PMMP MAIN	$30,503.16	$1,445.00
19026875500	INSTALL 14' OF 4"PMMP MAIN	$6,535.46	$10,075.43
19026877000	INSTALL 623' OF 4"CSHP MAIN	$125,819.92	($11,160.01)
19026877200	INSTALL 4,500' - 6" PMMP	$317,849.85	($26,197.52)
19026877500	INSTALL 50' OF 2"PMMP MAIN	$17,465.46	($7,269.46)
19026877700	INSTALL 154'-2" PM/CSMP	$49,694.98	($10,441.43)
19026878500	INSTALL 1500' OF 4"PHHP MAIN	$99,430.73	$4,178.48
19026878800	INSTALL REGULATION	$1,744.26	($1,744.26)
19026879500	INSTALL 900' OF 2"PMMP MAIN	$20,687.16	($61.97)
19026879700	INSTALL 5'-3" PMIP EMERGENCY	$114.75	($60.77)
19026880100	INSTALL 11'-3" PMLP	$7,810.53	$6,951.93

19026880400	LAND FACILITY FOR REG STATION	$72.09	$1,127.91
19026882501	INSTALL 2500' OF 2"PMMP MAIN	$161,456.08	($8,499.10)
19026882701	INSTALL 90' OF 2"PMMP MAIN	$22,347.52	($2,889.89)
19026883200	INSTALL 100'-4" PMIP	$15,476.14	($4,504.51)
19026885100	INSTALL 16' OF 2"PMMP MAIN	$23,899.08	($7,708.64)
19026885800	INSTALL 550' OF 2"PMMP MAIN	$29,896.76	($4,131.07)
19026886000	INSTALL 440' OF 4"PMMP MAIN	$47,785.95	($7,587.17)
19026886800	INSTALL 30' 2" PMMP	$11,471.30	($2,048.59)
19026887200	REPLACE DAMAGED BUILDING	$65,318.72	($1,457.32)
19026887700	INSTALL 1' - 2" PMMP AS-BUILT	$3,265.95	($179.46)
19026888000	INSTALL 40'-2" PMMP	$31,034.66	$13,500.29
19026890200	INSTALL 5' - 2" PMMP	$3,857.65	($1,541.79)
19026890900	INSTALL 4" POLY VALVE	$4,599.60	($3,964.71)
19026891100	OFFSET 20'-2"P-MP MAIN	$2,980.81	($2,425.58)
19026891500	INSTALL 1' - 2" PMMP	$6,675.38	($126.34)
19026891800	INSTALL 1' - 3" PMMP	$24,821.33	($680.19)
19026892000	INSTALL 1' - 2" PMMP	$5,823.04	($352.64)
19026892500	INSTALL NEW CHAIN LINK FENCE	$6,787.72	$2,335.83
19026892800	INSTALL 1' 2" PMLP	$4,989.57	($3,249.78)
19026893400	INSTALL 1' - 2" PMMP	$12,063.69	($9,185.74)
19026894500	INSTALL 3' - 3" PMMP	$8,920.86	$3,395.22
19026894900	INSTALL 100' 2" PMMP	$13,228.36	$1,927.46
19026895900	REPLACE MAIN - LEAKAGE	$3,261.70	($603.94)
19026896700	INSTALL 100' OF 2"PMMP MAIN	$7,866.91	$1,265.67
19026896800	REPLACE MAIN - DIG IN	$1,669.06	$738.00
19026897200	INSTALL 2" SS FITTING	$6,488.17	($1,612.11)
19026897600	REPLACE MAIN - DIG IN	$3,086.81	$2,282.78
19026899200	INSTALL 20'- 2" PMMP	$8,977.36	($8,590.21)
19026899400	INSTALL 350' OF 2"PMMP MAIN	$21,423.16	$35,042.57
19026899500	INSTALL 385' OF 2"PMMP MAIN	$27,253.82	$1,275.58
19026900400	INSTALL 5' - 2" PMMP D096803	$8,024.18	$4,169.95
19026901300	INSTALL 5'-6" PMMP	$16,908.46	$4,711.87
19026902300	INSTALL 200'-4" PMMP	$75,295.23	$36,144.01
19026903500	INSTALL ELECTRONIC EQUIP	$6,741.69	($1,078.52)
19026903800	INSTALL 5'-2" P-IP	$1,653.06	$351.16
19026904400	INSTALL 40'-2" PMMP	$8,368.91	($6,069.62)
19026904500	INSTALL 8' OF 3"PMMP MAIN	$9,724.61	($9,572.48)
19026904700	DIG IN - INSTALL 5'-4" PMLP	$5,076.49	($5,076.49)
19026906100	INSTALL 10' OF 3"PMIP MAIN	$15,368.93	($4,377.91)
19026906400	INSTALL 6' - 4" PMIP	$8,611.57	($3,472.90)
19026907400	REPLACE EFC WITH EC350	$3,366.29	$1,346.33
19026908900	INSTALL 3'-4" PMLP	$6,559.54	($712.28)
19026909500	INSTALL 5'-4" PMIP	$5,292.40	($4,504.07)
19026912700	INSTALL FENCE & BOLLARDS	$8,318.14	$290.48
19026915100	BUY PERMANENT NS RR RIGHTS	$25,861.00	$50.05
20026916400	INSTALL 5' OF 4"PMLP MAIN	$9,665.11	($4,699.74)

20026917300	INSTALL 5' - 2" PMMP	$1,409.11	($1,291.98)
20026948200	LAND AGREEMENT LR114666	$0.00	$0.00
20026948400	LAND AGREEMENT LR115003	$0.00	$19.65
20026948500	LAND AGREEMENT LR114662	$0.00	$0.00
	2019 Non SMRP Construction Projects	**$11,365,325.09**	**$665,070.51**

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2020 Non SMRP Construction Projects

Project No.	Project Title/Description	Total Budget Project Cost	Variance in Dollars
15026619900	INSTALL 575'-8" PHHP	$428,889.73	($125,178.10)
15026620100	INSTALL 1735'-4"/2" PMMP	$250,393.73	($27,554.95)
16026676800	INSTALL 350'-4" PMMP	$21,485.84	($11,583.56)
18026744800	INSTALL 35'-6" CSHP	$61,047.23	$88,139.23
18026763200	INSTALL 6500' - 2"/4" PMMP	$367,443.89	$79,866.08
18026774600	INSTALL 900' OF 8"CSHP	$362,869.57	$46,168.19
18026779600	R-1221 INSTALL NEW REG SETTING	$85,333.00	($33,495.68)
18026779800	R-1221 INSTALL NEW REG BLDG	$89,078.24	$7,395.59
18026780001	R-1221 ACQUIRE NEW REG SITE	$50,787.00	$13,439.88
18026783500	INSTALL 1500' - 4" PMMP	$54,214.28	$38,595.03
18026790901	INSTALL 800' OF 4"PMMP MAIN	$130,601.35	($3,066.12)
18026798301	INSTALL 2500'-12" CSHP	$1,166,541.25	($39,676.52)
18026843900	NSP INSTALL 800'-2" PMMP	$53,353.59	$4,255.52
18026844501	INSTALL 2478'-4" PMLP	$400,557.41	$250,759.49
18026848100	ACQUIRE LAND FOR USS	$5,291.00	$5,892.58
18026849200	INSTALL MI WIRELESS EFC	$10,338.96	$2,708.16
18026849400	INSTALL MI WIRELESS EFC	$10,338.96	($2,020.29)
19026865000	INSTALL 253'-4" PMMP	$35,049.11	$18,128.69
19026866900	INSTALL VRG CONTROLLER	$15,490.75	$15,006.66
19026870700	INSTALL 1500' OF 6"PMMP MAIN	$242,580.65	($7,639.55)
19026871400	INSTALL 1000'-2" PMIP	$75,531.57	$4,482.28
19026874100	INSTALL 2800' OF 2"/4"PMMP	$93,000.13	$13,780.05
19026876100	INSTALL 2760' OF 2"/4"PMMP	$70,211.56	($1,591.66)
19026883300	INSTALL 100' OF 2"PMIP MAIN	$25,386.03	$181.23
19026883600	INSTALL GMB STATION	$104,215.94	($21,727.25)
19026884501	INSTALL 70'-2" PMMP	$62,432.70	$67,667.31
19026885901	INSTALL 400' OF 2"PMMP MAIN	$43,080.80	($6,648.25)
19026887301	INSTALL 925' OF 2"PMMP MAIN	$59,176.44	$3,339.62
19026888600	ACQUIRE LAND RIGHTS	$5,332.00	($3,728.15)
19026888700	INSTALL NEW GMB SETTING	$83,475.56	($18,950.12)
19026888900	INSTALL 810' OF 8"CSHP MAIN	$389,698.12	($140,171.69)
19026890600	INSTALL 1440'-6" PMMP	$257,137.64	$55,255.37
19026893200	INSTALL 40' - 4" PMMP	$32,848.76	($25,683.51)

19026896200	INSTALL 570' OF 2"PMMP MAIN	$26,113.72	$40,141.12
19026897500	INSTALL 3400' OF 2"/4"PMMP	$75,934.46	$275.44
19026898200	INSTALL 300'-8" CSHP	$160,063.06	$52,631.51
19026899900	INSTALL 3720' OF 2"/4"PMMP	$83,267.46	$11,502.82
19026901500	INSTALL CHAIN LINK FENCE	$9,450.39	$2,220.98
19026901901	INSTALL 3480' OF 2"/4"PMMP	$154,827.60	$13,775.50
19026904900	INSTALL NEW CHAIN LINK FENCE	$7,539.78	$2,006.00
19026905900	INSTALL 35' OF 2"/4"PMMP MAIN	$24,704.11	$37,314.12
19026906700	INSTALL RECTIFIER, POLE	$9,754.84	($6,905.67)
19026908201	INSTALL 54'-4" PMMP	$73,887.29	($5,927.74)
19026911400	INSTALL NEW RECTIFIER	$10,181.07	($776.37)
19026911800	INSTALL 3,000' - 2"/4" PMMP	$99,658.80	($38,366.62)
19026912100	INSTALL NEW RECTIFIER	$10,181.07	($3,518.16)
19026912301	INSTALL 1800' OF 2"PMMP MAIN	$62,341.37	$6,079.61
19026912600	INSTALL 150' OF 2"PMMP	$12,601.09	$1,817.73
19026914700	INSTALL NEW CWT HEATER	$297,220.71	($159,014.35)
19026915400	PM INSTALL REG BUILDING PMF	$268,939.00	($26,095.44)
19026915500	PM INSTALL REGULATION PMF	$3,736,473.77	$46,117.23
19026916100	PM INSTALL OUTLET PIPING PMF	$224,570.00	($151,499.61)
20026916900	INSTALL 2960' 2" PMMP	$72,637.76	($771.02)
20026917700	INSTALL 5'-2" PMMP	$3,370.54	($314.66)
20026917901	INSTALL 1150' OF 2"PMMP MAIN	$40,732.35	($4,775.49)
20026918500	INSTALL 6'-2"PMMP	$5,610.78	($767.28)
20026919200	INSTALL 5'-4"PMLP	$5,187.78	($4,933.75)
20026920100	INSTALL 350'-2" PMMP	$26,075.93	($11,725.55)
20026920200	INSTALL 205'-2" PMMP	$24,080.93	$17,611.22
20026921200	INSTALL 150' - 4" PMMP	$12,877.47	$34,228.48
20026921800	INSTALL 1050'4" PMMP	$33,901.18	$5,868.97
20026921900	INSTALL 5'-1"CSHP W/GATE VLV	$29,034.47	$4,057.69
20026924001	INSTALL 165'-4" CSHP	$67,409.69	$16,054.00
20026924201	INSTALL 2000'-6" PMMP	$975,569.18	$140,061.97
20026924600	INSTAL REGULATOR STATION	$149,467.43	($35,717.26)
20026925100	UPGRADE ELECTRONICS	$3,205.00	$410.83
20026925600	UPGRADE ELECTRONICS	$3,038.00	$597.83
20026925700	UPGRADE ELECTRONICS	$3,038.00	$588.23
20026927000	UPGRADE ELECTRONICS	$3,038.00	$5,633.75
20026927200	UPGRADE ELECTRONICS	$3,038.00	$676.82
20026927300	UPGRADE ELECTRONICS	$3,038.00	$666.23
20026927400	UPGRADE ELECTRONICS	$3,038.00	$737.71
20026927500	UPGRADE ELECTRONICS	$3,038.00	$5,063.24
20026927600	UPGRADE ELECTRONICS	$3,038.00	$565.22
20026927700	UPGRADE ELECTRONICS	$3,038.00	$615.56
20026927800	UPGRADE ELECTRONICS	$3,038.00	$3,366.17
20026929000	UPGRADE ELECTRONICS	$3,038.00	$4,089.42
20026929200	UPGRADE ELECTRONICS	$3,038.00	$619.08
20026929800	UPGRADE ELECTRONICS	$3,038.00	$822.13

20026929900	UPGRADE ELECTRONICS	$3,038.00	$9,252.02
20026930200	UPGRADE ELECTRONICS	$3,038.00	$3,206.14
20026930600	INSTALL 10'-2" PMMP	$5,414.55	($3,513.24)
20026931000	UPGRADE ELECTRONICS	$3,150.00	($2,681.37)
20026932800	INSTALL FENCE	$4,126.59	($5,241.19)
20026935800	UPGRADE ELECTRONICS	$3,205.00	$365.85
20026938300	INSTALL 5' OF 6"PMLP MAIN	$8,731.86	($8,548.73)
20026938500	INSTALL 2" STOPPLE FITTING	$16,117.97	($9,781.89)
20026938800	INSTALL 10' OF 2"PMMP MAIN	$11,025.98	($7,278.60)
20026939700	ACQ ESMT OFF OF 325 WEBSTER AV	$34,881.00	($5,000.12)
20026940300	INSTALL 10' PMIP	$4,738.91	($293.91)
20026940500	INSTALL 10' OF 4"PMMP MAIN	$7,726.70	($5,966.16)
20026941200	INSTALL 145' OF 4"PMMP	$27,431.39	($163.18)
20026943500	INSTALL 420'-4" PMMP	$59,269.16	($12,387.00)
20026943900	INSTALL NEW 4"POLY VALVE	$5,878.46	($2,939.65)
20026945700	INSTALL 100' OF 2" PMMP MAIN	$11,849.22	($2,357.84)
20026945800	INSTAL 5'-2" PMMP (AS BUILT)	$4,095.95	($1,377.33)
20026946900	INSTALL 300' OF 2"PMMP MAIN	$16,395.52	($5,943.64)
20026947100	INSTALL 20'-4" PMLP	$9,973.74	$722.28
20026947500	INSTALL 300' - 2" PMMP	$24,580.96	$10,569.16
20026948600	INSTALL 10' - 2" PMMP	$3,859.90	$953.51
20026948800	INSTALL 6'-4"/2" PMMP	$8,336.50	($3,574.41)
20026949100	INSTALL 12'-2" CSHP HEATER PIP	$23,398.32	$5,525.51
20026949400	INSTALL 5' OF 2"PMMP MAIN	$8,641.70	($6,747.40)
20026950800	INSTALL WOOD FENCE	$9,731.85	($5,404.41)
20026951100	INSTALL 550' OF 2"PMMP MAIN	$46,540.70	($11,029.49)
20026952100	INSTALL 20' OF 2"PMMP MAIN	$8,084.54	($7,527.13)
20026952300	INSTALL 5'-6" PMMP	$2,468.89	$2,172.81
20026953300	INSTALL 20' OF 4"PMMP MAIN	$6,050.38	($2,159.95)
20026953500	INSTALL 20' OF 2"PMIP MAIN	$4,692.54	($2,004.48)
20026955100	INSTALL 400'-4" PMMP	$36,445.65	($17,177.62)
20026955200	INSTALL 1850' OF 2"/4"PMMP	$88,356.86	$48,242.63
20026955300	INSTALL 3700' OF 2"/4"PMMP	$100,593.96	$13,140.77
20026956400	INSTALL 3000' OF 2"PMMP MAIN	$83,398.48	$4,125.82
20026956500	INSTALL 5'-4" PMMP	$4,635.76	$10,876.14
20026956700	INSTALL 5'-4" PMLP AS-BUILT	$3,901.65	($3,692.10)
20026956901	INSTALL 20'-6" PMMP	$42,614.31	($9,947.59)
20026957100	INSTALL 5'-2" PMMP	$3,193.01	$118.39
20026957400	INSTALL 5'-2" PMMP	$3,933.35	($2,738.14)
20026957700	INSTALL 150' - 6" PMMP	$67,436.42	($1,372.75)
20026958000	INSTALL 5'-4" PMIP LEAK REPAIR	$6,231.41	($4,313.56)
20026958600	INSTAL 5'2" PMMP	$3,022.06	$20,838.99
20026959400	INSTALL 5'-4" PMMP	$5,950.52	$4,169.40
20026959600	INSTALL 800' OF 2"PMIP MAIN	$33,356.39	($18,400.98)
20026959800	INSTALL 3' - 4" PMLP	$4,448.19	($4,268.86)
20026960000	INSTALL 5'-2" PMMP	$5,425.13	($5,270.99)

20026960200	INSTALL 5' OF 4"PMMP MAIN	$7,137.12	($6,850.14)
20026960900	INSTALL 40' OF 2"PMMP MAIN	$17,478.17	($11,337.28)
20026961300	INSTALL 10'-6" PMMP	$13,678.34	($6,460.84)
20026961900	REPLACE REGULATORS	$2,574.98	$17,566.25
20026963900	INSTALL 10' - 2" PMMP	$2,010.06	$1,005.15
20026964400	INSTALL 5' OF 4"PMMP MAIN	$4,046.08	$5,806.07
20026964800	INSTALL 5' OF 2"PMMP MAIN	$3,448.16	($1,395.55)
20026966300	INSTALL 200'-2" PMMP	$29,254.46	($2,082.22)
20026966500	REPLACE MAIN - LEAKAGE	$7,662.82	$1,255.75
20026966900	OBTAIN EASEMENT FOR 3"CSMP MN	$18,170.00	($3,101.57)
20026967500	INSTALL 90' - 2" PMMP	$11,568.06	$9,310.36
20026967700	REPLACE MAIN - LEAKAGE	$7,808.24	($7,087.07)
20026968000	INSTALL 10' OF 3"PMMP MAIN	$28,353.83	($6,489.33)
20026968900	INSTALL 15' OF 4"PMMP MAIN	$7,221.70	($2,539.70)
20026969200	INSTALL 490' OF 4"PMIP MAIN	$34,319.24	$9,492.80
20026969500	INSTALL 680' OF 4"PMMP MAIN	$52,475.57	$667.90
20026970600	INSTALL 5' OF 4"PMLP MAIN	$5,549.90	($3,316.43)
20026971300	INSTALL 1900' OF 2"PMMP MAIN	$60,260.47	$7,358.46
20026974800	INSTALL 15' OF 6"PMLP MAIN	$12,246.43	($3,352.80)
20026976100	INSTALL 100' - 2" PMMP	$10,097.58	$4,199.48
20026976700	INSTALL 5'-2" PMMP	$2,239.06	($2,239.06)
20026977900	INSTALL 10' - 2" PMMP	$4,498.84	($4,270.35)
20026978500	INSTALL 15' - 2" PMMP	$10,711.94	($4,746.38)
20026978700	INSTALL 10' - 3" PMMP	$3,412.39	$174.50
20026979800	INSTALL 5'-2" PMMP	$4,118.06	($3,252.01)
20026980800	INSTALL 50'-2" PMMP	$13,229.56	($7,342.31)
20026981900	INSTALL 170'-2" PMMP	$14,695.12	($5,557.00)
20026983100	INSTALL 10' OF 3"PMMP MAIN	$4,601.67	($657.36)
20026985900	INSTALL 5'-4" PMLP DIG IN	$5,898.07	($4,265.24)
20026986200	INSTALL 5'-6" PMMP	$11,648.06	($11,318.02)
20026986700	INSTALL 5' - 4" PMLP MAIN	$4,734.50	($4,092.39)
20026987200	EMER-INSTALL 8' OF 2"PMMP MAIN	$4,618.11	($1,601.18)
20026989100	PM INSTALL REG PMF (FAC ONLY)	$0.00	$2,795.05
20026989300	EMRG - INSTALL 5'-4"PMLP MAIN	$5,551.82	($2,593.74)
20026989900	EMRG - INSTALL 5'-2"PMMP MAIN	$4,780.13	($2,166.83)
20026992300	EMRG - INSTALL 5' OF 3"PMMP	$38,582.91	($6,895.02)
20026992700	EMER-INSTALL 5'-4" PMMP	$12,865.65	($10,025.79)
	2020 Non SMRP Construction Projects	**$13,340,541.38**	**$141,225.09**

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2016 SMRP Construction Projects

Project No.	Project Title/Description	Total Budget Project Cost	Variance in Dollars
13026465402	INSTALL 3685' OF 2"/6" PMMP	$430,807.46	($41,293.98)
13026474404	INSTALL 1200' OF 2"/6" PMMP	$169,719.39	$53,514.25
13026477400	INSTALL 10644'-2"&4" PMIP	$969,382.19	$470,654.60
14026535200	INSTALL 240'-2" PMMP	$39,849.72	($20,532.09)
14026550000	INSTALL 2140' OF 2" & 4" MP	$375,887.37	($72,981.82)
14026550200	INSTALL 400' OF 4" PMMP	$122,276.01	($31,942.42)
14026550501	INSTALL 102' OF 4" PMLP	$64,910.16	$13,929.95
15026562600	INSTALL 1200' OF 4" PMLP	$211,167.70	$31,717.44
15026564901	INSTALL 1523' - 12" CSHP	$314,077.85	($20,242.27)
15026568101	INSTALL 200' OF 2"PMLP MAIN	$32,627.46	$5,516.39
15026569101	INSTALL 120' OF 12"CSHP MAIN	$110,485.71	$16,982.88
15026572300	INSTALL 38'-3" PMLP MAIN	$14,065.63	($7,029.37)
15026576701	INSTALL 391-4" PMLP	$93,576.21	$53,718.42
15026582900	INSTALL 5700'-4" & 2" PMMP	$724,237.09	($111,209.67)
15026583201	INSTALL 1163'-2" PMMP	$184,406.12	($39,078.87)
15026583901	INSTALL 436'-6" PMLP	$69,382.55	$3,061.62
15026586300	INSTALL 160'-4" PMLP	$16,767.63	$16,440.48
15026588700	INSERT 120' - 3" PMLP	$18,619.70	($14,369.84)
15026591201	INSTALL 5200' OF 4"PMMP	$1,731,007.51	$330,999.08
15026593901	INSTALL 2040'-2" PMMP	$361,731.19	($73,524.63)
15026594600	INSTALL DUAL RUN REGULATOR	$110,700.93	($119,066.21)
15026602201	INSTALL 100'-6"PMMP	$37,776.26	$9,211.20
15026603801	INSTALL 3035' OF 2"/4"/6"PMMP	$718,211.00	($86,289.47)
15026607600	INSTALL 360'-6"PMLP	$122,602.19	($21,038.57)
15026608201	INSTALL 392' OF 6" PMLP	$249,063.31	$27,010.39
15026608700	INSTALL 4500' OF 2" PMMP	$622,665.00	($143,495.47)
15026609800	INSTALL 1310' - 2" PMMP	$181,171.83	$7,691.10
15026613900	INSTALL 100' - 2" PMMP	$40,270.01	$17,353.09
15026615700	INSTALL 7200' - 2" & 4" PMMP	$696,093.92	($40,659.68)
15026617400	INSTALL 600' - 4" PM	$45,262.74	$26,880.69
15026618002	INSTALL 1200' OF 4"/8" PMMP	$570,029.69	($25,401.53)

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2016 SMRP Construction Projects

15026618201	INSTALL 3640' OF 6" PMMP	$532,804.34	$9,922.83
15026618600	INSTALL 660'-4" PMLP	$127,906.86	($88,460.71)
15026618900	INSTALL 4" PIF	$24,735.09	($6,460.16)
15026622800	INSTALL 15' OF 2"PMMP W/2"SST	$23,166.88	($9,985.42)
15026623900	INSTALL 6800' OF 12" CSHP	$1,922,533.70	($900,631.39)
15026625100	INSTALL 7156'-2"&4"PMIP	$948,640.70	($103,771.10)
15026625700	INSTALL 880' OF 6" PMLP	$76.81	($12.51)
16026628500	INSTALL 50' OF 4"PMLP	$28,864.59	$25,198.64
16026628900	INSTALL 30' OF 4"PMLP MAIN	$13,287.61	$2,224.00
16026629100	INSTALL 1450' OF 4" PMLP	$76.81	($76.81)
16026635900	INSTALL 50' OF 4"PMLP MAIN	$24,740.93	($8,442.85)
16026639900	INSTALL 200'-8" PMMP	$78,644.19	($24,262.24)
16026645500	INSTALL 56'-4"PMLP	$35,856.19	$9,777.88
16026647600	INSTALL 300' - 4" PMIP	$50,682.34	($6,119.43)
16026657901	INSTALL 220' OF 4" CSHP	$60,998.31	($13,483.75)
16026658000	725' OF 6" PMMP R-1860 OUTLET	$64,902.85	($6,357.58)
16026658700	INSTALL 250' OF 2" PMLP	$57,757.40	$3,156.21
16026660800	INSTALL 2 - 6" SS	$42,622.82	($39,591.67)
16026662500	INSTALL 200'-2" PMMP	$70,832.73	($52,251.25)
16026664500	INSTALL 15' OF 2"PMLP	$2,657.26	($259.62)
16026667000	INSTALL 15' OF 6" PMMP	$23,530.08	$12,791.49
16026669801	INSTALL 615' OF 6" PMMP	$176,080.80	$87,473.74
16026674500	INSTALL 300' OF 6"PMMP	$95,959.78	($15,968.02)
16026675500	INSTAL 20'-2" PMMP	$29,163.89	($24,437.78)
16026677300	INSTALL 11' - 6" CS HP	$19,923.33	($11,576.25)
16026679900	INSTALL 164' OF 4"PMLP MAIN	$48,653.27	$30,672.80
16026681600	INSTALL 13' OF 6"PMLP MAIN	$32,167.35	($3,223.57)
	2016 SMRP Construction Projects	**$13,068,470**	**($917,629)**

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2017 SMRP Construction Projects

Project No.	Project Title/Description	Total Budget Project Cost	Variance in Dollars
12026410402	INSTALL 3400' OF 12"CSHP	$954,076.35	$6,855.57
13026477201	INSTALL 3435' - 2"/4" PMMP	$719,646.27	$61,589.91
13026482501	INSERT 1100'-8"PMMP	$99,599.51	$43,216.82
15026568401	INSTALL 350' - 4" PMIP	$97,615.70	($1,116.08)
15026568600	INSTALL 350' - 4" PMLP	$86,877.83	($5,761.16)
15026597400	INSTALL 360'-4" PMLP	$53,119.70	$9,270.50
15026614900	INSTALL 1360'-2"/4" PMMP	$167,573.54	$23,373.12
15026619600	INSTALL 50'-6" PM	$21,748.83	($5,905.71)
15026620401	INSTALL 1750' OF 2"PMMP	$104,252.68	$5,410.74
15026620700	INSTALL 1585' - 2" PMMP	$213,123.40	($2,192.02)
16026640800	INSTALL 30'-4" PMLP	$13,653.59	$2,121.51
16026641700	INSTALL 4176' - 6" PM	$828,583.71	($344,372.83)
16026643001	INSTALL 490'- 8"& 2" PHHP	$158,886.30	($6,937.00)
16026644000	INSTALL 987' - 2" PMMP	$88,008.20	($29,505.40)
16026649200	INSERT 275' - 2" PMLP	$24,953.76	$23,931.24
16026651600	INSTALL 400' - 2" PMLP	$89,973.62	$15,786.49
16026651800	INSTALL 778' 6" PMLP	$206,269.28	($74,197.68)
16026654800	INSTALL 1200' OF 2"PMMP	$150,278.83	($10,674.06)
16026655802	INSTALL 720' OF 2" PMMP	$260,189.24	$151,245.99
16026656002	INSTALL 2655' OF 2"/6" PMMP	$492,362.79	($3,394.06)
16026656900	INSTALL 5150' OF 2" PMMP	$1,133,000.91	$56,014.38
16026658500	INSTALL 300' OF 2" PMMP	$54,170.62	($17,946.43)
16026659200	INSTALL 40' - 4" PMLP	$15,002.67	$5,534.21
16026661401	INSTALL 3610' OF 2"/4" PMMP	$725,389.30	($59,845.00)
16026664101	INSTALL 1450' OF 2'/4"PMMP	$129,586.30	($10,367.49)
16026665700	INSTALL 200' - 2" PMMP	$45,883.61	$76,410.71
16026670602	INSTALL 7750'OF 2"PMMP	$1,815,026.26	$5,864.21
16026670800	INSTALL 2350' OF 12" CSHP	$403,531.81	($81,594.80)
16026671001	INSTALL 8125' OF 2"PMMP	$524,789.77	($47,696.83)
16026672500	INSERT 20'-2" PMLP	$14,317.00	($9,893.33)
16026673100	INSTALL 510' - 2" PMLP	$104,572.69	$67,978.02
16026678202	INSTALL 4,045' OF 2"/4" PMMP	$1,074,028.54	($200,943.03)
16026678900	INSTALL 510' - 2" PMMP	$106,125.95	($34.76)

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2017 SMRP Construction Projects

16026681900	INSTALL 1400'-2"&4" PMIP	$259,689.91	($5,479.09)
17026686100	INSTALL 315' OF 4" PMMP	$71,845.65	($8,193.59)
17026686400	INSTALL 2500' OF 2"PMMP MAIN	$94,056.74	($26,472.71)
17026686900	INSTALL 662'-4"/6" PMLP	$113,502.89	$149,078.51
17026689900	INSTALL 550' - 4" PMLP	$83,648.49	($27,893.00)
17026691502	INSTALL 1600' OF 2"PMMP	$305,382.35	$36,376.57
17026692300	INSTALL 246'-8"/4" PMMP	$88,750.60	$19,203.24
17026692501	INSTALL 100' - 12" CSHP	$169,516.84	$54,313.94
17026694300	INSTALL 80'-6"PMLP MAIN	$24,679.36	$23,436.57
17026700000	INSTALL 100' - 2" PMLP	$7,862.02	($841.48)
17026703001	INSTALL 200' - 4" CSHP	$60,636.62	$36,438.38
17026703201	INSTALL 3925' - 2"/6" PMMP	$1,034,520.21	$187,683.45
17026703400	INSTALL 900' - 2" PMMP	$188,603.72	($46,022.79)
17026704300	INSTALL 90'2" PMLP	$5,620.08	$1,140.50
17026706800	INSTALL 170' - 4"/6" PMLP	$45,554.30	$14,648.68
17026708200	INSTALL NEW REGULATOR STATION	$98,438.00	$17,826.78
17026711000	INSTALL 84' - 4" PMLP	$32,414.31	($7,981.69)
17026712600	INSTALL 875' - 2" PMMP	$114,909.17	($37,426.10)
17026716000	INSTALL 24'-3" PMLP	$8,808.87	$5,894.19
17026719700	INSTALL 150'-2" PMIP	$14,399.38	($13,434.25)
17026722601	INSTALL 125' - 4" PMLP	$23,824.88	$28,146.74
17026727100	INSTALL 50'-4" PMLP	$24,324.28	($8,238.26)
17026729500	INSERT 110'-3" PMIP IN 4" CI	$17,473.53	($17,173.16)
17026730300	INSTALL 80' - 3" PMLP	$29,266.37	($27,971.33)
17026733700	INSTALL 300' - 2" PMMP	$22,363.12	($962.42)
	2017 SMRP Construction Projects	**$13,916,310**	**($11,677)**

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2018 SMRP Construction Projects

Project No.	Project Title/Description	Total Budget Project Cost	Variance in Dollars
15026626101	INSTALL 1658'-4"PMMP	$197,065.83	$11,439.41
16026644200	INSTALL 750' OF 2"PMMP MAIN	$144,783.21	($12,093.60)
16026674000	INSTALL 350' - 4" PM	$98,141.79	$6,414.10
16026676401	INSTALL 1950' - 8" PHHP	$352,418.48	($24,437.88)
16026677500	INSTALL 2905' OF 12"CSHP MAIN	$803,059.23	$39,791.74
16026680200	PM INSTALL 3600'- 6"HDPE	$415,898.00	$114,977.15
16026682600	INSTALL 1141'-4"/2" PMMP	$130,979.85	$71,609.75
17026690100	INSTALL 1050'- 8" & 4" PMMP	$303,456.53	$6,454.22
17026690300	INSTALL 671'- 4" PM/CSIP	$91,546.67	($4,247.34)
17026690500	INSTALL 370'- 4" PMLP	$44,947.97	$11,385.04
17026695602	INSTALL 4225' OF 2"/4"/8"PMLP	$998,106.96	$175,424.45
17026696200	INSTALL 670' OF 2"PMMP MAIN	$155,468.11	($6,780.12)
17026696600	INSTALL 1000' OF 4"PMMP MAIN	$282,069.86	($16,161.88)
17026699001	INSTALL 1825' - 2" PMMP	$221,605.41	$44,534.85
17026707301	INSTALL 1950' OF 2"PMMP	$221,016.63	$70,265.31
17026708400	INSTALL FENCE FOR R1862	$8,216.00	$20,373.69
17026715200	INSERT 115' - 3" PMLP	$13,602.94	$29,065.93
17026715600	INSTALL 4" SS	$7,959.22	($2,899.75)
17026715800	INSTALL 1200' OF 2"PMMP MAIN	$218,986.57	($112,933.99)
17026717000	INSTALL 8,725' - 2"/4" PMMP	$541,056.58	($48,458.00)
17026717901	INSTALL 1300' OF 4"/8"CSHP MN	$453,832.13	$89,330.19
17026720700	INSTALL 1845'-4" PMIP	$307,695.22	($120,195.89)
17026721000	INSTALL 2800' - 12" CSHP	$864,219.50	($14,898.52)
17026722800	INSERT 120' - 3" PMLP	$21,522.27	$653.60
17026725601	INSTALL 2,442' - 2"/4" PMMP	$450,266.50	$270,534.78
17026726000	INSTALL 3,812' - 6"/2" PMMP	$582,687.02	$165,495.81
17026726301	INSTALL 1400' - 4" PMIP	$142,935.14	$38,308.00
17026727300	NEW REG STATION 1216	$78,951.81	($20,310.09)
17026727900	INSTALL 175' - 3" PMLP	$31,751.27	$5,156.53
17026728401	INSTALL 3209' - 4"/2" PMLP	$687,146.02	($170,520.80)
17026728600	INSTALL 834'- 6" PMLP	$128,212.70	$33,987.61

17026730002	INSTALL 14248' - 2"/4" PMMP	$1,798,995.59	($346,097.90)
17026731201	INSTALL 550' - 2" PMMP	$52,379.72	$2,794.74
17026731301	INSTALL 16,843' - 2"/4" PMMP	$2,372,597.53	($211,211.86)
17026732603	INSTALL 2024' - 2" PMMP	$356,154.57	$28,025.03
17026734801	INSTALL 2192'-4"PMLP	$345,981.51	($15,098.29)
17026736301	INSTALL 3344' OF 2"/4"/6"PMMP	$605,787.35	$243,639.50
17026736601	INSTALL 40'- 4"PMLP	$64,825.51	($4,145.18)
17026738900	INSTALL 6,312'-2"/4" PMMP	$764,372.87	$265,560.11
17026741401	INSTALL 2915'-2" PMMP	$712,485.42	($366,123.12)
17026742100	INSTALL 1,428'-2"/6" PMMP	$213,643.47	$142,900.29
18026746600	INSTALL 1320'-2" PMMP	$110,516.49	$29,779.32
18026751301	INSTALL 8" FITTING	$28,684.82	($28,684.82)
18026764200	INSERT 50'-3" PMLP	$16,026.88	$845.90
18026766501	INSTALL SS FITTING	$33,470.37	($6,121.07)
18026768300	INSTALL 33' OF 6"PMLP MAIN	$10,546.51	($4,447.63)
18026771700	INSTALL 57' OF 4"PMLP MAIN	$17,249.84	($2,385.44)
18026772600	INSTALL 930'-8" PMMP	$357,192.69	($149,231.31)
18026774300	INSTALL 1500'-2" PMMP	$295,064.92	($69,125.07)
18026776300	INSTALL 3 SSTS	$26,633.43	$41,330.50
18026780200	INSTALL 12'-8" PMLP	$11,998.46	$18,074.03
18026785700	INSTALL 30' OF 8"PMLP MAIN	$31,520.01	$3,629.19
18026787200	INSTALL 40' OF 4"PMMP MAIN	$28,073.43	($17,573.09)
18026788100	INSTALL 6" SST	$3,588.58	($2,817.13)
18026788600	EMERGENCY 80'-4"BSLP REPL	$16,939.76	$35,266.62
18026790100	INSTALL 900' OF 4"PMLP MAIN	$3,810.58	($35.27)
18026800600	INSTALL 60' OF 2"PMLP MAIN	$28,611.25	($12,807.08)
19026879600	DOCUMENT MP MAIN INSTALL	$75.15	$2,105.20
	2018 SMRP Construction Projects	**$17,306,832**	**$229,310**

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2019 SMRP Construction Projects

Project No.	Project Title/Description	Total Budget Project Cost	Variance in Dollars
15026601101	INSTALL 3854'- 12 & 4" CSHP	$2,142,667.25	($2,779.19)
17026708901	INSTALL 4400' OF 2"/4"PMMP	$820,561.08	$343,940.05
17026714900	INSTALL 4225' OF 2"PMMP MAIN	$813,635.13	$109,482.09
17026722401	INSTALL 250' - 4" CSHP	$137,260.08	$32,598.47
17026728201	INSTL 3778'-6"&8"PMLP D096801	$999,130.13	$153,840.75
17026728801	INSTALL 1200' - 4" PMMP	$856,768.84	$147,921.50
17026732801	INSTALL 6450' OF 4"/6"/8" PMLP	$1,270,165.85	$412,026.69
17026734200	INSTALL 800' - 2" PMMP MAIN	$147,884.78	$11,066.88
17026736101	INSTALL 12500' OF 2"PMMP MAIN	$934,081.84	$197,733.38
17026739300	INSTALL 274'- 8" PM/CSMP	$76,197.54	$17,122.40
17026739600	INSTALL 295 -4"/8" PHHP+VALVES	$117,387.47	$22,671.13
17026740201	INSTALL 1900'-2"PMIP	$99,934.49	$27,707.36
17026742700	INSTALL 14'-8"CS&PMLP	$43,711.54	$6,160.51
18026747300	INSTALL 33' - 4" CSHP	$35,486.97	($9,293.67)
18026747501	INSTALL 1140'-4" PMLP	$212,341.95	($19,762.65)
18026754500	INSTALL 1260'-4"&6" PMLP	$300,465.32	($90,175.86)
18026756801	INSTALL 500' - 2" CSHP	$56,417.90	$15,692.52
18026763000	INSTALL 1600' OF 8"CSHP MAIN	$605,139.93	$88,769.53
18026764401	INSTALL 2000'-10" PMMP	$1,012,979.83	$27,909.11
18026768600	INSTALL 1402'-2"&4" PMIP	$105,475.57	$84,869.69
18026773101	INSTALL 175' - 12" CSHP	$599,149.54	$27,399.62
18026776901	INSTALL 15,400 OF 2"/4"/6"PMMP	$2,640,238.42	$430,598.84
18026792402	INSTALL 19,575' OF 2"/4" PMMP	$993,828.31	$100,736.50
18026793101	INSTALL 2990' OF 2"/4" PMMP	$1,176,455.31	($108,897.22)
18026794900	INSTALL 10' - 3" PMLP	$9,712.47	$20,322.12
18026795700	INSTALL 1720'-2"&4" PMMP	$134,950.54	($31,977.25)
18026796000	INSTALL 2450' OF 4"PMLP MAIN	$651,866.78	$127,364.80
18026796401	INSTALL 11,750' OF 2"/4"PMMP	$814,656.48	$38,717.21
18026797401	INSTALL 13225' OF 2"PMMP MAIN	$1,622,403.44	($123,342.95)
18026801200	INST. FN 50 EXTRA LP OPP	$21,708.87	$2,770.71
18026801400	INST. FN 16538 EXTRA LP OPP	$21,708.87	$6,771.50

18026801600	INST. FN 14063 EXTRA LP OPP	$21,708.87	($2,447.88)
18026801800	INST. FN 59 EXTRA LP OPP	$21,708.87	$920,595.71
18026802200	INST. FN 14459 EXTRA LP OPP	$21,708.87	$15,531.45
18026802400	INST. FN 13485 EXTRA LP OPP	$21,708.87	$16,183.42
18026802600	INST. FN 13502 EXTRA LP OPP	$22,950.87	$3,277.02
18026803000	INST. FN 72 EXTRA LP OPP	$21,708.87	$17,289.76
18026803200	INST. FN 13481 EXTRA LP OPP	$21,708.87	$12,323.44
18026803600	INST. FN 78 EXTRA LP OPP	$21,708.87	$14,677.71
18026803800	INST. FN 14160 EXTRA LP OPP	$21,708.87	$6,202.32
18026804000	INST. FN 14154 EXTRA LP OPP	$22,950.87	($922.91)
18026804300	INST. FN 83 EXTRA LP OPP	$21,708.87	$18,100.90
18026805200	INST. FN 88 EXTRA LP OPP	$21,708.87	$5,263.44
18026805600	INST. FN 13351 EXTRA LP OPP	$21,708.87	$3,576.00
18026805800	INST. FN 13487 EXTRA LP OPP	$22,950.87	$3,029.40
18026806000	INST. FN 13441 EXTRA LP OPP	$21,708.87	$32,846.76
18026806200	INST. FN 13573 EXTRA LP OPP	$21,708.87	$9,629.70
18026806400	INST. FN 14199 EXTRA LP OPP	$21,708.87	$102.68
18026806600	INST. FN 14143 EXTRA LP OPP	$21,708.87	$11,825.45
18026807600	INST. FN 14207 EXTRA LP OPP	$21,708.87	($1,865.26)
18026807800	INST. FN 119 EXTRA LP OPP	$21,708.87	($2,921.78)
18026808200	INST. FN 13665 EXTRA LP OPP	$21,708.87	$7,649.49
18026809200	INST. FN 264 EXTRA LP OPP	$21,708.87	$1,472.05
18026810800	INST. FN 14064 EXTRA LP OPP	$21,708.87	$26,547.62
18026811800	INST. FN 373 EXTRA LP OPP	$21,708.87	($1,962.02)
18026812000	INST. FN 13501 EXTRA LP OPP	$22,950.87	($5,679.89)
18026812400	INST. FN 14068 EXTRA LP OPP	$21,708.87	$6,551.49
18026812800	INST. FN 13476 EXTRA LP OPP	$21,708.87	$1,234.20
18026813200	INST. FN 19921 EXTRA LP OPP	$21,708.87	$7,287.75
18026813400	INST. FN 22195 EXTRA LP OPP	$21,708.87	$975.06
18026813600	INST. FN 22196 EXTRA LP OPP	$21,708.87	$327.66
18026813700	INST. FN 21499 EXTRA LP OPP	$21,708.87	($8,033.99)
18026813900	INST. FN 21500 EXTRA LP OPP	$21,708.87	($9,071.66)
18026814100	INST. FN 22270 EXTRA LP OPP	$22,950.87	$1,401.85
18026814300	INST. FN 22271 EXTRA LP OPP	$22,950.87	($6,649.79)
18026815100	INST. FN 130 EXTRA LP OPP	$21,708.87	$6,787.09
18026815300	INST. FN 132 EXTRA LP OPP	$21,708.87	$4,656.17
18026815500	INST. FN 134 EXTRA LP OPP	$21,708.87	($5,103.13)
18026815900	INST. FN 136 EXTRA LP OPP	$21,708.87	($4,735.62)
18026816100	INST. FN 14429 EXTRA LP OPP	$21,708.87	$4,567.16
18026816700	INST. FN 147 EXTRA LP OPP	$21,708.87	($7,269.02)
18026816900	INST. FN 190 EXTRA LP OPP	$21,708.87	$11,815.36
18026817100	INST. FN 193 EXTRA LP OPP	$21,708.87	$4,785.21
18026817300	INST. FN 194 EXTRA LP OPP	$21,708.87	$13,234.16
18026817500	INST. FN 199 EXTRA LP OPP	$21,708.87	$9,612.64
18026818100	INST. FN 14201 EXTRA LP OPP	$21,708.87	$15,389.28
18026818300	INST. FN 207 EXTRA LP OPP	$21,708.87	$23,889.40

18026818500	INST. FN 208 EXTRA LP OPP	$21,708.87	$8,566.99
18026818900	INST. FN 210 EXTRA LP OPP	$21,708.87	$11,115.58
18026819100	INST. FN 14426 EXTRA LP OPP	$21,708.87	$9,079.23
18026819300	INST. FN 218 EXTRA LP OPP	$21,708.87	$4,717.76
18026819500	INST. FN 219 EXTRA LP OPP	$21,708.87	$2,848.97
18026820100	INST. FN 352 EXTRA LP OPP	$21,708.87	$455.41
18026820700	INST. FN 37 EXTRA LP OPP	$21,708.87	($5,460.38)
18026821500	INST. FN 42 EXTRA LP OPP	$21,708.87	$43,960.04
18026821700	INST. FN 43 EXTRA LP OPP	$21,708.87	$4,924.60
18026821900	INST. FN 44 EXTRA LP OPP	$21,708.87	($2,947.53)
18026822200	INST. FN 47 EXTRA LP OPP	$21,708.87	$1,717.84
18026822400	INST. FN 48 EXTRA LP OPP	$21,708.87	($84.36)
18026822800	INST. FN 162 EXTRA LP OPP	$21,708.87	$6,003.04
18026823400	INST. FN 165 EXTRA LP OPP	$46,766.16	($21,830.66)
18026823600	INST. FN 182 EXTRA LP OPP	$43,700.16	($26,254.17)
18026823800	INST. FN 183 EXTRA LP OPP	$21,708.87	($4,766.62)
18026824000	INST. FN 220 EXTRA LP OPP	$21,708.87	($1,789.18)
18026824200	INST. FN 221 EXTRA LP OPP	$21,708.87	($5,017.19)
18026824400	INST. FN 13986 EXTRA LP OPP	$21,708.87	($3,309.11)
18026824600	INST. FN 232 EXTRA LP OPP	$21,708.87	($5,861.06)
18026824800	INST. FN 233 EXTRA LP OPP	$21,708.87	($1,538.09)
18026826200	INST. FN 316 EXTRA LP OPP	$46,766.16	($12,925.50)
18026826400	INST. FN 317 EXTRA LP OPP	$21,708.87	$1,134.86
18026827200	INST. FN 661 EXTRA LP OPP	$21,708.87	($5,867.76)
18026827500	INST. FN 691 EXTRA LP OPP	$21,708.87	$4,780.88
18026827700	INST. FN 693 EXTRA LP OPP	$21,708.87	($61.29)
18026827900	INST. FN 694 EXTRA LP OPP	$21,708.87	($2,283.59)
18026828600	INST. FN 21193 EXTRA LP OPP	$21,708.87	($1,024.82)
18026828800	INST. FN 21194 EXTRA LP OPP	$21,708.87	($6,709.06)
18026829000	INST. FN 5 EXTRA LP OPP	$40,101.16	($16,644.06)
18026829200	INST. FN 7 EXTRA LP OPP	$40,101.16	($13,029.52)
18026829400	INST. FN 10 EXTRA LP OPP	$40,101.16	($19,451.28)
18026829800	INST. FN 12 EXTRA LP OPP	$22,950.87	$1,357.58
18026830000	INST. FN 12954 EXTRA LP OPP	$43,677.16	($25,820.57)
18026830200	INST. FN 14 EXTRA LP OPP	$22,950.87	($6,235.95)
18026830400	INST. FN 16 EXTRA LP OPP	$22,950.87	($5,260.07)
18026830600	INST. FN 17 EXTRA LP OPP	$22,950.87	$409.80
18026830800	INST. FN 18 EXTRA LP OPP	$40,101.16	($21,179.89)
18026830900	INST. FN 19 EXTRA LP OPP	$40,101.16	($23,896.33)
18026831300	INST. FN 21 EXTRA LP OPP	$22,950.87	($3,931.73)
18026831500	INST. FN 22 EXTRA LP OPP	$48,480.16	($23,319.18)
18026831700	INST. FN 23 EXTRA LP OPP	$22,950.87	$3,501.56
18026831900	INST. FN 24 EXTRA LP OPP	$22,950.87	($5,482.52)
18026832100	INST. FN 25 EXTRA LP OPP	$40,101.16	($20,713.43)
18026832300	INST. FN 26 EXTRA LP OPP	$43,801.16	($21,620.04)
18026832500	INST. FN 27 EXTRA LP OPP	$40,101.16	($12,615.91)

18026832700	INST. FN 28 EXTRA LP OPP	$43,801.16	($16,025.52)
18026834700	INST. FN 157 EXTRA LP OPP	$22,950.87	($2,071.89)
18026834900	INST. FN 158 EXTRA LP OPP	$22,950.87	$12,607.40
18026835000	INST. FN 12957 EXTRA LP OPP	$21,579.16	$12,092.43
18026835400	INST. FN 167 EXTRA LP OPP	$21,708.87	$1,141.11
18026835800	INST. FN 216 EXTRA LP OPP	$21,708.87	($2,569.81)
18026836000	INST. FN 13023 EXTRA LP OPP	$21,708.87	($367.79)
18026836200	INST. FN 12819 EXTRA LP OPP	$21,708.87	$5,108.95
18026836400	INST. FN 12813 EXTRA LP OPP	$21,708.87	$238.07
18026836500	INST. FN 12831 EXTRA LP OPP	$21,708.87	$3,835.56
18026836700	INST. FN 254 EXTRA LP OPP	$35,132.16	($18,576.17)
18026836900	INST. FN 804 EXTRA LP OPP	$40,101.16	($18,145.44)
18026837200	INST. FN 174 EXTRA LP OPP	$21,708.87	($4,506.13)
18026837800	INST. FN 19809 EXTRA LP OPP	$21,708.87	$5,533.88
18026838000	INST. FN 179 EXTRA LP OPP	$21,708.87	$9,990.42
18026839300	INST. FN 19900 EXTRA LP OPP	$21,708.87	($508.80)
18026841700	INSTALL 950' OF 2"PMMP MAIN	$190,505.48	($16,057.78)
18026842000	INSTALL 725' OF 2"PMMP MAIN	$154,391.00	($61,431.60)
18026842500	INSTALL 1615'-12"/8" CSHP	$778,679.76	$72,217.72
18026843000	INSTALL 110'-2" PMLP	$34,180.44	$44,742.37
18026843700	INSTALL 8200' OF 2"PMMP MAIN	$645,599.70	$22,031.69
18026844201	INSTALL 1619'-4"/2" PMLP	$271,601.82	($25,264.29)
19026856500	INSTALL 445'-4" PMLP	$29,115.92	$143,187.85
19026859000	INSTALL 60'-4" PMLP	$10,460.17	$5,681.21
19026862600	INSTALL 2400'-2" PMMP	$436,945.80	($25,107.77)
19026864700	INSTALL 10' OF 4"PMLP MAIN	$12,412.08	($4,421.49)
19026867300	INSTALL 40' OF 3"PMLP MAIN	$24,214.69	$3,147.27
19026870000	INSTALL 60' OF 3"BSLP MAIN	$24,476.16	($21,719.41)
19026873800	INSTALL 223'-4' CS/PMIP	$76,834.88	($2,839.73)
19026874401	INSTALL 2520' OF 2"PMMP MAIN	$460,145.78	$20,246.48
19026875100	INSTALL 550' OF 2"PMMP MAIN	$91,886.51	$25,114.97
19026876700	INSTALL 3117'-2"PMMP	$359,131.16	$319,136.85
19026878200	INSTALL 55' OF 3"PMLP MAIN	$22,186.57	($17,698.90)
19026878600	INSTALL 320' OF 4"PMLP MAIN	$41,650.16	($4,940.11)
19026879900	INSTALL 40' OF 4"PMLP MAIN	$19,353.52	($4,863.83)
19026880501	INSTALL 590' OF 4"/8"PMLP MAIN	$89,456.24	($13,661.20)
19026880700	INSTALL DUAL RUN REG STATION	$48,448.58	($19,430.99)
19026881000	INSTALL 28' OF 12"CSHP MAIN	$54,774.41	$39,649.49
19026881200	INSTALL 5'-4" PMLP	$21,041.81	$9,860.69
19026885300	INSTALL 340' OF 2"PMLP	$10,016.81	$5,040.35
19026886100	INSTALL 10' 4" PMLP	$38,744.96	($13,189.58)
19026886500	INSTALL 1736'-2"PMIP	$80,811.32	$34,691.12
19026887500	INSTALL 20'-4" PMLP	$14,674.47	($6,399.86)
19026889300	INSTALL 6" SS	$15,110.23	($1,612.93)
19026891200	INSTALL 20'OF 8"PMLP MAIN	$48,701.10	$65,719.13
19026893800	INSTALL 40' OF 3"PMMP MAIN	$57,421.38	$501.39

19026895800	INSTALL 12" CSHP	$72.87	($72.87)
19026896300	INSTALL 5'-6" PMLP	$1,441.32	($1,441.32)
19026898700	INSERT 221' OF 4"PMLP MAIN	$45,101.80	$8,299.15
19026905700	INSTALL ERX	$4,096.59	($3,190.94)
19026907600	INSTALL 10'-3" PMLP EMERGENCY	$8,524.87	$13,428.10
	2019 SMRP Construction Projects	**$26,385,233**	**$3,604,711**

Columbia Gas of Kentucky
Case No. 2021-00183
Attachment A
2020 SMRP Construction Projects

Project No.	Project Title/Description	Total Budget Project Cost	Variance in Dollars
14026531302	INSTALL 20'-6" CSHP	$40,462.18	$34,454.09
17026689601	INSTALL 4100' OF 2"/4"PMMP	$1,070,240.19	($35,858.47)
17026712401	INSTALL 4000'-2" & 6" PMMP	$767,672.50	$176,274.67
17026726500	INSTALL 922' 6"-PHHP	$180,053.13	($31,615.23)
17026730701	INSTALL 780' 2" PMIP	$83,787.71	($35,598.91)
17026730900	INSTALL 3700'-12" CSHP	$812,061.69	($34,123.33)
17026735602	INSTALL 3486'-6" PMIP	$400,560.04	$158,059.68
17026743700	INSTALL 450'-2" PMMP	$39,245.94	($14,528.63)
18026747100	INSTALL 753'-4" CSHP	$160,774.00	$25,735.10
18026747200	INSTALL 216-8" CSHP	$83,038.42	($4,380.55)
18026776501	INSTALL 12,000' - 2"/4" PMMP	$1,751,148.40	$102,655.80
18026785901	INSTALL 1400'-6" PMLP-LEAKAGE	$310,400.47	$117,687.04
18026791102	INSTALL 2,700' - 8" PHHP	$623,910.18	$146,740.98
18026794100	INSTALL 80' - 4" PMLP	$69,878.19	($39,148.64)
18026796201	INSTALL 7600' - 2" PMMP	$1,236,118.67	$77,009.37
18026796700	INSTALL 2150' - 2" PMMP	$526,359.41	($128,001.62)
18026797902	INSTALL 925'- 4" PMMP MAIN	$200,349.05	$56,664.78
18026801100	INST. FN 49 EXTRA LP OPP	$41,778.16	($2,387.27)
18026802000	INST. FN 64 EXTRA LP OPP	$23,795.16	$12,689.04
18026802800	INST. FN 14168 EXTRA LP OPP	$42,784.16	$8,967.97
18026803400	INST. FN 14049 EXTRA LP OPP	$21,579.16	$2,215.28
18026804200	INST. FN 82 EXTRA LP OPP	$23,795.16	$1,393.51
18026804500	INST. FN 84 EXTRA LP OPP	$23,795.16	($1,359.44)
18026804700	INST. FN 13493 EXTRA LP OPP	$40,101.16	($8,466.40)
18026804800	INST. FN 86 EXTRA LP OPP	$43,801.16	$17,147.08
18026805000	INST. FN 13503 EXTRA LP OPP	$44,603.16	$19,738.97
18026805400	INST. FN 89 EXTRA LP OPP	$23,795.16	($386.77)
18026806800	INST. FN 114 EXTRA LP OPP	$43,910.16	($922.27)
18026807200	INST. FN 116 EXTRA LP OPP	$24,062.16	($2,674.67)
18026807400	INST. FN 117 EXTRA LP OPP	$22,920.16	$8,466.98
18026808000	INST. FN 212 EXTRA LP OPP	$24,102.87	$31,235.91
18026808600	INST. FN 224 EXTRA LP OPP	$24,062.16	$129,001.98
18026810200	INST. FN 275 EXTRA LP OPP	$23,795.16	$17,783.27

18026811200	INST. FN 311 EXTRA LP OPP	$38,500.16	($9,186.35)
18026812200	INST. FN 14184 EXTRA LP OPP	$23,795.16	$8,181.83
18026813000	INST. FN 842 EXTRA LP OPP	$23,795.16	$5,272.03
18026814900	INST. FN 129 EXTRA LP OPP	$24,062.16	$16,514.42
18026815700	INST. FN 135 EXTRA LP OPP	$22,470.16	$17,238.22
18026817900	INST. FN 14557 EXTRA LP OPP	$39,207.16	$6,701.69
18026818700	INST. FN 209 EXTRA LP OPP	$21,767.16	$17,399.37
18026819700	INST. FN 350 EXTRA LP OPP	$40,148.16	$2,462.15
18026819900	INST. FN 351 EXTRA LP OPP	$21,708.87	$8,088.17
18026820300	INST. FN 354 EXTRA LP OPP	$42,364.16	($5,675.97)
18026820900	INST. FN 38 EXTRA LP OPP	$39,188.16	($8,317.44)
18026821100	INST. FN 40 EXTRA LP OPP	$39,233.16	($10,375.08)
18026821300	INST. FN 41 EXTRA LP OPP	$24,062.16	$5,777.98
18026822100	INST. FN 45 EXTRA LP OPP	$23,886.16	$519.80
18026822600	INST. FN 161 EXTRA LP OPP	$24,062.16	$20,569.19
18026823000	INST. FN 163 EXTRA LP OPP	$23,889.16	$27,204.08
18026826600	INST. FN 357 EXTRA LP OPP	$24,062.16	$18,456.30
18026828100	INST. FN 733 EXTRA LP OPP	$23,795.16	$5,969.11
18026828300	INST. FN 854 EXTRA LP OPP	$42,364.16	$2,017.12
18026832900	INST. FN 29 EXTRA LP OPP	$42,364.16	($23,048.65)
18026833100	INST. FN 31 EXTRA LP OPP	$23,795.16	($727.26)
18026833500	INST. FN 33 EXTRA LP OPP	$40,101.16	($16,301.70)
18026833700	INST. FN 35 EXTRA LP OPP	$40,101.16	($2,022.13)
18026835200	INST. FN 160 EXTRA LP OPP	$40,101.16	($11,648.02)
18026835600	INST. FN 168 EXTRA LP OPP	$40,101.16	$11,265.51
19026855600	INSTALL 4,275' OF 2"/4" PMMP	$444,260.56	$210,280.78
19026869000	INSTALL 575'-2" PMMP	$51,230.94	($11,588.13)
19026874900	INSTALL 4500' OF 2"PMMP MAIN	$756,708.00	($193,835.00)
19026878700	ACQUIRE ESMT ON HOLT, ET AL	$56,500.00	($14,716.28)
19026881600	INSTALL 2240'-4" PMLP	$332,950.59	$60,079.40
19026882300	INSTALL 130' OF 3"PMLP MAIN	$45,765.56	($4,002.84)
19026884200	INSTALL 5'- 4" PMLP	$38,126.78	($8,136.43)
19026886901	INSTALL 985'-2" PMMP	$189,725.29	$48,626.83
19026889500	INSTALL 410' OF 4"PMLP MAIN	$184,461.62	$7,107.05
19026893001	INSTALL 75' - 4" CSHP	$102,933.74	$19,670.84
19026893600	INSTALL 6132'-2" PMMP/2" CSMP	$887,844.96	($187,805.88)
19026897801	INSTALL 12,500' - 2"/4" PMMP	$2,200,144.62	$29,960.98
19026898000	INSTALL 3,350' - 2" PMMP	$299,913.44	$21,144.88
19026900001	INSTALL 10150'-2"/6"/8"PMMP	$1,924,983.18	$614,065.39
19026900200	INSTALL 2775' 2"PMMP	$550,649.66	($118,041.10)
19026904100	INSTALL 1300' OF 2"PMMP MAIN	$155,044.59	$14,331.70
19026907800	RELOCATE 10'-3" PMMP	$16,966.87	($5,992.18)
19026908401	INSTALL 560-2" PMMP	$124,681.76	($37,513.50)
19026909901	INSTALL 1696'-4",6"&8" PMMP	$558,448.36	($189,391.45)
19026914300	INSTALL 555'-4" PMLP MAIN	$98,513.05	($17,248.30)
19026914900	INSTALL 1430'- 2" PMMP	$168,273.19	$4,837.66

19026915201	INSTALL 5075' OF 4"/6"PMLP MN	$1,601,511.95	$17,221.94
20026916700	INSTALL 65' OF 4"PMMP	$32,595.00	$11,917.84
20026919900	INSTALL 100'-8" PMLP	$72,449.27	$18,436.55
20026921400	INSTALL 30' OF 2"PMLP MAIN	$25,344.20	$22,187.33
20026922100	INSTALL 400' OF 8"PMMP MAIN	$78,194.46	$2,299.98
20026923300	INSTALL 790'-2" PMMP	$76,231.10	$11,210.15
20026923800	INSTALL 815'-4" PMLP/DIXON ST	$99,856.44	$14,052.28
20026924800	REPLACE 40'-2"PMMP	$1,911.12	$624.45
20026925400	INSTALL 775' OF 2"PMMP MAIN	$314,223.88	($103,327.61)
20026925801	INSTALL 6,500' - 2"/6" PMMP	$1,499,015.11	($78,719.76)
20026931600	INSTALL 920' OF 6"PMLP MAIN	$135,039.55	($5,305.28)
20026932600	INSTALL 900' OF 2"PMMP MAIN	$109,561.49	($25,925.50)
20026933101	INSTALL 430' 4" PMLP	$181,605.09	($47,330.57)
20026944100	INSTALL 1150'-2" PMMP	$197,605.19	($17,479.09)
20026944700	INSTALL 791' - 2" PMLP	$146,581.93	($3,847.08)
20026945500	INSTALL 535'-4"PMLP	$99,653.39	($24,747.06)
20026946100	INSTALL 1725' OF 2"PMMP MAIN	$289,443.11	$123,059.61
20026946500	INSTALL 1012'/2" PMIP MAIN	$173,270.41	($102,960.61)
20026949700	INSTALL 20' OF 8"PMLP MAIN	$8,890.72	($3,714.19)
20026954200	INSTALL 825' OF 4" PMMP MAIN	$96,092.68	($11,393.77)
20026958301	INSTALL 720'-6" PMLP	$282,646.17	$23,430.46
20026959100	INSTALL 200'-2" PMMP	$41,735.73	($14,340.00)
20026963300	INSTALL 30' OF 4"PMMP MAIN	$43,056.43	($6,251.70)
20026964301	OBTAIN EASEMENTS FOR HP MAIN	$250,078.00	$115,413.68
20026964600	INSTALL 2" SS	$3,010.10	($2,522.99)
20026965500	INST. FN 24836 EXTRA LP OPP	$21,960.54	($20,002.51)
20026966100	INSTALL 12" FITTING	$20,319.94	$91,897.31
20026966701	INSTALL 3740' OF 2/4"PMMP MAIN	$367,967.11	$9,954.75
20026986500	INSTALL FENCE AT R-1143	$7,073.58	$5,290.04
	2020 SMRP Construction Projects	**$25,102,716**	**$1,131,767**

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

30. Refer to the Direct Testimony of Kimra Cole, page 10. Provide an updated revenue increase and percentage increase with respect to the most recently authorized revenue requirement in Case No. 2016-00162.[1]

Response:

The total revenue from Case No. 2016-00162 was $105,935,779. This was calculated as sum of:

- Stipulation and Recommendation – Case No. 2016-00162 filed October 20, 2016 – Attachment B – Proof of Revenue – Page 6 of 6 – Proposed Revenue - $106,257,779.
- Commission Order Case No. 2016-00162, December 22, 2016 – Page 11 – reducing the revenue increase of $13.408 million to $13.086 million, or $322,000.

The requested increase in base rates including the impact of rolling in the federal tax rate reductions and SMRP riders approved subsequent to the last rate case is $26,694,987, or

[1] Case No. 2016-00162, *Application of Columbia Gas of Kentucky, Inc. for an Increase in Base Rates* (Ky. PSC Dec. 22, 2016).

25.2% from the total revenue from Case No. 2016-00162. The requested increase in base rates if the subsequently approved billing adjustments to recognize the federal income tax reduction and SMRP filings are not included in the calculation is $38,217,184, or 36.1%.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

31. Refer to the Direct Testimony of Kimberly Cartella.

a. For all levels and types of incentive compensation discussed in the testimony and provided by Columbia Kentucky, provide any studies showing the quantifiable benefits to ratepayers as a result of the various incentive compensations.

b. Refer to Attachments KKC-2, KKC-3, KKC-4.

(1) Confirm that no analyses were performed to directly compare the salaries and total cash compensation of Columbia Kentucky employees, union and non-union, paid by employers specifically in Kentucky.

(2) If confirmed, confirm that a regional comparison to the Southeast and North Central regions are the most granular analyses performed.

c. Refer to page 11. Provide explanation and support for the use of a 3.0 percent raise for union employees budgeted to be effective December 1, 2021, and December 1, 2022.

d. Refer to pages 13–22.

(1) For the CIP, provide a breakdown of the all metrics and measures used to determine if the incentive pool is created and funded as well as the amount to which it is funded.

(2) For the CIP, provide all job scope levels as well as the associated target incentive opportunities as a percentage of base pay.

(3) Provide a breakdown by employee type of all CIP expenses included in the base year and forecast test period.

e. Refer to page 18. For the discretionary portion of the CIP, provide a breakdown with explanations as well as attributable percentages for all goal categories for each employee.

f. Refer to pages 20–21.

(1) For the LTI, provide a breakdown of the all metrics and measures used to determine if performance shares are vested.

(2) For the LTI, provide a breakdown of the all metrics and measures used to determine whether restricted stock unites are vested.

(3) Provide a breakdown by employee type of all CIP expenses included in the base year and forecast test period.

g. Refer to page 22.

(1) Provide a detailed description of the method and any metrics used to determine the amount contributed to an employee's Retirement Savings Plan account from the Profit Sharing Plan by Columbia Kentucky.

(2) Provide a breakdown by employee type of all Profit Sharing Plan expenses in the base year and forecast test period.

h. Refer to page 40.

(1) Confirm that there are employees of Columbia Kentucky, NCSC, or NiSource that participate in both a defined benefit pension retirement plan, as well as a defined contribution 401(k) retirement plan.

(2) Confirm that the account balance pension formula used by Columbia Kentucky for qualifying employees is still accruing.

(3) Provide the amount of 401(k) matched contributions by Columbia Kentucky during the base and test period.

(4) Provide the amount of Columbia Kentucky's defined benefit pension expense during the base and test period.

(5) Provide the amount of 401(k)-matched contributions Columbia Kentucky provided during the test period for employees that participate in a defined benefit pension plan.

Response:

a. Please refer to Attorney General's First Set of Requests for Information, No. 55. No studies specifically responsive to this request have been performed. However, Columbia notes that in response to the Attorney General's First Set of Requests for Information, No. 55, Sections C and E, Columbia stated as follows:

The entire CIP is tied to measures that directly benefit Columbia Kentucky's ratepayers. CIP measures focus on meeting needs of customers, such as service quality, service reliability, safety, and cost containment. See Witness Cartella's testimony pages 18-19.

LTI is tied to measures that directly benefit Columbia Kentucky's ratepayers. LTI measures focus on achievement of customer, safety, environmental, diversity, and financial goals. See Witness Cartella's testimony pages 21-22.

b. (1) No analysis were performed to compare salaries and total cash compensation to Kentucky specific employers. Salary survey providers require a minimum number of incumbents, organizations and distinct organizations to present valid compensation data. If the minimum requirements are not met, data is aggregated at a broader level. Southeast and North Central region data was the most granular that was consistently available.

(2) See response above.

c. A projected 3% increase is budgeted for December 1, 2021 and December 1, 2022 based upon several factors. First, for the bargaining unit employees, the increase for December 1, 2020 was 3%. Second, the merit increase budget for non-union employees for 2021 was 3%. Third, refer to Kimberly Cartella - Attachment KKC 4 - CKY Merit Market Data. While union employees are not included in these survey results, non-exempt hourly employee merit increase projections are included. WorldatWork projects 2021 non-exempt hourly non-union increases to be 3% nationally and 3% within the utility industry. The Aon national survey projected 2021 increases to be 2.8-2.9% nationally, within the utility industry, within the Midwest states, and within the Southeast states. Based upon all of these factors, it is reasonable for the Company to budget 3% for 2021 and 2022 for bargaining unit employees. As stated in Witness Cartella's testimony, the Company will provide an update and adjust the budget, as necessary, upon completion of the contract negotiations that are projected to occur in November 2021.

d. (1) Columbia's Response to the Attorney General's Second Set of Requests for Information, No. 163 provides all metrics and measures used to determine if the incentive pool is created and funded. Columbia's Response to the Attorney General's Second Set of Requests for Information, No. 103 also asks for the amount to which it is funded for the forecast period. The split of incentive compensation costs is 30.6% Executive or $183,834 of the post-adjusted incentive compensation and 69.4% for Non-Executive or $416,932 of the post-adjusted incentive compensation.

(2) See table below for all job scope levels and the associated target incentive opportunity as a percentage of eligible earnings.

Incentive Opportunity Target (Job Scope Level)	Employee Group
120%	CEO
80%	COO
75%	CFO/EVP
60%	EVP/SVP
55%	President/SVP
50%	President/SVP
45%	SVP
40%	SVP/VP
30%	Director
25%	Director
20%	Manager
15%	Manager
12%	Front Line Leader
10%	Manager/ Team Leader/ Lead Individual Contributor
8%	Senior/ Intermediate Individual Contributor
4%	Nonexempt/

(3) See table below for a breakdown of CIP expenses by employee type in the base year and forecast test period.

Base Year

Employee Type	Columbia	NCSC Allocated
Executive	183,316	414,605
Nonexecutive	895,014	922,829
Total	1,078,330	1,337,434

Test Year

Employee Type	Columbia	NCSC Allocated
Executive	801,910	See AG 2-103 Attachment A
Nonexecutive	164,247	
Total	966,157	

e. See KY PSC Case No. 2021-00183, Staff 3-31, Attachment A for goal categories (measures), explanations (descriptions), and attributable percentages of the CIP program. This program is 100% discretionary for all exempt employees.

f. (1) Refer to CONFIDENTIAL KY PSC Case No. 2021-00183, AG-1-55, Attachment A for a breakdown of the all metrics and measures used to determine if performance shares are vested.

(2) Restricted stock units are time based and vest based upon continued employment through the vesting date.

(3) See response to part d(3) above.

g. (1) As previously stated in Columbia's Response to the Attorney General's First Set of Requests for Information, No. 56, all employees are eligible to participate in the Profit Sharing Plan. However, if an employee is not employed with the company on the last day of the plan year for a reason other than retirement, disability or death, then they are not entitled to a profit sharing contribution. Per the plan document, the profit sharing contribution is designated by the Benefits Committee annually, in its discretion. The discretionary profit sharing contribution is either 0%, 0.5%, 1.0%, or 1.5% of eligible earnings. Please refer to KY PSC Case No. 2021-00183, Staff 3-31, Attachment B for the NiSource Inc. Retirement Savings Plan, which includes the Profit Sharing Plan, and amendments. This Attachment was previously provided as KY PSC Case No. 2021-00183, Staff 1-56, Attachment A.

(2) Please see table below for a breakdown of Profit Sharing expenses by employee type.

Columbia Gas of Kentucky - Profit Sharing Expense		
Year	**Level**	**Profit Sharing Contribution**
Base Year	Directors	2,608
Base Year	Managers	5,424
Base Year	Exempt	11,997
Base Year	Union	58,679
Base Year	Non-Exempt	6,977
Base Year Total		**85,685**
Test Year	Directors	4,204
Test Year	Managers	8,743
Test Year	Exempt	19,338
Test Year	Union	94,586
Test Year	Non-Exempt	11,246
Test Year Total		**138,118**

h. (1) Yes. There are Columbia Kentucky and NCSC exempt employees hired prior to January 1, 2010 and union and non-exempt non-union employees hired prior to January 1, 2013 that participate in both the defined benefit pension plan and the defined contribution 401k plan. Note: NiSource is a legal entity and does not have any employees.

(2) Yes. Eligible employees of Columbia Kentucky are still accruing credits in the account balance pension plan.

(3) The amount of 401(k) matched contributions for Columbia Kentucky during the base period and the test period are $551,525 and $582,534, respectively.

(4) The amount of defined benefit pension expense for Columbia Kentucky during the base period and the test period are $84,347 and $294,935, respectively.

(5) As previously stated in Columbia's Response to the Attorney General's First Set of Requests for Information, No. 178, the 401k costs expensed related to employees who are covered under a defined benefit plan are $379,168 for the base period and $377,643 in the forecast period. The following compares these amounts to the company total 401k expenses for the periods:

Base Period	Total 401K	Defined Benefit Plan
CKY Direct	551,525	218,955
NCSC Allocated	398,539	160,213
	950,064	379,168

Forecast Period	Total 401K	Defined Benefit Plan
CKY Direct	582,534	231,266
NCSC Allocated	364,123	146,377
	946,657	377,643

2020 STI Weighting & Description

	Weighting		Description
STI Measure	**Executive**	**Non-Executive**	**2020**
NiSource Net Operating Earnings Per Share	75%	85%	Income from continuing operations determined in accordance with Generally Accepted Accounting Principles (GAAP) adjusted for certain items such as weather, gains, and losses on the sale of assets, and certain out-of-pocket period items and reserve adjustments or in management’s discussion and analysis of financial conditions and results of operations appearing in the Company’s consolidated report to the investment community or investor letters.
J.D. Power Gas Utility and Electric Residential Customer Satisfaction Studies			Operating company scores as measured by J.D. Power Gas and Electric Utility Residential Customer Satisfaction Studies. Categories include: -Safety and Reliability (Gas) -Efforts to maintain and communicate safe and reliable gas systems -Billing and Payment- provides a variety of clear, concise and easy to pay billing options -Price (affordability/value) -Fair pricing options that meets customer need -Power Quality and Reliability (Electric) -Promptly informs and restores quality electric power after an outage
Billing & Payment	2.5%		
Price	2.5%		
Safety / Power and Reliability	5%		
MSR Customer Satisfaction Survey	5%		Transactional customer satisfaction survey provided to customers; evaluates interactions with customer care center representatives, field personnel and/ or automated phone calls or online interaction.
DART (Days Away, Restricted or Transferred)	5%		Mathematical calculation that describes the number of OSHA (Occupational Safety and Health Administration) recordable incidents per 100 full time employees that resulted in lost or restricted days or job transfer due to work related injuries or illnesses; all operating units and corporate staff of the Company were united by one overall safety goal based on the total performance of all operating units.
National Safety Council Barometer Survey	5%		Measures the overall health of the Company's safety efforts, identifies areas in need of corrective action, provides valid leading indicator safety metrics, effectively incorporates safety into the improvement process, increases employee engagement and morale, allows us to find gaps, design action plans and make changes; survey is comprised of 50 questions in 6 areas: Management Participation, Supervisor Participation, Employee Participation, Safety Support Activities, Safety Support Climate, and Organizational Climate.

2021 STI Weighting & Description

	Weighting		Description
STI Measure	**Executive**	**Non-Executive**	**2021**
NiSource Net Operating Earnings Per Share	70%		Income from continuing operations determined in accordance with Generally Accepted Accounting Principles (GAAP) adjusted for certain items such as weather, gains, and losses on the sale of assets, and certain out-of-pocket period items and reserve adjustments or in management's discussion and analysis of financial conditions and results of operations appearing in the Company's consolidated report to the investment community or investor letters.
J.D. Power Gas Utility and Electric Residential Customer Satisfaction Studies			Operating company scores as measured by J.D. Power Gas and Electric Utility Residential Customer Satisfaction Studies. Categories include: -Safety and Reliability (Gas) -Efforts to maintain and communicate safe and reliable gas systems -Power Quality and Reliability (Electric) -Promptly informs and restores quality electric power after an outage -Billing and Payment- provides a variety of clear, concise and easy to pay billing options -Price (affordability/value) -Fair pricing options that meets customer need
Billing & Payment	[redacted]	5%	
Price	[redacted]	5%	
Safety & Reliability (Gas)	[redacted]	5%	
Power Quality and Reliability (Electric)	[redacted]	5%	
MSR Customer Satisfaction Survey	[redacted]	10%	Transactional customer satisfaction survey provided to customers; evaluates interactions with customer care center representatives, field personnel and/ or automated phone calls or online interaction.
Safety Scorecard			
DART (Days Away, Restricted or Transferred)	5%	[redacted]	Mathematical calculation that describes the number of OSHA (Occupational Safety and Health Administration) recordable incidents per 100 full time employees that resulted in lost or restricted days or job transfer due to work related injuries or illnesses; all operating units and corporate staff of the Company were united by one overall safety goal based on the total performance of all operating units.
Executive Observations	5%	[redacted]	Quality executive field observations
Process Safety Incidents	10%	[redacted]	Significant Injuries or Fatalities (SIF) or PHMSA reportable incidents due to process safety failures
Standard Operating Procedure (SOP) Development	5%	[redacted]	Supplemental mandatory job aids designed to assure adherence to company standards and policies by prompting the proper steps and decisions required for the safe and compliant completion of our work
Records & Mapping	5%	[redacted]	Increase the percentage of service lines that are mapped in GIS; complete, validate and publish in GIS isometric drawings for above ground assets for regulator stations with greater than 125 psig inlet pressures

NISOURCE INC. RETIREMENT SAVINGS PLAN

Amended and Restated Effective as of January 1, 2018

November 1, 2018

TABLE OF CONTENTS

NISOURCE INC. RETIREMENT SAVINGS PLAN

Purpose

NiSource Inc., a Delaware corporation (the "Company"), sponsors the NiSource Inc. Retirement Savings Plan (the "Plan") for the benefit of Eligible Employees of the Company and any other Related Employer that adopts the Plan. The Plan is hereby amended and restated in its entirety, effective as of January 1, 2018, unless otherwise stated herein.

Special effective dates are included with respect to a number of provisions as necessary to conform to various legislation and guidance under the Code and ERISA, including (but not limited to) the following: the Economic Growth and Tax Relief Reconciliation Act of 2001 (EGTRRA) (with technical corrections made by the Job Creation and Worker Assistance Act of 2002 (JCWAA)); revisions required to comply with Code Section 415 (as such provisions were previously adopted by the Company in a separate Plan amendment); the Pension Protection Act of 2006 (PPA '06); the Heroes Earnings Assistance and Relief Tax Act of 2008 (HEART); and the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA). The NiSource Benefits Committee (the "Committee") amended and restated the Plan effective as of January 1, 2009 to reflect various design changes and to update the Plan in accordance with the legislative changes referenced above (the "Plan 2009 Restatement"). The Committee amended and restated the Plan again generally effective January 1, 2009 to make certain clarifications with respect to the administration and operation of the Plan (the "Plan 2010 Restatement") and amended and restated the Plan effective as of January 1, 2012 to reflect the merger of Kokomo Gas and Fuel Company and Northern Indiana Fuel & Light Company, Inc. with and into Northern Indiana Public Service Company, a wholly owned subsidiary of NiSource Inc., as well as to make certain clarifications with respect to the administration and operation of the Plan (the "Plan 2012 Restatement"). The Committee further amended and restated the Plan on two separate occasions, in both cases generally effective as of January 1, 2013, to make various modifications with respect to the administration and operation of the Plan (the "Plan 2013 Restatements"). The Committee further amended and restated the Plan generally effective as of January 1, 2014, to make various modifications with respect to the administration and operation of the Plan (the "Plan 2014 Restatement"). The Committee now amends and restates the Plan as of the Effective Date to update the Plan as necessary to reflect negotiated benefit changes for various union employee groups participating in the Plan, to incorporate Amendments 1 – 6 to the Plan 2014 Restatement, and to reflect various additional clarifications with respect to the administration and operation of the Plan (the "Plan 2018 Restatement").

The Plan is intended to be qualified under Code Section 401(a), with a cash or deferred arrangement qualified under Code Section 401(k) and its corresponding trust exempt from taxation under Code Section 501(a). In addition, the Plan is intended to be a profit sharing plan pursuant to the requirements of Code Section 401(a)(27). The portion of the Plan related to Accounts invested in the Company Stock Fund, and the dividends thereon, shall constitute an employee stock ownership plan under Code §4975(e)(7).

The provisions of this amended and restated Plan shall apply solely to an Employee whose employment with the Employer terminates on or after the Effective Date, or with respect to the application of a specific Plan provision containing a different effective date, then such provision shall apply to an Employee who terminates on or after such effective date or as otherwise specified herein. An Employee whose employment with the Employer terminates prior to the Effective Date (or other applicable date with respect to a specific Plan provision containing a different effective date) shall be entitled to a benefit, if any, as determined under the provisions of the Plan or the Prior Plan (the plans as described below in the Plan Background section) in effect on the date that his employment terminated.

Plan Background

The Plan was designated the "NiSource Inc. Retirement Savings Plan" effective January 1, 2002 at the time of a merger of four plans into the Columbia Savings Plan (the "Columbia 401(k) Plan") (a plan that was originally effective September 1, 1958 and previously sponsored by Columbia Energy Group ("Columbia")). The four plans that merged effective January 1, 2002 into the Columbia 401(k) Plan (renamed the NiSource Inc. Retirement Savings Plan) are as follows: (1) the NiSource Inc. Tax Deferred Savings Plan ("NiSource 401(k) Plan") (originally effective May 1, 1984 and formerly known under certain other plan names as described in the Plan 2006 Restatement); (2) the Bay State Gas Company Employee Savings Plan (the "Bay State 401(k) Plan") (established effective January 1, 1979 by the Bay State Gas Company ("Bay State"); (3) the Kokomo Gas and Fuel Company Bargaining Unit Tax Deferred Savings Plan ("Kokomo 401(k) Plan") (established effective April 1, 1995 by Kokomo Gas and Fuel Company ("Kokomo")); and (4) the Northern Indiana Fuel & Light Company, Inc. Payroll Savings Plan ("NIFL 401(k) Plan") (established effective January 1, 1986 by Northern Indiana Fuel & Light Company, Inc. ("NIFL")). Columbia, Bay State, Kokomo, NIFL became wholly-owned subsidiaries of NiSource Inc. effective as of the dates described in the Plan 2006 Restatement. Effective as of the CPG Spin-Off (defined herein), Columbia is no longer a recognized operating entity or member of the NiSource Inc. controlled group of companies and thus no longer a wholly-owned subsidiary of NiSource Inc.

Effective December 31, 2008, two other plans were merged into the Plan: (1) the Bay State Gas Company Savings Plan for Operating Employees (the "Bay State Union 401(k) Plan") (originally established effective January 1, 1988); and (2) the Northern Indiana Public Service Company Bargaining Unit Tax Deferred Savings Plan (the "NIPSCO 401(k) Plan") (originally established October 1, 1987 by Northern Indiana Public Service Company ("NIPSCO")). Effective July 1, 2011, Kokomo and NIFL are merged with and into NIPSCO, a wholly owned subsidiary of NiSource Inc.

Effective as of the July 1, 2015, NiSource implemented the spin-off of its pipeline and transmission business, comprised of the Columbia Pipeline Group, Inc. ("CPG") and its related entities (collectively, the "CPG Entities"), to become independent and non-related to NiSource (the "CPG Spin-Off"). Prior to July 1, 2015, Employees of the CPG Entities participated in the Plan. Effective July 1, 2015, in connection with the CPG Spin-Off, the NiSource Benefits Committee, Plan Administrator and Named Fiduciary having amendment authority over the Plan, authorized the transfer of assets and liabilities of certain Participants and Former Participants in the Plan who are, or were prior to termination of employment, employees of the CPG Entities, to the Columbia Pipeline Group 401(k) Savings Plan, a new qualified defined contribution plan to be established by CPG. Pursuant to said transfer and the existing terms of the Plan, effective July 1, 2015, the Plan terms no longer apply to the above-mentioned Participants.

ARTICLE I
DEFINITIONS

Each word and phrase defined in this Article I shall have the following meaning whenever such word or phrase is capitalized and used herein unless a different meaning is clearly required by the context of this agreement.

Section 1.01 AB I Benefit. The term used to describe the "Account Balance Option" benefit (renamed the "AB I" benefit) in any of the applicable NiSource Pension Plans that offer such a cash balance benefit as defined therein.

Section 1.02 AB II Benefit. The term used to describe the "Account Balance 2011 Option" benefit (renamed the "AB II" benefit) in any of the applicable NiSource Pension Plans that offer such a cash balance benefit as defined therein.

Section 1.03 Account (or Account Balance). The separate bookkeeping account that the Plan Administrator or the Trustee shall maintain for a Participant pursuant to Section 3.01 of this Plan.

Section 1.04 After-tax Contribution Account. The portion of a Participant's Account credited with After-tax Contributions under Section 3.02C, and adjustments relating thereto.

Section 1.05 Bay State. Bay State Gas Company, or any successor(s).

Section 1.06 Bay State Pension Plan. The Bay State Gas Company Pension Plan, or any successor plan (as defined therein).

Section 1.07 Bay State Union 401(k) Plan. The Bay State Gas Company Savings Plan for Operating Employees, which merged into the Plan effective December 31, 2008.

Section 1.08 Bay State Union Employee. An Eligible Employee of Bay State (or any Related Employer of Bay State), whose compensation, conditions of employment or position are covered by a collective bargaining agreement to which Bay State is a party and which agreement calls for the Employee's participation in the Plan (or prior to December 31, 2008, in the Bay State Union 401(k) Plan).

Section 1.09 Bay State Union Plan. The Bay State Union Pension Plan (f/k/a the Pension Plan For Operating Employees of Bay State Gas Company), or any successor plan (as defined therein).

Section 1.10 Beneficiary. A person, including any individual, legal representative, estate or other entity, designated by a Participant who is or may become entitled to a benefit under the Plan. A Beneficiary who becomes entitled to a benefit under the Plan shall remain a Beneficiary under the Plan until the Trustee has fully distributed his benefit to him. A Beneficiary's right to (and the Plan Administrator's or a Trustee's duty to provide to the Beneficiary) information or data concerning the Plan shall not arise until he first becomes entitled to receive a benefit under the Plan. A Participant's designation of a Beneficiary shall not change upon divorce or dissolution of marriage unless such Participant designates a new Beneficiary or remarries.

Section 1.11 Catch-up Contribution Account. That portion of a Participant's Accounts credited with Catch-up Contributions under Section 3.02B, and adjustments relating thereto.

Section 1.12 Code. The Internal Revenue Code of 1986, as it may be amended from time to time.

Section 1.13 Columbia. Effective as of the CPG Spin-Off, a Columbia Gas company that is a Related Employer of NiSource Inc. participating in the Plan, or any successor(s). Prior to the CPG Spin-Off, Columbia Energy Group, or any successor(s).

Section 1.14 Columbia Pension Plan. The Columbia Energy Group Pension Plan (f/k/a the Retirement Plan of Columbia Energy Group Companies), or any successor plan (as defined therein).

Section 1.15 Columbia Union Employee. Effective as of the CPG Spin-Off, an Eligible Employee of NiSource Inc. (or any Related Employer of NiSource Inc., such as a Columbia Gas company), whose compensation, conditions of employment or position are covered by a collective bargaining agreement to which a Columbia Gas company, or its successor within the NiSource Inc. controlled group, was previously a party and which agreement calls for the Employee's participation in the Plan.

Prior to the CPG Spin-Off, a Columbia Union Employee was an Eligible Employee of Columbia, as previously defined (or any Related Employer of Columbia), whose compensation, conditions of employment or position are covered by a collective bargaining agreement to which Columbia is a party and which agreement calls for the Employee's participation in the Plan.

Section 1.16 Committee. The NiSource Benefits Committee, established and maintained pursuant to Article X to administer and amend the Plan.

Section 1.17 Company. NiSource Inc., a Delaware corporation, or its successor or successors. The Company is the Plan Sponsor.

Section 1.18 Company Stock. The common stock shares of NiSource Inc., a Delaware corporation.

Section 1.19 Company Stock Fund. The Investment Fund established to facilitate investments by Participants in Company Stock of the Company, as further described in Section 8.08.

Section 1.20 Compensation. Except to the extent modified for specific Participant groups as set forth below, Compensation means the aggregate basic annual salary or wage and commissions paid to a Participant by his Employer. Compensation shall include the following: (1) one-time payments in lieu of salary increases for any Plan Year (referred to as "lump-sum merit pay"); (2) amounts deferred and excluded from the Participant's taxable income pursuant to Code

Sections 125, 132(f)(4), 402(e)(3), or 402(h)(1)(B); (3) any amounts deferred to a nonqualified plan maintained by an Employer (provided such amounts are only included for purpose of calculating Participant contributions and Matching Contributions described in Sections 3.02 and 3.04 respectively); and (4) solely with respect to Participants subject to the NiSource Vacation Policy ("Vacation Policy") and subject to any payment timing limitations set forth below, any amounts attributable to "banked" vacation (as that term is described in the Vacation Policy) during the calendar year including such Participant's date of termination of employment.

For purposes of the foregoing paragraph, "aggregate basic annual salary or wages" shall exclude various forms of compensation, including (but not limited to) the following: overtime, performance-based pay (such as annual incentive payments or bonuses), supplementary compensation payments, retirement benefits, unused and accrued vacation, and other special forms of compensation such as shift differential, call-out, standby, upgrades, temporary reclassifications/promotions, relocation allowances, sign-on bonuses, retention premiums, payments for waiving certain benefits including health care and dental benefits (referred to as "flex credits"), attendance bonuses and awards, and imputed income.

For Participants on active duty in the uniformed services for a period of more than 30 days, Compensation shall include any differential wage payments, as defined by Code Section 3401(h)(2), to the extent such payments are made by the Company. Such differential wage payments shall be treated as compensation for all Plan purposes, including Code Section 415 and any other Code section that references the definition of compensation under Code Section 415. A Participant receiving such differential wage payment shall be treated as an Employee of the Employer making the payment. If all employees of the Employer performing service in the uniformed services described in Code Section 3401(h)(2)(A) are entitled to receive differential wage payments on reasonably equivalent terms and, if eligible to participate in a retirement plan maintained by the Employer, to make contributions based on the payments on reasonably equivalent terms (taking into account Code Sections 410(b)(3), (4), and (5)), then the Plan shall not be treated as failing to meet the requirements of any provision described in Code Section 414(u)(1)(C) by reason of any contribution or benefit which is based on the differential wage payment.

Compensation generally shall exclude amounts paid after Severance from Employment. However, Compensation shall include post-severance amounts set forth in items (i) and (ii) below to the extent such amounts are paid by the later of $2^{1/2}$ months after Severance from Employment or by the end of the Plan Year (the Limitation Year for purposes of Article VII) that includes the date of such Severance from Employment. Provided the foregoing timing-of-payment condition is met, Compensation shall include:

(i) Regular pay paid after Severance from Employment if: (a) the payment is regular compensation for services during the Participant's regular working hours, or compensation for services outside the Employee's regular working hours (such as overtime or shift differential), commissions, bonuses, or other similar payments; and (b) the payment would have been paid to the Employee prior to a Severance from Employment if the Employee had continued in employment with the Employer; and

(ii) Payments of unused accrued bona fide sick, vacation, or other leave (but only if the Employee would have been able to use the leave if employment had continued).

A. Considerations by Specific Group. Subject to any limitations imposed by Code Section 415 as set forth in this Section, the following additional provisions regarding Compensation shall apply:

(i) In General. The definition of Compensation set forth above shall apply to: (a) Participants eligible for the AB II Benefit (including Bay State Union Employees eligible for the AB II Benefit), (b) Next Gen Employees, and (c) NIPSCO Union Employees who are AB I Participants (subject to the exception in subparagraph (iii) below regarding the determination of Participant Contributions).

(ii) NIPSCO Union Employees who are FAP Participants. For Participants who are NIPSCO Union Employees (including former NIFL Union Employees and former Kokomo Union Employees) who are FAP Participants, the definition of Compensation set forth above shall apply with the following modifications: Compensation shall also include annual incentive payments, overtime, and shift differential.

(iii) NIPSCO Union Employees who are AB I Participants. For Participants who are NIPSCO Union Employees and are eligible for the AB I Benefit, the definition of Compensation set forth above shall not apply for purposes of determining Participant Contributions under Section 3.02: Instead, for the purpose determining such contributions, Compensation shall be the total amount paid to an Employee for personal services that are considered as "wages" on Federal Income Tax Withholding Statement (Form W-2) as adjusted below:

1. Compensation shall be included the extent that any amounts are included as Compensation on Form W-2. In accordance with this, Compensation shall specifically include items such as the following: (1) lump-sum merit pay (as defined earlier in this Section); (2) amounts deferred and excluded from the Participant's taxable income pursuant to Code Sections 125, 132(f)(4), 402(e)(3), or 402(h)(1)(B); (3) commissions (to the extent an Employee is compensated in whole or in part on a commission basis); (4) performance-based pay received by an Employee from an Employer; and (5) overtime payments.

2. Compensation shall be excluded the extent that any amounts are not included as Compensation on Form W-2, except that Compensation shall exclude the following : (1) severance pay; (2) amounts deferred to a nonqualified plan maintained by an Employer; (3) sign-on bonuses, retention premiums, and attendance bonuses and awards; and (4) all other taxable fringe benefits, including stock options and other stock related benefits, relocation expenses and imputed income.

(iv) Bay State Union Employees. For Bay State Union Employees (other than those eligible for the AB II Benefit as noted in subsection A.(i) above), the first sentence of this Section (describing Compensation as "basic annual salary or wage and commissions") shall not apply. Instead, Compensation is straight time wages. The Compensation inclusions set forth above shall continue to apply with the following modifications: Compensation shall also include shift differential, Saturday/Sunday premiums, compensation paid at an alternative rate (not including compensation paid at an alternative rate to a salesperson), and seventy-five percent of sales commissions paid to an Eligible Employee by an Employer while he is a Participant during the current period.

(v) For Participants who are employed in the position of Damage Prevention Coordinator with an assigned job code of NP3459 (or subsequent job title and/or code that becomes applicable for this specific position, as recognized by the Plan Administrator) during the period from June 1, 2016 to April 30, 2019, as negotiated in the Memorandum of Understanding resulting from collective bargaining with respect to such position between the United Steelworkers of America, Local 12775, AFL-CIO-CLC and the Company generally effective June 1, 2016 (hereinafter, "Damage Prevention Coordinator"), the definition of Compensation for purposes of determining Participant Contributions under Section 3.02 shall be determined under the provisions of subsection A(iii) above that is applicable for NIPSCO Union Employees who are AB I Participants.

The Compensation exclusions set forth above shall be disregarded and the following Compensation exclusions shall apply: (1) all daily or weekly overtime; (2) bonuses; (3) supplementary compensation payments; (4) retirement benefits; (5) unused and accrued vacation; and (6) other forms of non-recurring compensation or special forms of compensation including, but not limited to, the following (unless specifically included in this subsection (iv)): call-out, standby, upgrades, temporary reclassifications/promotions, relocation allowances, sign-on bonuses, retention premiums, payments for waiving certain benefits including health care and dental benefits (referred to as "flex credits"), attendance bonuses and awards, and imputed income.

B. Compensation - Contributions by the Employer. Subject to any limitations imposed by Code Section 415, and in order to comply with Code Section 401(a)(4), the following additional provisions regarding Compensation shall apply:

(i) Profit Sharing Contributions. For purposes of calculating Profit Sharing Contributions described in Section 3.06A, Compensation for a Plan Year shall be defined as determined under the Annual Incentive Plan of an Employer in effect for such Plan Year, reduced by any amounts deferred to a nonqualified plan maintained by an Employer. In clarification of the foregoing, for purposes of calculating Profit Sharing Contributions, Compensation means base earnings for the calendar year. Compensation shall include (1) all shift premiums (i.e., shift differential, call-out, standby, upgrades, and temporary reclassifications/promotions) and overtime pay for the calendar year; (2) sales commissions to the extent that such commissions are considered part of the Participant's "base earnings"; (3) one-time payments in lieu of salary increases for any Plan Year (referred to as "lump-sum merit pay"); and (4) amounts deferred and excluded from the Participant's taxable income pursuant to Code Sections 125, 132(f)(4), 402(e)(3), or

402(h)(1)(B). Compensation shall exclude reimbursements for educational assistance, relocation, meals and mileage, as well as incentive payments, bonuses, stock option gains, long-term disability payments, any amounts deferred to a nonqualified plan maintained by an Employer, supplementary compensation payments, retirement benefits, unused and accrued vacation, sign-on bonuses, retention premiums, payments for waiving certain benefits including health care and dental benefits (referred to as "flex credits"), attendance bonuses and awards, and imputed income.

(ii) Employer Contributions for Next Gen Employees. For purposes of calculating Employer contributions for Next Gen Employees (Next Gen Employer Contributions as described in Section 3.06C), the general definition of Compensation described in this Section shall apply with the following modification: Compensation shall exclude any amounts deferred to a nonqualified plan maintained by an Employer.

C. Compensation Limit. In addition to other applicable limitations set forth in the Plan, and notwithstanding any other provisions of the Plan to the contrary, the annual Compensation of each Employee taken into account under the Plan shall not exceed the "Compensation Limit." The Compensation Limit for 2018 is $275,000, and is subject to cost of living adjustments in subsequent years in accordance with Code Section 401(a)(17)(B). Any such cost of living adjustment in effect for a calendar year applies to any period, not exceeding 12 months, over which Compensation is determined (the "Determination Period") beginning in such calendar year. If a Determination Period consists of fewer than 12 months, the Compensation Limit will be multiplied by a fraction, the numerator of which is the number of months in the Determination Period, and the denominator of which is 12. Any reference in this Plan to the limitation under Section 401(a)(17) of the Code shall mean the Compensation Limit set forth in this provision.

D. Compensation - Special Rules. For purposes of Article VI ("Testing of Pre-Tax, After-Tax and Matching Contributions"), Article VII ("Limitations on Contributions and Benefits"), and Article XI ("Top Heavy Rules"), the definition of Compensation shall be determined in accordance with Treasury Regulation Section 1.415(c)-2(d)(4) (commonly known as "W-2 Compensation"). For purposes of Articles VI and XI, the Employer may elect to use an alternate nondiscriminatory definition of Compensation, in accordance with the requirements of Code Section 414(s) and the Treasury Regulations promulgated thereunder. In determining Compensation under Articles VI and XI, the Employer may elect to include as Compensation all Elective Contributions (as defined in Code Section 415(c)(3)(D)(i) and (ii)) made by the Employer on behalf of Employees. The Employer's election to include Elective Contributions must be consistent and uniform with respect to Employees and all plans of the Employer for any particular Plan Year. The Employer may make this election to include Elective Contributions irrespective of whether Elective Contributions are included in the general definition of Compensation applicable to the Plan.

Section 1.21 Disability. A physical or mental condition that results in a determination of disability status that entitles the Employee to disability benefits under any group long-term disability plan sponsored by the Employer, as determined under the terms of such plan.

Section 1.22 Effective Date. January 1, 2018, the date on which the provisions of this amended and restated Plan become effective, except as otherwise provided herein. The original Effective Date of the Plan was September 1, 1958.

Section 1.23 Eligible Employee. Any Employee employed by the Employer other than the following:

A. an intern;

B. an Employee covered by a collective bargaining agreement (recognized as such under applicable federal labor law), unless the agreement provides that such Employee is entitled to participate in the Plan or unless the Plan Administrator otherwise directs in a written instrument submitted to the Trustee;

C. any Leased Employee or any independent contractor (as determined by the Employer pursuant to its established payroll practices), regardless of whether a governmental agency, court or other entity subsequently determines such individual to be an Employee);

D. an Employee who is eligible (or would be eligible upon satisfaction of service and/or age criteria) for another Code Section 401(k) plan maintained by an Employer.

An Eligible Employee may become a Participant in the Plan pursuant to the requirements of Article II.

Section 1.24 Employee. Any person who, on or after the Effective Date, is directly employed by the Employer (or any other Related Employer required to be aggregated with the Employer under Code Sections 414(b), (c), (m) or (o)) in a position that the Plan Administrator determines to be subject to tax withholding by the Employer under the Federal Insurance Contribution Act (FICA) and for whom such taxes are regularly withheld by the Employer. To the extent required by Code Section 414(n), the term "Employee" shall include any Leased Employee (who shall nevertheless be ineligible to participate in the Plan). An Employee shall not include an individual providing services to an Employer as an "independent contractor" (*e.g.*, a person (who is not considered to be a Leased Employee) who is engaged as an independent contractor pursuant to a contract or agreement between such person and an Employer which designates him as an independent contractor or otherwise contemplates or implies that he shall function as an independent contractor). Only individuals who are paid as employees from an Employer payroll and treated by an Employer at all times as Employees shall be deemed Employees for purposes of the Plan. No independent contractor shall be treated as an Employee under the Plan during the period he renders services to an Employer as an independent contractor.

If the Employer does not characterize a person as an Employee and the Employer is later required to re-characterize such person's status with the Employer as an Employee, the person will be treated as an Employee under the Plan as of the date of the re-characterization, unless an earlier date is necessary to preserve the tax-qualified status of the Plan. Notwithstanding such general re-characterization, such person shall not be considered an "Eligible Employee" for purposes of Plan participation, except and to the extent necessary to preserve the tax-qualified status of the Plan.

Section 1.25 Employer(s). The Company and any Related Employers that shall ratify and adopt this Plan in a manner satisfactory to, and with the consent of, the Committee; any successor which shall maintain this Plan; and any predecessor which has maintained this Plan. Unless otherwise provided by the Committee, an Employer participating in the Plan shall automatically cease to participate in the Plan on the date that such entity is no longer considered a Related Employer of the Company and any employee of such Employer shall cease to be eligible to make or receive contributions under the Plan as of such date. The Company and any applicable Related Employer may limit or extend the adoption of the Plan and the Trust Agreement to one or more groups of Employees and/or divisions, locations or operations.

Section 1.26 Employment Commencement Date. The date upon which an Employee first performs an Hour of Service for the Employer or a Prior Employer.

Section 1.27 ERISA. The Employee Retirement Income Security Act of 1974, as it may be amended from time to time.

Section 1.28 FAP Benefit. The term used to describe the "Final Average Pay Option" benefit (renamed the "FAP Benefit") in any of the applicable NiSource Pension Plans that offers such a pension benefit as described therein.

Section 1.29 Former Participant. A Participant who has transferred to a classification of Employees ineligible to participate in the Plan, or a Participant whose employment with the Employer has terminated but who has a vested Account balance under the Plan that has not been paid in full and, therefore, is continuing to participate in the allocation of Trust Fund Income.

Section 1.30 Highly Compensated Employee. For a particular Plan Year, any Employee who:

A. at any time during the current or preceding Plan Year was a 5-percent owner (as defined in Code Section 416(i)(1)); or

B. for the preceding Plan Year:

(i) received annual Compensation from the Employer in excess of the amount provided under Code Section 414(q)(1)(B) ($120,000 for 2018 and as adjusted by the Secretary of the Treasury thereafter); and

(ii) was in the top 20% of Employees when ranked on the basis of Compensation for the prior Plan Year.

The term Highly Compensated Employee includes a former Employee whose Termination of Employment occurred prior to the Plan Year, and who was a Highly Compensated Employee for the Plan Year in which his Termination of Employment occurred (or was deemed to have occurred) or for any Plan Year ending on or after his 55th birthday.

The determination of who is a Highly Compensated Employee shall be made in accordance with Code Section 414(q) and applicable Treasury Regulations and Internal Revenue Service guidance promulgated thereunder.

Section 1.31 Income. The net gain or loss of the Trust Fund from investments, as reflected by interest payments, dividends, realized and unrealized gains and losses on securities, other investment transactions and expenses paid from the Trust Fund. In determining the Income of the Trust Fund as of any date, assets shall be valued on the basis of their then fair market value.

Section 1.32 Investment Manager. A person or organization who is appointed under Section 10.05 to direct the investment of all or part of the Trust Fund, and who is either (a) registered in good standing as an Investment Adviser under the Investment Advisers Act of 1940, (b) a bank, as defined in that Act, or (c) an insurance company qualified to perform investment management services under the laws of more than one state of the United States, and who has acknowledged in writing that he is a fiduciary with respect to the Plan.

Section 1.33 Kokomo. Kokomo Gas and Fuel Company, or any successor(s). Effective July 1, 2011, Kokomo merged with and into NIPSCO (see "NIPSCO" and "NIPSCO Union Employee" for further details).

Section 1.34 Kokomo Union Pension Plan. The Kokomo Union Pension Plan (f/k/a the Kokomo Gas and Fuel Company Bargaining Unit Employees' Retirement Plan), or any successor plan (as defined therein). Effective December 31, 2012, the Kokomo Union Pension Plan merged with and into the NIPSCO Union Pension Plan.

Section 1.35 Kokomo Union Employee. An Employee who was employed by Kokomo immediately prior to the merger of Kokomo into NIPSCO effective July 1, 2011, whose compensation, conditions of employment or position are covered by a collective bargaining agreement which called for the Employee's participation in the Plan. After the July 1, 2011 merger, the separate Kokomo bargaining unit no longer existed and Kokomo Union Employees became NIPSCO Union Employees. However, see the definition of NIPSCO Union Employee for limitation of this characterization for purposes of the Plan.

Section 1.36 Leased Employee. Any person (other than an Employee of the Employer) who, pursuant to an agreement between the Employer and any other person ("Leasing Organization"), has performed services for the Employer (or for the Employer and related persons determined in accordance with Code Section 414(n)(6)) on a substantially full time basis for a period of at least one year, which services are performed under the primary direction or control of the Employer. Contributions or benefits provided to a Leased Employee by the Leasing Organization that are attributable to services performed for the Employer shall be treated as provided by the Employer. If applicable, Compensation as defined in this Article includes compensation from the Leasing Organization that is attributable to services performed for the Employer.

A Leased Employee shall not be considered an Employee of the Employer if (a) such employee is covered by a money purchase pension plan providing: (i) a nonintegrated employer contribution rate of at least ten percent of compensation, as defined in Code Section 415(c)(3), but including amounts contributed pursuant to a salary reduction agreement that are excludible from the Employee's gross income under Section 125, Section 402(e)(3), Section 402(h) or Section 403(b) of the Code, (ii) immediate participation if such person received $1,000 or more of compensation during the four-year period ending with the measuring plan year, and (iii) full and immediate vesting; and (b) leased employees do not constitute more than 20% of the Employer's nonhighly compensated workforce (within the meaning of Code Section 414(n)(5)(C)(ii)).

Section 1.37 Matching Account. That portion of a Participant's Account credited with Matching Contributions pursuant to Section 3.04, and adjustments relating thereto.

Section 1.38 Next Gen Employee. Any Employee who participates in the "Next Gen" benefit structure offered by the Employer or a Related Employer. A Next Gen Employee does not actively participate in any defined benefit pension plan of the Employer or a Related Employer (*i.e.*, does not accrue a benefit under such plan(s) other than continued accrual of "Interest Credits" as defined in such plan(s) if applicable). A Next Gen Employee is eligible for the contribution described in Section 3.06C of the Plan and Matching Contributions as described in subsection F of Schedule I. "Next Gen Employee" shall include the following:

A. any "Exempt Employee" (as classified under the payroll practices of the Employer) who is hired or rehired on or after January 1, 2010;

B. any "Springfield C/T Employee" or "Northampton Employee" (as each is defined in Schedule II) who is hired or rehired on or after January 1, 2011;

C. any "Lawrence Employee" or "Brockton Operating Employee" (as each is defined in Schedule II) who is hired or rehired on or after January 1, 2013; and

D. any "Non-Exempt Employee" (as classified under the payroll practices of the Employer) or any Columbia Union Employee who is hired or rehired on or after January 1, 2013; and

E. any "Brockton C/T Employee" (as defined in Schedule II) who is hired or rehired on or after June 1, 2013; and

F. any "Springfield Operating Employee" (as defined in Schedule II) who is hired or rehire on or after January 1, 2014.

G. any Employee employed in the position of Damage Prevention Coordinator who was a Next Gen Employee under the Plan immediately prior to June 1, 2016, or, if later, immediately prior to becoming employed in the position of Damage Prevention Coordinator. Effective as of May 1, 2019, Employees employed in the position of Damage Prevention Coordinator shall no longer be considered Next Gen Employees for Plan purposes, unless otherwise negotiated in an agreement between the bargaining unit and the Company.

Section 1.39 Next Gen Employer Contribution Account. That portion of a Participant's Account credited with Next Gen Employer Contributions under Sections 3.06 and 3.07, and adjustments relating thereto.

Section 1.40 NIFL. Northern Indiana Fuel & Light Company, or any successor(s). Effective July 1, 2011, NIFL merged with and into NIPSCO (see "NIPSCO" and "NIPSCO Union Employee" for further details).

Section 1.41 NIFL Union Employee. An Employee who was employed by NIFL immediately prior to the merger of NIFL into NIPSCO effective July 1, 2011, whose compensation, conditions of employment or position are covered by a collective bargaining agreement which called for the Employee's participation in the Plan. After the July 1, 2011 merger, the separate NIFL bargaining unit no longer existed and NIFL Union Employees became NIPSCO Union Employees. However, see the definition of NIPSCO Union Employee for limitation of this characterization for purposes of the Plan.

Section 1.42 NIPSCO. Northern Indiana Public Service Company, or any successor(s). With reference to NIPSCO Union Employees and the NIPSCO 401(k) Plan, "NIPSCO" shall also include NiSource Inc. and any Related Employer that adopts the NIPSCO 401(k) Plan.

Effective July 1, 2011, NIFL and Kokomo merged with and into NIPSCO. References to "NIFL" and "Kokomo" shall continue to apply to the extent that employees employed by NIFL or Kokomo immediately prior to the merger remain subject to the pension plan provisions of either the Subsidiary Plan or the Kokomo Union Pension Plan. Effective December 31, 2012, the Subsidiary Pension Plan and the Kokomo Union Pension Plan merged into the NiSource Salaried Pension Plan and the NIP SCO Union Pension Plan (as applicable). On and after such date, NIFL Union Employees and Kokomo Union Employees became subject to the provisions of NIPSCO Union Pension Plan, while non-union employees who were employees of NIFL and Kokomo immediate prior to July 1, 2011 became subject to the provisions of the NiSource Salaried Pension Plan.

Section 1.43 NIPSCO 401(k) Plan. The Northern Indiana Public Service Company Bargaining Unit Tax Deferred Savings Plan, which merged into the Plan effective December 31, 2008.

Section 1.44 NIPSCO Union Employee. An Eligible Employee of NIPSCO, whose terms and conditions of employment are governed by a collective bargaining agreement to which NIPSCO is a party and which agreement calls for the Employee's participation in the Plan (or prior to December 31, 2008, in the NIPSCO 401(k) Plan).

Notwithstanding the foregoing, any Eligible Employee who was an employee of Kokomo or NIFL as of June 30, 2011 and transitioned to employment with NIPSCO as part of the July 1, 2011 merger of Kokomo and NIFL with and into NIPSCO shall not be considered a NIPSCO Union Employee for purposes of the Plan to the extent that pension plan provisions applicable to such NIPSCO employees who are former NIFL Union Employees or former Kokomo Union Employees remain in effect and consequently cause the matching contribution benefit structures under the of the Plan to remain unchanged for such employees. Effective December 31, 2012, the Subsidiary Pension Plan and the Kokomo Union Pension Plan merged into the NIPSCO Union Pension Plan; however the provisions of the Subsidiary Pension Plan or Kokomo Union Pension Plan as applicable to NIFL Union Employees or Kokomo Union Employees, respectively, immediately prior to the merger of such entities into NIPSCO effective July 1, 2011 continue to remain in effect under the NIPSCO Pension Plan on and after December 31, 2012 and, accordingly the matching contribution structures for such employees remain unchanged, except in instances where an employee's pension benefit structure changed, such as moving from the AB II Benefit structure to the AB I Benefit structure. Stated otherwise, for purposes of Matching Contributions under the Plan, such former NIFL Union Employees and Kokomo Union Employees are not considered NIPSCO Union Employees.

In addition, solely for purposes of the Plan and employer contributions accruing hereunder, any Employee employed in the position of Damage Prevention Coordinator shall not be considered a NIPSCO Union Employee unless such Employee was considered a NIPSCO Union Employee immediately prior to June 1, 2016, or if later, immediately prior to becoming employed in the position of Damage Prevention Coordinator. Effective as of May 1, 2019, Employees employed in the position of Damage Prevention Coordinator shall be considered NIPSCO Union Employees for Plan purposes, unless otherwise negotiated in an agreement between the bargaining unit and the Company.

Section 1.45 NIPSCO Union Pension Plan. The NIPSCO Union Pension Plan (f/k/a the NiSource Inc. and Northern Indiana Public Service Company Pension Plan Provisions Pertaining to Bargaining Unit Employees), or any successor plan (as defined therein).

Section 1.46 NiSource Pension Plans. Effective after December 31, 2012, the NiSource Salaried Pension Plan, the Columbia Pension Plan, the Bay State Pension Plan, the Bay State Union Plan, and the NIPSCO Union Pension Plan, (individually and/or collectively, as the context requires).

Section 1.47 NiSource Salaried Pension Plan. The NiSource Salaried Pension Plan (f/k/a the NiSource Inc. and Northern Indiana Public Service Company Pension Plan Provisions Pertaining to Salaried and Non-Exempt Employees), or any successor plan (as defined therein).

Section 1.48 Non-highly Compensated Employee. Any Eligible Employee who is not a Highly Compensated Employee.

Section 1.49 Participant. An Eligible Employee who becomes a Participant in accordance with the provisions of Article II. An Eligible Employee who becomes a Participant shall remain a Participant or Former Participant under the Plan until the Trustee has fully distributed the vested amount standing in his Account to him.

Section 1.50 Period of Service. The period of Service commencing on an Employee's Employment Commencement Date or Re-employment Commencement Date, whichever is applicable, and ending on the date his employment ends. Employment ends on the date the Employee quits, is discharged, retires or dies or (if earlier) the first anniversary of his absence for any other reason. The period of absence starting with the date an Employee's employment ends and ending on the date he next performs an hour of Service is (a) included in his Period of Employment if the period of absence does not exceed one year, and (b) excluded if such period exceeds one year

Section 1.51 Plan. The plan designated as the NiSource Inc. Retirement Savings Plan and sponsored by the Company, as set forth herein or in any amendments hereto.

Section 1.52 Plan 2006 Restatement. The amended and restated document for the Plan effective January 1, 2006.

Section 1.53 Plan Administrator. The Committee, or such delegate of the Committee designated to carry out the administrative functions of the Plan.

Section 1.54 Plan Sponsor. The Company is designated the sponsor of the Plan.

Section 1.55 Plan Year. The fiscal year of the Plan, a 12 consecutive month period commencing on January 1 and ending on December 31.

Section 1.56 Pre-tax Contribution Account. That portion of a Participant's Account credited with Pre-tax Contributions under Section 3.02, and adjustments relating thereto.

Section 1.57 Profit Sharing Account. That portion of a Participant's Account credited with Profit Sharing Contributions under Sections 3.06 and 3.07, and adjustments relating thereto.

Section 1.58 Reemployment Commencement Date. The date upon which an Employee first performs an hour of Service for the Employer following a break in Service.

Section 1.59 Related Employers. A controlled group of corporations (as defined in Code Section 414(b)) that includes the Company; trades or business (whether or not incorporated) which are under common control (as defined in Code Section 414(c)) with the Company; or an affiliated service group (as defined in Code Sections 414(m) and (o)) that includes the Company. If the Employer is a member of a group of Related Employers, the term "Employer" includes the Related Employers as required by the Code or by the Plan, including for purposes of crediting service, applying the coverage test of Code Section 410(b), applying the limitations of Article VII, applying the Top Heavy rules and the minimum benefit requirements of Article XI, the definitions of Employee, Highly Compensated Employee, Compensation, and Leased Employee contained in this Article I. However, only an Employer

as defined in this Article may contribute to the Plan, and only an Eligible Employee as defined in this Article is eligible to participate in this Plan.

Section 1.60 Required Beginning Date. For purposes of Article IV, for any Participant who is not a Five-percent Owner (as defined in Code Section 416(i)), the Required Beginning Date is the April 1 of the calendar year following the later of the calendar year in which the Participant (i) attains age $70^{1/2}$, or (ii) terminates employment with the Employer. For any Participant who is at least a Five-percent Owner (as defined in Code Section 416(i)), the Required Beginning Date is the April 1 immediately following the calendar year in which the Participant attains age $70^{1/2}$, regardless of whether the Participant has retired.

Section 1.61 Rollover Account. That portion of a Participant's Account credited with Rollover Contributions under Section 3.09, and adjustments relating thereto.

Section 1.62 Roth Contribution Account. That portion of a Participant's Account credited with Roth Contributions under section 3.02D, and adjustments relating thereto.

Section 1.63 Service. Any period of time the Employee is in the employ of the Employer, whether before or after adoption of the Plan, determined in accordance with reasonable and uniform standards and policies adopted by the Plan Administrator, which standards and policies shall be consistently observed.

Section 1.64 Severance from Employment. A termination of employment occurring when an Employee ceases to be an Employee of the Employer maintaining the Plan. An Employee does not have a "Severance from Employment" if, in connection with a change of employment, the Employee's new employer maintains the Plan with respect to the Employee.

Section 1.65 Spouse. The lawfully married spouse of the Participant as recognized under applicable law.

Section 1.66 Subsidiary Pension Plan. The NiSource Subsidiary Pension Plan, or any successor plan (as defined therein). Effective December 31, 2012, the Subsidiary Pension Plan merged with and into the NiSource Salaried Pension Plan and the NIPSCO Union Pension Plan (as applicable).

Section 1.67 Transfer Account. That portion of a Participant's Account credited with Transfer Contributions under Section 3.09, and adjustments relating thereto.

Section 1.68 Treasury Regulations. Regulations promulgated under the Internal Revenue Code by the Secretary of the Treasury.

Section 1.69 Trust. The trust maintained in accordance with Article VIII from which benefits provided under the Plan will be paid.

Section 1.70 Trust Agreement. The agreement establishing and maintaining the Trust, as provided for in Article VIII, as the same may be amended from time to time.

Section 1.71 Trust Fund. All property of every kind held or acquired by a Trustee under the Trust Agreement established pursuant to Section 8.01.

Section 1.72 Trustee(s). The individual(s) and/or entity or entities appointed to administer and maintain the Trust in accordance with Article VIII.

Section 1.73 Valuation Date. Each day on which Company Stock is available to be publicly traded.

Section 1.74 Terms Defined Elsewhere.

Actual Contribution Percentage....Section 6.01
Actual Deferral Percentage....Section 6.01
After-tax Contributions....Section 3.02
Annual Additions....Section 7.02
Cash-out Distribution....Section 4.03
Catch-up Contributions....Section 3.02
Claimant....Section 9.09
Determination Date....Section 11.06
Direct Rollover....Section 5.07

ARTICLE II
ELIGIBILITY AND PARTICIPATION

Section 2.01 Eligibility. Each Eligible Employee shall be eligible to become a Participant in the Plan. Each Eligible Employee who was a Participant in the Plan on the day before the Effective Date of this restated Plan shall continue as a Participant in this Plan as restated. An Eligible Employee shall become a Participant effective upon such Eligible Employee's Employment Commencement Date.

A. Enrollment Generally. As soon as administratively practicable, the Plan Administrator shall notify each Eligible Employee that he is eligible to make contributions to the Plan and shall explain the rights, privileges and duties of a Participant in the Plan. Each Eligible Employee may enroll as a Participant in the Pre-tax Contributions, Roth Contributions or the After-tax Contributions portions of the Plan at any time and as soon as administratively practicable on or after his date of hire, by properly completing the enrollment procedures established at the time by the Plan Administrator, or by following such other reasonable procedures as the Plan Administrator may implement. The Plan Administrator may establish rules and procedures governing the time and manner in which enrollments shall be processed.

B. Automatic Enrollment; Notice of Participation. Except as provided herein, all Eligible Employees hired or rehired on or after the Effective Date shall be subject to the automatic enrollment and notice provisions of this subsection B. Notwithstanding the foregoing, the provisions of this subsection B shall not apply to Kokomo Union Employees hired before March 1, 2009, and NIPSCO Union Employees hired before June 1, 2009, who shall instead be subject to the general enrollment provisions set forth in Section 2.01A. In addition, the provisions of this subsection B shall be modified as set forth in Schedule II for Bay State Union Employees (i.e., this subsection applies with varied effective dates for different Bay State Union Employee groups and applies uniformly to all Bay State Union Employees hired on or after January 1, 2014). Pursuant to the provisions of this subsection B, an Eligible Employee shall be automatically enrolled in the Plan as of the first pay period following 30 days after his Employment Commencement Date (or Reemployment Commencement Date). Such Eligible Employee shall be deemed to have elected to contribute the percentage of his Compensation identified below in this subsection as a Pre-tax Contribution (the "Automatic Percentage Amount") in accordance with Section 3.02A of the Plan, unless the Eligible Employee elects to contribute a different percentage of his Compensation or affirmatively elects not to contribute any portion of his Compensation.

(i) For any Eligible Employee hired or rehired on or after January 1, 2008, but before January 1, 2014, the Automatic Percentage Amount shall be 3% of Compensation, subject to the provisions of any applicable collective bargaining agreements.

(ii) For any non-union Eligible Employee hired or rehired on or after January 1, 2014, but before January 1, 2015, the Automatic Percentage Amount shall be 4% of Compensation.

(iii) For any non-union Eligible Employee hired or rehired on or after January 1, 2015, or any NIPSCO Union Employee hired or rehired on or after January 1, 2015, the Automatic Percentage Amount shall be 6% of Compensation, subject to the provisions of any applicable collective bargaining agreements.

(iv) For any Columbia Union Employee hired or rehired on or after July 1, 2018, the Automatic Percentage Amount shall be 6% of Compensation.

By his participation, the Participant shall be deemed to have agreed to abide by the provisions of the Plan. Unless otherwise provided above, the Automatic Percentage Amounts for Bay State Union Employees and NIPSCO Union Employees, and the effective dates thereof, are provided in Schedule II and Schedule III, respectively.

C. Notice. Within a reasonable time (generally 30 to 90 days before each Plan Year, or, in the case of a newly eligible Participant, within the 90 days prior to and including the date of eligibility), the Plan Administrator shall give each Participant that will be or is enrolled in the Plan pursuant to this Section 3.01B a written notice of the Participant's rights and obligations under the Plan's automatic enrollment provisions in accordance with the provisions of Treasury Regulation Section 1.414(w)-1 and subsequent guidance. Such notice generally shall include a description of the following: (i) the circumstances of automatic deferrals; (ii) the Participant's Automatic Percentage Amount; (iii) the Participant's right to make a contrary deferral election as provided in Section 3.02 of the Plan; (iv) how contributions will be invested in the absence of any investment election by the Participant; (v) any Company contributions made on behalf of the Participant; and (vi) the Plan's withdrawal and vesting provisions.

Any contributions pursuant to this automatic enrollment provision shall be reduced or stopped to meet the limitations under Code Sections 401(a)(17), 402(g) and 415 and to satisfy any suspension period required after a hardship distribution as described in Section 5.05.

Section 2.02 Participation Upon Re-Employment. Except as provided in Schedule II, an Eligible Employee who was a Participant shall again become a Participant on his Reemployment Commencement Date.

Section 2.03 Transfers Between Employers. For eligibility purposes, a Participant who transfers employment from one Employer to another Employer shall continue to be eligible to participate in the Plan if such Participant previously met the requirements of Section 2.01. In accordance with the Plan and Code, an Eligible Employee shall continue to be an Eligible Employee following a transfer between Employers as if such Eligible Employee had performed all Service during the Plan Year for the Employer to which the Eligible Employee last transferred.

Section 2.04 Changes in Participant's Job Classification. A Participant who transfers to a classification of Employee that causes him to cease to meet the definition of Eligible Employee, or who is granted a leave of absence or placed on inactive status by an Employer, shall not be deemed to have terminated employment and shall not be entitled to a distribution based upon a Severance from Employment. While such Participant is employed by an Employer but not as an Eligible Employee, or is on an unpaid leave of absence or in inactive status, neither the Participant nor an Employer on his behalf shall make contributions to the Plan other than Rollover Contributions pursuant to Section 3.09. If the Participant is later employed by an Employer, transfers to a classification of Employee which is eligible to participate in the Plan, returns to employment immediately upon expiration of a leave of absence, or is restored to active status, contributions to the Participant's account may resume under all applicable Plan provisions.

Section 2.05 Termination Of Participation. Subject to the provisions of Sections 2.02 and 2.04, an Employee who becomes a Participant shall remain a Participant until he or his Beneficiary is paid his entire Account Balance following his Severance Date.

ARTICLE III
CONTRIBUTIONS

Section 3.01 Individual Accounts. The Plan Administrator, or, if the Plan Administrator so determines, the Trustee, shall maintain an Account for each Participant and Former Participant having an amount to his credit in the Trust Fund. Each Account may be divided into separate subaccounts to the extent necessary to reflect different kinds of contributions, including "Pre-tax Contributions," "Roth Contributions," "Catch-up Contributions," "After-tax Contributions," "Matching Contributions," "Profit Sharing Contributions," "Next Gen Employer Contributions" and "Prior Profit Sharing Contributions, " as defined below. If a Participant has made a "Rollover Contribution" or "Transfer Contribution," as defined below, separate subaccounts shall be established for such contributions as well. The Plan Administrator will make its allocations, or request the Trustee to make its allocations, to the Accounts of the Participants in accordance with the provisions of Section 8.02. The Plan Administrator may direct the Trustee to maintain a temporary segregated investment Account in the name of a Participant to prevent a distortion of income, gain, or loss allocations under Section 8.02. The Plan Administrator shall ensure that records are maintained for all Account allocations and related recordkeeping activities.

Section 3.02 Participant Contributions.

A. Pre-tax Contributions. A Participant may elect to have his Employer make "Pre-tax Contributions" to the Trust on his behalf by following any deferral election procedures established pursuant to Section 3.03. Alternatively, in accordance with the automatic enrollment provisions of Section 2.01B, an Employer may make Pre-tax Contributions to the Trust on an automatic basis without the affirmative election of the Participant. The amount of Pre-tax Contributions that may be made on behalf of a Participant for any designated period shall be deducted from his Compensation and shall equal: (i) such whole percentage of his Compensation, in a range of 1% to 50%, as designated by the Participant in the salary reduction agreement; or (ii) if automatically enrolled pursuant to Section 2.01B, the Automatic Percentage Amount specified therein. For each calendar year or other taxable year of any Participant, each such Participant's Pre-tax contribution shall not exceed $18,500 in 2018 (or such other dollar amount as the Commissioner of Internal Revenue may subsequently prescribe in accordance with Code Section 402(g)(5)). The Employer shall not make a Pre-tax Contribution to the Trust to the extent that the Contribution would exceed the Participant's "Maximum Permissible Amount" as defined under Section 7.02.

B. Catch-up Contributions. An Employee who is eligible to make Pre-tax Contributions or Roth Contributions under the Plan and who has attained age 50 before the close of the Employee's taxable year shall be eligible to make "Catch-up Contributions" of not less than 1% but not more than 50% of Compensation in accordance with and subject to the limitations of Code Section 414(v). Such Catch-up Contributions shall not be taken into account for purposes of the provisions of the Plan implementing the required limitations of Code Sections 402(g) and 415. The Plan shall not be treated as failing to satisfy the provisions of the Plan implementing the requirements of Code Section 401(k)(3), 401(k)(11), 401(k))(12), 410(b), or 416, as applicable, by reason of the making of such Catch-up Contributions. For each Plan Year, each Participant's Catch-up Contributions shall not exceed $6,000 in 2018 (or such other dollar amount as the Commissioner of Internal Revenue may prescribe in accordance with Code Section 414(v)(2)(B)). Catch-up Contributions may consist of Pre-tax Contributions and/or Roth Contributions at the Participant's election. No Matching Contributions shall be contributed with respect to any Catch-up Contributions elected or deemed to have been made by a Participant.

C. After-tax Contributions. For any Plan Year, each Participant shall be permitted to make contributions on an after-tax basis ("After-tax Contributions") to the Trust in whole percentages between 1% and 25% of the Participant's Compensation per pay period. All Participant After-tax Contribution elections shall be made at the time, in the manner, and subject to the conditions specified by the Plan Administrator, which shall prescribe uniform and nondiscriminatory rules for such elections. The Trustee will maintain a separate account for a Participant's After-tax Contributions to which all income, expenses, gains and losses attributable to such contributions will be allocated. The Plan Administrator may establish whatever further procedures it deems necessary to facilitate After-tax Contributions.

D. Roth Contributions. A Participant may elect to have his Employer make "Roth Contributions" to the Trust on his behalf by following the deferral election procedures established pursuant to Section 3.03. Roth Contributions shall be irrevocably designated as Roth Contributions by the Participant in lieu of all or a portion of the Pre-tax Contributions the Participant is eligible to make under Section 3.02A(i) and shall be subject to the Compensation percentage and dollar limitations of Section 3.02A(i). Roth Contributions shall be treated by the Employer as includible in the Participant's income at the time the Participant would have received the amount if not for the cash or deferred election to make the Roth Contributions. A Participant's Roth Contributions shall be allocated to the Roth Contribution Account, a separate account to which all income, expenses, gains and losses attributable to such contributions will be allocated. No contributions other than Roth Contributions and properly attributable earnings will be credited to a Participant's Roth Contribution Account.

Notwithstanding anything in the Plan to the contrary, the sum of a Participant's Pre-tax Contributions, Catch-up Contributions, Roth Contributions and After-tax Contributions shall not exceed 75% of such Participant's Compensation.

Section 3.03 Elections, Changes and Suspensions of Participant Contributions. A Participant's Compensation for a Plan Year shall be reduced by the amount of the allocation he elects for such Plan Year. All elections shall be made at the time, in the manner, and subject to the conditions specified by the Plan Administrator, which shall prescribe uniform and nondiscriminatory rules for such elections, and shall become effective as of the first pay period as is administratively practicable after the election is properly made.

A Participant may change the rate of Pre-tax Contributions (including Catch-up Contributions, if any), Roth Contributions or After-tax Contributions to his Account at any time during each Plan Year, effective for the first payroll period for which it is administratively feasible to change the rate of such Participant's Pre-tax Contributions (including Catch-up Contributions, if any), Roth Contributions or After-tax Contributions, by communicating such rate change in accordance with uniform rules and procedures established by the Plan Administrator regarding the timing and manner of making such elections. In addition, a Participant may at any time elect to suspend all contributions to his Account by giving advance notice in any manner specified by the Plan Administrator in accordance with its uniform rules and procedures. An election to recommence contributions shall be effective for the first payroll period in which it is administratively feasible to begin deferral withholdings. All suspensions and recommencements of Pre-tax Contributions (including Catch-up Contributions, if any), Roth Contributions or After-tax Contributions shall be made in the manner and at the times specified in uniform rules and procedures established by the Plan Administrator, which rules and procedures may be changed from time to time.

Section 3.04 Matching Contributions. For each payroll period or such other interval as established by the Plan Administrator, each Employer shall deposit a "Matching Contribution" to the Trust in an amount provided in Schedule I. The Matching Contributions shall be allocated and invested in accordance with the provisions of Section 3.05. The Employer shall not make a Matching Contribution to the Trust for any Participant to the extent that the contribution would exceed the Participant's "Maximum Permissible Amount" under Section 7.02.

Section 3.05 Matching Contribution Allocation and Accrual of Benefit. Only Participants who have made Pre-tax Contributions, Roth Contributions or certain After-tax Contributions during the payroll period (or such other established interval) shall be eligible to share in the allocation of the Matching Contribution as set forth in Section 3.04 and Schedule I. No Matching Contributions shall be made, however, with respect to Catch-up Contributions.

Effective for contributions made on or after July 1, 2017, all Matching contributions shall be invested in accordance with Section 8.07 of the Plan. For contributions made prior to July 1, 2017, all Matching Contributions were initially allocated to the Company Stock Fund, except as otherwise provided in Schedule II. All Matching Contributions shall be 100% vested and nonforfeitable at all times.

Section 3.06 Profit Sharing Contributions and Next Gen Employer Contributions. Except as provided in subparagraph C below, for each Plan Year, the Employer may contribute to the Trust amounts determined in its discretion. Such contributions will be in the form of "Profit Sharing Contributions" (previously designated "Profit Participation Contributions" in the Plan 2006 Restatement) as described in subparagraph A and B below. In addition, as provided in subparagraph C below, the Employer shall make the "Next Gen Employer Contribution" described therein.

A. Amount of Profit Sharing Contribution. The Profit Sharing Contribution made for a Plan Year shall be a stated percentage of the Compensation of the Participants entitled to receive allocations of such Profit Sharing Contribution for such Plan Year in accordance with the eligibility and allocation provisions set forth in Plan

Section 3.07. The applicable percentage for each Plan Year shall be designated by the Committee, in its discretion exercised on a non-discriminatory basis, no later than the last day of the first quarter of the Plan Year following the Plan Year for which such percentage is applicable. For purposes of this Section 3.06A, Compensation for a Plan Year shall be defined as determined under the Annual Incentive Plan of an Employer in effect for such Plan Year, reduced by any amounts deferred to a nonqualified plan maintained by an Employer, as described in the definition of Compensation in Article I of the Plan. In allocating a Profit Sharing Contribution to a Participant's Account, the Plan Administrator, subject to Section 11.01, shall take into account only Compensation paid to the Employee during the portion of the Plan Year during which the Employee was a Participant. In no event shall a Profit Sharing Contribution be made with respect to any Participant for any Plan Year to the extent such Profit Sharing Contribution would cause the limitations of Code Section 415 to be exceeded for such Participant for such Plan Year.

B. Prior Profit Sharing Contributions. Prior to January 1, 2002, the Employer contributed other amounts as Profit Sharing Contributions to Participants as described in the Plan 2006 Restatement. The provisions relating to these "Prior Profit Sharing Contributions" including rules and conditions for eligibility, allocation, vesting, forfeitures, and investments, apply as set forth in the Plan 2006 Restatement. The Plan Administrator and/or Trustee shall maintain a "Prior Profit Sharing Contributions Account" to the extent that such contributions require a subaccount that is separate from the Profit Sharing Account.

C. Next Gen Employer Contributions. Notwithstanding the foregoing, the Employer shall contribute each pay period to the Account of each Participant who is both an Eligible Employee and a Next Gen Employee at such time an amount equal to 3% of such Participant's total Compensation for that pay period (as defined in Article I). Such contribution shall be a "Next Gen Employer Contribution." This amount shall be payable to applicable Participants regardless of whether such Participants have elected to make Pre-Tax Contributions, Roth Contributions or any other elective deferrals to the Plan and regardless of the Participants' status as of the end of the Plan Year. As provided in Section 3.07B, this Next Gen Employer Contribution shall be invested in accordance with Section 8.07 of the Plan and shall be 100% vested and nonforfeitable at all times. Eligibility for a Next Gen Employer Contribution under this subparagraph C shall not preclude eligibility for any other Profit Sharing Contribution under the terms contained herein.

Any Employee employed in the position of Damage Prevention Coordinator who was a Next Gen Employee immediately prior to becoming employed in the position of Damage Prevention Coordinator shall remain a Next Gen Employee for purposes of Next Gen Contributions described in this subparagraph for the duration of his employment in such position during the period from June 1, 2016 to April 30, 2019. For any new hire during this period into the position of Damage Prevention Coordinator, Next Gen Contributions shall apply. Any Next Gen Employer Contributions made to such Damage Prevention Coordinators during this period shall be invested as contributions for union Participants are invested in accordance with Section 8.07 of the Plan, as amended. Effective as of May 1, 2019, the date on which Employees employed in the position of Damage Prevention Coordinator shall become NIPSCO Union Employees for all Plan purposes, Plan provisions regarding Next Gen Contributions shall not apply to Employees in the position of Damage Prevention Coordinator, unless otherwise negotiated in an agreement between the bargaining unit and the Company.

Section 3.07 Profit Sharing and Next Gen Employer Contribution Allocation / Investment.

A. Eligibility and Accrual. Each Eligible Employee meeting the allocation requirements of this Section is entitled to participate in Profit Sharing Contributions; provided, however, that if an Eligible Employee is subject to a collective bargaining agreement, such agreement must provide that the Employee is eligible for Profit Sharing Contributions. For Profit Sharing Contributions other than those Next Gen Employer Contributions described in Section 3.06C, the Plan Administrator shall determine the accrual of a Profit Sharing Participant's benefit on the basis of the Plan Year. Although contributions may be made at other times (and therefore credited to Accounts at such other times), the Participant's status as of the end of the Plan Year for which the contribution is made shall determine his entitlement to share in an allocation of such contribution, regardless of when credited to his Account. For Profit Sharing Contributions other than Next Gen Employer Contributions described in Section 3.06C, the Plan Administrator shall not allocate any portion of a Profit Sharing Contribution for a Plan Year to the Account of any Participant, if such Participant is not employed by the Employer on the last day of that Plan Year (for a reason other than retirement, Disability, or death). The Plan shall suspend the accrual requirement described herein in accordance with the procedures described under subparagraphs (i) through (vii) of this Section 3.07A if the Plan fails to satisfy the requirements of Code Section 410(b). Notwithstanding any other provision to the contrary, a Profit Sharing Contribution or Next Gen Employer Contribution shall not be allocated to a Participant's Account to the extent the contribution would exceed the Participant's "Maximum Permissible Amount" under Section 7.02. The procedure for suspending the accrual requirement for purposes of satisfying the requirements of Code Section 410(b) are as follows:

(i) The Committee will identify the termination date for each Participant who terminated employment with the Employer during the Plan Year. The Committee shall then designate as "Includable Employees" all such Participants.

(ii) The Committee will suspend the accrual requirements for Includable Employees who are Participants, beginning first with the Includable Employee(s) employed with the Employer on the next to last day of the Plan Year.

(iii) If the Plan does not satisfy the ratio percentage test under Code Section 410(b)(1) once the accrual requirements for the individuals identified in Subsection (b) above are suspended, the Committee shall suspend the accrual requirements for the Includable Employee(s) who have the next latest termination of employment date during the Plan Year, and continuing to suspend in descending order the accrual requirements for each Includable Employee who terminated employment, from the latest to the earliest termination date, until the Plan satisfies the ratio percentage test under Code Section 410(b)(1) for the Plan Year.

(iv) If two or more Includable Employees terminated employment on the same day, the Committee will suspend the accrual requirements for all such Includable Employees, irrespective of whether the Plan can satisfy the ratio percentage test under Code Section 410(b)(1) by accruing benefits for fewer than all such Includable Employees.

(v) If the Plan suspends the accrual requirements for an Includable Employee, that Employee will share in the allocation of Employer contributions and Forfeitures, if any, without regard to whether he is employed by the Employer on the last day of the Plan Year.

(vi) For purposes of the ratio percentage test under Code Section 410(b)(1), an Employee is benefiting under the Plan on a particular date if he or she is entitled to an allocation for the Plan Year under this Section or as otherwise provided under applicable Treasury Regulations.

B. Allocation, Investment and Vesting. Subject to Article XI and except as provided for contributions described under Section 3.06C, the Plan Administrator shall allocate and credit to the Account of each Participant who satisfies the conditions of Section 3.07A a percentage of the annual Profit Sharing Contribution in the ratio that the sum of the Participant's total Compensation for the Plan Year bears to the sum of all such Participants' total Compensation for the Plan Year. Effective for contributions made on or after July 1, 2017, all Profit Sharing Contributions, including Next Gen Employer Contributions under Section 3.06C, shall be invested in accordance with Section 8.07 of the Plan. For contributions made prior to July 1, 2017, all Profit Sharing Contributions, including Next Gen Employer Contributions were initially allocated to the Company Stock Fund. All Profit Sharing Contributions, including Next Gen Employer Contributions under Section 3.06C, shall be 100% vested and nonforfeitable at all times.

Section 3.08 Time and Form of Payment of Contribution. The Employer may pay its contribution for each Plan Year in one or more installment payments without interest. In the discretion of the Committee, such payments may be made to the Plan in the form of cash or Company Stock. The Employer must make its contribution which Participants have elected to defer under Section 3.02 as soon as such amounts may reasonably be segregated from the Employer's general assets, but in no event later than 15 business days after the end of the calendar month in which such amounts were withheld from the Participant's Compensation, or such later time as may be permitted by regulations under ERISA and Code Section 401(k). The Employer must make the balance, if any, of its contribution to the Trustee within the time prescribed (including extensions) for filing its tax return for the taxable year for which it claims a deduction for its contribution, in accordance with Code Section 404(a)(6).

Section 3.09 Rollover and Transfer Contributions. The Trustee is authorized to accept and hold as part of the Trust Fund, assets transferred on behalf of an Employee, provided that such transfer satisfied any procedures or other requirements established by the Plan Administrator. The Trustee shall also accept and hold as part of the Trust Fund assets transferred in connection with a merger or consolidation of another plan with or into the Plan pursuant to Section 14.05 hereof and as may be approved by the Committee. In addition, the Trustee shall also accept "rollover" amounts (other than amounts attributable to after-tax contributions and earnings thereon) contributed directly by or on behalf of an Employee in accordance with procedures and rules established by the Plan Administrator in respect of a distribution made to or on behalf of such Employee from another plan pursuant to Section 14.05 hereof. All amounts so transferred to the Trust Fund shall be held in segregated subaccounts and shall be referred to as "Transfer Contributions" if such amounts are subject to the special distribution rules described in Section 14.05 and as "Rollover Contributions" if not subject to such rules. Rollover Contributions must conform to rules and procedures established by the Plan Administrator, including rules designed to assure the Plan Administrator that the funds so transferred qualify as a Rollover Contribution under the Code, including the rules specified in Section 5.07D herein.

Section 3.10 Return of Contributions. All contributions to the Plan are conditioned upon their deductibility under the Code. The Trustee, upon written request from the Plan Administrator, shall return to the Employer the amount of the Employer's contribution made by the Employer by mistake of fact or the amount of the Employer's contribution disallowed as a deduction under Code Section 404. The Trustee shall not return any portion of the Employer's contribution under this provision more than one year after:

A. The Employer made the contribution by mistake of fact; or

B. The disallowance of the contribution as a deduction, and then, only to the extent of the disallowance.

The Trustee shall not increase the amount of the Employer contribution returnable under this Section for any earnings attributable to the contribution, but the Trustee shall decrease the Employer contribution returnable for any losses attributable to it. The Trustee may require the Employer to furnish it whatever evidence the Trustee deems necessary to enable the Trustee to confirm the amount the Employer has requested be returned is properly returnable under ERISA.

ARTICLE IV
VESTING; TIME AND METHOD OF PAYMENT OF BENEFITS

Section 4.01 Vested Benefit. A Participant's interest in his Account shall at all times be fully vested and nonforfeitable.

Section 4.02 Distribution Upon Severance From Employment, Disability or Death. Upon a Participant's Severance from Employment, Disability or death, the Participant (or in the event of death, the Beneficiary) shall be entitled to receive the Participant's entire Account Balance (reduced by any amount attributable to an outstanding loan made by the Participant pursuant to Section 5.08) in accordance with the provisions of this Article IV.

Section 4.03 Payment Timing. Upon Severance from Employment before age 65, the Trustee shall, subject to the consent requirements described in this Section, distribute the Participant's Account Balance as set forth below. For purposes of the distribution timing rules, a "Cash-out Distribution" is a lump sum distribution of the Participant's Account Balance.

A. Timing Based on Account Balance Amount.

(i) If the Participant's Account Balance on the date the distribution commences is \$1,000 or less, the Trustee shall pay such Account Balance to the Participant in the form of a single, lump sum Cash-out Distribution as soon as administratively practicable after the Participant's Severance from Employment.

(ii) If the Participant's Account Balance on the date the distribution commences is more than \$1,000 but less than \$5,000, any distribution shall be automatically rolled over to an individual retirement account in the name of the Participant in accordance with Code Section 401(a)(31)(B)(i) and related regulations, unless the Participant otherwise consents to the distributions. For purposes of applying the rollover provisions of this subparagraph (ii) to an Account Balance consisting at least in part of a Roth Contribution Account, the amount of the Roth Contribution Account may be considered separately from the non-Roth portions of the Participant's Account Balance for the sole purpose of determining whether such Roth Contribution Account shall be automatically rolled over to an individual retirement account under this subparagraph (ii) or paid to the Participant in the form of a single lump-sum distribution under subparagraph (i) above.

(iii) If the Participant's Account Balance on the date the distribution commences is greater than \$5,000, such distribution shall be deferred until the Participant consents to the distribution (but no later than the Participant's Required Beginning Date).

B. Deferral of Distribution. If the Participant does not file his written consent (if required) with the Trustee within the reasonable period of time stated in the consent form, the Trustee shall continue to hold the Participant's Account in trust until the Participant files an application for distribution with the Plan Administrator. At that time, the Trustee shall commence payment of the Participant's Account in accordance with the provisions of this Article IV; provided, however, if the Participant dies after terminating employment but prior to attaining age 65, the Plan Administrator, upon notice of the death and application for benefits filed by the Beneficiary, shall direct the Trustee to commence payment of the Participant's Account to his Beneficiary in accordance with the provisions of Section 4.05.

C. Consent Requirements. The Participant must consent in writing to the Plan Administrator's direction to the Trustee to make a distribution to the Participant and to the form of the distribution if: (i) the Participant's Account Balance on the date the distribution commences exceeds $1,000, and (ii) the Plan Administrator directs the Trustee to make a distribution to the Participant prior to his attaining age 65.

The Plan Administrator shall notify the Participant of the right to defer any distribution until the Participant's Account Balance is no longer immediately distributable. The description of a Participant's right to defer receipt of a distribution will describe the consequences of failing to defer receipt, as required by regulations under Code Section 411(a)(11). Such notice shall be provided no less than 30 days and no more than 180 days prior to the date of distribution. However, if the Participant, after having received this notice, affirmatively elects a distribution, such distribution may commence less than 30 days after the notice was provided.

The consent of the Participant shall not be required to the extent that a distribution is required to satisfy Code Section 401(a)(9) or Code Section 415. An Account balance is immediately distributable if any part of the Account balance could be distributed to the Participant (or the surviving Spouse) before the Participant attains, or would have attained if not deceased, age 65.

D. Minimum Legal Distribution Requirements. Unless the Participant elects otherwise in writing, the Participant's Account Balance shall be distributed not later than 60 days after the close of the Plan Year in which the later of the following events occurs:

(i) The date the Participant attains age 65; or

(ii) The date the Participant dies, becomes disabled, or otherwise terminates Service (employment) with the Employer.

In no event shall the distribution commence, nor shall the Participant elect to have distribution commence, later than the Required Beginning Date.

Furthermore, once distributions have begun to a Five-percent Owner (as defined in Code Section 416(i)), they must continue to be distributed, even if the Participant ceases to be a Five-percent Owner in a subsequent year.

In no event shall the payment commence later than the time prescribed by this Article IV or in a form not permitted under Article IV. The Plan Administrator shall make its determinations under this Article IV in a nondiscriminatory, consistent and uniform manner. The Participant shall be provided with the appropriate form to consent to the distribution direction, if required.

Section 4.04 Form of Benefit Payment. A Participant shall receive payment of his Account Balance in one of the following forms:

A. In a single lump sum payment in cash, or if elected by the Participant or Beneficiary, in shares of stock held in the Company Stock Fund or any other stock fund maintained under the Plan based on the number of whole shares allocated to the Company Stock Fund or other stock fund for the Participant; or

B. In a partial lump sum payment in cash or, if elected by the Participant or Beneficiary, in shares of Company Stock or any other stock fund maintained under the Plan, with the remainder of the Account paid later as elected by the Participant pursuant to this Section.

C. In annual, semi-annual, quarterly, or monthly installments, on an equal or decrementing counter basis.

Notwithstanding the preceding provisions of this Section, unless the Participant otherwise elects, the distribution of the balance in his Account invested in the Company Stock Fund shall be in substantially equal annual or more frequent payments over a period not longer than the greater of five years, or in the case of the Participant whose balance in the portion of his Account invested in the Company Stock Fund exceeds $1,105,000, five years plus one additional year (but not more than five additional years) for each $220,000 or fraction thereof by which such balance exceeds $1,105,000, as adjusted pursuant to Code Section 409(o)(2).

Section 4.05 Distributions Upon Death. Upon the death of the Participant, the Participant's Account Balance shall be paid in accordance with Code Section 401(a)(9) and Plan Sections 4.03 and 4.04.

If a Participant dies while performing qualified military service (as defined in Code Section 414(u)), the survivors of the Participant are entitled to any additional benefits (other than benefit accruals relating to the period of qualified military service) provided under the Plan as if the Participant had resumed and then terminated employment on account of death.

Section 4.06 Required Minimum Distributions. The Participant's Account Balance shall be distributed, as of the Required Beginning Date, in accordance with the minimum distribution requirements established by Code Section 401(a)(9) and the applicable Treasury Regulations thereunder.

A. Definitions. For purposes of this Section 4.06, the following definitions shall apply:

"Designated Beneficiary" is the individual who is designated as the beneficiary under the Plan and is the Designated Beneficiary under Code Section 401(a)(9) and Section 1.401(a)(9)-1, Q&A-4 of the Treasury Regulations.

"Distribution Calendar Year" is a calendar year for which a minimum distribution is required. For distributions beginning before the Participant's death, the first Distribution Calendar Year is the calendar year immediately preceding the calendar year which contains the Participant's Required Beginning Date. For distributions beginning after the Participant's death, the first Distribution Calendar Year is the calendar year in which the distributions are required to begin. The required minimum distribution for the Participant's first Distribution Calendar Year will be made on or before the Participant's Required Beginning Date. The required minimum distribution for other Distribution Calendar Years, including the required minimum distribution for the Distribution Calendar Year in which the Participant's Required Beginning Date occurs, will be made on or before December 31 of that Distribution Calendar Year.

"Life Expectancy" is a beneficiary's life expectancy as computed by use of the Single Life Table in Section 1.401(a)(9)-9 of the Treasury Regulations.

"Participant's Account Balance" is the Account Balance as of the last valuation date in the calendar year immediately preceding the Distribution Calendar Year (the "Valuation Calendar Year") increased by the amount of any contributions made and allocated or forfeitures allocated to the Account Balance as of dates in the Valuation Calendar Year after the valuation date and decreased by distributions made in the Valuation Calendar Year after the valuation date. The Account Balance for the Valuation Calendar Year includes any amounts rolled over or transferred to the Plan either in the Valuation Calendar Year or in the Distribution Calendar Year if distributed or transferred in the Valuation Calendar Year.

B. Time And Manner of Distribution.

(i) Required Beginning Date. The Participant's entire interest will be distributed, or begin to be distributed, to the Participant no later than the Participant's Required Beginning Date.

(ii) Death of Participant Before Distributions Begin. Subject to the provisions of Section 4.06E, if the Participant dies before distributions begin, the Participant's entire interest will be distributed, or begin to be distributed, no later than as follows:

a. If the Participant's surviving Spouse is the Participant's sole Designated Beneficiary, then, except as provided herein, distributions to the surviving Spouse will begin by December 31 of the calendar year immediately following the calendar year in which the Participant died, or by December 31 of the calendar year in which the Participant would have attained age 70½ , if later.

b. If the Participant's surviving Spouse is not the Participant's sole Designated Beneficiary, then, except as provided herein, distributions to the Designated Beneficiary will begin by December 31 of the calendar year immediately following the calendar year in which the Participant died.

c. If there is no Designated Beneficiary as of September 30 of the year following the year of the Participant's death, the Participant's entire interest will be distributed by December 31 of the calendar year containing the fifth anniversary of the Participant's death.

d. If the Participant's surviving Spouse is the Participant's sole Designated Beneficiary and the surviving Spouse dies after the Participant but before distributions to the surviving Spouse begin, this Section 4.06B(ii), other than subsection a, above, will apply as if the surviving Spouse were the Participant.

For purposes of this Section 4.06B(ii) and Section 4.06D, unless subsection d, above applies, distributions are considered to begin on the Participant's Required Beginning Date. If subsection d applies, distributions are considered to begin on the date distributions are required to begin to the surviving Spouse under subsection a, above. If distributions under an annuity purchased from an insurance company irrevocably commence to the Participant before the Participant's Required Beginning Date (or to the Participant's surviving Spouse before the date distributions are required to begin to the surviving Spouse under subsection a, above), the date distributions are considered to begin is the date distributions actually commence.

(iii) Forms of Distribution. Unless the Participant's interest is distributed in the form of an annuity purchased from an insurance company or in a single sum on or before the Required beginning Date, as of the first Distribution Calendar Year distributions will be made in accordance with Sections 4.06C and 4.06D. If the Participant's interest is distributed in the form of an annuity purchased from an insurance company, distributions thereunder will be made in accordance with Code Section 401(a)(9) and the Treasury Regulations.

C. Required Minimum Distributions During Participant's Lifetime.

(i) Amount of Required Minimum Distributions for Each Distribution Calendar Year. During the Participant's lifetime, the minimum amount that will be distributed for each Distribution Calendar Year is the lesser of:

a. the quotient obtained by dividing the Participant's Account Balance by the distribution period in the Uniform Lifetime Table set forth in Treasury Regulations Section 1.401(a)(9)-9, using the Participant's age as of the Participant's birthday in the Distribution Calendar Year; or

b. if the Participant's sole Designated Beneficiary for the Distribution Calendar Year is the Participant's Spouse, the quotient obtained by dividing the Participant's Account Balance by the number in the Joint and Last Survivor Table set forth in Treasury Regulations Section 1.401(a)(9)-9, using the Participant's and the Spouse's attained ages as of the Participant's and Spouse's birthdays in the Distribution Calendar Year.

(ii) Lifetime Required Minimum Distributions Continue Through Year of Participant's Death. Required minimum distributions will be determined under this Section 4.06C beginning with the first Distribution Calendar Year and up to and including the Distribution Calendar Year that includes the Participant's date of death.

D. Required Minimum Distributions After Participant's Death.

(i) Death On or After Date Distributions Begin.

a. Participant Survived by Designated Beneficiary. If the Participant dies on or after the date distributions begin and there is a Designated Beneficiary, the minimum amount that will be distributed for each Distribution Calendar Year after the year of the Participant's death is the quotient obtained by dividing the Participant's Account Balance by the longer of the remaining Life Expectancy of the Participant or the remaining Life Expectancy of the Participant's Designated Beneficiary, determined as follows:

1. The Participant's remaining Life Expectancy is calculated using the age of the Participant in the year of death, reduced by one for each subsequent year.

2. If the Participant's surviving Spouse is the Participant's sole Designated Beneficiary, the remaining Life Expectancy of the surviving Spouse is calculated for each Distribution Calendar Year after the year of the Participant's death using the surviving Spouse's age as of the Spouse's birthday in that year. For Distribution Calendar Years after the year of the surviving Spouse's death, the remaining Life Expectancy of the surviving Spouse is calculated using the age of the surviving Spouse as of the Spouse's birthday in the calendar year of the Spouse's death, reduced by one for each subsequent calendar year.

3. If the Participant's surviving Spouse is not the Participant's sole Designated Beneficiary, the Designated Beneficiary's remaining Life Expectancy is calculated using the age of the Beneficiary in the year following the year of the Participant's death, reduced by one for each subsequent year.

b. No Designated Beneficiary. If the Participant dies on or after the date distributions begin and there is no Designated Beneficiary as of September 30 of the year after the year of the Participant's death, the minimum amount that will be distributed for each Distribution Calendar Year after the year of the Participant's death is the quotient obtained by dividing the Participant's Account Balance by the

Participant's remaining Life Expectancy calculated using the age of the Participant in the year of death, reduced by one for each subsequent year.

(ii) Death Before Date Distributions Begin.

a. Participant Survived by Designated Beneficiary. Except as provided herein, if the Participant dies before the date distributions begin and there is a Designated Beneficiary, the minimum amount that will be distributed for each Distribution Calendar Year after the year of the Participant's death is the quotient obtained by dividing the Participant's Account Balance by the remaining Life Expectancy of the Participant's Designated Beneficiary, determined as provided in Section 4.06D(i).

b. No Designated Beneficiary. If the Participant dies before the date distributions begin and there is no Designated Beneficiary as of September 30 of the year following the year of the Participant's death, distribution of the Participant's entire interest will be completed by December 31 of the calendar year containing the fifth anniversary of the Participant's death.

c. Death of Surviving Spouse Before Distributions to Surviving Spouse are Required to Begin. If the Participant dies before the date distributions begin, the Participant's surviving Spouse is the Participant's sole Designated Beneficiary, and the surviving Spouse dies before distributions are required to begin to the surviving Spouse under Section 4.06B(ii)(a), this Section 4.06D(ii) will apply as if the surviving Spouse were the Participant.

E. Election to Apply 5-Year Rule to Distributions to Designated Beneficiaries. If the Participant dies before distributions begin and there is a Designated Beneficiary, distribution to the Designated Beneficiary is not required to begin by the date specified in Section 4.06B(ii) of the Plan, but the Participant's entire interest will be distributed to the Designated Beneficiary by December 31 of the calendar year containing the fifth anniversary of the Participant's death. If the Participant's surviving Spouse is the Participant's sole Designated Beneficiary and the surviving Spouse dies after the Participant but before distributions to either the Participant or the surviving Spouse begin, this election will apply as if the surviving Spouse were the Participant. This election will apply to all distributions.

Section 4.07 Designation of Beneficiary. A Participant may, from time to time, designate in writing a Beneficiary or Beneficiaries, contingently or successively, to whom the Trustee shall pay his Account in the event of his death. A Participant's Beneficiary designation shall not be valid unless the Participant's Spouse consents (in accordance with the requirements of Code Section 417) to the Beneficiary designation. A Participant's Beneficiary designation does not require spousal consent if the Participant's Spouse is the Participant's designated Beneficiary. The Plan

Administrator shall prescribe the form for the written designation of Beneficiary and, upon the Participant's filing the form with the Plan Administrator, the Participant shall effectively revoke all designations filed prior to that date by the same Participant.

The Plan Administrator may determine the identity of the distributees of any benefit payable under the Plan and in so doing may act and rely upon any information it may deem reliable upon reasonable inquiry, and upon any affidavit, certificate or other paper believed by it to be genuine, and upon any evidence believed by it sufficient. Any payment made in accordance with this Section shall be a complete discharge of obligations of the Plan Administrator and the Employers to the extent of such payment without regard to the application of any payment so made.

Section 4.08 Failure of Beneficiary Designation. If a Participant fails to name a Beneficiary in accordance with Section 4.07, or if the Beneficiary named by a Participant predeceases him, then the Participant's benefits otherwise payable pursuant to this Section shall be paid:

A. to his surviving Spouse, or if none,

B. to his descendants, per stirpes, or if none,

C. to his father and mother, in equal parts, or if none,

D. to his brothers and sisters, in equal parts, or if none,

E. to his estate.

Section 4.09 Special Rules for Transfer Accounts. By operation of relevant law and regulation (including, but not limited to, ERISA and the Code), any Participant who has one or more Transfer Accounts consisting in whole or in part of Transfer Contributions which, must be distributed or made available under the same terms and conditions under which amounts held thereunder were previously held (prior to their becoming Transfer Contributions), Accordingly, notwithstanding any provision of this Article IV to the contrary, but only to the extent required to comply with Code Section 411(d)(6), the Plan Administrator shall, upon the written request of the Participant (in the case of optional forms of benefit), cause the Trustee to distribute or make available such Transfer Contributions at such times and in such manner as may be so required.

Section 4.10 Distributions Under Domestic Relations Orders. Nothing contained in this Plan shall prevent the Trustee from complying with the provisions of a qualified domestic relations order (as defined in Code Section 414(p)). This Plan specifically permits distribution to an alternate payee under a qualified domestic relations order at any time, irrespective of whether the Participant has attained his earliest retirement age (as defined under Code Section 414(p)) under the Plan. A distribution to an alternate payee prior to the Participant's attainment of the earliest retirement age is available only if the order specifies distribution at that time or permits an agreement between the Plan and the alternate payee to authorize such an earlier distribution. Nothing in this Section gives a Participant the right to receive a distribution at a time not permitted under the Plan, nor does this Section give the alternate payee the right to receive a form of payment not permitted under the Plan.

The Plan Administrator shall establish reasonable procedures to determine the qualified status of a domestic relations order. Upon receiving a domestic relations order, the Plan Administrator promptly shall notify the Participant and any alternate payee named in the order, in writing, of the receipt of the order and the Plan's procedures for determining the qualified status of the order. Within a reasonable period of time after receiving the domestic relations order, the Plan Administrator shall determine the qualified status of the order and shall notify the Participant and each alternate payee, in writing, of its determination. The Plan Administrator shall provide notice under this paragraph by mailing to the individual's address specified in the domestic relations order, or in a manner consistent with Labor Regulations.

If any portion of the Participant's Account Balance is payable during the period the Plan Administrator is making its determination of the qualified status of the domestic relations order, the Trustee shall segregate the amounts payable in a separate account and to invest the segregated account solely in fixed income investments or to maintain a separate bookkeeping account of said amounts. If the Plan Administrator determines the order is a qualified domestic relations order within 18 months of the first date on which payments were due under the terms of the order, the Plan Administrator shall direct the Trustee to distribute the separate account in accordance with the order. If the Plan Administrator does not make its determination of the qualified status of the order within the above-described 18-month period, the Plan Administrator shall direct the Trustee to distribute the segregated account in the manner the Plan would distribute it if the order did not exist, and shall apply the order prospectively if the Plan Administrator later determines the order is a qualified domestic relations order.

To the extent it is not inconsistent with the provisions of the qualified domestic relations order, the Plan Administrator may direct the Trustee to invest any partitioned amount in a segregated subaccount or separate account and to invest the account in the money market investment option or in other fixed income investments. A segregated subaccount shall remain a part of the Trust, but it alone shall share in any income it earns, and it alone shall bear any expense or loss it incurs.

The Trustee shall make any payment or distributions required under this Section by separate benefit checks or other separate distribution to the alternate payee(s).

A domestic relations order that otherwise satisfies the requirements of a qualified domestic relations order as defined in Section 414(p) of the Code and Section 206(d)(3)(B) of ERISA will not fail to be a qualified domestic relations order: (i) solely because the order is issued after, or revises, another domestic relations order or qualified domestic relations order; or (ii) solely because of the time at which the order is issued, including issuance after the Participant begins receipt of benefits or after the Participant's death. Such a domestic relations order is subject to the same requirements and protections that apply to qualified domestic relations orders.

Section 4.11 Lost Participant or Beneficiary. The Account of a Participant shall be forfeited if the Plan Administrator, after reasonable effort, is unable to locate the Participant or his Beneficiary to whom payment is due. The Plan Administrator may allocate the forfeited Account in accordance with Section 10.21. However, any such forfeited Account will be reinstated and become payable if a claim is made by the Participant or Beneficiary for such Account. The Plan Administrator shall prescribe uniform and non-discriminatory rules for carrying out this provision.

Section 4.12 Facility of Payment. If any person entitled to receive any amount under the provisions of this Plan is determined to be incapable of receiving or disbursing the same by reason of minority, illness or infirmity, mental incompetence, or incapacity of any kind, the Plan Administrator may, in its discretion, direct the Trustee to take any one or more of the following actions:

A. To apply such amount directly for the comfort, support and maintenance of such person;

B. To reimburse any person for any such support theretofore supplied to the person entitled to receive any such payment;

C. To pay such amount to any person selected by the Plan Administrator to disburse it for such comfort, support and maintenance, including without limitation, any relative who has undertaken, wholly or partially, the expense of such person's comfort, care and maintenance, or any institution in whose care or custody the person entitled to the amount may be. The Plan Administrator may, in its discretion, deposit any amount due to a minor to his credit in any savings or commercial bank of the Plan Administrator's choice, direct that such distribution be paid to the legal guardian, or if none, to a parent of such person or a responsible adult with whom the minor maintains his residence, or to the custodian for such Beneficiary under the Uniform Gift to Minors Act or gift to Minors Act, if such is permitted by the laws of the state in which such minor Beneficiary resides.

Payment pursuant to this Section shall fully discharge the Company, Committee, Trustee, Employer and the Plan from further liability on account thereof.

Section 4.13 No Distribution Prior to Severance From Employment, Death or Disability. Except as provided below, Pre-tax Contributions, Roth Contributions and Catch-up Contributions, and income allocable to each, are not distributable to a Participant or his Beneficiary or Beneficiaries, in accordance with such Participant's or Beneficiary's election, earlier than upon Severance from Employment, death or Disability.

Such amounts may also be distributed upon:

A. Termination of the Plan without the establishment of another defined contribution plan, as defined in the Code and applicable Treasury Regulations.

B. The hardship of the Participant, as described in Section 5.05 herein.

C. The attainment by the Participant of age $59^{1/2}$, as described in Section 5.04 herein.

All distributions that may be made pursuant to one or more of the foregoing distributable events are subject to the spousal and Participant consent requirements (if applicable) contained in Sections 401(a)(11) and 417 of the Code.

Section 4.14 Written Instruction Not Required. Any elections made or distributions processed under this Article IV may be accomplished through telephonic or similar instructions in accordance with the rules and procedures established by the Plan Administrator, to the extent they are consistent with the requirements of the Code and ERISA. Notwithstanding the foregoing, however, spousal consents and waivers, to the extent required, may only be granted in writing.

ARTICLE V
WITHDRAWALS; DIRECT ROLLOVERS AND WITHHOLDING; LOANS

Section 5.01 General Rules. This Article provides the rules that apply to a Participant's request for a withdrawal from the Plan while the Participant is employed by an Employer.

A. A Participant's Account Balance, for purposes of in-service withdrawals shall be determined as of the Valuation Date coinciding with or immediately succeeding the date the request for withdrawal specified in such Sections is delivered to the Plan Administrator.

B. Any withdrawal under Section 5.02, 5.03, 5.04 or 5.05 shall be paid to the Participant as soon as is reasonably practicable.

C. All rules governing withdrawal privileges under this Article shall be administered by the Plan Administrator or its delegate in a uniform manner, and are subject to the claims procedure described in Section 9.07.

D. Any election to begin, change or cease withdrawals shall be made in accordance with procedures established by the Plan Administrator or in such other manner as permitted by the Plan Administrator. Payment of amounts so requested shall be made within an administratively reasonable period of time after the withdrawal has been requested. The Plan Administrator may establish other rules of uniform applicability regarding the timing of and procedures for such withdrawals.

E. Any withdrawals under this Article V may be made in cash or, with respect to the portion of a Participant's Account invested in the Company Stock Fund or any other stock fund maintained under the Plan, in kind at the Participant's election.

Section 5.02 Withdrawals of After-tax and Rollover Contributions. A Participant may elect to withdraw from either his After-tax Contribution Account or his Rollover Contribution Account at any time.

Section 5.03 Withdrawals of Matching Contributions and Profit Sharing Contributions. Upon application, a Participant who has completed 60 months as a Participant may elect to receive a distribution of all or any portion of his Matching Contribution Account and/or Profit Sharing Account, including if applicable the Next Gen Employer Contribution Account.

Section 5.04 Withdrawals at Age 59½. Upon application, a Participant may, upon written request to the Plan Administrator, make withdrawals of any amount up to his entire Account Balance on or after he has attained age 59½.

Section 5.05 Hardship Withdrawals. Subject to any additional legal restrictions on in-service withdrawal rights (such as those outlined in Section 4.13), upon the application, a

Participant may withdraw all or a portion of his Pre-tax Contributions Account, Roth Contributions Account, and Catch-up Contributions Account (excluding, on or after January 1, 1989, all trust earnings credited to such subaccounts) if the withdrawal is necessary due to the immediate and heavy financial need of the Participant.

A. Only distributions made pursuant to conditions arising under the following circumstances shall be conclusively considered to be made on account of immediate and heavy financial need:

(i) Alleviating extraordinary financial hardship arising from deductible medical expenses (within the meaning of Code Section 213(d)) previously incurred by the Participant or his Spouse, children, other dependents, or Beneficiary, or necessary for such persons to obtain such care;

(ii) Purchasing real property (excluding mortgage payments) that is to serve as the principal residence of the Participant;

(iii) Expenditures necessary to prevent eviction from the Participant's principal residence or foreclosure of a mortgage on the same;

(iv) Financing the tuition and related educational fees for the next 12 months of post-secondary education for the Participant, his Spouse, his children, other dependents or Beneficiary.

(v) payments for funeral or burial expenses for the employee's deceased parent, Spouse, child, dependent or Beneficiary; or

(vi) expenses to repair damage to the employee's principal residence that would qualify for a casualty loss deduction under Code Section 165 (determined without regard to whether the loss exceeds 10% of adjusted gross income).

B. A distribution will be considered to be necessary to satisfy an immediate and heavy financial need of the Participant only if:

(i) The Participant has obtained all distributions other than hardship distributions, all nontaxable loans currently available under all plans maintained by the Employer, or by borrowing from commercial sources on reasonable commercial terms in an amount sufficient to satisfy the need;

(ii) The Participant has elected to receive any and all dividends attributable to the Participant's Account invested in the Company Stock Fund under Section 8.08.

(iii) All plans maintained by the Employer provide that the Participant's Pre-tax Contributions, Roth Contributions, Catch-up Contributions, or other Participant contributions will be suspended for 6 months after the receipt of the hardship distribution (which this Plan hereby so provides); and

(iv) The distribution is not in excess of the amount necessary to satisfy the immediate and heavy financial need, including any amounts necessary to pay any federal, state, or local income taxes or penalties reasonably anticipated to result from the distribution.

C. A Participant making an application under this Section 5.05 shall have the burden of presenting to the Plan Administrator evidence of such need, and the Plan Administrator shall not permit withdrawal under this Section without first receiving such evidence. If a Participant's application for a hardship withdrawal is approved, the Plan Administrator shall then instruct the Trustee to make payment of the approved amount of the hardship withdrawal to the Participant.

D. Notwithstanding the foregoing, in the event a Section 16(b) Officer requests a hardship distribution pursuant to this Section, any such distribution amount shall not be available in whole or in part from the portion of the Participant's Account that is invested in the Company Stock Fund if restricted from transacting in Company stock by law or by the provisions of the Company's Securities Trading Policy. For purposes of this Section, "Section 16(b)" Officer shall mean an officer of the Company who is subject to the short-swing profit recapture rules of section 16(b) of the Securities Exchange Act of 1934, as amended.

Section 5.06 Withdrawals During Military Service.

A. Effective January 1, 2009, certain individuals performing military service shall have an additional in-service withdrawal right. Specifically, notwithstanding the definition of Compensation in Article I (stating in part that any Participant receiving differential wage payments shall be treated as an Employee) or any other provision herein to the contrary, for purposes of Code §401(k)(2)(B)(i)(I), and in accordance with Code §414(u)(12)(B), an individual shall be treated as having been severed from employment during any period the individual is performing service in the uniformed services (as defined in Chapter 43 of Title 38 of the United States Code) while on active duty for a period of more than 30 days. Accordingly, in accordance with Section 4.13, such Participant shall be eligible to take a distribution due to this considered Severance from Employment. However, the Plan will not distribute the benefit of such an individual without that individual's consent, so long as the individual is receiving differential wage payments.

B. Suspension of deferrals. If an individual elects to receive a distribution pursuant to this Section, the individual may not make an elective deferral or employee contribution during the 6-month period beginning on the date of the distribution.

Section 5.07 Direct Rollover and Withholding Rules.

A. Notwithstanding any provision of the Plan to the contrary that would otherwise limit a Distributee's election under this Section, a Distributee may elect, at the time and in the manner prescribed by the Plan Administrator, to have any portion of an Eligible Rollover Distribution paid directly to an Eligible Retirement Plan specified by the Distributee in a Direct Rollover. The Plan Administrator may establish rules and procedures governing the processing of Direct Rollovers and limiting the amount or number of such Direct Rollovers in accordance with applicable Treasury Regulations. Distributions not transferred to an Eligible Retirement Plan in a Direct Rollover shall be subject to income tax withholding as provided under the Code and applicable state and local laws, if any.

B. Definitions.

(i) "Eligible Rollover Distribution." An Eligible Rollover Distribution is any distribution of all or any portion of the balance to the credit of the Distributee, except that an Eligible Rollover Distribution does not include: (a) any distribution that is one of a series of substantially equal periodic payments (not less frequently than annually) made for life (or life expectancy) of the Distributee or the joint lives (or joint life expectancies) of the Distributee and the Distributee's designated beneficiary, or for a specified period of ten years of more; (b) any distribution to the extent such distribution is required under Code Section 401(a)(9); and (c) any hardship distribution. An Eligible Rollover Distribution shall also include any After-tax Contributions or Roth Contributions if such rollover distribution is made by means of a direct rollover to a qualified plan or to a 403(b) plan that agrees to account separately for amounts so transferred, including accounting separately for the portion of such distribution which is includible in gross income and the portion of such distribution which is not includible in gross income.

(ii) "Eligible Retirement Plan." An Eligible Retirement Plan is an individual retirement account described in Code Section 408(a) or Code Section 408A(b), an individual retirement annuity described in Code Section 408(b), an annuity plan described in Code Section 403(a), a qualified trust described in Code Section 401(a), a tax sheltered annuity plan described in Code Section 403(b) or an eligible deferred compensation plan described in Code Section 457(b) that is maintained by an eligible employer described in Code Section 457(e)(1)(A) which agrees to separately account for amounts transferred into such plan, that accepts the distributor's Eligible Rollover Distribution. The definition of "Eligible Retirement Plan" shall also apply in the case of a distribution to the employee's or former employee's surviving Spouse or the employee's or former employee's Spouse or former Spouse who is the alternate payee under a qualified domestic relations order, as defined in Code Section 414(p). The definition of "Eligible Retirement Plan" also shall apply in the case of a distribution to an individual retirement account described in Code Section 408(a) or individual retirement annuity described in Code Section 408(b) established for the purpose of receiving such distribution on behalf of a non-spouse beneficiary of the Employee.

(iii) "Distributee." A Distributee includes an Employee or former Employee. In addition, the Employee's or former Employee's surviving Spouse and the Employee's or former Employee's Spouse or former Spouse who is the alternate payee under a qualified domestic relations order, as defined in Code Section 414(p), are Distributees with regard to the interest of the Spouse or former Spouse. The Employee's non-spouse beneficiary also is a Distributee, but only for distributions to individual retirement accounts described in Code Section 408(a) or individual retirement annuities described in Code Section 408(b), as described in paragraph (ii) above.

(iv) "Direct Rollover." A Direct Rollover is a payment by the Plan to the Eligible Retirement Plan specified by the Distributee.

C. Special Rules Pertaining to Non-spouse Beneficiary Rollover Right. A non-spouse beneficiary who is a "designated beneficiary" under Code Section 401(a)(9)(E) and the regulations thereunder, by a direct trustee-to-trustee transfer ("direct rollover"), may roll over all or any portion of his/her distribution to an individual retirement account the beneficiary establishes for purposes of receiving the distribution. In order to be able to roll over the distribution, the distribution otherwise must satisfy the definition of an Eligible Rollover Distribution.

(i) Indirect Rollover Not Permitted. If a non-spouse beneficiary receives a distribution from the Plan, the distribution is not eligible for a "60-day" rollover.

(ii) Trust Beneficiary. If the Participant's named beneficiary is a trust, the Plan may make a direct rollover to an individual retirement account on behalf of the trust, provided the trust satisfies the requirements to be a designated beneficiary within the meaning of Code Section 401(a)(9)(E).

(iii) Required Minimum Distributions Not Eligible for Rollover. A non-spouse beneficiary may not roll over an amount which is a required minimum distribution, as determined under applicable Treasury regulations and other Revenue Service guidance. If the Participant dies before his/her required beginning date and the non-spouse beneficiary rolls over to an IRA the maximum amount eligible for rollover, the beneficiary may elect to use either the 5-year rule or the life expectancy rule, pursuant to Treas. Reg. Section 1.401(a)(9)-3, A-4(c), in determining the required minimum distributions from the IRA that receives the non-spouse beneficiary's distribution

D. Special Rules Pertaining to Rollovers of Roth Contributions. Notwithstanding Section 5.07A above, a Direct Rollover of an Eligible Rollover Distribution from a Participant's Roth Contribution Account shall only be made to another Eligible Retirement Plan if such plan maintains a Roth elective deferral account thereunder and such plan is an "applicable retirement plan" as described in Code Section 402(A)(e)(1) or a Roth IRA described in Code Section 408A.

The Plan will accept a Rollover Contribution to the Roth Contribution Account on behalf of a Participant only if such Rollover Contribution is a Direct Rollover from another Roth elective deferral account under an applicable retirement plan described in Section Code 402A(e)(1). Where such Direct Rollover of Roth elective deferrals from an applicable retirement plan is made, the period for determining whether distributions of such amounts are qualified distributions (as defined in Code Section 402A(d)(2)) shall be determined according to the rules under Code Section 402A(d)(2)(B).

Section 5.08 Loans to Participants. Loans may be granted to any Participant under the Plan in accordance with applicable rules under the Code and ERISA and the provisions of this Section.

A. General Rules. The Plan Administrator shall establish the procedures a Participant must follow to request a loan from his Account Balance under the Plan. Loans shall be made available to all Participants on a reasonably equivalent basis; provided, however, that loans will not be made available to a Former Participant, other than a Former Participant who is a Party-In-Interest as defined in Section 3(14) of ERISA whose Account has not been distributed.

In no event will the total of any outstanding loan balances made to any Participant, including any interest accrued thereon, when aggregated with corresponding loan balances of the Participant under any other plans of the Employer or any Related Employer, exceed the lesser of (i) or (ii), below:

(i) $50,000, reduced by the excess (if any) of the highest outstanding balance of such loans during the one-year period ending on the day before the date any such loan is made over the outstanding balance of such loans on the date any such loan is made; or

(ii) One-half of the value of the Participant's Account. For purposes of this Section, the value of a Participant's Account shall be determined as of the Valuation Date coinciding with or next preceding the date on which a properly completed loan request is received by the Plan Administrator (or its delegate) or the Trustee, as applicable.

The minimum amount of any loan shall be $1,000.

B. Term of Loan. The term of any loan shall be determined by mutual agreement between the Plan Administrator and the Participant. Every Participant who is granted a loan shall receive a statement of the charges and interest rates involved in each loan transaction and periodic statements reflecting the current loan balance and all transactions with respect to that loan to date. Except for loans used to acquire any dwelling unit that within a reasonable time (determined at the time the loan is made) is to be used as the principal residence of the Participant, the term of any loan shall not exceed five years. The term of any loan that within a reasonable time (determined at the time the loan is made) is to be used as the principal residence of the Participant shall not exceed 15 years. All loans shall be amortized in level payments made not less frequently than quarterly over the term of the loan, or in accordance with other procedures established by the Plan Administrator.

C. Security. Each loan shall be secured by no more than one-half of the vested portion the Participant's nonforfeitable Account Balance (determined as of the Valuation Date coinciding with or next preceding the date on which the loan is made).

D. Interest. Each Participant loan shall be considered an investment of the Trust, and interest shall be charged thereon at a reasonable rate established by, or in accordance with procedures approved by, the Plan Administrator commensurate with the interest rates then being charged by persons in the business of lending money under similar circumstances. Notwithstanding the foregoing sentence, the Plan Administrator will reduce the interest rate of an outstanding Participant loan to 6% during a period of qualified military leave, as defined in Code Section 414(u)(5), to the extent required by the Soldiers' and Sailors' Civil Relief Act of 1940. Participant loans under this Section will be considered the directed investment of the Participant requesting such loan, and interest paid on such loan will be allocated to the Account of the Participant-borrower.

E. Party-In-Interest. The provisions of this Section shall apply to any Participant who is a Party-In-Interest (as defined in Section 3(14) of ERISA) and who retains an Account Balance in the Plan following termination of employment. Payments of principal and interest on a loan to any such Participant shall be made through direct debit from his bank account in accordance with the electronic loan payment procedures established by the Plan Administrator.

Such Participant's Account Balance, except for the portion secured by the loan (or loans), may at any time be distributed pursuant to the applicable terms of the Plan. Notwithstanding the preceding sentence, a loan to a Participant to whom this subsection E applies shall become payable in full on the date such Participant receives a final distribution of his Account Balance.

F. Repayment Terms.

(i) Generally. The terms and conditions of each loan shall be determined by mutual agreement between the Plan Administrator and the Participant. The Plan Administrator shall take all necessary actions to ensure that each loan is repaid on schedule by its maturity date, including requiring repayment of the loan by payroll deduction. In the event a Participant (or his Beneficiary or Spouse) elects to receive a distribution from the Trust Fund at a time when there is an unpaid balance of a loan against such Participant's Account, the Trustee shall deduct the unpaid balance of the principal of such loan or any portion thereof, and any interest accrued to the date of such deduction, from any payment or distribution from the Trust Fund to which such Participant or his Beneficiary or Spouse may be entitled. If the amount of such payment or distribution is not sufficient to repay the outstanding balance of such loan and any interest accrued thereon, the Participant (or his estate, if applicable) shall be liable for and continue to make payments on any balance still due from him.

(ii) Bank Debit. The provisions of this subsection F(ii) shall apply to any Participant who (a) terminates employment with all Employers on or after July 1, 2005, and (b) has an outstanding loan (or loans) as of his termination date. Payments of principal and interest on any such Participant's loan (or loans) may be made through direct debit from his bank account, in accordance with the electronic loan payment procedures established by the Plan Administrator. If any such Participant does not authorize payments through direct debit from his bank account, his outstanding loan shall be considered in default.

Except as set forth in subsection E, no Participant described in this subsection F(ii) shall be entitled to receive any new loan pursuant to this Section 5.08 from and after the date of his termination of employment. The balance of his Account, except for the portion secured by the loan (or loans), may be distributed pursuant to the applicable terms of the Plan. A loan to a Participant to whom this subsection F(ii) applies shall become payable in full on the date such Participant receives a final distribution of his Account Balance.

(iii) Suspension of Loan Payments during Disability. Loan payments shall be suspended during a period of Disability of up to one year if the period of leave is unpaid or paid at a rate that does not accommodate a Participant's scheduled loan repayments. Following the Participant's return to employment after Disability or, if earlier, the expiration of the one-year period noted in the previous sentence, loan payments shall resume at an amount not less than that required by the terms of the original loan, and at a frequency such that the loan will be repaid in full during a period that is no longer than the "latest permissible term of the loan" (defined as the latest date permitted under Code Section 72(p)(2)(B). The latest permissible term of the loan determined under Code Section 72(p)(2)(B) shall not be extended due to the period of the Disability.

(iv) Suspension of Loan Payments during Qualified Military Leave. Loan payments shall be suspended during a period of "qualified military service," as defined in Code Section 414(u)(5). The duration of such period of service shall not be taken into account in determining the maximum permissible term of the loan under Code Section 72(p) and the regulations promulgated thereunder. Following the Participant's timely reemployment after a period of qualified military service, loan payments shall resume at an amount no less than required by the terms of the original loan, and at a frequency such that the loan will be repaid in full during a period that is no longer than the "latest permissible term of the loan" (defined as latest date permitted under

Code Section 72(p)(2)(B) plus the period of suspension due to such military service).

G. Restrictions on Loans. No Participant shall have more than two loans under this Section 5.08 outstanding at the same time. All loans will be paid by payroll deduction and a loan will be approved only if the Participant has sufficient income to support the required payroll withholdings.

H. Nondiscrimination. Loans will not be made available to Highly Compensated Employees in an amount greater than the amount made available to other Employees.

I. Default. Failure to make a payment within 90 days of the date payment is due will generally constitute a default, unless loan procedures and applicable law do not so require. Upon default (or, to the extent prohibited by law or by the terms of the Plan until a distributable event occurs, upon such event) the Plan Administrator will deduct the total unpaid amount of the loan and any unpaid interest due on the loan from the Participant's Account. The Plan Administrator may establish additional rules and procedures for handling loan defaults, including, but not limited to, restrictions on future borrowing.

J. Procedure. The Plan Administrator will establish nondiscriminatory policies and procedures to administer Participant loans.

Section 5.09 Special Withdrawal Rules Applicable to Transfer Accounts. Notwithstanding any other Plan provision to the contrary, if the Internal Revenue Service requires distribution to be made (or offered) with respect to any or all amounts held on behalf of a Participant with respect to a predecessor or transferor plan, as a condition of preserving the tax-qualified status of this Plan or of said predecessor or transferor plan, or if a court of competent jurisdiction issues an order or decree in respect of the Plan or its fiduciaries which is determined under relevant federal law to be enforceable, and which compels the distribution of a Participant's Plan interest, the Plan Administrator will be entitled to direct the prompt distribution (or offer of distribution) of such amounts.

ARTICLE VI
TESTING OF PRE-TAX, ROTH, AFTER-TAX AND MATCHING CONTRIBUTIONS

Section 6.01 Definitions. For purposes of this Article, the following definitions shall apply:

A. "Actual Deferral Percentage" means the average of the actual deferral ratios (calculated separately for each Eligible Employee) of the amount of Pre-tax Contributions and Roth Contributions actually made by the Eligible Employee for such Plan Year to the Eligible Employee's Compensation for the period of time during such Plan Year that he participated in the Plan, rounded to the nearest one-hundredth of one percent.

B. "Actual Contribution Percentage" means the average of the actual contribution ratios (calculated separately for each Eligible Employee) of the amount of Matching Contributions actually made by an Employer for the Eligible Employee for such Plan Year, plus the amount of After-tax Contributions made by the Eligible Employee during such Plan Year, to such Employee's Compensation for the period of time during such Plan Year in which he participated in the Plan, rounded to the nearest one-hundredth of one percent.

C. "Eligible Employee" means any Participant in the Plan and any Employee who would be eligible to make Pre-tax Contributions, Roth Contributions or After-tax Contributions to the Plan for a Plan Year but for a suspension due to a distribution or a failure to elect to participate in the Plan.

D. "Excess Contributions" means, with respect to any Plan Year, the excess of the aggregate amount of the Pre-tax Contributions and Roth Contributions actually made on behalf of Highly Compensated Employees for such Plan Year over the maximum amount of such contributions permitted under the limitations of Code Section 401(k)(3)(A)(ii).

E. "Excess Aggregate Contributions" means, with respect to any Plan Year, the excess of the aggregate amount of the After-tax Contributions and Matching Contributions actually made on behalf of Highly Compensated Employees for such Plan Year over the maximum amount of such contributions permitted under the limitations of Code Section 401(m)(2)(A).

F. "Highly Compensated Eligible Employee" means an Eligible Employee who is a Highly Compensated Employee.

Section 6.02 Pre-tax and Roth Contributions: 401(k) Tests.

A. Actual Deferral Percentage Test. The total amount of Pre-tax Contributions and Roth Contributions shall comply with either (i) or (ii) below for each Plan Year:

(i) The Actual Deferral Percentage for the Highly Compensated Eligible Employees shall not exceed the Actual Deferral Percentage for all other Eligible Employees multiplied by 1.25; or

(ii) The Actual Deferral Percentage for Highly Compensated Eligible Employees shall not exceed the Actual Deferral Percentage of all other Eligible Employees multiplied by 2.0, provided that the Actual Deferral Percentage for the Highly Compensated Eligible Employees does not exceed that of all other Eligible Employees by more than two percentage points.

B. The Actual Deferral Percentage for the Plan Year for any Highly Compensated Eligible Employee who is eligible to make Pre-tax Contributions or Roth Contributions under two or more plans that are qualified under Code Section 401(a) or 401(k) and that are maintained by an Employer or a Related Employer must be determined as if all such deferrals were made under a single plan. Plans may be aggregated only if they have the same Plan Year.

C. In determining whether the requirements of Section 6.02A of the Plan are met, the Plan Administrator may aggregate plans on any basis as permitted under Code Section 401(a)(4) and Treasury Regulations thereunder.

D. Pre-tax Contributions and Roth Contributions shall be taken into account for purposes of determining the Actual Deferral Percentage of any Eligible Employee for a Plan Year only if such Pre-tax Contributions and Roth Contributions relate to Compensation that either (1) would have been received by the Eligible Employee in such Plan Year (but for the election to make such Pre-tax Contributions or Roth Contributions), or (2) is attributable to services performed by the Eligible Employee in such Plan Year and would have been received by the Eligible Employee within $2^{1/2}$ months after the end of such Plan Year (but for the election to make such Pre-tax Contributions or Roth Contributions).

E. Pre-tax Contributions and Roth Contributions shall be taken into account for purposes of determining the Actual Deferral Percentage of an Eligible Employee for a Plan Year only if such Pre-tax Contributions and Roth Contributions are allocated to the Pre-tax Contributions Account and Roth Contribution Account, as applicable, of the Eligible Employee as of a date that occurs within such Plan Year. For this purpose, Pre-tax Contributions and Roth Contributions are considered allocated as of a date within a Plan Year if the allocation is not contingent upon participation or performance of services after such date and the Pre-tax Contributions and Roth Contributions are actually paid to the Trustee no later than 12 months after the end of the Plan Year to which the Pre-tax Contributions and Roth Contributions relate.

F. The determination and treatment of the Actual Deferral Percentage of any Participant shall satisfy such other requirements as may be prescribed by the Secretary of the Treasury. In performing the required testing hereunder, any variations in procedures or methods permitted under the Code and applicable Treasury Regulations may be employed

Section 6.03 Correction of Excess Contributions.

A. If the amount of Pre-tax Contributions and Roth Contributions made for Highly Compensated Eligible Employees in a Plan Year would not comply with either clause (i) or (ii) in Section 6.02A above, then the Plan Administrator in its discretion may choose either (i), (ii) or (iii) below, or any combination, in order to comply with such tests:

(i) In determining the Actual Deferral Percentage of Eligible Employees, the Plan Administrator may treat Matching Contributions, other than Matching Contributions used to meet the test in Section 6.04A, as Pre-tax Contributions; or

(ii) The Excess Contributions can, with the consent of the applicable Highly Compensated Eligible Employees, be recharacterized as After-tax Contributions solely for the purposes of Sections 6.02 and 6.04 of the Plan, within $2^{1/2}$ months after the related Plan Year, but only to the extent that it shall not cause the limitations in Section 6.04A to be exceeded, or

(iii) The Excess Contributions for such Plan Year (including the income, gains and losses attributable to such contributions as provided in B below) shall be distributed by the last day of the following twelve-month period to Highly Compensated Eligible Employees. Excess Contributions attributable to each Highly Compensated Eligible Employee shall be determined according to the following leveling method:

1. The Actual Deferral Percentage of the Highly Compensated Eligible Employee with the highest Actual Deferral Percentage for the Plan Year shall be reduced to the extent necessary to cause such Highly Compensated Eligible Employee's Actual Deferral Percentage to equal the Actual Deferral Percentage of the Highly Compensated Eligible Employee with the next highest Actual Deferral Percentage. This process shall be repeated until the Plan satisfies one of the tests set forth in Section 6.02 for such Plan Year.

2. The dollar amount of each prospective reduction made pursuant to (1) next above shall be determined for each Highly Compensated Eligible Employee and all such dollar amounts for such Plan Year shall be aggregated.

3. The total Pre-tax Contributions and, to the extent necessary, Roth Contributions of the Highly Compensated Eligible Employee with the highest dollar amount of total Pre-tax Contributions and Roth Contributions for the Plan Year shall be reduced by the amount necessary to cause the amount of such Highly Compensated Eligible Employee's total Pre-tax Contributions and Roth Contributions to equal the total amount of Pre-tax Contributions and Roth Contributions of the Highly Compensated Eligible Employee with the next highest total dollar amount of Pre-tax Contributions and Roth Contributions for such Plan Year. This process shall be repeated until the total amount of Pre-tax Contributions and, to the extent necessary, Roth Contributions so reduced equals the aggregate dollar amount determined in (2) next above. For purposes of this leveling method, any necessary reductions for Highly Compensated Employees shall be first taken from Pre-tax Contributions to the extent necessary to complete the reductions under this subparagraph (3). Should such Pre-tax Contributions for a Plan Year for any affected Highly Compensated Employee be exhausted by this method, any remaining reduction required under

this subparagraph (3) shall then be taken from Roth Contributions, if available, for the affected Highly Compensated Employees.

Following completion of this process, the amount of Excess Contributions for each Highly Compensated Eligible Employee shall be equal to the total of his Pre-tax Contributions and Roth Contributions reduced pursuant to the aforementioned leveling method.

In the event of the complete termination of the Plan during the Plan Year in which Excess Contributions arose, such distributions are to be made after termination of the Plan and before the close of the 12-month period that immediately follows such termination. Any distribution of Excess Contributions may be made without regard to any notice or consent requirements of the Plan.

B. The income, gains and losses allocable to Excess Contributions shall be the income, gains and losses attributable to such Excess Contributions for the Plan Year in which they occurred, determined pursuant to Code Section 401(k)(8).

C. For purposes of this Section, a distribution occurring on or before the fifteenth day of the month shall be treated as having been made as of the last day of the preceding month and a distribution occurring after such fifteenth day shall be treated as having been made on the first day of the following month.

D. The amount of Excess Contributions to be distributed to, or recharacterized with respect to, a Highly Compensated Eligible Employee for a Plan Year shall be reduced by any Excess Contributions previously distributed to the Highly Compensated Eligible Employee for the taxable year of the Highly Compensated Eligible Employee ending with or within the same Plan Year, and Excess Contributions to be distributed to a Highly Compensated Eligible Employee for a taxable year of the Highly Compensated Eligible Employee shall be reduced by Excess Contributions previously distributed, or recharacterized with respect to, such Highly Compensated Eligible Employee for the Plan Year beginning in such taxable year.

E. An amount of Matching Contributions attributable to the Pre-tax Contributions and, to the extent necessary, Roth Contributions distributed to a Highly Compensated Eligible Employee as an Excess Contribution pursuant to clause (iii) of Section 6.03A shall also be distributed to the applicable Highly Compensated Eligible Employee by the last day of the 12-month period following the end of the Plan Year in which such Excess Contributions occurred.

F. Excess Contributions that are recharacterized pursuant to clause (ii) Section 6.03A shall be nonforfeitable and fully vested and shall be subject to the distribution limitations set forth in Section 4.13 that are applicable to Pre-tax Contributions and Roth Contributions.

G. For purposes of this Section, the Actual Deferral Percentage for Highly Compensated Eligible Employees and for Eligible Employees who are not Highly Compensated Eligible Employees shall be determined for the current Plan Year.

Section 6.04 After-tax and Matching Contributions: 401(m) Tests.

A. Actual Contribution Percentage Test. The total amount of Matching Contributions as described in Section 3.04, except for any Matching Contributions used to satisfy the test in Section 6.02A, plus the total amount of After-tax Contributions as described under Section 3.02C, including any amount recharacterized as an After-tax Contribution under Section 6.03A(ii) above shall comply with either (i) or (ii) below for each Plan Year:

(i) The Actual Contribution Percentage for the Highly Compensated Eligible Employees shall not exceed the Actual Contribution Percentage for all other Eligible Employees multiplied by 1.25; or

(ii) The Actual Contribution Percentage for Highly Compensated Eligible Employees shall not exceed the Actual Contribution Percentage of all other Eligible Employees multiplied by 2.0, provided that the Actual Contribution Percentage for the Highly Compensated Eligible Employees does not exceed that of all other Eligible Employees by more than two percentage points.

B. The Actual Contribution Percentage for the Plan Year for any Highly Compensated Eligible Employee who is eligible to receive Matching Contributions or to make After-tax Contributions under two or more plans that are qualified under Code Section 401(a) or 401(k) and that are maintained by an Employer or a Related Employer, must be determined as if all such contributions were made under a single plan. Plans may be aggregated only if they have the same Plan Year.

C. In determining whether the requirements in Section 6.04A are met, the Plan Administrator may aggregate plans as permitted under Code Section 401(a)(4) and Treasury Regulations thereunder.

D. The determination and treatment of the Actual Contribution Percentage of any Participant shall satisfy such other requirements as may be prescribed by the Secretary of the Treasury. In performing the required testing hereunder, any variations in procedures or methods permitted under the Code and applicable Treasury Regulations may be employed.

Section 6.05 Correction of Excess Aggregate Contributions.

A. If the amount of Matching Contributions plus After-tax Contributions made for Highly Compensated Eligible Employees in a Plan Year would not comply with either clause (i) or (ii) in Section 6.04A above, then the Plan Administrator in its discretion shall choose either (i) or (ii) below in order to comply with such tests:

(i) The Pre-tax Contributions and, to the extent necessary, Roth Contributions of nonhighly compensated Eligible Employees shall be recharacterized as Matching Contributions to the extent necessary to comply with either clause (i) or (ii) in Section 6.04A, provided that the Code Section 401(k) test for Pre-tax Contributions and Roth Contributions (as described in 6.02A(i) or (ii)) shall still be met both before and after such recharacterization; or

(ii) The Excess Aggregate Contributions for such Plan Year (including any income, gains or losses attributable to such contributions as provided in paragraph (b) below) shall be distributed by the last day of the following 12-month period to Highly Compensated Eligible Employees. Excess Aggregate Contributions attributable to each Highly Compensated Eligible Employee shall be determined according to the following leveling method:

1. The Actual Contribution Percentage of the Highly Compensated Eligible Employee with the highest Actual Contribution Percentage for the Plan Year shall be reduced to the extent necessary to cause such Highly Compensated Eligible Employee's Actual Contribution Percentage to equal the Actual Contribution Percentage of the Highly Compensated Eligible Employee with the next highest Actual Contribution Percentage for such Plan Year. This process shall be repeated until the Plan satisfies one of the tests set forth in Section 6.04 for such Plan Year.

2. The dollar amount of each reduction made pursuant to (1) next above shall be determined for each Highly Compensated Eligible Employee and all such dollar amounts for such Plan Year shall be aggregated.

3. The Matching Contributions and After-tax Contributions of the Highly Compensated Eligible Employee with the highest dollar amount of Matching Contributions and After-tax Contributions for the Plan Year shall be reduced to the extent necessary to cause the amount of such Highly Compensated Eligible Employee's Matching Contributions and After-tax Contributions to equal the amount of Matching Contributions and After-tax Contributions of the Highly Compensated Eligible Employee with the next highest dollar amount of Matching Contributions and After-tax Contributions. This process shall be repeated until the total amount of Matching Contributions and After-tax Contributions so reduced equals the aggregate dollar amount in (2) next above.

The amount of Excess Aggregate Contributions for a Plan Year shall be determined only after first determining the Excess Contributions that are recharacterized as After-tax Contributions pursuant to clause (ii) of Section 6.03A. The amount of Excess Aggregate Contributions to be distributed to each Highly Compensated Eligible Employee pursuant to this clause (ii) for a Plan Year shall be distributed on a pro rata basis from the After-tax Contributions made by such Highly Compensated Eligible Employee for such Plan Year and the Matching Contributions allocable to the Matching Contribution Account of the Highly Compensated Eligible Employee for such Plan Year.

In the event of the complete termination of the Plan during the Plan Year in which an Excess Aggregate Contribution arose, such distributions are to be made after termination of the Plan and before the close of the 12-month period that immediately follows such termination. Any distribution of Excess Aggregate Contributions may be made without regard to any notice or consent requirements of the Plan.

B. The income, gains and losses allocable to Excess Aggregate Contributions shall be such income, gains and losses attributable to such Excess Aggregate Contributions for the Plan Year in which they occurred, determined pursuant to Code Section 401(m)(6).

C. For purposes of this Section 6.05, a distribution occurring on or before the fifteenth day of the month shall be treated as having been made as of the last day of the preceding month and a distribution occurring after such fifteenth day shall be treated as having been made on the first day of the following month.

D. For purposes of this Section 6.05, the Actual Contribution Percentage for Highly

Compensated Eligible Employees and for Eligible Employees who are not Highly Compensated Eligible Employees shall be determined for the current Plan Year.

Section 6.06 Alternative to Distribution of Excess Amounts. In lieu of distributing Excess Contributions as provided in Section 6.03, or Excess Aggregate Contributions as provided in Section 6.05, and to the extent elected by the Plan Administrator, with respect either to all or some Employers or groups, the Employer may make "Qualified Non-elective Contributions" on behalf of Non-highly Compensated Employees (or all Employees) that are sufficient to satisfy either the Actual Deferral Percentage test or the Actual Contribution Percentage test, or both, pursuant to regulations under the Code, and in accordance with this Section.

For purposes of this Article, "Qualified Non-elective Contributions" shall mean contributions made by the Employer and allocated to Participants' Accounts that the Participants may not elect to receive in cash until distributed from the Plan; that are vested when made; and that are distributable only in accordance with the distribution provisions that are applicable to Pre-Tax Contributions. Qualified Non-elective Contributions shall be allocated to Participants' Accounts either (i) in the same proportion that each Participant's Compensation for the Plan Year for which the Employer makes the contribution bears to the total Compensation of all Participants for the Plan Year (or of all Non-highly Compensated Participants, as applicable) or (ii) in a flat dollar amount, as determined by the Plan Administrator. Qualified Non-elective Contributions may be made only with respect to eligible Participants within one or more Employers or divisions or with respect to all eligible Participants, as determined by the Plan Administrator.

ARTICLE VII
LIMITATIONS ON CONTRIBUTIONS AND BENEFITS

Section 7.01 Dollar Limitations on Pre-tax Contributions.

A. Code Section 402(g) Limitation. In no event shall the sum of (i) a Participant's Pre-tax Contributions for any calendar year (ii) a Participant's Roth Contributions and (iii) any other "elective deferrals" (as defined in Code Section 402(g)(3)) for any calendar year, exceed the dollar limitation set forth in Code Section 402(g) ($18,500 for 2018, and as adjusted thereafter), except to the extent Catch-up Contributions are permitted under Plan Section 3.02B and Code Section 414(v).

B. Distribution of Excess Deferrals. In the event that the aggregate amount of Pre-tax Contributions and Roth Contributions by a Participant exceeds the maximum dollar limitation as determined under subsection A above, the amount of such excess Pre-tax Contributions and Roth Contributions (the "Excess Elective Deferrals"), increased by any income and decreased by any losses attributable thereto, shall be returned to the Participant no later than April 15th of the calendar year following the calendar year for which the Pre-tax Contributions and Roth Contributions were made.

C. Determination of Income or Loss. Excess Elective Deferrals shall be adjusted for any income or loss for the calendar year in which such contributions occurred. Adjustment for income or loss during the period between the end of the Plan Year to the date of distribution (the "Gap Period") shall not be required. The income or loss allocable to Excess Elective Deferrals is equal to the sum of the allocable gain or loss for the Plan Year and, to the extent that such Excess Elective Deferrals would otherwise be credited with gain or loss for the Gap Period if the total Account were to be distributed, the allocable gain or loss during that period.

The Plan Administrator may use any reasonable method for computing the income allocable to Excess Elective Deferrals, provided that the method does not violate Code Section 401(a)(4), is used consistently for all Participants and for all corrective distributions under the Plan for the Plan Year, and is used by the Plan for allocating income to Participants' Accounts. The Plan will not fail to use a reasonable method for computing the income allocable to Excess Elective Deferrals merely because the income allocable to such contributions is determined on a date that is no more than seven days before the actual distribution. In addition, the Plan Administrator may allocate income in any manner permitted under applicable Treasury Regulations.

Section 7.02 Annual Additions - Definitions. For purposes of Section 7.03, the following definitions and rules of interpretation shall apply:

A. "Annual Additions." The sum of the following amounts credited to a Participant's Account for any Limitation Year:

(i) Employer contributions;

(ii) Employee contributions (not including Catch-up Contributions); and

(iii) Forfeitures, if any.

Except to the extent provided in Treasury Regulations, Annual Additions also include any excess contributions described in Code Section 401(k), excess aggregate contributions described in Code Section 401(m), and excess deferrals described in Code Section 402(g), irrespective of whether the Plan distributes or forfeits such excess amounts. Annual Additions also include amounts allocated to an individual medical account (as defined in Code Section 415(1)(2)) included as part of a pension or annuity plan maintained by the Employer. Furthermore, Annual Additions include contributions attributable to post-retirement medical benefits allocated to the separate account of a Key Employee (as defined in Code Section 419(A)(d)(3)) under a welfare benefit fund (Code Section 419(e)) maintained by the Employer.

Annual Additions shall not include the following: (i) Transfer Contributions; (ii) Rollover Contributions; (iii) reinvestment of dividends pursuant to Section 8.08; and (iv) restorative payments allocated to a Participant's Account, which include payments made to restore losses to the Plan resulting from actions (or a failure to act) by a fiduciary for which there is a reasonable risk of liability under Title I of ERISA or under other applicable federal or state law, where similarly situated Participants are similarly treated.

B. "Excess Amount." For a Participant for each Limitation Year, the excess, if any of (i) the Annual Additions that would be credited to his Account under the terms of the Plan without regard to Code Section 415 over (ii) the maximum Annual Additions allowed under Code Section 415(c)(1)(A).

C. "Limitation Year." The Plan Year.

D. "Maximum Permissible Amount." The Maximum Permissible Amount with respect to any Participant shall be the lesser of:

(i) $55,000 for 2018 (and thereafter as adjusted for increases in cost-of-living under Code Section 415(d)), or

(ii) 100% of the Participant's Compensation for the Limitation Year.

The Compensation limit set forth in (ii) above, shall not apply to any contribution for medical benefits after separation from Service (within the meaning of Code Section 401(h) or Code Section 419(f)(2)), which is otherwise treated as an Annual Addition.

Section 7.03 Limitations Under Code Section 415. The amount of the Annual Addition that may be credited under the Plan to any Participant's Account, or that may be credited to such Participant under any other qualified plan, welfare benefit fund (as defined in Code Section 419(e)) or an individual medical account (as defined in Code Section 415(1)(2)), maintained by an Employer, for any Limitation Year shall not exceed the Maximum Permissible Amount.

The following provisions shall apply:

A. Notwithstanding anything contained in the Plan to the contrary, the provisions of the Plan shall at all times comply with the limitations, adjustments and other requirements prescribed in Code Section 415 and the Treasury Regulations thereunder, the terms of which are specifically incorporated herein by reference.

B. Subject to the provisions of subsection E, if the foregoing limitation on allocations would be exceeded in any Limitation Year for any Participant as a result of (i) reasonable error in estimating such Participant's Compensation, (ii) reasonable error in determining the amount of elective deferrals within the meaning of Code Section 402(g)(3) (that may be made with respect to such Participant) or (iii) under such other limited facts and circumstances that the Commissioner of Internal Revenue (pursuant to Treasury Regulation Section 415-6(b)(6)) finds justify the availability of this Section), the After-tax Contributions, Pre-tax Contributions and Roth Contributions made by or with respect to such Participant shall be distributed to him, to the extent that any such distribution would reduce the amount in excess of the limits of this Section. Any amount in excess of the limits of this Section remaining after such distribution shall be placed, unallocated to any Participant, in a designated Plan account ("Suspense Account.") If a Suspense Account is in existence at any time during a particular Limitation Year, other than the Limitation Year described in the preceding sentence, all amounts in the Suspense Account must be allocated to the Participants' Accounts (subject to the limits of this Section) before any contributions which would constitute Annual Additions may be made to the Plan for that Limitation Year. The excess amount allocated pursuant to this Section shall be used to reduce Matching Contributions for the next Limitation Year (and succeeding Limitation Years), as necessary, for that Participant. However, if that Participant is not covered by the Plan as of the end of the applicable Limitation Year, then the excess amounts must be held unallocated in the Suspense Account for the Limitation Year and allocated and reallocated in the next Limitation Year to all of the remaining Participants in the Plan. The Suspense Account shall not share in the valuation of Participants' Accounts, and the allocation of earnings set forth in Section 8.02 of the Plan and the change in fair market value and allocation of earnings attributable to the Suspense Account shall be allocated to the remaining Accounts hereunder as set forth in Section 8.02.

C. Prior to determining a Participant's actual Compensation for the Limitation Year, the Plan Administrator may determine the Maximum Permissible Amount for a Participant on the basis of a reasonable estimate of the Participant's Compensation for the Limitation Year uniformly determined for all Participants similarly situated.

D. As soon as is administratively feasible after the end of the Limitation Year, the Maximum Permissible Amount for the Limitation Year shall be determined on the basis of the Participant's actual Compensation for the Limitation Year.

E. If pursuant to subsections B and D, there is an Excess Amount to be distributed to a Participant covered by the Plan at the end of the Limitation Year, the Employer may only correct such excess in accordance with the Employee Plans Compliance Resolution System (EPCRS), or any successor thereto.

ARTICLE VIII
TRUST CREATION, ALLOCATION AND INVESTMENTS

Section 8.01 Establishment of Trust. On behalf of the Plan, an agreement has been executed (the "Trust Agreement") to establish a trust to hold the assets of the Plan (the "Trust") and to appoint one or more persons or parties who shall serve as the Trustee. The Trustee so selected shall serve as the Trustee until otherwise replaced by the Committee or said Trust Agreement is terminated. The Committee may, from time to time, enter into such further agreements with the Trustee or other parties and make such amendments to said Trust Agreement as it may deem necessary or desirable to carry out this Plan. Any and all rights or benefits which may accrue to a person under this Plan shall be subject to all the terms and provisions of the Trust Agreement.

Section 8.02 Accounting and Adjustments. With respect to each Participant, the Plan Administrator and Trustee may maintain separate subaccounts (for accounting purposes only) to reflect the different kinds of contributions made to the Plan, as follows: Pre-tax Contributions Account, Roth Contributions Account, Catch-up Contributions Account, After-tax Contribution Account, Matching Contribution Account, Profit Sharing Account, Next Gen Employer Contribution Account, Prior Profit Sharing Account, Rollover Account and Transfer Account(s), if any, and any additional subaccounts as needed.

Amounts credited to such subaccounts shall be allocated among the Participant's designated investments on a reasonable pro rata basis, in accordance with the valuation procedures of the Trustee and the Investment Funds. The Trustee and the Plan Administrator shall also establish uniform procedures which they may change from time to time, for the purpose of adjusting the subaccounts of a Participant's Account for withdrawals, loans, distributions and contributions. Gains, losses, withdrawals, distributions, forfeitures and other credits or charges may be separately allocated among such subaccounts on a reasonable and consistent basis in accordance with such procedures.

Section 8.03 Value of Participant's Account. The value of each Participant's Account shall be based on its fair market value on the appropriate Valuation Date. A valuation shall occur at least once every Plan Year, and otherwise in accordance with the terms of the Trust and administratively practicable procedures approved by the Plan Administrator. Periodically, on a frequency determined by the Plan Administrator and the Trustee, the Participant will receive a statement showing the transaction activity and value of his Account as of a date set forth in the statement.

Section 8.04 Investment Funds. The Committee and the Trustee shall establish certain investment funds (the "Investment Funds"), rules governing the administration of the Investment Funds, and procedures for directing the investment of Participant Accounts among the Investment Funds. Among these investment funds shall be the Company Stock Fund as defined in Article I and as further described in Section 8.08 of this Article, which remains at all times invested primarily in Company Stock. The Trustee shall invest and reinvest the principal and income of each Account in the Trust Fund as required by ERISA and as directed by Participants. The Committee reserves the right to change the investment options available under the Plan and the rules governing investment designations at any time and from time to time; provided, however, that the Committee shall at all times maintain the Company Stock Fund as an investment fund option.

Notwithstanding any other provisions of the Plan, assets of the Trust may be invested in any collective investment fund or funds, including common and group trust funds presently in existence or hereafter established. The assets so invested shall be subject to all the provisions of the instruments establishing such funds as they may be amended from time to time, and which are hereby incorporated by reference.

Section 8.05 Participant Direction of Investment. The Plan Administrator and the Trustee shall establish rules governing the administration of Investment Funds and procedures for Participant direction of investment, including rules governing the timing, frequency and manner of making investment elections. Nothing in this or any other provision of the Plan shall require the Trustee or the Plan Administrator to implement Participant investment directions or changes in such directions, or to establish any procedures, other than on an administratively practicable basis, as determined by the Committee in its discretion.

Each Participant shall, in accordance with procedures established by the Plan Administrator and the Trustee, direct that his Account and contributions thereto be invested and reinvested in any one or more of the Investment Funds. The investment of any such monies shall be subject to such restrictions as the Plan Administrator may determine, in its sole discretion, to be advisable or necessary under the circumstances. Moreover, in accordance with procedures established by the Trustee and agreed to by the Plan Administrator, Participants may, when administratively practicable, be permitted to change their current and prospective investment designations through telephone, "on-line" or similar instructions to the Trustee or its authorized agent on a frequency established under such procedures, as in effect from time to time.

The exercise of investment direction by a Participant will not cause the Participant to be a fiduciary solely by reason of such exercise, and neither the Trustee nor any other fiduciary of this Plan will be liable for any loss or any breach that results from the exercise of investment direction by the Participant. The investment designation procedures established under the Plan shall be and are intended to be in compliance with the requirements of ERISA Section 404(c) and the regulations thereunder.

Notwithstanding any provision to the contrary, the Committee may, in its sole discretion and where the terms of any relevant investment contracts, regulated investment companies or pooled or group trusts so require, impose special terms, conditions and restrictions upon a Participant's right to direct the investment in, or transfer into or out of, such contracts, companies or trusts.

Section 8.06 Administration of Investment Designations.

A. Affirmative Direction. The Trustees shall invest and reinvest the Account as the Participant shall instruct the Plan Administrator, according to the provisions of Section 8.05 by such means of instruction as provided by the Plan Administrator. The instructions of a Participant shall remain in force until altered by him. With the exception of automatic Pre-tax Contributions, no contributions may be authorized by or made for a Participant unless an investment instruction with respect to such contributions is provided by him prior to the date such contributions are authorized or delivered. A Participant shall not be allowed to withdraw all prior investment instructions unless simultaneous therewith he delivers new investment instructions.

B. Default Investments. To the extent that a Participant fails to give the investment directions contemplated in subsection A above with respect to automatic Pre-tax Contributions, the Participant's Account related to such contributions shall be invested in such default investment fund(s) established by the Committee in its discretion. In addition, with respect to any Rollover Contributions for a Participant who fails to give the investment directions contemplated in subsection A above, the Participant's Account related to such contributions shall be invested in such default investment fund(s) established by the Committee in its discretions, which such fund(s) may or may not be the same fund(s) established for automatic Pre-Tax Contributions. In establishing such default investment fund(s), the Committee may elect to comply with the rules and regulations applicable to "qualified default investment alternatives" as established by the Department of Labor pursuant to Section 404(c)(5) of ERISA.

C. Changing Designations. Any investment election given by a Participant for investment of his Account shall continue in effect until changed by the Participant or Beneficiary. A Participant or Beneficiary may change his current investment election as to his future Account in accordance with procedures established by the Plan Administrator.

Section 8.07 Special Rules Pertaining to Investment of Matching Contributions, Profit Sharing Contributions and Next Gen Employer Contributions. Matching Contributions, Profit Sharing Contributions and Next Gen Employer Contributions (whether each is made in the form of cash or Company Stock, pursuant to Section 3.08) shall be allocated as follows:

A. Non-Union Employees. Effective for contributions made prior to July 1, 2017, all Matching Contributions, Profit Sharing Contributions and Next Gen Employer Contributions made to the Accounts of non-union Participants were initially invested in the Company Stock Fund. Following such initial investment, in accordance with the provisions of Section 8.05 and 8.06, a Participant may elect to change such investment designation to a different Investment Fund.

Effective for contributions made on or after July 1, 2017, all Matching Contributions, Profit Sharing Contributions and Next Gen Employer Contributions made to the Accounts of non-union Participants shall be invested in accordance with the Participant's direction (or in the absence of Participant direction, according the applicable default) under the provisions of Sections 8.05 and 8.06.

B. Union Employees. Except as provided in Section II.04C and Section II.05C of Schedule II, all Matching Contributions, Profit Sharing Contributions (if applicable) and Next Gen Employer Contributions (if applicable) made to the Accounts of union Participants on and after July 1, 2017 shall continue to be initially invested in the Company Stock Fund. In accordance with the provisions of Sections 8.05 and 8.06, a Participant may elect to change such investment designation to a different Investment Fund at any time after such initial contribution.

Notwithstanding the foregoing, effective for contributions made on or after July 1, 2018, all Matching Contributions, Profit Sharing Contributions (if applicable) and Next Gen Employer Contributions (if applicable) made to the Accounts of Columbia Union Employees shall be invested in accordance with the Participant's direction (or in the absence of Participant direction, according to the applicable default) under the provisions of Sections 8.05 and 8.06.

With respect to the Participant's ability change such investment designation, the following provisions shall apply: (1) the Plan shall offer not less than three different Investment Funds, other than the Company Stock Fund, to which the Participant may direct the investment of his Account, each of which options is diversified and has materially different risk and return characteristics; (2) the Plan shall provide reasonable divestment and reinvestment opportunities no less than quarterly; and (3) except as provided in regulations, the Plan shall not impose restrictions or conditions on the investment of Company Stock which the Plan does not impose on the investment of other Plan assets, other than restrictions or conditions imposed by reason of the application of securities laws or a condition permitted under IRS Notice 2006-107 or other applicable guidance or any Company policy restricting Participant divestiture rights during specified periods.

Section 8.08 Special Rules Pertaining to the Company Stock Fund.

A. Dividends. Dividends attributable to a Participant's Account invested in the Company Stock Fund shall, at the election of the Participant, be payable to him in cash or reinvested in the Company Stock Fund. Such election shall be made no later than 15 days before the date on which such dividend is paid by the Company. Any Participant who fails to make a timely election shall have dividends attributable to the investment of his Account in the Company Stock Fund reinvested in the Company Stock Fund. Notwithstanding the previous sentences, any dividend payment less than $10 shall be so reinvested.

B. Procedures for Voting.

(i) When the issuer of Company Stock files preliminary proxy solicitation materials with the Securities and Exchange Commission, the Company shall cause a summary of the items being voted upon to be simultaneously sent to the Trustee. Based on this summary the Trustee shall prepare a voting instruction form. At the time of mailing of the notice of each annual or special stockholders' meeting of the Company, the Company shall cause a copy of the notice and all proxy solicitation materials to be sent to each Participant, together with the foregoing voting instruction form to be returned to the Trustee or its designee. The form shall show the number of full and fractional shares of Company Stock credited to the Participant's Account. For purposes of this Section, the number of shares of Company Stock deemed "credited" to the Participant's Account, attributable to the Company Stock Fund, shall be determined as of the last preceding valuation date for which an allocation has been completed and Company Stock has actually been credited to Participants' Accounts. The Company shall provide the Trustee with a copy of any materials provided to the Participants and shall certify to the Trustee that the materials have been mailed or otherwise sent to Participants.

(ii) Each Participant shall have the right to direct the Trustee as to the manner in which the Trustee is to vote that number of shares of Company Stock credited to the Participant's Account. Directions from a Participant to the Trustee concerning the voting of Company Stock shall be communicated in writing, or by such other means as agreed upon by the Trustee and the Committee; these directions shall be held in confidence by the Trustee and shall not be divulged to the Company, or any officer or employee thereof, or any other person. Upon its receipt of the directions, the Trustee shall vote the shares of Company Stock as directed by the Participant. The Trustee shall not vote shares of Company Stock credited to a Participant's Account for which it has received no directions from the Participant. Notwithstanding the foregoing, the Trustee shall vote shares of Company Stock that are credited to a Participant's Account and for which it has received no directions from the Participant, in the same proportion as it votes those shares for which it has received voting direction from Participants.

(iii) The Trustee shall vote that number of shares of Company Stock not credited to Participants' Accounts, which is determined by multiplying the total number of shares not credited to Participants' Accounts by a fraction, the numerator of which is the number of shares of Company Stock credited to Participants' Accounts for which the Trustee received voting directions from Participants and the denominator of which is the total number of shares of Company Stock credited to Participants' Accounts. The Trustee shall vote those shares of Company Stock not credited to Participants' Accounts which are to be voted by the Trustee pursuant to the foregoing formula in the same proportion on each issue as it votes those shares credited to Participants' Accounts for which it received voting directions from Participants. The Trustee shall not vote the remaining shares of Company Stock not credited to Participants' Accounts.

C. Procedures for Tendering.

(i) Upon commencement of a tender offer for any securities held in the Trust that are Company Stock, attributable to the Company Stock Fund, the Company shall notify each Participant of the tender offer and utilize its best efforts to timely distribute or cause to be distributed to the Participant the same information that is distributed to shareholders of the issuer of Company Stock in connection with the tender offer, and, after consulting with the Trustee, shall provide and pay for a means by which the Participant may direct the Trustee whether or not to tender the Company Stock credited to the Participant's Account. The Company shall provide the Trustee with a copy of any material provided to the Participants and shall certify to the Trustee that the materials have been mailed or otherwise sent to Participants.

(ii) Each Participant shall have the right to direct the Trustee to tender or not to tender some or all of the shares of Company Stock credited to the Participant's Account. Directions from a Participant to the Trustee concerning the tender of Company Stock shall be communicated in writing. The Trustee shall tender or not tender shares of Company Stock as directed by the Participant. The Trustee shall not tender shares of Company Stock credited to Participants' Accounts for which it has received no directions from the Participants. Directions received from Participants shall be held in confidence by the Trustee and shall not be divulged to the Company or any officer or employee thereof or any other person.

(iii) The Trustee shall tender that number of shares of Company Stock not credited to Participants' Accounts which is determined by multiplying the total number of shares of Company Stock not credited to Participants' Accounts by a fraction, the numerator of which is the number of shares of Company Stock credited to Participants' Accounts for which the Trustee has received directions from Participants to tender (which directions have not been withdrawn as of the date of this determination) and the denominator of which is the total number of shares of Company Stock credited to Participants' Accounts.

(iv) A Participant who has directed the Trustee to tender some or all of the shares of Company Stock credited to the Participant's Account may, at any time prior to the tender offer withdrawal date, direct the Trustee to withdraw some or all of the tendered shares, and the Trustee shall withdraw the directed number of shares from the tender offer prior to the tender offer withdrawal deadline. Prior to the withdrawal deadline, if any shares of Company Stock not credited to Participants' Accounts have been tendered, the Trustee shall redetermine the number of shares of Company Stock that would be tendered if the date of the tender offer withdrawal were the date of determination, and withdraw from the tender offer the number of shares of Company Stock not credited to Participants' Accounts necessary to reduce the amount of tendered Company Stock not credited to Participants' Accounts to the amount so redetermined. A Participant shall not be limited as to the number of directions to tender or withdraw that the Participant may give to the Trustee.

(v) A direction by a Participant to the Trustee to tender shares of Company Stock credited to the Participant's Account shall not be considered a written election under the Plan by the Participant to withdraw, or have distributed, any or all of his withdrawable shares. The Trustee shall credit to each Participant's Account from which the tendered shares were taken the proceeds received by the Trustee in exchange for the shares of Company Stock tendered from that Account.

ARTICLE IX
PARTICIPANT ADMINISTRATIVE PROVISIONS

Section 9.01 Personal Data to Committee. Each Participant and each Beneficiary of a deceased Participant must furnish to the Plan Administrator such evidence, data or information as the Plan Administrator considers necessary or desirable for the purpose of administering the Plan. The provisions of this Plan are effective for the benefit of each Participant upon the condition precedent that each Participant will furnish promptly full, true and complete evidence, data and information when requested by the Plan Administrator, provided the Plan Administrator shall advise each Participant of the effect of his failure to comply with its request.

Section 9.02 Address For Notification. Each Participant and each Beneficiary of a deceased Participant shall file with the Plan Administrator, from time to time, in writing, or otherwise notify the Plan Administrator (in accordance with its rules and procedures) of, his post office address and any change of post office address. Any communication, statement or notice addressed to a Participant, or Beneficiary, at his last post office address filed with the Plan Administrator, or as shown on the records of the Employer, shall bind the Participant, or Beneficiary, for all purposes of this Plan.

Section 9.03 Assignment or Alienation. Subject to Code Section 414(p) relating to qualified domestic relations orders, neither a Participant nor a Beneficiary shall anticipate, assign or alienate (either at law or in equity) any benefit provided under the Plan, and the Trustee shall not recognize any such anticipation, assignment or alienation. Furthermore, a benefit under the Plan is not subject to attachment, garnishment, levy, execution or other legal or equitable process.

Section 9.04 Notice of Change in Terms. Within the time prescribed by ERISA and the applicable regulations, the Plan Administrator, on behalf of the Employer, shall furnish all Participants and Beneficiaries a summary description of any material amendment to the Plan or notice of discontinuance of the Plan and all other information required by ERISA to be furnished without charge.

Section 9.05 Litigation Against the Trust. If any legal action filed against the Trustee, the Plan Administrator, the Committee, or against any member or members of the Committee, by or on behalf of any Participant or Beneficiary, results adversely to the Participant or to the

Beneficiary, the Trustee shall reimburse itself, the Plan Administrator, the Committee, or any member or members of the Committee, all costs and fees expended by it or them by surcharging all costs and fees against the sums payable under the Plan to the Participant or to the Beneficiary, but only to the extent a court of competent jurisdiction specifically authorizes and directs any such surcharges and only to the extent Code Section 401(a)(13) does not prohibit any such surcharges.

Section 9.06 Information Available. Any Participant in the Plan or any Beneficiary may examine copies of the Plan, the Trust, the Plan description, the latest annual report, any bargaining agreement, contract or any other instrument under which the Plan was established or is operated. The Plan Administrator will maintain all of the items listed in this Section in the Company's offices, or in such other place or places as it may designate from time to time in order to comply with the regulations issued under ERISA, for examination during reasonable business hours. Upon the written request of a Participant or Beneficiary, the Employer shall furnish him with a copy of any item listed in this Section. The Employer may make a reasonable charge to the requesting person for the copy so furnished.

Section 9.07 Special Rules Relating to Veterans Reemployment Rights Under USERRA. The following special provisions of this Section shall apply to an Employee or Participant who is reemployed in accordance with the reemployment provisions of the Uniformed Services Employment and Reemployment Rights Act ("USERRA") following a period of qualifying military service (as determined under USERRA):

A. Each period of qualifying military service served by an Employee or Participant shall, upon such reemployment, be deemed to constitute service with an Employer for all purposes of the Plan.

B. The Participant shall be permitted to make up Pre-tax Contributions and Roth Contributions missed during the period of qualifying military service. The Participant shall have a period of time beginning on the date of the Participant's reemployment with an Employer following his period of qualifying military service and extending over the lesser of (1) the product of three and the Participant's period of qualifying military service, and (2) five years, to make up such missed Pre-tax Contributions and Roth Contributions.

C. If an Employer made any Matching Contributions, Profit Sharing Contributions or Next Gen Employer Contributions to the Plan during the period of qualifying military service, it shall make a Matching Contribution, Profit Sharing Contribution or Next Gen Employer Contribution, as applicable, on behalf of the Participant upon the Participant's reemployment following his period of qualifying military service, in the amount that would have been made on behalf of such Participant had the Participant been employed during the period of qualifying military service.

D. An Employer shall not (1) credit earnings to a Participant's Accounts with respect to any Pre-tax Contribution, Roth Contribution, Matching Contribution, Profit Sharing Contribution or Next Gen Employer Contribution before such contribution is actually made, or (2) make up any allocation of forfeitures, with respect to the period of qualifying military service.

E. For all purposes under the Plan, including an Employer's liability for making contributions on behalf of a reemployed Participant as described above, the Participant shall be treated as having received Compensation from an Employer based on the rate of Compensation the Participant would have received during the period of qualifying military service, or if that rate is not reasonably certain, on the basis of the Participant's average rate of Compensation during the 12-month period immediately preceding such period.

F. If the Participant makes a Pre-tax Contribution or Roth Contribution, or an Employer makes a Matching Contribution, Profit Sharing Contribution or Next Gen Employer Contribution in accordance with the foregoing provisions of this Section 9.07, such contributions shall not be subject to any otherwise applicable limitation under Code Sections 402(g), 404(a) or 415, and shall not be taken into account in applying such limitations to other Pre-tax, Roth, Matching, Profit Sharing or Next Gen Employer Contributions under the Plan, or any other plan, with respect to the year in which such contributions are made, and such contributions shall be subject to these limitations only with respect to the year to which such contributions relate and only in accordance with Treasury Regulations prescribed by the Internal Revenue Service; and

G. The Plan shall not be treated as failing to meet the requirements of Code Sections 401(a)(4), 401(a)(26), 401(m), 410(b), or 416 by reason of such contributions.

Section 9.08 Claims Procedure. Claims for benefits under the Plan shall be made in writing to the Committee (or its delegate). Benefits under the Plan shall be paid only if the Committee, in its discretion, decides that the Claimant is entitled to them. If the Committee wholly or partially denies a claim for benefits, the Committee (or its delegate) shall, within a reasonable period of time, but no later than 90 days after receiving the claim, notify the Participant or Beneficiary (the "Claimant") in writing of the denial of the claim If the Committee (or its delegate) fails to notify the Claimant in writing of the denial of the claim within 90 days after the Committee receives it, the claim shall be deemed denied. A notice of denial shall be written in a manner calculated to be understood by the Claimant, and shall contain:

A. The specific reason or reasons for denial of the claim;

B. Specific references to the pertinent Plan provisions upon which the denial is based;

C. A description of any additional material or information necessary for the Claimant to perfect the claim, together with an explanation of why such material or information is necessary; and

D. An explanation of the Plan's review procedure.

Within 60 days of the receipt by the Claimant of the written notice of denial of the claim, or within 60 days after the claim is deemed denied as set forth above, if applicable, the Claimant may file a written request with the Committee that it conduct a full and fair review of the denial of the Claimant's claim for benefits, including the conducting of a hearing, if the Committee deems one necessary. In connection with the Claimant's appeal of the denial of his benefit, the Claimant may review pertinent documents and may submit issues and comments in writing. The Committee shall render a decision on the claim appeal promptly, but not later than 60 days after receiving the Claimant's request for review, unless, in the discretion of the Committee, special circumstances (such as the need to hold a hearing) require an extension of time for processing, in which case the 60-day period may be extended to 120 days. The Committee shall notify the Claimant in writing of any such extension. Notwithstanding the foregoing, if the Committee's meeting schedule is such that it holds regularly scheduled meetings at least quarterly, the Committee's final determination with respect to the applicant's application for review may be made within the period outlined in Department of Labor Regulations Section 2560.503-1(i)(1)(ii) in lieu of the 60-day period (120-day period if extended due to special circumstances) described above.

The decision upon review shall (1) include specific reasons for the decision, (2) be written in a manner calculated to be understood by the Claimant and (3) contain specific references to the pertinent Plan provisions upon which the decision is based. If the decision on review is not furnished within the time period set forth above, the claim shall be deemed denied on review.

If such final determination is favorable to the Claimant, it shall be binding and conclusive. If such final determination is adverse to such Claimant, it shall be binding and conclusive unless the applicant notifies the Committee within 90 days after the mailing or delivery to him by the Committee of its determination that he intends to institute legal proceedings challenging the determination of the Committee, and actually institutes such legal proceeding within 180 days after such mailing or delivery.

ARTICLE X
ADMINISTRATION OF THE PLAN

Section 10.01 Allocation of Responsibility Among Fiduciaries For Plan and Trust Administration. The fiduciaries shall have only those powers, duties, responsibilities and obligations as are specifically given to them under this Plan and the Trust. The Employers shall have the sole responsibility for making the contributions provided for under Article III. The Committee shall have the sole authority to appoint and remove the Trustee and to amend or terminate, in whole or in part, the Plan or the Trust. The Committee shall have the final responsibility for the administration of the Plan, which responsibility is specifically described in this Plan and the Trust. The Committee shall be the "plan administrator" and the 'named fiduciary" within the meaning of Title I of ERISA. In addition, the Committee shall have the specific delegated powers and duties described in the further provisions of this Article X and such further powers and duties as specified in the Committee charter. The Trustee shall have the sole responsibility for the administration of the Trust and the management of the assets held under the Trust, all as specifically provided in the Trust.

Each fiduciary warrants that any directions given, information furnished, or action taken by it shall be in accordance with the provisions of this Plan and the Trust, authorizing or providing for such direction, information or action. Furthermore, each fiduciary may rely upon any such direction, information or action of another fiduciary as being proper under this Plan and the Trust, and is not required under this Plan or the Trust to inquire into the propriety of any such direction, information or action. It is intended under this Plan and the Trust that each fiduciary shall be responsible for the proper exercise of its own powers, duties, responsibilities and obligations under this Plan and the Trust and shall not be responsible for any act or failure to act of another fiduciary. No fiduciary guarantees the Trust Fund in any manner against investment loss or depreciation in asset value.

Section 10.02 Appointment of Committee. The NiSource Benefits Committee (the "Committee") has administrative and investment responsibilities with respect to the Plan. In accordance with the Committee charter, the Chief Executive officer of the Company (the "CEO") has the authority to appoint and remove members of the Committee. All usual and reasonable expenses of the Committee may be paid in whole or in part by the Company, and any expenses not paid by the Company shall be paid by the Trustee out of the principal or income of the Trust Fund. Any members of the Committee who are Employees shall not receive compensation with respect to their services for the Committee.

Section 10.03 Committee Procedures. The Committee may act at a meeting or in writing without a meeting, pursuant to the applicable Committee charter. The Committee may adopt such bylaws and regulations as it deems desirable for the conduct of its affairs. All decisions of the Committee shall be made by the vote of the majority of members or of a quorum of members, including actions in writing taken without a meeting. By appropriate action, the Committee may authorize one or more of its members to execute documents on its behalf, and the Trustee, upon written notification of such authorization, shall accept and rely upon such documents until notified in writing that such authorization has been revoked by the Committee.

Section 10.04 Other Committee Powers and Duties. The Committee shall have such powers as may be necessary to discharge its duties hereunder, including, but not by way of limitation, the discretionary authority to perform the following powers and duties:

A. To construe and enforce the terms of the Plan and the rules and regulations it adopts, including the discretionary authority to interpret the Plan documents and documents related to the Plan's operation (including, but not limited to, issues of fact and questions of eligibility, benefits, status and rights of participants);

B. To adopt rules of procedure, uniform policies and regulations necessary for the proper and efficient administration of the Plan, provided the rules are not inconsistent with the terms of this Plan and the Trust;

C. To authorize and approve amendments to and restatements of the Plan;

D. To direct the Trustee with respect to the crediting and distribution of the Trust;

E. To review and render decisions respecting a claim for (or denial of a claim for) a benefit under the Plan, including judgment of the standard of proof required in any claim, subject to the requirements of applicable law and the Plan;

F. To furnish the Employer with information that the Employer may require for tax or other purposes;

G. To cause to be made all reports or other filing necessary to meet the reporting, disclosure and other filing requirements of the Code, ERISA and other applicable statutes, regulations and other authorities issued thereunder that are the responsibility of the Plan Administrator;

H. Act as the employer representatives or members on each committee having administrative and/or investment responsibilities with respect to any plan maintained by NiSource or its affiliates pursuant to a collective bargaining agreement;

I. To engage the service of agents whom it may deem advisable to assist it with the performance of its duties;

J. To engage the services of an Investment Manager or Investment Managers (as defined in ERISA Section 3(38)), each of whom shall have full power and authority to manage, acquire or dispose (or direct the Trustee with respect to acquisition or disposition) of any Plan asset under its control; and

K. As permitted by the Employee Plans Compliance Resolution System ("EPCRS") issued by the Internal Revenue Service ("IRS"), as in effect from time to time, (i) to voluntarily correct any Plan qualification failure, including, but not limited to failures involving Plan operation, impermissible discrimination in favor of highly compensated employees, the specific terms of the Plan document, or demographic failures; (ii) implement any correction methodology permitted under EPCRS; and (iii) negotiate the terms of a compliance statement or a closing agreement proposed by the IRS with respect to correction of a plan qualification failure.

Section 10.05 Rules and Decisions. The Committee may adopt such rules as it deems necessary, desirable or appropriate. All rules and decisions of the Committee shall be uniformly and consistently applied to all Participants in similar circumstances. When making a determination or calculation, the Committee shall be entitled to rely upon information furnished by an Employee, Participant or Beneficiary, an Employer, the legal counsel of an Employer, or the Trustee. Any determination by the Committee shall presumptively be conclusive and binding on all persons. The regularly kept records of the Company shall be conclusive and binding upon all persons with respect to an Employee's date and length of employment, time and amount of Compensation and the manner of payment thereof, type and length of any absence from work, and all other matters contained therein relating to Employees.

Section 10.06 Application and Forms For Benefits. The Committee may require a Participant or Beneficiary to complete and file with the Committee an application for a benefit and all other forms approved by the Committee, and to furnish all pertinent information requested by the Committee. The Committee may rely upon all such information so furnished to it, including the Participant's or Beneficiary's current mailing address.

Section 10.07 Authorization of Benefit Payments. The Committee shall issue directions to the Trustee concerning all benefits that are to be paid from the Trust Fund pursuant to the provisions of the Plan, or establish other procedures on which the Trustee may act, and warrants that all such directions are in accordance with this Plan.

Section 10.08 Funding Policy. The Committee shall, from time to time, review all pertinent Employee information and Plan data in order to establish the funding policy of the Plan and to determine the appropriate methods of carrying out the Plan's objectives. The Committee shall communicate periodically, as it deems appropriate, to the Trustee and to any Plan Investment Manager, the Plan's short-term and long-term financial needs so that investment policy can be coordinated with Plan financial requirements.

Section 10.09 Fiduciary Duties. In performing their duties, all fiduciaries with respect to the Plan shall act solely in the interest of the Participants and their Beneficiaries, and:

A. For the exclusive purpose of providing benefits to the Participants and their Beneficiaries;

B. With the care, skill, prudence and diligence under the circumstances then prevailing that a prudent man acting in like capacity and familiar with such matters would use in the conduct of an enterprise of like character and with like aims;

C. To the extent a fiduciary possesses and exercises investment responsibilities, by diversifying the investments of the Trust Fund so as to minimize the risk of large losses, unless under the circumstances it is clearly prudent not to do so; and

D. In accordance with the documents and instruments governing the Plan insofar as such documents and instruments are consistent with the provisions of Title I of ERISA.

Section 10.10 Allocation or Delegation of Duties and Responsibilities. In furtherance of their duties and responsibilities under the Plan, the Committee may, subject always to the requirements of Section 10.09:

A. Employ agents to carry out nonfiduciary responsibilities;

B. Employ agents to carry out fiduciary responsibilities (other than trustee responsibilities as defined in Section 405(c)(3) of ERISA);

C. Consult with counsel, who may be of counsel to the Company; and

D. Provide for the allocation of fiduciary responsibilities (other than trustee responsibilities as defined in Section 405(c)(3) of ERISA) between and among the members of the Committee.

Section 10.11 Procedure For the Allocation or Delegation of Fiduciary Duties. Any action described in subsections B or D of Section 10.10 may be taken by the Committee only in accordance with the following procedure:

A. Such action shall be taken by a majority of the Committee in a resolution approved by a majority of such Committee.

B. The vote cast by each member of the Committee for or against the adoption of such resolution shall be recorded and made a part of the written record of the Committee's proceedings.

C. Any delegation of fiduciary responsibilities or any allocation of fiduciary responsibilities among members of the Committee may be modified or rescinded by the Committee according to the procedure set forth in subsections A and B of this Section 10.11.

Section 10.12 Records and Reports. The Employer (or the Committee if so designated by the Employer) shall exercise such authority and responsibility as it deems appropriate in order to comply with ERISA and governmental regulations issued thereunder relating to records of Participant's Service and Account balances; notifications to Participants; annual registration with the Internal Revenue Service; and annual reports to the Department of Labor.

Section 10.13 Individual Statement. As determined by the Committee in its discretion, the Plan Administrator shall furnish to the Participant (or to the Beneficiary of a deceased Participant) an individual statement reflecting the condition of his Account. In addition, subject to the requirements of ERISA, the Plan Administrator shall provide to any Participant or Beneficiary of a deceased Participant who so requests in writing, a statement indicating the total value of his Account and the nonforfeitable portion of such Account, if any. The Plan Administrator shall also furnish a written statement to any Participant who terminates employment during the Plan Year and is entitled to a deferred vested benefit under the Plan as of the end of the Plan Year, if no retirement benefits have been paid with respect to such Participant during the Plan year. No Participant, except a member of the Committee and its designees, shall have the right to inspect the records reflecting the Account of any other Participant.

Section 10.14 Fees and Expenses From Fund. The Trustee, other than the Company when serving as such, shall receive reasonable annual compensation as may be agreed upon from time to time between the Committee and the Trustee. The Trustee shall pay all expenses reasonably incurred by it or by the Employer(s), the Committee, or other professional advisers or administrators in the administration of the Plan from the Trust Fund unless the Employer(s) pay the expenses. The Committee shall not treat any fee or expense paid, directly or indirectly, by an Employer as an Employer contribution. No person who is receiving full pay from the Employer shall receive compensation for services from the Trust Fund. Brokerage commissions, transfer taxes, and other charges and expenses in connection with the purchase and sale of securities shall be charged to each Investment Fund and/or Participant's Account, as applicable. Fees related to investments subject to Participant direction, and other fees resulting from or attributable to expenses incurred in relation to a Participant or Beneficiary or his Account may be charged to his Account to the extent permitted under the Code and ERISA.

The Trustee or other service provider may provide refunds of expenses, rebates or other similar revenue sharing credits on behalf of the Plan that relate to the assets of the Plan. At the Plan Administrator's sole discretion, such amounts paid by the Trustee or other service provider on behalf of the Plan may be used to pay reasonable administrative expenses of the Plan, or may be allocated to Participants in reasonable and nondiscriminatory manner, or in any combination of these solely to the extent permitted by applicable law.

Section 10.15 Use of Alternative Media. The Plan Administrator may include in any process or procedure for administering the Plan, the use of alternative media, including, but not limited to, telephonic, facsimile, computer or other such electronic means as available. Use of such alternative media shall be deemed to satisfy any Plan provision requiring a "written" document or an instrument to be signed "in writing" to the extent permissible under the Code, ERISA and applicable regulations.

Section 10.16 Information to Plan Administrator. Each Employer shall supply current information to the Plan Administrator as to the name, date of birth, date of employment, annual compensation, leaves of absence, Service, and date of termination of employment of each Employee who is, or who will be eligible to become, a Participant under the Plan, together with any other information that the Committee considers necessary. The Employer's records as to the current information that the Employer furnishes to the Committee shall be conclusive as to all persons.

Section 10.17 Limitation of Liability. Notwithstanding any other provision of the Plan or the Trust, no Employer nor member of the Committee, nor an individual acting as an employee or agent of any of them, shall be liable to any Participant or former Participant, or any Beneficiary or Spouse of any Participant or former Participant, for any claim, loss, liability, or expense incurred in connection with the Plan or the Trust, except when the same shall have been judicially determined to be due to the willful misconduct of such person.

Section 10.18 Indemnity. The Company shall indemnify and hold harmless each member of the Committee, or any employee of an Employer or any individual acting as an employee or agent of any of them or of an Employer (to the extent not indemnified or saved harmless under any liability insurance or any other indemnification arrangement with respect to the Plan or the Trust) from any and all claims, losses, liabilities, costs, and expenses (including attorneys' fees) arising out of any actual or alleged act or failure to act with respect to the administration of the Plan or the Trust, except that no indemnification or defense shall be provided to any person with respect to any conduct that has been judicially determined, or agreed by the parties, to have constituted willful misconduct on the part of such person, or to have resulted in his receipt of personal profit or advantage to which he is not entitled. In connection with the indemnification provided by the preceding sentence, expenses incurred in defending a civil or criminal action, suit or proceeding, or incurred in connection with a civil or criminal investigation may be paid by the Company in advance of the final disposition of such action, suit, proceeding, or investigation, as authorized by the Committee in the specific case, upon receipt of an undertaking by or on behalf of the party to be indemnified to repay such amount unless it shall ultimately be determined that he is entitled to be indemnified by the Company pursuant to this paragraph.

Section 10.19 Severability. Each of the Sections contained in the Plan, and each provision in each Section, shall be enforceable independently of every other Section or provision in the Plan, and the invalidity or unenforceability of any Section or provision shall not invalidate or render unenforceable any other Section or provision contained herein. If any Section or provision in a Section is found invalid or unenforceable, it is the intent of the parties that a court of competent jurisdiction shall reform the Section or provision to produce its nearest enforceable economic equivalent.

Section 10.20 Recovery of Overpaid Benefits. If a payment of benefits to a Participant, Beneficiary or other individual entitled to payment under the Plan (such as an alternate payee pursuant to Section 4.10) (collectively, the "Recipient") exceeds the amount provided for under the terms of the Plan, either by mistake or for any other reason, the Plan Administrator shall have the authority to seek reimbursement of such overpaid benefits from the Recipient (plus interest calculated in accordance with guidance set forth by the Internal Revenue Service). If a Recipient is receiving benefit payments at the time an overpayment of prior benefits is discovered, the Plan Administrator shall have the authority to reduce such Recipient's benefit payments going forward in an amount as necessary in the Plan Administrator's discretion to recover the overpaid benefits.

Section 10.21 Forfeitures. To the extent permitted by applicable law, forfeitures may be used at the Plan Administrator's sole discretion to pay reasonable administrative expenses and/or to reduce Employer contributions.

ARTICLE XI
TOP HEAVY RULES

Section 11.01 Minimum Employer Contribution. If this Plan is "Top Heavy," as defined below, in any Plan Year, the Plan guarantees a minimum contribution (subject to the provisions of this Article XI) of three percent of Compensation for each "Non-Key Employee," as defined below, who is a Participant employed by the Employer on the Accounting Date of the Plan Year without regard to hours of Service completed during the Plan Year or to whether he has elected to make Pre-tax Contributions or Roth Contributions under Section 3.02, and who is not a Participant in a Top Heavy defined benefit plan maintained by the Employer. Participants who also participate in a Top Heavy defined benefit plan of the Employer shall receive the required minimum benefit in the defined benefit plan rather than in this Plan. The Plan satisfies the guaranteed minimum contribution for the Non-Key Employee if the Non-Key Employee's contribution rate is at least equal to the minimum contribution. For purposes of this paragraph, a Non-Key Employee Participant includes any Employee otherwise eligible to participate in the Plan but who is not a Participant because his Compensation does not exceed a specified level.

If the contribution rate for the "Key Employee," as defined below, with the highest contribution rate is less than three percent, the guaranteed minimum contribution for Non-Key Employees shall equal the highest contribution rate received by a Key Employee. The contribution rate is the sum of Employer contributions (not including Employer contributions to Social Security) and forfeitures allocated to the Participant's Account for the Plan Year divided by his "Compensation," as defined below, not in excess of the compensation limitation under Code Section 401(a)(17) for the Plan Year. For purposes of determining the minimum contribution for a Plan Year, the Plan Administrator shall consider contributions made to any plan pursuant to a compensation reduction agreement or similar arrangement as Employer contributions. To determine the contribution rate, the Plan Administrator shall consider all qualified Top Heavy defined contribution plans maintained by the Employer as a single plan.

Notwithstanding the preceding provisions of this Section 11.01, if a defined benefit plan maintained by the Employer that benefits a Key Employee depends on this Plan to satisfy the anti-discrimination rules of Code Section 401(a)(4) or the coverage rules of Code Section 410 (or another plan benefiting the Key Employee so depends on such defined benefit plan), the guaranteed minimum contribution for a Non-Key Employee is three percent of his Compensation regardless of the contribution rate for the Key Employees.

The minimum employer contribution required (to the extent required to be nonforfeitable under Code Section 416(b)) may not be forfeited under Code Section 411(a)(3)(B) or 411(a)(3)(D).

Section 11.02 Additional Contribution. If the contribution rate (excluding Pre-tax Contributions and Roth Contributions) for the Plan Year with respect to a Non-Key Employee described in Section 11.01 is less than the minimum contribution, the Employer will increase its contribution for such Employee to the extent necessary so his contribution rate for the Plan Year will equal the guaranteed minimum contribution. Matching Contributions will be taken into account to satisfy the minimum contribution requirement under the Plan, or if the Plan provides that the minimum contribution requirement shall be met in another plan, such other plan. Matching Contributions that are used to satisfy the minimum contribution requirements shall be treated as matching contributions for purposes of the actual contribution percentage test and other requirements of Code Section 401(m). The additional contribution shall be allocated to the Account of a Non-Key Employee for whom the Employer makes the contribution.

Section 11.03 Determination of Top Heavy Status. The Plan is "Top Heavy" for a Plan Year if the Top Heavy ratio as of the Determination Date exceeds sixty percent (60%). The Top Heavy ratio is a fraction, the numerator of which is the sum of the present value of the Accounts of all Key Employees as of the Determination Date, and the denominator of which is a similar sum determined for all Employees. For purposes of determining the present value of the Accounts for the foregoing fraction, the Plan Administrator shall include contributions due as of the Determination Date and distributions made for any purpose within the one-year period ending on the Determination Date. In addition, the Plan Administrator shall also include distributions made within the five-year period ending on the Determination Date if such distributions were made for reasons other than upon severance from employment, death or disability (e.g., in-service withdrawals); provided, however, that no distribution shall be counted more than once. In addition, the Plan Administrator shall calculate the Top Heavy ratio by disregarding the Account (including distributions, if any, of the Account balance) of an individual who has not received credit for at least one Hour of Service with the Employer during the one-year period ending on the Determination Date in such calculation. The Top Heavy ratio, including the extent to which it must take into account distributions, rollovers and transfers, shall be calculated in accordance with Code Section 416 and the Treasury Regulations thereunder.

If the Employer maintains other qualified plans (including a simplified employee pension plan), this Plan is Top Heavy only if it is part of the Required Aggregation Group, and the Top Heavy ratio for both the Required Aggregation Group and the Permissive Aggregation Group exceeds 60%. The Top Heavy ratio shall be calculated in the same manner as required by the first paragraph of this Section 11.03, taking into account all plans within the Aggregation Group. To the extent distributions to a Participant must be taken into account, the Plan Administrator shall include distributions from a terminated plan that would have been part of the Required Aggregation Group if it were in existence on the Determination Date. The present value of accrued benefits and the other amounts the Plan Administrator must take into account, under defined benefit plans or simplified employee pension plans included within the group, shall be calculated in accordance with the terms of those plans, Code Section 416 and the Treasury Regulations thereunder. If an aggregated plan does not have a valuation date coinciding with the Determination Date, the Plan Administrator shall value the accrued benefits or Accounts in the aggregated plan as of the most recent valuation date falling within the 12-month period ending on the Determination Date. The Plan Administrator shall calculate the Top Heavy ratio with reference to the Determination Dates that fall within the same calendar year.

The accrued benefit of a Participant other than a Key Employee shall be determined under (a) the method, if any, that uniformly applies for accrual purposes under all defined benefit plans maintained by the Employer, or (b) if there is no such method, as if such benefit accrued not more rapidly than the slowest accrual rate permitted under the fractional rule of Code Section 411(b)(1)(C).

Code Section 416(g)(4)(H) as clarified by Revenue Ruling 2004-13 excludes from the definition of Top Heavy plan those plans that make only contributions described in Code Sections 401(k)(12) or 401(m)(11) for any Plan Year. If any other contributions are made (e.g., profit sharing contributions or forfeitures) for a Plan Year, the requirements of Code Section 416(g)(4)(H) are not met and the Plan is subject to the Top Heavy rules in Code Section 416 for that Plan Year.

Section 11.04 Top Heavy Vesting Schedule. For any Plan Year for which the Plan is Top Heavy, as determined in accordance with this Article XI, any Participant who severs from the employment of all Employers and all Affiliates shall have, as of the date thereof, a vested right to his entire Account Balance.

Section 11.05 Definitions. For purposes of applying the provisions of this Article XI:

A. "Key Employee" means any Employee or former Employee (including any deceased Employee) who at any time during the Plan Year that includes the Determination Date was (i) an officer of the Employer having annual Compensation greater than $175,000 (as adjusted under Code Section 416(i)(1)), (ii) a more than five-percent owner of the Employer, or (iii) a more than one-percent owner of the Employer having annual Compensation of more than $175,000. The Plan Administrator shall make the determination of who is a Key Employee in accordance with Code Section 416(i) and the Treasury Regulations promulgated thereunder.

B. "Non-Key Employee" is an Employee who does not meet the definition of Key Employee.

C. "Compensation" shall mean the first $275,000 for 2018 (or such larger amount as the Commissioner of Internal Revenue may thereafter prescribe in accordance with Code Section 401(a)(17)) of Compensation as defined in Code Section 415(c)(3), but including amounts contributed by the Employer pursuant to a salary reduction agreement that are excludible from the Employee's gross income under Section 125, "deemed compensation" under Code Section 125, Section 132(f)(4), Section 402(a)(8), Section 402(h) or Section 403(b) of the Code.

D. "Required Aggregation Group" means:

(i) Each qualified plan of the Employer in which at least one Key Employee participates at any time during the five Plan Year period ending on the Determination Date; and

(ii) Any other qualified plan of the Employer that enables a plan described in (i) to meet the requirements of Code Section 401(a)(4) or Code Section 410.

The Required Aggregation Group includes any plan of the Employer which was maintained within the last five years ending on the Determination Date on which a top heaviness determination is being made if such plan would otherwise be part of the Required Aggregation Group for the Plan Year but for the fact it has been terminated.

E. "Permissive Aggregation Group" is the Required Aggregation Group plus any other qualified plans maintained by the Employer, but only if such group would satisfy in the aggregate the requirements of Code Section 401(a)(4) and Code Section 410. The Plan Administrator shall determine which plans to take into account in determining the Permissive Aggregation Group.

F. "Employer" shall mean all the members of a controlled group of corporations (as defined in Code Section 414(b)), of a commonly controlled group of trades or businesses (whether or not incorporated) (as defined in Code Section 414(c)), or an affiliated service group (as defined in Code Section 414(m)), of which the Employer is a part. However, the Plan Administrator shall not aggregate ownership interests in more than one member of a related group to determine whether an individual is a Key Employee because of his ownership interest in the Employer.

G. "Determination Date" for any Plan Year is the Accounting Date of the preceding Plan Year or, in the case of the first Plan Year of the Plan, the Accounting Date of that Plan Year.

ARTICLE XII
MISCELLANEOUS

Section 12.01 Evidence. Anyone required to give evidence under the terms of the Plan may do so by certificate, affidavit, document or other information that the person to act in reliance may consider pertinent, reliable and genuine, and to have been signed, made or presented by the proper party or parties. Both the Committee and the Trustee shall be fully protected in acting and relying upon any evidence described under the immediately preceding sentence.

Section 12.02 No Responsibility For Employer Action. Neither the Trustee nor the Committee shall have any obligation or responsibility with respect to any action required by the Plan to be taken by the Employer, any Participant or Eligible Employee, nor for the failure of any of the above persons to act or make any payment or contribution, or otherwise to provide any benefit contemplated under this Plan, nor shall the Trustee or the Committee be required to collect any contribution required under the Plan, or determine the correctness of the amount of any Employer contribution. Neither the Trustee nor the Committee need inquire into or be responsible for any action or failure to act on the part of the others. Any action required of a corporate Employer shall be by its Board or its designee.

Section 12.03 Fiduciaries Not Insurers. The Trustee, the Committee, the Plan Administrator and the Employer in no way guarantee the Trust Fund from loss or depreciation. The Employer does not guarantee the payment of any money that may be or becomes due to any person from the Trust Fund. The liability of the Committee, the Plan Administrator and the Trustee to make any payment from the Trust Fund at any time and all times is limited to the then available assets of the Trust.

Section 12.04 Waiver of Notice. Any person entitled to notice under the Plan may waive the notice, unless the Code or Treasury Regulations require the notice, or ERISA specifically or impliedly prohibits such a waiver.

Section 12.05 Successors. The Plan shall be binding upon all persons entitled to benefits under the Plan, their respective heirs and legal representatives, upon the Employer, its successors and assigns, and upon the Trustee, the Committee, the Plan Administrator and their successors.

Section 12.06 Word Usage. Words used in the masculine shall apply to the feminine where applicable, and wherever the context of the Plan dictates, the plural shall be read as singular and the singular as the plural.

Section 12.07 Headings. The headings are for reference only. In the event of a conflict between a heading and the content of a section, the content of the section shall control.

Section 12.08 Governing Law and Venue. In order to benefit Plan Participants by establishing a uniform application of law with respect to the administration of the Plan, the provisions of this Section shall apply. Indiana law shall determine all questions arising with respect to the provisions of the Plan, except to the extent superseded by federal law. Any suit, action or proceeding seeking to enforce any provision of, or based on any matter arising out of or in connection with, this Plan shall be brought in any court of the State of Indiana and of the United States for the Northern District of Indiana. The Company, each Related Employer that adopts the Plan, each Participant, and any related parties irrevocably and unconditionally consent to the exclusive jurisdiction of such courts in any such litigation related to this Plan and any transactions contemplated hereby. Such parties irrevocably and unconditionally waive any objection that venue is improper or that such litigation has been brought in an inconvenient forum.

Section 12.09 Employment Not Guaranteed. Nothing contained in this Plan, and nothing with respect to the establishment of the Trust, any modification or amendment to the Plan or the Trust, the creation of any Account, or the payment of any benefit, shall give any Employee, Employee-Participant or Beneficiary any right to continue employment, or any legal or equitable right against the Employer, or an Employee of the Employer, the Committee, the Trustee or its agents or employees, or the Plan Administrator. Nothing in the Plan shall be deemed or construed to impair or affect in any manner the right of the Employer, in its discretion, to hire Employees and, with or without cause, to discharge or terminate the service of Employees.

ARTICLE XIII
PLAN ADOPTION

Section 13.01 Adoption Procedure. With the written consent of the Committee, any Related Employer may adopt the Plan and the Trust for its eligible employees by appropriate resolution, that shall specify the effective date of such adoption and that may contain such changes and variations in Plan terms as the Committee approves. Any such adoption shall be contingent upon a determination by the Internal Revenue Service that such resolution, in conjunction with the Plan and with the Trust, constitutes a qualified plan and trust under applicable provisions. An Employer adopting the Plan shall compile and submit all information required by the Trustee with reference to its Eligible Employees.

Section 13.02 Joint Employers. If an Employee receives Compensation simultaneously from more than one participating Employer, the total amount of such Compensation shall be considered for the purposes of the Plan as having been paid by one participating Employer and the respective participating Employers shall share pro-ratably in contributions to the Plan on account of said Employee.

Section 13.03 Expenses. Each participating Employer shall pay such part of actuarial and other necessary expenses incurred in the administration of the Plan as the Trustee shall determine Withdrawal. A participating Employer may withdraw from the Plan at any time by giving written notice of its intention to the Committee and the Trustee prior to the effective date of withdrawal; provided, however that such withdrawal may be subject to the provisions of Article XIV.

Section 13.04 Superseded Plans. If an Employer adopting the Plan already maintains a pension plan covering employees who shall be covered by the Plan, it may, with the consent of the Committee, provide in its resolution adopting the Plan for the merger, restatement and continuation, without discontinuance or termination, of its plan by the Plan.

ARTICLE XIV
EXCLUSIVE BENEFIT, AMENDMENT, TERMINATION

Section 14.01 Exclusive Benefit. Except as provided under Article III, the Employer shall have no beneficial interest in any asset of the Trust and no part of any asset in the Trust shall ever revert to or be repaid to the Employer, either directly or indirectly; nor prior to the satisfaction of all liabilities with respect to the Participants and their Beneficiaries under the Plan, shall any part of the corpus or income of the Trust Fund, or any asset of the Trust, be (at any time) used for, or diverted to, purposes other than the exclusive benefit of the Participants or their Beneficiaries.

Section 14.02 Amendment By the Committee. The Committee shall have the right at any time and from time to time:

A. To amend this agreement in any manner it deems necessary or advisable in order to qualify (or maintain qualification of) this Plan and the Trust created under it under the appropriate provisions of the Code; and

B. To amend this agreement in any other manner.

However, no amendment shall authorize or permit any part of the Trust Fund (other than the part required to pay taxes and administration expenses) to be used for or diverted to purposes other than for the exclusive benefit of the Participants or their Beneficiaries or estates. No amendment shall cause or permit any portion of the Trust Fund to revert to or become a property of the Employer; and the Committee shall not make any amendment that affects the rights, duties or responsibilities of the Plan Administrator or the Committee without the written consent of the affected Plan Administrator or the affected member of the Committee. Furthermore, no amendment shall decrease a Participant's Account balance or accrued benefit or reduce or eliminate any benefit protected under Code Section 411(d)(6), with respect to a Participant with an Account balance or accrued benefit at the date of the amendment, except to the extent permitted under Code Section 412(c)(8).

The Committee shall make all amendments in writing. Each amendment shall state the date to which it is either retroactively or prospectively effective, and may be executed by any authorized member or other delegate of the Committee. Notwithstanding the foregoing, no oral representation shall act to amend the Plan in an manner or at any time.

Section 14.03 Discontinuance. The Committee shall have the right, at any time, to suspend or discontinue any Employer contributions under the Plan, or revoke the Employer's participation in the Plan. At the time of any such discontinuance or revocation, satisfactory evidence thereof and of any applicable conditions imposed shall be delivered to the Trustee. The Trustee shall thereafter transfer, deliver and assign Trust Fund assets allocable to the Participants employed by such Employer to such new trustee as shall have been designated by such Employer, in the event that it has established a separate pension plan for its Employees; provided however, that no such transfer shall be made if the result is the elimination or reduction of any benefit protected under Code Section 411(d)(6). If no successor is designated, the Trustee shall retain such assets for the Employees of such Employer pursuant to the provisions of the Plan and Trust. In no such event shall any part of the corpus or income of the Trust as it relates to such Employer be used for or diverted to purposes other than for the exclusive benefit of the Employees of such Employer.

The Committee shall have the right to terminate, at any time, this Plan and the Trust created under this agreement. The Plan shall terminate upon the first to occur of the following:

A. The date terminated by action of the Committee.

B. The dissolution, merger, consolidation or reorganization of the Company or the sale by the Company of all or substantially all of its assets, unless the successor or purchaser makes provision to continue the Plan, in which event the successor or purchaser shall substitute itself as the Plan Sponsor under this Plan.

Section 14.04 Full Vesting on Termination. Notwithstanding any other provision of this Plan to the contrary, upon either full or partial termination of the Plan, or, if applicable, upon the date of complete discontinuance of contributions to the Plan, an affected Participant's right to his Account shall be 100% nonforfeitable.

Section 14.05 Merger, Direct Transfer and Elective Transfer. The Trustee shall not consent to, or be a party to, any merger or consolidation with another plan, or to a transfer of assets or liabilities to another plan, unless immediately after the merger, consolidation or transfer, the surviving plan provides each Participant a benefit equal to or greater than the benefit each Participant would have received had the Plan terminated immediately before the merger or consolidation or transfer. The Trustee possesses the specific authority to enter into merger agreements or direct transfer of assets agreements with the trustees of other retirement plans described in Code Section 401(a) and to accept the direct transfer of plan assets, or to transfer plan assets, as a party to any such agreement, only upon the consent or direction of the Committee.

If permitted by the Committee in its discretion, the Trustee may accept a direct transfer of plan assets on behalf of an Employee prior to the date the Employee satisfies the Plan's eligibility condition(s). If the Trustee accepts such a direct transfer of plan assets, the Committee and the Trustee shall treat the Employee as a Participant for all purposes of the Plan except that the Employee shall not share in Employer contributions or Participant forfeitures under the Plan until he actually becomes a Participant in the Plan. The Trustee shall hold, administer and distribute the transferred assets as a part of the Trust Fund, and the Trustee shall maintain a separate Transfer Account for the benefit of the Employee on whose behalf the Trustee accepted the transfer in order to reflect the value of the transferred assets.

The Trustee may not consent to, or be a party to, a merger, consolidation or transfer of assets with a defined benefit plan, except with respect to an elective transfer, unless the Committee consents and so directs, and the transfer is consistent with the Code and with ERISA. The Trustee will hold, administer and distribute the transferred assets as a part of the Trust Fund, and the Trustee shall maintain a separate Transfer Account for the benefit of the Employee on whose behalf the Trustee accepted the transfer in order to reflect the value of the transferred assets. Unless a transfer of assets to this Plan is an elective transfer, the Plan will preserve all Code Section 411(d)(6) protected benefits with respect to those transferred assets, in the manner described in Section 14.02.

A transfer is an elective transfer if: (a) the transfer satisfies the first paragraph of this Section 14.05; (b) the transfer is voluntary, under a fully informed election by the Participant; (c) the Participant has an alternative that retains his Code Section 411(d)(6) protected benefits (including an option to leave his benefit in the transferor plan, if that plan is not terminating); (d) the transfer satisfies the applicable spousal consent requirements of the Code; (e) the transferor plan satisfies the joint and survivor notice requirements of the Code, if the Participant's transferred benefit is subject to those requirements; (f) the Participant has a right to immediate distribution from the transferor plan, in lieu of the elective transfer; (g) the transferred benefit is at least the greater of the single sum distribution provided by the transferor plan for which the Participant is eligible or the present value of the Participant's accrued benefit under the transferor plan payable at that plan's normal retirement age; (h) the Participant has a 100% nonforfeitable interest in the transferred benefit; and (i) the transfer otherwise satisfies applicable Treasury Regulations. An elective transfer may occur between qualified plans of any type.

If the Plan receives a direct transfer (by merger or otherwise) of elective contributions (or amounts treated as elective contributions) under a plan with a Code Section 401(k) arrangement, the distribution restrictions of Code Sections 401(k)(2) and (10) continue to apply to those transferred elective contributions.

Section 14.06 Termination. Upon a complete or partial termination of the Plan, the Accounts of all Participants affected thereby shall be fully vested, and the Committee may direct the Trustee:

A. to continue to administer the Trust Fund and pay Account Balances in accordance with Article IV to each Participant affected by the complete or partial termination upon his termination of employment or to his Beneficiary upon such Participant's death, until the Trust Fund, or the portion thereof applicable to the Participants affected by the partial termination, has been liquidated; or

B. to distribute the assets remaining in the Trust Fund, or the portion thereof attributable to Participants affected by the partial termination, after payment of any expenses properly chargeable thereto, to the applicable Participants and Beneficiaries in proportion to the respective Account Balances.

Section 14.07 Manner of Distribution. Upon termination of the Plan, distribution shall be made in cash or Company Stock in a manner consistent with the requirements of Article IV.

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IN WITNESS WHEREOF, this Amendment and Restatement of the NiSource Inc. Retirement Savings Plan is hereby executed on this 19th day of November, 2018, by the duly authorized representative of the NiSource Benefits Committee, to be effective as of January 1, 2018 or such other date as set forth in this Amendment and Restatement.

NISOURCE BENEFITS COMMITTEE

By: Randall L. Bowl
Its: VP HR Operations & Benefits
Benefits Committee

SCHEDULE I

MATCHING CONTRIBUTIONS

Subject to the limitations of Article VI and VII, an Employer shall contribute and pay or cause to be paid to the Trustee a Matching Contribution, as described in Section 3.05, determined as set forth in this Schedule I. The amount of Matching Contribution varies based on certain factors as described below, including (i) the kind of benefit a Participant is eligible to receive under the applicable plan of the NiSource Pension Plans, and (ii) the Participant's Employer.

Notwithstanding the following provisions of this Schedule I, with respect to Participants who were employed by Kokomo or NIFL as of June 30, 2011 and who transitioned to employment with NIPSCO on July 1, 2011, the Matching Contribution provisions applicable to such Kokomo or NIFL employees immediately prior to the merger shall remain in effect to the extent that pension plan provisions applicable to NIPSCO, NIFL, or Kokomo remain in effect. Effective December 31, 2012, the Subsidiary Pension Plan and the Kokomo Union Pension Plan merged into the NiSource Salaried Pension Plan and the NIPSCO Union Pension Plan (as applicable). However, the matching contribution provisions applicable to Kokomo or NIFL employees shall continue to be determined as immediately prior to the merger of the entities on July 1, 2011 as described above (except to the extent that any such employee changed pension benefit structures (e.g., switching from the AB II to the AB I Benefit structure)).

A. <u>AB II Participants</u>

For the Account of each Participant who participates in the AB II Benefit of any of the NiSource Pension Plans that offers such benefit, the Matching Contribution shall be an amount equal to 100% of the Pre-tax Contribution, Roth Contribution and After-tax Contribution made by or for each Participant, not to exceed 6% of the total Compensation of such Participant.

B. <u>AB I Participants</u>

For the Account of each Participant who participates in the AB I Benefit of any of the NiSource Pension Plans that offers such benefit, the Matching Contribution shall be an amount equal to 75% of the Pre-tax Contribution, Roth Contribution and After-tax Contribution made by or for each Participant, not to exceed 6% of the total Compensation of such Participant.

C. <u>FAP Participants</u>

(i) <u>NIFL Participants</u>. For the Account of each Participant who was employed by NIFL immediately prior to the merger of NIFL with NIPSCO on July 1, 2011 who participated in the FAP Benefit of the former Subsidiary Pension Plan (merged into the NIPSCO Union Pension Plan effective as of December 31, 2012), the Matching Contribution shall be an amount equal to 50% of the Pre-tax Contribution and Roth Contribution made by or for each Participant, not to exceed 6% of the total Compensation of such Participant.

(ii) Other FAP Participants. For the Account of each Participant employed by any Employer not covered in subsection C paragraph (i), above, who participates in the FAP Benefit of the NiSource Salaried Pension Plan or the NIPSCO Union Pension Plan (including for purposes of this subsection (ii) employees of Kokomo immediately prior to the merger of Kokomo with NIPSCO on July 1, 2011 who participated in the Subsidiary Pension Plan or the Kokomo Union Pension Plan that merged into the NIPSCO Union Pension Plan effective December 31, 2012), the Matching Contribution shall be an amount equal to 11.1% of the Pre-tax Contribution and Roth Contribution made by or for such Participant.

D. Bay State Union Employees. For the Account of each Bay State Union Employee, the Matching Contribution shall be an amount as set forth in Schedule II.

E. NIPSCO Union Employees. In accordance with subsection B, above, for the Account of each NIPSCO Union Employee who participates in the AB I Benefit of the NIPSCO Union Pension Plan, the Matching Contribution amount shall be the amount described in such subsection B. In accordance with subsection C(iv), above, for the Account of each NIPSCO Union Employee who participates in the FAP Benefit of the NIPSCO Union Pension Plan (with the exception of any former NIFL employee as described in subsection C(iii) above), the Matching Contribution amount shall be the amount described in such subsection C(iv).

F. Next Gen Employees. Notwithstanding the foregoing, for any Eligible Employees who are or become Next Gen Employees, the Matching Contribution shall be an amount equal to 50% of the Pre-tax Contribution, Roth Contribution and After-tax Contribution made by or for each Participant, not to exceed 6% of the total Compensation of such Participant.

G. Special Provision for Damage Prevention Coordinators from June 1, 2016 to April 30, 2019. For any Employees employed in the position of Damage Prevention Coordinator during the period from June 1, 2016 to April 30, 2019, Matching Contributions for such Employees shall be determined according to the Matching Contribution provision in effect for the Employee under subsection A, subsection B or subsection F above, as applicable, immediately prior to becoming employed in the position of Damage Prevention Coordinator. For any new hire during this period into the position of Damage Prevention Coordinator, Matching Contributions shall be determined under subsection F above. Effective as of May 1, 2019, Matching Contributions for Employees employed in the position of Damage Prevention Coordinator shall be determined according to subparagraph E above.

SCHEDULE II

SPECIAL PROVISIONS FOR BAY STATE UNION EMPLOYEES

Section II.01 BACKGROUND AND APPLICABILITY. Effective December 31, 2008 (the "Merger Date"), the Bay State Gas Company Savings Plan for Operating Employees ("Bay State Union 401(k) Plan") merged into the Plan and the assets of the Bay State Union 401(k) Plan transferred to the Plan. After the Merger Date, Bay State Union Employees participate in and are subject to the terms of the Plan and this Schedule II.

Section II.02 PLAN VS. SPECIAL PROVISIONS. Except as set forth in this Schedule II or as specifically otherwise provided elsewhere in the Plan, the provisions of the Plan shall apply to Bay State Union Employees. This Schedule II sets forth special provisions that shall apply solely to Bay State Union Employees.

Section II.03 ELIGIBILITY, PARTICIPATION AND ENROLLMENT

A. Eligible Employee. An Eligible Employee that is subject to one of the collective bargaining agreements set forth below shall be considered a Bay State Union Employee. (Such list is described in this Schedule II for informational purposes only and may be updated or modified as necessary by the Company.)

Bay State Collective Bargaining Units

- Lawrence Division, International Brotherhood of Electrical Workers, Local No. 326 ("*Lawrence Employees*")
- Brockton Division, Utility Workers' Union of America, AFL-CIO, Local No. 273 ("*Brockton Operating Employees*")
- Brockton Division, Utility Workers' Union of America, AFL-CIO, Local No. 273 Clerical/Technical Unit ("*Brockton C/T Employees*")
- Springfield Division, United Steelworkers of America, AFL-CIO, Local No. 12026 ("*Springfield Operating Employees*")
- Springfield Division, International Brotherhood of Electrical Workers, Local No. 486 ("*Northampton Employees*")
- Springfield Division, United Steelworkers of America, AFL-CIO-CLC, Local 12026 Clerical Technical Unit ("*Springfield C/T Employees*")

B. Participation and Enrollment Generally. In accordance with Plan Section 2.01, and except as provided in Section II.03C, below, a Bay State Union Employee shall become a Participant in the Plan on the first day of the month following the completion of a 60-day Period of Service and may enroll in the Plan thereafter pursuant to the general enrollment provisions of Section 2.01A.

C. Participation and Enrollment Modifications, and Application of Automatic Enrollment for Specified Employees. Notwithstanding the provisions of Section II.03B above, Bay State Union Employees shall both (i) become Participants upon their Employment Commencement Date (meaning that the 60-day Period of Service provision from Section II.03B above shall not apply) and (ii) be subject to the automatic enrollment provisions set forth in Section 2.01B of the Plan, as set forth below.

(i) Participation. Bay State Union Employees shall become Participants upon their Employment Commencement Date as provided in the following schedule:

- Lawrence Employees hired or rehired on or after January 1, 2008.
- Brockton Operating Employees hired or rehired on or after January 1, 2008.
- Brockton C/T Employees hired or rehired on or after January 1, 2008.
- Northampton Employees hired or rehired on or after January 1, 2011.
- Springfield C/T Employees hired or rehired on or after January 1, 2011.
- Springfield Operating Employees hired or rehired on or after January 1, 2014.

(ii) Automatic Enrollment. The Automatic Percentage Amount for each group of Bay State Union Employees shall be 3% of Compensation, except as provided in the schedule below:

- The Automatic Percentage Amount for Northampton Employees hired or rehired on or after January 1, 2016 shall be 6% of Compensation.
- The Automatic Percentage Amount for Springfield C/T Employees hired or rehired on or after January 1, 2016 shall be 6% of Compensation.
- The Automatic Percentage Amount for Brockton Operating Employees hired or rehired on or after July 1, 2018 shall be 6% of Compensation.
- The Automatic Percentage Amount for Lawrence Employees hired or rehired on or after July 1, 2018 shall be 6% of Compensation.
- The Automatic Percentage Amount for Brockton C/T Employees hired or rehired on or after July 1, 2018 shall be 6% of Compensation.
- The Automatic Percentage Amount for Springfield Operating Employees hired or rehired on or after July 1, 2018 shall be 6% of Compensation.

Section II.04 MATCHING CONTRIBUTIONS.

A. Amount. Subject to the limitations of Article VI and VII, and in accordance with Section 3.04 and subsection D of Schedule I, Bay State or the Company shall contribute and pay or cause to be paid to the Trustee a Matching Contribution, determined as set forth in this Section II.04A. The amount of such Matching Contribution shall be determined by the Bay State Union Employee's collective bargaining agreement as set forth below.

(i) Lawrence Employees and Brockton Operating Employees. Participants who are Lawrence Employees or Brockton Operating Employees are considered either Next Gen Employees or AB II Participants under the Bay State Union Plan and are subject to subparagraphs (a) or (b) below, as applicable.

(a) Next Gen Employees. Each Lawrence Employee or Brockton Operating Employee hired or rehired on or after January 1, 2013 is considered a Next Gen Employee. Accordingly, as described in subsection F of Schedule I, each such Participant shall be entitled to a Matching Contribution equal to 50% of the Pre-tax Contribution, Roth Contribution and After-tax Contribution made by or for each Participant, not to exceed 6% of the total Compensation of such Participant.

(b) Employees Considered AB II Participants. Participants who are Lawrence or Brockton Operating Employees hired/rehired prior to January 1, 2013 (*i.e.*, not Next Gen Employees) are considered AB II Participants under the Bay State Union Plan. In accordance with the provisions of subsection A of Schedule I, each such Participant shall be entitled to a Matching Contribution equal to 100% of the Pre-tax Contribution, Roth Contribution and After-tax Contribution made by or for each Participant, not to exceed 6% of the total Compensation of such Participant.

(ii) Brockton C/T Employees. Participants who are Brockton C/T Employees are considered either Next Gen Employees or AB II Participants under the Bay State Pension Plan and are subject to subparagraphs (a) or (b) below, as applicable.

(a) Next Gen Employees. Each Brockton C/T Employee who is hired or rehired on or after June 1, 2013 is considered a Next Gen Employee. In accordance with subsection F of Schedule I, each such Participant shall be entitled to a Matching Contribution equal to 50% of the Pre-tax Contribution, Roth Contribution and After-tax Contribution made by or for each Participant, not to exceed 6% of the total Compensation of such Participant.

(b) Employees Considered AB II Participants. Participants who are Brockton C/T Employees hired/rehired prior to June 1, 2013 (i.e., not Next Gen Employees) are considered AB II Participants under the Bay State Union Plan. In accordance with the provisions of subsection A of Schedule I, the Matching Contribution for such Participants shall be an amount equal to 100% of the Pre-tax Contribution, Roth Contribution and After-tax Contribution made by or for each Participant, not to exceed 6% of the total Compensation of such Participant.

(iii) Northampton Employees. Participants who are Northampton Employees are considered either Next Gen Employees or AB II Participants under the Bay State Union Plan and are subject to subparagraphs (a) or (b) below, as applicable.

(a) Next Gen Employees. Each Northampton Participant hired or rehired on or after January 1, 2011 is considered a Next Gen Employee. Accordingly, each such Participant shall be entitled to a Matching Contribution equal to 50% of the Pre-tax Contribution, Roth Contribution and After-tax Contribution made by or for each Participant, not to exceed 6% of the total Compensation of such Participant.

(b) Employees Considered AB II Participants. Participants who are Northampton Employees hired/rehired prior to January 1, 2011 (i.e., not Next Gen Employees) are considered AB II Participants under the Bay State Union Plan. Accordingly, in accordance with the provisions of subsection A of Schedule I, each such Participant shall be entitled to a Matching Contribution equal to 100% of the Pre-tax Contribution, Roth Contribution and After-tax Contribution made by or for each Participant, not to exceed 6% of the total Compensation of such Participant.

(iv) Springfield C/T Employees. Participants who are Springfield C/T Employees are considered either Next Gen Employees or AB II Participants under the Bay State Union Plan and are subject to subparagraphs (a) or (b) below, as applicable.

(a) Next Gen Employees. Each Springfield C/T Participant hired or rehired on or after January 1, 2011 is considered a Next Gen Employee. Accordingly, each such Participant shall be entitled to a Matching Contribution equal to 50% of the Pre-tax Contribution, Roth Contribution and After-tax Contribution made by or for each Participant, not to exceed 6% of the total Compensation of such Participant.

(b) Employees Considered AB II Participants. Participants who are Springfield C/T Employees hired/rehired prior to January 1, 2011 (i.e., not Next Gen Employees) are considered AB II Participants under the Bay State Union Plan. Accordingly, in accordance with the provisions of subsection A of Schedule I, each such Participant shall be entitled to a Matching Contribution equal to 100% of the Pre-tax Contribution, Roth Contribution and After-tax Contribution made by or for each Participant, not to exceed 6% of the total Compensation of such Participant.

(v) Springfield Operating Employees. Participants who are Springfield Operating Employees are considered either Next Gen Employees or AB II Participants under the Bay State Union Plan and are subject to subparagraphs (a) or (b) below, as applicable.

(a) Next Gen Employees. Each Springfield Operating Employee hired or rehired on or after January 1, 2014 is considered a Next Gen Employee. Accordingly, each such Participant shall be entitled to a Matching Contribution equal to 50% of the Pre-tax Contribution, Roth Contribution and After-tax Contribution made by or for each Participant, not to exceed 6% of the total Compensation of such Participant.

(b) Employees Considered AB II Participants. Participants who are Springfield Operating Employees hired/rehired prior to January 1, 2014 (i.e., not Next Gen Employees) are considered AB II Participants under the Bay State Union Plan. Accordingly, in accordance with the provisions of subsection A of Schedule I, each such Participant shall be entitled to a Matching Contribution equal to 100% of the Pre-tax Contribution, Roth Contribution and After-tax Contribution made by or for each Participant, not to exceed 6% of the total Compensation of such Participant.

B. Matching Allocation. Notwithstanding the matching allocation provisions of Section 3.05, in accordance with the Plan enrollment provisions set forth in Section 11.03 subsection B or C, as applicable, a Bay State Union Employee shall become eligible to receive Matching Contributions upon becoming a Participant in the Plan and making Pre-tax Contributions or Roth Contributions (*i.e.*, on the first day of the month following the completion of a 60-day Period of Service or upon Employment Commencement Date, as applicable).

C. Matching Contribution Investment. Notwithstanding the matching allocation provisions of Section 3.05 and Section 8.07, Matching Contributions contributed on behalf of Bay State Union Employees shall be invested in accordance with the investment allocation selected by each Bay State Union Employee, in accordance with Section 8.05 and 8.06, rather than invested automatically in the Company Stock Fund.

Notwithstanding the foregoing, Matching Contributions contributed on behalf of Bay State Union Employees who are Next Gen Employees shall be automatically invested in the Company Stock Fund in accordance with Section 3.05 and Section 8.07, except with respect to Matching Contributions contributed on or after July 1, 2018 on behalf of (i) Springfield Operating Employees who are Next Gen Employees; (ii) Brockton C/T Employees who are Next Gen Employees; (iii) Brockton Operating Employees who are Next Gen Employees; or (iv) Lawrence Employees who are Next Gen Employees.

Section II.05 PROFIT SHARING CONTRIBUTIONS AND NEXT GEN EMPLOYER CONTRIBUTIONS.

A. Profit Sharing Contributions. No Bay State collective bargaining agreement currently provides for a Profit Sharing Contribution to be allocated to any Bay State Union Employee.

B. Next Gen Employer Contributions. In addition, for any Bay State Union Employee who is a Next Gen Employee, the Employer shall contribute a Next Gen Employer Contribution each pay period to the Account of each such Participant in an amount equal to 3% of such Participant's total Compensation for that pay period (as applicable for Next Gen Employees) in accordance with the provisions set forth in Section 3.06C (applicable to Next Gen Employees). Also in accordance with Section 3.06C, the Next Gen Employer Contribution shall be payable regardless of whether Next Gen Employee Participants have elected to make any elective deferrals to the Plan and regardless of the Participant's status as of the end of the Plan Year.

C. Profit Sharing Contribution and Next Gen Employer Contribution Investment.

(i) Profit Sharing Contributions. Profit Sharing Contributions described in Section II.05A above shall be invested and allocated in accordance with the Participant's direction (or in the absence of Participant direction, according to the applicable default) under the provisions of Section 8.05 and 8.06.

(ii) Next Gen Employer Contributions. Next Gen Employer Contributions shall be allocated to the Company Stock Fund and shall be 100% vested and nonforfeitable at all times. Notwithstanding the foregoing, Next Gen Employer Contributions made on or after July 1, 2018 on behalf of any Brockton Operating Employee, Brockton C/T Employee, Springfield Operating Employee, or Lawrence Employee shall be allocated in accordance with the Participant's direction (or in the absence of Participant direction, according to the applicable default) under the provisions of Section 8.05 and 8.06.

Section II.06 DISTRIBUTIONS AND WITHDRAWALS. The provisions of Article IV (regarding payment of benefits) and Article V (regarding in-service withdrawals and loans) shall be applicable to the Account balance of any Bay State Union employee in the same manner as other Account balances.

SCHEDULE III

SPECIAL PROVISIONS FOR NIPSCO UNION EMPLOYEES

Section III.01 BACKGROUND AND APPLICABILITY. Effective December 31, 2008 (the "Merger Date"), the Northern Indiana Public Service Company Bargaining Unit Tax Deferred Savings Plan ("NIPSCO 401(k) Plan") merged into the Plan and the assets of the NIPSCO 401(k) Plan transferred to the Plan. After the Merger Date, NIPSCO Union Employees participate in and are subject to the terms of the Plan and this Schedule III.

Prior to the Merger Date, NIPSCO Union Employees participated in and were governed by the terms of the NIPSCO 401(k) Plan. While operated as a separate plan with a separate trust up until the Merger Date, the NIPSCO 401(k) Plan is amended and restated pursuant to the terms of this restated Plan document (including this Schedule III) as of the Effective Date shall be operated in accordance with the terms set forth in the Plan as modified by this Schedule III.

The NIPSCO 401(k) Plan has been operated in accordance with all applicable recent legislation, including without limitation, the Economic Growth and Tax Relief Reconciliation Act of 2001 ("EGTRRA") (as such provisions were previously adopted and reflected in a restated plan document effective January 1, 2003); revisions required to comply with Internal Revenue Code Section 415; the Pension Protection Act of 2006 (PPA); and the Heroes Earnings Assistance and Relief Tax Act of 2008 ("HEART"). Upon amendment of the Plan to comply with all recent legislation (whether by this restated Plan or subsequent amendment), such amendment shall also apply to the assets transferred from the NIPSCO 401(k) Plan, and such plan shall be deemed to have been amended effective as of the specified date(s) required by applicable legislation.

Section III.02 PLAN VS. SPECIAL PROVISIONS. Except as set forth in this Schedule III or as specifically otherwise provided elsewhere in the Plan, the provisions of the Plan shall apply to NIPSCO Union Employees. This Schedule III sets forth special provisions that shall apply solely to NIPSCO Union Employees.

Section III.03 ELIGIBILITY, PARTICIPATION AND ENROLLMENT. The provisions of Article II (regarding Plan eligibility and enrollment) shall apply to the Account balance of any NIPSCO Union Employee in the same manner as other Account balances as described therein. Accordingly, NIPSCO Union Employees are eligible to participate in the Plan on their Employment Commencement Date or Reemployment Commencement Date and shall be subject to the general enrollment provisions. However, the automatic enrollment provisions of Section 2.01B shall not apply to any NIPSCO Union Employee hired prior to June 1, 2009. The Automatic Percentage Amount for NIPSCO Union Employees hired or rehired on or after June 1, 2009 shall be 3% of Compensation. The Automatic Percentage Amount for any NIPSCO Union Employees hired or rehired on or after January 1, 2015 shall be 6% of Compensation.

Section III.04 MATCHING CONTRIBUTIONS. The Matching Contributions of NIPSCO Union Employees shall be determined in accordance with Section 3.04 and 3.05, and Schedule I.

Pursuant to Section 1.44 of the Plan, as amended, for any Employee employed in the position of Damage Prevention Coordinator, Matching Contributions shall be determined as provided in Schedule I, as amended during the period from June 1, 2016 to April 30, 2019. Any Matching Contributions made to such Damage Prevention Coordinators during this period shall be invested as contributions for union Participants are invested in accordance with Section 8.07 of the Plan, as amended.

Section III.05 PROFIT SHARING CONTRIBUTIONS. As provided in Section 3.07A regarding eligibility for Profit Sharing Contributions for Employees subject to collective bargaining agreements, no NIPSCO collective bargaining agreement currently provides for a Profit Sharing Contribution to be allocated to any NIPSCO Union Employee. For purposes of this Section 111.05, former employees of NIFL and Kokomo who became employees of NIPSCO pursuant to the merger of those entities effective July 1, 2011 shall be considered NIPSCO Union Employees. The prior Kokomo or NIFL collective bargaining agreements did not provide for a Profit Sharing Contribution to be allocated to any such former employees of NIFL and Kokomo and, pursuant to the foregoing sentence, the current NIPSCO collective bargaining agreement to which such former NIFL and Kokomo employee became subject also does not provide for a Profit Sharing Contribution to Employees subject to the agreement.

Notwithstanding the foregoing, and pursuant to Section 1.44 of the Plan, as amended, any Employee employed in the position of Damage Prevention Coordinator during the period from June 1, 2016 to April 30, 2019 and eligible for Profit Sharing Contributions immediately prior to June 1, 2016, or if later, immediately prior to becoming employed in or transferring to the position of Damage Prevention Coordinator, shall be eligible for Profit Sharing Contributions under the Plan while employed in such position to the extent and on the same terms applicable to such Employees immediately prior to employment in the position of Damage Prevention Coordinator. In addition, any Employee who is a new hire during the period from June 1, 2016 to April 30, 2019 into the position of Damage Prevention Coordinator shall be eligible for Profit Sharing Contributions under the provisions set forth in Sections 3.06 and 3.07 of the Plan. In clarification of the foregoing, no Employee employed in the position of Damage Prevention Coordinator during the period from June 1, 2016 to April 30, 2019 shall be subject to the first paragraph above that provides no Profit Sharing Contributions for NIPSCO Union Employees. Any such Profit Sharing Contributions that may be made to Damage Prevention Coordinators during this period shall be invested as contributions for union Participants are invested in accordance with Section 8.07 of the Plan, as amended.

FIRST AMENDMENT TO THE NISOURCE INC. RETIREMENT SAVINGS PLAN

Background Information

A. NiSource Inc. ("NiSource") is the Plan Sponsor of the NiSource Inc. Retirement Savings Plan, amended and restated effective as of January 1, 2018 (the "Plan").

B. The NiSource Benefits Committee (the "Committee"), has the power to amend the Plan pursuant to Article XIV thereof.

C. The Committee desires to amend the Plan, effective as of January 1, 2019 or as otherwise indicated below, to revise the definition of eligible "Compensation" to include certain stipends payable to Bay State Union Employees employed in the role of Maintenance Mechanic M&R pursuant to the applicable collective bargaining agreement, clarify the definition of "NIPSCO" by adding additional information about the type of entity and state of formation and revise the description of the Plan's loan program to add the securities law limitations that restrict certain officers of the Company from taking loans from the portion of their accounts that are invested in the Company Stock Fund.

Plan Amendment

1. A new subparagraph A.(v) shall be added to Section 1.20 to be and read as follows:

> "(v) <u>Bay State Union Employees who are employed in the role of Maintenance Mechanic M&R.</u> For Participants who are Bay State Union Employees who are employed in the role of Maintenance Mechanic M&R and are entitled to receive an annual stipend pursuant to the terms of a collective bargaining agreement, the general definition of Compensation set forth above; the modified definition of Compensation set forth under subparagraph A.(iv), to the extent applicable; and the definition of Compensation applicable to Profit Sharing Contributions under Section 1.20B(i) below, to the extent applicable, shall apply with the following modification: Compensation shall also include any annual stipend that is required to be treated as eligible "Compensation" pursuant to the applicable collective bargaining agreement or subsequent memorandum of understanding. Notwithstanding the provisions of Section 2.04, a Bay State Union Employee who is employed in the role of Maintenance Mechanic M&R and is on an unpaid leave of absence shall be treated as an Eligible Employee during any period such individual is receiving the annual stipend payment under this subparagraph A(v)."

2. The existing subparagraph A.(v) under Section 1.20 shall be renumbered to be subparagraph 1.20A.(vi) and the renumbered subparagraph shall be titled "<u>Damage Prevention Coordinators.</u>".

3. The first sentence under Section 1.42 of the Plan ("NIPSCO") shall be amended and restated in its entirety as follows:

> "Northern Indiana Public Service Company LLC, an Indiana limited liability company, or any successor(s)."

4. Section 2.04 of the Plan ("Changes in Participant's Job Classification") shall be amended and restated in its entirety as follows (with added language indicated in bold, underlined text):

> "Section 2.04 Changes in Participant's Job Classification. A Participant who transfers to a classification of Employee that causes him to cease to meet the definition of Eligible Employee, or who is granted a leave of absence or placed on inactive status by an Employer, shall not be deemed to have terminated employment and shall not be entitled to a distribution based upon a Severance from Employment. While such Participant is employed by an Employer but not as an Eligible Employee, or is on an unpaid leave of absence or in inactive status, neither the Participant nor an Employer on his behalf shall make contributions to the Plan other than Rollover Contributions pursuant to Section 3.09, **except as provided in Section 1.20A.(v) with respect to Participants who are Bay State Union Employees who are employed in the role of Maintenance Mechanic M&R and are entitled to receive an annual stipend pursuant to the terms of a collective bargaining agreement.** If the Participant is later employed by an Employer, transfers to a classification of Employee which is eligible to participate in the Plan, returns to employment immediately upon expiration of a leave of absence, or is restored to active status, contributions to the Participant's account may resume under all applicable Plan provisions."

5. Section 5.08 of the Plan ("Loans to Participants") shall be amended by adding a new subsection "K" to be and read as follows:

> "Notwithstanding the foregoing, in the event a Section 16(b) Officer requests a loan pursuant to this Section, any such loan amount shall not be available in whole or in part from the portion of the Participant's Account that is invested in the Company Stock Fund if such Participant is restricted from transacting in Company stock by law or by the provisions of the Company's Securities Trading Policy. For purposes of this Section, "Section 16(b)" Officer shall mean an officer of the Company who is subject to the short-swing profit recapture rules of section 16(b) of the Securities Exchange Act of 1934, as amended."

6. All other provisions of the Plan shall remain unchanged.

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The Committee has caused this First Amendment to the NiSource Inc. Retirement Savings Plan to be executed on its behalf, by one of its members duly authorized, to be effective as of such date as set forth in this amendment.

NISOURCE BENEFITS COMMITTEE

By: [signature]
Name: Jillian K. Hanson
Title: Dir. of Benefits

SECOND AMENDMENT
TO THE
NISOURCE INC. RETIREMENT SAVINGS PLAN

Background Information

A. NiSource Inc. ("NiSource") is the Plan Sponsor of the NiSource Inc. Retirement Savings Plan, amended and restated effective as of January 1, 2018 (the "Plan").

B. The NiSource Benefits Committee (the "Committee"), has the power to amend the Plan pursuant to Article XIV thereof.

C. The Committee desires to amend the Plan, effective as of January 1, 2019 or as otherwise indicated below, to incorporate language enabling retired Former Participants to make rollover contributions to the Plan, provide language permitting the appointment of an independent fiduciary for the NiSource Company Stock Fund, and to provide for profit sharing contributions to Bay State Union Employees.

Plan Amendment

1. Section 3.09 of the Plan shall be amended and restated in its entirety as follows:

> "Section 3.09 Rollover and Transfer Contributions. The Trustee is authorized to accept and hold as part of the Trust Fund, assets transferred on behalf of an Employee, provided that such transfer satisfied any procedures or other requirements established by the Plan Administrator. The Trustee shall also accept and hold as part of the Trust Fund assets transferred in connection with a merger or consolidation of another plan with or into the Plan pursuant to Section 14.05 hereof and as may be approved by the Committee. In addition, the Trustee shall also accept "rollover" amounts (other than amounts attributable to after-tax contributions and earnings thereon) contributed directly by or on behalf of (i) an Employee or (ii) or a Former Participant who has retired from employment with the Company after completing at least ten years of service and attaining age 55 (a "Retired Former Participant") in accordance with procedures and rules established by the Plan Administrator in respect of a distribution made to or on behalf of such-Employee or Retired Former Participant from another plan pursuant to Section 14.05 hereof. All amounts so transferred to the Trust Fund shall be held in segregated subaccounts and shall be referred to as "Transfer Contributions" if such amounts are subject to the special distribution rules described in Section 14.05 and as "Rollover Contributions" if not subject to such rules. Rollover Contributions must conform to rules and procedures established by the Plan Administrator, including rules designed to assure the Plan Administrator that the funds so transferred qualify as a Rollover Contribution under the Code, including the rules specified in Section 5.07D herein."

2. Section 8.08 of the Plan is hereby amended by adding a new paragraph D to be and read as follows:

"D. Independent Fiduciary. Effective November 25, 2019, the Committee shall appoint an independent fiduciary (the "Independent Fiduciary") to manage the Company Stock Fund. The Independent Fiduciary shall at all times have the exclusive fiduciary authority and responsibility under the Plan and ERISA with respect to the Company Stock Fund as an investment option under the Plan. In exercising its authority and responsibility, the Independent Fiduciary shall have authority to exercise any or all of the following powers, and to instruct the Trustee of the Plan accordingly:

(i) to suspend or prohibit new investment in the Company Stock Fund;

(ii) to suspend or prohibit the transfer of Participant Accounts into the Company Stock Fund;

(iii) in connection with a determination that holding Company Stock is no longer prudent under ERISA, to liquidate the Company Stock in the Company Stock Fund;

(iv) to direct that the proceeds from any liquidation of Company Stock be invested on a temporary basis in the default investment option otherwise provided under the Plan (or in the absence of such a default option, in such investment option then available under the Plan as directed by the Committee), pending participant directions to the Trustee with respect to the investment of such proceeds;

(v) to suspend or prohibit the transfer of Participant Accounts out of the Company Stock Fund during any period in which the Independent Fiduciary is directing the liquidation of the Company Stock in the Company Stock Fund;

(vi) to determine the level of cash and cash equivalents in the Company Stock Fund necessary to facilitate participant transactions into and out of the Company Stock Fund and, in the event the Committee elects to cause the Plan to pay administrative fees and expenses, the payment of fees and expenses incurred to administer the Plan;

(vii) to instruct the Trustee or its designee as necessary to carry out its duties and responsibilities hereunder; and

(viii) to the extent provided in a written agreement with the Plan Sponsor and the Committee, to serve as the fiduciary responsible for voting shares of Company Stock or responding to tender offers for Company Stock.

An Independent Fiduciary may be removed by the Committee at any time and within its sole discretion in accordance with the applicable governing documents. In the event that the Independent Fiduciary resigns or is terminated, the duties and responsibilities provided to the Independent Fiduciary under this Section 8.08(D) shall become the duties and responsibilities of the Committee until a successor Independent Fiduciary is appointed by the Committee."

3. Section I.E of Schedule I is hereby amended by replacing cross references to "subsection C(iii)" and "subsection C(iv)" with cross references to "subsection C(i)" and "subsection C(ii)", respectively.

4. Section II.05A of Schedule II is hereby amended and restated in its entirety to be and read as follows:

> "Profit Sharing Contributions. Effective for Plan Years beginning on or after January 1, 2019, Bay State Union Employees are eligible for Profit Sharing Contributions in accordance with Section 3.07 of the Plan. The Profit Sharing Contribution made for a Plan Year shall be a stated percentage of Compensation (ranging from 0.5% to 1.5% of Compensation) of the Participants entitled to receive allocations of such Profit Sharing Contribution for such Plan Year in accordance with the eligibility and allocation provisions set forth in Section 3.07 of the Plan. The applicable percentage for each Plan Year shall be designated by the Committee, in its discretion exercised on a non-discriminatory basis, no later than the last day of the first quarter of the Plan Year following the Plan Year for which such percentage is applicable."

5. All other provisions of the Plan shall remain unchanged.

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The Committee has caused this Second Amendment to the NiSource Inc. Retirement Savings Plan to be executed on its behalf, by one of its members duly authorized, to be effective as of such date as set forth in this amendment.

NISOURCE BENEFITS COMMITTEE

By: JKH
Name: Jillian K. Hansen
Title: Dir Benefits

THIRD AMENDMENT TO THE NISOURCE INC. RETIREMENT SAVINGS PLAN

Background Information

A. NiSource Inc. ("NiSource") is the Plan Sponsor of the NiSource Inc. Retirement Savings Plan, amended and restated effective as of January 1, 2018 (the "Plan").

B. The NiSource Benefits Committee (the "Committee"), has the power to amend the Plan pursuant to Article XIV thereof.

C. The Committee desires to amend the Plan, effective as of April 15, 2020, to provide that matching contributions contributed on behalf of NIPSCO Union Employees for periods on or after April 15, 2020 shall be invested in accordance with the investment allocation selected by each NIPSCO Union Employee rather than being invested automatically in the Company Stock Fund.

Plan Amendment

1. Section III.04 of Schedule III to the Plan shall be amended by adding the following language to the end thereof, to be and read as follows:

> "Notwithstanding the matching allocation provisions of Section 3.05 and Section 8.07, Matching Contributions contributed on behalf of NIPSCO Union Employees on or after April 15, 2020, shall be invested in accordance with the investment allocation selected by each NIPSCO Union Employee, in accordance with Section 8.05 and 8.06, rather than invested automatically in the Company Stock Fund. "

2. All other provisions of the Plan shall remain unchanged.

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The Committee has caused this Third Amendment to the NiSource Inc. Retirement Savings Plan to be executed on its behalf, by one of its members duly authorized, to be effective as of such date as set forth in this amendment.

NISOURCE BENEFITS COMMITTEE

By: J. K. Hansen
Name: Jillian K. Hansen
Title: Director of Benefits

FOURTH AMENDMENT
TO THE
NISOURCE INC. RETIREMENT SAVINGS PLAN

Background Information

A. NiSource Inc. ("NiSource") is the Plan Sponsor of the NiSource Inc. Retirement Savings Plan, amended and restated effective as of January 1, 2018 (the "Plan").

B. The NiSource Benefits Committee (the "Committee") has the power to amend the Plan pursuant to Article XIV thereof.

C. The Committee desires to amend the Plan, effective as of January 1, 2020, to provide that certain employees who terminate employment during the Plan Year ending December 31, 2020 shall not be ineligible for an allocation of Employer Profit Sharing Contributions due to such termination of employment.

Plan Amendment

1. Effective January 1, 2020, Section 3.07A of the Plan shall be amended to be and read as follows:

A. Eligibility and Accrual.

(i) In General. Each Eligible Employee meeting the allocation requirements of this Section is entitled to participate in Profit Sharing Contributions; provided, however, that if an Eligible Employee is subject to a collective bargaining agreement, such agreement must provide that the Employee is eligible for Profit Sharing Contributions. For Profit Sharing Contributions other than those Next Gen Employer Contributions described in Section 3.06C, the Plan Administrator shall determine the accrual of a Profit Sharing Participant's benefit on the basis of the Plan Year. Although contributions may be made at other times (and therefore credited to Accounts at such other times), the Participant's status as of the end of the Plan Year for which the contribution is made shall determine his entitlement to share in an allocation of such contribution, regardless of when credited to his Account. For Profit Sharing Contributions other than Next Gen Employer Contributions described in Section 3.06C, the Plan Administrator shall not allocate any portion of a Profit Sharing Contribution for a Plan Year to the Account of any Participant, if such Participant is not employed by the Employer on the last day of that Plan Year (for a reason other than retirement, Disability, or death).

(ii) Special Rule. Notwithstanding paragraph (i) of this Section 3.07A, the following special rule applies if an Employer contributes a Profit Sharing Contribution (other than Next Gen Employer Contributions) to the Trust for the Plan Year ending December 31, 2020. With respect to Participants who terminate employment with an Employer during the Plan Year ending

December 31, 2020 and are hired by Eversource Energy (or one of its affiliates), pursuant to Section 8.3(a) of the Asset Purchase Agreement by and Among NiSource Inc., Bay State Gas Company and Eversource Energy, dated February 26, 2020, the Plan Administrator shall include in the allocation of such Profit Sharing Contribution the Account of any such Participant who would otherwise have received an allocation of such Profit Sharing Contribution notwithstanding the fact that such Participant is not employed by an Employer on the last day of such Plan Year.

(iii) Suspension of Accrual Requirements. The Plan shall suspend the accrual requirement described herein in accordance with the procedures described under subparagraphs (a) through (f) of this Section 3.07A(iii) if the Plan fails to satisfy the requirements of Code Section 410(b). Notwithstanding any other provision to the contrary, a Profit Sharing Contribution or Next Gen Employer Contribution shall not be allocated to a Participant's Account to the extent the contribution would exceed the Participant's "Maximum Permissible Amount" under Section 7.02. The procedure for suspending the accrual requirement for purposes of satisfying the requirements of Code Section 410(b) are as follows:

(a) The Committee will identify the termination date for each Participant who terminated employment with the Employer during the Plan Year. The Committee shall then designate as "Includable Employees" all such Participants.

(b) The Committee will suspend the accrual requirements for Includable Employees who are Participants, beginning first with the Includable Employee(s) employed with the Employer on the next to last day of the Plan Year.

(c) If the Plan does not satisfy the ratio percentage test under Code Section 410(b)(1) once the accrual requirements for the individuals identified in Subsection (b) above are suspended, the Committee shall suspend the accrual requirements for the Includable Employee(s) who have the next latest termination of employment date during the Plan Year, and continuing to suspend in descending order the accrual requirements for each Includable Employee who terminated employment, from the latest to the earliest termination date, until the Plan satisfies the ratio percentage test under Code Section 410(b)(1) for the Plan Year.

(d) If two or more Includable Employees terminated employment on the same day, the Committee will suspend the accrual requirements for all such Includable Employees, irrespective of whether the Plan can satisfy the ratio percentage test under Code Section 410(b)(1) by accruing benefits for fewer than all such Includable Employees.

(e) If the Plan suspends the accrual requirements for an Includable Employee, that Employee will share in the allocation of Employer contributions and Forfeitures, if any, without regard to whether he is employed by the Employer on the last day of the Plan Year.

(f) For purposes of the ratio percentage test under Code Section 410(b)(1), an Employee is benefiting under the Plan on a particular date if he or she is entitled to an allocation for the Plan Year under this Section or as otherwise provided under applicable Treasury Regulations.

2. All other provisions of the Plan shall remain unchanged.

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The Committee has caused this Fourth Amendment to the NiSource Inc. Retirement Savings Plan to be executed on its behalf, by one of its members duly authorized, to be effective as of such date as set forth in this amendment.

NISOURCE BENEFITS COMMITTEE

By: J. K. Han
Name: Jillian K. Hansen
Title: Director of Benefits

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

32. Refer to the Roy Testimony.

a. Refer to pages 36–40, regarding the need for Columbia Kentucky's proposed training facility.

(1) Provide the location of the training facilities in Ohio, Virginia, and Pennsylvania as well as any other locations to which employees from Columbia Kentucky travel for training purposes.

(2) Provide the amount of training expense, including travel, lodging, meals, curriculum, etc., that Columbia Kentucky has incurred in the five calendar years ending December 31, 2020, the base period, and the test year broken down by direct costs incurred by Columbia Kentucky and costs allocated to Columbia Kentucky.

b. Refer to pages 40–41 regarding the costs of Columbia Kentucky's proposed training facility.

(1) Provide a detailed breakdown of the approximate capital and ongoing O&M expense associated with the construction and operation of the proposed training facility. State all assumptions made in the process of projecting the costs.

(2) Confirm whether any additional staff will be necessary specifically to operate the facility and train employees.

(3) Explain how any costs savings as a result of Columbia Kentucky's proposed new facility and curriculum have been reflected in the base period and forecasted test year.

(4) Explain whether the Training Facility in Lexington, Kentucky, can be used by other entities, whether these entities are affiliated companies, and whether any revenues collected from its usage can offset the annual cost of operation

Response:

a.

1) The cities where new training facilities were built are Gahanna, Ohio, Monaca, Pennsylvania and Chester, Virginia. Please note that these locations were also provided in Columbia's response to the Attorney General's First Set of Requests for Information, No. 17 part a.

2) Due to the variety of business travel expenses involved and the various ways those are charged, Columbia is unable to accurately provide the requested information. However, the following schedule was developed showing estimated costs based on trips taken and was provided in response to the Attorney General's First Set of Requests for Information, No. 17 part c.

2017-2021 Estimated Cost to Send Employees to Training Facilities					
Site	**2017**	**2018**	**2019**	**2020**	**2021 YTD***
Ohio	$288,300	$191,500	$399,100	$162,500	$ 76,900
Pennsylvania			$ 6,400		
Virginia			$ 22,500		
* YTD through June					

Columbia also noted that costs are expected to substantially climb in 2022 as enhanced operator qualification training gets implemented. Columbia expects to average approximately $460,000 per year going forward on travel expenses.

b.

1) Please see KY PSC Case No. 2021-00183, Staff 3-32, Attachment A, which was previously provided in response to the Attorney General's First Set of Requests for Information, No. 18. The proposed construction would occur throughout 2022. Project cost assumptions are based on recent design, material and construction pricing experienced by Columbia's facility management team.

2) One additional trainer is assumed and included in the annual O&M cost at $125,000.

3) No cost savings have been included in the base period and forecasted test year because the facility modifications to support local training would not be complete until the end of the forecasted test year.

4) Please see Columbia's response to Staff's Second Set of Requests for Information, No. 12. Based on the response from question 12, revenues could only be collected from other entities if a stand-alone facility was constructed.

Project Name	CKY Training Improvements					4/8/2021
Line Item	**Safety Town & Site Scenarios**	**Plant / Service Lab (1560 SF)**	**Plant / Service Classrooms (1560 SF, Mezz.)**	**OQ Prometric Testing (600 SF)**	**OQ Hands On / Plant Fusion Lab (750 SF)**	**Storage Building at Propane Site (40 ft x 80 ft)**
General Conditions Allowance	$ 75,000	$ 20,000	$ 20,001	$ 20,000	$ 20,000	$ 20,000
Demolition Allowance ($10 / SF)	$ 75,000	$ 31,000	$ 31,000	$ 7,500	$ 24,000	$ 24,000
Site Work Allowance (Paving, gravel, stormwater , Conduit, gas extension, fence)	$ 500,000	$ -	$ -	$ -	$ -	$ 75,000
Electrical Allowance	$ 325,000	$ 20,000	$ 20,000	$ 20,000	$ 15,000	$ 25,000
Training Village (buildings, leaks, plumbing)	$ 1,300,000	$ -	$ -	$ -	$ -	$ -
Storage / Compressor Metal Buildings	$ 250,000	$ -	$ -	$ -	$ -	$ 250,000
Compressor Allowance	$ 200,000	$ -	$ -	$ -	$ -	$ -
Building Renovation Cost ($140 / SF)	$ -	$ 218,400	$ 218,400	$ 84,000	$ 105,000	$ -
Prometric Testing Fee	$ -	$ -	$ -	$ 60,000	$ -	$ -
Fees / Overhead / Contingency / Misc.(10%)	$ 272,500	$ 28,940	$ 28,940	$ 13,150	$ 16,400	$ 39,400
Subtotal Capital Spend Construction	**$ 2,997,500**	**$ 318,340**	**$ 318,341**	**$ 204,650**	**$ 180,400**	**$ 433,400**
Professional Services	$ 200,000	(SAFETY TOWN)	(SAFETY TOWN)	(SAFETY TOWN)	(SAFETY TOWN)	(SAFETY TOWN)
IT	$ 150,000	(SAFETY TOWN)	(SAFETY TOWN)	(SAFETY TOWN)	(SAFETY TOWN)	(SAFETY TOWN)
Security (card readers)	$ 30,000	(SAFETY TOWN)	(SAFETY TOWN)	(SAFETY TOWN)	(SAFETY TOWN)	(SAFETY TOWN)
Cabling	$ 75,000	$ 15,000	$ 5,000	$ 10,000	$ -	$ -
Furniture	$ 20,000	$ 25,000	$ 50,000	$ 25,000	$ 25,000	$ -
Cabling / Shelving / Racking	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 15,000
Appliances	$ -	TOOLING BY BU	TOOLING BY BU	$ -	TOOLING BY BU	$ -
Audio/Visual	$ 150,000	$ 25,000	$ 25,000	Included in Prometric Fee	$ 25,000	$ -
Window Treatments	$ -	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ -
Signage (exterior)	$ 10,000	(SAFETY TOWN)	(SAFETY TOWN)	(SAFETY TOWN)	(SAFETY TOWN)	$ -
Arts / Graphics	$ 10,000	(SAFETY TOWN)	(SAFETY TOWN)	(SAFETY TOWN)	(SAFETY TOWN)	$ -
Miscellaneous	$ -	TOOLING BY BU	TOOLING BY BU	$ -	TOOLING BY BU	$ -
Decommissioning Existing Site	$ -	$ -	$ -	$ -	$ -	$ -
Tenant Improvements (Non-Reimbursable)	$ -	$ -	$ -	$ -	$ -	$ -
Tenant Allowance (Reimbursable)	$ -	$ -	$ -	$ -	$ -	$ -
Contingency (20%)	$ 130,000	$ 16,000	$ 19,000	$ 10,000	$ 13,000	$ 3,000
Subtotal Capital Spend FF&E	**$ 780,000**	**$ 96,000**	**$ 114,000**	**$ 60,000**	**$ 78,000**	**$ 18,000**
TOTAL	**$ 3,777,500**	**$ 414,340**	**$ 432,341**	**$ 264,650**	**$ 258,400**	**$ 451,400**

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

33. Refer to the Columbia Kentucky's response to Staff's First Request, Item 9.

a. Provide the same information and tables for the base year and the test year.

b. Provide a further breakdown of account 923 by NiSource Service Company activity/department for 2020, the base year, and the test year.

c. Provide a variance analysis for the test year compared to 2020. Describe all identifiable reasons for the variances and quantify each such reason. Provide the variance analysis for account 923 by activity/department.

d. Refer to Item 9.b. Provide a comparative table for calendar years 2015–2020 with the same information provided in Columbia Kentucky's response to Item 9.b.

Response:

a. Please refer to KY PSC Case No. 2021-00183, Staff 3-33, Attachment A for the same information and tables for the base year and the test year as supplied in Columbia's Response to Staff's First Set of Requests for Information, No. 9.

b. Please refer to KY PSC Case No. 2021-00183, Staff 3-33, Attachment B for a further breakdown of account 923 by NiSource Service Company activity/department for 2020, the base year, for the months of September 2020 through July 2021. Breakdowns of accounts for NiSource Service Company is only available for actual data and is therefore unavailable for August 2021 and for the test year.

c. Increase in NCSC costs from 2020 to the 2022 forecasted adjusted test period of $1,783,810 is primarily related to 1) merit for labor and inflation increases on third party contracted costs of $739,715, 2) Columbia's Safety Plan initiative of $443,397 and other safety training, Safety Management System Asset and Risk Management of an additional $989,359 in the forecasted test period, 3) increase for CIP and stock compensation of $251,496 over pro-forma adjusted amounts from ST-4; 4) offset by net impact of ($786,605) from NiSource O&M initiatives efficiencies (as noted in Columbia's Response to the Attorney General's Second Set of Requests for Information, No. 48) less change in allocation of costs due to change in entities (as noted in Columbia's Response to the Attorney General's First Set of Requests for Information, No.152). For the same reasons as noted in part b, variance analysis for account 923 by activity/department from 2020 to 2022 forecasted period cannot be completed as the budget is not compiled by FERC account.

d. Please refer to KY PSC Case No. 2021-00183, Staff 3-33, Attachment C for a comparative table for calendar years 2015-2020 to that provided in Columbia's Response to Staff's First Set of Requests for Information, No. 9b.

ATTACHMENTS ARE EXCEL SPREADSHEETS AND UPLOADED SEPARATELY

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

34. Refer to page 7 of the Direct Testimony of Kevin L. Johnson (Johnson Testimony). Mr. Johnson explains that the calendar year 2020 was used to perform Columbia Kentucky's lead/lag study because it is in line with the forecasted test year ending December 31, 2022.

a. Provide a detailed definition of the term "in line with," and explain how calendar year 2020 is in line with Columbia Kentucky's forecasted test year.

b. Given the impact that COVID-19 restrictions had on Columbia Kentucky's financial operations in 2020, explain why 2020 represents a normal year to base Columbia Kentucky's lead/lag study.

c. Describe the process Columbia Kentucky used to decide which calendar year its lead/lag study would be based on.

d. Provide a revised lead/lag study using calendar year 2019 information in Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible.

Response:

a.

The term "in line with" in the context of Witness Johnson's testimony means the calendar year (January-December) of 2020 includes the same months that are included in the Columbia Forecasted Test Period ending December 31, 2022.

b & c.

A lead lag study is essentially a statistical analysis that utilizes historical payment information to calculate the revenue lag days and expense lead days. When determining the period to use to perform the Lead Lag study, the company considered where potential significant issues could arise in regards to the company making any payments (expense leads) and our customers making their payments (revenue lags). While preparing for the rate case, the company determined that the timing of the payments it was making (expense leads) would likely not be impacted by Covid-19 restrictions as the company continued to make its payments in a similar cadence as the prior periods. From a revenue lag perspective, the company did compare the revenue collection lag from the calendar year 2019 to calendar year 2020 while preparing for this rate case. The collection lag showed 2.51 days for calendar year 2019 compared to 4.86 in calendar year 2020. When comparing the collection lag in the overall context of the revenue lag, the overall revenue lag was higher by 2.34 days overall, primarily due to the collection lag. Based on the overall revenue lag not being significantly different year over year, the company determined calendar year 2020 was an appropriate period to use to perform the Lead Lag study as the 2020 calendar year was closer to the rate case period and the results year over year were not significantly different. As indicated in part D of this response, which shows the results of the 2019 Lead Lag study, the overall results of the 2019 study were not significantly different than the results of the 2020 study. The Company believes the 2020 calendar year was an appropriate period to use for the Lead Lag study calculation.

d.

Provided in KY PSC Case No. 2021-00183, Staff 3-034, Attachment A is the Lead Lag study performed using calendar year 2019 as the basis. Overall, the results of the 2019 Lead Lag study were not significantly different when comparing to the filed 2020 Lead Lag study. KY PSC Case No. 2021-00183, Staff 3-034, Attachment B shows the Columbia Kentucky forecasted period Cash Working Capital calculation using the results of the 2019 Lead Lag study. As shown on Line 33 of KY PSC Case No. 2021-00183, Staff 3-034 - Attachment B, the forecasted period Calculated Cash Working Capital Requirement was $(7,273,291) using the results of the 2019 Lead Lag study, a $(330,294) difference than what was calculated using the results of the 2020 Lead Lag study. As mentioned above in the response to b & c of this data request, the Company believes the 2020 calendar year was an appropriate period to use for the Lead Lag study calculation.

ATTACHMENTS
ARE EXCEL
SPREADSHEETS
AND UPLOADED
SEPARATELY

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

35. Refer to page 19 of the Johnson Testimony. The results of Columbia Kentucky's lead/lag study results in a cash working capital allowance of ($6,942,997). Given that Columbia Kentucky's lag days for its receivables is grossly lower than the lead days of its payables, explain why Columbia Kentucky's shareholders are entitled to earn a return on capital that is not supported by their invest.

Response:

Columbia Kentucky's receivables are low as a result of the cumulative impact of credit balances building in certain customers' accounts who are enrolled in the Budget Plan offered by Columbia Kentucky. The Columbia Kentucky Budget Plan allows customers to pay the same amount each month as calculated based on the usage, weather, and projected costs of that customer. The Columbia Kentucky Budget Plan resets annually in April. As a result of the Budget Plan resetting in April, these Budget Plan customers may build a credit in their accounts as they go through the summer months into the heating season. As the credits build for these Budget Plan customers, this results in Columbia Kentucky's Accounts Receivable balances being lower and even turning negative in some months (ie, August – November) which further results in a lower Collection Lag being calculated and presented in the company's Lead Lag Study. Table 1 below shows the total Utility Accounts Receivable for each month as shown on Attachment KLJ-CWC-1, Sheet 3b, of Witness Johnson's testimony and illustrates the company's accounts receivable being negative in the months of August-November.

Table 1

January	$6,154,795
February	$10,264,951
March	$8,846,816
April	$6,626,605
May	$6,515,203
June	$3,300,984
July	$257,166
August	$(2,327,730)
September	$(4,379,989)
October	$(5,879,453)
November	$(5,231,029)
December	$441,765
Total	$24,590,085

To account for the credits showing on the Budget Plan customers' accounts and in the company's accounts receivable balance, each month the Company makes a Generally

Accepted Accounting Principles (GAAP) accounting entry on its books to debit account 14200160 (Cust AR-Credit Balances) and credit a liability account. This journal entry essentially removes the credit balances from the company's total GAAP accounts receivable balances. This Cust AR-Credit Balances account was not included in the Company's filed Lead Lag study. Including this account (Cust AR-Credit Balances) in the Company's Lead Lag study would show what the Company's Revenue Lag would be if the cumulative impacts of the Budget Plan were removed. KY PSC Case No. 2021-00183, Staff 3-035, Attachment A, illustrates the impact to the company's Revenue Lag by removing impacts of the Budget Plan from the Company's Collection Lag calculation. As noted on tab 'Sh 3b – AR Summ' in KY PSC Case No. 2021-00183, Staff 3-035, Attachment A, Column 8 was added to add back the amount of Budget Plan credit balances. As shown in Column 8, since the Budget Plan resets in April each year, the amounts of the customer's credit balance accumulates throughout the year into the heating season. Removing impacts of the Budget Plan results in higher average accounts receivable balances ($8,710,394 vs. $2,049,174) for the year (See Column 9 of KY PSC Case No. 2021-00183, Staff 3-035, Attachment A). Taking into account the average accounts receivable balance without impacts of the Budget Plan results in a Revenue Collection Lag of 20.66 days (see tab 'Sh 3a – Coll-Lag', in KY PSC Case No. 2021-00183, Staff 3-035, Attachment A). Incorporating the Revenue Collection Lag of 20.66 days into the overall Revenue Lag calculation results in 38.13 Revenue Lag days for the company if the impacts of the Budget Plan are removed (see tab ‘Sh 3 – RevLag’, in KY PSC Case No. 2021-00183, Staff 3-035, Attachment A). For reference, the Company’s as filed Revenue Lag was 22.33 days and its Collection Lag was 4.86 days.

KY PSC Case No. 2021-00183, Staff 3-035, Attachment B, shows the calculated Cash Working Capital requirement of $(365,312), an increase of $(6,577,685) from what was filed, by removing the Budget Plan credits from the Collection Lag calculation by using the 38.13 Revenue Lag days instead of the filed 22.33 Revenue Lag days.

The above illustration of removing the impacts of the Budget Plan from the company’s Revenue Lag calculation shows that the company’s entire Cash Working Capital calculation is impacted by resetting the Budget Plan each year in April. Selecting a month later in the year, closer to the heating season, to reset the Budget Plan would result in those same customer’s balances showing an amount greater than the amount billed during a month and result in higher Accounts Receivable balances and a higher Cash Working Capital requirement. Rather than changing the month it annually resets its Budget Plan in order to impact future Cash Working Capital requirement calculations, the Company believes the value the Budget Plan provides its customers and the effective management of cash of the Company should warrant Rate Base not being lowered for Cash Working Capital.

It should also be noted that a Lead Lag study is only one method of measuring Cash Working Capital. The Commission has previously accepted the Company's calculation of Cash Working Capital using the formula approach of taking 1/8 of operations and maintenance expenses. As shown on KY PSC Case No. 2021-00183, Staff 3-035, Attachment C, using the formula approach of 1/8 of the forecasted period operations and maintenance expenses results in a calculated Cash Working Capital requirement of $6,983,685. The varying results of the two methods to calculate Cash Working Capital (1/8 O&M Expenses, $6,983,685 vs. Lead Lag study, $(6,942,997)) further supports the Company's decision to not request a Cash Working Capital adjustment to Rate Base.

ATTACHMENTS ARE EXCEL SPREADSHEETS AND UPLOADED SEPARATELY

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

36. Refer to page 4 of the Johnson Testimony. Mr. Johnson explains that lead/lag methodology used to Columbia Kentucky's cash working capital is consistent with the methodology used by Columbia Gas of Virginia (Columbia Virginia), a NiSource affiliate.

a. Identify each NiSource affiliate that uses a lead/lag study to calculate its cash working capital requirements.

b. Provide a copy of each affiliate's most recent lead/lag study.

c. Explain why Columbia Kentucky used the lead/lag methodology of Columbia Virginia rather than a lead/lag methodology that has been accepted by this Commission.

Response:

a. NiSource affiliates Columbia Gas of Ohio, Columbia Gas of Pennsylvania, and NIPSCO (both gas and electric) do not use Lead Lag studies to calculate their cash working capital requirements. NiSource affiliates Columbia Gas of Maryland and Columbia Gas of Virginia prepare Lead Lag studies to calculate their cash working capital requirements.

b. Please see KY PSC Case No. 2021-00183, Staff 3-036, Attachment A showing the Columbia Gas of Maryland Lead Lag study as filed in its 2021 Rate Case (Case No. 9664).

   Please see KY PSC Case No. 2021-00183, Staff 3-036, Attachment B showing the Columbia Gas of Virginia Lead Lag study as filed in its 2018 Rate Case (Case No. PUR-2018-00131).

c. In preparation for this Rate Case, Columbia Kentucky noted that Louisville Gas and Electric (LG&E) prepared its lead-lag studies based on practices prescribed by the Virginia State Corporation Commission in 2018 in Case Nos. 2018-00294 and 2018-00295 and used the same methodology in its 2020 Cases (Case Nos. 2020-00349 and 2020-00350)[1]. Based on the precedent of LG&E using the Virginia methodology in multiple cases before the Kentucky Public Service Commission and Columbia Kentucky having a sister company in Virginia (Columbia Gas of Virginia), Columbia Kentucky made the decision to use the Lead Lag methodology used in Virginia as a basis for its Lead Lag study.

[1] Kentucky Utilities Company & Louisville Gas & Electric Company, Case Nos. 2020-00349 & 2020-00350, Direct Testimony of William Steven Seelye, Pages 134 and 135.

Exhibit No. 9
Sheet 1 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc.
Summary of Cash Working Capital - Lead/Lag Study
Twelve Months Ended February 28, 2021

Line No.	Cost Category	Reference	Pro Forma Expense	Daily Requirement	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Requirement
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)=(4)*(7)
			$	$				$
1	**OPERATING EXPENSES**							
2	Gas Purchased	Exh. No. 1, Sh. 1, Ln. 6	18,285,693	50,098	32.57	39.47	(6.90)	(345,676)
3	Payroll	Exh. No. 3, Sh. 2, Lns.1 & 2	3,362,058	9,211	32.57	18.23	14.34	132,086
4	OPEB	Exh. No. 3, Sh. 6, Col. 7, Ln. 12	(42,306)	(116)	32.57	45.00	(12.43)	1,442
5	Pension	Exh. No. 3, Sh. 6, Col. 7, Ln. 20	148,752	408	32.57	0.00	32.57	13,289
6	Other Employee Benefits	Exh. No. 3, Sh. 2, Ln. 4	531,873	1,457	32.57	11.85	20.72	30,189
7	NiSource Corporate Services	Exh. No. 3, Sh. 2, Ln. 5	6,825,504	18,700	32.57	34.20	(1.63)	(30,481)
8	Corporate Insurance	Exh. No. 3, Sh. 2, Ln. 14	380,047	1,041	32.57	(146.11)	178.68	186,006
9	PSC Fees and OPC Fees	Exh. No. 3, Sh. 2, Ln. 25	110,349	302	32.57	(37.55)	70.12	21,176
10	Uncollectibles	Exh. No. 3, Sh. 2, Ln. 19	427,374	1,171	0.00	0.00	0.00	0
11	Other O & M Expense	Exh. No. 3, Sh. 2 Ln. 31 - Sum (Line 3 thru Line 10)	2,689,166	7,368	32.57	26.75	5.82	42,882
12	**Total Operating Expense**		32,718,510	14,255,686				
13	**Depreciation & Amortization**	Exh. No. 1, Sh. 1, Ln. 9	7,513,030	20,584	0.00	0.00	0.00	0
14	**TAXES OTHER THAN INCOME**							
15	Payroll Taxes - F.I.C.A, FUTA, SUTA	Exh. No. 5, Sh. 1, Ln. 1	269,519	738	32.57	8.00	24.57	18,133
16	Property Tax	Exh. No. 5, Sh. 1, Ln. 2	4,075,355	11,165	32.57	(53.76)	86.33	963,874
17	Gross Receipts Tax and Consumption Tax	Exh. No. 5, Sh. 1, Ln. 3	1,016,764	2,786	32.57	49.86	(17.29)	(48,170)
18	Other Taxes	Exh. No. 5, Sh. 1, Ln. 4	9,986	27	32.57	(132.00)	164.57	4,443
19	**Total Other Taxes**		5,371,624					
20	**INCOME TAXES**							
21	Current - Federal	Exh. No. 6, Sh. 1, Ln. 9	1,262,722	3,460	32.57	37.50	(4.93)	(17,058)
22	Deferred - Federal	Exh. No. 6, Sh. 1, Lns. 13, 14 & 16	1,155,194		0.00	0.00	0.00	0
23	Investment Tax Credit	Exh. No. 6, Sh. 1, Ln. 15	(12,489)		0.00	0.00	0.00	0
24	Current - State	Exh. No. 6, Sh. 1, Ln. 7	317,507	870	32.57	37.50	(4.93)	(4,289)
25	Deferred - State	Exh. No. 6, Sh. 1, Ln. 23	837,617		0.00	0.00	0.00	0
26	Interest on Customer Deposits	Exh. No. 7, Sh. 1, Ln. 3	388	1	32.57	0.00	32.57	33
27	**INTEREST ON DEBT**	Exh. No. 6, Sh. 1, Ln. 2	3,618,336	9,913	32.57	92.00	(59.43)	(589,130)
28	**TOTAL CASH WORKING CAPITAL REQUIREMENT**							378,749

( ) Denotes Credit

Exhibit No. 9
Sheet 2 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc.
Analysis of Cash Working Capital Requirement
Revenue Lag
Twelve Months Ended February 28, 2021

Line No.	Lag Component (1)	Number of Days (2)
1	Collection	14.12
2	Meter Reading 1/	15.21
3	Billing	3.24
4	Total Revenue Lag Days	**32.57**

1/ Meter reading lag days computed as:
365 days / 12 Months / 2 (midpoint) = 15.21 days

Exhibit No. 9
Sheet 3 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc.
Analysis of Cash Working Capital Requirement
Adjusted / Average Daily Revenue
Twelve Months Ended February 28, 2021

Line No.		Amount (1) $
1	Total Tariff Revenues:	
2	Residential Revenues	29,965,692
3	Commercial Revenues	15,262,296
4	Industrial Revenues	353,108
5	Billed RNA Revenues	87,050
6	**TOTAL TARIFF REVENUE**	45,668,147
7	Transportation Revenue	6,156,422
8	Forfeited Discounts	26,687
9	Miscellaneous Service Revenue	6,317
10	**SUBTOTAL OF ADDITIONAL REVENUE**	6,189,427
11	**TOTAL REVENUE**	**51,857,573**
12	**Average Daily Revenue (Line 11 / 366 days)**	142,076
13	**Average Daily A/R Balance (Per Sheet No. 4)**	2,005,594
14	**Revenue Collection Lag Days (Line 13 / Line 12)**	**14.12**

Exhibit No. 9
Sheet 4 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc.
Analysis of Cash Working Capital Requirement
Summary of Accounts Receivable
Twelve Months Ended February 28, 2021

Line No.	Test Year (1)	14200250 Utility Service Other Balance (2)	14200260 Customer Premises Work Balance (3)	14300240, 14300330 Transportation A/R Month-End Balance (4)	14300280 Home Energy Assistance Program Balance (5) $	Utility Accounts Receivables (6)=(2 thru 5)
1	Mar 2020	168,463	6,165	1,022,476	0	1,197,103
2	Apr	160,264	20,873	846,658	(3,040)	1,024,755
3	May	125,055	8,030	645,261	(4,502)	773,844
4	Jun	91,594	6,457	521,600	0	619,651
5	Jul	127,098	7,958	579,770	0	714,826
6	Aug	108,240	8,301	546,030	0	662,572
7	Sep	102,629	7,315	593,933	26,534	730,412
8	Oct	168,808	8,090	724,677	24,552	926,127
9	Nov	94,718	11,038	862,943	83,839	1,052,539
10	Dec	152,230	11,193	1,215,979	76,012	1,455,414
11	Jan 2021	204,347	6,956	1,602,829	(41,977)	1,772,156
12	Feb	206,090	6,727	1,837,647	70,416	2,120,879
13	Total					13,050,276
14	Avg. 12 Mo.					1,087,523

15	Average Daily A/R Balance - Account 14200200 (Exh 9 Sheet 4a, Page 7, Ln. 56)	918,071
16	Average Daily A/R Balance - TME 2-28-21 Accounts 14200250, 14200260, 14300240 and 14300280 A/R Balances	1,087,523
17	Total Average Daily Accounts Receivable (Lns. 15 thru 16)	2,005,594

Exhibit No. 9
Sheet 4a of 18
Page 1 of 7
Witness: C. Lash

Columbia Gas of Maryland
Analysis of Cash Working Capital Requirements
Twelve Months Ended February 28, 2021
Average Daily Accounts Receivable Balance

Ln. No.	Month / Day	14200200 Daily Customer Accounts Receivable Balance
	(1)	(2) $
1	03/01/20	1,778,831.85
2	03/02/20	1,778,831.85
3	03/03/20	1,808,860.01
4	03/04/20	1,935,714.48
5	03/05/20	2,207,761.58
6	03/06/20	2,036,480.14
7	03/07/20	2,104,032.62
8	03/08/20	2,104,032.62
9	03/09/20	2,104,032.62
10	03/10/20	2,150,209.34
11	03/11/20	2,095,707.24
12	03/12/20	2,177,934.10
13	03/13/20	2,193,469.21
14	03/14/20	1,928,304.29
15	03/15/20	1,928,304.29
16	03/16/20	1,928,304.29
17	03/17/20	2,069,558.18
18	03/18/20	2,363,301.62
19	03/19/20	2,108,610.50
20	03/20/20	2,255,478.73
21	03/21/20	2,281,860.80
22	03/22/20	2,281,860.80
23	03/23/20	2,281,860.80
24	03/24/20	2,355,649.04
25	03/25/20	2,121,727.85
26	03/26/20	2,099,869.82
27	03/27/20	2,185,425.94
28	03/28/20	2,292,544.77
29	03/29/20	2,292,544.77
30	03/30/20	2,292,544.77
31	03/31/20	2,020,663.19
32	04/01/20	2,071,984.88
33	04/02/20	2,136,386.23
34	04/03/20	2,390,658.34
35	04/04/20	2,238,051.72
36	04/05/20	2,238,051.72
37	04/06/20	2,238,051.72
38	04/07/20	2,209,023.27
39	04/08/20	2,245,144.98
40	04/09/20	2,287,992.02
41	04/10/20	2,367,230.80
42	04/11/20	2,370,313.42
43	04/12/20	2,370,313.42
44	04/13/20	2,370,313.42
45	04/14/20	2,085,298.88
46	04/15/20	2,136,010.80
47	04/16/20	2,275,894.88
48	04/17/20	2,214,267.47
49	04/18/20	2,254,041.66
50	04/19/20	2,254,041.66
51	04/20/20	2,254,041.66
52	04/21/20	2,174,854.61

Exhibit No. 9
Sheet 4a of 18
Page 2 of 7
Witness: C. Lash

Columbia Gas of Maryland
Analysis of Cash Working Capital Requirements
Twelve Months Ended February 28, 2021
Average Daily Accounts Receivable Balance

Ln. No.	Month / Day	14200200 Daily Customer Accounts Receivable Balance
	(1)	(2) $
1	04/22/20	2,217,971.83
2	04/23/20	2,067,679.40
3	04/24/20	2,058,272.95
4	04/25/20	2,129,145.72
5	04/26/20	2,129,145.72
6	04/27/20	2,129,145.72
7	04/28/20	2,098,140.13
8	04/29/20	2,001,562.95
9	04/30/20	2,082,350.07
10	05/01/20	2,247,295.05
11	05/02/20	2,458,783.18
12	05/03/20	2,458,783.18
13	05/04/20	2,458,783.18
14	05/05/20	2,259,844.95
15	05/06/20	2,275,607.23
16	05/07/20	2,337,567.14
17	05/08/20	2,353,135.79
18	05/09/20	2,437,211.44
19	05/10/20	2,437,211.44
20	05/11/20	2,437,211.44
21	05/12/20	2,403,061.34
22	05/13/20	2,247,934.12
23	05/14/20	2,387,345.31
24	05/15/20	2,408,723.33
25	05/16/20	2,344,171.64
26	05/17/20	2,344,171.64
27	05/18/20	2,344,171.64
28	05/19/20	2,327,293.38
29	05/20/20	2,323,742.02
30	05/21/20	2,329,511.91
31	05/22/20	2,229,109.83
32	05/23/20	2,183,356.65
33	05/24/20	2,183,356.65
34	05/25/20	2,183,356.65
35	05/26/20	2,183,356.65
36	05/27/20	2,129,873.84
37	05/28/20	2,135,221.27
38	05/29/20	1,972,061.93
39	05/30/20	1,981,777.52
40	05/31/20	1,981,777.52
41	06/01/20	1,981,822.81
42	06/02/20	2,007,995.53
43	06/03/20	2,100,945.02
44	06/04/20	2,023,864.93
45	06/05/20	2,055,928.81
46	06/06/20	2,090,359.92
47	06/07/20	2,090,359.92
48	06/08/20	2,090,359.92
49	06/09/20	1,983,708.11
50	06/10/20	2,004,828.01
51	06/11/20	1,934,945.46
52	06/12/20	1,766,971.16

Exhibit No. 9
Sheet 4a of 18
Page 3 of 7
Witness: C. Lash

Columbia Gas of Maryland
Analysis of Cash Working Capital Requirements
Twelve Months Ended February 28, 2021
Average Daily Accounts Receivable Balance

Ln. No.	Month / Day	14200200 Daily Customer Accounts Receivable Balance
	(1)	(2) $
1	06/13/20	1,758,457.01
2	06/14/20	1,758,457.01
3	06/15/20	1,758,457.01
4	06/16/20	1,731,711.69
5	06/17/20	1,633,729.70
6	06/18/20	1,598,308.29
7	06/19/20	1,584,850.44
8	06/20/20	1,568,157.11
9	06/21/20	1,568,157.11
10	06/22/20	1,568,157.11
11	06/23/20	1,370,806.36
12	06/24/20	1,357,672.52
13	06/25/20	1,337,377.53
14	06/26/20	1,292,339.64
15	06/27/20	1,186,013.30
16	06/28/20	1,186,013.30
17	06/29/20	1,186,013.30
18	06/30/20	1,123,024.14
19	07/01/20	1,098,316.70
20	07/02/20	1,058,892.99
21	07/03/20	976,739.24
22	07/04/20	976,739.24
23	07/05/20	976,739.24
24	07/06/20	976,739.24
25	07/07/20	826,416.43
26	07/08/20	792,599.86
27	07/09/20	770,136.63
28	07/10/20	754,807.60
29	07/11/20	711,468.21
30	07/12/20	711,468.21
31	07/13/20	711,468.21
32	07/14/20	573,753.49
33	07/15/20	532,258.66
34	07/16/20	598,715.42
35	07/17/20	563,259.34
36	07/18/20	550,808.13
37	07/19/20	550,808.13
38	07/20/20	550,808.13
39	07/21/20	479,870.81
40	07/22/20	456,682.72
41	07/23/20	364,548.84
42	07/24/20	330,599.02
43	07/25/20	273,454.89
44	07/26/20	273,454.89
45	07/27/20	273,454.89
46	07/28/20	213,750.23
47	07/29/20	110,968.62
48	07/30/20	109,175.29
49	07/31/20	152,319.90
50	08/01/20	161,271.38
51	08/02/20	161,271.38
52	08/03/20	161,271.38

Exhibit No. 9
Sheet 4a of 18
Page 4 of 7
Witness: C. Lash

Columbia Gas of Maryland
Analysis of Cash Working Capital Requirements
Twelve Months Ended February 28, 2021
Average Daily Accounts Receivable Balance

Ln. No.	Month / Day	14200200 Daily Customer Accounts Receivable Balance
	(1)	(2) $
1	08/04/20	65,025.73
2	08/05/20	16,422.35
3	08/06/20	4,474.45
4	08/07/20	(31,847.03)
5	08/08/20	(90,996.48)
6	08/09/20	(90,996.48)
7	08/10/20	(90,996.48)
8	08/11/20	(172,647.02)
9	08/12/20	(276,616.36)
10	08/13/20	(296,352.82)
11	08/14/20	(306,793.32)
12	08/15/20	(391,417.58)
13	08/16/20	(391,417.58)
14	08/17/20	(391,417.58)
15	08/18/20	(401,673.85)
16	08/19/20	(478,140.96)
17	08/20/20	(526,036.02)
18	08/21/20	(587,012.10)
19	08/22/20	(611,853.46)
20	08/23/20	(611,853.46)
21	08/24/20	(611,853.46)
22	08/25/20	(699,481.36)
23	08/26/20	(714,593.61)
24	08/27/20	(761,277.53)
25	08/28/20	(757,116.37)
26	08/29/20	(740,223.21)
27	08/30/20	(740,223.21)
28	08/31/20	(740,223.21)
29	09/01/20	(730,144.71)
30	09/02/20	(802,832.91)
31	09/03/20	(817,985.72)
32	09/04/20	(874,949.70)
33	09/05/20	(911,856.20)
34	09/06/20	(911,856.20)
35	09/07/20	(911,856.20)
36	09/08/20	(911,856.20)
37	09/09/20	(945,154.06)
38	09/10/20	(1,002,217.18)
39	09/11/20	(1,085,033.69)
40	09/12/20	(1,117,737.87)
41	09/13/20	(1,117,737.87)
42	09/14/20	(1,117,737.87)
43	09/15/20	(1,149,715.98)
44	09/16/20	(1,246,056.93)
45	09/17/20	(1,266,339.36)
46	09/18/20	(1,255,140.45)
47	09/19/20	(1,274,012.67)
48	09/20/20	(1,274,012.67)
49	09/21/20	(1,274,012.67)
50	09/22/20	(1,375,616.55)
51	09/23/20	(1,410,359.80)
52	09/24/20	(1,436,979.51)

Exhibit No. 9
Sheet 4a of 18
Page 5 of 7
Witness: C. Lash

Columbia Gas of Maryland
Analysis of Cash Working Capital Requirements
Twelve Months Ended February 28, 2021
Average Daily Accounts Receivable Balance

Ln. No.	Month / Day	14200200 Daily Customer Accounts Receivable Balance
	(1)	(2) $
1	09/25/20	(1,449,014.29)
2	09/26/20	(1,598,820.99)
3	09/27/20	(1,598,820.99)
4	09/28/20	(1,598,820.99)
5	09/29/20	(1,593,770.74)
6	09/30/20	(1,520,778.81)
7	10/01/20	(1,489,932.02)
8	10/02/20	(1,563,997.05)
9	10/03/20	(1,582,782.44)
10	10/04/20	(1,582,782.44)
11	10/05/20	(1,582,782.44)
12	10/06/20	(1,619,473.92)
13	10/07/20	(1,659,116.47)
14	10/08/20	(1,622,821.64)
15	10/09/20	(1,618,058.99)
16	10/10/20	(1,780,654.33)
17	10/11/20	(1,780,654.33)
18	10/12/20	(1,780,654.33)
19	10/13/20	(1,742,925.65)
20	10/14/20	(1,703,196.10)
21	10/15/20	(1,774,836.76)
22	10/16/20	(1,779,549.90)
23	10/17/20	(1,775,257.83)
24	10/18/20	(1,775,257.83)
25	10/19/20	(1,775,257.83)
26	10/20/20	(1,783,954.56)
27	10/21/20	(1,833,558.17)
28	10/22/20	(1,847,557.50)
29	10/23/20	(1,832,150.00)
30	10/24/20	(1,872,471.39)
31	10/25/20	(1,872,471.39)
32	10/26/20	(1,872,471.39)
33	10/27/20	(2,002,042.90)
34	10/28/20	(1,941,396.84)
35	10/29/20	(1,875,633.72)
36	10/30/20	(1,768,787.45)
37	10/31/20	(1,839,542.16)
38	11/01/20	(1,839,135.50)
39	11/02/20	(1,839,135.50)
40	11/03/20	(1,856,057.13)
41	11/04/20	(1,818,930.04)
42	11/05/20	(1,809,737.77)
43	11/06/20	(1,698,362.84)
44	11/07/20	(1,685,133.96)
45	11/08/20	(1,685,133.96)
46	11/09/20	(1,685,133.96)
47	11/10/20	(1,920,775.75)
48	11/11/20	(1,863,622.87)
49	11/12/20	(1,717,787.59)
50	11/13/20	(1,697,478.07)
51	11/14/20	(1,638,985.39)
52	11/15/20	(1,638,985.39)

Exhibit No. 9
Sheet 4a of 18
Page 6 of 7
Witness: C. Lash

Columbia Gas of Maryland
Analysis of Cash Working Capital Requirements
Twelve Months Ended February 28, 2021
Average Daily Accounts Receivable Balance

Ln. No.	Month / Day	14200200 Daily Customer Accounts Receivable Balance
	(1)	(2) $
1	11/16/20	(1,638,985.39)
2	11/17/20	(1,764,959.57)
3	11/18/20	(1,792,229.20)
4	11/19/20	(1,926,880.63)
5	11/20/20	(1,883,022.14)
6	11/21/20	(1,819,705.39)
7	11/22/20	(1,819,705.39)
8	11/23/20	(1,819,705.39)
9	11/24/20	(1,748,048.81)
10	11/25/20	(1,991,054.10)
11	11/26/20	(1,853,016.31)
12	11/27/20	(1,853,016.31)
13	11/28/20	(1,853,016.31)
14	11/29/20	(1,853,016.31)
15	11/30/20	(1,853,016.31)
16	12/01/20	(1,727,006.74)
17	12/02/20	(1,429,418.71)
18	12/03/20	(1,583,199.67)
19	12/04/20	(1,509,862.17)
20	12/05/20	(1,309,407.86)
21	12/06/20	(1,309,407.86)
22	12/07/20	(1,309,407.86)
23	12/08/20	(1,203,411.85)
24	12/09/20	(984,369.33)
25	12/10/20	(893,077.80)
26	12/11/20	(1,060,794.80)
27	12/12/20	(824,877.14)
28	12/13/20	(824,877.14)
29	12/14/20	(824,877.14)
30	12/15/20	(654,638.44)
31	12/16/20	(639,918.09)
32	12/17/20	(352,401.82)
33	12/18/20	(165,535.43)
34	12/19/20	42,578.92
35	12/20/20	42,578.92
36	12/21/20	42,578.92
37	12/22/20	(136,826.33)
38	12/23/20	(34,154.16)
39	12/24/20	229,424.07
40	12/25/20	229,424.07
41	12/26/20	229,424.07
42	12/27/20	229,424.07
43	12/28/20	229,424.07
44	12/29/20	379,962.46
45	12/30/20	263,729.95
46	12/31/20	461,177.16
47	01/01/21	910,212.72
48	01/02/21	910,212.72
49	01/03/21	910,212.72
50	01/04/21	910,212.72
51	01/05/21	1,485,080.42
52	01/06/21	1,366,139.81

Exhibit No. 9
Sheet 4a of 18
Page 7 of 7
Witness: C. Lash

Columbia Gas of Maryland
Analysis of Cash Working Capital Requirements
Twelve Months Ended February 28, 2021
Average Daily Accounts Receivable Balance

Ln. No.	Month / Day	14200200 Daily Customer Accounts Receivable Balance
	(1)	(2) $
1	01/07/21	1,565,320.79
2	01/08/21	1,935,064.36
3	01/09/21	2,137,875.84
4	01/10/21	2,137,875.84
5	01/11/21	2,137,875.84
6	01/12/21	2,417,280.91
7	01/13/21	2,629,806.34
8	01/14/21	2,383,425.87
9	01/15/21	2,718,303.75
10	01/16/21	3,414,321.84
11	01/17/21	3,414,321.84
12	01/18/21	3,414,321.84
13	01/19/21	3,482,534.47
14	01/20/21	3,827,711.93
15	01/21/21	3,985,479.90
16	01/22/21	4,263,434.62
17	01/23/21	3,847,075.88
18	01/24/21	3,847,075.88
19	01/25/21	3,847,075.88
20	01/26/21	3,753,864.52
21	01/27/21	3,499,647.49
22	01/28/21	4,283,006.55
23	01/29/21	3,888,388.07
24	01/30/21	4,194,825.61
25	01/31/21	4,194,825.61
26	02/01/21	4,425,816.45
27	02/02/21	3,961,057.14
28	02/03/21	5,286,573.13
29	02/04/21	4,857,969.89
30	02/05/21	5,080,118.80
31	02/06/21	5,265,437.86
32	02/07/21	5,265,437.86
33	02/08/21	5,265,437.86
34	02/09/21	5,064,695.18
35	02/10/21	5,333,281.59
36	02/11/21	5,230,341.55
37	02/12/21	5,032,873.47
38	02/13/21	5,156,255.14
39	02/14/21	5,156,255.14
40	02/15/21	5,156,255.14
41	02/16/21	5,538,173.85
42	02/17/21	5,376,574.75
43	02/18/21	5,464,399.87
44	02/19/21	5,684,986.62
45	02/20/21	5,924,310.22
46	02/21/21	5,924,310.22
47	02/22/21	5,924,310.22
48	02/23/21	5,246,816.72
49	02/24/21	5,223,482.06
50	02/25/21	5,442,281.73
51	02/26/21	5,484,152.07
52	02/27/21	5,141,984.67
53	02/28/21	5,141,984.67
54		
55	Total	335,095,804.48

56 Average Account 142 Daily Accounts Receivable Balance (Column 2, Ln. 55 / 365 days) 918,070.70

Exhibit No. 9
Sheet 5 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc
Analysis of Cash Working Capital Requirement
Billing Lag Calculation
Twelve Months Ended February 28, 2021

Line No.	Description (1)	Revenue Amount (2) $	Billing Lag (3)=(4)/(2)	Weighted Revenue (4) $
1	Tariff / Transportation Revenues - (DIS)	45,368,687	1.00	45,368,687
2	GTS Revenues - GTS System	5,378,181	21.37	114,942,722
3	GMB Revenues - GAS System	1,077,701	7.12	7,670,011
4	Calculated Billing Lag	51,824,569	**3.24**	167,981,421

Exhibit No. 9
Sheet 6 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc
Analysis of Cash Working Capital Requirement
Gas Purchased
Twelve Months Ended February 28, 2021

Line No.	Service Month (1)	Lag Days (2)=(4)/(3)	Payment (3) $	Weighted Days (4) $
1	Feb, 2020	38.64	1,139,776.72	44,039,442.00
2	Mar, 2020	39.43	638,962.78	25,194,317.03
3	Apr, 2020	37.90	486,593.26	18,442,866.62
4	May, 2020	39.50	1,124,752.06	44,424,201.90
5	Jun, 2020	39.13	915,592.68	35,829,208.80
6	Jul, 2020	40.13	997,514.25	40,029,505.88
7	Aug, 2020	39.21	1,151,146.46	45,135,891.39
8	Sep, 2020	39.40	927,839.39	36,559,919.43
9	Oct, 2020	39.51	961,797.39	37,996,708.28
10	Nov, 2020	38.03	684,658.68	26,036,179.98
11	Dec, 2020	40.50	1,858,066.56	75,251,695.68
12	Jan, 2021	39.80	2,108,719.17	83,925,724.91
13	Total Lead Days	**39.47**	12,995,419.40	512,865,661.89

Exhibit No. 9
Sheet 7 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc.
Analysis of Cash Working Capital Requirement
Payroll
Twelve Months Ended February 28, 2021

Line No.	Description (1)	Payroll Costs (2) $	Lead Days (3)	Weighted Lead Days (4)=(2)*(3) $
1	Bi-Weekly			
2	F.I.T. & F.I.C.A.	1,313,356	5.93	7,784,268
3	State Withholding	280,558	5.93	1,662,570
4	Net Pay	3,581,164	5.93	21,224,917
5	Total	5,175,078	5.93	30,671,755
6	Monthly			
7	F.I.T. & F.I.C.A.	327,007	14.52	4,747,360
8	State Withholding	74,578	14.52	1,083,133
9	Net Pay	763,744	14.54	11,104,436
10	Total	1,165,329	14.53	16,934,929
11	Annual Incentive Pay	296,735	247.40	73,412,737
12	Grand Total	6,637,141		121,019,421
13	Weighted Average Lead Days		**18.23**	

Exhibit No. 9
Sheet 8 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc.
Analysis of Cash Working Capital Requirement
OPEB
Twelve Months Ended February 28, 2021

Line No.	Service Period Beginning (1)	Service Period Ending (2)	Payment Date (3)	Midpoint of Service Period (4)	Lead Days (5)=(3)-(2)+(4)	Amount Paid (6) $	Weighted Lead Days (7)=(5)*(6) $
1	1/1/2020	3/31/2020	3/30/2020	2/14/2020	44.50	10,000	445,000
2	4/1/2020	6/30/2020	6/30/2020	5/15/2020	45.50	10,000	455,000
3	7/1/2020	9/30/2020	9/29/2020	8/15/2020	45.00	10,000	450,000
4	10/1/2020	12/31/2020	12/30/2020	11/15/2020	45.00	10,000	450,000
5	Total					40,000	1,800,000
6	Weighted Average Days				**45.00**		

Exhibit No. 9
Sheet 9 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc.
Analysis of Cash Working Capital Requirement
Pension
Twelve Months Ended February 28, 2021

Line No.	Service Period Beginning (1)	Service Period Ending (2)	Payment Date (3)	Midpoint of Service Period (4)	Lead Days (5)=(3)-(2)+(4)	Amount Paid (6) $	Weighted Lead Days (7)=(5)*(6) $
1					-	0	0
2					-	0	0
3	Total					0	0
4	Weighted Average Days				-		

Exhibit No. 9
Sheet 10 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc.
Analysis of Cash Working Capital Requirement
Other Employee Benefits
Twelve Months Ended February 28, 2021

Line No.	Service Period (1)	Payment Date (2)	Midpoint of Service Period (3)	Lead Days (4)=(2)-(1)+(3)	Payment (5) $	Weighted Lead Days (6)=(4)*(5) $
1	3/31/2020	3/30/2020	15.5	14.50	60,304	874,410
2	4/30/2020	4/27/2020	15.0	12.00	80,185	962,219
3	5/31/2020	5/28/2020	15.5	12.50	62,132	776,646
4	6/30/2020	6/25/2020	15.0	10.00	79,393	793,928
5	7/31/2020	7/30/2020	15.5	14.50	65,018	942,758
6	8/31/2020	8/27/2020	15.5	11.50	96,904	1,114,397
7	9/30/2020	9/22/2020	15.0	7.00	64,528	451,697
8	10/31/2020	10/29/2020	15.5	13.50	93,001	1,255,509
9	11/30/2020	11/30/2020	15.0	15.00	93,894	1,408,416
10	12/31/2020	12/23/2020	15.5	7.50	68,795	515,961
11	1/31/2021	1/28/2021	15.5	12.50	93,826	1,172,824
12	2/28/2021	2/25/2021	14.0	11.00	122,238	1,344,620
13	Total				980,218	11,613,385
14	Weighted Average Days			**11.85**		

Exhibit No. 9
Sheet 11 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc.
Analysis of Cash Working Capital Requirement
NiSource Corporate Services
Twelve Months Ended February 28, 2021

Line No.	Service Period (1)	Payment Date (2)	Midpoint of Service Period (3)	Lead Days (4)=(2)-(1)+(3)	Payment (5) $	Weighted Lead Days (6)=(4)*(5) $
1	2/29/2020	3/16/2020	14.0	30.00	458,553	13,756,593
2	3/31/2020	4/17/2020	15.5	32.50	830,725	26,998,553
3	4/30/2020	5/19/2020	15.0	34.00	747,865	25,427,419
4	5/31/2020	6/19/2020	15.5	34.50	492,633	16,995,841
5	6/30/2020	7/20/2020	15.0	35.00	639,852	22,394,827
6	7/31/2020	8/19/2020	15.5	34.50	713,435	24,613,504
7	8/31/2020	9/16/2020	15.5	31.50	805,538	25,374,447
8	9/30/2020	10/27/2020	15.0	42.00	881,254	37,012,687
9	10/31/2020	11/20/2020	15.5	35.50	675,915	23,994,965
10	11/30/2020	12/16/2020	15.0	31.00	700,324	21,710,040
11	12/31/2020	1/19/2021	15.5	34.50	1,215,642	41,939,665
12	1/31/2021	2/17/2021	15.5	32.50	704,428	22,893,925
13	Total				8,866,165	303,112,466
14	Weighted Average Days			**34.20**		

Columbia Gas of Maryland, Inc.
Analysis of Cash Working Capital Requirement
Corporate Insurance
Twelve Months Ended February 28, 2021

Line No.	Fee (1)	Payment Date (2)	Amount Paid (3) $	Midpoint of Period (4)	Lead Days (5)	Dollar Lead Days (6)=(3)*(5) $
1	LTD	2/27/2020	13,019.66	7/1/2020	(125.00)	(1,627,458)
2	Life	2/27/2020	12,781.82	7/1/2020	(125.00)	(1,597,728)
3	Property	6/18/2020	9,368.89	12/1/2020	(166.00)	(1,555,236)
4	Casualty	7/31/2020	49,930.02	1/1/2021	(154.00)	(7,689,223)
5	Casualty	7/16/2020	17,160.00	1/1/2021	(169.00)	(2,900,040)
6	Casualty	7/21/2020	4,442.15	1/1/2021	(164.00)	(728,512)
7	Workers Comp	8/7/2020	1,083.22	1/1/2021	(147.00)	(159,234)
8	Workers Comp	8/26/2020	4,868.02	1/1/2021	(128.00)	(623,106)
9	Casualty	8/28/2020	9,450.29	1/1/2021	(126.00)	(1,190,737)
10	Casualty	8/7/2020	28,238.00	1/1/2021	(147.00)	(4,150,987)
11	Casualty	8/13/2020	2,160.00	1/1/2021	(141.00)	(304,560)
12	Casualty	8/12/2020	72,529.27	1/1/2021	(142.00)	(10,299,157)
13	Cyber	11/6/2020	514.30	5/1/2021	(176.00)	(90,517)
14	Cyber	11/19/2020	9,094.78	5/1/2021	(163.00)	(1,482,449)
15	Fiduciary/D&O/Crime	11/6/2020	1,642.85	5/1/2021	(176.00)	(289,142)
16	Fiduciary	11/6/2020	6,326.27	5/1/2021	(176.00)	(1,113,424)
17	D&O	11/6/2020	3,565.35	5/1/2021	(176.00)	(627,501)
18	D&O	11/6/2020	1,865.69	5/1/2021	(176.00)	(328,361)
19	D&O	11/19/2020	31,373.26	5/1/2021	(163.00)	(5,113,841)
20	D&O	11/6/2020	9,428.13	5/1/2021	(176.00)	(1,659,351)
21	D&O	11/9/2020	1,541.79	5/1/2021	(173.00)	(266,730)
22	D&O	11/9/2020	181.25	5/1/2021	(173.00)	(31,356)
23	Crime	11/6/2020	1,961.97	5/1/2021	(176.00)	(345,306)
24	Casualty	8/7/2020	9,412.67	1/1/2021	(147.00)	(1,383,662)
25	LTD	2/27/2020	16,826.55	7/1/2020	(125.00)	(2,103,319)
26	Life	2/27/2020	27,930.54	7/1/2020	(125.00)	(3,491,318)
27	MSL	2/12/2020	21,140.00	7/1/2020	(140.00)	(2,959,600)
28	Property	6/23/2020	1,383.84	12/1/2020	(161.00)	(222,798)
29	WC	8/7/2020	20,467.69	1/1/2021	(147.00)	(3,008,750)
30	Casualty	8/27/2020	18,000.00	1/1/2021	(127.00)	(2,286,000)
31	Casualty	8/12/2020	21,015.64	1/1/2021	(142.00)	(2,984,220)
32	Casualty	8/7/2020	28,238.00	1/1/2021	(147.00)	(4,150,986)
33	Total		456,942			(66,764,609)
34	Weighted Average Days				**(146.11)**	

( ) Denotes Pre-paid expense

Exhibit No. 9
Sheet 13 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc.
Analysis of Cash Working Capital Requirement
Other Operation and Maintenance Expenses
Twelve Months Ended February 28, 2021

Line No.	Description (1)	Approved Check Amount (2) $	Lead Days (3)	Dollar Weighted Days (4) $	Percentage (5)	Lead Days (6)=(3)*(5)
1	Total Work Management Contracts	5,282,514	33.42	176,530,658	53.50%	17.88
2	Total General Office Source	84,085	19.07	1,603,410	46.50%	8.87
3	Total	5,366,599		178,134,069	100.00%	**26.75**

Exhibit No. 9
Sheet 14 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc.
Analysis of Cash Working Capital Requirement
Payroll Taxes
Twelve Months Ended February 28, 2021

Line No.	Description (1)	Payroll Costs (2) $	Lead Days (3) (3)=(4)/(2)	Dollar Lead Days (4) $
1	F.I.C.A.	934,589	7.50	7,024,100
2	Federal Unemployment	3,164	16.00	50,548
3	State Unemployment	7,675	66.40	509,974
4	Total	945,428		7,584,622
5	Weighted Average Days		**8.00**	

Exhibit No. 9
Sheet 15 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc.
Analysis of Cash Working Capital Requirement
Gross Receipts Tax and Consumption Tax
Twelve Months Ended February 28, 2021

Line No.	Service Period Beginning (1)	Service Period Ending (2)	Payment Date (3)	Midpoint of Service Period (4)	Lead Days (5)=(3)-(4)	Amount Paid (6) $	Weighted Lead Days (7)=(5)*(6) $
1	1/1/2019	12/31/2019	4/3/2020	7/1/2019	276.50	69,942	19,338,963
2	1/1/2020	3/31/2020	4/7/2020	2/14/2020	52.50	242,286	12,720,015
3	4/1/2020	6/30/2020	6/17/2020	5/15/2020	32.50	242,286	7,874,295
4	7/1/2020	9/30/2020	9/10/2020	8/15/2020	26.00	242,286	6,299,436
5	10/1/2020	12/31/2020	12/8/2020	11/15/2020	23.00	242,286	5,572,578
6	Total					1,039,086	51,805,287
7	Weighted Average Days				**49.86**		

Exhibit No. 9
Sheet 16 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc.
Analysis of Cash Working Capital Requirement
Property Taxes / PSC Fees / Franchise Fees
Twelve Months Ended February 28, 2021

Line No.	Description (1)	Amount Due (2) $	Date of Statutory Payment (3)	Midpoint of Tax Year (4)	Lead Days (5)=(3)-(4)	Weighted Lead Days (6)=(2)*(5) $
1	**Property Taxes**					
2	ALLEGANY COUNTY			1/1/2020	(43,831.00)	0
3	CUMBERLAND			1/1/2020	(43,831.00)	0
4	DEER PARK			1/1/2020	(43,831.00)	0
5	FROSTBURG			1/1/2020	(43,831.00)	0
6	FUNKSTOWN			1/1/2020	(43,831.00)	0
7	GARRETT COUNTY			1/1/2020	(43,831.00)	0
8	GRANTSVILLE			1/1/2020	(43,831.00)	0
9	HAGERSTOWN			1/1/2020	(43,831.00)	0
10	HANCOCK			1/1/2020	(43,831.00)	0
11	KITZMILLER, TOWN OF			1/1/2020	(43,831.00)	0
12	LOCH LYNN			1/1/2020	(43,831.00)	0
13	LUKE			1/1/2020	(43,831.00)	0
14	MOUNTAIN LAKE			1/1/2020	(43,831.00)	0
15	OAKLAND			1/1/2020	(43,831.00)	0
16	PRINCE GEORGE COUNTY			1/1/2020	(43,831.00)	0
17	WASHINGTON COUNTY			1/1/2020	(43,831.00)	0
18	WILLIAMSPORT			1/1/2020	(43,831.00)	0
19	**Gas Stored**					
20	West Virginia State Auditor	6,889	24-Aug-2020	7/1/2020	54.00	372,020
21	West Virginia State Auditor	6,889	02-Feb-2021	7/1/2020	216.00	1,488,080
22	**Total**	13,779			**(53.76)**	1,860,100
23	**PSC Fees**					
24	Maryland Public Service Commission	26,113	25-Mar-2020	1/1/2020	84.00	2,193,509
25	Maryland Public Service Commission	25,522	17-Jul-2020	1/1/2021	(168.00)	(4,287,718)
26	Maryland Public Service Commission	25,522	14-Oct-2020	1/1/2021	(79.00)	(2,016,248)
27	Maryland Public Service Commission	25,522	11-Jan-2021	1/1/2021	10.00	255,221
28	Total	102,680			**(37.55)**	(3,855,236)
29	**Other Taxes - License & Franchise**					
30	BARTON	75	2/20/2020	7/1/2020	(132.00)	(9,900)
31	CUMBERLAND	5,000	2/20/2020	7/1/2020	(132.00)	(660,000)
32	DEER PARK	100	2/20/2020	7/1/2020	(132.00)	(13,200)
33	FROSTBURG	1,500	2/20/2020	7/1/2020	(132.00)	(198,000)
34	HAGERSTOWN	500	2/20/2020	7/1/2020	(132.00)	(66,000)
35	KITZMILLER	500	2/20/2020	7/1/2020	(132.00)	(66,000)
36	LOCH LYNN HEIGHTS	50	2/20/2020	7/1/2020	(132.00)	(6,600)
37	LONACONING	100	2/20/2020	7/1/2020	(132.00)	(13,200)
38	LUKE	75	2/20/2020	7/1/2020	(132.00)	(9,900)
39	MIDLAND	50	2/20/2020	7/1/2020	(132.00)	(6,600)
40	MOUNTAIN LAKE PARK	1,500	2/20/2020	7/1/2020	(132.00)	(198,000)
41	WESTERNPORT	200	2/20/2020	7/1/2020	(132.00)	(26,400)
42	WILLIAMSPORT	1,000	2/20/2020	7/1/2020	(132.00)	(132,000)
43	Total	10,650			**(132.00)**	(1,405,800)

( ) Denotes Pre-paid expense

Exhibit No. 9
Sheet 17 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc.
Analysis of Cash Working Capital Requirement
Income Taxes
Twelve Months Ended February 28, 2021

Line No.	Amount Due (1)	Date of Statutory Payment (2)	Midpoint of Year (3)	Lead Days (4)=(2)-(3)	Weighted Lead Days (5)=(1)*(4)
1	FEDERAL INCOME TAXES				
2	25.0%	15-Apr-20	01-Jul-20	(77.00)	(19.30)
3	25.0%	15-Jun-20	01-Jul-20	(16.00)	(4.00)
4	25.0%	15-Sep-20	01-Jul-20	76.00	19.00
5	25.0%	15-Dec-20	01-Jul-20	167.00	41.80
6	Total Federal Lead Days				**37.50**
7	CORPORATE INCOME TAXES				
8	25.0%	15-Apr-20	01-Jul-20	(77.00)	(19.30)
9	25.0%	15-Jun-20	01-Jul-20	(16.00)	(4.00)
10	25.0%	15-Sep-20	01-Jul-20	76.00	19.00
11	25.0%	15-Dec-20	01-Jul-20	167.00	41.80
12	Total Corporate Lead Days				**37.50**

( ) Denotes Pre-paid expense

Exhibit No. 9
Sheet 18 of 18
Witness: C. Lash

Columbia Gas of Maryland, Inc.
Analysis of Cash Working Capital Requirement
Interest on Debt
Twelve Months Ended February 28, 2021

Line No.	Debt Instrument (1)	Interest Charges (2) $	Lead Days (3)	Dollar Weighted (4)=(2)*(3) $
1	Installment Promissory Notes	3,239,288	92.25	298,826,539
2	Money Pool	9,695	16.35	158,519
3	Total	3,248,983		298,985,058
4	Weighted Average Days		**92.00**	

ATTACHMENTS
ARE EXCEL
SPREADSHEETS
AND UPLOADED
SEPARATELY

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

37. Refer to Columbia Kentucky's responses to the First Request for Information of the Attorney General, Item 30.d. Cite any instance where a lead/lag study that was presented by a utility to the Commission resulted in a negative cash working capital.

Response:

As companies have only recently began to prepare Lead Lag studies in Kentucky to calculate their cash working capital requirement, Columbia Kentucky is not aware of another utility's study resulting in negative cash working capital.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

38. Provide a comparison by asset category of the depreciation lives approved by the Commission in Case No. 2016-00162[1] to the depreciation lives proposed in the Depreciation Study presented by Jon J. Spanos. Provide the depreciation life comparison in an Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible.

Response:

The attached schedule, KY PSC Case No. 2021-00183, Staff 3-38, Attachment A, sets forth a comparison by asset category of the depreciation lives and net salvage estimates approved by the Commission in Case No. 2016-00162 to the depreciation lives and net salvage estimates proposed in the Depreciation Study presented by John J. Spanos in Case No. 2021-00183.

[1] Case No. 2016-00162, *Application of Columbia Gas of Kentucky, Inc. for an Increase in Base Rates* (Ky. PSC Dec. 22, 2016).

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COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

39. Provide a comparison by asset category of the net salvage values approved by the Commission in Case No. 2016-00162 to the net salvage values proposed in the Depreciation Study presented by Jon J. Spanos. Provide the net salvage value comparison in Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible.

Response:

Please see Columbia's Response to Staff's Third Set of Requests for Information, 38, including attachment KY PSC Case No. 2021-00183, Staff 3-38, Attachment A, which sets forth a comparison of the net salvage percentages proposed by asset category and those currently approved.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 10, 2021

40. Using the depreciation lives and net salvage values in the Depreciation Study presented by Jon J. Spanos, Columbia Kentucky calculated a forecasted depreciation expense is $19,609,323. Provide an Excel spreadsheet with all formulas, columns, and rows unprotected and fully accessible showing the forecasted depreciation expense if the net salvage values are eliminated.

Response:

As the analysis on this request was developed, it was discovered that some of the depreciation rates used in WPB2.2 in the forecast year did not align with the depreciation rates as developed in the depreciation study. Refer to KY PSC Case No. 2021-00183, Staff 3-40, Attachment A for a revised WPB2.2. The net impact of this change is a reduction of the forecasted test year depreciation expense as follows:

Depreciation Expense	Depreciation	Reserve Amortization Adjustment	Total Depreciation
Revised	19,210,422.00	120,473.00	19,330,895.00
Original Filing	19,488,850.00	120,473.00	19,609,323.00
Difference	(278,428.00)	-	(278,428.00)

The reduced depreciation also impact the Accumulated Depreciation balances used in rate base and results in an increase in rate base of approximately $138,000.

Depreciation rates and expense should include the recovery of the full service value of all assets which includes the net salvage component. Additionally, past depreciation rates and expense have included the incurred and accrued net salvage amounts. This is a critical factor in the development of the accumulated depreciation (book reserve) which is a primary component of a remaining life rate. Therefore, with an understanding that developing depreciation expense on a go forward basis without a net salvage percentage is not a reasonable calculation particularly when past depreciation rates have been based on a net salvage component and forecasted data requires appropriate rate development, the calculation prepared is only established to respond to this request for information. These depreciation rates and the total depreciation expense do not include the appropriate monthly bringforward of the accumulated depreciation that would be developed with the elimination of the net salvage component. Refer to KY PSC Case No. 2021-00183, Staff 3-40, Attachment B for another version of WPB2.2 with depreciation rates developed as described without the net salvage percentages. A comparison of the 19,330.895 (revised above) depreciation to the $13,502,649 depreciation provided in KY PSC Case No. 2021-00183, Staff 3-40, Attachment B is not reasonable.

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