FORM 10-K

WILLIAMS COMPANIES INC - WMB

Filed: February 22, 2018 (period: December 31, 2017)

Annual report with a comprehensive overview of the company

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2017

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 1-4174

The Williams Companies, Inc.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**73-0569878**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
One Williams Center, Tulsa, Oklahoma	**74172**
(Address of Principal Executive Offices)	(Zip Code)

918-573-2000

(Registrant's Telephone Number, Including Area Code)

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

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock, $1.00 par value	New York Stock Exchange

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 Section 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 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

Large accelerated filer ☑	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐	Emerging growth company ☐

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold as of the last business day of the registrant's most recently completed second quarter was approximately $24,993,673,967.

The number of shares outstanding of the registrant's common stock outstanding at February 19, 2018 was 827,327,336.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Definitive Proxy Statement for the Registrant's Annual Meeting of Stockholders to be held on May 10, 2018, are incorporated into Part III, as specifically set forth in Part III.

THE WILLIAMS COMPANIES, INC.

FORM 10-K

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DEFINITIONS

The following is a listing of certain abbreviations, acronyms and other industry terminology that may be used throughout this Annual Report.

Measurements:

Barrel: One barrel of petroleum products that equals 42 U.S. gallons

Bcf : One billion cubic feet of natural gas

Bcf/d: One billion cubic feet of natural gas per day

British Thermal Unit (Btu): A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit

Dekatherms (Dth): A unit of energy equal to one million British thermal units

Mbbls/d: One thousand barrels per day

Mdth/d: One thousand dekatherms per day

MMcf/d: One million cubic feet per day

MMdth: One million dekatherms or approximately one trillion British thermal units

MMdth/d: One million dekatherms per day

Tbtu: One trillion British thermal units

Consolidated Entities:

Cardinal: Cardinal Gas Services, L.L.C.

Constitution: Constitution Pipeline Company, LLC

Gulfstar One: Gulfstar One LLC

Jackalope: Jackalope Gas Gathering Services, L.L.C.

Northwest Pipeline: Northwest Pipeline LLC

Transco: Transcontinental Gas Pipe Line Company, LLC

WPZ: Williams Partners L.P.

Partially Owned Entities: Entities in which we do not own a 100 percent ownership interest and which, as of December 31, 2017, we account for as an equity-method investment, including principally the following:

Aux Sable: Aux Sable Liquid Products LP

Caiman II: Caiman Energy II, LLC

Discovery: Discovery Producer Services LLC

Gulfstream: Gulfstream Natural Gas System, L.L.C.

Laurel Mountain: Laurel Mountain Midstream, LLC

OPPL: Overland Pass Pipeline Company LLC

UEOM: Utica East Ohio Midstream LLC

Government and Regulatory:

EPA: Environmental Protection Agency

Exchange Act, the: Securities and Exchange Act of 1934, as amended

FERC: Federal Energy Regulatory Commission

GAAP: Generally accepted accounting principles

IRS: Internal Revenue Service

SEC: Securities and Exchange Commission

Other:

ACMP: Access Midstream Partners, L.P. prior to its merger with Pre-Merger WPZ

Energy Transfer: Energy Transfer Equity, L.P.

ETC: Energy Transfer Corp LP

ETC Merger: Merger wherein Williams would have been merged into ETC

Fractionation: The process by which a mixed stream of natural gas liquids is separated into its constituent products, such as ethane, propane, and butane

IDR: Incentive distribution right

LNG: Liquefied natural gas; natural gas which has been liquefied at cryogenic temperatures

Merger Agreement: Merger Agreement and Plan of Merger of Williams with Energy Transfer and certain of its affiliates

MVC: Minimum volume commitment

NGLs: Natural gas liquids; natural gas liquids result from natural gas processing and crude oil refining and are used as petrochemical feedstocks, heating fuels, and gasoline additives, among other applications

NGL margins: NGL revenues less Btu replacement cost, plant fuel, transportation, and fractionation

Pre-merger WPZ: Williams Partners L.P. prior to its merger with ACMP

PDH facility: Propane dehydrogenation facility

RGP Splitter: Refinery grade propylene splitter

Throughput: The volume of product transported or passing through a pipeline, plant, terminal, or other facility

The statements in this Annual Report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements. Forward-looking statements may be identified by various forms of words such as "anticipates," "believes," "seeks," "could," "may," "should," "continues," "estimates," "expects," "forecasts," "intends," "might," "goals," "objectives," "targets," "planned," "potential," "projects," "scheduled," "will," "assumes," "guidance," "outlook," "in-service date," or other similar expressions and other words and terms of similar meaning. Although we believe that our expectations regarding future events are based on reasonable assumptions, we can give no assurance that such expectations or assumptions will be achieved. Additional information regarding forward-looking statements and important factors that could cause actual results to differ materially from those in the forward-looking statements are described under Part I, Item 1A in this Annual Report.

PART I

Item 1. *Business*

In this report, Williams (which includes The Williams Companies, Inc. and, unless the context otherwise indicates, all of our subsidiaries) is at times referred to in the first person as "we," "us" or "our." We also sometimes refer to Williams as the "Company."

WEBSITE ACCESS TO REPORTS AND OTHER INFORMATION

We file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other documents electronically with the SEC under the Exchange Act. You may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. You may also obtain such reports from the SEC's Internet website at www.sec.gov.

Our Internet website is http://investor.williams.com/. We make available, free of charge, through the Investors tab of our Internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Our Corporate Governance Guidelines, Code of Ethics for Senior Officers, Board committee charters, and the Williams Code of Business Conduct are also available on our Internet website. We will also provide, free of charge, a copy of any of our corporate documents listed above upon written request to our Corporate Secretary, One Williams Center, Suite 4700, Tulsa, Oklahoma 74172.

GENERAL

We are an energy infrastructure company focused on connecting North America's significant hydrocarbon resource plays to markets for natural gas and NGLs. Our operations are located principally in the United States.

As of December 31, 2017, our interstate gas pipelines and midstream interests were largely held through our significant investment in WPZ. We own the general partner interest and a 74 percent limited partner interest in WPZ.

We were founded in 1908, originally incorporated under the laws of the state of Nevada in 1949 and reincorporated under the laws of the state of Delaware in 1987. Williams' headquarters are located in Tulsa, Oklahoma, with other major offices in Salt Lake City, Utah; Houston, Texas; Pittsburgh, Pennsylvania; and the Four Corners Area. Our telephone number is 918-573-2000.

FINANCIAL INFORMATION ABOUT SEGMENTS

See Part II, "Item 8. Financial Statements and Supplementary Data — Notes to Consolidated Financial Statements — Note 18 – Segment Disclosures."

BUSINESS SEGMENTS

Substantially all our operations are conducted through our subsidiaries. Our activities in 2017 were operated through the following reporting segments as presented in the accompanying financial statements and management's discussion and analysis.

- *Williams Partners* — comprised of our consolidated master limited partnership, WPZ, which includes gas pipeline and midstream businesses. The gas pipeline business includes interstate natural gas pipelines and pipeline joint project investments. The midstream business provides natural gas gathering, treating, processing and compression services; NGL production, fractionation, storage, marketing and transportation; deepwater production handling and crude oil transportation services; an olefin production business (see Note 2 –

Acquisitions and Divestitures of Notes to Consolidated Financial Statements), and is comprised of several wholly owned and partially owned subsidiaries and joint project investments.

This reporting segment also included our former Canadian midstream operations comprised of an oil sands offgas processing plant near Fort McMurray, Alberta, an NGL/olefin fractionation facility, and the Boreal Pipeline, which were sold in September 2016 (see Note 2 – Acquisitions and Divestitures of Notes to Consolidated Financial Statements).

- *Other* — comprised of business activities that are not operating segments, as well as corporate operations. Other also includes certain domestic olefins pipeline assets as well as certain Canadian assets, which included a liquids extraction plant located near Fort McMurray, Alberta, that began operations in March 2016, and a propane dehydrogenation facility which was under development. In September 2016, the Canadian assets were sold (see Note 2 – Acquisitions and Divestitures of Notes to Consolidated Financial Statements).

Detailed discussion of each of our reporting segments follows. For a discussion of our ongoing expansion projects, see Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Williams Partners

Gas Pipeline Business

Williams Partners' gas pipeline businesses consist primarily of Transco and Northwest Pipeline. Our gas pipeline business also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 50 percent equity-method investment in Gulfstream and a 41 percent interest in Constitution (a consolidated entity), which is developing a pipeline project (see Note 3 – Variable Interest Entities of Notes to Consolidated Financial Statements). Transco and Northwest Pipeline own and operate a combined total of approximately 13,600 miles of pipelines with a total annual throughput of approximately 4,533 TBtu of natural gas and peak-day delivery capacity of approximately 18.8 MMdth of natural gas.

Transco

Transco is an interstate natural gas transmission company that owns and operates a 9,700-mile natural gas pipeline system, which is regulated by the FERC, extending from Texas, Louisiana, Mississippi and the Gulf of Mexico through Alabama, Georgia, South Carolina, North Carolina, Virginia, Maryland, Delaware, Pennsylvania and New Jersey to the New York City metropolitan area. The system serves customers in Texas and 12 southeast and Atlantic seaboard states, including major metropolitan areas in Georgia, North Carolina, Washington, D.C., Maryland, New York, New Jersey, and Pennsylvania.

Pipeline system and customers

At December 31, 2017, Transco's system, which extends from Texas to New York, had a system-wide delivery capacity totaling approximately 15.0 MMdth of natural gas per day. During 2017, Transco completed five fully-contracted expansions, which added more than 2.8 MMdth of firm transportation capacity per day to the existing pipeline system. Transco's system includes 50 compressor stations, four underground storage fields, and an LNG storage facility. Compression facilities at sea level-rated capacity total approximately 2.1 million horsepower.

Transco's major natural gas transportation customers are public utilities and municipalities that provide service to residential, commercial, industrial and electric generation end users. Shippers on Transco's system include public utilities, municipalities, intrastate pipelines, direct industrial users, electric power generators, and natural gas marketers and producers. Transco's firm transportation agreements are generally long-term agreements with various expiration dates and account for the major portion of Transco's business. Additionally, Transco offers interruptible transportation services under shorter-term agreements.

Transco has natural gas storage capacity in four underground storage fields located on or near its pipeline system or market areas and operates two of these storage fields. Transco also has storage capacity in an LNG storage facility that it owns and operates. The total usable gas storage capacity available to Transco and its customers in such underground storage fields and LNG storage facility and through storage service contracts is approximately 200 Bcf of natural gas. At December 31, 2017, Transco's customers had stored in its facilities approximately 141

Bcf of natural gas. In addition, wholly owned subsidiaries of Transco operate and hold a 35 percent equity-method investment in Pine Needle LNG Company, LLC, an LNG storage facility with 4 Bcf of storage capacity. Storage capacity permits Transco's customers to inject gas into storage during the summer and off-peak periods for delivery during peak winter demand periods.

Northwest Pipeline

Northwest Pipeline is an interstate natural gas transmission company that owns and operates a natural gas pipeline system, which is regulated by the FERC, extending from the San Juan basin in northwestern New Mexico and southwestern Colorado through Colorado, Utah, Wyoming, Idaho, Oregon, and Washington to a point on the Canadian border near Sumas, Washington. Northwest Pipeline provides services for markets in Washington, Oregon, Idaho, Wyoming, Nevada, Utah, Colorado, New Mexico, California, and Arizona, either directly or indirectly through interconnections with other pipelines.

<u>Pipeline system and customers</u>

At December 31, 2017, Northwest Pipeline's system, having long-term firm transportation and storage redelivery agreements with aggregate capacity reservations of approximately 3.8 MMdth/d, was composed of approximately 3,900 miles of mainline and lateral transmission pipeline and 41 transmission compressor stations having a combined sea level-rated capacity of approximately 472,000 horsepower.

Northwest Pipeline transports and stores natural gas for a broad mix of customers, including local natural gas distribution companies, municipal utilities, direct industrial users, electric power generators, and natural gas marketers and producers. Northwest Pipeline's firm transportation and storage contracts are generally long-term contracts with various expiration dates and account for the major portion of Northwest Pipeline's business. Additionally, Northwest Pipeline offers interruptible and short-term firm transportation service.

Northwest Pipeline owns a one-third interest in the Jackson Prairie underground storage facility in Washington and contracts with a third party for natural gas storage services in the Clay Basin underground field in Utah. Northwest Pipeline also owns and operates an LNG storage facility in Washington. These storage facilities have an aggregate working natural gas storage capacity of 14.2 MMdth of natural gas, which is substantially utilized for third-party natural gas. These natural gas storage facilities enable Northwest Pipeline to balance daily receipts and deliveries and provide storage services to customers.

Gulfstream

Gulfstream is a 745-mile interstate natural gas pipeline system extending from the Mobile Bay area in Alabama to markets in Florida, which has a capacity to transport 1.3 Bcf/d. Williams Partners owns, through a subsidiary, a 50 percent equity-method investment in Gulfstream. Williams Partners shares operating responsibilities for Gulfstream with the other 50 percent owner.

Midstream Business

Williams Partners' midstream business, one of the nation's largest natural gas gatherers and processors, has primary service areas concentrated in major producing basins in Arkansas, Colorado, New Mexico, Oklahoma, Texas, Wyoming, the Gulf of Mexico, Louisiana, Pennsylvania, West Virginia, New York, and Ohio. The primary businesses are: (1) natural gas gathering, treating, and processing; (2) NGL fractionation, storage and transportation; (3) crude oil transportation; and (4) olefins production (see Note 2 – Acquisitions and Divestitures of Notes to Consolidated Financial Statements). These fall within the middle of the process of taking raw natural gas and crude oil from the producing fields to the consumer.

Key variables for this business will continue to be:

- Producer drilling activities impacting natural gas supplies supporting our gathering and processing volumes;

- Prices impacting commodity-based activities;

- Retaining and attracting customers by continuing to provide reliable services;
- Revenue growth associated with additional infrastructure either completed or currently under construction;
- Disciplined growth in service areas.

Gathering, Processing, and Treating

Williams Partners' gathering systems receive natural gas from producers' oil and natural gas wells and gather these volumes to gas processing, treating or redelivery facilities. Typically, natural gas, in its raw form, is not acceptable for transportation in major interstate natural gas pipelines or for commercial use as a fuel. Williams Partners' treating facilities remove water vapor, carbon dioxide, and other contaminants and collect condensate, but do not extract NGLs. Williams Partners' is generally paid a fee based on the volume of natural gas gathered and/or treated, generally measured in the Btu heating value.

In addition, natural gas contains various amounts of NGLs, which generally have a higher value when separated from the natural gas stream. Our processing plants extract the NGLs in addition to removing water vapor, carbon dioxide, and other contaminants. NGL products include:

- Ethane, primarily used in the petrochemical industry as a feedstock for ethylene production, one of the basic building blocks for plastics;
- Propane, used for heating, fuel and as a petrochemical feedstock in the production of ethylene and propylene, another building block for petrochemical-based products such as carpets, packing materials, and molded plastic parts;
- Normal butane, isobutane and natural gasoline, primarily used by the refining industry as blending stocks for motor gasoline or as a petrochemical feedstock.

Our gas processing services generate revenues primarily from the following types of contracts:

- Fee-based: We are paid a fee based on the volume of natural gas processed, generally measured in the Btu heating value. Our customers are entitled to the NGLs produced in connection with this type of processing agreement. A portion of our fee-based processing revenues includes a share of the margins on the NGLs produced. For the year ended December 31, 2017, 70 percent of our NGL production volumes were under fee-based contracts.
- Noncash commodity-based: We also process gas under two types of commodity-based contracts, keep-whole and percent-of-liquids, where we receive consideration for our services in the form of NGLs. Under these contracts, we retain some or all of the extracted NGLs as compensation for our services. For a keep-whole arrangement we replace the Btu content of the retained NGLs that were extracted during processing with natural gas purchases, also known as shrink replacement gas. For a percent-of-liquids arrangement, we deliver to customers an agreed-upon percentage of the extracted NGLs and retain the remainder. NGLs we retain in connection with these types of processing agreements are referred to as our equity NGL production. Under keep-whole agreements, we have commodity price exposure on the difference between NGL and natural gas prices. For the year ended December 31, 2017, 30 percent of our NGL production volumes were under noncash commodity-based contracts.

Our gathering and processing agreements have terms ranging from month-to-month to the life of the producing lease. Generally, our gathering and processing agreements are long-term agreements. Some contracts have price escalators which annually increase our gathering rates. In addition, certain contracts include fee redetermination or cost of service mechanisms that are designed to support a return on invested capital and allow our gathering rates to be adjusted, subject to specified caps in certain cases, to account for variability in volume, capital expenditures, commodity price fluctuations, compression and other expenses. Certain of our gas gathering agreements include MVCs. If the minimum annual or semi-annual volume commitment is not met, these customers are obligated to pay a fee equal to the applicable fee for each Mcf by which the applicable customer's minimum annual or semi-annual volume commitment exceeds the actual volume gathered. The revenue associated with such shortfall fees is generally recognized in the fourth quarter of each year.

Demand for gas gathering and processing services is dependent on producers' drilling activities, which is impacted by the strength of the economy, natural gas prices, and the resulting demand for natural gas by manufacturing and industrial companies and consumers. Williams Partners' gas gathering and processing customers are generally natural gas producers who have proved and/or producing natural gas fields in the areas surrounding its infrastructure. During 2017, Williams Partners' facilities gathered and processed gas and crude oil for approximately 260 customers. Williams Partners' top ten customers accounted for approximately 75 percent of our gathering and processing fee revenues and NGL margins from our noncash commodity-based agreements.

Demand for our equity NGLs is affected by economic conditions and the resulting demand from industries using these commodities to produce petrochemical-based products such as plastics, carpets, packing materials and blending stocks for motor gasoline and the demand from consumers using these commodities for heating and fuel. NGL products are currently the preferred feedstock for ethylene and propylene production, which has shifted away from the more expensive crude-based feedstocks.

Geographically, the midstream natural gas assets are positioned to maximize commercial and operational synergies with our other assets. For example, most of the offshore gathering and processing assets attach and process or condition natural gas supplies delivered to the Transco pipeline. Our San Juan basin, southwest Wyoming, and Piceance systems are capable of delivering residue gas volumes into Northwest Pipeline's interstate system in addition to third-party interstate systems. Our gathering systems in Pennsylvania delivers residue gas volumes into Transco's pipeline in addition to third-party interstate systems.

The following table summarizes our significant consolidated natural gas gathering assets:

	Natural Gas Gathering Assets				
	Location	Pipeline Miles	Inlet Capacity (Bcf/d)	Ownership Interest	Supply Basins/Shale Formations
Northeast					
Ohio Valley Midstream	Ohio, West Virginia, & Pennsylvania	216	0.8	100%	Appalachian
Susquehanna Supply Hub	Pennsylvania & New York	436	3.2	100%	Appalachian
Cardinal (1)	Ohio	353	1.0	66%	Appalachian
Flint	Ohio	75	0.4	100%	Appalachian
Marcellus South (2)	Pennsylvania	41	0.1	100%	Appalachian
Atlantic-Gulf					
Canyon Chief, including Blind Faith and Gulfstar extensions	Deepwater Gulf of Mexico	156	0.5	100%	Eastern Gulf of Mexico
Other Eastern Gulf	Offshore shelf and other	46	0.2	100%	Eastern Gulf of Mexico
Seahawk	Deepwater Gulf of Mexico	115	0.4	100%	Western Gulf of Mexico
Perdido Norte	Deepwater Gulf of Mexico	105	0.3	100%	Western Gulf of Mexico
Other Western Gulf	Offshore shelf and other	105	0.5	100%	Western Gulf of Mexico
West					
Four Corners	Colorado & New Mexico	3,742	1.8	100%	San Juan
Wamsutter	Wyoming	2,084	0.7	100%	Wamsutter
Southwest Wyoming	Wyoming	1,614	0.5	100%	Southwest Wyoming
Piceance	Colorado	352	1.8	(3)	Piceance
Niobrara	Wyoming	224	0.2	(4)	Powder River
Barnett Shale	Texas	858	0.8	100%	Barnett Shale
Eagle Ford Shale	Texas	1,225	0.6	100%	Eagle Ford Shale
Haynesville Shale	Louisiana	626	1.8	100%	Haynesville Shale
Permian	Texas	365	0.1	100%	Permian
Mid-Continent	Oklahoma, Texas, & Kansas	2,248	0.9	100%	Miss-Lime, Granite Wash, Colony Wash, Arkoma

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(1) Statistics reflect 100 percent of the assets from our 66 percent ownership of Cardinal gathering system.

(2) Statistics reflect 100 percent of the Beaver Creek assets in the consolidated Marcellus South gathering system.

(3) Includes our 60 percent ownership of a gathering system in the Ryan Gulch area with 140 miles of pipeline and 0.2 Bcf/d of inlet capacity, and our 67 percent ownership of a gathering system at Allen Point with 8 miles of pipeline and 0.1 Bcf/d of inlet capacity. We operate both systems. We own and operate 100 percent of the balance of the Piceance gathering assets.

(4) Statistics reflect 100 percent of the assets from our 50 percent ownership of the Jackalope gathering system.

The following table summarizes our significant consolidated natural gas processing facilities:

	Natural Gas Processing Facilities				
	Location	Inlet Capacity (Bcf/d)	NGL Production Capacity (Mbbls/d)	Ownership Interest	Supply Basins
Northeast					
Fort Beeler	Marshall County, WV	0.5	62	100%	Appalachian
Oak Grove	Marshall County, WV	0.2	25	100%	Appalachian
Atlantic-Gulf					
Markham	Markham, TX	0.5	45	100%	Western Gulf of Mexico
Mobile Bay	Coden, AL	0.7	30	100%	Eastern Gulf of Mexico
West					
Echo Springs	Echo Springs, WY	0.7	58	100%	Wamsutter
Opal	Opal, WY	1.1	47	100%	Southwest Wyoming
Bucking Horse (1)	Converse County, WY	0.1	7	50%	Powder River
Willow Creek	Rio Blanco County, CO	0.5	30	100%	Piceance
Parachute	Garfield County, CO	1.1	6	100%	Piceance
Ignacio	Ignacio, CO	0.5	29	100%	San Juan
Kutz	Bloomfield, NM	0.2	12	100%	San Juan

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(1) Statistics reflect 100 percent of the assets from our 50 percent ownership of Bucking Horse gas processing facility.

In addition, we own and operate several natural gas treating facilities in New Mexico, Colorado, Texas, and Louisiana which bring natural gas to specifications allowable by major interstate pipelines.

We also own and operate fractionation facilities at Moundsville, de-ethanization and condensate facilities at our Oak Grove processing plant, a condensate stabilization facility near our Oak Grove plant, and an ethane transportation pipeline. Our three condensate stabilizers are capable of handling 17 Mbbls/d of field condensate. NGLs are extracted from the natural gas stream in our cryogenic processing plants. Our Oak Grove de-ethanizer is capable of handling up to approximately 80 Mbbls/d of mixed NGLs to extract up to approximately 40 Mbbls/d of ethane. The remaining mixed NGL stream from the de-ethanizer is then transported and fractionated at our Moundsville facilities, which are capable of handling more than 43 Mbbls/d of mixed NGLs. Ethane produced at our de-ethanizer is transported to markets via our 50-mile ethane pipeline from Oak Grove to Houston, Pennsylvania.

Our gathering business in the Northeast also provides multiple takeaway options to its customers. Ohio Valley Midstream makes customer deliveries with interconnections to two pipelines. Susquehanna Supply Hub makes deliveries for its customers with interconnections to Transco, as well as five other pipelines, while our Cardinal system utilizes interconnections with Blue Racer Midstream, LLC (Blue Racer), and UEOM. In addition, our NGL processing business utilizes connections with multiple pipelines, as well as truck and rail transportation to local and regional markets.

Crude Oil Transportation and Production Handling Assets

In addition to our natural gas assets, we own and operate four deepwater crude oil pipelines and own production platforms serving the deepwater in the Gulf of Mexico. Our crude oil transportation revenues are typically volumetric-based fee arrangements. However, a portion of our marketing revenues are recognized from purchase and sale arrangements whereby the oil that we transport is purchased and sold as a function of the same index-based price. Our offshore floating production platforms provide centralized services to deepwater producers such as compression, separation, production handling, water removal, and pipeline landings. Revenue sources have historically included a combination of fixed-fee, volumetric-based fee and cost reimbursement arrangements. Fixed fees associated with the resident production at our Devils Tower facility are recognized on a units-of-production basis. Fixed fees associated with the resident production at our Gulfstar One facility are recognized as the guaranteed capacity is made available.

The following tables summarize our significant crude oil transportation pipelines and production handling platforms:

	Crude Oil Pipelines			
	Pipeline Miles	Capacity (Mbbls/d)	Ownership Interest	Supply Basins
Mountaineer, including Blind Faith and Gulfstar extensions	155	150	100%	Eastern Gulf of Mexico
BANJO	57	90	100%	Western Gulf of Mexico
Alpine	96	85	100%	Western Gulf of Mexico
Perdido Norte	74	150	100%	Western Gulf of Mexico

	Production Handling Platforms			
	Gas Inlet Capacity (MMcf/d)	Crude/NGL Handling Capacity (Mbbls/d)	Ownership Interest	Supply Basins
Devils Tower	210	60	100%	Eastern Gulf of Mexico
Gulfstar I FPS (1)	172	80	51%	Eastern Gulf of Mexico

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(1) Statistics reflect 100 percent of the assets from our 51 percent interest in Gulfstar One.

Canadian Operations

Williams Partners completed the sale of its Canadian operations in September 2016. This business included an oil sands offgas processing plant located near Fort McMurray, Alberta, and an NGL/olefin fractionation facility located at Redwater, Alberta, which is near Edmonton, Alberta, and the Boreal Pipeline which transported NGLs and associated olefins from the Fort McMurray plant to the Redwater fractionation facility. This business allowed us to extract, fractionate, treat, store, terminal and sell the ethane/ethylene, propane, propylene, normal butane (butane), iso-butane, alky feedstock, and condensate recovered from a third-party oil sands bitumen upgrader.

Operating statistics

The following table summarizes our significant operating statistics:

	2016	2015
Volumes:		
Canadian propylene sales (millions of pounds)	87	161
Canadian NGL sales (millions of gallons)	141	284

Gulf Olefins

In mid-2017, Williams Partners completed the sale of its 88.5 percent undivided interest and operatorship of an olefins production facility in Geismar, Louisiana, along with a refinery grade propylene splitter in the Gulf region. The olefins business also operated an ethylene storage hub at Mont Belvieu using leased third-party underground storage caverns.

Our refinery grade propylene splitter had production capacity of approximately 500 million pounds per year of propylene. At the propylene splitter, we purchased refinery grade propylene and fractionated it into polymer grade propylene and propane; as a result, the asset was exposed to the price spread between those commodities.

Marketing Services

We market NGL products to a wide range of users in the energy and petrochemical industries. The NGL marketing business transports and markets our equity NGLs from the production at our processing plants, and also markets NGLs on behalf of third-party NGL producers, including some of our fee-based processing customers, and the NGL volumes owned by Discovery. The NGL marketing business bears the risk of price changes in these NGL volumes while they are being transported to final sales delivery points. In order to meet sales contract obligations, we may purchase products in the spot market for resale. Other than a long-term agreement to sell our equity NGLs transported on OPPL, the majority of sales are based on supply contracts of one year or less in duration.

In certain situations to facilitate our gas gathering and processing activities, we buy natural gas from our producer customers for resale.

Prior to the sale of our olefin operations, we marketed olefin products to a wide range of users in the energy and petrochemical industries.

Other NGL & Petchem Operations

We own interests in and/or operate NGL fractionation and storage assets in central Kansas near Conway. These assets include a 50 percent interest in an NGL fractionation facility with capacity of slightly more than 100 Mbbls/d and we own approximately 20 million barrels of NGL storage capacity.

We own 283 miles of pipeline systems in Louisiana and Texas that provide feedstock transportation from fractionation and storage facilities to various third-party crackers. These systems include the Bayou ethane pipeline, which provides ethane transportation from Mont Belvieu, Texas; certain ethane and propane systems in Louisiana; and a pipeline that has the capacity to transport 12 Mbbls/d of ethane from Discovery's Paradis fractionator.

We own 114 miles of pipelines in the Houston Ship Channel area which transport a variety of products including ethane, propane, ammonia, tertiary butyl alcohol, and other industrial products used in the petrochemical industry. We also own a tunnel crossing pipeline under the Houston Ship Channel. A portion of these pipelines are leased to third parties.

WPZ Operating Areas

WPZ organizes these businesses into the following operating areas:

Northeast G&P is comprised of natural gas gathering and processing, compression, and NGL fractionation businesses in the Marcellus and Utica Shale regions in Pennsylvania, West Virginia, New York, and Ohio, as well as a 66 percent interest in Cardinal (a consolidated entity), a 62 percent equity-method investment in UEOM, a 69 percent equity-method investment in Laurel Mountain, a 58 percent equity-method investment in Caiman II, and Appalachia Midstream Services, LLC, which owns an approximate average 66 percent interest in multiple gas gathering systems in the Marcellus Shale.

Atlantic-Gulf is comprised of an interstate natural gas pipeline, Transco, and significant natural gas gathering and processing and crude oil production handling and transportation assets in the Gulf Coast region, including a 51 percent interest in Gulfstar One (a consolidated entity) which is a proprietary floating production system, and various petrochemical and feedstock pipelines in the Gulf Coast region, as well as a 50 percent equity-method investment in Gulfstream, a 41 percent interest in Constitution (a consolidated entity) which is developing a pipeline project (see Note 3 – Variable Interest Entities of Notes to Consolidated Financial Statements), and a 60 percent equity-method investment in Discovery.

West is comprised of an interstate natural gas pipeline, Northwest Pipeline, and natural gas gathering, processing, and treating operations in New Mexico, Colorado, and Wyoming, as well as the Barnett Shale region of north-central Texas, the Eagle Ford Shale region of south Texas, the Haynesville Shale region of northwest Louisiana, and the Mid-Continent region which includes the Anadarko, Arkoma, Delaware, and Permian basins. West also includes an NGL and natural gas marketing business, storage facilities, and an undivided 50 percent interest in an NGL fractionator near Conway, Kansas, as well as our previously owned 50 percent equity-method investment in the Delaware basin gas gathering system in the Permian basin, and a 50 percent equity-method investment in OPPL.

NGL & Petchem Services is comprised of previously owned operations, including an 88.5 percent undivided interest in an olefins production facility in Geismar, Louisiana, which was sold in July 2017 (see Note 2 – Acquisitions and Divestitures of Notes to Consolidated Financial Statements), and a refinery grade propylene splitter in the Gulf region, which was sold in June 2017. This operating area also included an oil sands offgas processing plant near Fort McMurray, Alberta, and an NGL/olefin fractionation facility, which were sold in September 2016.

Certain Equity-Method Investments

Discovery

We own a 60 percent interest in and operate the facilities of Discovery. Discovery's assets include a 600 MMcf/d cryogenic natural gas processing plant near Larose, Louisiana, a 32 Mbbls/d NGL fractionator plant near Paradis, Louisiana, and a 614-mile offshore natural gas gathering and transportation system in the Gulf of Mexico. Discovery's mainline has a gathering inlet capacity of 600 MMcf/d, while the Keathley Canyon Connector, a deepwater lateral pipeline in the central deepwater Gulf of Mexico has a gathering inlet capacity of 400 MMcf/d. Discovery's assets also include a crude oil production handling platform with a crude oil/NGL handling capacity of 10 Mbbls/d and natural gas processing capacity of 75 MMcf/d.

Laurel Mountain

We own a 69 percent interest in a joint venture, Laurel Mountain, that includes a 2,053-mile gathering system that we operate in western Pennsylvania with the capacity to gather 0.7 Bcf/d of natural gas. Laurel Mountain has a long-term, dedicated, volumetric-based fee agreement, with exposure to natural gas prices, to gather the anchor customer's production in the western Pennsylvania area of the Marcellus Shale.

Caiman II

We own a 58 percent interest in Caiman II, which owns a 50 percent interest in Blue Racer, a joint project to own, operate, develop and acquire midstream assets in the Utica Shale and certain adjacent areas in the Marcellus Shale. Blue Racer's assets include 721 miles of gathering pipelines, and the Natrium complex in Marshall County, West Virginia, with a cryogenic processing capacity of 400 MMcf/d and fractionation capacity of approximately 120,000 Bbls/d. Blue Racer also owns the Berne complex in Monroe County, Ohio, with a cryogenic processing capacity of 400 MMcf/d, and NGL and condensate pipelines connecting Natrium to Berne.

Utica East Ohio Midstream

We own a 62 percent interest in UEOM, which includes infrastructure for the gathering, processing, and fractionation of natural gas and NGLs in the Utica Shale play in eastern Ohio. We operate a natural gas gathering pipeline, while our partner operates inlet compression, two processing plants with a total capacity of 800 MMcf/d, 41 Mbbls/d of condensate stabilization capacity, a 135 Mbbls/d NGL fractionation facility, approximately 950,000 barrels of NGL storage capacity and other ancillary assets, including loading and terminal facilities. These assets earn a fixed fee that escalates annually within a specified range.

Appalachia Midstream Investments

Through our Appalachia Midstream Investments, we operate 100 percent of and own an approximate average 66 percent interest in the Bradford Supply Hub gathering system and own an approximate average 68 percent interest in the Marcellus South gathering system, together which consist of approximately 987 miles of gathering pipeline in the Marcellus Shale region. The majority of our volumes in the region are gathered from northern Pennsylvania, southwestern Pennsylvania and the northwestern panhandle of West Virginia in core areas of the Marcellus Shale. Appalachia Midstream Investments operates the assets under long-term, 100 percent fixed-fee gathering agreements that include significant acreage dedications and cost of service mechanisms.

During the first quarter of 2017, we exchanged all of our 50 percent interest in the Delaware basin gas gathering system for an increased interest in the Bradford Supply Hub natural gas gathering system that is part of the Appalachia Midstream Investments and $155 million in cash. Following this exchange, we have an approximate average 66 percent interest in the Appalachia Midstream Investments. We continue to account for this investment under the equity-method due to the significant participatory rights of our partners such that we do not exercise control. (See Note 5 – Investing Activities of Notes to Consolidated Financial Statements.)

Aux Sable

We also own a 15 percent interest in Aux Sable and its Channahon, Illinois, gas processing and NGL fractionation facility near Chicago. The facility is capable of processing up to 2.1 Bcf/d of natural gas from the Alliance Pipeline system and fractionating approximately 132 Mbbls/d of extracted liquids into NGL products. Additionally, Aux Sable owns an 80 MMcf/d gas conditioning plant and a 12-inch, 83-mile gas pipeline infrastructure in North Dakota that provides additional NGLs to Channahon from the Bakken Shale in the Williston basin.

Delaware basin gas gathering system

We previously owned a non-operated 50 percent interest in the Delaware basin gas gathering system in the Permian basin, which was sold in February 2017. The system was comprised of more than 450 miles of gathering pipeline, located in west Texas.

Overland Pass Pipeline

We also operate and own a 50 percent interest in OPPL. OPPL is capable of transporting 255 Mbbls/d and includes approximately 1,096 miles of NGL pipeline extending from Opal, Wyoming, to the Mid-Continent NGL market center near Conway, Kansas, along with extensions into the Piceance and Denver-Julesberg basins in Colorado and the Bakken Shale in the Williston basin in North Dakota. Our equity NGL volumes from two of our three Wyoming plants and our Willow Creek facility in Colorado are dedicated for transport on OPPL under a long-term transportation agreement.

Operating Statistics

The following table summarizes our significant operating statistics for Williams Partners' domestic midstream business:

	2017	2016	2015
Volumes: (1)			
Gathering (Bcf/d)	8.15	8.25	8.34
Plant inlet natural gas (Bcf/d)	3.05	3.50	3.52
NGL production (Mbbls/d) (2)	148	151	131
NGL equity sales (Mbbls/d) (2)	39	46	31
Crude oil transportation (Mbbls/d) (2)	134	113	126
Geismar ethylene sales (millions of pounds)	566	1,638	1,066

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(1) Excludes volumes associated with equity-method investments.

(2) Annual average Mbbls/d.

Additional Business Segment Information

Our ongoing business segments are presented as continuing operations in the accompanying financial statements and Notes to Consolidated Financial Statements included in Part II.

We perform certain management, legal, financial, tax, consultation, information technology, administrative and other services for our subsidiaries.

Our principal sources of cash are from dividends, distributions, and advances from our subsidiaries, investments, payments by subsidiaries for services rendered, and, if needed, external financings, and net proceeds from asset sales. The terms of certain subsidiaries' borrowing arrangements may limit the transfer of funds to us under certain conditions.

We believe that we have adequate sources and availability of raw materials and commodities for existing and anticipated business needs. Our interstate pipeline systems are all regulated in various ways resulting in the financial return on the investments made in the systems being limited to standards permitted by the regulatory agencies. Each of the pipeline systems has ongoing capital requirements for efficiency and mandatory improvements, with expansion opportunities also necessitating periodic capital outlays.

Revenues by service within our Williams Partners segment that exceeded 10 percent of consolidated revenue include:

	Total
	(Millions)
2017	
Service:	
Regulated natural gas transportation and storage	$ 2,148
Gathering, processing, and production handling	2,715
2016	
Service:	
Regulated natural gas transportation and storage	$ 2,001
Gathering, processing, and production handling	2,729
2015	
Service:	
Regulated natural gas transportation and storage	$ 1,938
Gathering, processing and production handling	2,804

We have one customer, Chesapeake Energy Corporation, and its affiliates, that accounts for 10 percent of our total revenue in 2017. (See Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements for additional details.)

REGULATORY MATTERS

FERC

Our gas pipeline interstate transmission and storage activities are subject to FERC regulation under the Natural Gas Act of 1938 (NGA) and under the Natural Gas Policy Act of 1978, and, as such, our rates and charges for the transportation of natural gas in interstate commerce, accounting, and the extension, enlargement, or abandonment of our jurisdictional facilities, among other things, are subject to regulation. Each gas pipeline company holds certificates of public convenience and necessity issued by the FERC authorizing ownership and operation of all pipelines, facilities, and properties for which certificates are required under the NGA. FERC Standards of Conduct govern how our interstate pipelines communicate and do business with gas marketing employees. Among other things, the Standards of Conduct require that interstate pipelines not operate their systems to preferentially benefit gas marketing functions.

FERC regulation requires all terms and conditions of service, including the rates charged, to be filed with and approved by the FERC before any changes can go into effect. Each of our interstate natural gas pipeline companies establishes its rates primarily through the FERC’s ratemaking process. Key determinants in the ratemaking process are:

- Costs of providing service, including depreciation expense;
- Allowed rate of return, including the equity component of the capital structure and related income taxes;
- Contract and volume throughput assumptions.

The allowed rate of return is determined in each rate case. Rate design and the allocation of costs between the reservation and commodity rates also impact profitability. As a result of these proceedings, certain revenues previously collected may be subject to refund.

We also own interests in and operate two offshore transmission pipelines that are regulated by the FERC because they are deemed to transport gas in interstate commerce. Black Marlin Pipeline Company provides transportation service for offshore Texas production in the High Island area and redelivers that gas to intrastate pipeline interconnects near Texas City. Discovery provides transportation service for offshore Louisiana production from the South Timbalier, Grand Isle, Ewing Bank, and Green Canyon (deepwater) areas to an onshore processing facility and downstream interconnect points with major interstate pipelines. In addition, Williams Partners owns a 50 percent equity-method investment in and is the operator of OPPL, which is an interstate natural gas liquids pipeline regulated by the FERC pursuant to the Interstate Commerce Act. OPPL provides transportation service pursuant to tariffs filed with the FERC. We also own an ethane pipeline in West Virginia and Pennsylvania (Williams Ohio Valley Pipeline LLC) and an ethane pipeline in Texas and Louisiana (Williams Bayou Ethane Pipeline) each of which provides interstate service subject to FERC jurisdiction under the Interstate Commerce Act.

Pipeline Safety

Our gas pipelines are subject to the Natural Gas Pipeline Safety Act of 1968, as amended, the Pipeline Safety Improvement Act of 2002, the Pipeline Safety, Regulatory Certainty, and Jobs Creation Act of 2011 (Pipeline Safety Act), and the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016, which regulate safety requirements in the design, construction, operation, and maintenance of interstate natural gas transmission facilities. The United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) administers federal pipeline safety laws.

Federal pipeline safety laws authorize PHMSA to establish minimum safety standards for pipeline facilities and persons engaged in the transportation of gas or hazardous liquids by pipeline. These safety standards apply to the design, construction, testing, operation, and maintenance of gas and hazardous liquids pipeline facilities affecting interstate or foreign commerce. PHMSA has also established reporting requirements for operators of gas and hazardous liquid pipeline facilities, as well as provisions for establishing the qualification of pipeline personnel and requirements for managing the integrity of gas transmission and distribution lines and certain hazardous liquid pipelines. To ensure compliance with these provisions, PHMSA performs pipeline safety inspections and has the authority to initiate enforcement actions.

Federal pipeline safety regulations contain an exemption that applies to gathering lines in certain rural locations. A substantial portion of our gathering lines qualify for that exemption and are currently not regulated under federal law.

States are largely preempted by federal law from regulating pipeline safety for interstate pipelines but most are certified by PHMSA to assume responsibility for enforcing intrastate pipeline safety regulations and inspecting intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines, they vary considerably in their authority and capacity to address pipeline safety.

On January 3, 2012, the Pipeline Safety Act was enacted. The Pipeline Safety Act requires PHMSA to complete a number of reports in preparation for potential rulemakings. The issues addressed in these rulemaking provisions include, but are not limited to, the use of automatic or remotely controlled shut-off valves on new or replaced transmission line facilities, modifying the requirements for pipeline leak detection systems, and expanding the scope of the pipeline integrity management requirements for both gas and liquid pipeline systems. On June 22, 2016, the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 was enacted, further strengthening PHMSA’s safety authority.

Pipeline Integrity Regulations

We have an enterprise-wide Gas Integrity Management Plan that we believe meets the PHMSA final rule that was issued pursuant to the requirements of the Pipeline Safety Improvement Act of 2002. The rule requires gas pipeline operators to develop an integrity management program for gas transmission pipelines that could affect high-consequence areas in the event of pipeline failure. The integrity management program includes a baseline assessment plan along with periodic reassessments to be completed within required time frames. In meeting the integrity regulations, we have identified high-consequence areas and developed baseline assessment plans. Ongoing periodic reassessments and initial assessments of any new high-consequence areas have been completed. We estimate that the cost to be incurred in 2018 associated with this program to be approximately $99 million. Management considers the costs associated with compliance with the rule to be prudent costs incurred in the ordinary course of business and, therefore, recoverable through Northwest Pipeline’s and Transco’s rates.

We have an enterprise-wide Liquid Integrity Management Plan that we believe meets the PHMSA final rule that was issued pursuant to the requirements of the Pipeline Safety Improvement Act of 2002. The rule requires liquid pipeline operators to develop an integrity management program for liquid transmission pipelines that could affect high-consequence areas in the event of pipeline failure. The integrity management program includes a baseline assessment plan along with periodic reassessments expected to be completed within required time frames. In meeting the integrity regulations, we utilized government defined high-consequence areas and developed baseline assessment plans. We completed assessments within the required time frames. We estimate that the cost to be incurred in 2018 associated with this program will be approximately $4 million. Ongoing periodic reassessments and initial assessments of any new high-consequence areas are expected to be completed within the time frames required by the rule. Management considers the costs associated with compliance with the rule to be prudent costs incurred in the ordinary course of business.

State Gathering Regulation

Our onshore midstream gathering operations are subject to laws and regulations in the various states in which we operate. For example, the Texas Railroad Commission has the authority to regulate the terms of service for our intrastate natural gas gathering business in Texas. Although the applicable state regulations vary widely, they generally require that pipeline rates and practices be reasonable and nondiscriminatory, and may include provisions covering marketing, pricing, pollution, environment, and human health and safety. Some states, such as New York, have specific regulations pertaining to the design, construction, and operations of gathering lines within such state.

Intrastate Liquids Pipelines in the Gulf Coast

Our intrastate liquids pipelines in the Gulf Coast are regulated by the Louisiana Department of Environmental Quality, the Texas Railroad Commission, and various other state and federal agencies. These pipelines are also subject to the liquid pipeline safety and integrity regulations discussed above since both Louisiana and Texas have adopted the integrity management regulations defined in PHMSA.

OCSLA

Our offshore midstream gathering is subject to the Outer Continental Shelf Lands Act (OCSLA). Although offshore gathering facilities are not subject to the NGA, offshore transmission pipelines are subject to the NGA, and in recent years the FERC has taken a broad view of offshore transmission, finding many shallow-water pipelines to be jurisdictional transmission. Most offshore gathering facilities are subject to the OCSLA, which provides in part that outer continental shelf pipelines “must provide open and nondiscriminatory access to both owner and nonowner shippers.”

See Part II, Item 8. Financial Statements and Supplementary Data — Note 17 – Contingent Liabilities and Commitments of Notes to Consolidated Financial Statements for further details on our regulatory matters. For additional information regarding regulatory matters, please also refer to “Risk Factors — *The operation of our businesses might also be adversely affected by regulatory proceedings, changes in government regulations or in their interpretation or implementation, or the introduction of new laws or regulations applicable to our businesses or our customers,” and “The natural gas sales, transportation, and storage operations of our gas pipelines are subject to regulation by the FERC, which could have an adverse impact on their ability to establish transportation and storage rates that would allow them to recover the full cost of operating their respective pipelines, including a reasonable rate of return*."

ENVIRONMENTAL MATTERS

Our operations are subject to federal environmental laws and regulations as well as the state, local, and tribal laws and regulations adopted by the jurisdictions in which we operate. We could incur liability to governments or third parties for any unlawful discharge of pollutants into the air, soil, or water, as well as liability for cleanup costs. Materials could be released into the environment in several ways including, but not limited to:

- Leakage from gathering systems, underground gas storage caverns, pipelines, processing or treating facilities, transportation facilities, and storage tanks;

- Damage to facilities resulting from accidents during normal operations;
- Damages to onshore and offshore equipment and facilities resulting from storm events or natural disasters;
- Blowouts, cratering, and explosions.

In addition, we may be liable for environmental damage caused by former owners or operators of our properties.

We believe compliance with current environmental laws and regulations will not have a material adverse effect on our capital expenditures, earnings, or current competitive position. However, environmental laws and regulations could affect our business in various ways from time to time, including incurring capital and maintenance expenditures, fines and penalties, and creating the need to seek relief from the FERC for rate increases to recover the costs of certain capital expenditures and operation and maintenance expenses.

For additional information regarding the potential impact of federal, state, tribal, or local regulatory measures on our business and specific environmental issues, please refer to "Risk Factors — *"Our operations are subject to environmental laws and regulations, including laws and regulations relating to climate change and greenhouse gas emissions, which may expose us to significant costs, liabilities, and expenditures that could exceed our expectations,"* and Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Environmental" and "Environmental Matters" in Part II, Item 8. Financial Statements and Supplementary Data — Note 17 – Contingent Liabilities and Commitments of Notes to Consolidated Financial Statements.

COMPETITION

Gas Pipeline Business

The market for supplying natural gas is highly competitive and new pipelines, storage facilities, and other related services are expanding to service the growing demand for natural gas. Additionally, pipeline capacity in many growing natural gas supply basins is constrained causing competition to increase among pipeline companies as they strive to connect those basins to major natural gas demand centers.

In our business, we compete with major intrastate and interstate natural gas pipelines. In the last few years, local distribution companies have also started entering into the long haul transportation business through joint venture pipelines. The principle elements of competition in the interstate natural gas pipeline business are based on rates, reliability, quality of customer service, diversity of supply, and proximity to customers and market hubs.

Significant entrance barriers to build new pipelines exist, including federal and growing state regulations and public opposition against new pipeline builds, and these factors will continue to impact potential competition for the foreseeable future. However, we believe the position of our existing infrastructure, established strategic long-term contracts, and the fact that our pipelines have numerous receipt and delivery points along our systems provide us a competitive advantage, especially along the eastern seaboard and northwestern United States.

Midstream Business

Competition for natural gas gathering, processing, treating, transporting, and storing natural gas continues to increase as production from shales and other resource areas continues to grow. Our midstream services compete with similar facilities that are in the same proximity as our assets.

We face competition from major and independent natural gas midstream providers, private equity firms, and major integrated oil and natural gas companies that gather, transport, process, fractionate, store, and market natural gas and NGLs, as well as some larger exploration and production companies that are choosing to develop midstream services to handle their own natural gas.

Our gathering and processing agreements are generally long-term agreements that may include acreage dedication. We primarily face competition to the extent these agreements approach renewal and new volume opportunities arise. Competition for natural gas volumes is primarily based on reputation, commercial terms (products retained or fees charged), array of services provided, efficiency and reliability of services, location of gathering facilities, available capacity, downstream interconnects, and latent capacity. We believe our significant presence in traditional prolific supply basins, our solid positions in growing shale plays, and our ability to offer integrated packages of services position us well against our competition.

For additional information regarding competition for our services or otherwise affecting our business, please refer to "Risk Factors - *The financial condition of our natural gas transportation and midstream businesses is dependent on the continued availability of natural gas supplies in the supply basins that we access and demand for those supplies in the markets we serve,"* "*Our industry is highly competitive and increased competitive pressure could adversely affect our business and operating results*," and "*We may not be able to replace, extend, or add additional customer contracts or contracted volumes on favorable terms, or at all, which could affect our financial condition, the amount of cash available to pay dividends, and our ability to grow.*"

EMPLOYEES

At February 1, 2018, we had approximately 5,425 full-time employees.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

See Part II, Item 8. Financial Statements and Supplementary Data — Note 18 – Segment Disclosures of Notes to Consolidated Financial Statements for amounts of revenues during the last three fiscal years from external customers attributable to the United States and all foreign countries. Also see Part II, Item 8. Financial Statements and Supplementary Data — Note 18 – Segment Disclosures of Notes to Consolidated Financial Statements for information relating to long-lived assets during the last three fiscal years, located in the United States and all foreign countries.

Item 1A. ***Risk Factors***

FORWARD-LOOKING STATEMENTS AND CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

The reports, filings, and other public announcements of Williams may contain or incorporate by reference statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (Securities Act) and Section 21E of the Securities Exchange Act of 1934, as amended (Exchange Act). These forward-looking statements relate to anticipated financial performance, management's plans and objectives for future operations, business prospects, outcome of regulatory proceedings, market conditions, and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

All statements, other than statements of historical facts, included in this report that address activities, events, or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. Forward-looking statements can be identified by various forms of words such as "anticipates," "believes," "seeks," "could," "may," "should," "continues," "estimates," "expects," "forecasts," "intends," "might," "goals," "objectives," "targets," "planned," "potential," "projects," "scheduled," "will," "assumes," "guidance," "outlook," "in-service date," or other similar expressions. These forward-looking statements are based on management's beliefs and assumptions and on information currently available to management and include, among others, statements regarding:

- Expected levels of cash distributions by WPZ with respect to limited partner interests;
- Levels of dividends to Williams stockholders;
- Future credit ratings of Williams, WPZ, and their affiliates;
- Amounts and nature of future capital expenditures;
- Expansion and growth of our business and operations;
- Expected in-service dates for capital projects;
- Financial condition and liquidity;
- Business strategy;
- Cash flow from operations or results of operations;
- Seasonality of certain business components;
- Natural gas and natural gas liquids prices, supply, and demand;
- Demand for our services.

Forward-looking statements are based on numerous assumptions, uncertainties, and risks that could cause future events or results to be materially different from those stated or implied in this report. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from results contemplated by the forward-looking statements include, among others, the following:

- Whether WPZ will produce sufficient cash flows to provide expected levels of cash distributions;
- Whether we are able to pay current and expected levels of dividends;
- Whether WPZ elects to pay expected levels of cash distributions and we elect to pay expected levels of dividends;
- Whether we will be able to effectively execute our financing plan;
- Availability of supplies, including lower than anticipated volumes from third parties served by our midstream business, and market demand;
- Volatility of pricing including the effect of lower than anticipated energy commodity prices and margins;
- Inflation, interest rates, and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);
- The strength and financial resources of our competitors and the effects of competition;
- Whether we are able to successfully identify, evaluate, and timely execute our capital projects and other investment opportunities in accordance with our forecasted capital expenditures budget;
- Our ability to successfully expand our facilities and operations;
- Development and rate of adoption of alternative energy sources;
- The impact of operational and developmental hazards and unforeseen interruptions, and the availability of adequate insurance coverage;
- The impact of existing and future laws (including, but not limited to, the Tax Cuts and Job Acts of 2017), regulations, the regulatory environment, environmental liabilities, and litigation, as well as our ability to obtain necessary permits and approvals and achieve favorable rate proceeding outcomes;
- Our costs and funding obligations for defined benefit pension plans and other postretirement benefit plans;
- Changes in maintenance and construction costs;
- Changes in the current geopolitical situation;
- Our exposure to the credit risk of our customers and counterparties;
- Risks related to financing, including restrictions stemming from debt agreements, future changes in credit ratings as determined by nationally recognized credit rating agencies, and the availability and cost of capital;
- The amount of cash distributions from and capital requirements of our investments and joint ventures in which we participate;
- Risks associated with weather and natural phenomena, including climate conditions and physical damage to our facilities;

- Acts of terrorism, including cybersecurity threats, and related disruptions;

- Additional risks described in our filings with the Securities and Exchange Commission (SEC).

Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. We disclaim any obligations to and do not intend to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

In addition to causing our actual results to differ, the factors listed above and referred to below may cause our intentions to change from those statements of intention set forth in this report. Such changes in our intentions may also cause our results to differ. We may change our intentions, at any time and without notice, based upon changes in such factors, our assumptions, or otherwise.

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. These factors are described in the following section.

RISK FACTORS

You should carefully consider the following risk factors in addition to the other information in this report. Each of these factors could adversely affect our business, prospects, financial condition, results of operations, cash flows, and, in some cases our reputation. The occurrence of any of such risks could also adversely affect the value of an investment in our securities.

Risks Related to Our Business

The financial condition of our natural gas transportation and midstream businesses is dependent on the continued availability of natural gas supplies in the supply basins that we access and demand for those supplies in the markets we serve.

Our ability to maintain and expand our natural gas transportation and midstream businesses depends on the level of drilling and production by third parties in our supply basins. Production from existing wells and natural gas supply basins with access to our pipeline and gathering systems will naturally decline over time. The amount of natural gas reserves underlying these existing wells may also be less than anticipated, and the rate at which production from these reserves declines may be greater than anticipated. We do not obtain independent evaluations of natural gas reserves connected to our systems and processing facilities. Accordingly, we do not have independent estimates of total reserves dedicated to our systems or the anticipated life of such reserves. In addition, low prices for natural gas, regulatory limitations, or the lack of available capital could adversely affect the development and production of additional natural gas reserves, the installation of gathering, storage, and pipeline transportation facilities and the import and export of natural gas supplies. Localized low natural gas prices in one or more of our existing supply basins, whether caused by a lack of infrastructure or otherwise, could also result in depressed natural gas production in such basins and limit the supply of natural gas made available to us. The competition for natural gas supplies to serve other markets could also reduce the amount of natural gas supply for our customers. A failure to obtain access to sufficient natural gas supplies will adversely impact our ability to maximize the capacities of our gathering, transportation, and processing facilities.

Demand for our services is dependent on the demand for gas in the markets we serve. Alternative fuel sources such as electricity, coal, fuel oils, or nuclear energy, as well as technological advances and renewable sources of energy, could reduce demand for natural gas in our markets and have an adverse effect on our business.

A failure to obtain access to sufficient natural gas supplies or a reduction in demand for our services in the markets we serve could result in impairments of our assets and have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Prices for natural gas, NGLs, oil, and other commodities, are volatile and this volatility has and could continue to adversely affect our financial results, cash flows, access to capital, and ability to maintain our existing businesses.

Our revenues, operating results, future rate of growth, and the value of certain components of our businesses depend primarily upon the prices of natural gas, NGLs, oil, or other commodities, and the differences between prices of these commodities and could be materially adversely affected by an extended period of current low commodity prices, or a further decline in commodity prices. Price volatility has and could continue to impact both the amount we receive for our products and services and the volume of products and services we sell. Prices affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Price volatility has and could continue to have an adverse effect on our business, results of operations, financial condition, and cash flows.

The markets for natural gas, NGLs, oil, and other commodities are likely to continue to be volatile. Wide fluctuations in prices might result from one or more factors beyond our control, including:

- Worldwide and domestic supplies of and demand for natural gas, NGLs, oil, and related commodities;
- Turmoil in the Middle East and other producing regions;
- The activities of the Organization of Petroleum Exporting Countries;
- The level of consumer demand;
- The price and availability of other types of fuels or feedstocks;
- The availability of pipeline capacity;
- Supply disruptions, including plant outages and transportation disruptions;
- The price and quantity of foreign imports of natural gas and oil;
- Domestic and foreign governmental regulations and taxes;
- The credit of participants in the markets where products are bought and sold.

We are exposed to the credit risk of our customers and counterparties, including Chesapeake Energy Corporation and its affiliates, and our credit risk management will not be able to completely eliminate such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties in the ordinary course of our business. Generally, our customers are rated investment grade, are otherwise considered creditworthy, or are required to make prepayments or provide security to satisfy credit concerns. However, our credit procedures and policies cannot completely eliminate customer and counterparty credit risk. Our customers and counterparties include industrial customers, local distribution companies, natural gas producers, and marketers whose creditworthiness may be suddenly and disparately impacted by, among other factors, commodity price volatility, deteriorating energy market conditions, and public and regulatory opposition to energy producing activities. In a low commodity price environment certain of our customers could be negatively impacted, causing them significant economic stress including, in some cases, to file for bankruptcy protection or to renegotiate contracts. To the extent one or more of our key customers commences bankruptcy proceedings, our contracts with the customers may be subject to rejection under applicable provisions of the United States Bankruptcy Code, or may be renegotiated. Further, during any such bankruptcy proceeding, prior to assumption, rejection or renegotiation of such contracts, the bankruptcy court may temporarily authorize the payment of value for our services less than contractually required, which could have a material adverse effect on our business, financial condition, results of operations, and cash flows. For example, Chesapeake

Energy Corporation and its affiliates, which accounted for approximately 10 percent of our 2017 consolidated revenues, have experienced significant, negative financial results due to sustained low commodity prices. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties or otherwise do not take or are unable to take sufficient mitigating actions, including obtaining sufficient collateral, deterioration in their creditworthiness, and any resulting increase in nonpayment and/or nonperformance by them could cause us to write down or write off accounts receivable. Such write-downs or write-offs could negatively affect our operating results in the periods in which they occur, and, if significant, could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

We may not be able to grow or effectively manage our growth.

As part of our growth strategy, we consider acquisition opportunities and engage in significant capital projects. We have both a project lifecycle process and an investment evaluation process. These are processes we use to identify, evaluate, and execute on acquisition opportunities and capital projects. We may not always have sufficient and accurate information to identify and value potential opportunities and risks or our investment evaluation process may be incomplete or flawed. Regarding potential acquisitions, suitable acquisition candidates may not be available on terms and conditions we find acceptable or, where multiple parties are trying to acquire an acquisition candidate, we may not be chosen as the acquirer. If we are able to acquire a targeted business, we may not be able to successfully integrate the acquired businesses and realize anticipated benefits in a timely manner.

Our growth may also be dependent upon the construction of new natural gas gathering, transportation, compression, processing or treating pipelines, and facilities, NGL transportation, or fractionation or storage facilities as well as the expansion of existing facilities. In the current environment, we may face political opposition by landowners, environmental activists, and others resulting in the delay and/or denial of required governmental permits. Additional risks associated with construction may include the inability to obtain rights-of-way, skilled labor, equipment, materials, and other required inputs in a timely manner such that projects are completed, on time or at all, and the risk that construction cost overruns could cause total project costs to exceed budgeted costs. Additional risks associated with growing our business include, among others, that:

- Changing circumstances and deviations in variables could negatively impact our investment analysis, including our projections of revenues, earnings, and cash flow relating to potential investment targets, resulting in outcomes which are materially different than anticipated;

- We could be required to contribute additional capital to support acquired businesses or assets;

- We may assume liabilities that were not disclosed to us, that exceed our estimates and for which contractual protections are either unavailable or prove inadequate;

- Acquisitions could disrupt our ongoing business, distract management, divert financial and operational resources from existing operations and make it difficult to maintain our current business standards, controls, and procedures;

- Acquisitions and capital projects may require substantial new capital, including the issuance of debt or equity, and we may not be able to access capital markets or obtain acceptable terms.

If realized, any of these risks could have an adverse impact on our financial condition, results of operations, including the possible impairment of our assets, or cash flows.

We may face opposition to the construction and operation of our pipelines and facilities from various groups.

We may face opposition to the construction and operation of our pipelines and facilities from environmental groups, landowners, tribal groups, local groups and other advocates. Such opposition could take many forms, including organized protests, attempts to block or sabotage our operations, intervention in regulatory or administrative proceedings involving our assets, or lawsuits or other actions designed to prevent, disrupt or delay the operation of our assets and business. In addition, acts of sabotage or eco-terrorism could cause significant damage or injury to people, property or the environment or lead to extended interruptions of our operations. Any such event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could adversely affect our financial condition and results of operations.

Holders of our common stock may not receive dividends in the amount expected or any dividends.

We may not have sufficient cash each quarter to pay dividends or maintain current or expected levels of dividends. The actual amount of cash we dividend may fluctuate from quarter to quarter and will depend on various factors, some of which are beyond our control, including:

- The amount of cash that WPZ and our other subsidiaries distribute to us;
- The amount of cash we generate from our operations, our working capital needs, our level of capital expenditures, and our ability to borrow;
- The restrictions contained in our indentures and credit facility and our debt service requirements;
- The cost of acquisitions, if any.

A failure either to pay dividends or to pay dividends at expected levels could result in a loss of investor confidence, reputational damage, and a decrease in the value of our stock price.

Our cash flow is heavily dependent on the earnings and distributions of WPZ.

Our partnership interest in WPZ is our largest cash-generating asset. Therefore, we are indirectly exposed to all of the risks to which WPZ is subject, as our cash flow is heavily dependent upon the ability of WPZ to make distributions to its partners. A significant decline in WPZ's earnings and/or distributions would have a corresponding negative impact on us.

One of our subsidiaries acts as the general partner of a publicly traded limited partnership, Williams Partners L.P. As such, this subsidiary's operations may involve a greater risk of liability than ordinary business operations.

One of our subsidiaries acts as the general partner of WPZ, a publicly traded limited partnership. This subsidiary may be deemed to have undertaken contractual obligations with respect to WPZ as the general partner and to the limited partners of WPZ. Activities, determined to involve such obligations to other persons or entities typically involve a higher standard of conduct than ordinary business operations and therefore may involve a greater risk of liability, particularly when a conflict of interest is found to exist. Our control of the general partner of WPZ may increase the possibility of claims of breach of such duties, including claims brought due to conflicts of interest (including conflicts of interest that may arise between WPZ, on the one hand, and its general partner and that general partner's affiliates, including us, on the other hand). Any liability resulting from such claims could be material.

Our industry is highly competitive and increased competitive pressure could adversely affect our business and operating results.

We have numerous competitors in all aspects of our businesses, and additional competitors may enter our markets. Any current or future competitor that delivers natural gas, NGLs, or other commodities into the areas that we operate could offer transportation services that are more desirable to shippers than those we provide because of price, location, facilities or other factors. In addition, current or potential competitors may make strategic acquisitions or have greater financial resources than we do, which could affect our ability to make strategic investments or acquisitions. Our competitors may be able to respond more quickly to new laws or regulations or emerging technologies or to devote greater resources to the construction, expansion, or refurbishment of their facilities than we can. Failure to successfully compete against current and future competitors could have a material adverse effect on our business, results of operations, financial condition, and cash flows.

We do not own all of the interests in the Partially Owned Entities, which could adversely affect our ability to operate and control these assets in a manner beneficial to us.

Because we do not control the Partially Owned Entities, we may have limited flexibility to control the operation of or cash distributions received from these entities. The Partially Owned Entities' organizational documents generally require distribution of their available cash to their members on a quarterly basis; however, in each case, available cash is reduced, in part, by reserves appropriate for operating the businesses. As of December 31, 2017, our investments in the Partially Owned Entities accounted for approximately 7 percent of our total consolidated assets. Conflicts of interest may arise in the future between us, on the one hand, and our Partially Owned Entities, on the other hand, with regard to our Partially Owned Entities' governance, business, or operations. If a conflict of interest arises between us and a Partially Owned Entity, other owners may control the Partially Owned Entity's actions with respect to such matter (subject to certain limitations), which could be detrimental to our business. Any future disagreements with the other co-owners of these assets could adversely affect our ability to respond to changing economic or industry conditions, which could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

We will conduct certain operations through joint ventures that may limit our operational flexibility or require us to make additional capital contributions.

Some of our operations are conducted through joint venture arrangements, and we may enter additional joint ventures in the future. In a joint venture arrangement, we have less operational flexibility, as actions must be taken in accordance with the applicable governing provisions of the joint venture. In certain cases:

- We cannot control the amount of capital expenditures that we are required to fund with respect to these operations;
- We are dependent on third parties to fund their required share of capital expenditures;
- We may be subject to restrictions or limitations on our ability to sell or transfer our interests in the jointly owned assets;
- We may be forced to offer rights of participation to other joint venture participants in the area of mutual interest;
- We have limited ability to influence or control certain day to day activities affecting the operations.

In addition, joint venture participants may have obligations that are important to the success of the joint venture, such as the obligation to pay substantial carried costs pertaining to the joint venture and to pay their share of capital and other costs of the joint venture, the performance of which is outside our control. Similarly, if we fail to make a required capital contribution under the applicable governing provisions of a joint venture arrangement, we could be deemed to be in default under the joint venture agreement. Joint venture partners may be in a position to take actions contrary to instructions or requests or contrary to our policies or objectives, and disputes between us and our joint venture partners may result in delays, litigation or operational impasses.

The risks described above or the failure to continue joint ventures, or to resolve disagreements with joint venture partners could adversely affect our ability to conduct our operations that are the subject of any joint venture, which could in turn negatively affect our financial condition and results of operations.

We may not be able to replace, extend, or add additional customer contracts or contracted volumes on favorable terms, or at all, which could affect our financial condition, the amount of cash available to pay dividends, and our ability to grow.

We rely on a limited number of customers and producers for a significant portion of our revenues and supply of natural gas and NGLs. Although many of our customers and suppliers are subject to long-term contracts, if we are unable to replace or extend such contracts, add additional customers, or otherwise increase the contracted volumes of natural gas provided to us by current producers, in each case on favorable terms, if at all, our financial condition, growth plans, and the amount of cash available to pay dividends could be adversely affected. Our ability to replace, extend, or add additional customer or supplier contracts, or increase contracted volumes of natural gas from current producers, on favorable terms, or at all, is subject to a number of factors, some of which are beyond our control, including:

- The level of existing and new competition in our businesses or from alternative sources, such as electricity, renewable resources, coal, fuel oils, or nuclear energy;
- Natural gas and NGL prices, demand, availability, and margins in our markets. Higher prices for energy commodities related to our businesses could result in a decline in the demand for those commodities and, therefore, in customer contracts or throughput on our pipeline systems. Also, lower energy commodity prices could negatively impact our ability to maintain or achieve favorable contractual terms, including pricing, and could also result in a decline in the production of energy commodities resulting in reduced customer contracts, supply contracts, and throughput on our pipeline systems;
- General economic, financial markets, and industry conditions;
- The effects of regulation on us, our customers, and our contracting practices;
- Our ability to understand our customers' expectations, efficiently and reliably deliver high quality services and effectively manage customer relationships. The results of these efforts will impact our reputation and positioning in the market.

Certain of our gas pipeline services are subject to long-term, fixed-price contracts that are not subject to adjustment, even if our cost to perform such services exceeds the revenues received from such contracts.

Our gas pipelines provide some services pursuant to long-term, fixed-price contracts. It is possible that costs to perform services under such contracts will exceed the revenues our pipelines collect for their services. Although most of the services are priced at cost-based rates that are subject to adjustment in rate cases, under FERC policy, a regulated service provider and a customer may mutually agree to sign a contract for service at a "negotiated rate" that may be above or below the FERC regulated cost-based rate for that service. These "negotiated rate" contracts are not generally subject to adjustment for increased costs that could be produced by inflation or other factors relating to the specific facilities being used to perform the services.

Some of our businesses are exposed to supplier concentration risks arising from dependence on a single or a limited number of suppliers.

Some of our businesses may be dependent on a small number of suppliers for delivery of critical goods or services. If a supplier on which one of our businesses depends were to fail to timely supply required goods and services, such business may not be able to replace such goods and services in a timely manner or otherwise on favorable terms or at all. If our business is unable to adequately diversify or otherwise mitigate such supplier concentration risks and such risks were realized, such businesses could be subject to reduced revenues and increased expenses, which could have a material adverse effect on our financial condition, results of operation, and cash flows.

Failure of our service providers or disruptions to our outsourcing relationships might negatively impact our ability to conduct our business.

Certain of our accounting and information technology services are currently provided by third-party vendors, and sometimes from service centers outside of the United States. Services provided pursuant to these agreements could be disrupted. Similarly, the expiration of such agreements or the transition of services between providers could lead to loss of institutional knowledge or service disruptions. Our reliance on others as service providers could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

An impairment of our assets, including goodwill, property, plant, and equipment, intangible assets, and/or equity-method investments, could reduce our earnings.

GAAP requires us to test certain assets for impairment on either an annual basis or when events or circumstances occur which indicate that the carrying value of such assets might be impaired. The outcome of such testing could result in impairments of our assets including our goodwill, property, plant, and equipment, intangible assets, and/or equity method investments. Additionally, any asset monetizations could result in impairments if any assets are sold or otherwise exchanged for amounts less than their carrying value. If we determine that an impairment has occurred, we would be required to take an immediate noncash charge to earnings.

Our operations are subject to operational hazards and unforeseen interruptions.

There are operational risks associated with the gathering, transporting, storage, processing, and treating of natural gas, the fractionation, transportation, and storage of NGLs, and crude oil transportation and production handling, including:

- Aging infrastructure and mechanical problems;
- Damages to pipelines and pipeline blockages or other pipeline interruptions;
- Uncontrolled releases of natural gas (including sour gas), NGLs, crude oil, or other products;
- Collapse or failure of storage caverns;
- Operator error;
- Damage caused by third-party activity, such as operation of construction equipment;
- Pollution and other environmental risks;
- Fires, explosions, craterings, and blowouts;
- Security risks, including cybersecurity;
- Operating in a marine environment.

Any of these risks could result in loss of human life, personal injuries, significant damage to property, environmental pollution, impairment of our operations, loss of services to our customers, reputational damage, and substantial losses to us. The location of certain segments of our facilities in or near populated areas, including residential areas, commercial business centers, and industrial sites, could increase the level of damages resulting from these risks. An event such as those described above could have a material adverse effect on our financial condition and results of operations, particularly if the event is not fully covered by insurance.

We do not insure against all potential risks and losses and could be seriously harmed by unexpected liabilities or by the inability of our insurers to satisfy our claims.

In accordance with customary industry practice, we maintain insurance against some, but not all, risks and losses, and only at levels we believe to be appropriate. The occurrence of any risks not fully covered by our insurance could have a material adverse effect on our business, financial condition, results of operations, and cash flows and our ability to repay our debt.

Our assets and operations, as well as our customers' assets and operations, can be adversely affected by weather and other natural phenomena.

Our assets and operations, especially those located offshore, and our customers' assets and operations can be adversely affected by hurricanes, floods, earthquakes, landslides, tornadoes, fires, and other natural phenomena and weather conditions, including extreme or unseasonable temperatures, making it more difficult for us to realize the historic rates of return associated with our assets and operations. A significant disruption in our or our customers' operations or a significant liability for which we are not fully insured could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Our business could be negatively impacted by acts of terrorism and security threats, including cybersecurity threats, and related disruptions.

Given the volatile nature of the commodities we transport, process, store, and sell, our assets and the assets of our customers and others in our industry may be targets of terrorist activities. A terrorist attack could create significant price volatility, disrupt our business, limit our access to capital markets, or cause significant harm to our operations, such as full or partial disruption to our ability to produce, process, transport, or distribute natural gas, NGLs, or other commodities. Acts of terrorism, as well as events occurring in response to or in connection with acts of terrorism, could cause environmental repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

We rely on our information technology infrastructure to process, transmit, and store electronic information, including information we use to safely operate our assets. While we believe that we maintain appropriate information security policies, practices, and protocols, we face cybersecurity and other security threats to our information technology infrastructure, which could include threats to our operational industrial control systems and safety systems that operate our pipelines, plants, and assets. We could face unlawful attempts to gain access to our information technology infrastructure, including coordinated attacks from hackers, whether state-sponsored groups, "hacktivists", or private individuals. The age, operating systems, or condition of our current information technology infrastructure and software assets and our ability to maintain and upgrade such assets could affect our ability to resist cybersecurity threats. We could also face attempts to gain access to information related to our assets through attempts to obtain unauthorized access by targeting acts of deception against individuals with legitimate access to physical locations or information. Breaches in our information technology infrastructure or physical facilities, or other disruptions including those arising from theft, vandalism, fraud, or unethical conduct, could result in damage to our assets, unnecessary waste, safety incidents, damage to the environment, reputational damage, potential liability, or the loss of contracts, and have a material adverse effect on our operations, financial condition, results of operations, and cash flows.

If third-party pipelines and other facilities interconnected to our pipelines and facilities become unavailable to transport natural gas and NGLs or to treat natural gas, our revenues could be adversely affected.

We depend upon third-party pipelines and other facilities that provide delivery options to and from our pipelines and facilities for the benefit of our customers. Because we do not own these third-party pipelines or other facilities, their continuing operation is not within our control. If these pipelines or facilities were to become temporarily or permanently unavailable for any reason, or if throughput were reduced because of testing, line repair, damage to pipelines or facilities, reduced operating pressures, lack of capacity, increased credit requirements or rates charged by such pipelines or facilities or other causes, we and our customers would have reduced capacity to transport, store or deliver natural gas or NGL products to end use markets or to receive deliveries of mixed NGLs, thereby reducing our revenues. Any temporary or permanent interruption at any key pipeline interconnect or in operations on third-party pipelines or facilities that would cause a material reduction in volumes transported on our pipelines or our gathering systems or processed, fractionated, treated, or stored at our facilities could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Our operating results for certain components of our business might fluctuate on a seasonal basis.

Revenues from certain components of our business can have seasonal characteristics. In many parts of the country, demand for natural gas and other fuels peaks during the winter. As a result, our overall operating results in the future might fluctuate substantially on a seasonal basis. Demand for natural gas and other fuels could vary significantly from our expectations depending on the nature and location of our facilities and pipeline systems and the terms of our natural gas transportation arrangements relative to demand created by unusual weather patterns.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and facilities have been constructed. As such, we are subject to the possibility of increased costs to retain necessary land use. In those instances in which we do not own the land on which our facilities are located, we obtain the rights to construct and operate our pipelines and gathering systems on land owned by third parties and governmental agencies for a specific period of time. In addition, some of our facilities cross Native American lands pursuant to rights-of-way of limited terms. We may not have the right of eminent domain over land owned by Native American tribes. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Our business could be negatively impacted as a result of stockholder activism.

In recent years, stockholder activism, including threatened or actual proxy contests, has been directed against numerous public companies, including ours. During the latter part of fiscal year 2016, we were the target of a proxy contest from a stockholder activist, which resulted in our incurring significant costs. If stockholder activists were to again take or threaten to take actions against the Company or seek to involve themselves in the governance, strategic direction or operations of the Company, we could incur significant costs as well as the distraction of management, which could have an adverse effect on our business or financial results. In addition, actions of activist stockholders may cause significant fluctuations in our stock price based on temporary or speculative market perceptions or other factors that do not necessarily reflect the underlying fundamentals and prospects of our business.

Litigation pertaining to the ETC Merger, including litigation related to Energy Transfer Equity, L.P.'s (ETE's) termination of and failure to close the ETC Merger, may negatively impact our business and operations.

We have incurred and may continue to incur additional costs in connection with the prosecution, defense or settlement of the currently pending and any future litigation relating to the ETC Merger or ETE's termination of and failure to close the ETC Merger. We cannot predict the outcome of this litigation. Such litigation may also create a distraction for our management team and board of directors and require time and attention. In addition, any litigation relating to the ETC Merger or ETE's termination of and failure to close the ETC Merger could, among other things, adversely affect our financial condition and results of operations.

Our costs and funding obligations for our defined benefit pension plans and costs for our other postretirement benefit plans are affected by factors beyond our control.

We have defined benefit pension plans covering substantially all of our U.S. employees and other postretirement benefit plans covering certain eligible participants. The timing and amount of our funding requirements under the defined benefit pension plans depend upon a number of factors that we control, including changes to pension plan benefits, as well as factors outside of our control, such as asset returns, interest rates, and changes in pension laws.

Changes to these and other factors that can significantly increase our funding requirements could have a significant adverse effect on our financial condition and results of operations.

Failure to attract and retain an appropriately qualified workforce could negatively impact our results of operations.

Events such as an aging workforce without appropriate replacements, mismatch of skill sets to future needs, or unavailability of contract labor may lead to operating challenges such as lack of resources, loss of knowledge, and a lengthy time period associated with skill development, including with the workforce needs associated with projects and ongoing operations. Failure to hire and adequately obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect our ability to manage and operate the businesses. If we are unable to successfully attract and retain an appropriately qualified workforce, results of operations could be negatively impacted.

If there is a determination that the spin-off of WPX Energy, Inc. (WPX) stock to our stockholders is taxable for U.S. federal income tax purposes because the facts, representations or undertakings underlying a U.S. Internal Revenue Service (IRS) private letter ruling or a tax opinion are incorrect or for any other reason, then we and our stockholders could incur significant income tax liabilities.

In connection with our original separation plan that called for an initial public offering (IPO) of stock of WPX and a subsequent spin-off of our remaining shares of WPX to our stockholders, we obtained a private letter ruling from the IRS and an opinion of our outside tax advisor, to the effect that the distribution by us of WPX shares to our stockholders, and any related restructuring transaction undertaken by us, would not result in recognition for U.S. federal income tax purposes, of income, gain or loss to us or our stockholders under section 355 and section 368(a)(1)(D) of the U.S. Internal Revenue Code of 1986, as amended (Code), except for cash payments made to our stockholders in lieu of fractional shares of WPX common stock. In addition, we received an opinion from our outside tax advisor to the effect that the spin-off pursuant to our revised separation plan which was ultimately consummated on December 31, 2011, which did not involve an IPO of WPX shares, would not result in the recognition, for federal income tax purposes, of income, gain, or loss to us or our stockholders under section 355 and section 368(a)(1)(D) of the Code, except for cash payments made to our stockholders in lieu of fractional shares of WPX. The private letter ruling and opinion have relied on or will rely on certain facts, representations, and undertakings from us and WPX regarding the past and future conduct of the companies' respective businesses and other matters. If any of these facts, representations, or undertakings are, or become, incorrect or are not otherwise satisfied, including as a result of certain significant changes in the stock ownership of us or WPX after the spin-off, or if the IRS disagrees with any such facts and representations upon audit, we and our stockholders may not be able to rely on the private letter ruling or the opinion of our tax advisor and could be subject to significant income tax liabilities.

The WPX spin-off may expose us to potential liabilities arising out of state and federal fraudulent conveyance laws and legal dividend requirements that we did not assume in our agreements with WPX.

The spin-off is subject to review under various state and federal fraudulent conveyance laws. A court could deem the spin-off or certain internal restructuring transactions undertaken by us in connection with the separation to be a fraudulent conveyance or transfer. Fraudulent conveyances or transfers are defined to include transfers made or obligations incurred with the actual intent to hinder, delay, or defraud current or future creditors or transfers made or obligations incurred for less than reasonably equivalent value when the debtor was insolvent, or that rendered the debtor insolvent, inadequately capitalized or unable to pay its debts as they become due. A court could void the transactions or impose substantial liabilities upon us, which could adversely affect our financial condition and our results of operations. Whether a transaction is a fraudulent conveyance or transfer will vary depending upon the jurisdiction whose law is being applied. Under the separation and distribution agreement between us and WPX, from and after the spin-off, each of WPX and we are responsible for the debts, liabilities, and other obligations related to the business or businesses which each owns and operates. Although we do not expect to be liable for any such obligations not expressly assumed by us pursuant to the separation and distribution agreement, it is possible that a court would disregard the allocation agreed to between the parties, and require that we assume responsibility for obligations allocated to WPX, particularly if WPX were to refuse or were unable to pay or perform the subject allocated obligations.

Risks Related to Financing Our Business

Downgrades of our credit ratings, which are determined outside of our control by independent third parties, impact our liquidity, access to capital, and our costs of doing business.

Downgrades of our credit ratings increase our cost of borrowing and could require us to provide collateral to our counterparties, negatively impacting our available liquidity. In addition, our ability to access capital markets could continue to be limited by the downgrading of our credit ratings.

Credit rating agencies perform independent analysis when assigning credit ratings. This analysis includes a number of criteria such as, business composition, market, and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are subject to revision or withdrawal at any time by the ratings agencies. As of the date of the filing of this report, we have been assigned below investment-grade credit ratings by each of the three credit ratings agencies.

Our ability to obtain credit in the future could be affected by WPZ's credit ratings.

A substantial portion of our operations are conducted through, and our cash flows are substantially derived from, distributions paid to us by WPZ. Due to our relationship with WPZ, our ability to obtain credit will be affected by WPZ's credit ratings. If WPZ were to experience a deterioration in its credit standing or financial condition, our access to capital, and our ratings could be adversely affected. Any future downgrading of a WPZ credit rating could also result in a downgrading of our credit rating. A downgrading of a WPZ credit rating could limit our ability to obtain financing in the future upon favorable terms, if at all.

Difficult conditions in the global financial markets and the economy in general could negatively affect our business and results of operations.

Our businesses may be negatively impacted by adverse economic conditions or future disruptions in global financial markets. Included among these potential negative impacts are industrial or economic contraction leading to reduced energy demand and lower prices for our products and services and increased difficulty in collecting amounts owed to us by our customers. If financing is not available when needed, or is available only on unfavorable terms, we may be unable to implement our business plans or otherwise take advantage of business opportunities or respond to competitive pressures. In addition, financial markets have periodically been affected by concerns over U.S. fiscal and monetary policies. These concerns, as well as actions taken by the U.S. federal government in response to these concerns, could significantly and adversely impact the global and U.S. economies and financial markets, which could negatively impact us in the manner described above.

Restrictions in our debt agreements and the amount of our indebtedness may affect our future financial and operating flexibility.

Our total outstanding long-term debt (including current portion) as of December 31, 2017, was $20.9 billion.

The agreements governing our indebtedness contain covenants that restrict our and our material subsidiaries' ability to incur certain liens to support indebtedness and our ability to merge or consolidate or sell all or substantially all of our assets in certain circumstances. In addition, certain of our debt agreements contain various covenants that restrict or limit, among other things, our ability to make certain distributions during the continuation of an event of default, the ability of our subsidiaries to incur additional debt, and our, and our material subsidiaries', ability to enter into certain affiliate transactions and certain restrictive agreements. Certain of our debt agreements also contain, and those we enter into in the future may contain, financial covenants, and other limitations with which we will need to comply.

Our debt service obligations and the covenants described above could have important consequences. For example, they could:

- Make it more difficult for us to satisfy our obligations with respect to our indebtedness, which could in turn result in an event of default on such indebtedness;

- Impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate purposes, or other purposes;

- Diminish our ability to withstand a continued or future downturn in our business or the economy generally;

- Require us to dedicate a substantial portion of our cash flow from operations to debt service payments, thereby reducing the availability of cash for working capital, capital expenditures, acquisitions, the payments of dividends, general corporate purposes, or other purposes;

- Limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate, including limiting our ability to expand or pursue our business activities and preventing us from engaging in certain transactions that might otherwise be considered beneficial to us.

Our ability to comply with our debt covenants, to repay, extend, or refinance our existing debt obligations and to obtain future credit will depend primarily on our operating performance. Our ability to refinance existing debt obligations or obtain future credit will also depend upon the current conditions in the credit markets and the availability of credit generally. If we are unable to comply with these covenants, meet our debt service obligations, or obtain future credit on favorable terms, or at all, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain financing or sell assets on satisfactory terms, or at all.

Our failure to comply with the covenants in the documents governing our indebtedness could result in events of default, which could render such indebtedness due and payable. We may not have sufficient liquidity to repay our indebtedness in such circumstances. In addition, cross-default or cross-acceleration provisions in our debt agreements could cause a default or acceleration to have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. For more information regarding our debt agreements, please read Note 13 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements.

Increases in interest rates could adversely impact our share price, our ability to issue equity or incur debt for acquisitions or other purposes, and our ability to make cash dividends at our intended levels.

Interest rates may increase in the future. As a result, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our share price will be impacted by the level of our dividends and implied dividend yield. The dividend yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our shares, and a rising interest rate environment could have an adverse impact on our share price and our ability to issue equity or incur debt for acquisitions or other purposes and to pay cash dividends at our intended levels.

Our hedging activities might not be effective and could increase the volatility of our results.

In an effort to manage our financial exposure related to commodity price and market fluctuations, we have entered, and may in the future enter into contracts to hedge certain risks associated with our assets and operations. In these hedging activities, we have used, and may in the future use, fixed-price, forward, physical purchase, and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges. Nevertheless, no single hedging arrangement can adequately address all risks present in a given contract. For example, a forward contract that would be effective in hedging commodity price volatility risks would not hedge the contract's counterparty credit or performance risk. Therefore, unhedged risks will always continue to exist. While we attempt to manage counterparty credit risk within guidelines established by our credit policy, we may not be able to successfully manage all credit risk and as such, future cash flows and results of operations could be impacted by counterparty default.

Risks Related to Regulations

The natural gas sales, transportation, and storage operations of our gas pipelines are subject to regulation by the FERC, which could have an adverse impact on their ability to establish transportation and storage rates that would allow them to recover the full cost of operating their respective pipelines, including a reasonable rate of return.

In addition to regulation by other federal, state, and local regulatory authorities, under the Natural Gas Act of 1938, interstate pipeline transportation and storage service is subject to regulation by the FERC. Federal regulation extends to such matters as:

- Transportation and sale for resale of natural gas in interstate commerce;
- Rates, operating terms, types of services, and conditions of service;
- Certification and construction of new interstate pipelines and storage facilities;
- Acquisition, extension, disposition, or abandonment of existing interstate pipelines and storage facilities;
- Accounts and records;
- Depreciation and amortization policies;
- Relationships with affiliated companies who are involved in marketing functions of the natural gas business;
- Market manipulation in connection with interstate sales, purchases, or transportation of natural gas.

Regulatory or administrative actions in these areas, including successful complaints or protests against the rates of the gas pipelines, can affect our business in many ways, including decreasing tariff rates and revenues, decreasing volumes in our pipelines, increasing our costs, and otherwise altering the profitability of our pipeline business.

The operation of our businesses might also be adversely affected by regulatory proceedings, changes in government regulations or in their interpretation or implementation, or the introduction of new laws or regulations applicable to our businesses or our customers.

Public and regulatory scrutiny of the energy industry has resulted in the proposal and/or implementation of increased regulations. Such scrutiny has also resulted in various inquiries, investigations, and court proceedings, including litigation of energy industry matters. Both the shippers on our pipelines and regulators have rights to challenge the rates we charge under certain circumstances. Any successful challenge could materially affect our results of operations.

Certain inquiries, investigations, and court proceedings are ongoing. Adverse effects may continue as a result of the uncertainty of ongoing inquiries, investigations, and court proceedings, or additional inquiries and proceedings by federal or state regulatory agencies or private plaintiffs. In addition, we cannot predict the outcome of any of these inquiries or whether these inquiries will lead to additional legal proceedings against us, civil or criminal fines and/or penalties, or other regulatory action, including legislation, which might be materially adverse to the operation of our business and our results of operations or increase our operating costs in other ways. Current legal proceedings or other matters, including environmental matters, suits, regulatory appeals, and similar matters might result in adverse decisions against us which, among other outcomes, could result in the imposition of substantial penalties and fines and could damage our reputation. The result of such adverse decisions, either individually or in the aggregate, could be material and may not be covered fully or at all by insurance.

In addition, existing regulations, including those pertaining to financial assurances to be provided by our businesses in respect of potential asset decommissioning and abandonment activities, might be revised, reinterpreted, or otherwise enforced in a manner which differs from prior regulatory action. New laws and regulations, including those pertaining to oil and gas hedging and cash collateral requirements, might also be adopted or become applicable to us, our customers, or our business activities. If new laws or regulations are imposed relating to oil and gas extraction, or if additional or revised levels of reporting, regulation, or permitting moratoria are required or imposed, including those related to hydraulic fracturing, the volumes of natural gas and other products that we transport, gather, process, and treat could decline, our compliance costs could increase, and our results of operations could be adversely affected.

Our operations are subject to environmental laws and regulations, including laws and regulations relating to climate change and greenhouse gas emissions, which may expose us to significant costs, liabilities, and expenditures that could exceed our expectations.

Our operations are subject to extensive federal, state, tribal, and local laws and regulations governing environmental protection, endangered and threatened species, the discharge of materials into the environment, and the security of industrial facilities. Substantial costs, liabilities, delays, and other significant issues related to environmental laws and regulations are inherent in the gathering, transportation, storage, processing, and treating of natural gas, fractionation, transportation, and storage of NGLs, and crude oil transportation and production handling as well as waste disposal practices and construction activities. Failure to comply with these laws, regulations, and permits may result in the assessment of administrative, civil and/or criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, the issuance of injunctions limiting or preventing some or all of our operations, and delays or denials in granting permits.

Joint and several, strict liability may be incurred without regard to fault under certain environmental laws and regulations, for the remediation of contaminated areas and in connection with spills or releases of materials associated with natural gas, oil, and wastes on, under or from our properties and facilities. Private parties, including the owners of properties through which our pipeline and gathering systems pass and facilities where our wastes are taken for reclamation or disposal, may have the right to pursue legal actions to enforce compliance as well as to seek damages for noncompliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites at which we operate are located near current or former third-party hydrocarbon storage and processing or oil and natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours.

We are generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses.

In addition, climate change regulations and the costs associated with the regulation of emissions of greenhouse gases (GHGs) have the potential to affect our business. Regulatory actions by the Environmental Protection Agency or the passage of new climate change laws or regulations could result in increased costs to operate and maintain our facilities, install new emission controls on our facilities, or administer and manage our GHG compliance program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. Climate change and GHG regulation could also reduce demand for our services.

We expect that certain aspects of Tax Cuts and Jobs Act signed into law on December 22, 2017 (Tax Reform), including regulatory liabilities relating to reduced corporate federal income tax rates, could adversely impact our financial condition and our future financial results.

Certain of the rates we charge to our customers are subject to the rate-making policies of the FERC. These policies permit us to include in our cost-of-service an income tax allowance that includes a deferred income tax component. The recently enacted Tax Reform makes significant changes to the U.S. federal income tax rules applicable to both individuals and entities, including among other things, a reduction in corporate federal income tax rates. Although we expect the decreased federal income tax rates will require us to return amounts to certain customers for this item through future rates and have recognized a regulatory liability, the details of any regulatory implementation guidance remain uncertain.

Item 1B. ***Unresolved Staff Comments***

Not applicable.

Item 2. ***Properties***

Please read "Business" for a description of the location and general character of our principal physical properties. We generally own our facilities, although a substantial portion of our pipeline and gathering facilities is constructed and maintained pursuant to rights-of-way, easements, permits, licenses, or consents on and across properties owned by others.

Item 3. ***Legal Proceedings***

Environmental

Certain reportable legal proceedings involving governmental authorities under federal, state, and local laws regulating the discharge of materials into the environment are described below. While it is not possible for us to predict the final outcome of the proceedings which are still pending, we do not anticipate a material effect on our consolidated financial position if we receive an unfavorable outcome in any one or more of such proceedings.

On June 13, 2013, an explosion and fire occurred at our formerly owned Geismar olefins plant and rendered the facility temporarily inoperable (Geismar Incident). On October 21, 2013, the EPA issued an Inspection Report pursuant to the Clean Air Act's Risk Management Program following its inspection of the facility on June 24 through June 28, 2013. The report notes the EPA's preliminary determinations about the facility's documentation regarding process safety, process hazard analysis, as well as operating procedures, employee training, and other matters. On June 16, 2014, we received a request for information related to the Geismar Incident from the EPA under Section 114 of the Clean Air Act to which we responded on August 13, 2014. The EPA could issue penalties pertaining to final determinations.

On February 21, 2017, we received notice from the Environmental Enforcement Section of the United States Department of Justice (DOJ) regarding certain alleged violations of the Clean Air Act at our Moundsville facility as set forth in a Notice of Noncompliance issued by the EPA on January 14, 2016. The notice includes an offer to avoid further legal action on the alleged violations by paying $2 million. In discussion with the DOJ and the EPA, the EPA has indicated its belief that additional similar violations have occurred at our Oak Grove facility and has expressed interest in pursuing a global settlement. On January 19, 2018, we received an offer from the DOJ to globally settle the government's claim for civil penalties associated with the alleged violations at both the Moundsville and the Oak Grove facilities for $1.955 million. We are currently evaluating the penalty assessment and the proposed global settlement offer and will respond to the agencies.

On May 5, 2017, we entered into a Consent Order with the Georgia Department of Natural Resources, Environmental Protection Division (GADNR) pertaining to alleged violations of the Georgia Water Quality Control Act and associated rules arising from a permit issued by GADNR for construction of the Dalton Project. Pursuant to the Consent Order, we paid a fine of $168,750 and agreed to perform a Corrective Action Order to remedy the alleged violations.

On January 19, 2018, we received notice from the PHMSA regarding certain alleged violations of PHMSA regulations in connection with a fire and release of liquid ethane that occurred at our Houston Meter Station located near Houston, Washington County, PA on December 24, 2014. The Notice of Probable Violation and Proposed Civil Penalty issued by PHMSA alleges failure to timely notify the National Response Center of a release of a hazardous liquid resulting in a fire or explosion and failure to verify that the facility was constructed, inspected, tested, and calibrated in accordance with comprehensive written specifications or standards and proposes a total civil penalty of $174,100. We are currently evaluating the penalty assessment and will respond to the agency.

Other environmental matters called for by this Item are described under the caption "*Environmental Matters*" in Note 17 – Contingent Liabilities and Commitments of Notes to Consolidated Financial Statements included under Part II, Item 8 Financial Statements of this report, which information is incorporated by reference into this Item.

Other Litigation

The additional information called for by this Item is provided in Note 17 – Contingent Liabilities and Commitments of Notes to Consolidated Financial Statements included under Part II, Item 8 Financial Statements of this report, which information is incorporated by reference into this Item.

Item 4. *Mine Safety Disclosures*

Not applicable.

Executive Officers of the Registrant

The name, age, period of service, and title of each of our executive officers as of February 22, 2018, are listed below. Williams Partners L.P. merged with ACMP in February 2015 (the ACMP Merger). ACMP was the surviving entity in the ACMP Merger and changed its name to Williams Partners L.P. References in the biographical information below to (a) "Pre-merger WPZ" will mean Williams Partners L.P. prior to the ACMP Merger and (b) "ACMP/WPZ" will refer to both ACMP prior to and after the ACMP Merger, when it changed its name to Williams Partners L.P.

Alan S. Armstrong	Director, Chief Executive Officer, and President Age: 55 Position held since January 2011. Mr. Armstrong has served as our Chief Executive Officer and President and a director of Williams since January 2011. Mr. Armstrong has served as a director of the general partner of ACMP/WPZ since 2012, as Chief Executive Officer of ACMP/WPZ since December 31, 2014, and as Chairman of the Board of ACMP/WPZ since February 2, 2015. Mr. Armstrong also served as Chairman of the Board and Chief Executive Officer of the general partner of Pre-merger WPZ from 2011 until the ACMP Merger, as Senior Vice President - Midstream of Pre-merger WPZ from 2010 to 2011, and a director and Chief Operating Officer of Pre-merger WPZ from 2005 to 2010. From 2002 to 2011, Mr. Armstrong served as Williams' Senior Vice President - Midstream and acted as president of our midstream business. From 1999 to 2002, Mr. Armstrong was Vice President, Gathering and Processing in our midstream business and from 1998 to 1999 was Vice President, Commercial Development. Mr. Armstrong has served as a director of BOK Financial Corporation, a financial services company, since 2013.
Walter J. Bennett	Senior Vice President - West Age: 48 Position held since January 2015. Mr. Bennett has served as our Senior Vice President - West since January 2015. Mr. Bennett has served as Senior Vice President - West of the general partner of ACMP/WPZ since December 2013 and as Senior Vice President - West of the general partner of Pre-merger WPZ from January 2015 until the ACMP Merger. Mr. Bennett previously served as a director of the general partner of ACMP/WPZ from February 2017 through November 2017. Mr. Bennett was formerly Chief Operating Officer of Chesapeake Midstream Development and served as Senior Vice President - Operations at Boardwalk Pipeline Partners.

John D. Chandler	Senior Vice President and Chief Financial Officer Age: 48 Position held since September 2017. Mr. Chandler has served as our Senior Vice President and Chief Financial Officer since September 2017, and as a director of the general partner of ACMP/WPZ since November 2017. Mr. Chandler most recently served as Senior Vice President and Chief Financial Officer of Magellan GP, LLC, the general partner of Magellan Midstream Partners, LP from 2009 until his retirement in March 2014. From 2003 until 2009, he served as Senior Vice President and Chief Financial Officer for the general partner of Magellan Midstream Holdings, L.P. From 1992 until 2002, Mr. Chandler held various accounting and finance roles within Williams and MAPCO Inc., prior to its acquisition by Williams. Mr. Chandler has served as a director of Matrix Service Company since June 2017.
Micheal G. Dunn	Executive Vice President and Chief Operating Officer Age: 52 Position held since February 2017. Mr. Dunn has served as our Executive Vice President and Chief Operating Officer and as a director of the general partner of ACMP/WPZ since February 2017. Previously, Mr. Dunn served as President of Questar Pipeline and as Executive Vice President of Questar Corporation from 2015 through 2017. Prior to that, Mr. Dunn served as President and Chief Executive Officer of PacifiCorp Energy from 2010 through 2015, a subsidiary of Berkshire Hathaway Energy. Earlier, Mr. Dunn was president of Kern River Gas Transmission Company, a Berkshire Hathaway Energy interstate natural gas pipeline subsidiary. He joined Kern River in 1990, having served in various leadership roles in the areas of operations, construction, engineering and information technology before being named President of Kern River in 2007. Mr. Dunn began his career with Williams as an operations engineer and spent 14 years with the company in a variety of technical and leadership roles.
Frank J. Ferazzi	Senior Vice President - Atlantic Gulf Age: 61 Position held since June 2017 Mr. Ferazzi has served as our Senior Vice President - Atlantic-Gulf since June 2017. Previously, Mr. Ferazzi served as VP & GM Eastern Interstates from November 2014 through June 2017, and previously as VP & GM Transco from January 2013 through January 2015. Prior to that, Mr. Ferazzi served as VP Commercial Operations - Gas Pipeline from May 2010 through December 2012.

John E. Poarch

Senior Vice President - Engineering Services

Age: 52

Position held since November 2017.

Mr. Poarch has served as our Senior Vice President - Engineering Services since November 2017. Previously, he served as VP Commercial West OA from March 2017 through November 2017, and before that, as VP Commercial & Business Development from January 2015 through March 2017. Previously, Mr. Poarch was the general manager for Access Midstream's Eagle Ford operations.

James E. Scheel

Senior Vice President - Northeast G&P

Age: 53

Position held since January 2014.

Mr. Scheel has served as our Senior Vice President - Northeast G&P since January 2014. Mr. Scheel served as a director of ACMP/WPZ from the ACMP Merger until November 2017. Mr. Scheel served as a director of the Pre-merger WPZ general partner from 2012 until the ACMP Merger. Mr. Scheel served as a director of the Pre-merger ACMP general partner from December 2012 to February 2014. Previously, Mr. Scheel served as Senior Vice President - Corporate Strategic Development of Williams and the Pre-merger WPZ general partner from February 2012 to January 2014. Mr. Scheel served as Vice President of Business Development of Williams' midstream business from January 2011 to February 2012.

Ted T. Timmermans

Vice President, Controller, and Chief Accounting Officer

Age: 61

Position held since July 2005.

Mr. Timmermans has served as our Vice President, Controller, and Chief Accounting Officer since July 2005. Mr. Timmermans has served in the same roles for the general partner of ACMP/WPZ since the ACMP Merger. Mr. Timmermans served as Chief Accounting Officer of WMZ from 2008 until its merger with Pre-Merger WPZ in 2010. Previously, Mr. Timmermans served as our Assistant Controller from 1998 to 2005.

T. Lane Wilson

Senior Vice President, General Counsel and Chief Compliance Officer

Age: 51

Position held since April 2017.

Mr. Wilson has served as Senior Vice President, General Counsel and Chief Compliance Officer since April 2017. Prior to joining Williams, Mr. Wilson served as a United States Magistrate Judge for the Northern District of Oklahoma from 2009 until he joined Williams in April 2017. Mr. Wilson previously served as a shareholder and member of the board of directors of the Hall Estill law firm from 1994 through 2008.

Chad J. Zamarin	Senior Vice President - Corporate Strategic Development
	Age: 41 Position held since June 2017. Mr. Zamarin has served as our Senior Vice President - Corporate Strategic Development since June 2017. Mr. Zamarin has served as a director of the general partner of ACMP/WPZ since November 2017. Previously, he served as President, Pipeline and Midstream at Cheniere Energy from 2014 through 2017. Prior to joining Cheniere, Mr. Zamarin served as the Chief Operating Officer at NiSource Midstream, LLC and NiSource Energy Ventures, LLC, as well as the President of Pennant Midstream, LLC, a joint venture with Hilcorp Energy.

PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

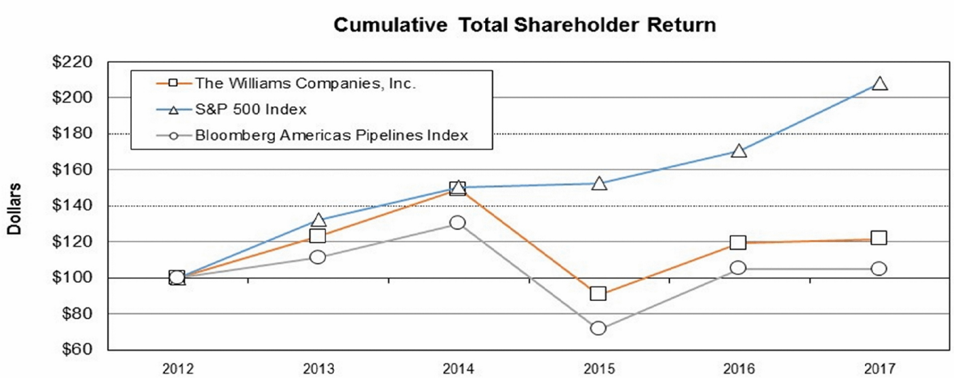
Our common stock is listed on the New York Stock Exchange under the symbol "WMB." At the close of business on February 19, 2018, we had approximately 6,979 holders of record of our common stock. The high and low sales price ranges (New York Stock Exchange composite transactions) and dividends declared by quarter for each of the past two years are as follows:

	High	Low	Dividend
2017			
First Quarter	$ 32.69	$ 27.68	$ 0.30
Second Quarter	31.25	27.65	0.30
Third Quarter	32.18	28.76	0.30
Fourth Quarter	30.72	26.82	0.30
2016			
First Quarter	$ 26.68	$ 10.22	$ 0.64
Second Quarter	23.89	14.60	0.64
Third Quarter	31.43	19.68	0.20
Fourth Quarter	32.21	27.35	0.20

Some of our subsidiaries' borrowing arrangements may limit the transfer of funds to us. These terms have not impeded, nor are they expected to impede, our ability to pay dividends. On February 21, 2018, our board of directors approved a regular quarterly dividend of $0.34 per share payable on March 26, 2018.

Performance Graph

Set forth below is a line graph comparing our cumulative total stockholder return on our common stock (assuming reinvestment of dividends) with the cumulative total return of the S&P 500 Stock Index and the Bloomberg Americas Pipelines Index for the period of five fiscal years commencing January 1, 2013. The Bloomberg Americas Pipelines Index is composed of Enbridge Inc., Kinder Morgan, Inc., TransCanada Corporation, ONEOK, Inc., Pembina Pipeline Corporation, Cheniere Energy, Inc., Targa Resources Corp., Inter Pipeline Ltd., Keyera Corp., AltaGas Ltd., Plains GP Holdings, L.P., and Williams. The graph below assumes an investment of $100 at the beginning of the period.



	2012	2013	2014	2015	2016	2017
The Williams Companies, Inc.	100.0	122.8	149.1	90.6	119.1	121.5
S&P 500 Index	100.0	132.4	150.5	152.5	170.8	208.1
Bloomberg Americas Pipelines Index	100.0	111.0	130.0	71.5	105.0	104.7

Item 6. ***Selected Financial Data***

The following financial data at December 31, 2017 and 2016, and for each of the three years in the period ended December 31, 2017, should be read in conjunction with the other financial information included in Part II, Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations* and Part II, Item 8, *Financial Statements and Supplementary Data* of this Form 10-K. All other financial data has been prepared from our accounting records.

	2017	2016	2015	2014	2013
	(Millions, except per-share amounts)				
Revenues (1)	$ 8,031	$ 7,499	$ 7,360	$ 7,637	$ 6,860
Income (loss) from continuing operations (2)	2,509	(350)	(1,314)	2,335	679
Amounts attributable to The Williams Companies, Inc.:					
Income (loss) from continuing operations (2)	2,174	(424)	(571)	2,110	441
Diluted earnings (loss) per common share:					
Income (loss) from continuing operations (2)	2.62	(.57)	(.76)	2.91	.64
Total assets at December 31 (3)	46,352	46,835	49,020	50,455	27,065
Commercial paper and long-term debt due within one year at December 31 (4)	501	878	675	802	226
Long-term debt at December 31 (3)	20,434	22,624	23,812	20,780	11,276
Stockholders' equity at December 31 (3) (5)	9,656	4,643	6,148	8,777	4,864
Cash dividends declared per common share	1.200	1.680	2.450	1.958	1.438

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(1) Revenues for 2014 increased reflecting the consolidation of ACMP beginning in third quarter and new Canadian construction management services.

(2) Income (loss) from continuing operations:

- For 2017 includes a $1.923 billion benefit for income taxes resulting from Tax Reform rate change, a $1.095 billion pre-tax gain on the sale of our Geismar Interest, partially offset by $1.248 billion of pre-tax impairments of certain assets, and $776 million of pre-tax regulatory charges resulting from Tax Reform;
- For 2016 includes an $873 million impairment of certain assets and a $430 million impairment of certain equity-method investments;
- For 2015 includes a $1.4 billion impairment of certain equity-method investments and a $1.1 billion impairment of goodwill;
- For 2014 includes $2.5 billion pre-tax gain recognized as a result of remeasuring to fair value the equity-method investment we held before we acquired a controlling interest in ACMP, $246 million of insurance recoveries related to the 2013 Geismar Incident, and $154 million of cash received related to a contingency settlement. 2014 also includes $78 million of pre-tax equity losses from Bluegrass Pipeline and Moss Lake related primarily to the underlying write-off of previously capitalized project development costs and $76 million of pre-tax acquisition, merger, and transition expenses related to our acquisition of ACMP;
- For 2013 includes $99 million of deferred income tax expense incurred on undistributed earnings of our foreign operations that are no longer considered permanently reinvested.

(3) The increases in 2014 reflect assets acquired and debt assumed primarily related to our acquisition of ACMP in third quarter as well as $1.9 billion of related debt issuances and $2.8 billion of debt issuances at WPZ. Additionally, we issued $3.4 billion of equity.

(4) The increase in 2014 reflects borrowings under WPZ's commercial paper program, which was initiated in 2013.

(5) The increase in 2017 includes our issuance of common stock as part of our Financial Repositioning.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

General

We are an energy infrastructure company focused on connecting North America's significant hydrocarbon resource plays to growing markets for natural gas and NGLs. Our operations are located principally in the United States. We have one reportable segment, Williams Partners. All remaining business activities are included in Other.

Williams Partners

Williams Partners consists of our consolidated master limited partnership, WPZ, which includes gas pipeline and midstream businesses. The gas pipeline businesses include interstate natural gas pipelines and pipeline joint project investments; and the midstream businesses provide natural gas gathering, treating, and processing services; NGL production, fractionation, storage, marketing, and transportation; deepwater production handling and crude oil transportation services; and are comprised of several wholly owned and partially owned subsidiaries and joint project investments. As of December 31, 2017, we own 74 percent of the interests in WPZ.

Williams Partners' gas pipeline businesses consist primarily of Transco and Northwest Pipeline. The gas pipeline business also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 50 percent equity-method investment in Gulfstream and a 41 percent interest in Constitution (a consolidated entity), which is developing a pipeline project. (See Note 3 – Variable Interest Entities of Notes to Consolidated Financial Statements.) As of December 31, 2017, Transco and Northwest Pipeline owned and operated a combined total of approximately 13,600 miles of pipelines with a total annual throughput of approximately 4,533 Tbtu of natural gas and peak-day delivery capacity of approximately 18.8 MMdth of natural gas.

Williams Partners' midstream businesses primarily consist of (1) natural gas gathering, treating, compression, and processing; (2) NGL fractionation, storage, and transportation; (3) crude oil production handling and transportation; and (4) olefins production. (See Note 2 – Acquisitions and Divestitures of Notes to Consolidated Financial Statements.) The primary service areas are concentrated in major producing basins in Colorado, Texas, Oklahoma, Kansas, New Mexico, Wyoming, the Gulf of Mexico, Louisiana, Pennsylvania, West Virginia, New York, and Ohio, which include the Barnett, Eagle Ford, Haynesville, Marcellus, Niobrara, and Utica shale plays as well as the Mid-Continent region.

The midstream businesses include equity-method investments in natural gas gathering and processing assets and NGL fractionation and transportation assets, including a 62 percent equity-method investment in UEOM, a 69 percent equity-method investment in Laurel Mountain, a 58 percent equity-method investment in Caiman II, a 60 percent equity-method investment in Discovery, a 50 percent equity-method investment in OPPL, and Appalachia Midstream Services, LLC, which owns an approximate average 66 percent equity-method investment interest in multiple gas gathering systems in the Marcellus Shale (Appalachia Midstream Investments), as well as our previously owned 50 percent equity-method investment in the Delaware basin gas gathering system (DBJV) in the Mid-Continent region (see Note 5 – Investing Activities of Notes to Consolidated Financial Statements).

The midstream businesses previously included Canadian midstream operations, which were comprised of an oil sands offgas processing plant near Fort McMurray, Alberta and an NGL/olefin fractionation facility at Redwater, Alberta. In September 2016, these Canadian operations were sold.

Williams Partners' ongoing strategy is to safely and reliably operate large-scale, interstate natural gas transmission and midstream infrastructures where our assets can be fully utilized and drive low per-unit costs. We focus on consistently attracting new business by providing highly reliable service to our customers and investing in growing markets and areas of increasing natural gas demand.

Williams Partners' interstate transmission and related storage activities are subject to regulation by the FERC and as such, our rates and charges for the transportation of natural gas in interstate commerce, and the extension, expansion or abandonment of jurisdictional facilities and accounting, among other things, are subject to regulation. The rates are established through the FERC's ratemaking process. Changes in commodity prices and volumes transported have limited near-term impact on these revenues because the majority of cost of service is recovered through firm capacity reservation charges in transportation rates.

Other

Other is comprised of business activities that are not operating segments, as well as corporate operations. Other also includes certain domestic olefins pipeline assets as well as certain Canadian assets, which included a liquids extraction plant located near Fort McMurray, Alberta, that began operations in March 2016, and a propane dehydrogenation facility which was under development. In September 2016, the Canadian assets were sold.

Financial Repositioning

In January 2017, we entered into agreements with WPZ, wherein we permanently waived the general partner's IDRs and converted our 2 percent general partner interest in WPZ to a noneconomic interest in exchange for 289 million newly issued WPZ common units. Pursuant to this agreement, we also purchased approximately 277 thousand WPZ common units for $10 million. Additionally, we purchased approximately 59 million common units of WPZ at a price of $36.08586 per unit in a private placement transaction, funded with proceeds from our equity offering (see Note 14 – Stockholders' Equity of Notes to Consolidated Financial Statements). According to the terms of this agreement, concurrent with WPZ's quarterly distributions in February 2017 and May 2017, we paid additional consideration totaling $56 million to WPZ for these units. Subsequent to these transactions and as of December 31, 2017, we own a 74 percent limited partner interest in WPZ.

Unless indicated otherwise, the following discussion and analysis of results of operations and financial condition and liquidity relates to our current continuing operations and should be read in conjunction with the consolidated financial statements and notes thereto included in Part II, Item 8 of this report.

Dividends

In December 2017, we paid a regular quarterly dividend of $0.30 per share. On February 21, 2018, our board of directors approved a regular quarterly dividend of $0.34 per share payable on March 26, 2018.

Overview

Net income (loss) attributable to The Williams Companies, Inc., for the year ended December 31, 2017, changed favorably by $2.598 billion compared to the year ended December 31, 2016, reflecting a $1.949 billion improvement in the provision (benefit) for income taxes primarily due to Tax Reform, the absence of $430 million of impairments of equity-method investments incurred in 2016, a $219 million increase in *Other investing income (loss) – net* primarily associated with the disposition of certain equity-method investments in 2017, a $204 million increase in operating income and reduced interest expense, partially offset by a $261 million increase in net income attributable to noncontrolling interests primarily due to increased income at WPZ. The increase in operating income reflects a gain of $1.095 billion from the sale of our Geismar Interest, increased service revenue from expansion projects, and lower costs and expenses, partially offset by a $674 million regulatory charge resulting from Tax Reform, a $375 million increase in impairments of certain assets, and a $184 million decrease in product margins primarily due to the loss of olefins volumes as a result of the sale of our Gulf Olefins and Canadian operations.

Tax Reform

In December 2017, the Tax Cuts and Jobs Act was enacted, which, among other things, reduced the federal corporate income tax rate from 35 percent to 21 percent (Tax Reform). As a result, we have remeasured our existing deferred income tax assets and liabilities, to reflect the expected future realization of existing temporary differences at the lower income tax rate. This resulted in the recognition of a net income tax provision benefit of $1.923 billion for the year ended December 31, 2017. Certain adjustments within the provision benefit are considered provisional and are potentially subject to change in the future. (See Note 7 – Provision (Benefit) for Income Taxes of Notes to Consolidated Financial Statements.)

Transco and Northwest Pipeline have recognized regulatory liabilities to reflect the probable return to customers through future rates of the future decrease in income taxes payable associated with Tax Reform. These liabilities represent an obligation to return amounts directly to our customers. The regulatory liabilities were recorded in December 2017 through regulatory charges to operating income totaling $674 million. (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies of Notes to Consolidated Financial Statements.) The timing and actual amount of such return will be subject to future negotiations regarding this matter and many other elements of cost-of-service rate proceedings, including other costs of providing service.

Revenue Recognition

As a result of the adoption of Accounting Standards Update 2014-09, Revenues from Contracts with Customers (ASC 606), we expect that our 2018 revenues will increase in situations where we receive noncash consideration, which exists primarily in certain of our gas processing contracts where we receive commodities as full or partial consideration for services provided. This increase in revenues will be offset by a similar increase in costs and expenses when the commodities received are subsequently sold. Based on commodities received during 2017 as consideration for services and market prices during 2017, we estimate the impact to revenues and costs would have been approximately $350 million.

Additionally, we expect future revenues will be impacted by application of the new accounting standard to certain contracts for which we received prepayments for services and have recorded deferred revenue (contract liabilities). For these contracts, which underwent modifications in periods prior to January 1, 2018, the modification is treated as a termination of the existing contract and the creation of a new contract. The new accounting guidance requires that the transaction price, including any remaining deferred revenue from the old contract, be allocated to the performance obligations over the term of the new contract. As a result, we will recognize the deferred revenue over longer periods than application of revenue recognition under accounting guidance prior to January 1, 2018. The application of ASC 606 to prior periods related to these contracts would have resulted in lower revenues in 2016 and 2017. Revenues will also be lower in 2018 and 2019 than what would have been recorded under the previous guidance, offset by increased revenues in later reporting periods given the longer period of recognition.

We are adopting ASC 606 utilizing the modified retrospective transition approach, effective January 1, 2018, by recognizing the cumulative effect of initially applying ASC 606 for periods prior to January 1, 2018, which we expect to result in a decrease of approximately $255 million, net of tax, to the opening balance of *Total equity* in the Consolidated Balance Sheet. This adjustment is primarily associated with the impact to the timing of deferred revenue (contract liabilities) for certain contracts as noted above.

Pension Deferred Vested Benefit Early Payout Program

In September 2017, we initiated a program to pay out certain deferred vested pension benefits to reduce investment risk, cash funding volatility, and administrative costs. In December 2017, the lump-sum payments were made and the annuity payments were commenced in relation to this program. As a result of these lump-sum payments, as well as lump-sum benefit payments made throughout 2017, settlement accounting was required. We settled $261 million in liabilities and recognized a pre-tax, non-cash settlement charge of $71 million. (See Note 9 – Employee Benefit Plans of Notes to Consolidated Financial Statements.)

Expansion Project Completions

Virginia Southside II

In December 2017, the Virginia Southside II expansion project to the Transco system was placed into service. The project expanded Transco's existing natural gas transmission system together with greenfield facilities to provide incremental firm transportation capacity from our Station 210 in New Jersey and our Station 165 in Virginia to a new lateral extending from our Brunswick Lateral in Virginia. The project increased capacity by 250 Mdth/d.

New York Bay Expansion

In October 2017, the New York Bay expansion to the Transco system was placed into service. The project expanded Transco's existing natural gas transmission system to provide incremental firm transportation capacity from Station 195 in Pennsylvania to the Rockaway Delivery Lateral transfer point and the Narrows meter station in New York. The project increased capacity by 115 Mdth/d.

Dalton

In August 2017, the Dalton expansion to the Transco system was placed into service. This project expanded Transco's existing natural gas transmission system together with greenfield facilities to provide incremental firm transportation capacity from our Station 210 in New Jersey to markets in northwest Georgia. On April 1, 2017, we began providing firm transportation service through the mainline portion of the project on an interim basis and we placed the full project into service in August 2017. The project increased capacity by 448 Mdth/d.

Hillabee

In July 2017, Phase I of the Hillabee Expansion Project was placed into service. The project involves an expansion of Transco's existing natural gas transmission system from our Station 85 in west central Alabama to a new interconnection with the Sabal Trail pipeline in Alabama. The project will be constructed in phases, and all of the project expansion capacity is dedicated to Sabal Trail pursuant to a capacity lease agreement. We placed a portion of Phase I into service in June of 2017 and the remainder of Phase I into service in July of 2017. Phase I increased capacity by 818 Mdth/d. The in-service date of Phase II is planned for the second quarter of 2020 and together they are expected to increase capacity by 1,025 Mdth/d.

In March 2016, WPZ entered into an agreement with the member-sponsors of Sabal Trail to resolve several matters. In accordance with the agreement, the member-sponsors paid us an aggregate amount of $240 million in three equal installments as certain milestones of the project were met. The first $80 million payment was received in March 2016, the second installment was received in September 2016 and the third installment was received in July 2017. WPZ expects to recognize income associated with these receipts over the term of the capacity lease agreement.

In August 2017, the Court of Appeals for the District of Columbia Circuit granted an appeal of the FERC certificate order for the Southeast Market Pipelines projects (a group of related projects, including the Hillabee Expansion Project) filed by certain non-governmental organizations. In doing so, the court (i) remanded the matter to the FERC for preparation of an Environmental Impact Statement (EIS) that conforms with the court's opinion regarding quantifying certain greenhouse gas emissions, and (ii) vacated the FERC's certificate order for the projects, which would be effective following the court's mandate (by court order, the mandate will not issue until after disposition of all petitions for rehearing). We, along with other intervenors, and the FERC filed petitions for rehearing with the court to overturn the remedy that would involve vacating the FERC certificate order, but on January 31, 2018 the court denied the petitions. In compliance with the court's directive, on February 5, 2018, the FERC issued a Final Supplemental EIS for the projects, reaffirming that while the projects would result in temporary and permanent impacts on the environment, those impacts would not be significant. On February 6, 2018, we, along with other intervenors, and the FERC filed motions with the court to stay the issuance of the mandate in order to give the FERC time to re-issue the authorizations for the projects. The filing of the motions automatically stays the effectiveness of the court's mandate. If the court's mandate is issued prior to the FERC re-issuing the authorizations for the projects, we believe that the FERC will take the necessary steps (which may include issuing temporary certificate authority) to avoid any lapse in federal authorization for the projects.

Geismar olefins facility monetization

In July 2017, WPZ completed the sale of its Geismar Interest for $2.084 billion in cash. WPZ received a final working capital adjustment of $12 million in October 2017. Additionally, WPZ entered into a long-term supply and transportation agreement with the purchaser to provide feedstock to the plant via its Bayou Ethane pipeline system, which is expected to provide a long-term, fee-based revenue stream. (See Note 2 – Acquisitions and Divestitures of Notes to Consolidated Financial Statements.)

Following this sale, the cash proceeds were used to repay WPZ's $850 million term loan. WPZ has also been using these proceeds to fund a portion of the capital and investment expenditures that are a part of its growth portfolio.

Acquisition of additional interests in Appalachia Midstream Investments

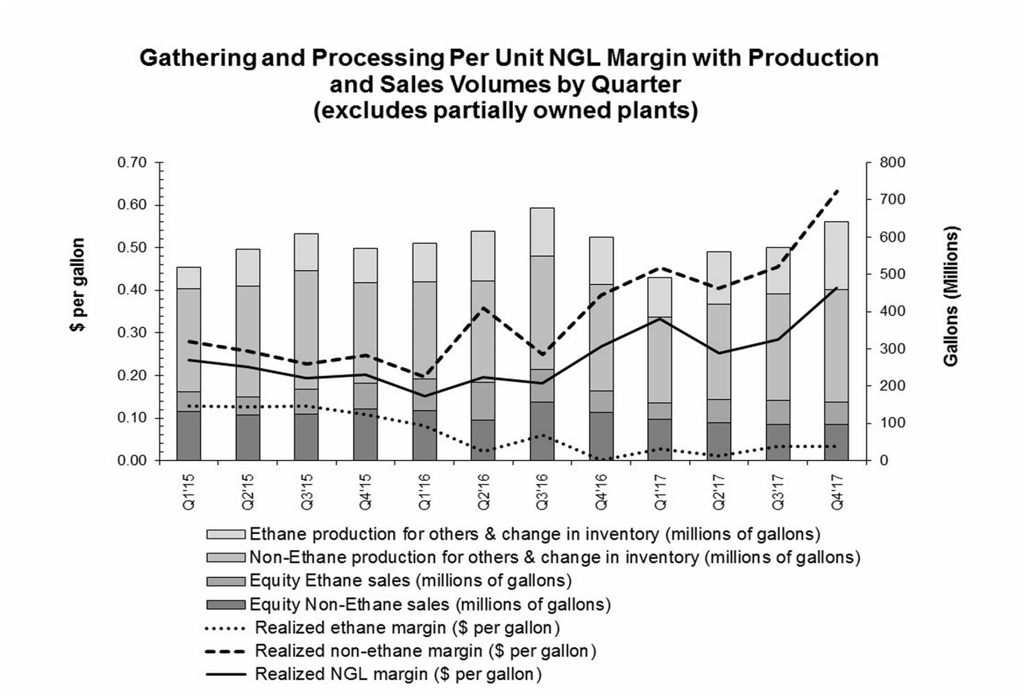
During the first quarter of 2017, WPZ exchanged all of its 50 percent interest in DBJV for an increased interest in two natural gas gathering systems that are part of the Appalachia Midstream Investments and $155 million in cash. Following this exchange, WPZ has an approximate average 66 percent interest in the Appalachia Midstream Investments. WPZ also sold all of its interest in Ranch Westex JV LLC for $45 million. These transactions resulted in a total gain of $269 million reflected in *Other investing income (loss) – net* in the Consolidated Statement of Operations within the Williams Partners segment. (See Note 5 – Investing Activities of Notes to Consolidated Financial Statements.)

Commodity Prices

NGL per-unit margins were approximately 62 percent higher in 2017 compared to 2016 due to a 42 percent increase in per-unit non-ethane prices. The per-unit margin increase also reflects the absence of our former Canadian operations which had lower per-unit non-ethane margins in the prior year compared to our domestic operations. These favorable impacts were partially offset by an approximate 26 percent increase in per-unit natural gas feedstock prices.

NGL margins are defined as NGL revenues less any applicable Btu replacement cost, plant fuel, and third-party transportation and fractionation. Per-unit NGL margins are calculated based on sales of our own equity volumes at the processing plants. Our equity volumes include NGLs where we own the rights to the value from NGLs recovered at our plants under both "keep-whole" processing agreements, where we have the obligation to replace the lost heating value with natural gas, and "percent-of-liquids" agreements whereby we receive a portion of the extracted liquids with no obligation to replace the lost heating value.

The following graph illustrates the NGL production and sales volumes, as well as the margin differential between ethane and non-ethane products and the relative mix of those products.



The potential impact of commodity prices on our business is further discussed in the following Company Outlook.

Company Outlook

Our strategy is to provide large-scale energy infrastructure designed to maximize the opportunities created by the vast supply of natural gas and natural gas products that exists in the United States. We accomplish this by connecting the growing demand for cleaner fuels and feedstocks with our major positions in the premier natural gas and natural gas products supply basins. We continue to maintain a strong commitment to safety, environmental stewardship, operational excellence, and customer satisfaction. We believe that accomplishing these goals will position us to deliver safe and reliable service to our customers and an attractive return to our shareholders.

Our business plan for 2018 includes a continued focus on growing our fee-based businesses, executing growth projects and accomplishing cost discipline initiatives to ensure operations support our strategy. We anticipate operating results will increase through organic business growth driven primarily by Transco expansion projects and continued growth in the Northeast region. WPZ intends to fund planned growth capital with retained cash flow and debt, and based on currently forecasted projects, does not expect to access public equity markets for the next several years.

Our growth capital and investment expenditures in 2018 are expected to be approximately $2.7 billion. Approximately $1.7 billion of our growth capital funding needs include Transco expansions and other interstate pipeline growth projects, most of which are fully contracted with firm transportation agreements. The remaining growth capital spending in 2018 primarily reflects investment in gathering and processing systems in the Northeast region limited primarily to known new producer volumes, including volumes that support Transco expansion projects including our Atlantic Sunrise project. In addition to growth capital and investment expenditures, we also remain committed to projects that maintain our assets for safe and reliable operations, as well as projects that meet legal, regulatory, and/or contractual commitments.

As a result of our significant continued capital and investment expenditures on Transco expansions and fee-based gathering and processing projects, fee-based businesses are a significant component of our portfolio and serve to reduce the influence of commodity price fluctuations on our operating results and cash flows. We expect to benefit as continued growth in demand for low-cost natural gas is driven by increases in LNG exports, industrial demand and power generation. For 2018, current forward market prices indicate oil prices are expected to be higher compared to 2017, while natural gas and NGL prices are expected to be lower or comparable with 2017. We continue to address certain pricing risks through the utilization of commodity hedging strategies. However, some of our customers may continue to curtail or delay drilling plans until there is a more sustained recovery in prices, which may negatively impact our gathering and processing volumes. The credit profiles of certain of our producer customers have been, and may continue to be, challenged as a result of lower energy commodity prices. Unfavorable changes in energy commodity prices or the credit profile of our producer customers may also result in noncash impairments of our assets.

In 2018, our operating results are expected to include increases from our regulated Transco fee-based business, primarily related to projects recently placed in-service or expected to be placed in-service in 2018 including the Atlantic Sunrise project. For our non-regulated businesses, we anticipate increases in fee-based revenue in the Northeast region, partially offset by lower fee-based revenue in the West region. As previously discussed, under the new accounting guidance for revenue recognition, deferred revenue under certain contracts will be recognized over longer periods than under the prior guidance, resulting in a decrease in revenue for the West region. We expect overall gathering and processing volumes to grow in 2018 and increase thereafter to meet the growing demand for natural gas and natural gas products. We also anticipate lower general and administrative expenses due to the full year impact of prior year cost reduction initiatives.

Potential risks and obstacles that could impact the execution of our plan include:

- Certain aspects of Tax Reform, including regulatory liabilities relating to reduced corporate federal income tax rates, could adversely impact the rates we can charge on our regulated pipelines;
- Opposition to infrastructure projects, including the risk of delay or denial in permits and approvals needed for our projects;
- Unexpected significant increases in capital expenditures or delays in capital project execution;
- Counterparty credit and performance risk, including that of Chesapeake Energy Corporation and its affiliates;
- Lower than anticipated demand for natural gas and natural gas products which could result in lower than expected volumes, energy commodity prices and margins;
- General economic, financial markets, or further industry downturn, including increased interest rates;
- Physical damages to facilities, including damage to offshore facilities by named windstorms;
- Lower than expected distributions from WPZ;
- Production issues impacting offshore gathering volumes;
- Other risks set forth under Part I, Item 1A. Risk Factors in this report.

We seek to maintain a strong financial position and liquidity, as well as manage a diversified portfolio of energy infrastructure assets which continue to serve key growth markets and supply basins in the United States.

Expansion Projects

Williams Partners' ongoing major expansion projects include the following:

Atlantic Sunrise

In February 2017, we received approval from the FERC to expand Transco's existing natural gas transmission system along with greenfield facilities to provide incremental firm transportation capacity from the northeastern Marcellus producing area to markets along Transco's mainline as far south as Station 85 in west central Alabama. We placed a portion of the mainline project facilities into service in September 2017 and it increased capacity by 400 Mdth/d. We plan to place the full project into service during mid-2018, assuming timely receipt of all remaining regulatory approvals. The full project is expected to increase capacity by 1,700 Mdth/d.

Constitution Pipeline

We currently own 41 percent of Constitution with three other parties holding 25 percent, 24 percent, and 10 percent, respectively. We are the operator of Constitution. The 126-mile Constitution pipeline is proposed to connect our gathering system in Susquehanna County, Pennsylvania, to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems in New York, as well as to a local distribution company serving New York and Pennsylvania.

In December 2014, Constitution received approval from the FERC to construct and operate its proposed pipeline, which will have an expected capacity of 650 Mdth/d. However, in April 2016, the New York State Department of Environmental Conservation (NYSDEC) denied the necessary water quality certification under Section 401 of the Clean Water Act for the New York portion of the pipeline. In May 2016, Constitution appealed the NYSDEC's denial of the Section 401 certification to the United States Court of Appeals for the Second Circuit and in August 2017, the court issued a decision denying in part and dismissing in part Constitution's appeal. The court expressly declined to rule on Constitution's argument that the delay in the NYSDEC's decision on Constitution's Section 401 application constitutes a waiver of the certification requirement. The court determined that it lacked jurisdiction to address that contention, and found that jurisdiction over the waiver issue lies exclusively with the United States Court of Appeals for the District of Columbia Circuit. As to the denial itself, the court determined that NYSDEC's action was not arbitrary or capricious. Constitution filed a petition for rehearing with the Second Circuit Court of Appeals, but in October the court denied our petition.

In October 2017, we filed a petition for declaratory order requesting the FERC to find that, by operation of law, the Section 401 certification requirement for the New York State portion of Constitution's pipeline project was waived due to the failure by the NYSDEC to act on Constitution's Section 401 application within a reasonable period of time as required by the express terms of such statute. In January 2018, the FERC denied our petition, finding that Section 401 provides that a state waives certification only when it does not act on an application within one year from the date of the application.

The project's sponsors remain committed to the project, and, in that regard, we are pursuing two separate and independent paths in order to overturn the NYSDEC's denial of the Section 401 certification. In January 2018, we filed a petition with the United States Supreme Court to review the decision of the Second Circuit Court of Appeals that upheld the merits of the NYSDEC's denial of the Section 401 certification. And, in February 2018, we filed a request with the FERC for rehearing of its finding that the NYSDEC did not waive the Section 401 certification requirement. If the FERC denies such request, we will file a petition for review with the D.C. Circuit Court of Appeals.

We estimate that the target in-service date for the project would be approximately 10 to 12 months following any court or FERC decision that the NYSDEC denial order was improper or that the NYSDEC waived the Section 401 certification requirement. (See Note 3 – Variable Interest Entities of Notes to Consolidated Financial Statements.)

Garden State

In April 2016, we received approval from the FERC to expand Transco's existing natural gas transmission system to provide incremental firm transportation capacity from Station 210 in New Jersey to a new interconnection on our Trenton Woodbury Lateral in New Jersey. The project will be constructed in phases and is expected to increase capacity by 180 Mdth/d. We placed the initial phase of the project into service in September 2017 and plan to place the remaining portion of the project into service during the first quarter of 2018.

Gateway

In November 2017, we filed an application with the FERC to expand Transco's existing natural gas transmission system to provide incremental firm transportation capacity from PennEast Pipeline Company's proposed interconnection with Transco's mainline south of Station 205 in New Jersey to other existing Transco meter stations within New Jersey. We plan to place the project into service in the first quarter of 2021, assuming timely receipt of all necessary regulatory approvals. The project is expected to increase capacity by 65 Mdth/d.

Gulf Connector

In November 2017, we received approval from the FERC allowing Transco to expand its existing natural gas transmission system to provide incremental firm transportation capacity from Station 65 in Louisiana to delivery points in Wharton and San Patricio Counties, Texas. The project will be constructed in two phases and we plan to place both phases into service during the first half of 2019, assuming timely receipt of all necessary regulatory approvals. The project is expected to increase capacity by 475 Mdth/d.

Hillabee

In February 2016, the FERC issued a certificate order for the initial phases of Transco's Hillabee Expansion Project. The project involves an expansion of Transco's existing natural gas transmission system from Station 85 in west central Alabama to a new interconnection with the Sabal Trail pipeline in Alabama. The project will be constructed in phases, and all of the project expansion capacity will be leased to Sabal Trail. We placed a portion of Phase I into service in June of 2017 and the remainder of Phase I into service in July of 2017. Phase I increased capacity by 818 Mdth/d. The in-service date of Phase II is planned for the second quarter of 2020 and together they are expected to increase capacity by 1,025 Mdth/d. See Expansion Project Completions within Overview.

Norphlet Project

In March 2016, we announced that we have reached an agreement to provide deepwater gas gathering services to the Appomattox development in the Gulf of Mexico. The project will provide offshore gas gathering services to our existing Transco lateral, which will provide transmission services onshore to our Mobile Bay processing facility. We also plan to make modifications to our Main Pass 261 Platform to install an alternate delivery route from the platform, as well as modifications to our Mobile Bay processing facility. The project is scheduled to go into service during the second half of 2019.

North Seattle Lateral Upgrade

In May 2017, we filed an application with the FERC to expand delivery capabilities on Northwest Pipeline's North Seattle Lateral. The project consists of the removal and replacement of approximately 5.9 miles of 8-inch diameter pipeline with new 20-inch diameter pipeline. We plan to place the project into service as early as the fourth quarter of 2019. The project is expected to increase capacity by up to 159 Mdth/d.

Northeast Supply Enhancement

In March 2017, we filed an application with the FERC to expand Transco's existing natural gas transmission system to provide incremental firm transportation capacity from Station 195 in Pennsylvania to the Rockaway Delivery Lateral transfer point in New York. We plan to place the project into service in late 2019 or during the first half of 2020, assuming timely receipt of all necessary regulatory approvals. The project is expected to increase capacity by 400 Mdth/d.

Ohio River Supply Hub Expansion

We agreed to expand our services to a customer to provide 660 MMcf/d of processing wet gas capacity in the Marcellus and Upper Devonian Shale in West Virginia. Associated with this agreement, we expect to further expand the processing capacity of our Oak Grove facility, which has the ability to increase capacity by an additional 1.8 Bcf/d. Additionally, with the same customer, we secured a gathering dedication agreement to gather dry gas in this same region. These expansions will be supported by long-term, fee-based agreements and volumetric commitments.

Rivervale South to Market

In August 2017, we filed an application with the FERC to expand Transco's existing natural gas transmission system to provide incremental firm transportation capacity from the existing Rivervale interconnection with Tennessee Gas Pipeline on Transco's North New Jersey Extension to other existing Transco locations within New Jersey. We plan to place the project into service as early as the fourth quarter of 2019, assuming timely receipt of all necessary regulatory approvals. The project is expected to increase capacity by 190 Mdth/d.

Susquehanna Supply Hub Expansion

The Susquehanna Supply Hub Expansion, which involves two new compression facilities with an additional 49,000 horsepower and 59 miles of 12 inch to 24 inch pipeline, is expected to increase gathering capacity, allowing a certain producer to fulfill its commitment to deliver 850 Mdth/d to our Atlantic Sunrise development. We placed a portion of this project into service in January 2018 and anticipate this expansion will be fully commissioned in the first quarter of 2018.

Critical Accounting Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions. We believe that the nature of these estimates and assumptions is material due to the subjectivity and judgment necessary, or the susceptibility of such matters to change, and the impact of these on our financial condition or results of operations.

Pension and Postretirement Obligations

We have employee benefit plans that include pension and other postretirement benefits. Net periodic benefit cost and obligations for these plans are impacted by various estimates and assumptions. These estimates and assumptions include the expected long-term rates of return on plan assets, discount rates, expected rate of compensation increase, health care cost trend rates, and employee demographics, including retirement age and mortality. These assumptions are reviewed annually and adjustments are made as needed. The assumptions utilized to compute cost and the benefit obligations are shown in Note 9 – Employee Benefit Plans of Notes to Consolidated Financial Statements.

The following table presents the estimated increase (decrease) in net periodic benefit cost and obligations resulting from a one-percentage-point change in the specific assumption.

	Benefit Cost		Benefit Obligation	
	One-Percentage-Point Increase	One-Percentage-Point Decrease	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Millions)			
Pension benefits:				
Discount rate	$ (8)	$ 9	$ (118)	$ 140
Expected long-term rate of return on plan assets	(12)	12	—	—
Rate of compensation increase	2	(1)	9	(6)
Other postretirement benefits:				
Discount rate	1	1	(22)	27
Expected long-term rate of return on plan assets	(2)	2	—	—
Assumed health care cost trend rate	—	—	5	(5)

Our expected long-term rates of return on plan assets, as determined at the beginning of each fiscal year, are based on the average rate of return expected on the funds invested in the plans. We determine our long-term expected rates of return on plan assets using our expectations of capital market results, which include an analysis of historical results as well as forward-looking projections. These capital market expectations are based on a period of at least 10 years and take into account our investment strategy and mix of assets. We develop our expectations using input from our third-party independent investment consultant. The forward-looking capital market projections start with current conditions of interest rates, equity pricing, economic growth, and inflation and those are overlaid with forward looking projections of normal inflation, growth, and interest rates to determine expected returns. The capital market return projections for specific asset classes in the investment portfolio are then applied to the relative weightings of the asset classes in the investment portfolio. The resulting rates are an estimate of future results and, thus, likely to be different than actual results.

In 2017, the benefit plans' assets outperformed their respective benchmarks for fixed income strategies, but generally underperformed the respective benchmarks for equity strategies. While the 2017 investment performance was greater than our expected rates of return, the expected rates of return on plan assets are long-term in nature and are not significantly impacted by short-term market performance. Changes to our asset allocation would also impact these expected rates of return. Our expected long-term rate of return on plan assets used for our pension plans was 6.45 percent in 2017. The 2017 actual return on plan assets for our pension plans was approximately 15.5 percent. The 10-year average rate of return on pension plan assets through December 2017 was approximately 4.3 percent.

The discount rates are used to measure the benefit obligations of our pension and other postretirement benefit plans. The objective of the discount rates is to determine the amount, if invested at the December 31 measurement date in a portfolio of high-quality debt securities, that will provide the necessary cash flows when benefit payments are due. Increases in the discount rates decrease the obligation and, generally, decrease the related cost. The discount rates for our pension and other postretirement benefit plans are determined separately based on an approach specific to our plans and their respective expected benefit cash flows as described in Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies and Note 9 – Employee Benefit Plans of Notes to Consolidated Financial Statements. Our discount rate assumptions are impacted by changes in general economic and market conditions that affect interest rates on long-term, high-quality debt securities as well as by the duration of our plans' liabilities.

The expected rate of compensation increase represents average long-term salary increases. An increase in this rate causes the pension obligation and cost to increase.

The assumed health care cost trend rates are based on national trend rates adjusted for our actual historical cost rates and plan design. An increase in this rate causes the other postretirement benefit obligation and cost to increase.

Property, Plant, and Equipment and Other Identifiable Intangible Assets

We evaluate our property, plant, and equipment and other identifiable intangible assets for impairment when events or changes in circumstances indicate, in our judgment, that the carrying value of such assets may not be recoverable. When an indicator of impairment has occurred, we compare our estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether an impairment has occurred and we may apply a probability-weighted approach to consider the likelihood of different cash flow assumptions and possible outcomes including selling in the near term or holding for the remaining estimated useful life. If an impairment of the carrying value has occurred, we determine the amount of the impairment recognized by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value. This evaluation is performed at the lowest level for which separately identifiable cash flows exist.

During the third quarter of 2017, we received solicitations and engaged in negotiations for the sale of certain gas gathering assets within the Mid-Continent region. As a result of these events, we evaluated the Mid-Continent asset group, which includes property, plant, and equipment and intangible assets, for impairment. Our evaluation considered the likelihood of divesting certain assets within the Mid-Continent region as well as information developed from the negotiation process that impacted our estimate of future cash flows associated with these assets. The estimated undiscounted future cash flows were determined to be below the carrying amount for these assets. We computed the estimated fair value using an income approach and incorporated market inputs based on ongoing negotiations for the potential sale of a portion of the underlying assets. For the income approach, we utilized a discount rate of 10.2 percent, reflecting an estimated cost of capital and risks associated with the underlying assets. As a result of this evaluation, we recorded an impairment charge of $1.019 billion for the difference between the estimated fair value and carrying amount of these assets.

Judgments and assumptions are inherent in estimating undiscounted future cash flows, fair values, and the probability-weighting of possible outcomes. The use of alternate judgments and assumptions could result in a different determination affecting the consolidated financial statements.

Equity-Method Investments

At December 31, 2017, our Consolidated Balance Sheet includes approximately $6.6 billion of investments that are accounted for under the equity-method of accounting. We evaluate these investments for impairment when events or changes in circumstances indicate, in our management's judgment, that the carrying value of such investments may have experienced an other-than-temporary decline in value. We continue to monitor our equity-method investments for any indications that the carrying value may have experienced an other-than-temporary decline in value. When evidence of a loss in value has occurred, we compare our estimate of the fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. We generally estimate the fair value of our investments using an income approach where significant judgments and assumptions include expected future cash flows and the appropriate discount rate. In some cases, we may utilize a form of market approach to estimate the fair value of our investments.

If the estimated fair value is less than the carrying value and we consider the decline in value to be other-than-temporary, the excess of the carrying value over the fair value is recognized in the consolidated financial statements as an impairment charge. Events or changes in circumstances that may be indicative of an other-than-temporary decline in value will vary by investment, but may include:

- A significant or sustained decline in the market value of an investee;
- Lower than expected cash distributions from investees;
- Significant asset impairments or operating losses recognized by investees;
- Significant delays in or lack of producer development or significant declines in producer volumes in markets served by investees;
- Significant delays in or failure to complete significant growth projects of investees.

As of December 31, 2017, the carrying value of our equity-method investment in Discovery is $534 million. During the fourth quarter of 2017, certain customers of Discovery terminated a significant offshore gas gathering agreement following the shut-in of production after the associated wells ceased flowing. As a result, we evaluated this investment for impairment and determined that no impairment was necessary.

We estimated the fair value of our investment in Discovery using an income approach that primarily considered probability-weighted assumptions of additional commercial development, the continued operation of the business under existing contracts, and a discount rate of 11.3 percent. Higher probabilities were generally assigned to those commercial development opportunities that were more advanced in the discussion and contracting process, utilizing existing infrastructure due to producer capital constraints, and/or we believe Discovery has a competitive advantage due to geographical proximity to the prospect. The estimated fair value of our investment in Discovery exceeded its carrying value by approximately 6 percent and thus no impairment was necessary.

Judgments and assumptions are inherent in our estimates of future cash flows, discount rates, and additional development probabilities. It is reasonably possible that an impairment could be required in the future if commercial development activities are not as successful or as timely as assumed. The use of alternate judgments and assumptions could result in a different calculation of fair value, which could ultimately result in the recognition of an impairment charge in the consolidated financial statements.

Constitution Pipeline Capitalized Project Costs

As of December 31, 2017, *Property, plant, and equipment – net* in our Consolidated Balance Sheet includes approximately $381 million of capitalized project costs for Constitution, for which we are the construction manager and own a 41 percent consolidated interest. As a result of the events discussed in Company Outlook, we evaluated the capitalized project costs for impairment as recently as December 31, 2017, and determined that no impairment was necessary. Our evaluation considered probability-weighted scenarios of undiscounted future net cash flows, including scenarios assuming construction of the pipeline, as well as a scenario where the project does not proceed. These scenarios included our most recent estimate of total construction costs. The probability-weighted scenarios also considered our assessment of the likelihood of success of the two separate and independent paths to obtain necessary certification, as described in Company Outlook. It is reasonably possible that future unfavorable developments, such as a reduced likelihood of success, increased estimates of construction costs, or further significant delays, could result in a future impairment.

Regulatory Liabilities resulting from Tax Reform

In December 2017, Tax Reform was enacted, which, among other things, reduced the corporate income tax rate from 35 percent to 21 percent. Rates charged to customers of our regulated natural gas pipelines are subject to the rate-making policies of the FERC, which permit the recovery of an income tax allowance that includes a deferred income tax component. As a result of the reduced income tax rate from Tax Reform and the collection of historical rates that reflected historical federal income tax rates, we expect that our regulated natural gas pipelines will be required to return amounts to certain customers through future rates and have established regulatory liabilities accordingly. These liabilities were recorded in December 2017 through regulatory charges to operating income totaling $674 million. (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies of Notes to Consolidated Financial Statements.) The timing and actual amount of such return will be subject to future negotiations regarding this matter and many other elements of cost–of–service rate proceedings, including other costs of providing service.

Our estimation of these regulatory liabilities incorporated the following significant judgments and assumptions involving income taxes collected from our customers.

- We utilized current FERC guidance for the default income tax rate for non-corporate taxpayers, which is an element of our overall effective tax rate. It is possible that the FERC will provide updated implementation guidance in the future, including an updated default income tax rate for non-corporate taxpayers. We estimate that a decline of one percentage point in our assumed overall effective tax rate would increase our regulatory liabilities by approximately $42 million.

- We made assumptions regarding the allocation of WPZ taxable income between corporate and non-corporate taxpayers. This allocation is subject to annual variation that could impact the weighted average federal tax component of the overall income tax allowance rate.

- We made assumptions regarding the allocation of WPZ taxable income among the states in which WPZ conducts business. This allocation is subject to annual variation that could impact the weighted average state tax component of the overall income tax allowance rate. It is possible that certain states may change their income tax laws and/or rates in the future in response to Tax Reform.

- In determining the estimated liability that we currently believe is probable of return to customers through future rates, we considered the mix of services provided by our regulated natural gas pipelines, taking into consideration that certain of these services are provided under contractually-based rates, in lieu of recourse-based rates. The contractually-based rates are designed to recover the cost of providing those services, with no expected future rate adjustment for the term of those contracts. We estimate that a one percent change in the relative mix of services would change the regulatory liability by approximately $8 million.

The use of alternative judgments and assumptions could result in the recognition of different regulatory liabilities and associated charges in the consolidated financial statements.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three years ended December 31, 2017. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Years Ended December 31,						
	2017	$ Change from 2016*	% Change from 2016*	2016	$ Change from 2015*	% Change from 2015*	2015
	(Millions)						
Revenues:							
Service revenues	$ 5,312	+141	+3 %	$ 5,171	+7	— %	$ 5,164
Product sales	2,719	+391	+17 %	2,328	+132	+6 %	2,196
Total revenues	8,031			7,499			7,360
Costs and expenses:							
Product costs	2,300	-575	-33 %	1,725	+54	+3 %	1,779
Operating and maintenance expenses	1,585	-5	— %	1,580	+75	+5 %	1,655
Depreciation and amortization expenses	1,736	+27	+2 %	1,763	-25	-1 %	1,738
Selling, general, and administrative expenses	608	+115	+16 %	723	+18	+2 %	741
Impairment of goodwill	—	—	— %	—	+1,098	+100 %	1,098
Impairment of certain assets	1,248	-375	-43 %	873	-664	NM	209
Gain on sale of Geismar Interest	(1,095)	+1,095	NM	—	—	— %	—
Regulatory charges resulting from Tax Reform	674	-674	NM	—	—	— %	—
Insurance recoveries – Geismar Incident	(9)	+2	+29 %	(7)	-119	-94 %	(126)
Other (income) expense – net	80	+62	+44 %	142	-102	NM	40
Total costs and expenses	7,127			6,799			7,134
Operating income (loss)	904			700			226
Equity earnings (losses)	434	+37	+9 %	397	+62	+19 %	335
Impairment of equity-method investments	—	+430	+100 %	(430)	+929	+68 %	(1,359)
Other investing income (loss) – net	282	+219	NM	63	+36	+133 %	27
Interest expense	(1,083)	+96	+8 %	(1,179)	-135	-13 %	(1,044)
Other income (expense) – net	(2)	-76	NM	74	-28	-27 %	102
Income (loss) before income taxes	535			(375)			(1,713)
Provision (benefit) for income taxes	(1,974)	+1,949	NM	(25)	-374	-94 %	(399)
Net income (loss)	2,509			(350)			(1,314)
Less: Net income (loss) attributable to noncontrolling interests	335	-261	NM	74	-817	NM	(743)
Net income (loss) attributable to The Williams Companies, Inc.	$ 2,174			$ (424)			$ (571)

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* + = Favorable change; - = Unfavorable change; NM = A percentage calculation is not meaningful due to a change in signs, a zero-value denominator, or a percentage change greater than 200.

2017 vs. 2016

Service revenues increased due to higher transportation fee revenues at Transco and in the eastern Gulf reflecting expansion projects placed in-service in 2016 and 2017; partially offset by a decrease in gathering, processing, and fractionation revenue including lower rates, primarily in the Barnett Shale region associated with the restructuring of contracts in the fourth quarter of 2016; lower volumes in the western regions, driven by natural declines and extreme weather conditions in the Rocky Mountains in 2017; and the sale of our former Canadian and Gulf Olefins operations.

Product sales increased primarily due to higher marketing revenues reflecting significantly higher prices and volumes. Revenues from the sale of our equity NGLs increased primarily due to higher non-ethane NGL prices, partially offset by lower volumes. These increases were partially offset by lower olefin production sales due to lower volumes resulting from the sale of our former Gulf Olefins and Canadian operations.

The increase in *Product costs* is primarily due to the same factors that increased marketing sales, partially offset by lower olefin feedstock purchases associated with the sale of our Gulf Olefins and Canadian operations.

Operating and maintenance expenses increased primarily due to higher pipeline integrity testing and general maintenance at Transco and a settlement charge from a pension early payout program (see Note 9 – Employee Benefit Plans of Notes to Consolidated Financial Statements), partially offset by the absence of costs associated with our former Canadian and Gulf Olefins operations and lower labor-related costs resulting from our workforce reductions that occurred late in first-quarter 2016, and ongoing cost containment efforts.

Depreciation and amortization expenses decreased primarily due to the absence of our former Canadian and Gulf Olefins operations, partially offset by new assets placed in-service.

Selling, general, and administrative expenses (SG&A) decreased primarily due to the absence of certain project development costs associated with the Canadian PDH facility that were expensed in 2016, lower labor-related costs resulting from our workforce reductions that occurred late in first-quarter 2016, ongoing cost containment efforts, lower strategic development costs, and the absence of costs associated with our former Canadian and Gulf Coast operations. These decreases were partially offset by higher severance and organizational realignment costs in 2017 (see Note 6 – Other Income and Expenses of Notes to Consolidated Financial Statements) and a settlement charge from a pension early payout program.

The unfavorable change in *Impairment of certain assets* reflects 2017 impairments of certain gathering operations in the Mid-Continent and Marcellus South regions, certain NGL pipeline assets, and an olefins pipeline project in the Gulf coast region. These 2017 impairments are partially offset by the absence of 2016 impairments of our former Canadian operations and certain Mid-Continent assets (see Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements).

The *Gain on sale of Geismar Interest* reflects the gain recognized on the sale of our Geismar Interest in July 2017. (See Note 2 – Acquisitions and Divestitures of Notes to Consolidated Financial Statements.)

Regulatory charges resulting from Tax Reform relates to the recognition of regulatory liabilities for the probable return to customers through future rates of the future decrease in income taxes payable associated with Tax Reform. (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies of Notes to Consolidated Financial Statements).

The favorable change in *Other (income) expense – net* within *Operating income (loss)* includes the absence of the 2016 loss on the sale of our Canadian operations, gains from certain contract settlements and terminations in 2017, a gain on the sale of our RGP Splitter in 2017, and the absence of an unfavorable change in foreign currency exchange associated with our former Canadian operations. These favorable changes are partially offset by additional expense associated with an annual revision to the ARO liability, accrual of additional expenses in 2017 related to the Geismar Incident, as well as the absence of a gain in first-quarter 2016 associated with the sale of unused pipe.

Operating income (loss) changed favorably primarily due to the *Gain on sale of Geismar Interest*, the absence of the 2016 impairments of certain Mid-Continent assets and our former Canadian operations, higher service revenues primarily from expansion projects placed in-service in 2016 and 2017, the absence of expensed Canadian PDH facility project development costs in 2016, as well as ongoing cost containment efforts, including workforce reductions in first-quarter 2016. *Operating income (loss)* also improved due to the absence of a 2016 loss on the sale of our Canadian operations, the absence of an operating loss associated with our former Canadian operations, gains from certain contract settlements and the sale of our RGP Splitter. These favorable changes were partially offset by 2017 impairments of certain gathering operations in the Mid-Continent and Marcellus South regions, regulatory charges resulting from Tax Reform, and certain NGL pipeline assets, as well as the absence of operating income associated with our former Gulf Olefins operations, and a settlement charge from a pension early payout program.

The favorable change in *Equity earnings (losses)* is due to an increase in ownership of our Appalachia Midstream Investments and improved results at Aux Sable due to favorable pricing and higher volumes, partially offset by lower UEOM results driven by lower processing volumes from the Utica gathering system and lower Discovery results due to lower volumes.

The decrease in *Impairment of equity-method investments* reflects the absence of 2016 impairment charges associated with our Appalachia Midstream Investments, DBJV, Laurel Mountain, and Ranch Westex equity-method investments. (See Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements.)

Other investing income (loss) – net reflects the gain on disposition of our investments in DBJV and Ranch Westex JV LLC in 2017, partially offset by the absence of interest income received in 2016 associated with a receivable related to the sale of certain former Venezuelan assets and the absence of a 2016 gain on the sale of an equity-method investment interest in a gathering system that was part of our Appalachia Midstream Investments. (See Note 5 – Investing Activities of Notes to Consolidated Financial Statements).

Interest expense decreased primarily due to lower *Interest incurred* primarily attributable to debt retirements in 2017 and lower borrowings on our credit facilities in 2017. (See Note 13 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements.)

Other income (expense) – net below *Operating income (loss)* changed unfavorably primarily due to charges reducing regulatory assets related to deferred taxes on equity funds used during construction (AFUDC) resulting from Tax Reform and a settlement charge from a pension early payout program, partially offset by a net gain on early debt retirements in 2017, and other favorable changes related to AFUDC. (See Note 5 – Other Income and Expenses of Notes to Consolidated Financial Statements.)

Provision (benefit) for income taxes changed favorably primarily due to a reduction in the federal statutory rate from 35 percent to 21 percent with the enactment of Tax Reform. The remeasurement of our existing deferred tax assets and liabilities at the reduced rate resulted in the recognition of a net income tax provision benefit of $1.923 billion. Adjustments within this provision benefit are considered provisional and are potentially subject to change in the future. See Note 7 – Provision (Benefit) for Income Taxes of Notes to Consolidated Financial Statements for a discussion of the effective tax rate compared to the federal statutory rate for both periods.

The unfavorable change in *Net income (loss) attributable to noncontrolling interests* is primarily due to the impact of decreased income allocated to us driven by the permanent waiver of IDRs and higher operating results at WPZ, partially offset by a decrease in the ownership of the noncontrolling interests. Both the permanent waiver of IDRs and the change in ownership are associated with the first-quarter 2017 Financial Repositioning (see Note 1 – General, Description of Business, and Basis of Presentation of Notes to Consolidated Financial Statements). In addition, improved results in our Gulfstar operations also contributed to the increase in *Net income (loss) attributable to noncontrolling interests,* partially offset by lower results for our Cardinal gathering system.

2016 vs. 2015

Service revenues increased slightly primarily due to expansion projects placed in service in 2015 and 2016, partially offset by a decrease in gathering, processing, and fractionation revenue primarily due to lower volumes in the Barnett Shale and Anadarko basin.

Product sales increased primarily due to higher olefin sales reflecting increased volumes at our former Geismar plant as a result of the plant operating at higher production levels in 2016, partially offset by a decrease from our other olefin operations associated with lower volumes and per-unit sales prices. *Product sales* also reflect higher marketing revenues associated with higher NGL and propylene prices and natural gas and crude oil volumes, partially offset by lower NGL volumes, and crude oil prices.

The decrease in *Product costs* includes lower olefin feedstock purchases and lower costs associated with other product sales, partially offset by higher marketing purchases primarily due to the same factors that increased marketing sales. The decline in olefin feedstock purchases is primarily associated with lower per-unit feedstock costs and volumes at our other olefin operations, partially offset by an increase in olefin feedstock purchases at our former Geismar plant reflecting increased volumes resulting from higher production levels in 2016.

Operating and maintenance expenses decreased primarily due to lower labor-related and outside service costs resulting from our first-quarter 2016 workforce reductions and cost containment efforts and lower costs associated with general maintenance activities in the Marcellus Shale, as well as the absence of ACMP transition-related costs recognized in 2015. These decreases are partially offset by $16 million of severance and related costs recognized in 2016 and higher pipeline testing and general maintenance costs at Transco.

Depreciation and amortization expenses increased primarily due to depreciation on new assets placed in service, including Transco pipeline projects, partially offset by lower depreciation related to Canadian operations sold in 2016.

SG&A decreased primarily due to lower merger and transition costs associated with the ACMP merger and lower labor-related costs resulting from our first-quarter 2016 workforce reductions and cost containment efforts. These decreases were partially offset by certain project development costs associated with the Canadian PDH facility that we began expensing in 2016, as well as $26 million of severance and related costs recognized in 2016 and $17 million of higher costs associated with our evaluation of strategic alternatives.

Impairment of goodwill decreased due to the absence of a 2015 impairment charge associated with certain goodwill. (See Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements.)

Impairment of certain assets reflects 2016 impairments of our Canadian operations and certain Mid-Continent assets, and other assets. Impairments recognized in 2015 relate primarily to previously capitalized development costs and surplus equipment write-downs. (See Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements.)

Insurance recoveries – Geismar Incident changed unfavorably reflecting the receipt of $126 million of insurance proceeds in the second quarter of 2015, as compared to the receipt of $7 million of proceeds in the fourth quarter of 2016.

The unfavorable change in *Other (income) expense – net* within *Operating income (loss)* includes a loss on the sale of our Canadian operations that were sold in September 2016, project development costs at Constitution as we discontinued capitalization of these costs in April 2016, and an unfavorable change in foreign currency exchange that primarily relates to losses incurred on foreign currency transactions and the remeasurement of the U.S. dollar-denominated current assets and liabilities within our former Canadian operations, partially offset by a $10 million gain on the sale of idle pipe in 2016.

Operating income (loss) changed favorably primarily due to the absence of a goodwill impairment in 2015, higher olefin margins related to the Geismar plant operating at higher production levels in 2016, lower costs related to the merger and integration of ACMP, and lower costs and expenses primarily associated with cost containment efforts. These favorable changes are partially offset by impairments and loss on sale of certain assets in 2016, a decrease in insurance proceeds received, expensed Canadian PDH facility project development costs, and higher depreciation expenses related to new projects placed in service.

Equity earnings (losses) changed favorably primarily due to a $30 million increase at Discovery driven by the completion of the Keathley Canyon Connector in the first quarter of 2015. Additionally, OPPL, Laurel Mountain, and DBJV improved $16 million, $11 million, and $10 million, respectively.

Impairment of equity-method investments reflects 2016 impairment charges associated with our Appalachia Midstream Investments, DBJV, Laurel Mountain, and Ranch Westex equity-method investments, while the 2015 impairment charges relate to our equity-method investments in Appalachia Midstream Investments, DBJV, UEOM, and Laurel Mountain. (See Note 5 – Investing Activities of Notes to Consolidated Financial Statements.)

Other investing income (loss) – net changed favorably due to a 2016 gain on the sale of an equity-method investment interest in a gathering system that was part of our Appalachia Midstream Investments and higher interest income associated with a receivable related to the sale of certain former Venezuela assets. (See Note 5 – Investing Activities of Notes to Consolidated Financial Statements.)

Interest expense increased due to higher *Interest incurred* of $99 million primarily attributable to new debt issuances in 2016 and 2015 and lower *Interest capitalized* of $36 million primarily related to construction projects that have been placed into service, partially offset by lower interest due to 2015 and 2016 debt retirements. (See Note 13 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements.)

Other income (expense) – net below *Operating income (loss)* changed unfavorably primarily due to a decrease in AFUDC due to decreased spending on Constitution and the absence of a $14 million gain on early debt retirement in 2015.

Provision (benefit) for income taxes changed unfavorably primarily due to a decrease in pre-tax loss in 2016. See Note 7 – Provision (Benefit) for Income Taxes of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both years.

The unfavorable change in *Net income (loss) attributable to noncontrolling interests* is primarily due to higher operating results at WPZ, the impact of decreased income allocated to the WPZ general partner driven by the impact of reduced incentive distributions from WPZ, and the absence of the accelerated amortization of a beneficial conversion feature from the first quarter of 2015. These changes are partially offset by a favorable change primarily related to our partners' share of Constitution project development costs in 2016.

Year-Over-Year Operating Results – Segments

We evaluate segment operating performance based upon *Modified EBITDA*. Note 18 – Segment Disclosures of Notes to Consolidated Financial Statements includes a reconciliation of this non-GAAP measure to *Net income (loss)*. Management uses *Modified EBITDA* because it is an accepted financial indicator used by investors to compare company performance. In addition, management believes that this measure provides investors an enhanced perspective of the operating performance of our assets. *Modified EBITDA* should not be considered in isolation or as a substitute for a measure of performance prepared in accordance with GAAP.

Williams Partners

	Years Ended December 31,		
	2017	2016	2015
	(Millions)		
Service revenues	$ 5,292	$ 5,173	$ 5,135
Product sales	2,718	2,318	2,196
Segment revenues	8,010	7,491	7,331
Product costs	(2,300)	(1,728)	(1,779)
Other segment costs and expenses	(2,124)	(2,203)	(2,229)
Net insurance recoveries – Geismar Incident	9	7	126
Gain on sale of Geismar Interest	1,095	—	—
Impairment of certain assets	(1,156)	(457)	(145)
Regulatory charges resulting from Tax Reform	(713)	—	—
Proportional Modified EBITDA of equity-method investments	795	754	699
Williams Partners Modified EBITDA	$ 3,616	$ 3,864	$ 4,003
NGL margin	$ 203	$ 169	$ 159
Olefin margin	126	337	226

2017 vs. 2016

Modified EBITDA decreased primarily due to $713 million of regulatory charges associated with the impact of Tax Reform for Transco and Northwest Pipeline, impairments of certain gathering operations in 2017 and lower olefin margins due to the sale of our Gulf Olefins operations early in the third quarter of 2017 and $35 million of expense in 2017 related to a settlement charge from a pension early payout program (see Note 9 – Employee Benefit Plans of Notes to Consolidated Financial Statements). These decreases are partially offset by the $1.095 billion gain on the sale of our Geismar Interest in third-quarter 2017, the absence of impairments of our former Canadian operations and certain gathering assets in the Mid-Continent region in 2016, the absence of a loss on the sale of our former Canadian operations in third-quarter 2016, higher service revenues, lower segment costs and expenses, and higher *Proportional Modified EBITDA of equity-method investments*.

Service revenues increased primarily due to:

- Transco's natural gas transportation fee revenues increased $135 million primarily due to a $150 million increase associated with expansion projects placed in-service in 2016 and 2017, partially offset by lower volume-based transportation services revenues;
- Higher eastern Gulf Coast region revenue of $103 million associated primarily with higher volumes, including the impact of new volumes at Gulfstar One related to the Gunflint expansion placed in-service in the third quarter of 2016, the absence of the temporary shut-down and subsequent ramp-up of Gulfstar One in the second and third quarters of 2016 to tie-in Gunflint and the absence of producers' operational issues in the Tubular Bells field during the first quarter of 2016. This increase is partially offset by lower volumes as a result of a temporary increase in 2016 due to disrupted operations of a competitor;
- A $39 million increase related to the amortization of deferred revenue associated with the up-front cash payment received in conjunction with the fourth quarter 2016 Barnett Shale contract restructuring;
- A $15 million increase in Transco's storage revenue primarily reflecting the absence of an accrual for potential refunds associated with a ruling received in certain rate case litigation in 2016;
- In the Northeast region, a slight increase reflecting a $38 million increase in gathering fee revenue at Susquehanna Supply Hub driven by 11 percent higher gathered volumes reflecting increased customer production and a $23 million increase in fee revenue at Ohio Valley Midstream reflecting the absence of shut-in volumes from the first half of 2016, as well as new production coming online. The increases were substantially offset by a $56 million decrease in the Utica gathering system primarily due to 14 percent lower gathered volumes driven by natural declines in the wet gas areas which are partially offset by higher volumes from new development in the dry gas areas;
- A $79 million decrease in the West region related to net lower gathering rates in the Barnett Shale area primarily due to the fourth quarter 2016 contract restructuring, along with lower rates recognized in the Niobrara, Eagle Ford Shale, and Haynesville Shale regions. These rate decreases are offset by higher commodity-based fee revenues in the Piceance area primarily due to higher per-unit NGL margins and higher rates in the Wamsutter area as a result of renegotiated rates in conjunction with infrastructure expansions. Rates recognized in the Niobrara region represent a portion of the total contractual rate that is received, with the difference reflected as deferred revenue;
- A $34 million decrease driven by lower volumes in the West region primarily as a result of natural declines and more extreme weather conditions in the Rocky Mountains in the first quarter of 2017, partially offset by higher volumes in the Haynesville Shale region as a result of increased drilling in certain areas;
- A $36 million decrease due to the absence of revenue generated by our former Canadian operations that were sold in September 2016;

- A $15 million decrease in western Gulf Coast region fee revenues due to lower volumes primarily associated with producer maintenance.

Product sales increased primarily due to:

- A $735 million increase in marketing revenues primarily due to significantly higher prices across all products and higher NGL volumes (substantially offset in marketing purchases);

- A $32 million increase in revenues from our equity NGLs including a $102 million increase driven primarily by higher non-ethane prices, partially offset by a $36 million decrease due to the absence of NGL production revenues associated with our former Canadian operations and a $34 million decrease primarily related to lower non-ethane volumes at our domestic plants driven by the absence of temporary volumes in 2016 related to disrupted operations of a competitor, severe winter conditions in the first quarter of 2017, and natural declines;

- A $12 million increase in system management gas sales from Transco. System management gas sales are offset in *Product costs* and, therefore, have no impact on *Modified EBITDA*;

- A $380 million decrease in olefin sales primarily due to a $343 million decrease reflecting the absence of third- and fourth-quarter sales of our Gulf Olefins operations, a $29 million decrease due to the sale of the Canadian operations in 2016, and a $16 million decrease at our Geismar plant in the first half of 2017 primarily due to lower volumes associated with the electrical outage in second-quarter 2017, as well as planned maintenance downtime in first-quarter 2017. These items were partially offset by $8 million higher sales at the RGP Splitter in the first half 2017 primarily due to higher propylene prices.

Product costs increased primarily due to:

- A $725 million increase in marketing purchases primarily due to the same factors that increased marketing sales (more than offset in marketing revenues). The increase in marketing costs does not reflect the intercompany costs associated with certain gathering and processing services performed by an affiliate;

- A $12 million increase in system management gas costs (offset in *Product sales*);

- A $166 million decrease in olefin feedstock purchases primarily due to the absence of $163 million in feedstock purchases in the second half of 2017 reflecting the sale of the Gulf Olefins operations, as well as the absence of $9 million in costs associated with our former Canadian operations, partially offset by $6 million higher feedstock costs in the first half of 2017.

- A $2 million decrease in costs from our equity NGLs including a $35 million increase driven primarily by higher gas prices, partially offset by a $24 million decrease due to the absence of NGL production revenues associated with our former Canadian operations and a $13 million decrease primarily related to lower volumes at our domestic plants driven by severe winter conditions in the first quarter of 2017, and the absence of temporary volumes in 2016 related to disrupted operations of a competitor and natural declines.

The favorable change in *Other segment costs and expenses* includes a decrease in labor-related expenses primarily due to our first quarter 2016 workforce reduction and ongoing cost containment efforts; the absence of $117 million of operating and other expenses associated with our Gulf Olefins and Canadian operations; and the absence of a $34 million loss on the sale of our former Canadian operations. Additional favorable changes in *Other segment costs and expenses* include a $27 million net gain associated with early debt retirement; a $15 million gain related to favorable contract settlements and terminations; a favorable change in equity AFUDC, primarily associated with an increase in Transco's capital spending, which is partially offset by a decrease in capital spending at Constitution; and a $12 million gain on the sale of the RGP Splitter. These decreases are partially offset by $35 million of expense in 2017 related to a settlement charge from a pension early payout program (see Note 9 – Employee Benefit Plans of Notes to Consolidated Financial Statements), higher various maintenance expenses, an increase in pipeline integrity testing on Transco, and higher Geismar selling expenses and repairs related to a Geismar electrical outage.

Gain on sale of Geismar Interest reflects the gain recognized on the sale of our Geismar Interest in July 2017. (See Note 2 - Acquisitions and Divestitures of Notes to Consolidated Financial Statements.)

Impairment of certain assets increased primarily due to a $1.032 billion impairment of certain gathering operations primarily in the Mid-Continent region and a $115 million impairment of certain gathering operations in the Marcellus South region, partially offset by the absence of a $341 million impairment of our former Canadian operations and a $100 million impairment of certain Mid-Continent gathering assets and impairments or write-downs of other certain assets that may no longer be in use or are surplus in nature during 2016. (See Note 16 - Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements.)

Regulatory charges resulting from Tax Reform reflects $713 million of regulatory charges associated with the impact of Tax Reform at Transco and Northwest Pipeline with $674 million presented as *Regulatory charges resulting from Tax Reform* and $39 million included within *Other income (expense) – net* below *Operating income (loss)* in the Consolidated Statement of Operations.

The increase in *Proportional Modified EBITDA of equity-method investments* includes a $100 million increase at Appalachia Midstream Investments reflecting our increased ownership acquired late in the first quarter of 2017, higher gathering volumes reflecting the absence of shut-in volumes from 2016 and increased customer production, and a $20 million increase at Aux Sable due to increased customer production. These increases are partially offset by a $34 million decrease at UEOM reflecting lower processing volumes from the wet gas areas of the Utica gathering system, the divestiture of our interests in DBJV and Ranch Westex JV LLC late in the first quarter of 2017, a $12 million decrease from Discovery primarily attributable to lower fee revenue driven by production issues at certain wells and higher turbine maintenance expenses.

2016 vs. 2015

Modified EBITDA decreased primarily due to higher impairments, lower insurance recoveries associated with the Geismar Incident, and loss on sale associated with our Canadian operations. These decreases were partially offset by higher olefin margins related to the Geismar plant operating at higher production levels in 2016, lower segment costs and expenses, and higher earnings related to our equity-method investments, including the completion of the Keathley Canyon Connector at Discovery in the first quarter of 2015. Additionally, higher marketing margins, higher service revenues related to projects placed in service, and higher NGL margins improved *Modified EBITDA.*

The increase in *Service revenues* is primarily due to a $79 million increase in Transco's natural gas transportation fee revenues primarily associated with expansion projects placed in service in 2015 and 2016 and a $31 million transportation and fractionation revenue increase associated with Williams' Horizon liquids extraction plant in Canada. The Canadian operations were sold in late September 2016. These increases were partially offset by a decrease in gathering, processing, and fractionation revenue primarily due to lower volumes primarily in the Barnett Shale and Anadarko basin and a $15 million decrease in Transco's storage revenue related to potential refunds associated with a ruling received in certain rate case litigation in 2016.

Product sales increased primarily due to:

- A $94 million increase in olefin sales comprised of a $170 million increase from the Geismar plant that returned to service in late March 2015, partially offset by a $76 million decrease from our other former olefin operations. The increase at Geismar includes $153 million associated with increased volumes as a result of the plant operating at higher production levels in 2016 than when production resumed in March 2015 following the Geismar Incident and $17 million primarily associated with higher ethylene per-unit sales prices. The decrease in other olefin sales includes a $14 million reduction due to the absence of our former Canadian operations in the fourth quarter of 2016, as well as lower volumes and lower per-unit sales prices within our other olefin operations;

- A $70 million increase in marketing revenues primarily due to higher NGL and propylene prices and natural gas and crude oil volumes, partially offset by lower NGL volumes and crude oil prices (partially offset in marketing purchases);

- A $6 million increase in revenues from our equity NGLs due to a $10 million increase associated with higher volumes, partially offset by a $4 million decrease associated with lower NGL prices;

- A $39 million decrease in system management gas sales from Transco. System management gas sales are offset in *Product costs* and, therefore, have no impact on *Modified EBITDA.*

The decrease in *Product costs* includes:

- A $39 million decrease in system management gas costs (offset in *Product sales*);

- A $17 million decrease in olefin feedstock purchases is primarily comprised of $78 million in lower purchases at our former other olefins operations, partially offset by $61 million of higher purchases due primarily to increased volumes at the Geismar plant resulting from higher productions levels. The lower costs at our former other olefin operations are comprised of $54 million in lower per-unit feedstock costs and $24 million in primarily lower propylene volumes;

- A $4 million decrease in natural gas purchases associated with the production of equity NGLs reflecting a decrease of $13 million due to lower natural gas prices, partially offset by a $9 million increase associated with higher volumes;

- Lower costs associated with various other products, primarily condensate;

- A $22 million increase in marketing purchases primarily due to the same factors that increased marketing sales (more than offset in marketing revenues). The increase in marketing costs does not reflect the intercompany costs associated with certain gathering and processing services performed by an affiliate.

The decrease in *Other segment costs and expenses* is primarily due to lower operating costs and general and administrative expenses reflecting decreases in primarily labor-related and outside services costs resulting from our first-quarter 2016 workforce reductions and ongoing cost containment efforts and lower costs associated with general maintenance activities in the Marcellus Shale, as well as $43 million of lower ACMP Merger and transition-related expenses. Other items partially offsetting these decreases are as follows:

- $37 million increase for severance and related costs associated with workforce reductions incurred in the first quarter of 2016 and the organizational realignment in the fourth quarter of 2016;

- $34 million increase related to the 2016 loss on sale of our Canadian operations;

- $28 million higher project development costs at Constitution as we discontinued capitalization of development costs related to this project beginning in April 2016;

- $22 million higher contract services for pipeline testing and general maintenance at Transco;

- $20 million unfavorable change in foreign currency exchange that primarily relates to losses incurred on foreign currency transactions and the remeasurement of the U.S. dollar-denominated current assets and liabilities within our former Canadian operations;

- $19 million unfavorable change in AFUDC associated with a decrease in spending on Constitution;

- The absence of a $14 million gain recognized in second-quarter 2015 resulting from the early retirement of certain debt.

Net insurance recoveries – Geismar Incident decreased reflecting $7 million of insurance proceeds received in 2016 compared to $126 million received in 2015.

Impairment of certain assets increased primarily due to 2016 impairments of $341 million associated with our Canadian operations and $63 million associated with certain Mid-Continent gathering assets as well as impairments or write-downs of other certain assets that may no longer be in use or are surplus in nature, partially offset by the absence of 2015 impairments of $94 million associated with previously capitalized project development costs for a gas processing plant and $20 million associated with certain surplus equipment within our Ohio Valley Midstream business. (See Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements.)

The increase in *Proportional Modified EBITDA of equity-method investments* is primarily due to a $30 million increase from Discovery primarily associated with higher fee revenues attributable to the completion of the Keathley Canyon Connector in the first quarter of 2015. Additionally, Caiman II contributed a $20 million increase resulting from higher volumes due to assets placed into service in 2015, OPPL contributed a $16 million increase primarily due to higher transportation volumes and lower expenses, and UEOM contributed an $11 million increase primarily associated with an increase in our ownership percentage. These increases were partially offset by a $29 million decrease from Appalachia Midstream Investments primarily due to lower fee revenues driven by lower rates, partially offset by lower impairments and higher volumes.

Other

	Years Ended December 31,		
	2017	2016	2015
		(Millions)	
Other Modified EBITDA	$ (150)	$ (542)	$ (112)

2017 vs. 2016

The favorable change in *Modified EBITDA* is primarily due to:

- The absence of the $406 million 2016 impairment of our Canadian operations, partially offset by the $23 million impairment of an olefins pipeline project in the Gulf Coast region in the second quarter of 2017 and the $68 million impairment of a certain NGL pipeline asset in the third quarter of 2017 (see Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements);
- The absence of $61 million of certain project development costs associated with the Canadian PDH facility that we expensed in 2016;
- A $31 million favorable change in the loss on the sale of our Canadian operations in September 2016;
- The absence of $32 million of transportation and fractionation fees incurred in 2016 related to the Redwater fractionation facility, which was included in the sale of our Canadian operations in September 2016;
- A $38 million decrease in costs related to our evaluation of strategic alternatives;
- A $29 million increase in income associated with an increase in a regulatory asset primarily driven by our increased ownership in WPZ.

These favorable changes are partially offset by:

- A $63 million charge reducing regulatory assets related to deferred taxes on AFUDC resulting from Tax Reform (see Note 6 – Other Income and Expenses of Notes to Consolidated Financial Statements);
- A $35 million settlement charge expense related to the program to pay out certain deferred vested pension benefits of employees associated with former operations. (See Note 9 – Employee Benefit Plans of Notes to Consolidated Financial Statements);

- A reduction in revenues associated with an NGL pipeline near the Houston Ship Channel region;
- The absence of a $10 million gain on the sale of unused pipe in 2016.

2016 vs. 2015

The unfavorable change in *Modified EBITDA* is primarily due to:

- The impairment and loss on sale of our Canadian operations totaling $438 million in 2016;
- An increase of $61 million of certain project development costs associated with the Canadian PDH facility that we began expensing in 2016;
- A $17 million increase in costs related to our evaluation of strategic alternatives.

These unfavorable changes are partially offset by:

- A $10 million gain on the sale of unused pipe in 2016;
- A $31 million decrease in ACMP merger and transition related costs;
- The absence of a $64 million write-off of previously capitalized project development costs for an olefins pipeline project in 2015.

Management's Discussion and Analysis of Financial Condition and Liquidity

Overview

In 2017, we exceeded our target for asset sales, significantly improved our balance sheet to provide ample available liquidity, and continued to focus on growth in our businesses by identifying, contracting, permitting, and constructing attractive expansion projects. Examples of this activity included:

- Sale of our Geismar Interest (see Note 2 – Acquisitions and Divestitures of Notes to Consolidated Financial Statements).
- Repayment of WPZ's $850 million variable interest rate term loan that was due December 2018, and early retirement of WPZ's $750 million of 6.125 percent senior unsecured notes that were due in 2022;
- Repayment of WPZ's $1.4 billion of 4.875 percent senior unsecured notes that were due in 2023 with proceeds from the issuance of WPZ's $1.45 billion of 3.75 percent senior unsecured notes due in 2027;
- Extension to 2021 for the maturity dates of our long-term credit facility and WPZ's long-term credit facility;
- Expansion of WPZ's interstate natural gas pipeline system through completion of 2017 strategic projects (Gulf Trace, Hillabee Phase 1, Dalton, New York Bay, and Virginia Southside II) to meet the demand of growth markets.

Outlook

Fee-based businesses are a significant component of our portfolio and serve to reduce the influence of commodity price fluctuations on our cash flows. We expect to benefit as continued growth in demand for low-cost natural gas is driven by increases in LNG exports, industrial demand, and power generation.

As previously discussed in Company Outlook, our consolidated growth capital and investment expenditures in 2018 are expected to be approximately $2.7 billion. Approximately $1.7 billion of our growth capital funding needs include Transco expansions and other interstate pipeline growth projects, most of which are fully contracted with firm transportation agreements. The remaining growth capital spending in 2018 primarily reflects investment in gathering and processing systems in the Northeast region limited primarily to known new producer volumes, including volumes that support Transco expansion projects including our Atlantic Sunrise project. In addition to growth capital and investment expenditures, we also remain committed to projects that maintain our assets for safe and reliable operations, as well as projects that meet legal, regulatory, and/or contractual commitments. WPZ intends to fund their planned 2018 growth capital with retained cash flow and debt. We retain the flexibility to adjust planned levels of growth capital and investment expenditures in response to changes in economic conditions or business opportunities.

Liquidity

Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses in 2018. WPZ expects to be self-funding and maintain separate bank accounts and credit facilities, including its commercial paper program. Our potential material internal and external sources and uses of consolidated liquidity for 2018 are as follows:

	Applicable To:	
	WPZ	WMB
Sources:		
Cash and cash equivalents on hand	✓	✓
Cash generated from operations	✓	
Distributions from investment in WPZ		✓
Distributions from equity-method investees	✓	
Utilization of credit facilities and/or commercial paper program	✓	✓
Cash proceeds from issuance of debt and/or equity securities	✓	✓
Proceeds from asset monetizations	✓	
Uses:		
Working capital requirements	✓	✓
Capital and investment expenditures	✓	
Investment in WPZ		✓
Quarterly distributions to unitholders	✓	
Quarterly dividends to shareholders		✓
Debt service payments, including payments of long-term debt	✓	✓

Potential risks associated with our planned levels of liquidity discussed above include those previously discussed in Company Outlook.

As of December 31, 2017, we had a working capital deficit of $467 million. Our available liquidity is as follows:

Available Liquidity	December 31, 2017		
	WPZ	WMB	Total
		(Millions)	
Cash and cash equivalents	$ 881	$ 18	$ 899
Capacity available under our $1.5 billion credit facility (1)		1,230	1,230
Capacity available to WPZ under its $3.5 billion credit facility, less amounts outstanding under its $3 billion commercial paper program (2)	3,500		3,500
	$ 4,381	$ 1,248	$ 5,629

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(1) The highest amount outstanding under our credit facility during 2017 was $805 million. At December 31, 2017, we were in compliance with the financial covenants associated with this credit facility. See Note 13 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements for additional information on our credit facility. Borrowing capacity available under this facility as of February 20, 2018, was $1.5 billion.

(2) In managing our available liquidity, we do not expect a maximum outstanding amount in excess of the capacity of WPZ's credit facility inclusive of any outstanding amounts under its commercial paper program. As of December 31, 2017, no *Commercial paper* was outstanding under WPZ's commercial paper program. The highest amount outstanding under WPZ's commercial paper program and credit facility during 2017 was $178 million. At December 31, 2017, WPZ was in compliance with the financial covenants associated with this credit facility. See Note 13 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements for additional information on WPZ's credit facility and WPZ's commercial paper program. Borrowing capacity available under WPZ's $3.5 billion credit facility as of February 20, 2018, was $3.5 billion.

As described in Note 13 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements, we have determined that we have net assets that are technically considered restricted in accordance with Rule 4-08(e) of Regulation S-X of the Securities and Exchange Commission in excess of 25 percent of our consolidated net assets. We do not expect this determination will impact our ability to pay dividends or meet future obligations as the terms of WPZ's partnership agreement require it to make quarterly distributions of all available cash, as defined, to its unitholders.

Dividends

As part of the Financial Repositioning, we increased our regular quarterly cash dividend by 50 percent from the previous quarterly dividend of $0.20 per share paid in December 2016, to $0.30 per share for the dividends paid in each quarter of 2017.

Registrations

In September 2016, WPZ filed a registration statement for its distribution reinvestment program.

In May 2015, we filed a shelf registration statement, as a well-known seasoned issuer.

In February 2015, WPZ filed a shelf registration statement, as a well-known seasoned issuer, registering common units representing limited partner interests and debt securities. Also in February 2015, WPZ filed a shelf registration statement for the offer and sale from time to time of common units representing limited partner interests in WPZ having an aggregate offering price of up to $1 billion. These sales are to be made over a period of time and from time to time in transactions at prices which are market prices prevailing at the time of sale, prices related to market price, or at negotiated prices. Such sales are to be made pursuant to an equity distribution agreement between WPZ and certain banks who may act as sales agents or purchase for their own accounts as principals. During 2016 and 2015, WPZ received net proceeds of approximately $115 million and approximately $59 million, respectively, from equity issued under this registration; there was no activity during 2017.

Distributions from Equity-Method Investees

The organizational documents of entities in which we have an equity-method investment generally require distribution of their available cash to their members on a quarterly basis. In each case, available cash is reduced, in part, by reserves appropriate for operating their respective businesses. (See Note 5 – Investing Activities of Notes to Consolidated Financial Statements for our more significant equity-method investees.)

Credit Ratings

Our ability to borrow money is impacted by our credit ratings and the credit ratings of WPZ. The current ratings are as follows:

	Rating Agency	Outlook	Senior Unsecured Debt Rating	Corporate Credit Rating
WMB:	S&P Global Ratings	Stable	BB+	BB+
	Moody’s Investors Service	Positive	Ba2	N/A
	Fitch Ratings	Stable	BB+	N/A
WPZ:	S&P Global Ratings	Stable	BBB	BBB
	Moody’s Investors Service	Positive	Baa3	N/A
	Fitch Ratings	Positive	BBB-	N/A

During March 2017, S&P Global Ratings upgraded its rating for both WMB and WPZ. These credit ratings are included for informational purposes and are not recommendations to buy, sell, or hold our or WPZ’s securities, and each rating should be evaluated independently of any other rating. No assurance can be given that the credit rating agencies will continue to assign us or WPZ the ratings shown above even if we or WPZ meet or exceed their current criteria. A downgrade of our credit ratings or the credit ratings of WPZ might increase our future cost of borrowing and would require us to provide additional collateral to third parties, negatively impacting our available liquidity.

Sources (Uses) of Cash

The following table summarizes the sources (uses) of cash and cash equivalents for each of the periods presented (see Notes to Consolidated Financial Statements for the Notes referenced in the table):

	Cash Flow Category	Years Ended December 31, 2017	2016	2015
		(Millions)		
Sources of cash and cash equivalents:				
Operating activities – net	Operating	$ 2,556	$ 3,680	$ 2,708
Proceeds from equity offerings	Financing	2,131	123	86
Proceeds from sale of businesses, net of cash divested (see Note 2)	Investing	2,067	1,020	—
Proceeds from long-term debt (see Note 13)	Financing	1,698	998	3,842
Proceeds from our credit-facility borrowings	Financing	1,635	2,280	2,097
Distributions from unconsolidated affiliates in excess of cumulative earnings	Investing	529	472	404
Contributions in aid of construction	Investing	426	218	87
Proceeds from dispositions of equity-method investments (see Note 5)	Investing	200	34	—
Contributions from noncontrolling interests	Financing	17	29	111
Proceeds from WPZ's credit-facility borrowings	Financing	—	3,250	3,832
Special distribution from Gulfstream (see Note 5)	Financing	—	—	396
Uses of cash and cash equivalents:				
Payments of long-term debt (see Note 13)	Financing	(3,785)	(375)	(1,533)
Capital expenditures	Investing	(2,399)	(2,051)	(3,167)
Payments on our credit-facility borrowings	Financing	(2,140)	(2,155)	(1,817)
Dividends paid	Financing	(992)	(1,261)	(1,836)
Dividends and distributions paid to noncontrolling interests	Financing	(822)	(940)	(942)
Purchases of and contributions to equity-method investments	Investing	(132)	(177)	(595)
Payments of WPZ's commercial paper – net	Financing	(93)	(409)	(306)
Payments on WPZ's credit-facility borrowings	Financing	—	(4,560)	(3,162)
Contribution to Gulfstream for repayment of debt (see Note 5)	Financing	—	(148)	(248)
Purchases of businesses, net of cash acquired	Investing	—	—	(112)
Other sources / (uses) – net	Financing and Investing	(167)	42	15
Increase (decrease) in cash and cash equivalents		$ 729	$ 70	$ (140)

Operating activities

The factors that determine operating activities are largely the same as those that affect *Net income (loss)*, with the exception of noncash items such as *Depreciation and amortization*, *Provision (benefit) for deferred income taxes*, *Net (gain) loss on disposition of equity-method investments*, *Impairment of goodwill*, *Impairment of equity-method investments*, *Impairment of and net (gain) loss on sale of assets and businesses*, *Gain on sale of Geismar Interest*, and *Regulatory charges resulting from Tax Reform.*

Our *Net cash provided (used) by operating activities* in 2017 decreased from 2016 primarily due to the absence in 2017 of receipts from 2016 contract restructurings, partially offset by higher operating income in 2017.

Our *Net cash provided (used) by operating activities* in 2016 increased from 2015 primarily due to the impact of net favorable changes in operating working capital and receipts from contract restructurings.

Off-Balance Sheet Arrangements and Guarantees of Debt or Other Commitments

We have various other guarantees and commitments which are disclosed in Note 3 – Variable Interest Entities, Note 10 – Property, Plant, and Equipment, Note 13 – Debt, Banking Arrangements, and Leases, Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk, and Note 17 – Contingent Liabilities and Commitments of Notes to Consolidated Financial Statements. We do not believe these guarantees and commitments or the possible fulfillment of them will prevent us from meeting our liquidity needs.

Contractual Obligations

The table below summarizes the maturity dates of our contractual obligations at December 31, 2017:

	2018	2019 - 2020	2021 - 2022	Thereafter	Total
			(Millions)		
Long-term debt: (1)					
Principal	$ 502	$ 2,156	$ 3,146	$ 15,277	$ 21,081
Interest	1,049	1,995	1,743	7,795	12,582
Operating leases	44	74	62	137	317
Purchase obligations (2)	1,171	914	632	277	2,994
Other obligations (3)(4)	1	2	1	1	5
Total	$ 2,767	$ 5,141	$ 5,584	$ 23,487	$ 36,979

(1) Includes the borrowings outstanding under credit facilities, but does not include any related variable-rate interest payments.

(2) Includes approximately $348 million in open property, plant, and equipment purchase orders. Includes an estimated $314 million long-term ethane purchase obligation with index-based pricing terms that is reflected in this table at December 31, 2017 prices. This obligation is part of an overall exchange agreement whereby volumes we transport on OPPL are sold at a third-party fractionator near Conway, Kansas, and we are subsequently obligated to purchase ethane volumes at Mont Belvieu. The purchased ethane volumes may be utilized or sold at comparable prices in the Mont Belvieu market. Includes an estimated $454 million long-term ethane purchase obligation with index-based pricing terms that primarily supplies third parties at their plants and is valued in this table at a price calculated using December 31, 2017 prices. Any excess purchased volumes may be sold at comparable market prices. Includes an estimated $765 million long-term mixed NGLs purchase obligation with index-based pricing terms that is reflected in this table at December 31, 2017 prices. Includes an estimated $278 million long-term ethane purchase obligation with index-based pricing terms that primarily supplies a third party for consumption at their plant and is reflected in this table at a price calculated using December 31, 2017 prices. Any excess purchased volumes may be sold at comparable market prices. In addition, we have not included certain natural gas life-of-lease contracts for which the future volumes are indeterminable. We have not included commitments, beyond purchase orders, for the acquisition or construction of property, plant, and equipment or expected contributions to our jointly owned investments. (See Company Outlook — Expansion Projects.)

(3) Does not include estimated contributions to our pension and other postretirement benefit plans. We made contributions to our pension and other postretirement benefit plans of $90 million in 2017 and $72 million in 2016. In 2018, we expect to contribute approximately $91 million to these plans (see Note 9 – Employee Benefit Plans of Notes to Consolidated Financial Statements). Tax-qualified pension plans are required to meet minimum contribution requirements. In the past, we have contributed amounts to our tax-qualified pension plans in excess of the minimum required contribution. These excess amounts can be used to offset future minimum contribution requirements. During 2017, we contributed $80 million to our tax-qualified pension plans. In addition to these contributions, a portion of the excess contributions was used to meet the minimum contribution requirements. During 2018, we expect to contribute approximately $80 million to our tax-qualified pension plans and use excess amounts to satisfy minimum contribution requirements, if needed. Additionally, estimated future minimum funding requirements may vary significantly from historical requirements if actual results differ significantly from estimated results for assumptions such as returns on plan assets, interest rates, retirement rates, mortality, and other significant assumptions or by changes to current legislation and regulations.

(4) We have not included income tax liabilities in the table above. See Note 7 – Provision (Benefit) for Income Taxes of Notes to Consolidated Financial Statements for a discussion of income taxes, including our contingent tax liability reserves.

Effects of Inflation

Our operations have historically not been materially affected by inflation. Approximately 43 percent of our gross property, plant, and equipment is comprised of our interstate natural gas pipeline assets. They are subject to regulation, which limits recovery to historical cost. While amounts in excess of historical cost are not recoverable under current FERC practices, we anticipate being allowed to recover and earn a return based on increased actual cost incurred to replace existing assets. Cost-based regulations, along with competition and other market factors, may limit our ability to recover such increased costs. For our gathering and processing assets, operating costs are influenced to a greater extent by both competition for specialized services and specific price changes in crude oil and natural gas and related commodities than by changes in general inflation. Crude oil, natural gas, and NGL prices are particularly sensitive to the market perceptions concerning the supply and demand balance in the near future, as well as general economic conditions. However, our exposure to certain of these price changes is reduced through the fee-based nature of certain of our services and the use of hedging instruments.

Environmental

We are a participant in certain environmental activities in various stages including assessment studies, cleanup operations, and/or remedial processes at certain sites, some of which we currently do not own (see Note 17 – Contingent Liabilities and Commitments of Notes to Consolidated Financial Statements). We are monitoring these sites in a coordinated effort with other potentially responsible parties, the EPA, or other governmental authorities. We are jointly and severally liable along with unrelated third parties in some of these activities and solely responsible in others. Current estimates of the most likely costs of such activities are approximately $38 million, all of which are included in *Accrued liabilities* and *Regulatory liabilities, deferred income, and other* in the Consolidated Balance Sheet at December 31, 2017. We will seek recovery of the accrued costs related to remediation activities by our interstate gas pipelines totaling approximately $7 million through future natural gas transmission rates. The remainder of these costs will be funded from operations. During 2017, we paid approximately $6 million for cleanup and/or remediation and monitoring activities. We expect to pay approximately $10 million in 2018 for these activities. Estimates of the most likely costs of cleanup are generally based on completed assessment studies, preliminary results of studies, or our experience with other similar cleanup operations. At December 31, 2017, certain assessment studies were still in process for which the ultimate outcome may yield different estimates of most likely costs. Therefore, the actual costs incurred will depend on the final amount, type, and extent of contamination discovered at these sites, the final cleanup standards mandated by the EPA or other governmental authorities, and other factors.

The EPA and various state regulatory agencies routinely promulgate and propose new rules, and issue updated guidance to existing rules. More recent rules and rulemakings include, but are not limited to, rules for reciprocating internal combustion engine maximum achievable control technology, air quality standards for one hour nitrogen dioxide emissions, and volatile organic compound and methane new source performance standards impacting design and operation of storage vessels, pressure valves, and compressors. On October 1, 2015, the EPA issued its rule regarding National Ambient Air Quality Standards for ground-level ozone, setting a stricter standard of 70 parts per billion. We are monitoring the rule's implementation as the reduction will trigger additional federal and state regulatory actions that may impact our operations. Implementation of the regulations is expected to result in impacts to our operations and increase the cost of additions to *Property, plant, and equipment – net* in the Consolidated Balance Sheet for both new and existing facilities in affected areas. We are unable to reasonably estimate the cost of additions that may be required to meet the regulations at this time due to uncertainty created by various legal challenges to these regulations and the need for further specific regulatory guidance.

Our interstate natural gas pipelines consider prudently incurred environmental assessment and remediation costs and the costs associated with compliance with environmental standards to be recoverable through rates.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio. Our debt portfolio is primarily comprised of fixed rate debt, which mitigates the impact of fluctuations in interest rates. Any borrowings under the credit facilities and any issuances under WPZ's commercial paper program could be at a variable interest rate and could expose us to the risk of increasing interest rates. The maturity of our long-term debt portfolio is partially influenced by the expected lives of our operating assets. (See Note 13 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements.)

The tables below provide information by maturity date about our interest rate risk-sensitive instruments as of December 31, 2017 and 2016. The fair value of our publicly traded long-term debt is valued using indicative year-end traded bond market prices. Private debt is valued based on market rates and the prices of similar securities with similar terms and credit ratings.

	2018	2019	2020	2021	2022	Thereafter (1)	Total	Fair Value December 31, 2017
					(Millions)			
Long-term debt, including current portion:								
Fixed rate	$ 502	$ 33	$ 2,123	$ 873	$ 2,003	$ 15,131	$ 20,665	$ 22,735
Weighted-average interest rate	5.1%	5.1%	5.1%	5.1%	5.2%	5.7%		
Variable rate (2)	$ —	$ —	$ —	$ 270	$ —	$ —	$ 270	$ 270

	2017	2018	2019	2020	2021	Thereafter (1)	Total	Fair Value December 31, 2016
					(Millions)			
Long-term debt, including current portion:								
Fixed rate	$ 785	$ 500	$ 32	$ 2,121	$ 871	$ 17,475	$ 21,784	$ 22,465
Weighted-average interest rate	5.2%	5.2%	5.2%	5.2%	5.2%	5.6%		
Variable rate (3)	$ —	$ 850	$ —	$ 775	$ —	$ —	$ 1,625	$ 1,625
Commercial paper:								
Variable rate (4)	$ 93	$ —	$ —	$ —	$ —	$ —	$ 93	$ 93

(1) Includes unamortized discount / premium and debt issuance costs.

(2) The weighted-average interest rate for our $270 million credit facility borrowing at December 31, 2017 was 3.16 percent.

(3) The weighted-average interest rates for WPZ's $850 million term loan and our $775 million credit facility borrowing at December 31, 2016 were 2.50 percent and 2.51 percent, respectively.

(4) The weighted-average interest rate was 1.06 percent at December 31, 2016.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of NGLs and natural gas, as well as other market factors, such as market volatility and energy commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts, and limited proprietary trading activities. Our management of the risks associated with these market fluctuations includes maintaining sufficient liquidity, as well as using various derivatives and nonderivative energy-related contracts. The fair value of derivative contracts is subject to many factors, including changes in energy commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted, and changes in interest rates. At December 31, 2017 and 2016, our derivative activity was not material. (See Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements.)

Item 8. ***Financial Statements and Supplementary Data***

Report of Independent Registered Public Accounting Firm

The Stockholders and the Board of Directors of
The Williams Companies, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of The Williams Companies, Inc. (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and financial statement schedules listed in the index at Item 15(a) (collectively referred to as the "consolidated financial statements"). In our opinion, based on our audits and the reports of other auditors, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2017 and 2016, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We did not audit the financial statements of Gulfstream Natural Gas System, L.L.C. ("Gulfstream"), a limited liability corporation in which the Company has a 50 percent interest. In the consolidated financial statements, the Company's investment in Gulfstream was $244 million and $261 million as of December 31, 2017 and 2016, respectively, and the Company's equity earnings in the net income of Gulfstream were $75 million in 2017, $69 million in 2016 and $65 million in 2015. Gulfstream's financial statements were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Gulfstream, is based solely on the reports of the other auditors.

We also have 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, 2017, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 22, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated financial statements. We believe that our audits and the reports of other auditors provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 1962.
Tulsa, Oklahoma
February 22, 2018

Report of Independent Registered Public Accounting Firm

To the Management Committee and Members of Gulfstream Natural Gas System, L.L.C.:

Opinion on the Financial Statements

We have audited the balance sheet of Gulfstream Natural Gas System, L.L.C. (the "Company") as of December 31, 2017, and the related statements of operations, comprehensive income, cash flows, and members' equity for the year then ended, including the related notes (collectively referred to as the "financial statements;" not presented herein). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

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 audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("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 of these financial statements in accordance with the standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. 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 audit 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 audit 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 audit provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 22, 2018

We have served as the Company's auditor since 2018.

Report of Independent Registered Public Accounting Firm

To the Members of Gulfstream Natural Gas System, L.L.C.

We have audited the balance sheet of Gulfstream Natural Gas System, L.L.C. (the "Company") as of December 31, 2016, and the related statement of operations, comprehensive income, cash flows, and members' equity for each of the two years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States) and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Gulfstream Natural Gas System, L.L.C. as of December 31, 2016, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 22, 2017

The Williams Companies, Inc.
Consolidated Statement of Operations

	Years Ended December 31,		
	2017	2016	2015
	(Millions, except per-share amounts)		
Revenues:			
Service revenues	$ 5,312	$ 5,171	$ 5,164
Product sales	2,719	2,328	2,196
Total revenues	8,031	7,499	7,360
Costs and expenses:			
Product costs	2,300	1,725	1,779
Operating and maintenance expenses	1,585	1,580	1,655
Depreciation and amortization expenses	1,736	1,763	1,738
Selling, general, and administrative expenses	608	723	741
Impairment of goodwill (Note 16)	—	—	1,098
Impairment of certain assets (Note 16)	1,248	873	209
Gain on sale of Geismar Interest (Note 2)	(1,095)	—	—
Regulatory charges resulting from Tax Reform (Note 1)	674	—	—
Insurance recoveries – Geismar Incident	(9)	(7)	(126)
Other (income) expense – net	80	142	40
Total costs and expenses	7,127	6,799	7,134
Operating income (loss)	904	700	226
Equity earnings (losses)	434	397	335
Impairment of equity-method investments (Note 16)	—	(430)	(1,359)
Other investing income (loss) – net	282	63	27
Interest incurred	(1,116)	(1,217)	(1,118)
Interest capitalized	33	38	74
Other income (expense) – net	(2)	74	102
Income (loss) before income taxes	535	(375)	(1,713)
Provision (benefit) for income taxes	(1,974)	(25)	(399)
Net income (loss)	2,509	(350)	(1,314)
Less: Net income (loss) attributable to noncontrolling interests	335	74	(743)
Net income (loss) attributable to The Williams Companies, Inc.	$ 2,174	$ (424)	$ (571)
Basic earnings (loss) per common share:			
Net income (loss)	$ 2.63	$ (.57)	$ (.76)
Weighted-average shares (thousands)	826,177	750,673	749,271
Diluted earnings (loss) per common share:			
Net income (loss)	$ 2.62	$ (.57)	$ (.76)
Weighted-average shares (thousands)	828,518	750,673	749,271

See accompanying notes.

The Williams Companies, Inc.
Consolidated Statement of Comprehensive Income (Loss)

	Years Ended December 31,		
	2017	2016	2015
		(Millions)	
Net income (loss)	$ 2,509	$ (350)	$ (1,314)
Other comprehensive income (loss):			
Cash flow hedging activities:			
Net unrealized gain (loss) from derivative instruments, net of taxes of $2, ($1), and $0 in 2017, 2016, and 2015, respectively	(9)	4	6
Reclassifications into earnings of net derivative instruments (gain) loss, net of taxes of ($1) in 2017, and $1 in 2016 and 2015	6	(2)	(6)
Foreign currency translation activities:			
Foreign currency translation adjustments, net of taxes of $0, ($37), and $31 in 2017, 2016, and 2015, respectively	1	50	(204)
Reclassification into earnings upon sale of foreign entities, net of taxes of ($36) in 2016	—	119	—
Pension and other postretirement benefits:			
Amortization of prior service cost (credit) included in net periodic benefit cost (credit), net of taxes of $2, $2, and $3 in 2017, 2016, and 2015, respectively	(3)	(4)	(3)
Net actuarial gain (loss) arising during the year, net of taxes of ($15), $8, and ($5) in 2017, 2016 and 2015, respectively	44	(15)	8
Amortization of actuarial (gain) loss and net actuarial loss from settlements included in net periodic benefit cost (credit), net of taxes of ($37), ($12), and ($18) in 2017, 2016, and 2015, respectively (Note 9)	61	20	28
Other comprehensive income (loss)	100	172	(171)
Comprehensive income (loss)	2,609	(178)	(1,485)
Less: Comprehensive income (loss) attributable to noncontrolling interests	334	143	(813)
Comprehensive income (loss) attributable to The Williams Companies, Inc.	$ 2,275	$ (321)	$ (672)

See accompanying notes.

The Williams Companies, Inc.
Consolidated Balance Sheet

	December 31,	
	2017	2016
	(Millions, except per-share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 899	$ 170
Trade accounts and other receivables (net of allowance of $9 at December 31, 2017 and $6 at December 31, 2016)	976	938
Inventories	113	138
Other current assets and deferred charges	191	216
Total current assets	2,179	1,462
Investments	6,552	6,701
Property, plant, and equipment – net	28,211	28,428
Intangible assets – net of accumulated amortization	8,791	9,663
Regulatory assets, deferred charges, and other	619	581
Total assets	$ 46,352	$ 46,835
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 978	$ 623
Accrued liabilities	1,167	1,448
Commercial paper	—	93
Long-term debt due within one year	501	785
Total current liabilities	2,646	2,949
Long-term debt	20,434	22,624
Deferred income tax liabilities	3,147	4,238
Regulatory liabilities, deferred income, and other	3,950	2,978
Contingent liabilities and commitments (Note 17)		
Equity:		
Stockholders' equity:		
Common stock (960 million shares authorized at $1 par value; 861 million shares issued at December 31, 2017 and 785 million shares issued at December 31, 2016)	861	785
Capital in excess of par value	18,508	14,887
Retained deficit	(8,434)	(9,649)
Accumulated other comprehensive income (loss)	(238)	(339)
Treasury stock, at cost (35 million shares of common stock)	(1,041)	(1,041)
Total stockholders' equity	9,656	4,643
Noncontrolling interests in consolidated subsidiaries	6,519	9,403
Total equity	16,175	14,046
Total liabilities and equity	$ 46,352	$ 46,835

See accompanying notes.

The Williams Companies, Inc.
Consolidated Statement of Changes in Equity

	The Williams Companies, Inc., Stockholders							
	Common Stock	Capital in Excess of Par Value	Retained Deficit	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Stockholders' Equity	Noncontrolling Interests	Total Equity
	(Millions)							
Balance – December 31, 2014	$ 782	$ 14,925	$ (5,548)	$ (341)	$ (1,041)	$ 8,777	$ 11,395	$ 20,172
Net income (loss)	—	—	(571)	—	—	(571)	(743)	(1,314)
Other comprehensive income (loss)	—	—	—	(101)	—	(101)	(70)	(171)
Cash dividends – common stock (Note 14)	—	—	(1,836)	—	—	(1,836)	—	(1,836)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	(942)	(942)
Stock-based compensation and related common stock issuances, net of tax	2	28	—	—	—	30	—	30
Sales of limited partner units of Williams Partners L.P.	—	—	—	—	—	—	59	59
Changes in ownership of consolidated subsidiaries, net	—	(160)	—	—	—	(160)	254	94
Contributions from noncontrolling interests	—	—	—	—	—	—	111	111
Other	—	14	(5)	—	—	9	13	22
Net increase (decrease) in equity	2	(118)	(2,412)	(101)	—	(2,629)	(1,318)	(3,947)
Balance – December 31, 2015	784	14,807	(7,960)	(442)	(1,041)	6,148	10,077	16,225
Net income (loss)	—	—	(424)	—	—	(424)	74	(350)
Other comprehensive income (loss)	—	—	—	103	—	103	69	172
Cash dividends – common stock (Note 14)	—	—	(1,261)	—	—	(1,261)	—	(1,261)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	(940)	(940)
Stock-based compensation and related common stock issuances, net of tax	1	56	—	—	—	57	—	57
Sales of limited partner units of Williams Partners L.P.	—	—	—	—	—	—	114	114
Changes in ownership of consolidated subsidiaries, net	—	12	—	—	—	12	(18)	(6)
Contributions from noncontrolling interests	—	—	—	—	—	—	29	29
Other	—	12	(4)	—	—	8	(2)	6
Net increase (decrease) in equity	1	80	(1,689)	103	—	(1,505)	(674)	(2,179)
Balance – December 31, 2016	785	14,887	(9,649)	(339)	(1,041)	4,643	9,403	14,046
Net income (loss)	—	—	2,174	—	—	2,174	335	2,509
Other comprehensive income (loss)	—	—	—	101	—	101	(1)	100
Issuance of common stock (Note 14)	75	2,043	—	—	—	2,118	—	2,118
Cash dividends – common stock (Note 14)	—	—	(992)	—	—	(992)	—	(992)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	(883)	(883)
Stock-based compensation and related common stock issuances, net of tax	1	73	—	—	—	74	—	74
Adoption of ASU 2016-09 (Note 1)	—	1	36	—	—	37	—	37
Sales of limited partner units of Williams Partners L.P.	—	—	—	—	—	—	61	61
Changes in ownership of consolidated subsidiaries, net	—	1,497	—	—	—	1,497	(2,407)	(910)
Contributions from noncontrolling interests	—	—	—	—	—	—	17	17
Other	—	7	(3)	—	—	4	(6)	(2)
Net increase (decrease) in equity	76	3,621	1,215	101	—	5,013	(2,884)	2,129
Balance – December 31, 2017	$ 861	$ 18,508	$ (8,434)	$ (238)	$ (1,041)	$ 9,656	$ 6,519	$ 16,175

See accompanying notes.

The Williams Companies, Inc.
Consolidated Statement of Cash Flows

	Years Ended December 31,		
	2017	2016	2015
	(Millions)		
OPERATING ACTIVITIES:			
Net income (loss)	$ 2,509	$ (350)	$ (1,314)
Adjustments to reconcile to net cash provided (used) by operating activities:			
Depreciation and amortization	1,736	1,763	1,738
Provision (benefit) for deferred income taxes	(2,012)	(26)	(337)
Net (gain) loss on disposition of equity-method investments	(269)	(27)	—
Impairment of goodwill	—	—	1,098
Impairment of equity-method investments	—	430	1,359
Impairment of and net (gain) loss on sale of assets and businesses	1,249	918	215
Gain on sale of Geismar Interest (Note 2)	(1,095)	—	—
Amortization of stock-based awards	78	73	82
Regulatory charges resulting from Tax Reform (Note 1)	776	—	—
Cash provided (used) by changes in current assets and liabilities:			
Accounts and notes receivable	(88)	82	39
Inventories	8	(25)	105
Other current assets and deferred charges	(21)	(4)	4
Accounts payable	118	35	(88)
Accrued liabilities	(92)	512	54
Other, including changes in noncurrent assets and liabilities	(341)	299	(247)
Net cash provided (used) by operating activities	2,556	3,680	2,708
FINANCING ACTIVITIES:			
Proceeds from (payments of) commercial paper – net	(93)	(409)	(306)
Proceeds from long-term debt	3,333	6,528	9,772
Payments of long-term debt	(5,925)	(7,091)	(6,516)
Proceeds from issuance of common stock	2,131	9	27
Proceeds from sale of limited partner units of consolidated partnership	—	114	59
Dividends paid	(992)	(1,261)	(1,836)
Dividends and distributions paid to noncontrolling interests	(822)	(940)	(942)
Contributions from noncontrolling interests	17	29	111
Payments for debt issuance costs	(17)	(9)	(35)
Special distribution from Gulfstream	—	—	396
Contribution to Gulfstream for repayment of debt	—	(148)	(248)
Other – net	(92)	(16)	(31)
Net cash provided (used) by financing activities	(2,460)	(3,194)	451
INVESTING ACTIVITIES:			
Property, plant, and equipment:			
Capital expenditures (1)	(2,399)	(2,051)	(3,167)
Dispositions – net	(41)	30	3
Contributions in aid of construction	426	218	87
Proceeds from sale of businesses, net of cash divested	2,067	1,020	—
Proceeds from dispositions of equity-method investments	200	34	—
Purchases of businesses, net of cash acquired	—	—	(112)
Purchases of and contributions to equity-method investments	(132)	(177)	(595)
Distributions from unconsolidated affiliates in excess of cumulative earnings	529	472	404
Other – net	(17)	38	81
Net cash provided (used) by investing activities	633	(416)	(3,299)
Increase (decrease) in cash and cash equivalents	729	70	(140)
Cash and cash equivalents at beginning of year	170	100	240
Cash and cash equivalents at end of year	$ 899	$ 170	$ 100

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(1) Increases to property, plant, and equipment	$ (2,662)	$ (1,912)	$ (3,024)
Changes in related accounts payable and accrued liabilities	263	(139)	(143)
Capital expenditures	$ (2,399)	$ (2,051)	$ (3,167)

See accompanying notes.

Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies

General

Unless the context clearly indicates otherwise, references in this report to "Williams," "we," "our," "us," or like terms refer to The Williams Companies, Inc. and its subsidiaries. Unless the context clearly indicates otherwise, references to "Williams," "we," "our," and "us" include the operations in which we own interests accounted for as equity-method investments that are not consolidated in our financial statements. When we refer to our equity investees by name, we are referring exclusively to their businesses and operations.

Financial Repositioning

In January 2017, we entered into agreements with Williams Partners L.P. (WPZ), wherein we permanently waived the general partner's incentive distribution rights (IDRs) and converted our 2 percent general partner interest in WPZ to a noneconomic interest in exchange for 289 million newly issued WPZ common units. Pursuant to this agreement, we also purchased approximately 277 thousand WPZ common units for $10 million. Additionally, we purchased approximately 59 million common units of WPZ at a price of $36.08586 per unit in a private placement transaction, funded with proceeds from our equity offering (see Note 14 – Stockholders' Equity). According to the terms of this agreement, concurrent with WPZ's quarterly distributions in February 2017 and May 2017, we paid additional consideration totaling $56 million to WPZ for these units. Subsequent to these transactions and as of December 31, 2017, we own a 74 percent limited partner interest in WPZ.

Termination of WPZ Merger Agreement

On May 12, 2015, we entered into an agreement for a unit-for-stock transaction whereby we would have acquired all of the publicly held outstanding common units of WPZ in exchange for shares of our common stock (WPZ Merger Agreement).

On September 28, 2015, we entered into a Termination Agreement and Release (Termination Agreement), terminating the WPZ Merger Agreement. Under the terms of the Termination Agreement, we were required to pay a $428 million termination fee to WPZ, at which time we owned approximately 60 percent, including the interests of the general partner and IDRs. Such termination fee settled through a reduction of quarterly incentive distributions we were entitled to receive from WPZ (such reduction not to exceed $209 million per quarter). The distributions from WPZ in November 2015, February 2016, and May 2016 were reduced by $209 million, $209 million, and $10 million, respectively, related to this termination fee.

ACMP Merger

On February 2, 2015, Williams Partners L.P. merged with and into Access Midstream Partners, L.P. (ACMP Merger). For the purpose of these financial statements and notes, WPZ refers to the renamed merged partnership, while Pre-merger Access Midstream Partners, L.P. (ACMP) and Pre-merger Williams Partners L.P. (Pre-merger WPZ) refer to the separate partnerships prior to the consummation of the ACMP Merger and subsequent name change. The net assets of Pre-merger WPZ and ACMP were combined at our historical basis. Our basis in ACMP reflected our business combination accounting resulting from acquiring control of ACMP on July 1, 2014.

Description of Business

We are a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange. Our operations are located principally in the United States. We have one reportable segment, Williams Partners. All remaining business activities are included in Other.

Williams Partners

Williams Partners consists of our consolidated master limited partnership, WPZ, and primarily includes gas pipeline and midstream businesses.

WPZ's gas pipeline businesses primarily consist of two interstate natural gas pipelines, which are Transcontinental Gas Pipe Line Company, LLC (Transco) and Northwest Pipeline LLC (Northwest Pipeline), and several joint venture investments in interstate and intrastate natural gas pipeline systems, including a 50 percent equity-method investment in Gulfstream Natural Gas System, L.L.C. (Gulfstream), and a 41 percent interest in Constitution Pipeline Company, LLC (Constitution) (a consolidated entity), which is developing a pipeline project (see Note 3 – Variable Interest Entities).

WPZ's midstream businesses primarily consist of (1) natural gas gathering, treating, compression, and processing; (2) natural gas liquid (NGL) fractionation, storage, and transportation; (3) crude oil production handling and transportation; and (4) olefins production (see Note 2 – Acquisitions and Divestitures). The primary service areas are concentrated in major producing basins in Colorado, Texas, Oklahoma, Kansas, New Mexico, Wyoming, the Gulf of Mexico, Louisiana, Pennsylvania, West Virginia, New York, and Ohio, which include the Barnett, Eagle Ford, Haynesville, Marcellus, Niobrara, and Utica shale plays as well as the Mid-Continent region.

The midstream businesses include equity-method investments in natural gas gathering and processing assets and NGL fractionation and transportation assets, including a 62 percent equity-method investment in Utica East Ohio Midstream, LLC (UEOM), a 69 percent equity-method investment in Laurel Mountain Midstream, LLC (Laurel Mountain), a 58 percent equity-method investment in Caiman Energy II, LLC (Caiman II), a 60 percent equity-method investment in Discovery Producer Services, LLC (Discovery), a 50 percent equity-method investment in Overland Pass Pipeline, LLC (OPPL), and Appalachia Midstream Services, LLC, which owns equity-method investments with an approximate average 66 percent interest in multiple gathering systems in the Marcellus Shale (Appalachia Midstream Investments), as well as our previously owned 50 percent equity-method investment in the Delaware basin gas gathering system (DBJV) in the Mid-Continent region (see Note 5 – Investing Activities).

The midstream businesses also included our Canadian midstream operations, which were comprised of an oil sands offgas processing plant near Fort McMurray, Alberta, and an NGL/olefin fractionation facility at Redwater, Alberta. In September 2016, we completed the sale of our Canadian operations. (See Note 2 – Acquisitions and Divestitures.)

Other

Other is comprised of business activities that are not operating segments, as well as corporate operations. Other also includes certain domestic olefins pipeline assets as well as certain Canadian assets, which included a liquids extraction plant located near Fort McMurray, Alberta, that began operations in March 2016, and a propane dehydrogenation facility which was under development. In September 2016, the Canadian assets were sold. (See Note 2 – Acquisitions and Divestitures.)

Basis of Presentation

Consolidated master limited partnership

As of December 31, 2017, we owned approximately 74 percent of the interests in WPZ, a variable interest entity (VIE) (see Note 3 – Variable Interest Entities).

Pursuant to WPZ's distribution reinvestment program, 1,606,448 common units were issued to the public during 2017 associated with reinvested distributions of $61 million. These common unit issuances, the Financial Repositioning, WPZ's quarterly distribution of additional paid-in-kind Class B units to us, and other equity issuances by WPZ had the combined net impact of decreasing *Noncontrolling interests in consolidated subsidiaries* by $2.407 billion, and increasing *Capital in excess of par value* by $1.497 billion and *Deferred income tax liabilities* by $910 million in the Consolidated Balance Sheet.

WPZ is self-funding and maintains separate lines of bank credit and cash management accounts and also has a commercial paper program. (See Note 13 – Debt, Banking Arrangements, and Leases.) Cash distributions from WPZ to all partners, including us, are governed by WPZ's partnership agreement.

Discontinued operations

Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates to our continuing operations.

Significant risks and uncertainties

We may monetize assets that are not core to our strategy which could result in impairments of certain equity-method investments, property, plant, and equipment, and intangible assets. Such impairments could potentially be caused by indications of fair value implied through the monetization process or, in the case of asset dispositions that are part of a broader asset group, the impact of the loss of future estimated cash flows.

Summary of Significant Accounting Policies

Principles of consolidation

The consolidated financial statements include the accounts of all entities that we control and our proportionate interest in the accounts of certain ventures in which we own an undivided interest. Our judgment is required to evaluate whether we control an entity. Key areas of that evaluation include:

- Determining whether an entity is a VIE;
- Determining whether we are the primary beneficiary of a VIE, including evaluating which activities of the VIE most significantly impact its economic performance and the degree of power that we and our related parties have over those activities through our variable interests;
- Identifying events that require reconsideration of whether an entity is a VIE and continuously evaluating whether we are a VIE's primary beneficiary;
- Evaluating whether other owners in entities that are not VIEs are able to effectively participate in significant decisions that would be expected to be made in the ordinary course of business such that we do not have the power to control such entities.

We apply the equity method of accounting to investments over which we exercise significant influence but do not control.

Equity-method investment basis differences

Differences between the cost of our equity-method investments and our underlying equity in the net assets of investees are accounted for as if the investees were consolidated subsidiaries. *Equity earnings (losses)* in the Consolidated Statement of Operations includes our allocable share of net income (loss) of investees adjusted for any depreciation and amortization, as applicable, associated with basis differences.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Significant estimates and assumptions include:

- Impairment assessments of investments, property, plant, and equipment, goodwill, and other identifiable intangible assets;
- Litigation-related contingencies;
- Environmental remediation obligations;
- Realization of deferred income tax assets;
- Depreciation and/or amortization of equity-method investment basis differences;
- Asset retirement obligations;
- Pension and postretirement valuation variables;
- Measurement of regulatory liabilities;
- Measurement of deferred income tax assets and liabilities.

These estimates are discussed further throughout these notes.

Regulatory accounting

Transco and Northwest Pipeline are regulated by the Federal Energy Regulatory Commission (FERC). Their rates, which are established by the FERC, are designed to recover the costs of providing the regulated services, and their competitive environment makes it probable that such rates can be charged and collected. Therefore, we have determined that it is appropriate under Accounting Standards Codification (ASC) Topic 980, “Regulated Operations,” to account for and report regulatory assets and liabilities related to these operations consistent with the economic effect of the way in which their rates are established. Accounting for these operations that are regulated can differ from the accounting requirements for nonregulated operations. For example, for regulated operations, allowance for funds used during construction (AFUDC) represents the estimated cost of debt and equity funds applicable to utility plant in the process of construction and is capitalized as a cost of property, plant, and equipment because it constitutes an actual cost of construction under established regulatory practices; nonregulated operations are only allowed to capitalize the cost of debt funds related to construction activities, while a component for equity is prohibited. The components of our regulatory assets and liabilities relate to the effects of deferred taxes on equity funds used during construction, asset retirement obligations, fuel cost differentials, levelized incremental depreciation, negative salvage, pension and other postretirement benefits, and rate allowances for deferred income taxes at a historically higher federal income tax rate.

In December 2017, the Tax Cuts and Jobs Act was enacted, which, among other things, reduced the federal corporate income tax rate from 35 percent to 21 percent (Tax Reform) (see Note 7 – Provision (Benefit) for Income Taxes). In accordance with ASC 980-740-25-2, Transco and Northwest Pipeline have recognized regulatory liabilities to reflect the probable return to customers through future rates of the future decrease in income taxes payable associated with Tax Reform. These liabilities represent an obligation to return amounts directly to our customers. While a majority of our customers have entered into tariff rates based on our cost-of-service proceedings and related rate base therein, certain other contracts with customers reflect contractually-based rates that are designed to recover the cost of providing those services, including an allowance for income taxes, with no expected future rate adjustment for the term of those contracts. This relative mix of contracts for services was considered in determining the probable amount to be returned to customers through future rates. The regulatory liabilities were recorded in December 2017 through regulatory charges to operating income totaling $674 million. The timing and actual amount of such return will be subject to future negotiations regarding this matter and many other elements of cost-of-service rate proceedings, including other costs of providing service.

Certain of our equity-method investees recorded similar regulatory liabilities, for which our *Equity earnings (losses)* in the Consolidated Statement of Operations have been reduced by $11 million related to our proportionate share of the associated regulatory charges.

Our regulatory assets associated with the effects of deferred taxes on equity funds used during construction were also impacted by Tax Reform and were reduced by $102 million in December 2017 through a charge to *Other income (expense) – net* below *Operating income (loss)* in the Consolidated Statement of Operations (see Note 6 – Other Income and Expenses). This amount, along with the previously described charges for establishing the regulatory liabilities resulting from Tax Reform, is reported within *Regulatory charges resulting from Tax Reform* within the Consolidated Statement of Cash Flows.

Our current and noncurrent regulatory asset and liability balances for the years ended December 31, 2017 and 2016 are as follows:

	December 31,	
	2017	2016
	(Millions)	
Current assets reported within *Other current assets and deferred charges*	$ 102	$ 91
Noncurrent assets reported within *Regulatory assets, deferred charges, and other*	376	387
Total regulated assets	$ 478	$ 478
Current liabilities reported within *Accrued liabilities*	$ 18	$ 11
Noncurrent liabilities reported within *Regulatory liabilities, deferred income, and other*	1,250	498
Total regulated liabilities	$ 1,268	$ 509

Cash and cash equivalents

Cash and cash equivalents in the Consolidated Balance Sheet includes amounts primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government. These have maturity dates of three months or less when acquired.

Accounts receivable

Accounts receivable are carried on a gross basis, with no discounting, less an allowance for doubtful accounts. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial condition of our customers, and the amount and age of past due accounts. We consider receivables past due if full payment is not received by the contractual due date. Interest income related to past due accounts receivable is generally recognized at the time full payment is received or collectability is assured. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted.

Inventories

Inventories in the Consolidated Balance Sheet primarily consist of natural gas liquids, olefins, natural gas in underground storage, and materials and supplies and are stated at the lower of cost or net realizable value. The cost of inventories is primarily determined using the average-cost method.

Property, plant, and equipment

Property, plant, and equipment is initially recorded at cost. We base the carrying value of these assets on estimates, assumptions, and judgments relative to capitalized costs, useful lives, and salvage values.

As regulated entities, Northwest Pipeline and Transco provide for depreciation using the straight-line method at FERC-prescribed rates. Depreciation for nonregulated entities is provided primarily on the straight-line method over estimated useful lives, except for certain offshore facilities that apply an accelerated depreciation method.

Gains or losses from the ordinary sale or retirement of property, plant, and equipment for regulated pipelines are credited or charged to accumulated depreciation. Other gains or losses are recorded in *Other (income) expense – net* included in *Operating income (loss)* in the Consolidated Statement of Operations.

Ordinary maintenance and repair costs are generally expensed as incurred. Costs of major renewals and replacements are capitalized as property, plant, and equipment.

We record a liability and increase the basis in the underlying asset for the present value of each expected future asset retirement obligation (ARO) at the time the liability is initially incurred, typically when the asset is acquired or constructed. As regulated entities, Northwest Pipeline and Transco offset the depreciation of the underlying asset that is attributable to capitalized ARO cost to a regulatory asset as we expect to recover these amounts in future rates. We measure changes in the liability due to passage of time by applying an interest rate to the liability balance. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense included in *Operating and maintenance expenses* in the Consolidated Statement of Operations, except for regulated entities, for which the liability is offset by a regulatory asset. The regulatory asset is amortized commensurate with our collection of those costs in rates.

Measurements of AROs include, as a component of future expected costs, an estimate of the price that a third party would demand, and could expect to receive, for bearing the uncertainties inherent in the obligations, sometimes referred to as a market-risk premium.

Goodwill

Goodwill included within *Intangible assets – net of accumulated amortization* in the Consolidated Balance Sheet represents the excess of the consideration, plus the fair value of any noncontrolling interest or any previously held equity interest, over the fair value of the net assets acquired. It is not subject to amortization but is evaluated annually as of October 1 for impairment or more frequently if impairment indicators are present that would indicate it is more likely than not that the fair value of the reporting unit is less than its carrying amount. Generally, the evaluation of goodwill for impairment involves a two-step quantitative test, although under certain circumstances an initial qualitative evaluation may be sufficient to conclude goodwill is not impaired. If a quantitative assessment is performed, we compare our estimate of the fair value of the reporting unit with its carrying value, including goodwill. If the carrying value of the reporting unit exceeds its fair value, a computation of the implied fair value of the goodwill is compared with its related carrying value. If the carrying value of the reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in the amount of the excess. Judgments and assumptions are inherent in our estimate of fair value. Effective October 1, 2017, we early adopted Accounting Standards Update (ASU) 2017-04 “Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment” (ASU 2017-04), which removed the computation of the implied fair value of goodwill from the measurement process.

Other intangible assets

Our identifiable intangible assets included within *Intangible assets – net of accumulated amortization* in the Consolidated Balance Sheet are primarily related to gas gathering, processing, and fractionation contractual customer relationships. Our intangible assets are amortized on a straight-line basis over the period in which these assets contribute to our cash flows. We evaluate these assets for changes in the expected remaining useful lives and would reflect any changes prospectively through amortization over the revised remaining useful life.

Impairment of property, plant, and equipment, other identifiable intangible assets, and investments

We evaluate our property, plant, and equipment and other identifiable intangible assets for impairment when events or changes in circumstances indicate, in our judgment, that the carrying value of such assets may not be recoverable.

When an indicator of impairment has occurred, we compare our estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether an impairment has occurred and we may apply a probability-weighted approach to consider the likelihood of different cash flow assumptions and possible outcomes including selling in the near term or holding for the remaining estimated useful life. If an impairment of the carrying value has occurred, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value. This evaluation is performed at the lowest level for which separately identifiable cash flows exist.

For assets identified to be disposed of in the future and considered held for sale, we compare the carrying value to the estimated fair value less the cost to sell to determine if recognition of an impairment is required. Until the assets are disposed of, the estimated fair value, which includes estimated cash flows from operations until the assumed date of sale, is recalculated when related events or circumstances change.

We evaluate our investments for impairment when events or changes in circumstances indicate, in our judgment, that the carrying value of such investments may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, we compare our estimate of fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. If the estimated fair value is less than the carrying value and we consider the decline in value to be other-than-temporary, the excess of the carrying value over the fair value is recognized in the consolidated financial statements as an impairment charge.

Judgments and assumptions are inherent in our estimate of undiscounted future cash flows and an asset's or investment's fair value. Additionally, judgment is used to determine the probability of sale with respect to assets considered for disposal.

Deferred income

We record a liability for deferred income related to cash received from customers in advance of providing our services. Such amounts are generally recognized in revenue upon satisfying our performance obligations, primarily providing services based on units of production or over remaining contractual service periods ranging from 1 to 25 years. Deferred income is reflected within *Accrued liabilities* and *Regulatory liabilities, deferred income, and other* on the Consolidated Balance Sheet. (See Note 12 – Accrued Liabilities.)

WPZ received an aggregate amount of $240 million in three equal installments as certain milestones of Transco's Hillabee Expansion Project were met related to an agreement to resolve several matters in relation to the project. (See Note 12 – Accrued Liabilities.) During the third quarter of 2017, WPZ received the final installment and placed the project into service. As a result of placing the project into service, WPZ reclassified the refundable deposits to deferred income and expects to recognize income associated with these receipts over the term of an underlying contract.

During 2016, we received cash proceeds totaling $820 million associated with restructuring certain gas gathering contracts in the Barnett Shale and Mid-Continent regions. The proceeds were recorded as deferred income and are being amortized into income.

In October 2016, we received $104 million of newly constructed assets as part of a noncash investing transaction with a customer for which we provide production handling and other services. The transaction was recorded in *Property, plant, and equipment – net* and deferred income in the Consolidated Balance Sheet and is being amortized based on units of production through 2024. Due to the noncash nature of this transaction, it is not presented within the Consolidated Statement of Cash Flows.

Contingent liabilities

We record liabilities for estimated loss contingencies, including environmental matters, when we assess that a loss is probable and the amount of the loss can be reasonably estimated. These liabilities are calculated based upon our assumptions and estimates with respect to the likelihood or amount of loss and upon advice of legal counsel, engineers, or other third parties regarding the probable outcomes of the matters. These calculations are made without consideration of any potential recovery from third parties. We recognize insurance recoveries or reimbursements from others when realizable. Revisions to these liabilities are generally reflected in income when new or different facts or information become known or circumstances change that affect the previous assumptions or estimates.

Cash flows from revolving credit facilities and commercial paper program

Proceeds and payments related to borrowings under our credit facilities are reflected in the financing activities in the Consolidated Statement of Cash Flows on a gross basis. Proceeds and payments related to borrowings under our commercial paper program are reflected in the financing activities in the Consolidated Statement of Cash Flows on a net basis, as the outstanding notes generally have maturity dates less than three months from the date of issuance. (See Note 13 – Debt, Banking Arrangements, and Leases.)

Treasury stock

Treasury stock purchases are accounted for under the cost method whereby the entire cost of the acquired stock is recorded as *Treasury stock* in the Consolidated Balance Sheet. Gains and losses on the subsequent reissuance of shares are credited or charged to *Capital in excess of par value* in the Consolidated Balance Sheet using the average-cost method.

Derivative instruments and hedging activities

We may utilize derivatives to manage a portion of our commodity price risk. These instruments consist primarily of swaps, futures, and forward contracts involving short- and long-term purchases and sales of energy commodities. We report the fair value of derivatives, except those for which the normal purchases and normal sales exception has been elected, in *Other current assets and deferred charges; Regulatory assets, deferred charges, and other; Accrued liabilities*; or *Regulatory liabilities, deferred income, and other* in the Consolidated Balance Sheet. We determine the current and noncurrent classification based on the timing of expected future cash flows of individual trades. We report these amounts on a gross basis. Additionally, we report cash collateral receivables and payables with our counterparties on a gross basis. (See Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk.)

The accounting for the changes in fair value of a commodity derivative can be summarized as follows:

Derivative Treatment	Accounting Method
Normal purchases and normal sales exception	Accrual accounting
Designated in a qualifying hedging relationship	Hedge accounting
All other derivatives	Mark-to-market accounting

We may elect the normal purchases and normal sales exception for certain short- and long-term purchases and sales of physical energy commodities. Under accrual accounting, any change in the fair value of these derivatives is not reflected on the balance sheet after the initial election of the exception.

We may also designate a hedging relationship for certain commodity derivatives. For a derivative to qualify for designation in a hedging relationship, it must meet specific criteria and we must maintain appropriate documentation. We establish hedging relationships pursuant to our risk management policies. We evaluate the hedging relationships at the inception of the hedge and on an ongoing basis to determine whether the hedging relationship is, and is expected to remain, highly effective in achieving offsetting changes in fair value or cash flows attributable to the underlying risk being hedged. We also regularly assess whether the hedged forecasted transaction is probable of occurring. If a derivative ceases to be or is no longer expected to be highly effective, or if we believe the likelihood of occurrence of the hedged forecasted transaction is no longer probable, hedge accounting is discontinued prospectively, and future changes in the fair value of the derivative are recognized currently in *Product sales* or *Product costs* in the Consolidated Statement of Operations.

For commodity derivatives designated as a cash flow hedge, the effective portion of the change in fair value of the derivative is reported in *Accumulated other comprehensive income (loss)* (AOCI) in the Consolidated Balance Sheet and reclassified into earnings in the period in which the hedged item affects earnings. Any ineffective portion of the derivative's change in fair value is recognized currently in *Product sales* or *Product costs* in the Consolidated Statement of Operations. Gains or losses deferred in AOCI associated with terminated derivatives, derivatives that cease to be highly effective hedges, derivatives for which the forecasted transaction is reasonably possible but no longer probable of occurring, and cash flow hedges that have been otherwise discontinued remain in AOCI until the hedged item affects earnings. If it becomes probable that the forecasted transaction designated as the hedged item in a cash flow hedge will not occur, any gain or loss deferred in AOCI is recognized in *Product sales* or *Product costs* in the Consolidated Statement of Operations at that time. The change in likelihood of a forecasted transaction is a judgmental decision that includes qualitative assessments made by us.

For commodity derivatives that are not designated in a hedging relationship, and for which we have not elected the normal purchases and normal sales exception, we report changes in fair value currently in *Product sales* or *Product costs* in the Consolidated Statement of Operations.

Certain gains and losses on derivative instruments included in the Consolidated Statement of Operations are netted together to a single net gain or loss, while other gains and losses are reported on a gross basis. Gains and losses recorded on a net basis include unrealized gains and losses on all derivatives that are not designated as hedges and for which we have not elected the normal purchases and normal sales exception.

Realized gains and losses on derivatives that require physical delivery, as well as natural gas derivatives for NGL processing activities and which are not held for trading purposes nor were entered into as a pre-contemplated buy/sell arrangement, are recorded on a gross basis.

Revenue recognition

Revenues

As a result of the ratemaking process, certain revenues collected by us may be subject to refunds upon the issuance of final orders by the FERC in pending rate proceedings. We record estimates of rate refund liabilities considering our and other third-party regulatory proceedings, advice of counsel, and other risks.

Service revenues

Revenues from our interstate natural gas pipeline businesses include services pursuant to long-term firm transportation and storage agreements. These agreements provide for a reservation charge based on the volume of contracted capacity and a commodity charge based on the volume of gas delivered, both at rates specified in our FERC tariffs. We recognize revenues for reservation charges ratably over the contract period regardless of the volume of natural gas that is transported or stored. Revenues for commodity charges, from both firm and interruptible transportation services and storage injection and withdrawal services, are recognized when natural gas is delivered at the agreed upon delivery point or when natural gas is injected or withdrawn from the storage facility.

Certain revenues from our midstream operations include those derived from natural gas gathering, processing, treating, and compression services and are performed under volumetric-based fee contracts. These revenues are recorded when services have been performed.

Certain of our gas gathering and processing agreements have minimum volume commitments. If a customer under such an agreement fails to meet its minimum volume commitment for a specified period, generally measured on an annual basis, it is obligated to pay a contractually determined fee based upon the shortfall between actual production volumes and the minimum volume commitment for that period. The revenue associated with minimum volume commitments is recognized in the period that the actual shortfall is determined and is no longer subject to future reduction or offset, which is generally at the end of the annual period or fourth quarter.

Crude oil gathering and transportation revenues and offshore production handling fees are recognized when the services have been performed. Certain offshore production handling contracts contain fixed payment terms that result in the deferral of revenues until such services have been performed or such capacity has been made available.

Storage revenues from our midstream operations associated with prepaid contracted storage capacity contracts are recognized on a straight-line basis over the life of the contract as services are provided.

Product sales

In the course of providing transportation services to customers of our interstate natural gas pipeline businesses, we may receive different quantities of gas from shippers than the quantities delivered on behalf of those shippers. The resulting imbalances are primarily settled through the purchase and sale of gas with our customers under terms provided for in our FERC tariffs. Revenue is recognized from the sale of gas upon settlement of the transportation and exchange imbalances.

We market NGLs, crude oil, and natural gas that we purchase from our producer customers as part of the overall service provided to producers. Revenues from marketing activities are recognized when the products have been sold and delivered.

Under our keep-whole and percent-of-liquids processing contracts, we retain the rights to all or a portion of the NGLs extracted from the producers' natural gas stream and recognize revenues when the extracted NGLs are sold and delivered.

Our former domestic olefins business produced olefins from purchased or produced feedstock and we recognized revenues when the olefins were sold and delivered.

Our Canadian businesses that were sold in September 2016 had processing and fractionation operations where we retained certain NGLs and olefins from an upgrader's offgas stream and we recognized revenues when the fractionated products were sold and delivered.

Interest capitalized

We capitalize interest during construction on major projects with construction periods of at least 3 months and a total project cost in excess of $1 million. Interest is capitalized on borrowed funds and, where regulation by the FERC exists, on internally generated funds (equity AFUDC). The latter is included in *Other income (expense) – net* below *Operating income (loss)* in the Consolidated Statement of Operations. The rates used by regulated companies are calculated in accordance with FERC rules. Rates used by nonregulated companies are based on our average interest rate on debt.

Employee stock-based awards

We recognize compensation expense on employee stock-based awards on a straight-line basis; forfeitures are recognized when they occur. (See Note 15 – Equity-Based Compensation.)

Pension and other postretirement benefits

The funded status of each of the pension and other postretirement benefit plans is recognized separately in the Consolidated Balance Sheet as either an asset or liability. The funded status is the difference between the fair value of plan assets and the plan's benefit obligation. The plans' benefit obligations and net periodic benefit costs (credits) are actuarially determined and impacted by various assumptions and estimates. (See Note 9 – Employee Benefit Plans.)

The discount rates are determined separately for each of our pension and other postretirement benefit plans based on an approach specific to our plans. The year-end discount rates are determined considering a yield curve comprised of high-quality corporate bonds and the timing of the expected benefit cash flows of each plan.

The expected long-term rates of return on plan assets are determined by combining a review of the historical returns within the portfolio, the investment strategy included in the plans' investment policy statement, and capital market projections for the asset classes in which the portfolio is invested, as well as the weighting of each asset class.

Unrecognized actuarial gains and losses and unrecognized prior service costs and credits are deferred and recorded in AOCI or, for Transco and Northwest Pipeline, as a regulatory asset or liability, until amortized as a component of net periodic benefit cost (credit). Unrecognized actuarial gains and losses in excess of 10 percent of the greater of the benefit obligation or the market-related value of plan assets are amortized over the participants' average remaining future years of service, which is approximately 13 years for our pension plans and approximately 7 years for our other postretirement benefit plans.

The expected return on plan assets component of net periodic benefit cost (credit) is calculated using the market-related value of plan assets. For our pension plans, the market-related value of plan assets is equal to the fair value of plan assets adjusted to reflect the amortization of gains or losses associated with the difference between the expected and actual return on plan assets over a 5-year period. Additionally, the market-related value of assets may be no more than 110 percent or less than 90 percent of the fair value of plan assets at the beginning of the year. The market-related value of plan assets for our other postretirement benefit plans is equal to the unadjusted fair value of plan assets at the beginning of the year.

Income taxes

We include the operations of our domestic corporate subsidiaries and income from our subsidiary partnerships in our consolidated federal income tax return and also file tax returns in various foreign and state jurisdictions as required. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of our assets and liabilities. Our judgment and income tax assumptions are used to determine the levels, if any, of valuation allowances associated with deferred tax assets.

Earnings (loss) per common share

Basic earnings (loss) per common share in the Consolidated Statement of Operations is based on the sum of the weighted-average number of common shares outstanding and vested restricted stock units. *Diluted earnings (loss) per common share* in the Consolidated Statement of Operations includes any dilutive effect of stock options, nonvested restricted stock units, and convertible debt, unless otherwise noted. *Diluted earnings (loss) per common share* are calculated using the treasury-stock method.

Foreign currency translation

Certain of our foreign subsidiaries that used the Canadian dollar as their functional currency were sold in 2016. The assets and liabilities of such foreign subsidiaries were translated at the spot rate in effect at the applicable reporting date, and the combined statements of operations were translated into the U.S. dollar at the average exchange rates in effect during the applicable period. The resulting cumulative translation adjustment was recorded as a separate component of AOCI in the Consolidated Balance Sheet.

Transactions denominated in currencies other than the functional currency were recorded based on exchange rates at the time such transactions arose. Subsequent changes in exchange rates when the transactions were settled resulted in transaction gains and losses which were reflected in *Other (income) expense – net* within *Costs and expenses* in the Consolidated Statement of Operations. Substantially all of our Canadian operations were sold in September 2016.

Accounting standards issued and adopted

Effective January 1, 2017, we adopted ASU 2016-09, "Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting" (ASU 2016-09). ASU 2016-09 changed the accounting for income taxes such that all excess tax benefits and all tax deficiencies are now recognized as a discrete item in the provision for income taxes in the financial reporting period they occur and the recognition of tax benefits is no longer delayed until the tax benefit is realized through a reduction in income taxes payable. These changes were applied prospectively beginning in 2017. We recorded a cumulative-effect adjustment as of January 1, 2017, decreasing *Retained deficit* by $37 million in the Consolidated Balance Sheet to recognize tax benefits that were not previously recognized. ASU 2016-09 requires entities to classify excess tax benefits as an operating activity on the statement of cash flows. We applied this part of the guidance prospectively beginning in 2017; therefore, the cash flows for prior periods were not adjusted. In recognizing compensation cost from share-based payments, ASU 2016-09 allows entities to make an accounting policy election to either recognize forfeitures when they occur or estimate the number of forfeitures expected to occur. We are recognizing forfeitures when they occur and as a result of the change in our accounting policy, we increased our *Retained deficit* for an insignificant cumulative-effect adjustment as of January 1, 2017. ASU 2016-09 requires entities to classify as a financing activity, on the statement of cash flows, cash paid by an employer to a taxing authority when directly withholding shares from an employee's award to satisfy the employer's statutory tax withholding obligation. This guidance was applied retrospectively.

Effective October 1, 2017, we early adopted ASU 2017-04 "Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment." ASU 2017-04 modified the concept of goodwill impairment to represent the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. Under ASU 2017-04, entities are no longer required to determine the implied fair value of goodwill by assigning the fair value of a reporting unit to its individual assets and liabilities as if that reporting unit had been acquired in a business combination. Our Williams Partners reportable segment has $47 million of goodwill included in *Intangible assets – net of accumulated amortization* in the Consolidated Balance Sheet (see Note 11 – Goodwill and Other Intangible Assets).

Accounting standards issued but not yet adopted

In February 2018, the Financial Accounting Standards Board (FASB) issued ASU 2018-02 "Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income" (ASU 2018-02). As a result of Tax Reform lowering the federal income tax rate, the tax effects of items within accumulated other comprehensive income may not reflect the appropriate tax rate. ASU 2018-02 allows for the reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from Tax Reform. ASU 2018-02 is effective for interim and annual periods beginning after December 15, 2018. Early adoption is permitted. ASU 2018-02 should be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the federal corporate income tax rate as a result of Tax Reform is recognized. We plan to early adopt ASU 2018-02 during the first quarter of 2018 and do not believe the adoption will have a significant impact on our consolidated financial statements.

In August 2017, the FASB issued ASU 2017-12 "Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities" (ASU 2017-12). ASU 2017-12 applies to entities that elect hedge accounting in accordance with Accounting Standards Codification (ASC) 815. The ASU affects both the designation and measurement guidance for hedging relationships and the presentation of hedging results. ASU 2017-12 is effective for interim and annual periods beginning after December 15, 2018. Early adoption is permitted. ASU 2017-12 will be applied using a modified retrospective approach for cash flow and net investment hedges existing at the date of adoption and prospectively for the presentation and disclosure guidance. During the first quarter of 2018, we early adopted ASU 2017-12. The adoption did not have a significant impact on our consolidated financial statements.

In March 2017, the FASB issued ASU 2017-07 "Compensation - Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost" (ASU 2017-07). ASU 2017-07 requires employers to report the service cost component of net benefit cost in the same line item or items as other compensation costs arising from employee services. The other components of net benefit cost must be presented in the income statement separately from the service cost component and outside a subtotal of income from operations, if one is presented. Only the service cost component is now eligible for capitalization when applicable. ASU 2017-07 is effective beginning January 1, 2018. The presentation aspect of ASU 2017-07 must be applied retrospectively and the capitalization requirement prospectively. Upon adoption, we will present the elements of net periodic benefit costs in the Consolidated Statement of Operations in accordance with ASU 2017-07. We do not expect the change in the costs eligible to be capitalized to have a material effect on our consolidated financial statements.

In August 2016, the FASB issued ASU 2016-15 "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments" (ASU 2016-15). ASU 2016-15 provides specific guidance on eight cash flow classification issues, including debt prepayment or debt extinguishment costs and distributions received from equity method investees, to reduce diversity in practice. ASU 2016-15 is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted. ASU 2016-15 requires a retrospective transition. We do not expect ASU 2016-15 to have a material impact on our consolidated financial statements.

In June 2016, the FASB issued ASU 2016-13 "Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments" (ASU 2016-13). ASU 2016-13 changes the impairment model for most financial assets and certain other instruments. For trade and other receivables, held-to-maturity debt securities, loans, and other instruments, entities will be required to use a new forward-looking "expected loss" model that generally will result in the earlier recognition of allowances for losses. The guidance also requires increased disclosures. ASU 2016-13 is effective for interim and annual periods beginning after December 15, 2019. Early adoption is permitted. The standard requires varying transition methods for the different categories of amendments. Although we do not expect ASU 2016-13 to have a significant impact, it will impact our trade receivables as the related allowance for credit losses will be recognized earlier under the expected loss model.

In February 2016, the FASB issued ASU 2016-02 "Leases (Topic 842)" (ASU 2016-02). ASU 2016-02 establishes a comprehensive new lease accounting model. ASU 2016-02 modifies the definition of a lease, requires a dual approach to lease classification similar to current lease accounting, and causes lessees to recognize leases on the balance sheet as a lease liability measured as the present value of the future lease payments with a corresponding right-of-use asset, with an exception for leases with a term of one year or less. Additional disclosures will also be required regarding the amount, timing, and uncertainty of cash flows arising from leases. In January 2018, the FASB issued ASU 2018-01 "Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842" (ASU 2018-01). Per ASU 2018-01, land easements and rights-of-way are required to be assessed under ASU 2016-02 to determine whether the arrangements are or contain a lease. ASU 2018-01 permits an entity to elect a transition practical expedient to not apply ASU 2016-02 to land easements that exist or expired before the effective date of ASU 2016-02 and that were not previously assessed under the previous lease guidance in ASC Topic 840 "Leases." ASU 2016-02 is effective for interim and annual periods beginning after December 15, 2018. Early adoption is permitted. ASU 2016-02 currently requires a modified retrospective transition for financing or operating leases existing at or entered into after the beginning of the earliest comparative period presented in the financial statements.

In January 2018, the FASB proposed an accounting standard update titled "Leases (Topic 842): Targeted Improvements," which is an update to ASU 2016-02 allowing entities an additional transition method to the existing requirements whereby an entity could adopt the provisions of ASU 2016-02 by recognizing a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption without adjustment to the financial statements for periods prior to adoption. We expect to adopt ASU 2016-02 effective January 1, 2019. We are in the process of reviewing contracts to identify leases based on the modified definition of a lease, implementing a financial lease accounting system, and evaluating internal control changes to support management in the accounting for and disclosure of leasing activities. While we are still in the process of completing our implementation evaluation of ASU 2016-02, we currently believe the most significant changes relate to the recognition of a lease liability and offsetting right-of-use asset in our consolidated balance sheet for operating leases. We are also evaluating ASU 2016-02's currently available and proposed practical expedients on adoption.

In May 2014, the FASB issued ASU 2014-09 establishing ASC Topic 606, "Revenue from Contracts with Customers" (ASC 606). ASC 606 establishes a comprehensive new revenue recognition model designed to depict the transfer of goods or services to a customer in an amount that reflects the consideration the entity expects to be entitled to receive in exchange for those goods or services and requires significantly enhanced revenue disclosures. In August 2015, the FASB issued ASU 2015-14 "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date" (ASU 2015-14). Per ASU 2015-14, the standard is effective for interim and annual reporting periods beginning after December 15, 2017. ASC 606 allows either full retrospective or modified retrospective transition and early adoption is permitted for annual periods beginning after December 15, 2016. We are adopting ASC 606 utilizing the modified retrospective transition approach, effective January 1, 2018, by recognizing the cumulative effect of initially applying ASC 606 for periods prior to January 1, 2018, which we expect to result in a decrease of approximately $255 million, net of tax, to the opening balance of *Total equity* in the Consolidated Balance Sheet.

We are in the final stages of evaluating the impact ASC 606 will have on our financial statements. For each revenue contract type, we have conducted a formal contract review process to evaluate the impact of ASC 606. We have substantially completed our evaluation. During the fourth quarter, we concluded on certain technical matters, including the evaluation of significant financing components, tiered pricing structures, and minimum volume commitments, and certain contracts for which we received prepayments for services. The adjustment to *Total equity* upon adoption of ASC 606 is primarily comprised of the impact to the timing of recognition of deferred revenue (contract liabilities) associated with certain contracts which underwent modifications in periods prior to January 1, 2018. Under the provisions of ASC 606, when a contract modification does not increase both the scope and price of the contract, and the remaining goods and services are distinct from the goods and services transferred prior to the modification, the modification is treated as a termination of the existing contract and the creation of a new contract. The new contract requires that the transaction price, including any remaining deferred revenue from the old contract, be allocated to the performance obligations over the term of the new contract. The contract modifications adjustments are partially offset by the impact of changes to the timing of recognizing revenue which is subject to the constraint on estimates of variable consideration of certain contracts. The constraint of variable consideration will result in the acceleration of revenue recognition and corresponding de-recognition of deferred revenue for certain contracts (as compared to the previous revenue recognition model) as a result of our assessment that it is probable such recognition would not result in a significant revenue reversal in the future. Additionally, under ASC 606, our revenues will increase in situations where we receive noncash consideration, which exists primarily in certain of our gas processing contracts where we receive commodities as full or partial consideration for services provided. This increase in revenues will be offset by a similar increase in costs and expenses when the commodities received are subsequently sold. Based on commodities received during 2017 as consideration for services and market prices during 2017, the increase in revenues and costs would have been approximately $350 million. Financial systems and internal controls necessary for adoption were implemented effective January 1, 2018.

Note 2 – Acquisitions and Divestitures

Eagle Ford Gathering System

In May 2015, WPZ acquired a gathering system comprised of approximately 140 miles of pipeline and a sour gas compression facility in the Eagle Ford Shale for $112 million. The acquisition was accounted for as a business combination, and the allocation of the acquisition-date fair value of the major classes of assets acquired includes $80 million of *Property, plant, and equipment – net* and $32 million of *Intangible assets – net of accumulated amortization* in the Consolidated Balance Sheet. Changes to the preliminary allocation disclosed in the second quarter of 2015 reflect an increase of $20 million in *Property, plant, and equipment – net*, and a decrease of $20 million in *Intangible assets – net of accumulated amortization*.

Sale of Geismar Interest

In July 2017, WPZ completed the sale of Williams Olefins, L.L.C., a wholly owned subsidiary which owned our 88.5 percent undivided interest in the Geismar, Louisiana, olefins plant (Geismar Interest) for total consideration of $2.084 billion in cash. We received a final working capital adjustment of $12 million in October 2017. Upon closing of the sale, WPZ entered into a long-term supply and transportation agreement with the purchaser to provide feedstock to the plant via its Bayou Ethane pipeline system. The assets and liabilities of the Geismar olefins plant were designated as held for sale within the Williams Partners segment during the first quarter of 2017. As a result of this sale, we recorded a gain of $1.095 billion in the third quarter of 2017. Following this sale, the cash proceeds were used to repay WPZ's $850 million term loan. Proceeds have also been funding a portion of the capital and investment expenditures that are a part of WPZ's growth portfolio.

The following table presents the results of operations for the Geismar Interest, excluding the gain noted above:

	Years Ended December 31,	
	2017	2016
	(Millions)	
Income (loss) before income taxes of the Geismar Interest	$ 26	$ 141
Income (loss) before income taxes of the Geismar Interest attributable to The Williams Companies, Inc.	19	85

Sale of Canadian Operations

In September 2016, we completed the sale of subsidiaries conducting Canadian operations, including subsidiaries of WPZ, (such subsidiaries, the Canadian disposal group). Consideration received totaled $1.020 billion, net of $31 million of cash divested and subject to customary working capital adjustments. In connection with the sale, we waived $150 million of incentive distributions otherwise payable by WPZ to us in the fourth quarter of 2016 in recognition of certain affiliate contracts wherein WPZ's Canadian operations provided services to certain of our other businesses. The proceeds were primarily used to reduce borrowings on credit facilities.

During the second quarter of 2016, we designated these operations as held for sale. As a result, we measured the fair value of the disposal group as of June 30, 2016, resulting in an impairment charge of $747 million, reflected in *Impairment of certain assets* in the Consolidated Statement of Operations. (See Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk.) During the second half of 2016 we recorded an additional loss of $66 million upon completion of the sale, primarily reflecting revisions to the sales price and estimated contingent consideration and including a $15 million benefit related to transactions to hedge our foreign currency exchange risk on the Canadian proceeds, reflected in *Other (income) expense – net* within *Costs and expenses* in the Consolidated Statement of Operations. The total loss consists of a loss of $34 million at Williams Partners and $32 million at Other.

The following table presents the results of operations for the Canadian disposal group, excluding the impairment and loss noted above:

	Years Ended December 31,	
	2017	2016
	(Millions)	
Income (loss) before income taxes of Canadian disposal group	$ —	$ (98)
Income (loss) before income taxes of Canadian disposal group attributable to The Williams Companies, Inc.	—	(95)

Note 3 – Variable Interest Entities

WPZ

We own a 74 percent interest in WPZ, a master limited partnership that is a VIE due to the limited partners' lack of substantive voting rights, such as either participating rights or kick-out rights that can be exercised with a simple majority of the vote of the limited partners. We are the primary beneficiary of WPZ because we have the power, through our general partner interest, to direct the activities that most significantly impact WPZ's economic performance.

The following table presents amounts included in our Consolidated Balance Sheet that are for the use or obligation of WPZ and/or its subsidiaries, and which comprise a significant portion of our consolidated assets and liabilities:

	December 31, 2017	December 31, 2016	Classification
	(Millions)		
Assets (liabilities):			
Cash and cash equivalents	$ 881	$ 145	*Cash and cash equivalents*
Trade accounts and other receivables – net	972	925	*Trade accounts and other receivables*
Inventories	113	138	*Inventories*
Other current assets	176	205	*Other current assets and deferred charges*
Investments	6,552	6,701	*Investments*
Property, plant, and equipment – net	27,912	28,021	*Property, plant, and equipment – net*
Intangible assets – net	8,790	9,662	*Intangible assets – net of accumulated amortization*
Regulatory assets, deferred charges, and other noncurrent assets	507	467	*Regulatory assets, deferred charges, and other*
Accounts payable	(957)	(589)	*Accounts payable*
Accrued liabilities including current asset retirement obligations	(857)	(1,122)	*Accrued liabilities*
Commercial paper	—	(93)	*Commercial paper*
Long-term debt due within one year	(501)	(785)	*Long-term debt due within one year*
Long-term debt	(15,996)	(17,685)	*Long-term debt*
Deferred income tax liabilities	(16)	(20)	*Deferred income tax liabilities*
Noncurrent asset retirement obligations	(944)	(798)	*Regulatory liabilities, deferred income, and other*
Long-term deferred income	(1,119)	(1,048)	*Regulatory liabilities, deferred income, and other*
Regulatory liabilities and other	(1,690)	(812)	*Regulatory liabilities, deferred income, and other*

The assets and liabilities presented in the table above also include the consolidated interests of the following individual VIEs within WPZ:

Gulfstar One

WPZ owns a 51 percent interest in Gulfstar One LLC (Gulfstar One), a subsidiary that, due to certain risk-sharing provisions in its customer contracts, is a VIE. Gulfstar One includes a proprietary floating-production system, Gulfstar FPS, and associated pipelines which provide production handling and gathering services in the eastern deepwater Gulf of Mexico. WPZ is the primary beneficiary because it has the power to direct the activities that most significantly impact Gulfstar One's economic performance.

Constitution

WPZ owns a 41 percent interest in Constitution, a subsidiary that, due to shipper fixed-payment commitments under its long-term firm transportation contracts, is a VIE. WPZ is the primary beneficiary because it has the power to direct the activities that most significantly impact Constitution's economic performance. WPZ, as operator of

Constitution, is responsible for constructing the proposed pipeline connecting its gathering system in Susquehanna County, Pennsylvania, to the Iroquois Gas Transmission and the Tennessee Gas Pipeline systems. The total remaining cost of the project is estimated to be approximately $740 million, which would be funded with capital contributions from WPZ and the other equity partners on a proportional basis.

In December 2014, Constitution received approval from the Federal Energy Regulatory Commission (FERC) to construct and operate its proposed pipeline. However, in April 2016, the New York State Department of Environmental Conservation (NYSDEC) denied the necessary water quality certification under Section 401 of the Clean Water Act for the New York portion of the pipeline. In May 2016, Constitution appealed the NYSDEC's denial of the Section 401 certification to the United States Court of Appeals for the Second Circuit, and in August 2017 the court issued a decision denying in part and dismissing in part Constitution's appeal. The court expressly declined to rule on Constitution's argument that the delay in the NYSDEC's decision on Constitution's Section 401 application constitutes a waiver of the certification requirement. The court determined that it lacked jurisdiction to address that contention, and found that jurisdiction over the waiver issue lies exclusively with the United States Court of Appeals for the District of Columbia Circuit. As to the denial itself, the court determined that NYSDEC's action was not arbitrary or capricious. Constitution filed a petition for rehearing with the Second Circuit Court of Appeals, but in October the court denied our petition.

In October 2017, WPZ filed a petition for declaratory order requesting the FERC to find that, by operation of law, the Section 401 certification requirement for the New York State portion of Constitution's pipeline project was waived due to the failure by the NYSDEC to act on Constitution's Section 401 application within a reasonable period of time as required by the express terms of such statute. In January 2018, the FERC denied WPZ's petition, finding that Section 401 provides that a state waives certification only when it does not act on an application within one year from the date of the application.

The project's sponsors remain committed to the project, and, in that regard, we are pursuing two separate and independent paths in order to overturn the NYSDEC's denial of the Section 401 certification. In January 2018, we filed a petition with the United States Supreme Court to review the decision of the Second Circuit Court of Appeals that upheld the merits of the NYSDEC's denial of the Section 401 certification. And, in February 2018, we filed a request with the FERC for rehearing of its finding that the NYSDEC did not waive the Section 401 certification requirement. If the FERC denies such request, we will file a petition for review with the D.C. Circuit Court of Appeals.

We estimate that the target in-service date for the project would be approximately 10 to 12 months following any court or FERC decision that the NYSDEC denial order was improper or that the NYSDEC waived the Section 401 certification requirement. An unfavorable resolution could result in the impairment of a significant portion of the capitalized project costs, which total $381 million on a consolidated basis at December 31, 2017, and are included within *Property, plant, and equipment – net* in the Consolidated Balance Sheet. Beginning in April 2016, we discontinued capitalization of development costs related to this project. It is also possible that we could incur certain supplier-related costs in the event of a prolonged delay or termination of the project.

Cardinal

WPZ owns a 66 percent interest in Cardinal Gas Services, L.L.C. (Cardinal), a subsidiary that provides gathering services for the Utica Shale region and is a VIE due to certain risks shared with customers. WPZ is the primary beneficiary because it has the power to direct the activities that most significantly impact Cardinal's economic performance. Future expansion activity is expected to be funded with capital contributions from WPZ and the other equity partner on a proportional basis.

Jackalope

WPZ owns a 50 percent interest in Jackalope Gas Gathering Services, L.L.C. (Jackalope), a subsidiary that provides gathering and processing services for the Powder River basin and is a VIE due to certain risks shared with customers. WPZ is the primary beneficiary because it has the power to direct the activities that most significantly impact Jackalope's economic performance. Future expansion activity is expected to be funded with capital contributions from WPZ and the other equity partner on a proportional basis.

Note 4 – Related Party Transactions

Transactions with Equity-Method Investees

We have purchases from our equity-method investees included in *Product costs* in the Consolidated Statement of Operations of $226 million, $180 million, and $187 million for the years ended 2017, 2016, and 2015, respectively. We have $20 million and $19 million included in *Accounts payable* in the Consolidated Balance Sheet with our equity-method investees at December 31, 2017 and 2016, respectively.

WPZ has operating agreements with certain equity-method investees. These operating agreements typically provide for reimbursement or payment to WPZ for certain direct operational payroll and employee benefit costs, materials, supplies, and other charges and also for management services. We supplied a portion of these services, primarily those related to employees since WPZ does not have any employees, to certain equity-method investees. The total charges to equity-method investees for these fees are $67 million, $66 million, and $64 million for the years ended 2017, 2016, and 2015, respectively.

Board of Directors

A former member of our Board of Directors, who was elected in 2013 and resigned during 2016, is also the current chairman, president, and chief executive officer of an energy services company that is a customer of ours. We recorded $144 million and $111 million in *Service revenues* in the Consolidated Statement of Operations from this company for transportation and storage of natural gas for the years ended December 31, 2016 and 2015, respectively.

Note 5 – Investing Activities

Impairment of equity-method investments

The following table presents other-than-temporary impairment charges related to certain equity-method investments (see Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk):

	Years Ended December 31,	
	2016	2015
	(Millions)	
Williams Partners		
Appalachia Midstream Investments	$ 294	$ 562
DBJV	59	503
Laurel Mountain	50	45
UEOM	—	241
Ranch Westex	24	—
Other	3	8
	$ 430	$ 1,359

Acquisition of Additional Interests in Appalachia Midstream Investments

During the first quarter of 2017, WPZ exchanged all of its 50 percent interest in DBJV for an increased interest in two natural gas gathering systems that are part of the Appalachia Midstream Investments and $155 million in cash. This transaction was recorded based on our estimate of the fair value of the interests received as we have more insight to this value as we operate the underlying assets. Following this exchange, WPZ has an approximate average 66 percent interest in the Appalachia Midstream Investments. We continue to account for this investment under the equity-method due to the significant participatory rights of our partners such that we do not exercise control. WPZ also sold all of its interest in Ranch Westex JV LLC (Ranch Westex) for $45 million. These transactions resulted in a total gain of $269 million reflected in *Other investing income (loss) – net* in the Consolidated Statement of Operations.

The fair value of the increased interests in the Appalachia Midstream Investments received as consideration was estimated to be $1.1 billion using an income approach based on expected cash flows and an appropriate discount rate (a Level 3 measurement within the fair value hierarchy). The determination of estimated future cash flows involved significant assumptions regarding gathering volumes, rates, and related capital spending. A 9.5 percent discount rate was utilized and reflected our estimate of the cost of capital as impacted by market conditions and risks associated with the underlying business.

Acquisition of Additional Interest in UEOM

In June 2015, WPZ acquired an approximate 13 percent additional interest in its equity-method investment, UEOM, for $357 million. Following the acquisition WPZ owns approximately 62 percent of UEOM. However, WPZ continues to account for this as an equity-method investment because WPZ does not control UEOM due to the significant participatory rights of its partner. In connection with the acquisition of the additional interest, we agreed to waive approximately $2 million of our WPZ IDR payments each quarter through 2017. See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies for discussion of agreement with WPZ wherein we permanently waived IDR payment obligations from WPZ.

Equity earnings (losses)

Equity earnings (losses) in 2015 includes a loss of $19 million associated with WPZ's share of underlying property impairments at certain of the Appalachia Midstream Investments.

Other investing income (loss) – net

In 2016, we recognized a $27 million gain from the sale of an equity-method investment interest in a gathering system that was part of the Appalachia Midstream Investments.

Other investing income (loss) – net also includes $36 million and $27 million of interest income for 2016 and 2015, respectively, associated with a receivable related to the sale of certain former Venezuela assets. Due to changes in circumstances that led to late payments and increased uncertainty regarding the recovery of the receivable, we began accounting for the receivable under a cost recovery model in first quarter 2015. Subsequently, we received payments greater than the remaining carrying amount of the receivable, which resulted in the recognition of interest income.

Investments

	Ownership Interest at December 31, 2017	December 31, 2017	December 31, 2016
		(Millions)	
Equity-method investments:			
Appalachia Midstream Investments	(1)	$ 3,104	$ 2,062
UEOM	62%	1,383	1,448
Discovery	60%	534	572
Caiman II	58%	429	426
OPPL	50%	422	430
Laurel Mountain	69%	309	324
Gulfstream	50%	244	261
DBJV	—	—	988
Other	Various	127	190
		$ 6,552	$ 6,701

(1) Includes equity-method investments in multiple gathering systems in the Marcellus Shale with an approximate average 66 percent interest.

We have differences between the carrying value of our equity-method investments and the underlying equity in the net assets of the investees of $1.8 billion at December 31, 2017 and $1.9 billion at December 31, 2016. For 2017 these differences primarily relate to our investments in Appalachia Midstream Investments and UEOM resulting from property, plant, and equipment, as well as customer-based intangible assets and goodwill. For 2016, the difference also includes DBJV.

Purchases of and contributions to equity-method investments

We generally fund our portion of significant expansion or development projects of these investees through additional capital contributions. These transactions increased the carrying value of our investments and included:

	Years Ended December 31,		
	2017	2016	2015
	(Millions)		
Appalachia Midstream Investments	$ 70	$ 28	$ 93
DBJV	32	105	57
Caiman II	24	22	—
Discovery	1	—	35
UEOM	—	—	357
Other	5	22	53
	$ 132	$ 177	$ 595

Dividends and distributions

The organizational documents of entities in which we have an equity-method interest generally require distribution of available cash to members on at least a quarterly basis. These transactions reduced the carrying value of our investments and included:

	Years Ended December 31,		
	2017	2016	2015
	(Millions)		
Appalachia Midstream Investments	$ 270	$ 211	$ 219
Discovery	127	141	116
Gulfstream	92	100	88
UEOM	80	92	42
OPPL	68	69	45
Caiman II	49	40	33
DBJV	39	39	33
Laurel Mountain	32	28	31
Other	27	22	26
	$ 784	$ 742	$ 633

In addition, on September 24, 2015, WPZ received a special distribution of $396 million from Gulfstream reflecting its proportional share of the proceeds from new debt issued by Gulfstream. The new debt was issued to refinance Gulfstream's debt maturities. Subsequently, WPZ contributed $248 million and $148 million to Gulfstream for its proportional share of amounts necessary to fund debt maturities of $500 million due on November 1, 2015, and $300 million due on June 1, 2016, respectively.

Summarized Financial Position and Results of Operations of All Equity-Method Investments

	December 31,	
	2017	2016
	(Millions)	
Assets (liabilities):		
Current assets	$ 447	$ 508
Noncurrent assets	9,181	9,695
Current liabilities	(295)	(412)
Noncurrent liabilities	(1,538)	(1,484)

	Years Ended December 31,		
	2017	2016	2015
	(Millions)		
Gross revenue	$ 1,961	$ 1,883	$ 1,707
Operating income	871	799	690
Net income	806	726	611

Note 6 – Other Income and Expenses

The following table presents certain gains or losses reflected in *Other (income) expense – net* within *Costs and expenses* in the Consolidated Statement of Operations:

	Years Ended December 31,		
	2017	2016	2015
	(Millions)		
Williams Partners			
Loss on sale of Canadian operations (Note 2)	$ 4	$ 34	$ —
Amortization of regulatory assets associated with asset retirement obligations	33	33	33
Accrual of regulatory liability related to overcollection of certain employee expenses	22	25	20
Project development costs related to Constitution (Note 3)	16	28	—
Gains on contract settlements and terminations	(15)	—	—
Gain on sale of Refinery Grade Propylene Splitter	(12)	—	—
Net foreign currency exchange (gains) losses (1)	—	10	(10)
Gain on asset retirement	—	(11)	—
Other			
Loss on sale of Canadian operations (Note 2)	1	32	—
Gain on sale of unused pipe	—	(10)	—

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(1) Primarily relates to gains and losses incurred on foreign currency transactions and the remeasurement of U.S. dollar-denominated current assets and liabilities within our former Canadian operations (see Note 2 – Acquisitions and Divestitures).

ACMP Acquisition, Merger, and Transition

Certain ACMP acquisition, merger, and transition costs included in the Consolidated Statement of Operations are as follows:

- *Selling, general, and administrative expenses* includes $26 million in 2015 primarily related to professional advisory fees within the Williams Partners segment.

- *Selling, general, and administrative expenses* includes $32 million in 2015 of general corporate expenses associated with integration and realignment of resources within the Other segment.

- *Operating and maintenance expenses* includes $12 million in 2015 primarily related to employee transition costs within the Williams Partners segment.

Additional Items

Certain additional items included in the Consolidated Statement of Operations are as follows:

- *Service revenues* includes $66 million, $58 million, and $239 million recognized in the fourth quarter of 2017, 2016, and 2015, respectively, from minimum volume commitment fees in the Barnett Shale and Mid-Continent regions within the Williams Partners segment.

- *Service revenues* for the year ended December 31, 2016, includes $173 million associated with the amortization of deferred income related to the restructuring of certain gas gathering contracts in the Barnett Shale and Mid-Continent regions within the Williams Partners segment.

- *Service revenues* were reduced by $15 million for the year ended December 31, 2016, related to potential refunds associated with a ruling received in certain rate case litigation within the Williams Partners segment.

- *Selling, general, and administrative expenses* includes $9 million and $47 million for the years ended December 31, 2017 and 2016, respectively, of costs associated with our evaluation of strategic alternatives within the Other segment. *Selling, general, and administrative expenses* also includes $61 million for the year ended December 31, 2016, of project development costs related to a proposed propane dehydrogenation facility in Alberta, Canada within the Other segment. Beginning in the first quarter of 2016, these costs did not qualify for capitalization.

- *Selling, general, and administrative expenses* and *Operating and maintenance expenses* includes $22 million in severance and other related costs for the year ended December 31, 2017, for the Williams Partners segment. The year ended December 31, 2016, included $42 million in severance and other related costs associated with an approximate 10 percent reduction in workforce in the first quarter of 2016, primarily within the Williams Partners segment.

- *Selling, general, and administrative expenses* and *Operating and maintenance expenses* includes $35 million of settlement charge expense in 2017 related to the program to pay out certain deferred vested pension benefits within the Williams Partners segment (see Note 9 – Employee Benefit Plans).

- *Other income (expense) – net* below *Operating income (loss)* includes $71 million, $66 million, and $77 million for equity AFUDC for the years ended December 31, 2017, 2016, and 2015, respectively. *Other income (expense) – net* below *Operating income (loss)* also includes $52 million, $23 million and $18 million for the years ended December 31, 2017, 2016 and 2015, respectively, of income associated with regulatory assets related to the effects of deferred taxes on equity funds used during construction.

- *Other income (expense) – net* below *Operating income (loss)* includes a $102 million charge for the year ended December 31, 2017, for regulatory assets associated with the effects of deferred taxes on equity funds used during construction as a result of Tax Reform comprised of $39 million within the Williams Partners segment and $63 million within the Other segment (see Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies).

- *Other income (expense) – net* below *Operating income (loss)* includes $35 million of settlement charge expense in 2017 related to the program to pay out certain deferred vested pension benefits (see Note 9 – Employee Benefit Plans).

- *Other income (expense) – net* below *Operating income (loss)* for the year ended December 31, 2017, includes a net gain of $30 million associated with the February 23, 2017, early retirement of $750 million of 6.125 percent senior unsecured notes that were due in 2022 and a net loss of $3 million associated with the July 3, 2017, early retirement of of $1.4 billion of 4.875 percent senior unsecured notes that were due in 2023. The net gain for the February 23, 2017, early retirement within the Other segment reflects $53 million of unamortized premium, partially offset by $23 million in premiums paid. The net loss for the July 3, 2017, early retirement within the Other segment reflects $51 million of unamortized premium, offset by $54 million in premiums paid (see Note 13 – Debt, Banking Arrangements, and Leases).

Note 7 – Provision (Benefit) for Income Taxes

The *Provision (benefit) for income taxes* includes:

	Years Ended December 31,		
	2017	2016	2015
		(Millions)	
Current:			
Federal	$ 15	$ —	$ —
State	23	2	(7)
Foreign	—	(1)	(55)
	38	1	(62)
Deferred:			
Federal	(2,004)	(6)	(317)
State	(8)	61	(25)
Foreign	—	(81)	5
	(2,012)	(26)	(337)
Provision (benefit) for income taxes	$ (1,974)	$ (25)	$ (399)

Reconciliations from the *Provision (benefit) at statutory rate* to recorded *Provision (benefit) for income taxes* are as follows:

	Years Ended December 31,		
	2017	2016	2015
		(Millions)	
Provision (benefit) at statutory rate	$ 187	$ (131)	$ (600)
Increases (decreases) in taxes resulting from:			
Impact of nontaxable noncontrolling interests	(117)	(22)	263
Federal Tax Reform rate change	(1,932)	—	—
State income taxes (net of federal benefit)	(17)	3	(21)
State deferred income tax rate change	26	43	—
Foreign operations – net (including tax effect of Canadian Sale)	(127)	78	8
Translation adjustment of certain unrecognized tax benefits	—	(1)	(71)
Other – net	6	5	22
Provision (benefit) for income taxes	$ (1,974)	$ (25)	$ (399)

Income (loss) before income taxes includes $7 million and $885 million of foreign loss in 2017 and 2016, respectively, and $20 million of foreign income in 2015.

Foreign operations – net (including tax effect of Canadian Sale) increased in 2016 due to a valuation allowance associated with impairments and losses on the sale of our Canadian operations (see Note 2 – Acquisitions and Divestitures) and the reversal of anticipatory foreign tax credits, partially offset by the tax effect of the impairments associated with our Canadian disposition.

On December 22, 2017, Tax Reform was enacted. Most of the provisions of Tax Reform are not effective until after January 1, 2018. However, the deferred tax impact of reducing the U.S. corporate tax rate from 35 percent to 21 percent is recognized in the period of enactment. This remeasurement resulted in a reduction of our deferred tax liabilities of approximately $1.9 billion, with a corresponding net adjustment to *Provision (benefit) for income taxes*. Under the guidance provided by Securities and Exchange Commission Staff Accounting Bulletin No. 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act, we are recording provisional adjustments related to the impact of Tax Reform, including items such as direct expensing of assets placed into service after September 27, 2017. We anticipate that additional guidance from the Internal Revenue Service (IRS) will be released to guide us in determining what assets are eligible for direct expensing in 2017. We are also recording provisional adjustments for valuation allowances associated with *State losses and credits* (see following table), since, at this time, we cannot assess the impact that the interest expense disallowance will have on our estimated future taxable income. We are not reducing our *Minimum tax credit* (see following table) for sequestration until we receive further guidance on that matter.

The *Translation adjustment of certain unrecognized tax benefits* in 2016 and 2015 reflects the impact of changes in foreign currency exchange rates on the remeasurement of a foreign currency denominated unrecognized tax benefit, including associated penalties and interest.

The 2015 federal and state income tax provisions include the tax effect of a $2.7 billion impairment loss associated with certain goodwill, equity-method investments, and other assets. (See Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk.)

During the course of audits of our business by domestic and foreign tax authorities, we frequently face challenges regarding the amount of taxes due. These challenges include questions regarding the timing and amount of deductions and the allocation of income among various tax jurisdictions. In evaluating the liability associated with our various filing positions, we apply the two-step process of recognition and measurement. In association with this liability, we record an estimate of related interest and tax exposure as a component of our tax provision. The impact of this accrual is included within *Other – net* in our reconciliation of the *Provision (benefit) at statutory rate* to recorded *Provision (benefit) for income taxes*.

Significant components of *Deferred income tax liabilities* and *Deferred income tax assets* are as follows:

	December 31, 2017	December 31, 2016
	(Millions)	
Deferred income tax liabilities:		
Investments	$ 3,565	$ 5,300
Other	19	29
Total deferred income tax liabilities	3,584	5,329
Deferred income tax assets:		
Accrued liabilities	53	145
Minimum tax credit	155	139
Foreign tax credit	140	140
Federal loss carryovers	—	651
State losses and credits	283	313
Other	30	37
Total deferred income tax assets	661	1,425
Less valuation allowance	224	334
Net deferred income tax assets	437	1,091
Overall net deferred income tax liabilities	$ 3,147	$ 4,238

As of December 31, 2017, *Overall net deferred income tax liabilities* reflects the 21 percent federal rate change as established by Tax Reform. We consider all amounts recorded related to Tax Reform to be reasonable estimates. The amounts recorded are provisional as our interpretation, assessment, and presentation of the impact of the tax law change may be further clarified with additional guidance from regulatory, tax, and accounting authorities. Should additional guidance be provided by these authorities or other sources, we will review the provisional amounts and adjust as appropriate.

The valuation allowance at December 31, 2017 and 2016 serves to reduce the available deferred income tax assets to an amount that will, more likely than not, be realized. We consider all available positive and negative evidence, including projected future taxable income and management's estimate of future reversals of existing taxable temporary differences, and have determined that a portion of our deferred income tax assets related to *State losses and credits* may not be realized. The change in *Valuation allowance* is partially due to this evaluation. The amounts presented in the table above are, with respect to state items, before any federal benefit. The change from prior year for the *State losses and credits* is primarily due to increases in losses and credits generated in the current and prior years less losses and/or credits utilized in the current year. We have loss and credit carryovers in multiple state taxing jurisdictions. These attributes generally expire between 2018 and 2037 with some carryovers having indefinite carryforward periods. The *Valuation allowance* change from prior year is primarily due to releasing a $127 million valuation allowance on a deferred tax asset associated with a capital loss carryover. Under Tax Reform, the federal *Minimum tax credit* of $155 million will be refunded/utilized no later than 2021. *Foreign tax credit* carryforwards of $140 million are expected to be utilized prior to their expiration between 2024 and 2027.

Federal deferred income tax assets related to our net operating loss carryovers and charitable contribution carryovers at the end of 2017 are fully offset by our unrecognized tax positions in the table below.

Cash payments for income taxes (net of refunds) were $28 million and $5 million in 2017 and 2016, respectively. Cash refunds for income taxes (net of payments and discontinued operations) were $136 million in 2015.

As of December 31, 2017, we had approximately $50 million of unrecognized tax benefits. If recognized, income tax expense would be reduced by $50 million and $49 million for 2017 and 2016, respectively, including the effect of these changes on other tax attributes, with state income tax amounts included net of federal tax effect. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2017	2016
	(Millions)	
Balance at beginning of period	$ 50	$ 55
Reductions for tax positions of prior years	—	(4)
Changes due to currency translation	—	(1)
Balance at end of period	$ 50	$ 50

We recognize related interest and penalties as a component of *Provision (benefit) for income taxes*. Total interest and penalties recognized as part of income tax provision were benefits of $400 thousand and $22 million for 2017 and 2015, respectively, and expenses of $300 thousand for 2016. Approximately $2 million and $3 million of interest and penalties primarily relating to uncertain tax positions have been accrued as of December 31, 2017 and 2016, respectively.

During the next 12 months, we do not expect ultimate resolution of any unrecognized tax benefit associated with domestic or international matters to have a material impact on our unrecognized tax benefit position.

Consolidated U.S. Federal income tax returns are open to IRS examination for years after 2010. As of December 31, 2017, examinations of tax returns for 2011 through 2013 are currently in process. We do not expect material changes in our financial position resulting from these examinations. The statute of limitations for most states expires one year after expiration of the IRS statute. Generally, tax returns for our previously owned Canadian entities are open to audit for tax years after 2012. Tax years 2013 and 2014 are currently under examination. We have indemnified the purchaser for any adjustments to Canadian tax returns for periods prior to the sale of our Canadian operations in September 2016.

On September 13, 2013, the IRS issued final regulations providing guidance on the treatment of amounts paid to acquire, produce, or improve tangible property. On August 18, 2014, the IRS issued final regulations providing guidance on the dispositions of such property. The implementation date for these regulations was January 1, 2014. The IRS is expected to issue additional procedural guidance regarding how the requirements may be implemented for the gas transmission and distribution industry. Pending the issuance of this additional procedural guidance from the IRS, we cannot at this time estimate the impact of implementing the regulations for our gas transmission business, although we anticipate that it will result in an immaterial balance-sheet-only impact.

Note 8 – Earnings (Loss) Per Common Share

	Years Ended December 31,		
	2017	2016	2015
	(Dollars in millions, except per-share amounts; shares in thousands)		
Net income (loss) attributable to The Williams Companies, Inc. available to common stockholders for basic and diluted earnings (loss) per common share	$ 2,174	$ (424)	$ (571)
Basic weighted-average shares	826,177	750,673	749,271
Effect of dilutive securities:			
Nonvested restricted stock units	1,704	—	—
Stock options	637	—	—
Diluted weighted-average shares (1)	828,518	750,673	749,271
Earnings (loss) per common share:			
Basic	$ 2.63	$ (.57)	$ (.76)
Diluted	$ 2.62	$ (.57)	$ (.76)

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(1) For the years ended December 31, 2016 and December 31, 2015, 0.6 million and 1.7 million weighted-average nonvested restricted stock units, and 0.5 million and 1.5 million weighted-average stock options have been excluded from the computation of diluted earnings (loss) per common share as their inclusion would be antidilutive due to our loss from continuing operations attributable to The Williams Companies, Inc.

Note 9 – Employee Benefit Plans

We have noncontributory defined benefit pension plans in which all eligible employees participate. Currently, eligible employees earn benefits primarily based on a cash balance formula. Various other formulas, as defined in the plan documents, are utilized to calculate the retirement benefits for plan participants not covered by the cash balance formula. At the time of retirement, participants may elect, to the extent they are eligible for the various options, to receive annuity payments, a lump-sum payment, or a combination of annuity and lump-sum payments. In addition to our pension plans, we currently provide subsidized retiree medical and life insurance benefits (other postretirement benefits) to certain eligible participants. Generally, employees hired after December 31, 1991, are not eligible for the subsidized retiree medical benefits, except for participants that were employees or retirees of Transco Energy Company on December 31, 1995, and other miscellaneous defined participant groups. Subsidized retiree medical benefits for eligible participants age 65 and older are paid through contributions to health reimbursement accounts. Subsidized retiree medical benefits for eligible participants under age 65 are provided through a self-insured medical plan sponsored by us. The self-insured retiree medical plan provides for retiree contributions and contains other cost-sharing features such as deductibles, co-payments, and co-insurance. The accounting for these plans anticipates estimated future increases to our contribution levels to the health reimbursement accounts for participants age 65 and older, as well as future cost-sharing that is consistent with our expressed intent to increase the retiree contribution level generally in line with health care cost increases for participants under age 65.

In September 2017, we initiated a program to pay out certain deferred vested pension benefits to reduce investment risk, cash funding volatility, and administrative costs. In December 2017, the lump-sum payments were made and the annuity payments were commenced in relation to this program. As a result of these lump-sum payments, as well as lump-sum benefit payments made throughout 2017, settlement accounting was required. We settled $261 million in liabilities of our pension plans and recognized a pre-tax, non-cash settlement charge of $71 million, of which $35 million is reported in *Other income (expense) – net* below *Operating income (loss)* in the Consolidated Statement of Operations (see Note 6 – Other Income and Expenses). These amounts are included within the subsequent tables of changes in benefit obligations and plan assets, net periodic benefit cost (credit), and other changes in plan assets and benefit obligations recognized in other comprehensive income (loss) before taxes.

Funded Status

The following table presents the changes in benefit obligations and plan assets for pension benefits and other postretirement benefits for the years indicated:

	Pension Benefits		Other Postretirement Benefits	
	2017	2016	2017	2016
	(Millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 1,466	$ 1,464	$ 197	$ 202
Service cost	50	54	1	1
Interest cost	59	62	8	8
Plan participants' contributions	—	—	3	2
Benefits paid	(35)	(130)	(14)	(15)
Actuarial loss (gain)	40	20	11	(1)
Settlements	(261)	(4)	—	—
Net increase (decrease) in benefit obligation	(147)	2	9	(5)
Benefit obligation at end of year	1,319	1,466	206	197
Change in plan assets:				
Fair value of plan assets at beginning of year	1,254	1,241	208	201
Actual return on plan assets	184	82	25	13
Employer contributions	85	65	5	7
Plan participants' contributions	—	—	3	2
Benefits paid	(35)	(130)	(14)	(15)
Settlements	(261)	(4)	—	—
Net increase (decrease) in fair value of plan assets	(27)	13	19	7
Fair value of plan assets at end of year	1,227	1,254	227	208
Funded status — overfunded (underfunded)	$ (92)	$ (212)	$ 21	$ 11
Accumulated benefit obligation	$ 1,294	$ 1,440		

The overfunded (underfunded) status of our pension plans and other postretirement benefit plans presented in the previous table are recognized in the Consolidated Balance Sheet within the following accounts:

	December 31,	
	2017	2016
	(Millions)	
Underfunded pension plans:		
Current liabilities	$ (2)	$ (2)
Noncurrent liabilities	(90)	(210)
Overfunded (underfunded) other postretirement benefit plans:		
Current liabilities	(6)	(7)
Noncurrent assets (liabilities)	27	18

The plan assets within our other postretirement benefit plans are intended to be used for the payment of benefits for certain groups of participants. The *Current liabilities* for the other postretirement benefit plans represent the current portion of benefits expected to be payable in the subsequent year for the groups of participants whose benefits are not expected to be paid from plan assets.

The pension plans' benefit obligation *Actuarial loss (gain)* of $40 million in 2017 is primarily due to the impact of a decrease in the discount rates utilized to calculate the benefit obligation. The pension plans' benefit obligation *Actuarial loss (gain)* of $20 million in 2016 is primarily due to the impact of a decrease in the discount rates utilized to calculate the benefit obligation.

The 2017 benefit obligation *Actuarial loss (gain)* of $11 million for our other postretirement benefit plans is primarily due to a decrease in the discount rate used to calculate the benefit obligation.

At December 31, 2017 and 2016, all of our pension plans had a projected benefit obligation and accumulated benefit obligation in excess of plan assets.

Pre-tax amounts not yet recognized in *Net periodic benefit cost (credit)* at December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2017	2016	2017	2016
	(Millions)			
Amounts included in *Accumulated other comprehensive income (loss)*:				
Prior service credit	$ —	$ —	$ —	$ 5
Net actuarial loss	(375)	(535)	(21)	(18)
Amounts included in regulatory liabilities associated with Transco and Northwest Pipeline:				
Prior service credit	N/A	N/A	$ 2	$ 10
Net actuarial gain	N/A	N/A	14	8

In addition to the regulatory liabilities included in the previous table, differences in the amount of actuarially determined *Net periodic benefit cost (credit)* for our other postretirement benefit plans and the other postretirement benefit costs recovered in rates for Transco and Northwest Pipeline are deferred as a regulatory asset or liability. We have regulatory liabilities of $108 million at December 31, 2017 and $94 million at December 31, 2016, related to these deferrals. Additionally, Transco recognizes a regulatory liability for rate collections in excess of its amount funded to the tax-qualified pension plans. At December 31, 2017 and 2016, these regulatory liabilities were $33 million and $21 million, respectively. These pension and other postretirement plans amounts will be reflected in future rates based on the rate structures of these gas pipelines.

Net Periodic Benefit Cost (Credit)

Net periodic benefit cost (credit) for the years ended December 31 consist of the following:

	Pension Benefits			Other Postretirement Benefits		
	2017	2016	2015	2017	2016	2015
	(Millions)					
Components of net periodic benefit cost (credit):						
Service cost	$ 50	$ 54	$ 59	$ 1	$ 1	$ 2
Interest cost	59	62	58	8	8	9
Expected return on plan assets	(82)	(85)	(75)	(11)	(12)	(12)
Amortization of prior service credit	—	—	—	(13)	(15)	(17)
Amortization of net actuarial loss	27	30	42	—	—	2
Net actuarial loss from settlements	71	2	2	—	—	—
Reclassification to regulatory liability	—	—	—	3	4	3
Net periodic benefit cost (credit)	$ 125	$ 63	$ 86	$ (12)	$ (14)	$ (13)

Items Recognized in Other Comprehensive Income (Loss) and Regulatory Assets and Liabilities

Other changes in plan assets and benefit obligations recognized in *Other comprehensive income (loss)* before taxes for the years ended December 31 consist of the following:

	Pension Benefits			Other Postretirement Benefits		
	2017	2016	2015	2017	2016	2015
	(Millions)					
Other changes in plan assets and benefit obligations recognized in *Other comprehensive income (loss)*:						
Net actuarial gain (loss)	$ 62	$ (23)	$ 5	$ (3)	$ —	$ 8
Amortization of prior service credit	—	—	—	(5)	(6)	(6)
Amortization of net actuarial loss	27	30	42	—	—	2
Net actuarial loss from settlements	71	2	2	—	—	—
Other changes in plan assets and benefit obligations recognized in *Other comprehensive income (loss)*	$ 160	$ 9	$ 49	$ (8)	$ (6)	$ 4

Other changes in plan assets and benefit obligations for our other postretirement benefit plans associated with Transco and Northwest Pipeline are recognized in regulatory assets and liabilities. Amounts recognized in regulatory assets and liabilities for the years ended December 31 consist of the following:

	2017	2016	2015
	(Millions)		
Other changes in plan assets and benefit obligations recognized in *regulatory (assets) and liabilities:*			
Net actuarial gain (loss)	$ 6	$ 2	$ 10
Amortization of prior service credit	(8)	(9)	(11)

Pre-tax amounts expected to be amortized in *Net periodic benefit cost (credit)* in 2018 are as follows:

	Pension Benefits	Other Postretirement Benefits
	(Millions)	
Amounts included in *Accumulated other comprehensive income (loss)*:		
Prior service credit	$ —	$ (1)
Net actuarial loss	23	—
Amounts included in regulatory liabilities associated with Transco and Northwest Pipeline:		
Prior service credit	N/A	$ (2)
Net actuarial loss	N/A	—

Key Assumptions

The weighted-average assumptions utilized to determine benefit obligations as of December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2017	2016	2017	2016
Discount rate	3.66%	4.17%	3.71%	4.27%
Rate of compensation increase	4.93	4.87	N/A	N/A

The weighted-average assumptions utilized to determine *Net periodic benefit cost (credit)* for the years ended December 31 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2017	**2016**	**2015**	**2017**	**2016**	**2015**
Discount rate	4.17%	4.37%	3.96%	4.27%	4.50%	4.12%
Expected long-term rate of return on plan assets	6.45	6.85	6.38	5.53	6.11	5.70
Rate of compensation increase	4.87	4.88	4.62	N/A	N/A	N/A

The mortality assumptions used to determine the benefit obligations for our pension and other postretirement benefit plans reflect generational projection mortality tables.

The assumed health care cost trend rate for 2018 is 8.0 percent. This rate decreases to 4.5 percent by 2026. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	Point increase	Point decrease
	(Millions)	
Effect on total of service and interest cost components	$ —	$ —
Effect on other postretirement benefit obligation	5	(5)

Plan Assets

Plan assets for our pension and other postretirement benefit plans consist primarily of equity and fixed income securities including mutual funds and commingled investment funds invested in equity and fixed income securities. The plans' investment policy provides for a strategy in accordance with the Employee Retirement Income Security Act (ERISA), which governs the investment of the assets in a diversified portfolio. The plans follow a policy of diversifying the investments across various asset classes and investment managers. Additionally, the investment returns on approximately 37 percent of the other postretirement benefit plan assets are subject to income tax; therefore, certain investments are managed in a tax efficient manner.

The investment policy for the pension plans includes a general target asset allocation at December 31, 2017, of 46 percent equity securities and 54 percent fixed income securities. The target allocation includes the investments in equity and fixed income mutual funds and commingled investment funds. The investment policy allows for a broad range of asset allocations that permit the plans to de-risk in response to changes in the plans' funded status.

Equity securities may include U.S. equities and non-U.S. equities. Investment in Williams' securities or an entity in which Williams has a majority ownership is prohibited except where these securities may be owned in a commingled investment fund in which the plans' trusts invest. No more than 5 percent of the total stock portfolio valued at market may be invested in the common stock of any one corporation.

Fixed income securities may consist of U.S. as well as international instruments, including emerging markets. The fixed income strategies may invest in government, corporate, asset-backed securities, and mortgage-backed obligations. The weighted-average credit rating of the fixed income strategies must be at least "investment grade" including ratings by Moody's and/or Standard & Poor's. No more than 5 percent of the total fixed income portfolio may be invested in the fixed income securities of any one issuer with the exception of bond index funds and U.S. government guaranteed and agency securities.

The following securities and transactions are not authorized: unregistered securities, commodities or commodity contracts, short sales or margin transactions, or other leveraging strategies. Investment strategies using direct investments in derivative securities require approval and, historically, have not been used; however, these instruments may be used in mutual funds and commingled investment funds held by the plans' trusts. Additionally, real estate equity, natural resource property, venture capital, leveraged buyouts, and other high-return, high-risk investments are generally restricted.

There are no significant concentrations of risk within the plans' investment securities because of the diversity of the types of investments, diversity of the various industries, and the diversity of the fund managers and investment strategies. Generally, the investments held in the plans are publicly traded, therefore, minimizing liquidity risk in the portfolio.

The fair values of our pension plan assets at December 31, 2017 and 2016 by asset class are as follows:

	2017			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(Millions)			
Pension assets:				
Cash management fund	$ 17	$ —	$ —	$ 17
Equity securities:				
U.S. large cap	62	—	—	62
U.S. small cap	54	—	—	54
Fixed income securities (1):				
U.S. Treasury securities	103	—	—	103
Government and municipal bonds	—	15	—	15
Mortgage and asset-backed securities	—	47	—	47
Corporate bonds	—	158	—	158
Insurance company investment contracts and other	—	5	—	5
	$ 236	$ 225	$ —	461
Commingled investment funds measured at net asset value practical expedient (2):				
Equities — U.S. large cap				265
Equities — International small cap				26
Equities — International emerging markets				41
Equities — International developed markets				110
Fixed income — U.S. long duration				205
Fixed income — Corporate bonds				119
Total assets at fair value at December 31, 2017				$ 1,227

	2016			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(Millions)			
Pension assets:				
Cash management fund	$ 14	$ —	$ —	$ 14
Equity securities:				
U.S. large cap	87	—	—	87
U.S. small cap	77	—	—	77
Fixed income securities (1):				
U.S. Treasury securities	68	—	—	68
Government and municipal bonds	—	10	—	10
Mortgage and asset-backed securities	—	80	—	80
Corporate bonds	—	148	—	148
Insurance company investment contracts and other	—	5	—	5
	$ 246	$ 243	$ —	489
Commingled investment funds measured at net asset value practical expedient (2):				
Equities — U.S. large cap				369
Equities — International small cap				27
Equities — International emerging markets				50
Equities — International developed markets				149
Fixed income — U.S. long duration				88
Fixed income — Corporate bonds				82
Total assets at fair value at December 31, 2016				$ 1,254

The fair values of our other postretirement benefits plan assets at December 31, 2017 and 2016 by asset class are as follows:

	2017			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(Millions)			
Other postretirement benefit assets:				
Cash management funds	$ 11	$ —	$ —	$ 11
Equity securities:				
U.S. large cap	25	—	—	25
U.S. small cap	14	—	—	14
International developed markets large cap growth	—	6	—	6
Fixed income securities (1):				
U.S. Treasury securities	12	—	—	12
Government and municipal bonds	—	2	—	2
Mortgage and asset-backed securities	—	5	—	5
Corporate bonds	—	19	—	19
Mutual fund — Municipal bonds	43	—	—	43
	$ 105	$ 32	$ —	137
Commingled investment funds measured at net asset value practical expedient (2):				
Equities — U.S. large cap				31
Equities — International small cap				3
Equities — International emerging markets				5
Equities — International developed markets				13
Fixed income — U.S. long duration				24
Fixed income — Corporate bonds				14
Total assets at fair value at December 31, 2017				$ 227

	2016			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(Millions)			
Other postretirement benefit assets:				
Cash management funds	$ 11	$ —	$ —	$ 11
Equity securities:				
U.S. large cap	24	—	—	24
U.S. small cap	15	—	—	15
International developed markets large cap growth	—	5	—	5
Fixed income securities (1):				
U.S. Treasury securities	7	—	—	7
Government and municipal bonds	—	1	—	1
Mortgage and asset-backed securities	—	8	—	8
Corporate bonds	—	15	—	15
Mutual fund — Municipal bonds	42	—	—	42
	$ 99	$ 29	$ —	128
Commingled investment funds measured at net asset value practical expedient (2):				
Equities — U.S. large cap				38
Equities — International small cap				3
Equities — International emerging markets				5
Equities — International developed markets				16
Fixed income — U.S. long duration				9
Fixed income — Corporate bonds				9
Total assets at fair value at December 31, 2016				$ 208

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(1) The weighted-average credit quality rating of the fixed income security portfolio is investment grade with a weighted-average duration of approximately 12 years for 2017 and 8 years for 2016.

(2) The stated intents of the funds vary based on each commingled fund's investment objective. These objectives generally include strategies to replicate or outperform various market indices. Certain standard withdrawal restrictions generally apply, which may include redemption notification period restrictions ranging from 10 to 30 days. Additionally, the fund managers retain the right to restrict withdrawals from and/or purchases into the funds so as not to disadvantage other investors in the funds. Generally, the funds also reserve the right to make all or a portion of the redemption in-kind rather than in cash or a combination of cash and in-kind.

The fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement of an asset.

Shares of the cash management funds and mutual funds are valued at fair value based on published market prices as of the close of business on the last business day of the year, which represents the net asset values of the shares held.

The fair values of equity securities traded on U.S. exchanges are derived from quoted market prices as of the close of business on the last business day of the year. The fair values of equity securities traded on foreign exchanges are also derived from quoted market prices as of the close of business on an active foreign exchange on the last business day of the year. However, the valuation requires translation of the foreign currency to U.S. dollars and this translation is considered an observable input to the valuation.

The fair values of all commingled investment funds are determined based on the net asset values per unit of each of the funds. The net asset values per unit represent the aggregate values of the funds' assets at fair value less liabilities, divided by the number of units outstanding.

The fair values of fixed income securities, except U.S. Treasury securities, are determined using pricing models. These pricing models incorporate observable inputs such as benchmark yields, reported trades, broker/dealer quotes, and issuer spreads for similar securities to determine fair value. The U.S. Treasury securities are valued at fair value based on closing prices on the last business day of the year reported in the active market in which the security is traded.

There have been no significant changes in the preceding valuation methodologies used at December 31, 2017 and 2016. Additionally, there were no transfers or reclassifications of investments between Level 1 and Level 2 from December 2016 to December 2017. If transfers between levels had occurred, the transfers would have been recognized as of the end of the period.

Plan Benefit Payments and Employer Contributions

Following are the expected benefits to be paid by the plans. These estimates are based on the same assumptions previously discussed and reflect future service as appropriate. The actuarial assumptions are based on long-term expectations and include, but are not limited to, assumptions as to average expected retirement age and form of benefit payment. Actual benefit payments could differ significantly from expected benefit payments if near-term participant behaviors differ significantly from the actuarial assumptions.

	Pension Benefits	Other Postretirement Benefits
	(Millions)	
2018	$ 91	$ 13
2019	90	13
2020	92	14
2021	96	13
2022	96	13
2023-2027	486	60

In 2018, we expect to contribute approximately $80 million to our tax-qualified pension plans and approximately $5 million to our nonqualified pension plans, for a total of approximately $85 million, and approximately $6 million to our other postretirement benefit plans.

Defined Contribution Plans

We also maintain defined contribution plans for the benefit of substantially all of our employees. Generally, plan participants may contribute a portion of their compensation on a pre-tax and after-tax basis in accordance with the plans' guidelines. We match employees' contributions up to certain limits. Our matching contributions charged to expense were $34 million in 2017, $36 million in 2016, and $39 million in 2015.

Note 10 – Property, Plant, and Equipment

The following table presents nonregulated and regulated *Property, plant, and equipment – net* as presented on the Consolidated Balance Sheet for the years ended:

	Estimated Useful Life (1) (Years)	Depreciation Rates (1) (%)	December 31, 2017	December 31, 2016
			(Millions)	
Nonregulated:				
Natural gas gathering and processing facilities (2)	5 - 40		$ 18,440	$ 19,523
Construction in progress	Not applicable		566	412
Other (2)	2 - 45		2,776	3,092
Regulated:				
Natural gas transmission facilities		1.20 - 6.97	14,460	12,692
Construction in progress	Not applicable	Not applicable	1,637	1,603
Other	5 - 45	1.35 - 33.33	1,634	1,590
Total property, plant, and equipment, at cost			39,513	38,912
Accumulated depreciation and amortization			(11,302)	(10,484)
Property, plant, and equipment — net			$ 28,211	$ 28,428

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(1) Estimated useful life and depreciation rates are presented as of December 31, 2017. Depreciation rates and estimated useful lives for regulated assets are prescribed by the FERC.

(2) The 2016 presentation has been changed to reflect $890 million of right-of-way assets previously presented in *Natural gas gathering and processing facilities*, now in *Other*.

Depreciation and amortization expense for *Property, plant, and equipment – net* was $1.389 billion, $1.407 billion, and $1.382 billion in 2017, 2016, and 2015, respectively.

Regulated *Property, plant, and equipment – net* includes approximately $626 million and $665 million at December 31, 2017 and 2016, respectively, related to amounts in excess of the original cost of the regulated facilities within our gas pipeline businesses as a result of our prior acquisitions. This amount is being amortized over 40 years using the straight-line amortization method. Current FERC policy does not permit recovery through rates for amounts in excess of original cost of construction.

Asset Retirement Obligations

Our accrued obligations relate to underground storage caverns, offshore platforms and pipelines, fractionation and compression facilities, gas gathering well connections and pipelines, and gas transmission pipelines and facilities. At the end of the useful life of each respective asset, we are legally obligated to plug storage caverns and remove any related surface equipment, to restore land and remove surface equipment at gas processing, fractionation, and compression facilities, to dismantle offshore platforms and appropriately abandon offshore pipelines, to cap certain gathering pipelines at the wellhead connection and remove any related surface equipment, and to remove certain components of gas transmission facilities from the ground.

The following table presents the significant changes to our ARO, of which $946 million and $801 million are included in *Regulatory liabilities, deferred income, and other* with the remaining current portion in *Accrued liabilities* at December 31, 2017 and 2016, respectively.

	December 31,	
	2017	2016
	(Millions)	
Beginning balance	$ 862	$ 915
Liabilities incurred	33	24
Liabilities settled	(16)	(8)
Accretion expense (1)	141	69
Revisions (2)	(22)	(138)
Ending balance	$ 998	$ 862

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(1) The increase in accretion expense for 2017 includes an adjustment associated with obligations identified from certain Transco land agreements.

(2) Several factors are considered in the annual review process, including inflation rates, current estimates for removal cost, market risk premiums, discount rates, and the estimated remaining useful life of the assets. The 2017 revisions reflect changes in removal cost estimates and decreases in the estimated remaining useful life of certain assets and discount rates used in the annual review process. The 2016 revisions reflect changes in removal cost estimates, increases in the estimated remaining useful life of certain assets, and decreases in the inflation rate and discount rates used in the annual review process.

The funds Transco collects through a portion of its rates to fund its ARO are deposited into an external trust account dedicated to funding its ARO (ARO Trust). (See Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk.) Under its current rate settlement, Transco's annual funding obligation is approximately $36 million, with installments to be deposited monthly.

Note 11 – Goodwill and Other Intangible Assets

Goodwill

At December 31, 2017, 2016, and 2015, our Consolidated Balance Sheet includes $47 million of goodwill in *Intangible assets – net of accumulated amortization*, reported in the Williams Partners segment. Our goodwill is not subject to amortization, but is evaluated at least annually for impairment or more frequently if impairment indicators are present. We did not identify or recognize any impairments to goodwill in connection with our annual evaluation of goodwill for impairment (performed as of October 1) during the years ended December 31, 2017 and 2016. During 2015, we performed an interim assessment and an annual assessment as of September 30, 2015 and October 1, 2015, respectively, of certain goodwill within the Williams Partners segment. The estimated fair value of the reporting units evaluated exceeded their carrying amounts, and thus no impairment was identified. We performed an additional goodwill impairment evaluation as of December 31, 2015, of the goodwill recorded within the Williams Partners segment. As a result of this evaluation, we recorded goodwill impairment charges totaling $1.098 billion. (See Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk.)

Other Intangible Assets

The gross carrying amount and accumulated amortization of other intangible assets, included in *Intangible assets – net of accumulated amortization*, at December 31 are as follows:

	2017		2016	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(Millions)			
Contractual customer relationships	$ 10,027	$ (1,283)	$ 10,635	$ (1,019)

Other intangible assets primarily relate to gas gathering, processing, and fractionation contractual customer relationships recognized in acquisitions including ACMP and Eagle Ford (see Note 2 – Acquisitions and Divestitures). The decrease in the gross carrying amount of other intangible assets during 2017 is primarily related to the impairment of certain gathering operations in the Mid-Continent and Marcellus South regions (see Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk). The write-off of accumulated amortization related to the impaired assets is the primary reason for the difference between the change in accumulated amortization during 2017 indicated above and the amortization expense for 2017 noted below. Other intangible assets are being amortized on a straight-line basis over an initial period of 30 years which represents a portion of the term over which the contractual customer relationships are expected to contribute to our cash flows.

We expense costs incurred to renew or extend the terms of our gas gathering, processing, and fractionation contracts with customers. Based on the estimated future revenues during the contract periods (as estimated at the time of the acquisition), the weighted-average period prior to the next renewal or extension of the contractual customer relationships associated with the Eagle Ford acquisition was approximately 10 years. Although a significant portion of the expected future cash flows associated with these contractual customer relationships are dependent on our ability to renew or extend the arrangements beyond the initial contract periods, these expected future cash flows are significantly influenced by the scope and pace of our producer customers' drilling programs. Once producer customers' wells are connected to our gathering infrastructure, their likelihood of switching to another provider before the wells are abandoned is reduced due to the significant capital investment required.

The amortization expense related to other intangible assets was $347 million, $356 million, and $353 million in 2017, 2016, and 2015, respectively. The estimated amortization expense for each of the next five succeeding fiscal years is approximately $337 million.

Note 12 – Accrued Liabilities

	December 31,	
	2017	2016
	(Millions)	
Deferred income	$ 361	$ 338
Interest on debt	267	310
Employee costs	202	223
Refundable deposits	—	160
Property taxes	63	55
Asset retirement obligations	53	61
Other, including other loss contingencies	221	301
	$ 1,167	$ 1,448

Deferred income includes cash proceeds associated with restructuring certain gas gathering contracts in the Barnett Shale and Mid-Continent regions. (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies.)

Refundable deposits in 2016 includes receipts related to an agreement to resolve several matters in relation to Transco's Hillabee Expansion Project. In accordance with the agreement, the member–sponsors of Sabal Trail paid WPZ an aggregate amount of $240 million in three equal installments as certain milestones of the project were met. During the third quarter of 2017 WPZ received the final installment and placed the project into service. As a result of placing the project into service, WPZ reclassified the *Refundable deposits* to *Accrued liabilities* and *Regulatory liabilities, deferred income, and other* and expects to recognize income associated with these receipts over the term of an underlying contract.

Note 13 – Debt, Banking Arrangements, and Leases

Long-Term Debt

	December 31,	
	2017	2016
	(Millions)	
Transco:		
6.05% Notes due 2018	$ 250	$ 250
7.08% Debentures due 2026	8	8
7.25% Debentures due 2026	200	200
7.85% Notes due 2026	1,000	1,000
5.4% Notes due 2041	375	375
4.45% Notes due 2042	400	400
Other financing obligation	231	—
Northwest Pipeline:		
5.95% Notes due 2017	—	185
6.05% Notes due 2018	250	250
7.125% Debentures due 2025	85	85
4% Notes due 2027	250	—
WPZ:		
7.25% Notes due 2017	—	600
5.25% Notes due 2020	1,500	1,500
4.125% Notes due 2020	600	600
4% Notes due 2021	500	500
3.6% Notes due 2022	1,250	1,250
3.35% Notes due 2022	750	750
6.125% Notes due 2022	—	750
4.5% Notes due 2023	600	600
4.875% Notes due 2023	—	1,400
4.3% Notes due 2024	1,000	1,000
4.875% Notes due 2024	750	750
3.9% Notes due 2025	750	750
4% Notes due 2025	750	750
3.75% Notes due 2027	1,450	—
6.3% Notes due 2040	1,250	1,250
5.8% Notes due 2043	400	400
5.4% Notes due 2044	500	500
4.9% Notes due 2045	500	500
5.1% Notes due 2045	1,000	1,000
Term Loan, variable interest rate, due 2018	—	850
WMB:		
7.875% Notes due 2021	371	371
3.7% Notes due 2023	850	850
4.55% Notes due 2024	1,250	1,250
7.5% Debentures due 2031	339	339
7.75% Notes due 2031	252	252
8.75% Notes due 2032	445	445
5.75% Notes due 2044	650	650
Various — 7.625% to 10.25% Notes and Debentures due 2019 to 2027	55	55
Credit facility loans	270	775
Debt issuance costs	(122)	(119)

Net unamortized debt premium (discount)	(24)	88
Total long-term debt, including current portion	20,935	23,409
Long-term debt due within one year	(501)	(785)
Long-term debt	$ 20,434	$ 22,624

Certain of our debt agreements contain covenants that restrict or limit, among other things, our ability to create liens supporting indebtedness, sell assets, and incur additional debt. Default of these agreements could also restrict our ability to make certain distributions or repurchase equity.

The following table presents aggregate minimum maturities of long-term debt, excluding net unamortized debt premium (discount) and debt issuance costs, for each of the next five years:

	December 31, 2017
	(Millions)
2018	$ 502
2019	33
2020	2,123
2021	1,143
2022	2,003

Issuances and retirements

On July 6, 2017, WPZ repaid its $850 million variable interest rate term loan that was due December 2018 using proceeds from the sale of its Geismar Interest.

On June 5, 2017, WPZ issued $1.45 billion of 3.75 percent senior unsecured notes due 2027. WPZ used the proceeds for general partnership purposes, primarily the July 3, 2017, repayment of $1.4 billion of 4.875 percent senior unsecured notes that were due in 2023.

On April 3, 2017, Northwest Pipeline issued $250 million of 4.0 percent senior unsecured notes due 2027 to investors in a private debt placement. Northwest Pipeline used the net proceeds to retire $185 million of 5.95 percent senior unsecured notes that matured on April 15, 2017, and for general corporate purposes. As part of the issuance, Northwest Pipeline entered into a registration rights agreement with the initial purchasers of the unsecured notes. Under the terms of the agreement, Northwest Pipeline was obligated to file and consummate a registration statement for an offer to exchange the notes for a new issue of substantially identical notes registered under the Securities Act of 1933, as amended, within 365 days from closing and to use commercially reasonable efforts to complete the exchange offer. Northwest Pipeline has filed the registration statement, which became effective in January 2018. The exchange offer is expected to be completed in the first quarter of 2018.

On February 23, 2017, using proceeds received from the Financial Repositioning (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies), WPZ early retired $750 million of 6.125 percent senior unsecured notes that were due in 2022.

WPZ retired $600 million of 7.25 percent senior unsecured notes that matured on February 1, 2017.

Northwest Pipeline retired $175 million of 7 percent senior unsecured notes that matured on June 15, 2016.

Transco retired $200 million of 6.4 percent senior unsecured notes that matured on April 15, 2016.

On January 22, 2016, Transco issued $1 billion of 7.85 percent senior unsecured notes due 2026 to investors in a private debt placement. In January 2017, Transco completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended. Transco used the net proceeds to repay debt and to fund capital expenditures.

Other financing obligation

During the construction of Transco's Dalton expansion project, WPZ received funding from a partner for its proportionate share of construction costs related to its undivided ownership interest in the project. Amounts received were recorded within noncurrent liabilities and 100 percent of the costs associated with construction were capitalized on our Consolidated Balance Sheet. Upon placing the project in service during the third quarter of 2017, WPZ began leasing this partner's undivided interest in the lateral, including the associated pipeline capacity, and reclassified approximately $237 million of funding previously received from its partner from noncurrent liabilities to debt to reflect the financing obligation payable to its partner over an expected term of 35 years.

Credit Facilities

	December 31, 2017	
	Available	Outstanding
	(Millions)	
WMB		
Long-term credit facility	$ 1,500	$ 270
Letters of credit under certain bilateral bank agreements		13
WPZ		
Long-term credit facility (1)	3,500	—
Letters of credit under certain bilateral bank agreements		1

(1) In managing our available liquidity, we do not expect a maximum outstanding amount in excess of the capacity of our credit facility inclusive of any outstanding amounts under our commercial paper program.

WMB long-term credit facility

On February 2, 2015, we entered into the Second Amended and Restated Credit Agreement. The aggregate commitments available remained at $1.5 billion, with up to an additional $500 million increase in aggregate commitments available under certain circumstances. In November 2017, the maturity date of the credit facility was extended to February 2, 2021. However, we may request an additional extension of the maturity date for a one year period to allow a maturity date as late as February 2, 2022, under certain circumstances. The agreement also allows for swing line loans up to an aggregate amount of $50 million, subject to available capacity under the credit facility, and the letters of credit up to $675 million.

The agreements governing the credit facilities contain the following terms and conditions:

- Various covenants may limit, among other things, a borrower's and its material subsidiaries' ability to grant certain liens supporting indebtedness, merge or consolidate, sell all or substantially all of its assets, enter into certain affiliate transactions, make certain distributions during an event of default, make investments, and allow any material change in the nature of its business.
- If an event of default with respect to a borrower occurs under its respective credit facility, the lenders will be able to terminate the commitments for the respective borrowers and accelerate the maturity of any loans of the defaulting borrower under the respective credit facility agreement and exercise other rights and remedies.
- Each time funds are borrowed under our credit facility, the borrower may choose from two methods of calculating interest: a fluctuating base rate equal to the bank's alternate base rate plus an applicable margin or a periodic fixed rate equal to the London Interbank Offered Rate (LIBOR) plus an applicable margin. The borrower is required to pay a commitment fee based on the unused portion of its respective credit facility. The applicable margin and the commitment fee are determined for us by reference to a pricing schedule based on our senior unsecured long-term debt ratings.

Significant financial covenants under the agreement require the ratio of debt to EBITDA (each as defined in the credit agreement) be no greater than 5 to 1, except for the fiscal quarter and the two following fiscal quarters in which one or more acquisitions has been executed, in which case the ratio of debt to EBITDA is to be no greater than 5.5 to 1.

We are in compliance with these financial covenants as measured at December 31, 2017.

As of February 20, 2018, there are no amounts outstanding under our long-term credit facility.

WPZ long-term credit facilities

On February 2, 2015, WPZ along with Transco, Northwest Pipeline, the lenders named therein, and an administrative agent entered into the Second Amended & Restated Credit Agreement with aggregate commitments available of $3.5 billion, with up to an additional $500 million increase in aggregate commitments available under certain circumstances. In November 2017, the maturity date of the credit facility was extended to February 2, 2021. However, the co-borrowers may request an additional extension of the maturity date for a one year period to allow a maturity date as late as February 2, 2022, under certain circumstances. The agreement allows for swing line loans up to an aggregate amount of $150 million, subject to available capacity under the credit facility, and letters of credit commitments of $1.125 billion. Transco and Northwest Pipeline are each able to borrow up to $500 million under this credit facility to the extent not otherwise utilized by the other co-borrowers.

The agreement governing this credit facility contains the following terms and conditions:

- Various covenants may limit, among other things, a borrower's and its material subsidiaries' ability to grant certain liens supporting indebtedness, merge or consolidate, sell all or substantially all of its assets, enter into certain affiliate transactions, make certain distributions during an event of default, enter into certain restrictive agreements, and allow any material change in the nature of its business.
- If an event of default with respect to a borrower occurs under the credit facility, the lenders will be able to terminate the commitments for all borrowers and accelerate the maturity of any loans of the defaulting borrower under the credit facility agreement and exercise other rights and remedies.
- Other than swing line loans, each time funds are borrowed, the borrower must choose whether such borrowing will be an alternate base rate borrowing or a Eurodollar borrowing. If such borrowing is an alternate base rate borrowing, interest is calculated on the basis of the greater of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus one half of 1 percent, and (c) a periodic fixed rate equal to the LIBOR plus 1 percent, plus, in the case of each of (a), (b), and (c), an applicable margin. If the borrowing is a Eurodollar borrowing, interest is calculated on the basis of LIBOR for the relevant period plus an applicable margin. Interest on swing line loans is calculated as the sum of the alternate base rate plus an applicable margin. The borrower is required to pay a commitment fee based on the unused portion of the credit facility. The applicable margin and the commitment fee are determined for each borrower by reference to a pricing schedule based on such borrower's senior unsecured long-term debt ratings.

Significant financial covenants under the agreement require the ratio of debt to EBITDA, each as defined in the credit facility, be no greater than 5.00 to 1, except for the fiscal quarter and the two following fiscal quarters in which one or more acquisitions has been executed, in which case the ratio of debt to EBITDA is to be no greater than 5.5 to 1.

The ratio of debt to capitalization (defined as net worth plus debt) must be no greater than 65 percent for each Transco and Northwest Pipeline. WPZ is in compliance with these financial covenants as measured at December 31, 2017.

As of February 20, 2018, there are no amounts outstanding under the WPZ long-term credit facility.

Commercial Paper Program

On February 2, 2015, WPZ amended and restated the commercial paper program for the ACMP Merger and to allow a maximum outstanding amount of unsecured commercial paper notes of $3 billion. The maturities of the commercial paper notes vary but may not exceed 397 days from the date of issuance. The commercial paper notes are sold under customary terms in the commercial paper market and are issued at a discount from par, or, alternatively, are sold at par and bear varying interest rates on a fixed or floating basis. Proceeds from these notes are used for general partnership purposes, including funding capital expenditures, working capital, and partnership distributions. At

December 31, 2017, WPZ had no *Commercial paper* outstanding. At December 31, 2016, WPZ had $93 million of *Commercial paper* outstanding at a weighted-average interest rate of 1.06 percent, which was classified in *Current liabilities* in the Consolidated Balance Sheet, as the outstanding notes had maturity dates less than three months from the date of issuance.

Cash Payments for Interest (Net of Amounts Capitalized)

Cash payments for interest (net of amounts capitalized) were $1.110 billion in 2017, $1.152 billion in 2016, and $1.023 billion in 2015.

Restricted Net Assets of Subsidiaries

We have considered the guidance in the Securities and Exchange Commission's Regulation S-X related to restricted net assets of subsidiaries. In accordance with Rule 4-08(e) of Regulation S-X, we have determined that certain net assets of our subsidiaries are considered restricted under this guidance and exceed 25 percent of our consolidated net assets. As of December 31, 2017, substantially all of these restricted net assets relate to the net assets of WPZ, which are technically considered restricted under this accounting rule due to terms within WPZ's partnership agreement that govern the partnerships' assets. Our interest in WPZ's net assets that are considered to be restricted at December 31, 2017, was $16 billion.

Leases-Lessee

The future minimum annual rentals under noncancelable operating leases, are payable as follows:

	December 31, 2017
	(Millions)
2018	$ 43
2019	41
2020	33
2021	33
2022	29
Thereafter	137
Total	$ 316

Total rent expense was $62 million in 2017, $64 million in 2016, and $69 million in 2015 and primarily included in *Operating and maintenance expenses* and *Selling, general, and administrative expenses* in the Consolidated Statement of Operations.

Note 14 – Stockholders' Equity

Cash dividends declared per common share were $1.20, $1.68, and $2.45 for 2017, 2016, and 2015, respectively. On February 21, 2018, our board of directors approved a regular quarterly dividend of $0.34 per share payable on March 26, 2018.

In January 2017, we issued 65 million shares of common stock in a public offering at a price of $29.00 per share. In February 2017, we issued 9.75 million shares of common stock pursuant to the full exercise of the underwriter's option to purchase additional shares. The net proceeds of approximately $2.1 billion were used to purchase newly issued common units in WPZ as part of our Financial Repositioning. (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies.)

AOCI

The following table presents the changes in AOCI by component, net of income taxes:

	Cash Flow Hedges	Foreign Currency Translation	Pension and Other Post Retirement Benefits	Total
		(Millions)		
Balance at December 31, 2016	$ —	$ (2)	$ (337)	$ (339)
Other comprehensive income (loss) before reclassifications	(6)	1	44	39
Amounts reclassified from *accumulated other comprehensive income (loss)*	4	—	58	62
Other comprehensive income (loss)	(2)	1	102	101
Balance at December 31, 2017	$ (2)	$ (1)	$ (235)	$ (238)

Reclassifications out of AOCI are presented in the following table by component for the year ended December 31, 2017:

Component	Reclassifications	Classification
	(Millions)	
Cash flow hedges:		
Energy commodity contracts	$ 7	*Product sales and Product costs*
Pension and other postretirement benefits:		
Amortization of prior service cost (credit) included in net periodic benefit cost (credit)	(5)	Note 9 – Employee Benefit Plans
Amortization of actuarial (gain) loss and net actuarial loss from settlements included in net periodic benefit cost (credit)	98	Note 9 – Employee Benefit Plans
Total before tax	100	
Income tax benefit	(36)	*Provision (benefit) for income taxes*
Net of income tax	64	
Noncontrolling interest	(2)	*Net income (loss) attributable to noncontrolling interests*
Reclassifications during the period	$ 62	

Note 15 – Equity-Based Compensation

Williams' Plan Information

On May 17, 2007, our stockholders approved The Williams Companies, Inc. 2007 Incentive Plan (the Plan) that provides common-stock-based awards to both employees and nonmanagement directors and reserved 19 million new shares for issuance. On May 20, 2010 and May 22, 2014, our stockholders approved amendments and restatements of the Plan to increase by 11 million and 10 million, respectively, the number of new shares authorized for making awards under the Plan, among other changes. The Plan permits the granting of various types of awards including, but not limited to, restricted stock units and stock options. At December 31, 2017, 26 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 15 million shares were available for future grants.

Additionally, on May 17, 2007, our stockholders approved an Employee Stock Purchase Plan (ESPP) which authorized up to 2 million new shares of our common stock to be available for sale under the ESPP. On May 22, 2014, our stockholders approved an amendment and restatement of the ESPP to increase by 1.6 million the number of new shares authorized for sale under the ESPP. Employees purchased 272 thousand shares at an average price of $25.83

per share during 2017. Approximately 1.1 million shares were available for purchase under the ESPP at December 31, 2017.

Operating and maintenance expenses and *Selling, general, and administrative expenses* include equity-based compensation expense for the years ended December 31, 2017, 2016, and 2015 of $70 million, $53 million, and $56 million, respectively. Income tax benefit recognized related to the stock-based compensation expense for the years ended December 31, 2017, 2016, and 2015 was $17 million, $20 million, and $21 million, respectively. Measured but unrecognized stock-based compensation expense at December 31, 2017, was $61 million, comprised of $4 million related to stock options and $57 million related to restricted stock units. These amounts are expected to be recognized over a weighted-average period of 1.8 years.

Stock Options

The following summary reflects stock option activity and related information for the year ended December 31, 2017:

Stock Options	Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value
	(Millions)		(Millions)
Outstanding at December 31, 2016	6.2	$ 31.32	
Granted	1.0	$ 28.85	
Exercised	(0.5)	$ 21.33	
Cancelled	(0.1)	$ 36.75	
Outstanding at December 31, 2017	6.6	$ 31.53	$ 23
Exercisable at December 31, 2017	5.1	$ 31.85	$ 19

The following table summarizes additional information related to stock option activity during each of the last three years:

	Years Ended December 31,		
	2017	2016	2015
	(Millions)		
Total intrinsic value of options exercised	$ 4	$ 2	$ 37
Tax benefits realized on options exercised	$ 1	$ 1	$ 13
Cash received from the exercise of options	$ 7	$ 4	$ 20

The weighted-average remaining contractual life for stock options outstanding and exercisable at December 31, 2017, was 5.0 years and 4.0 years, respectively.

The estimated fair value at date of grant of options for our common stock granted in each respective year, using the Black-Scholes option pricing model, is as follows:

	2017	2016	2015
Weighted-average grant date fair value of options for our common stock granted during the year, per share	$ 6.61	$ 7.90	$ 7.61
Weighted-average assumptions:			
Dividend yield	4.2%	3.2%	4.8%
Volatility	35.1%	44.7%	27.8%
Risk-free interest rate	2.1%	1.2%	1.8%
Expected life (years)	6.0	6.0	6.0

The 2017 expected dividend yield is based on the 2017 dividend forecast and the grant-date market price of our stock. Our expected future volatility is determined using the historical volatility of our stock and implied volatility on our traded options. Historical volatility is based on the blended 10-year historical volatility of our stock and certain peer companies. The risk-free interest rate is based on the U.S. Treasury Constant Maturity rates as of the grant date. The expected life of the option is based on historical exercise behavior and expected future experience.

Nonvested Restricted Stock Units

The following summary reflects nonvested restricted stock unit activity and related information for the year ended December 31, 2017:

Restricted Stock Units Outstanding	Shares		Weighted-Average Fair Value (1)
	(Millions)		
Nonvested at December 31, 2016	3.9	$	35.19
Granted	2.0	$	29.47
Forfeited	(0.8)	$	39.21
Vested	(0.9)	$	38.30
Nonvested at December 31, 2017	4.2	$	31.02

(1) Performance-based restricted stock units are valued utilizing a Monte Carlo valuation method using measures of total shareholder return. All other restricted stock units are valued at the grant-date market price. Restricted stock units generally vest after three years.

Value of Restricted Stock Units		2017		2016		2015
Weighted-average grant date fair value of restricted stock units granted during the year, per share	$	29.47	$	26.51	$	40.15
Total fair value of restricted stock units vested during the year ($'s in millions)	$	33	$	32	$	42

Performance-based restricted stock units granted under the Plan represent 31 percent of nonvested restricted stock units outstanding at December 31, 2017. These grants may be earned at the end of the vesting period based on actual performance against a performance target. Based on the extent to which certain financial targets are achieved, vested shares may range from zero percent to 200 percent of the original grant amount.

WPZ's Plan Information

During 2014, certain employees of ACMP's general partner received equity-based compensation through ACMP's equity-based compensation program. These awards were converted to WPZ equity-based awards in accordance with the terms of the ACMP Merger. No additional grants of restricted common units were awarded through WPZ's equity-based compensation programs, and no additional grants are expected in the future. Equity-based compensation expense of $8 million, $20 million, and $29 million related to WPZ's equity-based compensation program is included in *Operating and maintenance expenses* and *Selling, general, and administrative expenses* for the years ended December 31, 2017, 2016, and 2015, respectively. The total fair value of the restricted common units vested during 2017, 2016, and 2015 was $24 million, $34 million, and $5 million, respectively. As of December 31, 2017, there were 76 thousand nonvested units outstanding and $1 million of unrecognized compensation expense attributable to the outstanding awards which will be recognized in 2018.

Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk

The following table presents, by level within the fair value hierarchy, certain of our financial assets and liabilities. The carrying values of cash and cash equivalents, accounts receivable, commercial paper, and accounts payable approximate fair value because of the short-term nature of these instruments. Therefore, these assets and liabilities are not presented in the following table.

			Fair Value Measurements Using		
	Carrying Amount	Fair Value	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			(Millions)		
Assets (liabilities) at December 31, 2017:					
Measured on a recurring basis:					
ARO Trust investments	$ 135	$ 135	$ 135	$ —	$ —
Energy derivatives liabilities designated as hedging instruments	(3)	(3)	(2)	(1)	—
Energy derivatives liabilities not designated as hedging instruments	(3)	(3)	—	—	(3)
Additional disclosures:					
Other receivables	7	7	7	—	—
Long-term debt, including current portion	(20,935)	(23,005)	—	(23,005)	—
Guarantees	(43)	(30)	—	(14)	(16)
Assets (liabilities) at December 31, 2016:					
Measured on a recurring basis:					
ARO Trust investments	$ 96	$ 96	$ 96	$ —	$ —
Energy derivatives assets designated as hedging instruments	2	2	—	2	—
Energy derivatives assets not designated as hedging instruments	1	1	—	—	1
Energy derivatives liabilities not designated as hedging instruments	(6)	(6)	—	—	(6)
Additional disclosures:					
Other receivables	15	15	15	—	—
Long-term debt, including current portion	(23,409)	(24,090)	—	(24,090)	—
Guarantees	(44)	(30)	—	(14)	(16)

Fair Value Methods

We use the following methods and assumptions in estimating the fair value of our financial instruments:

Assets and liabilities measured at fair value on a recurring basis

ARO Trust investments: Transco deposits a portion of its collected rates, pursuant to its rate case settlement, into an external trust that is specifically designated to fund future asset retirement obligations. The ARO Trust invests in a portfolio of actively traded mutual funds that are measured at fair value on a recurring basis based on quoted prices in an active market, is classified as available-for-sale, and is reported in *Regulatory assets, deferred charges, and other* in the Consolidated Balance Sheet. Both realized and unrealized gains and losses are ultimately recorded as regulatory assets or liabilities.

Energy derivatives: Energy derivatives include commodity-based exchange-traded contracts and over-the-counter contracts, which consist of physical forwards, futures, and swaps that are measured at fair value on a recurring basis. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions. Energy derivatives assets are reported in *Other current assets and deferred charges* and *Regulatory assets, deferred charges, and other* in the Consolidated Balance Sheet. Energy derivatives liabilities are reported in *Accrued liabilities* and *Regulatory liabilities, deferred income, and other* in the Consolidated Balance Sheet.

Reclassifications of fair value between Level 1, Level 2, and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No transfers between Level 1 and Level 2 occurred during the years ended December 31, 2017 or 2016.

Additional fair value disclosures

Other receivables: Other receivables consist of margin deposits, which are reported in *Other current assets and deferred charges* in the Consolidated Balance Sheet. The disclosed fair value of our margin deposits is considered to approximate the carrying value generally due to the short-term nature of these items.

Long-term debt, including current portion: The disclosed fair value of our long-term debt is determined primarily by a market approach using broker quoted indicative period-end bond prices. The quoted prices are based on observable transactions in less active markets for our debt or similar instruments. The fair value of the financing obligation associated with our Dalton lateral, which is included within long-term debt, was determined using an income approach (see Note 13 – Debt, Banking Arrangements, and Leases).

Guarantees: Guarantees primarily consist of a guarantee we have provided in the event of nonpayment by our previously owned communications subsidiary, Williams Communications Group (WilTel), on a lease performance obligation that extends through 2042. Guarantees also include an indemnification related to a disposed operation.

To estimate the fair value of the WilTel guarantee, an estimated default rate is applied to the sum of the future contractual lease payments using an income approach. The estimated default rate is determined by obtaining the average cumulative issuer-weighted corporate default rate based on the credit rating of WilTel's current owner and the term of the underlying obligation. The default rate is published by Moody's Investors Service. The carrying value of the WilTel guarantee is reported in *Accrued liabilities* in the Consolidated Balance Sheet. The maximum potential undiscounted exposure is approximately $30 million at December 31, 2017. Our exposure declines systematically through the remaining term of WilTel's obligation.

The fair value of the guarantee associated with the indemnification related to a disposed operation was estimated using an income approach that considered probability-weighted scenarios of potential levels of future performance. The terms of the indemnification do not limit the maximum potential future payments associated with the guarantee.

The carrying value of this guarantee is reported in *Regulatory liabilities, deferred income, and other* in the Consolidated Balance Sheet.

We are required by our revolving credit agreements to indemnify lenders for certain taxes required to be withheld from payments due to the lenders and for certain tax payments made by the lenders. The maximum potential amount of future payments under these indemnifications is based on the related borrowings and such future payments cannot currently be determined. These indemnifications generally continue indefinitely unless limited by the underlying tax regulations and have no carrying value. We have never been called upon to perform under these indemnifications and have no current expectation of a future claim.

Nonrecurring fair value measurements

We performed an interim assessment of the goodwill associated with our former Central and Northeast G&P reporting units as of September 30, 2015, and the annual assessment of goodwill associated with our Northeast G&P and West reporting units as of October 1, 2015. No impairment charges were required following these evaluations.

During the fourth quarter of 2015, we observed a significant decline in the market values of WPZ and comparable midstream companies within the industry. This served to reduce our estimate of enterprise value and increased our estimates of discount rates. As a result, we performed an impairment assessment as of December 31, 2015, of the goodwill associated with these reporting units, all within the Williams Partners segment.

We estimated the fair value of each reporting unit based on an income approach utilizing discount rates specific to the underlying businesses of each reporting unit. These discount rates considered variables unique to each business area, including equity yields of comparable midstream businesses, expectations for future growth, and customer performance considerations. Weighted-average discount rates utilized ranged from approximately 10 percent to 13 percent across the three reporting units.

As a result of the increases in discount rates during the fourth quarter of 2015, coupled with certain reductions in estimated future cash flows determined during the same period, the fair values of the former Central and Northeast G&P reporting units were determined to be below their respective carrying values. For these measurements, the book basis of each reporting unit was reduced by the associated deferred tax liabilities. We then calculated the implied fair value of goodwill by performing a hypothetical application of the acquisition method wherein the estimated fair value was allocated to the underlying assets and liabilities of each reporting unit. As a result of these Level 3 measurements, we determined that the previously recorded goodwill associated with each reporting unit was fully impaired, resulting in a fourth-quarter 2015 noncash charge of $1,098 million, reflected in *Impairment of goodwill* in the Consolidated Statement of Operations. For the West reporting unit, the estimated fair value exceeded the carrying value and no impairment was recorded.

The following table presents impairments of assets and investments associated with certain nonrecurring fair value measurements within Level 3 of the fair value hierarchy.

	Classification	Segment	Date of Measurement	Fair Value	Impairments Years Ended December 31, 2017	2016	2015
					(Millions)		
Certain gathering operations (1)	*Property, plant, and equipment – net* and *Intangible assets - net of accumulated amortization*	Williams Partners	September 30, 2017	$ 439	$ 1,019		
Certain gathering operations (2)	*Property, plant, and equipment – net* and *Intangible assets - net of accumulated amortization*	Williams Partners	September 30, 2017	21	115		
Certain NGL pipeline (3)	*Property, plant, and equipment – net*	Other	September 30, 2017	32	68		
Certain olefins pipeline project (4)	*Property, plant, and equipment – net*	Other	June 30, 2017	18	23		
Canadian operations (5)	*Assets held for sale*	Other	June 30, 2016	206		$ 406	
Canadian operations (5)	*Assets held for sale*	Williams Partners	June 30, 2016	924		341	
Certain gathering operations (6)	*Property, plant, and equipment – net*	Williams Partners	June 30, 2016	18		48	
Certain idle assets	*Property, plant, and equipment – net*	Other	December 31, 2016	73		8	
Previously capitalized project development costs (7)	*Property, plant, and equipment – net*	Williams Partners	December 31, 2015	13			$ 94
Previously capitalized project development costs (8)	*Property, plant, and equipment – net*	Other	December 31, 2015	40			64
Surplus equipment (9)	*Property, plant, and equipment – net*	Williams Partners	June 30, 2015	17			20
Level 3 fair value measurements of certain assets					1,225	803	178
Other impairments and write-downs (10)					23	70	31
Impairment of certain assets					$ 1,248	$ 873	$ 209

	Classification	Segment	Date of Measurement	Fair Value	Impairments Years Ended December 31, 2017	2016	2015
					(Millions)		
Equity-method investments (11)	*Investments*	Williams Partners	December 31, 2016	$ 1,295		$ 318	
Equity-method investments (12)	*Investments*	Williams Partners	March 31, 2016	1,294		109	
Other equity-method investment	*Investments*	Williams Partners	March 31, 2016	—		3	
Equity-method investments (13)	*Investments*	Williams Partners	December 31, 2015	4,017			$ 890
Equity-method investments (14)	*Investments*	Williams Partners	September 30, 2015	1,203			461
Other equity-method investment	*Investments*	Williams Partners	December 31, 2015	58			8
Impairment of equity-method investments						$ 430	$ 1,359

____

(1) Relates to certain gathering operations in the Mid-Continent region. During the third quarter of 2017, we received solicitations and engaged in negotiations for the sale of certain of these assets which led to our impairment evaluation. The estimated fair value was determined using an income approach and incorporated market inputs based on ongoing negotiations for a potential sale of a portion of the underlying assets. For the income approach, we utilized a discount rate of 10.2 percent, reflecting an estimated cost of capital and risks associated with the underlying assets.

(2) Relates to certain gathering operations in the Marcellus South region resulting from an anticipated decline in future volumes following a third-quarter 2017 shut-in by the primary producer. The estimated fair value was determined by the income approach utilizing a discount rate of 11.1 percent, reflecting an estimated cost of capital and risks associated with the underlying assets.

(3) Relates to an NGL pipeline near the Houston Ship Channel region which we anticipate will be underutilized for the foreseeable future. The estimated fair value was primarily determined by using a market approach based on our analysis of observable inputs in the principal market.

(4) Relates primarily to project development costs associated with an olefins pipeline project in the Gulf Coast region, the likelihood of completion of which is now considered remote. The estimated fair value of the remaining pipe and equipment considered a market approach based on our analysis of observable inputs in the principal market, as well as an estimate of replacement cost.

(5) Relates to our Canadian operations. We designated these operations as held for sale as of June 30, 2016. As a result, we measured the fair value of the disposal group, resulting in an impairment charge. The estimated fair value was determined by a market approach based primarily on inputs received in the marketing process and reflected our estimate of the potential assumed proceeds. We disposed of our Canadian operations through a sale during the third quarter of 2016. (See Note 2 – Acquisitions and Divestitures).

(6) Relates to certain gathering assets within the Mid-Continent region. The estimated fair value was determined by a market approach based on our analysis of observable inputs in the principal market.

(7) Relates to a gas processing plant, the completion of which is considered remote due to unfavorable impact of low natural gas prices on customer drilling activities. The assessed fair value primarily represents the estimated salvage value of certain equipment measured using a market approach based on our analysis of observable inputs in the principal market.

(8) Relates to an olefins pipeline project, the completion of which is considered remote due to lack of customer interest. The assessed fair value primarily represents the estimated fair value of unused pipeline measured using a market approach based on our analysis of observable inputs in the principal market.

(9) Relates to certain surplus equipment. The estimated fair value was determined by a market approach based on our analysis of observable inputs in the principal market.

(10) Reflects multiple individually insignificant impairments and write-downs of other certain assets that may no longer be in use or are surplus in nature for which the fair value was determined to be lower than the carrying value.

(11) Relates to Williams Partners' previously held interest in Ranch Westex and multiple Appalachia Midstream Investments currently held. The historical carrying value of these equity-method investments was initially recorded based on estimated fair value during the third quarter of 2014 in conjunction with the acquisition of ACMP. We estimated the fair value of these Appalachia Midstream Investments using an income approach based on expected future cash flows and appropriate discount rates. The determination of estimated future cash flows involved significant assumptions regarding gathering volumes, rates, and related capital spending. The discount rate utilized for the Appalachia Midstream Investments evaluation was 10.2 percent and reflected an estimated cost of capital as impacted by market conditions and risks associated with the underlying businesses. In addition to utilizing an income approach, we also considered a market approach for certain Appalachia Midstream Investments and Ranch Westex based on an agreement reached in February 2017 to exchange our interests in DBJV and Ranch Westex for additional interests in certain Appalachia Midstream Investments and cash. (See Note 5 – Investing Activities).

(12) Relates to Williams Partners' previously held interest in DBJV and currently held equity-method investment in Laurel Mountain. Our carrying values in these equity-method investments had been written down to fair value at December 31, 2015. Our first-quarter 2016 analysis reflected higher discount rates for both of these equity-method investments, along with lower natural gas prices for Laurel Mountain. We estimated the fair value of these equity-method investments using an income approach based on expected future cash flows and appropriate discount rates. The determination of estimated future cash flows involved significant assumptions regarding gathering volumes and related capital spending. Discount rates utilized ranged from 13.0 percent to 13.3 percent and reflected increases in the estimated cost of capital, revised estimates of expected future cash flows, and risks associated with the underlying businesses.

(13) Relates to Williams Partners' previously held interest in DBJV, as well as equity-method investments in certain of the Appalachia Midstream Investments, UEOM, and Laurel Mountain, all of which are currently held. We estimated the fair value of these equity-method investments using an income approach based on expected future cash flows and appropriate discount rates. The determination of estimated future cash flows involved significant assumptions regarding gathering volumes and related capital spending. Discount rates utilized ranged from 10.8 percent to 14.4 percent and reflected further fourth-quarter 2015 increases in the estimated cost of capital, revised estimates of expected future cash flows, and risks associated with the underlying businesses.

(14) Relates to Williams Partners' previously held interest in DBJV and certain of the Appalachia Midstream Investments currently held. The historical carrying value of these equity-method investments was initially recorded based on estimated fair value during the third quarter of 2014 in conjunction with the acquisition of ACMP. We estimated the fair value of these equity-method investments using an income approach based on expected future cash flows and appropriate discount rates. The determination of estimated future cash flows involved significant assumptions regarding gathering volumes and related capital spending. Discount rates utilized were 11.8 percent and 8.8 percent for DBJV and certain of the Appalachia Midstream Investments, respectively, and reflected an estimated cost of capital as impacted by market conditions, and risks associated with the underlying businesses.

Concentration of Credit Risk

Cash equivalents

Our cash equivalents are primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government.

Trade accounts and other receivables

The following table summarizes concentration of receivables, net of allowances:

	December 31,	
	2017	**2016**
	(Millions)	
NGLs, natural gas, and related products and services	$ 760	$ 736
Transportation of natural gas and related products	212	187
Other	4	15
Total	$ 976	$ 938

Customers include producers, distribution companies, industrial users, gas marketers, and pipelines primarily located in the continental United States. As a general policy, collateral is not required for receivables, but customers' financial condition and credit worthiness are evaluated regularly. Based upon this evaluation, we may obtain collateral to support receivables. As of December 31, 2017 and 2016, Chesapeake Energy Corporation, and its affiliates (Chesapeake), a customer within our Williams Partners segment, accounted for $176 million and $133 million, respectively, of the consolidated *Trade accounts and other receivables* balances.

Revenues

In 2017, 2016, and 2015, Chesapeake accounted for 10 percent, 14 percent, and 18 percent, respectively, of our consolidated revenues.

Note 17 – Contingent Liabilities and Commitments

Reporting of Natural Gas-Related Information to Trade Publications

Direct and indirect purchasers of natural gas in various states filed an individual and class actions against us, our former affiliate WPX Energy, Inc. (WPX) and its subsidiaries, and others alleging the manipulation of published gas price indices and seeking unspecified amounts of damages. Such actions were transferred to the Nevada federal district court for consolidation of discovery and pre-trial issues. We have agreed to indemnify WPX and its subsidiaries related to this matter.

In the individual action, filed by Farmland Industries Inc. (Farmland), the court issued an order on May 24, 2016, granting one of our co-defendant's motion for summary judgment as to Farmland's claims. On January 5, 2017, the court extended such ruling to us, entering final judgment in our favor. Farmland has appealed.

In the putative class actions, on March 30, 2017, the court issued an order denying the plaintiffs' motions for class certification. On June 13, 2017, the United States Court of Appeals for the Ninth Circuit granted the plaintiffs' petition for permission to appeal the order, and the appeal is now pending.

Because of the uncertainty around the remaining pending unresolved issues, we cannot reasonably estimate a range of potential exposure at this time. However, it is reasonably possible that the ultimate resolution of these actions and our related indemnification obligation could result in a potential loss that may be material to our results of operations. In connection with this indemnification, we have an accrued liability balance associated with this matter, and as a result, have exposure to future developments in this matter.

Alaska Refinery Contamination Litigation

We are involved in litigation arising from our ownership and operation of the North Pole Refinery in North Pole, Alaska, from 1980 until 2004, through our wholly-owned subsidiaries, Williams Alaska Petroleum Inc. (WAPI) and MAPCO Inc. We sold the refinery to Flint Hills Resources Alaska, LLC (FHRA), a subsidiary of Koch Industries, Inc., in 2004. The litigation involves three cases, with filing dates ranging from 2010 to 2014. The actions arise from sulfolane contamination allegedly emanating from the refinery. A putative class action lawsuit was filed by James West in 2010 naming us, WAPI, and FHRA as defendants. We and FHRA filed claims against each other seeking, among other things, contractual indemnification alleging that the other party caused the sulfolane contamination. In 2011, we and FHRA settled the claim with James West. Certain claims by FHRA against us were resolved by the Alaska Supreme Court in our favor. FHRA's claims against us for contractual indemnification and statutory claims for damages related to off-site sulfolane remain pending. The State of Alaska filed its action in March 2014, seeking damages. The City of North Pole (North Pole) filed its lawsuit in November 2014, seeking past and future damages, as well as punitive damages. Both we and WAPI asserted counterclaims against the State of Alaska and North Pole, and cross-claims against FHRA. FHRA has also filed cross-claims against us.

The underlying factual basis and claims in the cases are similar and may duplicate exposure. As such, in February 2017, the three cases were consolidated into one action in state court containing the remaining claims from the James West case and those of the State of Alaska and North Pole. A trial encompassing all three cases was originally scheduled to commence in May 2017, but has been continued. A new trial date has not been scheduled. Due to the ongoing assessment of the level and extent of sulfolane contamination, the lack of an articulated cleanup level for sulfolane, and the lack of a concrete remedial proposal and cost estimate, we are unable to estimate a range of exposure to the State of Alaska or North Pole at this time. We currently estimate that our reasonably possible loss exposure to FHRA could range from an insignificant amount up to $32 million, although uncertainties inherent in the litigation process, expert evaluations, and jury dynamics might cause our exposure to exceed that amount.

Independent of the litigation matter described in the preceding paragraphs, in 2013, the Alaska Department of Environmental Conservation indicated that it views FHRA and us as responsible parties, and that it intended to enter a compliance order to address the environmental remediation of sulfolane and other possible contaminants including cleanup work outside the refinery's boundaries. To date, no compliance order has been issued. Due to the ongoing assessment of the level and extent of sulfolane contamination, the ultimate cost of remediation and division of costs among the potentially responsible parties, and the previously described separate litigation, we are unable to estimate a range of exposure at this time.

Royalty Matters

Certain of our customers, including one major customer, have been named in various lawsuits alleging underpayment of royalties and claiming, among other things, violations of anti-trust laws and the Racketeer Influenced and Corrupt Organizations Act. We have also been named as a defendant in certain of these cases filed in Pennsylvania based on allegations that we improperly participated with that major customer in causing the alleged royalty underpayments. We believe that the claims asserted are subject to indemnity obligations owed to us by that major customer. Due to the preliminary status of the cases, we are unable to estimate a range of potential loss at this time.

Shareholder Litigation

A purported shareholder filed a class action lawsuit in the Delaware Court of Chancery on January 15, 2016. The putative class action complaint alleged that the individual members of our Board of Directors breached their fiduciary duties by, among other things, agreeing to the WPZ Merger Agreement, which purportedly reduced the merger consideration to have been received in the subsequently proposed but now terminated merger with Energy Transfer Equity, L.P. (Energy Transfer). The plaintiff filed a motion to voluntarily dismiss, which the court granted on January 13, 2017. On September 2, 2016, the same purported shareholder filed a derivative action claiming that the members of our Board of Directors breached their fiduciary duties by executing the WPZ Merger Agreement as a defensive measure against Energy Transfer. On September 28, 2016, we requested the court dismiss this action, and on May 15, 2017, the court dismissed the action. On June 6, 2017, the plaintiff filed a notice of appeal, and on December 18, 2017, the Delaware Supreme Court affirmed the lower court's decision.

On March 7, 2016, a purported unitholder of WPZ filed a putative class action on behalf of certain purchasers of WPZ units in U.S. District Court in Oklahoma. The action names as defendants us, WPZ, Williams Partners GP LLC, Alan S. Armstrong, and former Chief Financial Officer Donald R. Chappel and alleges violations of certain federal securities laws for failure to disclose Energy Transfer's intention to pursue a purchase of us conditioned on us not closing the WPZ Merger Agreement when announcing the WPZ Merger Agreement. The complaint seeks, among other things, damages and an award of costs and attorneys' fees. The plaintiff filed an amended complaint on August 31, 2016. On October 17, 2016, we requested the court dismiss the action, and on March 8, 2017, the court dismissed the complaint with prejudice. On April 7, 2017, the plaintiff filed a notice of appeal.

We cannot reasonably estimate a range of potential loss related to these matters at this time.

Litigation Against Energy Transfer and Related Parties

On April 6, 2016, we filed suit in Delaware Chancery Court against Energy Transfer and LE GP, LLC (the general partner for Energy Transfer) alleging willful and material breaches of the Agreement and Plan of Merger (Merger Agreement) with Energy Transfer resulting from the private offering by Energy Transfer on March 8, 2016, of Series A Convertible Preferred Units (Special Offering) to certain Energy Transfer insiders and other accredited investors. The suit seeks, among other things, an injunction ordering the defendants to unwind the Special Offering and to specifically perform their obligations under the Merger Agreement. On April 19, 2016, we filed an amended complaint seeking the same relief. On May 3, 2016, Energy Transfer and LE GP, LLC filed an answer and counterclaims.

On May 13, 2016, we filed a separate complaint in Delaware Chancery Court against Energy Transfer, LE GP, LLC, and the other Energy Transfer affiliates that are parties to the Merger Agreement, alleging material breaches of the Merger Agreement for failing to cooperate and use necessary efforts to obtain a tax opinion required under the Merger Agreement (Tax Opinion) and for otherwise failing to use necessary efforts to consummate the merger under the Merger Agreement wherein we would be merged with and into the newly formed Energy Transfer Corp LP (ETC) (ETC Merger). The suit sought, among other things, a declaratory judgment and injunction preventing Energy Transfer from terminating or otherwise avoiding its obligations under the Merger Agreement due to any failure to obtain the Tax Opinion.

The Court of Chancery coordinated the Special Offering and Tax Opinion suits. On May 20, 2016, the Energy Transfer defendants filed amended affirmative defenses and verified counterclaims in the Special Offering and Tax Opinion suits, alleging certain breaches of the Merger Agreement by us and seeking, among other things, a declaration that we were not entitled to specific performance, that Energy Transfer could terminate the ETC Merger, and that Energy Transfer is entitled to a $1.48 billion termination fee. On June 24, 2016, following a two-day trial, the court issued a Memorandum Opinion and Order denying our requested relief in the Tax Opinion suit. The court did not rule on the substance of our claims related to the Special Offering or on the substance of Energy Transfer's counterclaims. On June 27, 2016, we filed an appeal of the court's decision with the Supreme Court of Delaware, seeking reversal and remand to pursue damages. On March 23, 2017, the Supreme Court of Delaware affirmed the Court of Chancery's ruling. On March 30, 2017, we filed a motion for reargument with the Supreme Court of Delaware, which was denied on April 5, 2017.

On September 16, 2016, we filed an amended complaint with the Court of Chancery seeking damages for breaches of the Merger Agreement by defendants. On September 23, 2016, Energy Transfer filed a second amended and supplemental affirmative defenses and verified counterclaim with the Court of Chancery seeking, among other things, payment of the $1.48 billion termination fee due to our alleged breaches of the Merger Agreement. On December 1, 2017, the court granted our motion to dismiss certain of Energy Transfer's counterclaims, including its claim seeking payment of the $1.48 billion termination fee. On December 8, 2017, Energy Transfer filed a motion for reargument with the Court of Chancery.

Environmental Matters

We are a participant in certain environmental activities in various stages including assessment studies, cleanup operations, and/or remedial processes at certain sites, some of which we currently do not own. We are monitoring these sites in a coordinated effort with other potentially responsible parties, the U.S. Environmental Protection Agency (EPA), or other governmental authorities. We are jointly and severally liable along with unrelated third parties in some of these activities and solely responsible in others. Certain of our subsidiaries have been identified as potentially responsible parties at various Superfund and state waste disposal sites. In addition, these subsidiaries have incurred, or are alleged to have incurred, various other hazardous materials removal or remediation obligations under environmental laws. As of December 31, 2017, we have accrued liabilities totaling $38 million for these matters, as discussed below. Estimates of the most likely costs of cleanup are generally based on completed assessment studies, preliminary results of studies, or our experience with other similar cleanup operations. At December 31, 2017, certain assessment studies were still in process for which the ultimate outcome may yield different estimates of most likely costs. Therefore, the actual costs incurred will depend on the final amount, type, and extent of contamination discovered at these sites, the final cleanup standards mandated by the EPA or other governmental authorities, and other factors.

The EPA and various state regulatory agencies routinely promulgate and propose new rules, and issue updated guidance to existing rules. More recent rules and rulemakings include, but are not limited to, rules for reciprocating internal combustion engine maximum achievable control technology, air quality standards for one hour nitrogen dioxide emissions, and volatile organic compound and methane new source performance standards impacting design and operation of storage vessels, pressure valves, and compressors. On October 1, 2015, the EPA issued its rule regarding National Ambient Air Quality Standards for ground-level ozone, setting a stricter standard of 70 parts per billion. We are monitoring the rule's implementation as the reduction will trigger additional federal and state regulatory actions that may impact our operations. Implementation of the regulations is expected to result in impacts to our operations and increase the cost of additions to *Property, plant, and equipment – net* in the Consolidated Balance Sheet for both new and existing facilities in affected areas. We are unable to reasonably estimate the cost of additions that may be required to meet the regulations at this time due to uncertainty created by various legal challenges to these regulations and the need for further specific regulatory guidance.

Continuing operations

Our interstate gas pipelines are involved in remediation activities related to certain facilities and locations for polychlorinated biphenyls, mercury, and other hazardous substances. These activities have involved the EPA and various state environmental authorities, resulting in our identification as a potentially responsible party at various Superfund waste sites. At December 31, 2017, we have accrued liabilities of $7 million for these costs. We expect that these costs will be recoverable through rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At December 31, 2017, we have accrued liabilities totaling $8 million for these costs.

Former operations, including operations classified as discontinued

We have potential obligations in connection with assets and businesses we no longer operate. These potential obligations include remediation activities at the direction of federal and state environmental authorities and the indemnification of the purchasers of certain of these assets and businesses for environmental and other liabilities existing at the time the sale was consummated. Our responsibilities relate to the operations of the assets and businesses described below.

- Former agricultural fertilizer and chemical operations and former retail petroleum and refining operations;
- Former petroleum products and natural gas pipelines;

- Former petroleum refining facilities;
- Former exploration and production and mining operations;
- Former electricity and natural gas marketing and trading operations.

At December 31, 2017, we have accrued environmental liabilities of $23 million related to these matters.

Other Divestiture Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, property damage, environmental matters, right of way, and other representations that we have provided.

At December 31, 2017, other than as previously disclosed, we are not aware of any material claims against us involving the indemnities; thus, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. Any claim for indemnity brought against us in the future may have a material adverse effect on our results of operations in the period in which the claim is made.

In addition to the foregoing, various other proceedings are pending against us which are incidental to our operations, none of which are expected to be material to our expected future annual results of operations, liquidity, and financial position.

Summary

We have disclosed our estimated range of reasonably possible losses for certain matters above, as well as all significant matters for which we are unable to reasonably estimate a range of possible loss. We estimate that for all other matters for which we are able to reasonably estimate a range of loss, our aggregate reasonably possible losses beyond amounts accrued are immaterial to our expected future annual results of operations, liquidity, and financial position. These calculations have been made without consideration of any potential recovery from third parties.

Commitments

Commitments for construction and acquisition of property, plant, and equipment are approximately $348 million at December 31, 2017.

Note 18 – Segment Disclosures

We have one reportable segment, Williams Partners. All remaining business activities are included in Other. (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies.)

Our segment presentation of Williams Partners, which includes our consolidated master limited partnership, is reflective of the parent-level focus by our chief operating decision-maker, considering the resource allocation and governance provisions associated with the master limited partnership structure. This partnership maintains capital and cash management structures that are separate from ours. It is self-funding and maintains its own lines of bank credit and cash management accounts. These factors serve to differentiate the management of this entity as a whole.

Performance Measurement

We evaluate segment operating performance based upon *Modified EBITDA* (earnings before interest, taxes, depreciation, and amortization). This measure represents the basis of our internal financial reporting and is the primary performance measure used by our chief operating decision maker in measuring performance and allocating resources among our reportable segments.

We define *Modified EBITDA* as follows:

- Net income (loss) before:
    - Provision (benefit) for income taxes;
    - Interest incurred, net of interest capitalized;
    - Equity earnings (losses);
    - Gain on remeasurement of equity-method investment;
    - Impairment of equity-method investments;
    - Other investing income (loss) – net;
    - Impairment of goodwill;
    - Depreciation and amortization expenses;
    - Accretion expense associated with asset retirement obligations for nonregulated operations.
- This measure is further adjusted to include our proportionate share (based on ownership interest) of *Modified EBITDA* from our equity-method investments calculated consistently with the definition described above.

The following geographic area data includes *Revenues from external customers* based on product shipment origin and *Long-lived assets* based upon physical location:

	United States	Canada	Total
		(Millions)	
Revenues from external customers:			
2017	$ 8,030	$ 1	$ 8,031
2016	7,425	74	7,499
2015	7,247	113	7,360
Long-lived assets:			
2017	$ 37,002	$ —	$ 37,002
2016	38,091	—	38,091
2015	38,016	1,580	39,596

Long-lived assets are comprised of property, plant, and equipment, goodwill, and other intangible assets.

The following table reflects the reconciliation of *Segment revenues* to *Total revenues* as reported in the Consolidated Statement of Operations and *Other financial information*:

	Williams Partners	Other	Eliminations	Total
	(Millions)			
2017				
Segment revenues:				
Service revenues				
External	$ 5,291	$ 21	$ —	$ 5,312
Internal	1	11	(12)	—
Total service revenues	5,292	32	(12)	5,312
Product sales				
External	2,718	1	—	2,719
Internal	—	—	—	—
Total product sales	2,718	1	—	2,719
Total revenues	$ 8,010	$ 33	$ (12)	$ 8,031
Other financial information:				
Additions to long-lived assets	$ 2,792	$ 22	$ —	$ 2,814
Proportional Modified EBITDA of equity-method investments	795	—	—	795
2016				
Segment revenues:				
Service revenues				
External	$ 5,140	$ 31	$ —	$ 5,171
Internal	33	19	(52)	—
Total service revenues	5,173	50	(52)	5,171
Product sales				
External	2,318	10	—	2,328
Internal	—	16	(16)	—
Total product sales	2,318	26	(16)	2,328
Total revenues	$ 7,491	$ 76	$ (68)	$ 7,499
Other financial information:				
Additions to long-lived assets	$ 2,102	$ 44	$ (1)	$ 2,145
Proportional Modified EBITDA of equity-method investments	754	—	—	754
2015				
Segment revenues:				
Service revenues				
External	$ 5,134	$ 30	$ —	$ 5,164
Internal	1	91	(92)	—
Total service revenues	5,135	121	(92)	5,164
Product sales				
External	2,196	—	—	2,196
Internal	—	—	—	—
Total product sales	2,196	—	—	2,196
Total revenues	$ 7,331	$ 121	$ (92)	$ 7,360
Other financial information:				
Additions to long-lived assets	$ 2,960	$ 388	$ (12)	$ 3,336

Proportional Modified EBITDA of equity-method investments	699	—	—	699

The following table reflects the reconciliation of *Modified EBITDA* to *Net income (loss)* as reported in the Consolidated Statement of Operations:

	Years Ended December 31,		
	2017	2016	2015
		(Millions)	
Modified EBITDA by segment:			
Williams Partners	$ 3,616	$ 3,864	$ 4,003
Other	(150)	(542)	(112)
	3,466	3,322	3,891
Accretion expense associated with asset retirement obligations for nonregulated operations	(33)	(31)	(28)
Depreciation and amortization expenses	(1,736)	(1,763)	(1,738)
Impairment of goodwill	—	—	(1,098)
Equity earnings (losses)	434	397	335
Impairment of equity-method investments	—	(430)	(1,359)
Other investing income (loss) – net	282	63	27
Proportional Modified EBITDA of equity-method investments	(795)	(754)	(699)
Interest expense	(1,083)	(1,179)	(1,044)
(Provision) benefit for income taxes	1,974	25	399
Net income (loss)	$ 2,509	$ (350)	$ (1,314)

The following table reflects *Total assets* and *Equity-method investments* by reportable segments:

	Total Assets		Equity-Method Investments	
	December 31, 2017	December 31, 2016	December 31, 2017	December 31, 2016
		(Millions)		
Williams Partners	$ 45,903	$ 46,265	$ 6,552	$ 6,701
Other	589	685	—	—
Eliminations	(140)	(115)	—	—
Total	$ 46,352	$ 46,835	$ 6,552	$ 6,701

The Williams Companies Inc.

Quarterly Financial Data
(Unaudited)

Summarized quarterly financial data are as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Millions, except per-share amounts)			
2017				
Revenues	$ 1,988	$ 1,924	$ 1,891	$ 2,228
Product costs	579	537	504	680
Net income (loss)	569	193	125	1,622
Amounts attributable to The Williams Companies, Inc.:				
Net income (loss)	373	81	33	1,687
Basic earnings (loss) per common share	.45	.10	.04	2.04
Diluted earnings (loss) per common share	.45	.10	.04	2.03
2016				
Revenues	$ 1,660	$ 1,736	$ 1,905	$ 2,198
Product costs	318	401	461	545
Net income (loss)	(13)	(505)	131	37
Amounts attributable to The Williams Companies, Inc.:				
Net income (loss)	(65)	(405)	61	(15)
Basic and diluted earnings (loss) per common share	(.09)	(.54)	.08	(.02)

The sum of earnings (loss) per share for the four quarters may not equal the total earnings (loss) per share for the year due to changes in the average number of common shares outstanding and rounding.

2017

Net income (loss) for fourth-quarter 2017 includes:

- $1.923 billion benefit for income taxes resulting from Tax Reform rate change (see Note 7 – Provision (Benefit) for Income Taxes of Notes to Consolidated Financial Statements);
- $674 million of regulatory charges resulting from Tax Reform and $102 million of charges associated with regulatory asset-related deferred taxes on equity funds used during construction due to Tax Reform (see Note 6 – Other Income and Expenses).

Net income (loss) for third-quarter 2017 includes includes:

- $1.095 billion gain on the sale of Williams Olefins, L.L.C., a wholly owned subsidiary which owned our interest in the Geismar, Louisiana, olefins plant (Geismar Interest) (see Note 2 – Acquisitions and Divestitures);
- $1.210 billion impairment on certain assets (see Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk).

Net income (loss) for first-quarter 2017 includes a gain of $269 million associated with the disposition of certain equity-method investments (see Note 5 – Investing Activities).

2016

Net income (loss) for fourth-quarter 2016 includes:

- $173 million of income associated with the amortization of deferred income related to the restructuring of certain gas gathering contracts in the Barnett Shale and Mid-Continent regions and $58 million of related minimum volume commitment fees (see Note 6 – Other Income and Expenses);
- $318 million impairment loss on certain equity-method investments (see Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk).

Net income (loss) for second-quarter 2016 includes a $747 million impairment loss on Canadian assets (see Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk).

Net income (loss) for first-quarter 2016 includes a $112 million impairment loss on certain equity-method investments (see Note 16 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk).

The Williams Companies, Inc.

Schedule I — Condensed Financial Information of Registrant
Statement of Comprehensive Income (Loss) (Parent)

	Years Ended December 31,		
	2017	2016	2015
	(Millions, except per-share amounts)		
Equity in earnings of consolidated subsidiaries	$ 898	$ 522	$ 232
Interest incurred — external	(261)	(268)	(255)
Interest incurred — affiliate	(413)	(568)	(828)
Interest income — affiliate	—	—	6
Other income (expense) — net	(23)	(53)	(75)
Income (loss) before income taxes	201	(367)	(920)
Provision (benefit) for income taxes	(1,973)	57	(349)
Net income (loss)	$ 2,174	$ (424)	$ (571)
Basic earnings (loss) per common share:			
Net income (loss)	$ 2.63	$ (.57)	$ (.76)
Weighted-average shares (thousands)	826,177	750,673	749,271
Diluted earnings (loss) per common share:			
Net income (loss)	$ 2.62	$ (.57)	$ (.76)
Weighted-average shares (thousands)	828,518	750,673	749,271
Other comprehensive income (loss):			
Equity in other comprehensive income (loss) of consolidated subsidiaries	$ (2)	$ 171	$ (204)
Other comprehensive income (loss) attributable to The Williams Companies, Inc.	102	1	33
Other comprehensive income (loss)	100	172	(171)
Less: Other comprehensive income (loss) attributable to noncontrolling interests	(1)	69	(70)
Comprehensive income (loss) attributable to The Williams Companies, Inc.	$ 2,275	$ (321)	$ (672)

See accompanying notes.

The Williams Companies, Inc.

Schedule I — Condensed Financial Information of Registrant – (Continued)
Balance Sheet (Parent)

	December 31,	
	2017	2016
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 14	$ 14
Other current assets and deferred charges	10	16
Total current assets	24	30
Investments in and advances to consolidated subsidiaries	25,268	22,359
Property, plant, and equipment — net	77	77
Other noncurrent assets	6	8
Total assets	$ 25,375	$ 22,474
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 20	$ 27
Other current liabilities	187	169
Total current liabilities	207	196
Long-term debt	4,438	4,939
Notes payable — affiliates	7,763	8,171
Pension, other postretirement, and other noncurrent liabilities	164	287
Deferred income tax liabilities	3,147	4,238
Contingent liabilities and commitments		
Equity:		
Common stock	861	785
Other stockholders' equity	8,795	3,858
Total stockholders' equity	9,656	4,643
Total liabilities and stockholders' equity	$ 25,375	$ 22,474

See accompanying notes.

The Williams Companies, Inc.

Schedule I — Condensed Financial Information of Registrant – (Continued)
Statement of Cash Flows (Parent)

	Years Ended December 31,		
	2017	2016	2015
	(Millions)		
NET CASH FLOWS PROVIDED (USED) BY OPERATING ACTIVITIES	$ (648)	$ (827)	$ (1,181)
FINANCING ACTIVITIES:			
Proceeds from long-term debt	1,635	2,280	2,097
Payments of long-term debt	(2,140)	(2,155)	(1,817)
Changes in notes payable to affiliates	(408)	9	2,211
Proceeds from issuance of common stock	2,131	9	27
Dividends paid	(992)	(1,261)	(1,836)
Other — net	(9)	(6)	(30)
Net cash provided (used) by financing activities	217	(1,124)	652
INVESTING ACTIVITIES:			
Capital expenditures	(22)	(13)	(29)
Changes in investments in and advances to consolidated subsidiaries	453	1,966	521
Net cash provided (used) by investing activities	431	1,953	492
Increase (decrease) in cash and cash equivalents	—	2	(37)
Cash and cash equivalents at beginning of year	14	12	49
Cash and cash equivalents at end of year	$ 14	$ 14	$ 12

See accompanying notes.

Note 1. Guarantees

In addition to the guarantees disclosed in the accompanying consolidated financial statements in Item 8, we have financially guaranteed the performance of certain consolidated subsidiaries. The duration of these guarantees varies, and we estimate the maximum undiscounted potential future payment obligation related to these guarantees as of December 31, 2017, is approximately $305 million.

Note 2. Cash Dividends Received

We receive dividends and distributions either directly from our subsidiaries or indirectly through dividends received by subsidiaries and subsequent transfers of cash to us through our corporate cash management system. The total of such receipts ultimately related to dividends and distributions for the years ended December 31, 2017, 2016, and 2015 was approximately $1.9 billion, $1.7 billion, and $1.8 billion, respectively.

The Williams Companies, Inc.

Schedule II — Valuation and Qualifying Accounts

	Beginning Balance	Additions: Charged (Credited) To Costs and Expenses	Additions: Other	Deductions	Ending Balance
			(Millions)		
2017					
Deferred tax asset valuation allowance (1)	$ 334	$ (110)	$ —	$ —	$ 224
2016					
Deferred tax asset valuation allowance (1)	190	144	—	—	334
2015					
Deferred tax asset valuation allowance (1)	206	(16)	—	—	190

____

(1) Deducted from related assets.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a - 15(e) and 15d - 15(e) of the Securities Exchange Act) (Disclosure Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There have been no changes during the fourth quarter of 2017 that have materially affected, or are reasonably likely to materially affect, our Internal Control over Financial Reporting.

Management's Annual Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a - 15(f) and 15d - 15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance to our management and board of directors regarding the preparation and fair presentation of financial statements in accordance with accounting principles generally accepted in the United States. Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorization of our management and board of directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

All internal control systems, no matter how well designed, have inherent limitations including the possibility of human error and the circumvention or overriding of controls. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of December 31, 2017, based on the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework* (2013). Based on our assessment, we concluded that, as of December 31, 2017, our internal control over financial reporting was effective.

Ernst & Young LLP, our independent registered public accounting firm, has audited our internal control over financial reporting, as stated in their report which is included in this Annual Report on Form 10-K.

Report of Independent Registered Public Accounting Firm
on Internal Control Over Financial Reporting

The Stockholders and the Board of Directors of
The Williams Companies, Inc.

Opinion on Internal Control Over Financial Reporting
We have audited The Williams Companies, Inc.'s internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the "COSO criteria"). In our opinion, The Williams Companies, Inc. (the "Company") maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheet of the Company as of December 31, 2017 and 2016, and the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and financial statement schedules listed in the index at Item 15(a) and our report dated February 22, 2018 expressed an unqualified opinion thereon.

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 Annual 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/ Ernst & Young LLP

Tulsa, Oklahoma
February 22, 2018

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information regarding our directors and nominees for director required by Item 401 of Regulation S-K will be presented under the heading "Election of Directors" in our definitive proxy statement prepared for the solicitation of proxies in connection with our Annual Meeting of Stockholders to be held May 10, 2018, which shall be filed no later than April 30, 2018 (Proxy Statement), which information is incorporated by reference herein.

Information regarding our executive officers required by Item 401(b) of Regulation S-K is presented at the end of Part I herein and captioned "Executive Officers of the Registrant" as permitted by General Instruction G(3) to and Instruction 3 to Item 401(b) of Regulation S-K.

Information required by Item 405 of Regulation S-K will be included under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement, which information is incorporated by reference herein.

Information required by paragraphs (c)(3), (d)(4) and (d)(5) of Item 407 of Regulation S-K will be included under the heading "Questions and Answers About the Annual Meeting and Voting" and "Corporate Governance and Board Matters" in our Proxy Statement, which information is incorporated by reference herein.

We have adopted a Code of Ethics for Senior Officers that applies to our Chief Executive Officer, Chief Financial Officer, and Controller, or persons performing similar functions. The Code of Ethics for Senior Officers, together with our Corporate Governance Guidelines, the charters for each of our board committees, and our Code of Business Conduct applicable to all employees are available on our Internet website at *www.williams.com.* We will provide, free of charge, a copy of our Code of Ethics or any of our other corporate documents listed above upon written request to our Corporate Secretary at Williams, One Williams Center, Suite 4700, Tulsa, Oklahoma 74172. We intend to disclose any amendments to or waivers of the Code of Ethics on behalf of our Chief Executive Officer, Chief Financial Officer, Controller, and persons performing similar functions on the corporate governance section of our Internet website at *www.williams.com*, promptly following the date of any such amendment or waiver.

Item 11. ***Executive Compensation***

The information required by Item 402 and paragraphs (e)(4) and (e)(5) of Item 407 of Regulation S-K regarding executive compensation will be presented under the headings "Compensation Discussion and Analysis," "Executive Compensation and Other Information," "Compensation of Directors," "Compensation and Management Development Committee Report on Executive Compensation," and "Compensation and Management Development Committee Interlocks and Insider Participation" in our Proxy Statement, which information is incorporated by reference herein. Notwithstanding the foregoing, the information provided under the heading "Compensation and Management Development Committee Report on Executive Compensation" in our Proxy Statement is furnished and shall not be deemed to be filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, is not subject to the liabilities of that section and is not deemed incorporated by reference in any filing under the Securities Act of 1933, as amended.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information regarding securities authorized for issuance under equity compensation plans required by Item 201(d) of Regulation S-K and the security ownership of certain beneficial owners and management required by Item 403 of Regulation S-K will be presented under the headings "Equity Compensation Stock Plans" and "Security

Ownership of Certain Beneficial Owners and Management" in our Proxy Statement, which information is incorporated by reference herein.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

The information regarding certain relationships and related transactions required by Item 404 and Item 407(a) of Regulation S-K will be presented under the heading "Corporate Governance and Board Matters" in our Proxy Statement, which information is incorporated by reference herein.

Item 14. ***Principal Accountant Fees and Services***

The information regarding our principal accounting fees and services required by Item 9(e) of Schedule 14A will be presented under the heading "Principal Accountant Fees and Services" in our Proxy Statement, which information is incorporated by reference herein.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) 1 and 2.

All other schedules have been omitted since the required information is not present or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and notes thereto.

(a) 3 and (b). The exhibits listed below are filed as part of this annual report.

INDEX TO EXHIBITS

Exhibit No.		Description
2.1+	—	Agreement and Plan of Merger dated as of May 12, 2015, by and among The Williams Companies, Inc., SCMS LLC, Williams Partners, L.P., and WPZ GP LLC (filed on May 13, 2015 as Exhibit 2.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
2.2	—	Amendment No 1. to Agreement and Plan of Merger dated as of May 1, 2016, by and among The Williams Companies, Inc., Energy Transfer Corp LP, Energy Transfer Corp GP, LLC, Energy Transfer Equity, L.P., LE GP, LLC and Energy Transfer Equity GP, LLC (filed on May 3, 2016 as Exhibit 2.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
2.3+	—	Agreement and Plan of Merger dated as of September 28, 2015, by and among The Williams Companies, Inc., Energy Transfer Corp LP, Energy Transfer Corp GP, LLC, Energy Transfer Equity, L.P., LE GP, LLC and Energy Transfer Equity GP, LLC (filed on October 1, 2015 as Exhibit 2.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).

Exhibit No.		Description
2.4	—	Share Purchase Agreement by and between The Williams Companies International Holdings B.V. and Inter Pipeline Ltd. and The Williams Companies, Inc., dated August 8, 2016 (filed on August 12, 2016 as Exhibit 2.1 to The Williams Companies, Inc.'s current report on Form 8-K (file No. 001-04174) and incorporated herein by reference).
2.5	—	Share Purchase Agreement by and between Williams Energy Canada LP and Inter Pipeline Ltd. and Williams Partners L.P., dated August 8, 2016 (filed on August 12, 2016 as Exhibit 2.2 to The Williams Companies, Inc.'s current report on Form 8-K (file No. 001-04174) and incorporated herein by reference).
2.6+	—	Interest Swap and Purchase Agreement by and among Western Gas Partners, LP, WGR Operating, LP, Delaware Basin JV Gathering LLC, Williams Partners L.P., Williams Midstream Gas Services LLC, and Appalachia Midstream Services, L.L.C., dated February 9, 2017 (filed on February 10, 2017 as Exhibit 2.1 to The Williams Companies Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
2.7	—	Membership Interest Purchase Agreement, dated as of April 13, 2017, among Williams Field Services Group, LLC, Williams Partners L.P., Williams Olefins, L.L.C., NOVA Chemicals Inc., and NOVA Chemicals Corporation (filed on August 3, 2017 as Exhibit 2.2 to Williams Partners L.P.'s quarterly report on Form 10-Q (File No. 001-34831) and incorporated herein by reference).
3.1	—	Amended and Restated Certificate of Incorporation, (filed on May 26, 2010 as Exhibit 3.(i)1 to The Williams Companies Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
3.2	—	By-Laws (filed on January 20, 2017, as Exhibit 3.1 to The Williams Companies Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
4.1	—	Senior Indenture, dated February 25, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed on February 25, 1997 as Exhibit 4.5.1 to MAPCO Inc.'s Amendment No. l to registration statement on Form S-3 (File No. 333-20837) and incorporated herein by reference).
4.2	—	Supplemental Indenture No. 1, dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed on March 4, 1998 as Exhibit 4(o) to MAPCO Inc.'s annual report on Form 10-K for the fiscal year ended December 31, 1997 (File No. 001-05254) and incorporated herein by reference).
4.3	—	Supplemental Indenture No. 2, dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed on March 4, 1998 as Exhibit 4(p) to MAPCO Inc.'s annual report on Form 10-K for the fiscal year ended December 31, 1997 (File No. 001-05254) and incorporated herein by reference).
4.4	—	Supplemental Indenture No. 3, dated March 31, 1998, among MAPCO Inc., Williams Holdings of Delaware, Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed on March 30, 1999 as Exhibit 4(J) to Williams Holdings of Delaware, Inc.'s annual report on Form 10-K for the fiscal year ended December 31, 1998 (File No. 000-20555) and incorporated herein by reference).
4.5	—	Fourth Supplemental Indenture, dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., The Williams Companies, Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed on March 28, 2000 as Exhibit 4(q) to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).

Exhibit No.		Description
4.6	—	Fifth Supplemental Indenture, dated as of February 1, 2010, between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. (filed on February 2, 2010 as Exhibit 4.3 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
4.7	—	Fifth Supplemental Indenture between The Williams Companies, Inc. and Bank One Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed on March 12, 2001 as Exhibit 4(k) to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
4.8	—	Seventh Supplemental Indenture, dated March 19, 2002, between The Williams Companies, Inc. as Issuer and Bank One Trust Company, National Association, as Trustee (filed on May 9, 2002 as Exhibit 4.1 to The Williams Companies, Inc.'s quarterly report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).
4.9	—	Eleventh Supplemental Indenture, dated as of February 1, 2010, between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. (filed on February 2, 2010 as Exhibit 4.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
4.10	—	Indenture, dated as of May 28, 2003, by and between The Williams Companies, Inc. and JPMorgan Chase Bank, as Trustee (filed on August 12, 2003 as Exhibit 4.2 to The Williams Companies, Inc.'s quarterly report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).
4.11	—	Indenture, dated as of March 5, 2009, among The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A., as Trustee (filed on March 11, 2009 as Exhibit 4.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
4.12	—	First Supplemental Indenture, dated as of February 1, 2010, between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. (filed on February 2, 2010 as Exhibit 4.2 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
4.13	—	Indenture, dated December 18, 2012, between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. as trustee (filed on December 20, 2012 as Exhibit 4.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
4.14	—	First Supplemental Indenture, dated December 18, 2012, between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. as trustee (filed on December 20, 2012 as Exhibit 4.2 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
4.15	—	Second Supplemental Indenture, dated as of June 24, 2014, between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on June 24, 2014 as Exhibit 4.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
4.16	—	Indenture, dated as of February 9, 2010, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A. (filed on February 10, 2010 as Exhibit 4.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
4.17	—	First Supplemental Indenture, dated as of February 2, 2015, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A. (filed on February 3, 2015, as Exhibit 4.5 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-34831) and incorporated herein by reference).

Exhibit No.		Description
4.18	—	Indenture, dated as of November 9, 2010, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on November 12, 2010 as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).
4.19	—	First Supplemental Indenture, dated as of November 9, 2010, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on November 12, 2010 as Exhibit 4.2 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).
4.20	—	Second Supplemental Indenture, dated as of November 17, 2011, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed November 18, 2011 as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).
4.21	—	Third Supplemental Indenture (including Form of 3.35% Senior Notes due 2022), dated as of August 14, 2012, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on August 14, 2012 as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).
4.22	—	Fourth Supplemental Indenture, dated as of November 15, 2013, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N .A., as trustee (filed on November 18, 2013 as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).
4.23	—	Fifth Supplemental Indenture, dated as of March 4, 2014, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on March 4, 2014 as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).
4.24	—	Sixth Supplemental Indenture, dated as of June 27, 2014, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on June 27, 2014 as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).
4.25	—	Seventh Supplemental Indenture, dated as of February 2, 2015, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A. (filed on February 3, 2015, as Exhibit 4.4 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-34831) and incorporated herein by reference).
4.26	—	Eighth Supplemental Indenture, dated as of March 3, 2015, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on March 3, 2015 as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-34831) and incorporated herein by reference).
4.27	__	Ninth Supplemental Indenture, dated as of June 5, 2017, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee. (filed on June 5, 2017 as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-34831) and incorporated herein by reference).
4.28	—	Indenture, dated as of December 19, 2012, by and among Access Midstream Partners, L.P., ACMP Finance Corp., the guarantors listed therein and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on December 19, 2012 as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-34831) and incorporated herein by reference).

Exhibit No.		Description
4.29	—	Third Supplemental Indenture, dated as of March 7, 2014, among the Access Midstream Partners, L.P., ACMP Finance Corp, the Guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on March 7, 2014 as Exhibit 4.2 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-34831) and incorporated herein by reference).
4.30	—	Senior Indenture, dated as of November 30, 1995, between Northwest Pipeline Corporation and Chemical Bank, Trustee (filed September 14, 1995 as Exhibit 4.1 to Northwest Pipeline's registration statement on Form S-3 (File No. 033-62639) and incorporated herein by reference).
4.31	—	Indenture, dated May 22, 2008, between Northwest Pipeline GP and The Bank of New York Trust Company, N.A., as Trustee (filed on May 23, 2008 as Exhibit 4.1 to Northwest Pipeline GP's current report on Form 8-K (File No. 001-07414) and incorporated herein by reference).
4.32	—	Indenture, dated as of April 3, 2017, between Northwest Pipeline LLC and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on April 3, 2017 as Exhibit 4.1 to Northwest Pipeline's current report on Form 8-K (File No. 001-07414) and incorporated herein by reference).
4.33	—	Senior Indenture, dated as of July 15, 1996, between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed on April 2, 1996 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's registration statement on Form S-3 (File No. 333-02155) and incorporated herein by reference).
4.34	—	Indenture, dated May 22, 2008, between Transcontinental Gas Pipe Line Corporation and The Bank of New York Trust Company, N.A., as Trustee (filed on May 23, 2008 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's current report on Form 8-K (File No. 001-07584) and incorporated herein by reference).
4.35	—	Indenture, dated as of August 12, 2011, between Transcontinental Gas Pipe Line Company, LLC and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on August 12, 2011 as Exhibit 4.1 to Transcontinental Gas Pipe Line Company, LLC's current report on Form 8-K (File No. 001-07584) and incorporated herein by reference).
4.36	—	Indenture, dated as of July 13, 2012, between Transcontinental Gas Pipe Line Company, LLC and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on July 16, 2012 as Exhibit 4.1 to Transcontinental Gas Pipe Line Company, LLC's current report on Form 8-K (File No. 001-07584) and incorporated herein by reference).
4.37	—	Indenture, dated as of January 22, 2016, between Transcontinental Gas Pipe Line Company, LLC and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on January 22, 2016 as Exhibit 4.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
10.1*§	—	The Williams Companies Amended and Restated Retirement Restoration Plan effective as of December 1, 2017.
10.2§	—	Form of Director and Officer Indemnification Agreement (filed on September 24, 2008 as Exhibit 10.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
10.3§	—	Form of 2013 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed on February 27, 2013 as Exhibit 10.6 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.4§	—	Form of 2013 Restricted Stock Unit Agreement among Williams and certain nonmanagement directors (filed on February 26, 2014 as Exhibit 10.11 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).

Exhibit No.		Description
10.5§	—	Form of 2014 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 26, 2014 as Exhibit 10.6 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.6§	—	Form of 2014 Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 26, 2014 as Exhibit 10.7 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.7§	—	Form of 2014 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed on February 26, 2014 as Exhibit 10.8 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.8§	—	Form of 2014 Restricted Stock Unit Agreement among Williams and certain nonmanagement directors (filed on February 25, 2015 as Exhibit 10.12 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.9§	—	Form of October 2014 Leveraged Performance Unit Award Agreement among Williams and certain officers (filed on February 25, 2015 as Exhibit 10.13 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.10§	—	Form of Leveraged Performance Unit Award Agreement dated January 1, 2015 between Williams and Walter Bennett (filed on February 25, 2015 as Exhibit 10.14 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.11§	—	Form of 2015 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 25, 2015 as Exhibit 10.15 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.12§	—	Form of 2015 Time-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 25, 2015 as Exhibit 10.16 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.13§	—	Form of 2015 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed on February 25, 2015 as Exhibit 10.17 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.14§	—	Form of 2015 Non-Equity Incentive Award Agreement among The Williams Companies Inc. and certain employees and officers (filed on October 29, 2015 as Exhibit 10.3 to The Williams Companies, Inc. quarterly report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).
10.15§	—	Form of 2016 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 22, 2017 as Exhibit 10.18 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.16§	—	Form of 2016 Time-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 22, 2017 as Exhibit 10.19 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.17§	—	Form of 2016 Time-Based Restricted Stock Unit Agreement among Williams and certain employees and officers vesting February 22, 2019 (filed on February 22, 2017 as Exhibit 10.20 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.18§	—	Form of 2016 Time-Based Restricted Stock Unit Agreement among Williams and certain non-management directors (filed on February 22, 2017 as Exhibit 10.21 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).

Exhibit No.		Description
10.19§	—	Form of 2016 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed on February 22, 2017 as Exhibit 10.22 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.20§	—	Form of 2017 Time-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 22, 2017 as Exhibit 10.23 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.21§	—	Form of 2017 Time-Based Restricted Stock Unit Agreement among Williams and certain non-management directors (filed on February 22, 2017 as Exhibit 10.24 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.22§	—	Form of 2017 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed on February 22, 2017 as Exhibit 10.25 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.23§	—	Form of 2017 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on May 4, 2017 as Exhibit 10.10 to The Williams Companies, Inc.'s quarterly report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).
10.24§	—	The Williams Companies, Inc. 1996 Stock Plan for Nonemployee Directors (filed on March 27, 1996 as Exhibit B to The Williams Companies, Inc.'s Definitive Proxy Statement (File No. 002-27038) and incorporated herein by reference).
10.25§	—	The Williams Companies, Inc. 2002 Incentive Plan as amended and restated effective as of January 23, 2004 (filed on August 5, 2004 as Exhibit 10.1 to The Williams Companies, Inc.'s quarterly report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).
10.26§	—	Amendment No. 1 to The Williams Companies, Inc. 2002 Incentive Plan (filed on February 25, 2009 as Exhibit 10.11 t o The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.27§	—	Amendment No. 2 to The Williams Companies, Inc. 2002 Incentive Plan (filed on February 25, 2009 as Exhibit 10.12 t o The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.28§	—	Amended and Restated Change-in-Control Severance Agreement between the Company and certain executive officers (Tier I Executives) (filed on February 27, 2013 as Exhibit 10.14 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.29§	—	Amended and Restated Change-in-Control Severance Agreement between the Company and certain executive officers (Tier II Executives) (filed on February 28, 2012, as Exhibit 10.14 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.30§	—	The Williams Companies, Inc. Executive Severance Pay Plan, dated November 14, 2012 (filed July 20, 2016, as Exhibit 10.2 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
10.31§	—	First Amendment to The Williams Companies Inc. Executive Severance Pay Plan (filed July 20, 2016, as Exhibit 10.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).

Exhibit No.		Description
10.32	—	Separation and Distribution Agreement dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (Filed on February 28, 2012 as Exhibit 10.19 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.33	—	Tax Sharing Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (filed on January 6, 2012 as Exhibit 10.3 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
10.34§	—	Letter Agreement, dated January 27, 2014, with James E. Scheel, Senior Vice President - Northeast G&P, regarding Relocation from Pennsylvania Benefits (filed on May 1, 2014 as Exhibit 10.2 to The Williams Companies, Inc.'s quarterly report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).
10.35§	—	The Williams Companies, Inc. 2007 Incentive Plan as amended and restated effective July 14, 2016 (filed on February 22, 2017 as Exhibit 10.38 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.36	—	Termination Agreement and Release, dated as of September 29, 2015, by and among The Williams Companies, Inc., SCMS LLC, Williams Partners L.P. and WPZ GP LLC (filed on September 28, 2015 as Exhibit 10.1 to Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
10.37	—	Second Amended and Restated Credit Agreement dated as of February 2, 2015, between The Williams Companies, Inc., the lenders named therein, and Citibank, N.A. as Administrative Agent (filed on February 3, 2015 as Exhibit 10.1 to The Williams Companies, Inc.'s current report on Form 8-K (File 001-04174) and incorporated herein by reference).
10.38	—	Amendment No. 1 and Extension Agreement, dated as of November 17, 2017, by and among The Williams Companies, Inc., the lenders party thereto and Citibank, N.A. (filed on November 22, 2017 as Exhibit 10.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
10.39	—	Second Amended and Restated Credit Agreement dated as of February 2, 2015, between Williams Partners L.P., Northwest Pipeline LLC, Transcontinental Gas Pipeline Company, LLC, as co-borrowers, the lenders named therein, and Citibank, N.A. as Administrative Agent (filed on February 3, 2015 as Exhibit 10.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-34831) and incorporated herein by reference).
10.40	—	Amendment No. 1 to Second Amended and Restated Credit Agreement dated as of December 18, 2015, between Williams Partners L.P., Northwest Pipeline LLC, Transcontinental Gas Pipe Line Company, LLC, as co-borrowers, the lenders named therein, and Citibank, N.A. as Administrative Agent (filed on December 23, 2015 as Exhibit 10.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
10.41	—	Amendment No. 2 and Extension Agreement, dated as of November 17, 2017, by and among Williams Partners L.P., Northwest Pipeline LLC, and Transcontinental Gas Pipe Line Company LLC, the lenders party thereto and Citibank, N.A. (filed on November 22, 2017 as Exhibit 10.2 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
10.42	—	Form of Amended and Restated Commercial Paper Dealer Agreement, dated as of February 2, 2015, between Williams Partners L.P., as Issuer, and the Dealer party thereto (filed on February 3, 2015 as Exhibit 10.3 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-34831) and incorporated herein by reference).

Exhibit No.		Description
10.43	—	Common Unit Issuance Agreement, dated January 9, 2017 (filed on January 10, 2017, as Exhibit 2 to Schedule 13D/A (File No. 005-86017) by The Williams Companies, Inc. relating to the common units representing limited partner interests of Williams Partners L.P. and incorporated herein by reference.)
10.44	—	Common Unit Purchase Agreement, dated January 9, 2017 (filed on January 10, 2017, as Exhibit 3 to Schedule 13D/A (File No. 005-86017) by The Williams Companies, Inc. relating to the common units representing limited partner interests of Williams Partners L.P. and incorporated herein by reference.)
10.45	—	Separation Agreement and General Release entered into by and among Robert S. Purgason and The William Companies, Inc., dated March 21, 2017 (filed on March 24, 2017, as Exhibit 10.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
12*	—	Computation of Ratio of Earnings to Combined Fixed Charges.
14	—	Code of Ethics for Senior Officers (filed on March 15, 2004 as Exhibit 14 to The Williams Companies, Inc.'s annual report on Form 10-K and incorporated herein by reference).
21*	—	Subsidiaries of the registrant.
23.1*	—	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
23.2*		Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP.
23.3*	—	Consent of Independent Registered Public Accounting Firm, Deloitte & Touche LLP.
31.1*	—	Certification of the Chief Executive Officer pursuant to Rules 13a-l 4(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(3 l) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	—	Certification of the Chief Financial Officer pursuant to Rules 13a-14(a) and l 5d-l 4(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32**	—	Certification of the Chief Executive Officer and the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	—	XBRL Instance Document.
101.SCH*	—	XBRL Taxonomy Extension Schema.
101.CAL*	—	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF*	—	XBRL Taxonomy Extension Definition Linkbase.
101.LAB*	—	XBRL Taxonomy Extension Label Linkbase.
101.PRE*	—	XBRL Taxonomy Extension Presentation Linkbase.

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* Filed herewith

** Furnished herewith

§ Management contract or compensatory plan or arrangement

+ Pursuant to item 601(6)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

Item 16. ***Form 10-K Summary***

Not applicable.

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, thereunto duly authorized.

THE WILLIAMS COMPANIES, INC.
(Registrant)

By: /s/ TED T. TIMMERMANS

Ted T. Timmermans
Vice President, Controller and
Chief Accounting Officer

Date: February 22, 2018

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.

Signature	Title	Date
/s/ ALAN S. ARMSTRONG Alan S. Armstrong	President, Chief Executive Officer and Director (Principal Executive Officer)	February 22, 2018
/s/ JOHN D. CHANDLER John D. Chandler	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 22, 2018
/s/ TED T. TIMMERMANS Ted T. Timmermans	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)	February 22, 2018
/s/ STEPHEN W. BERGSTROM Stephen W. Bergstrom	Chairman of the Board	February 22, 2018
/s/ STEPHEN I. CHAZEN Stephen I. Chazen	Director	February 22, 2018
/s/ CHARLES I. COGUT Charles I. Cogut	Director	February 22, 2018
/s/ KATHLEEN B. COOPER Kathleen B. Cooper	Director	February 22, 2018
/s/ MICHAEL A. CREEL Michael A. Creel	Director	February 22, 2018
/s/ PETER A. RAGAUSS Peter A. Ragauss	Director	February 22, 2018
/s/ SCOTT D. SHEFFIELD Scott D. Sheffield	Director	February 22, 2018
/s/ MURRAY D. SMITH Murray D. Smith	Director	February 22, 2018

Signature	Title	Date
/s/ WILLIAM H. SPENCE William H. Spence	Director	February 22, 2018
/s/ JANICE D. STONEY Janice D. Stoney	Director	February 22, 2018

THE WILLIAMS COMPANIES
AMENDED AND RESTATED
RETIREMENT RESTORATION PLAN

Effective as of December 1, 2017

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THE WILLIAMS COMPANIES
AMENDED AND RESTATED
RETIREMENT RESTORATION PLAN

ESTABLISHMENT OF PLAN

WHEREAS, The Williams Companies, Inc. and certain of its subsidiaries ("Employers") maintain The Williams Pension Plan ("Pension Plan") for the benefit of eligible employees of the Employers;

WHEREAS, Sections 401(a)(17) and 415 of the Internal Revenue Code (“Code”) establish limitations as to the amount of pension benefit which may be accrued under or payable from the Pension Plan on behalf of any participant therein; and

WHEREAS, The Williams Companies, Inc. desires to amend and restate The Williams Companies Retirement Restoration Plan, as effective January 1, 2008, a supplemental plan under which the portion of the pension benefit (and related death benefit) of an eligible employee of an Employer which becomes subject to such limitations of the Code shall be payable from general corporate assets, to reflect changes in the time of payment with respect to deferred amounts earned or vested on or prior to December 31, 2004, for certain Former Participants who are under age 55 as of December 31, 2017, who are not employed by an Employer as of December 1, 2017, and who had not commenced their benefit under Pre-409A Program under the Williams Retirement Restoration Plan prior to December 1, 2017.

NOW, THEREFORE, The Williams Companies, Inc. hereby adopts, effective as of December 1, 2017, The Williams Companies Retirement Restoration Plan as amended and restated and set forth hereinafter.

ARTICLE I
Introduction

This document is generally effective as of December 1, 2017 (the "Effective Date") and amends and restates The Williams Companies Retirement Restoration Plan, as effective January 1, 2008 (the "2008 Document"), with respect to periods commencing on and after the Effective Date. It sets forth the terms of the Plan applicable to deferrals which are subject to Section 409A of the Code (“Section 409A”), *i.e.*, generally, deferred amounts earned or vested after December 31, 2004 (the "409A Program") and certain deferred amounts earned or vested on or prior to December 31, 2004 for Participants who are under age 55 as of December 31, 2017, who are not employed by an Employer as of December 1, 2017, and who had not commenced their benefit under the Pre-409A Program under Williams Retirement Restoration Plan prior to December 1, 2017 (the “Designated Pre-55 Participants”). Certain other deferrals under the Plan shall be governed by a separate set of documents which set forth the pre-Section 409A terms of the Plan (the "Pre-409A Program") to the extent such other deferrals and the terms of Pre-409A Program are not incorporated into this document. Together, this document, the 2008 Document, The Williams Companies Retirement Restoration Plan, as effective January 1, 2005 (the "2005 Document") and the documents for the Pre-409A Program describe the terms of a single plan. However, amounts subject to the terms of this 409A Program and amounts subject to the terms of the Pre-409A Program shall be tracked separately at all times. Except as provided herein, the terms of the Pre-409A Program continue to apply with respect to amounts earned or vested on or prior to December 31, 2004, for the Designated Pre-55 Participants. The preservation of the terms of the Pre-409A Program, without material modification, and the separation between the 409A Program amounts and the Pre-409A Program amounts are intended to be sufficient to permit the Pre-409A Program, with the exception of the benefits for the Designated Pre-55 Participants, to remain exempt from Section 409A. For Plan benefits which are not exempt from Section 409A, the Plan will be interpreted and administered in a manner so that any amount or benefit payable hereunder shall be paid or provided in a manner that is compliant with the requirements Section 409A and applicable Internal Revenue Service guidance and Treasury Regulations issued thereunder (and any applicable relief under Section 409A). The tax treatment of the benefits provided under the Plan is not warranted or guaranteed. None of the Employers nor their respective directors, officers, employees or advisers shall be held liable for any taxes, interest, penalties or other monetary amounts owed as a result of the application of Section 409A. Subject to the applicable Plan termination provisions and except as provided with respect to the Designated Pre-55 Participants, with respect to vested benefits under the Pre-409A Program: (i) in the case of vested Participants on December 31, 2004 who were receiving vested benefits on such date, such benefits shall continue to be paid under the Pre-409A Program at the same time and in the same amounts as specified under the form of payment in effect on such date; and (ii) in the case of vested Participants who were not receiving vested benefits on such date, such benefits shall be paid under the Pre-409A Program in a lump sum at the time specified in Article IV of The Williams Companies Supplemental Retirement Plan as in effect on December 31, 2004.

ARTICLE II
Definitions

In this Plan, unless the context clearly implies otherwise, the singular includes the plural, the masculine includes the feminine, and initially capitalized words have the following meaning:

2.1 Actuarial Equivalent. An amount or benefit of equivalent current value to the amount or benefit which would otherwise have been provided to or on account of a Participant or Beneficiary determined on the basis of the actuarial assumptions then in effect under the Pension Plan and such other assumptions permitted by Code Section 409A and final regulations promulgated thereunder as may be deemed necessary by an actuary selected by the Company or the Committee.

2.2 Base Pay. The regular wages and salary of a Participant, which is in excess of Code limitations and which does not include any short term disability paid by an Employer, overriding royalties, amounts paid under a phantom override plan, bonuses (including, but not limited to bonuses under The Williams Companies, Inc. Executive Incentive Compensation Plan), salary reduction amounts contributed to The Williams Investment Plus Plan, salary reduction amounts contributed to any qualified transportation plan established by an Employer in accordance with Code Section 132(f)(7) or to any cafeteria plan or flexible benefits plan established by an Employer in accordance Section 125 and related sections of the Code, severance pay, cost of living pay, housing pay, relocation pay (including mortgage interest differential) or any such other taxable and non-taxable fringe benefits and extraordinary compensation of any kind.

2.3 Basic Supplemental Benefit. The amount payable to a Vested Participant in the form of a lump sum distribution based upon the amount credited to his Supplemental Pension Account pursuant to the applicable provisions of this Plan.

2.4 Beneficiary. The Surviving Spouse or other person who is entitled to receive benefits pursuant to Article V of this Plan.

2.5 Benefit Starting Date. With respect to a Supplemental Retirement Benefit, the date shall be the later of the first day of the month following the date the Participant attains age fifty-five (55) or the first day of the month following the expiration of the six (6) month period commencing with the date the Participant incurs a Separation from Service. With respect to a vested benefit, other than a Death Benefit, earned or vested on or prior to December 31, 2004, for a Designated Pre-55 Participant, the date shall be the later of the first day of the month following the date the Participant attains age fifty-five (55) or if the Participant has been reemployed by an Employer prior to age fifty-five (55) and remains so employed past age fifty-five (55), the first day of the month following the expiration of the six (6) month period commencing with the date the Participant incurs a Separation from Service on or after December 1, 2017. With respect to a Death Benefit, the date shall be the first day of the month following the expiration of the three (3) month period commencing with the Participant's date of death. With respect to a Supplemental Disability Benefit, the date shall be the date specified under the provisions of Section 3.5. A benefit payable under the Pre-409A Program, except with respect to a Designated Pre-55 Participant, shall be payable as of the date a corresponding benefit is payable under the Pension Plan.

2.6 Board. The Board of Directors of the Company as constituted from time to time.

2.7 Change in Control. The occurrence of (i) a Change in the Ownership of the Company, as defined below, (ii) a Change in Effective Control of the Company, as defined below, or (iii) a Change in the Ownership of a Substantial Portion of the Assets of the Company, as defined below. To qualify as a Change in Control event, the occurrence of the event shall be objectively determinable, strictly ministerial, and shall not involve any discretionary authority by the plan administrator. Code Section 318(a) shall be applied to determine stock ownership for purposes of this section. Substantially vested stock underlying a vested option is considered owned by the person who holds the vested option (and the stock underlying an unvested option is not considered owned by the person who holds an unvested option). To qualify as a Change in Control with respect to a Participant, the Change in Control must relate to (x) the corporation for whom the Participant is performing services at the time of the Change in Control event; (y) the corporation that is liable for the payment of benefits under this Plan (or all corporations which are liable for payment if more than one corporation is liable) but only if either the benefits are attributable to the performance of service by the Participant for such corporation (or corporations) or there is a bona fide business purpose for such corporation (or corporations) to be liable for such payment and, in either case, no significant purpose of making such corporation or corporations liable for such payment is the avoidance of Federal income tax; or (z) a corporation that is a majority shareholder of a corporation identified in subsections (x) or (y) above, or any corporation in a chain of corporations in which each corporation is a majority shareholder of another corporation in the chain, ending in a corporation identified in subsections (x) or (y) above. The provisions of Treas. Reg. § 1.409A-3, as amended, shall govern with respect to the definition of terms used therein and in the interpretation of whether a Change in Control has occurred.

(a) A "Change in the Ownership of the Company" occurs on the date that any one person or more than one person Acting as a Group, as defined below, acquires ownership of Stock of the Company ("Stock") that, together with Stock held by such person or group, constitutes more than fifty percent (50%) of the total fair market value or total voting power of the Stock. However, if any one person or more than one person Acting as a Group, is considered to own more than fifty percent (50%) of the total fair market value or total voting power of the Stock, the acquisition of additional Stock by the same person or persons is not considered to cause a Change in the Ownership of the Company. An increase in the percentage of Stock owned by any one person, or persons Acting as a Group, as a result of a transaction in which the Company acquires its Stock in exchange for property will be treated as an acquisition of Stock for purposes of this subsection. This subsection applies only when there is a transfer of Stock (or issuance of Stock) and Stock remains outstanding after the transaction.

(b) "Acting as a Group." persons will not be considered to be Acting as a Group solely because they purchase or own Stock at the same time or as a result of the same public offering. However, persons will be considered to be Acting as a Group if they are owners of a corporation that enters into a merger, consolidation, purchase or acquisition of Stock, or similar business transaction with the Company. If a person owns stock in both corporations that enter into a merger, consolidation, purchase or acquisition of Stock or similar transaction involving another corporation, such shareholder is considered to be Acting as a Group with other shareholders only in such corporation prior to the transaction giving rise to the change and not with respect to the ownership interest in the other corporation.

(c) A "Change in the Effective Control of the Company" occurs only on either of the following dates: (1) The date that any one person, or more than one person Acting as a Group, acquires (or has acquired during the twelve (12)-month period ending on the date of the most recent acquisition by such person or persons) ownership of the Stock possessing thirty percent (30%) or more of the total voting power of the Stock of the Company; or (2) The date a majority of members of the Board is replaced during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of the Board before the date of the appointment or election.

If any one person, or more than one person Acting as a Group, is considered to be in effective control of the Company, the acquisition of additional control of the Company by the same person or persons is not considered to cause a Change in the Effective Control of the Company.

(d) A "Change in the Ownership of a Substantial Portion of the Assets of the Company" occurs on the date that any one person, or more than one person Acting as a Group, acquires (or has acquired during the twelve (12)-month period ending on the date of the most recent acquisition by such person or persons) assets from the Company that have a total gross fair market value equal to or more than forty percent (40%) of the total gross fair market value of all assets of the Company immediately prior to such acquisition or acquisitions. For this purpose, the gross fair market value means the value of the assets of the Company or the value of the assets being disposed of, determined without regard to any liabilities associated with such assets. Notwithstanding the foregoing, there is no Change in the Ownership of a Substantial Portion of the Assets of the Company when there is a transfer of assets to an entity that is controlled by the shareholders of the Company immediately after the transfer. A transfer of assets by the Company is not treated as a Change in the Ownership of a Substantial Portion of the Assets of the Company if the assets are transferred to (1) a shareholder of the Company (immediately before the asset transfer) in exchange for or with respect to its Stock; (2) an entity, fifty percent (50%) or more of the total value or voting power of which is owned, directly or indirectly, by the Company; (3) a person, or more than one person Acting as a Group, that owns, directly or indirectly, fifty percent (50%) or more of the total value or voting power of all the outstanding Stock; or (4) an entity, at least fifty percent (50%) of the total value or voting power of which is owned, directly or indirectly, by a person, or more than one person Acting as a Group, that owns, directly or indirectly, fifty percent (50%) or more of the total value or voting power of all the outstanding Stock. For purposes of this subsection (d), and except as otherwise provided, a person's status is determined immediately after the transfer of assets.

2.8 Code. The Internal Revenue Code of 1986, as amended.

2.9 Code Limitations. The limitations on compensation which may be taken into account in determining benefits under and on benefits payable from the Pension Plan imposed by Sections 401(a)(17) and 415 of the Code.

2.10 Committee. The Compensation Committee of the Board.

2.11 Company. The Williams Companies, Inc., a Delaware corporation or any successor thereto.

2.12 Credit Date. (a) With respect to Supplemental Compensation Credits, the last day of the applicable Plan Year referenced in the context in which such term is used, and (b) with respect to Supplemental Interest Credits, the last day of each quarter of each Plan Year.

2.13 Death Benefit. The benefit provided under Article V of this Plan to the Surviving Spouse or other Beneficiary of a Participant. With respect to a Designated Pre-55 Participant, Death Benefit will also include the benefit, if any, provided under Article V of the Pre-409A Program.

2.14 Disability. A physical or mental condition which satisfies the requirements for disability payments under The Williams Companies, Inc. Long-Term Disability Plan as in effect on January 1, 2008.

2.15 Eligible Employee. Any Employee of an Employer who (a) is a participant in the Pension Plan and (b) holds a position that has been classified as an executive position by the Company's executive compensation department.

2.16 Employee. An "eligible Employee" as such term is defined under the Pension Plan.

2.17 Employer. An "Employer" as such term is defined under the Pension Plan.

2.18 Former Participant. A Participant who has a benefit which becomes payable after November 31, 2017 under either the Pre-409A Program portion or the 409A Program portion of this Plan but who is no longer an Eligible Employee.

2.19 Key Employee. An employee designated on an annual basis by the Company as of December 31 (the "Key Employee Designation Date") as an employee meeting the requirements of Section 416(i) of Code without regard to paragraph (5) thereof utilizing the definition of compensation under Treasury Regulation § 1.415(c)-2(d)(2). A Participant designated as a "key employee" shall be a "key employee" for the entire twelve (12) month period beginning on April 1 following the Key Employee Designation Date.

2.20 Nonservice Participant. A Vested Participant who is a "Nonservice Participant" as such term is defined under the Pension Plan.

2.21 Normalized Pension Benefit. The pension benefit which would have been paid during a Plan Year to the Participant or his Beneficiary (including a spouse or other contingent annuitant) pursuant to the benefit formula set forth in Section 2.1 of the Pension Plan which is applicable to such Participant and the method of payment selected by the Participant under the Pension Plan, without taking into account the Code Limitations; but (for any Plan Year beginning on or after January 1, 2002) taking into account only the Supplemental Retirement Compensation of the Participant in lieu of "Compensation" under Section 2.19 of the Pension Plan.

2.22 Participant. An Eligible Employee who agrees to be bound by the terms of this Plan by filing such form or forms, if any, as the Committee may require. Such term includes a Former Participant, a Rule of 55 Participant, a Transitional Participant and a Vested Participant as appropriate in the circumstances in which the term is used in the Plan.

2.23 Pension Plan. The Williams Pension Plan, as in effect on January 1, 2005 and as amended and/or restated from time to time. With respect to a Participant who has a benefit payable under the Williams Inactive Employees Pension Plan, as in effect January 1, 2005 and as amended and/or restated from time to time, such plan is also included within such term.

2.24 Pension Plan Benefit. The pension benefit actually paid during a Plan Year to the Participant or his Beneficiary (including a spouse or other contingent annuitant) pursuant to the benefit formula (set forth in Section 2.1 of the Pension Plan) which is applicable to such Participant and the method of payment selected by the Participant under such plan.

2.25 Plan. The Williams Companies Retirement Restoration Plan, effective as of December 1, 2017 as set forth in this and related documents which comprise the 409A Program and the Pre-409A Program and as amended and/or restated from time to time. The provisions of this document are generally effective for periods commencing on and after December 1, 2017 with respect to deferred amounts earned or vested after December 31, 2004 under the 409A Program as described in Article I and for deferred amounts earned or vested on or prior to December 31, 2004, for Designated Pre-55 Participants. As described in Article I, vested benefits of Participants, other than Designated Pre-55 Participants, who were not receiving payment of vested benefits on December 31, 2004 are payable under the Pre-409A Program in a lump sum at the time specified in Article IV of The Williams Companies Supplemental Retirement Plan as in effect on December 31, 2004.

2.26 Plan Interest Rate . The rate of interest applicable under the terms of the Plan for determining Supplemental Interest Credits as of any Credit Date determined as the rate for the month of September immediately preceding the respective Plan Year in which the rate is applicable under the Plan, which rate is based upon the annual rate for 30-year Treasury securities as specified by the Commissioner of Internal Revenue in revenue rulings, notices and other guidance published in the Internal Revenue Bulletin.

2.27 Plan Year. Each twelve (12) consecutive month fiscal year beginning January 1 and ending December 31.

2.28 Rule of 55 Participant. A Vested Participant: (a) whose attained age in years and number of Years of Service credited as Benefit Service aggregated pursuant to the terms of the Pension Plan as of March 31, 1998 equaled at least fifty-five (55); (b) who is not a Transitional Participant; and (c) who incurs a Separation from Service after attaining age fifty-five (55) and is then eligible for an Early Pension pursuant to Section 5.2 of the Pension Plan.

2.29 Separation from Service. The Participant's termination or deemed termination from employment with the Company and its Affiliates. For purposes of determining whether a separation from service has occurred, the employment relationship is treated as continuing intact while the Participant is on military leave, sick leave or other bona fide leave of absence if the period of such leave does not exceed six (6) months, or if longer, so long as the Participant retains a right to reemployment with his or her employer under an applicable statute or by contract. For this purpose, a leave of absence constitutes a bona fide leave of absence only if there is a reasonable expectation that the Participant will return to perform services for his or her employer. If the period of leave exceeds six (6) months and the Participant does not retain a right to reemployment under an applicable statute or by contract, the employment relationship will be deemed to terminate on the first date immediately following such six (6) month period. Notwithstanding the foregoing, if a leave of absence is due to any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than six (6) months, and such impairment causes the Participant to be unable to perform the duties of the Participant's position of employment or any substantially similar position of employment, a twenty-nine (29) month period of absence shall be substituted for such six (6) month period. For purposes of this Section 2.29, a separation from service occurs at the date as of which the facts and circumstances indicate either that, after such date: (A) the Participant and the Company reasonably anticipate the Participant will perform no further services for the Company and its Affiliates (whether as an employee or an independent contractor), or (B) that the level of bona fide services the Participant will perform for the Company and its Affiliates (whether as an employee or independent contractor) will permanently decrease to no more than twenty (20%) of the average level of bona fide services performed over the immediately preceding thirty-six (36) month period or, if the Participant has been providing services to the Company and its Affiliates for less than thirty-six (36) months, the full period over which the Participant has rendered services, whether as an employee or independent contractor. The determination of whether a separation from service has occurred shall be governed by the provisions of Treasury Regulation § 1.409A-1, as amended, taking into account the objective facts and circumstances with respect to the level of bona fide services performed by the Participant after a certain date.

2.30 Service Participant. A Vested Participant who is a "Service Participant" as such term is defined under the Pension Plan.

2.31 Supplemental Compensation Credit. The amount deemed credited to a Participant's Supplemental Pension Account based upon his Supplemental Retirement Compensation for a Plan Year (or any part of a Plan Year and for a disabled Participant accruing Benefit Service credit or Compensation Credit pursuant to Section 5.3 of the Pension Plan, based upon his rate of Supplemental Retirement Compensation as of the date his Disability commenced), with such amount deemed to be credited as of the Credit Date for such Plan Year and determined in accordance with the following:

(a) Service Participant.

Age* on Credit Date	**Credit Rate On Supplemental Retirement Compensation**		**Credit Rate On Supplemental Retirement Compensation Above Wage Base****		**Credit Rate For Past Service*** On All Supplemental Retirement Compensation**
Prior to 29	4.50%	+	1.00%	+	0.30% x Past Service
29	4.50%	+	See **** below	+	0.30% x Past Service
30 through 39	6.00%	+	2.00%	+	0.30% x Past Service
40 through 49	8.00%	+	3.00%	+	0.30% x Past Service
50 and older	10.00%	+	5.00%	+	0.30% x Past Service

(b) Nonservice Participant.

Age* on Credit Date	Credit Rate On Supplemental Retirement Compensation		Credit Rate On Supplemental Retirement Compensation Above Wage Base**
Prior to 29	4.50%	+	1.00%
29	4.50%	+	See **** below
30 through 39	6.00%	+	2.00%
40 through 49	8.00%	+	3.00%
50 and older	10.00%	+	5.00%

* Age means actual age measured in years attained as of the applicable Credit Date.
** Wage Base means the taxable wage base under the Federal Insurance Contributions Act applicable for the Plan Year of the applicable Credit Date (Plan Year of Disability for a disabled Participant accruing Compensation Credit pursuant to Section 5.3 of the Pension Plan).
*** Past Service means Benefit Service credited as of March 31, 1998.
****For Plan Years beginning on or after January 1, 2002, and before January 1, 2008, the rate is 1.00% on Compensation up to 170 percent of the Wage base and the rate is 1.13% on Compensation greater than 170 percent of the Wage Base. For Plan Years beginning on or after January 1, 2008, the rate is 1.20% on Compensation above the Wage Base.

2.32 Supplemental Interest Credit. The amount deemed credited to a Participant's Supplemental Pension Account based upon the balance in his Supplemental Pension Account on the Credit Date in a Plan Year (prior to the inclusion of the Supplemental Compensation Credit, if any, for such Plan Year) multiplied by the Plan Interest Rate applicable for such Plan Year.

2.33 Supplemental Pension Account. A hypothetical account maintained for recordkeeping purposes only on behalf of a Participant to record the amount which would have accumulated if contributions had been made for each Plan Year of such Participant's active participation equal to his Supplemental Compensation Credit and if such contributions and Supplemental Interest Credits had accumulated with interest at the applicable Plan Interest Rate until his Benefit Starting Date.

2.34 Supplemental Retirement Benefit. The portion of a Participant's pension benefit under the 409A Program portion of this Plan determined in accordance with Article III for periods commencing on and after December 31, 2004, as described in Article I.

2.35 Supplemental Retirement Compensation. The portion of the total wages or salary, if any, which is in excess of Code Limitations paid to a Participant each Plan Year by an Employer or an affiliate, including Base Pay, short term disability ("STD") paid by an Employer, overriding royalties, amounts paid under a phantom override plan, bonuses (unless specifically excluded under a written bonus arrangement such as The Williams Companies, Inc. Executive Incentive Compensation Plan), if any, when paid, salary reduction amounts contributed to The Williams Investment Plus Plan, salary reduction amounts contributed to any qualified transportation plan established by the Company in accordance with Code Section 132(f)(4) or to any cafeteria plan or flexible benefits plan established by the Company in accordance with Code Section 125 and related sections of the Code, but excluding severance pay, cost of living pay, housing pay, relocation pay (including mortgage interest differential) and all such other taxable and non-taxable fringe benefits and extraordinary compensation, all as determined by the Committee, in its sole and absolute discretion. For purposes of determining "Average Monthly Compensation" and "Compensation Credits" under the Pension Plan, the Supplemental Retirement Compensation taken into account with respect to any Plan Year beginning on or after January 1, 2002, shall not exceed three (3) times such Participant's rate of Base Pay as of the last day of such Plan Year. For purposes of determining an "Accrued Benefit" under the Pension Plan, if a Participant is credited with less than two thousand eighty (2,080) "Hours of Service" under the Pension Plan for determining "Benefit Service" under the Pension Plan during a Plan Year, his Supplemental Retirement Compensation for that Plan Year shall be the product of his actual Supplemental Retirement Compensation for such Plan Year as described above multiplied by a fraction the numerator of which is two thousand eighty (2,080) and the denominator of which is the number of "Hours of Service" under the Pension Plan with which he is credited for such Plan Year.

2.36 Supplemental Survivor Pension. An amount payable in accordance with Section 5.1 to the Surviving Spouse or Beneficiary of a Vested Participant who died prior to the Benefit Starting Date of his Supplemental Retirement Benefit in a lump sum distribution determined by the balance of such Participant's Supplemental Pension Account at the date the amount of such distribution is determined.

2.37 Surviving Spouse. The person to whom a Participant is married on the date of his death and/or any former spouse to the extent provided in a qualified domestic relations order within the meaning of Code Section 414(p) and determined by the Committee to be effective with respect to the Participant's interest in the Plan; provided, however, a spouse shall not be a Surviving Spouse for purposes of eligibility for a Survivor Pension or other death benefit payable under Article V, unless such spouse was continuously married to the vested Participant on whose behalf such Survivor Pension or other death benefit is payable for the thirty (30) day period immediately prior to such vested Participant's death.

2.38 Termination of Employment. The date on which a Participant incurs a "Termination of Employment" as defined in Section 2.71 of the Pension Plan.

2.39 Transitional Participant. A Participant who (a) was a Participant and an Eligible Employee or a disabled Participant accruing Benefit Service pursuant to Section 5.3 of the Pension Plan on March 31, 1998 and April 1, 1998; (b) had attained at least age fifty (50) as of April 1, 1998; or (c) was a "Transitional Participant" under the terms of the Transco Energy Company Retirement Plan or the Texas Gas Retirement Plan, as defined under either such plan on the date his employment was directly transferred to an Employer.

2.40 Vested Participant. A Participant who is not a Transitional Participant and who is vested in his Basic Supplemental Benefit under the provisions of Article IV of this Plan.

ARTICLE III

Supplemental Retirement Benefits

3.1 Restoration of Credited Service for a Transitional Participant Following the recommencement of employment with an Employer by a Transitional Participant whose employment with an Employer was terminated at a time when such Transitional Participant had a Supplemental Retirement Benefit and whose benefit had commenced to be paid, such Transitional Participant's subsequent Supplemental Retirement Benefit shall be reduced, but not below zero, by an amount which is the Actuarial Equivalent of the amount of Supplemental Retirement Benefit previously paid. If the Transitional Participant does not have a subsequent Supplemental Retirement Benefit, then the Transitional Participant shall not be required to reimburse this Plan with respect to any portion of the Supplemental Retirement Benefit previously paid to such Transitional Participant.

3.2 Cash Balance Supplemental Retirement Benefit for a Vested Participant . A Vested Participant's cash balance Supplemental Retirement Benefit shall be the amount credited to the Vested Participant's Supplemental Pension Account upon his Benefit Starting Date.

3.3 Cash Balance Supplemental Early Retirement Benefit . Solely with respect to a Rule of 55 Participant who incurs a Separation from Service with an Employer on or after age fifty-five (55), the amount credited to the Participant's Supplemental Pension Account shall be multiplied by the applicable percentage in the following schedule and any amount in excess of 100% of the Supplemental Pension Account shall be paid on the Benefit Starting Date.

Aggregate of Attained Age and Credited Benefit Service as of March 31, 1998	**Multiplier Percentage for Attained Age at Benefit Starting Date**			
	55 - 62	63	64	65
55 - 64	115%	115%	108%	100%
65 - 69	120%	120%	108%	100%
70 and over	125%	122%	108%	100%

3.4 Supplemental Disability Benefit. If the Disability of a Participant continues past age fifty-five (55), the amounts credited to such Participant's Supplemental Pension Account until age fifty-five (55) shall be distributed pursuant to the first or last sentences of Section 2.5, as applicable. Such Participant shall also be entitled to additional Supplemental Compensation Credits and Supplemental Interest Credits after age fifty-five (55) until the earlier of age sixty-five (65), or the cessation of the Disability for any reason including death. Any such additional supplemental disability credits shall be distributed upon the earlier of the first day of the month following the expiration of the three (3) month period commencing with the Participant's date of death (to the Participant's Beneficiary), or the first day of the month following the date the Participant attains age sixty-five (65).

ARTICLE IV

Vesting and Forfeitures

4.1 Vesting. A Participant shall become vested in his or her Supplemental Retirement Benefit in accordance with the same schedule and rules as are applicable in determining when he or she becomes vested in his or her Pension Plan Benefit.

4.2 Forfeitures. Any amount forfeited by a Participant who does not become vested in a benefit under this Plan shall constitute a reduction of the Employers' liability under this Plan and shall not be allocated to the remaining Participants.

ARTICLE V

Death Benefit

5.1 Cash Balance Supplemental Survivor Pension. The Surviving Spouse or other designated Beneficiary or Beneficiaries of a deceased, Vested Participant shall receive a Supplemental Survivor Pension with payments commencing on the Benefit Starting Date. Payment shall be made in accordance with a properly completed Beneficiary designation form provided by the Committee, signed and dated by such Participant and timely filed with the Committee (or its delegate). In the event a properly completed and timely filed Beneficiary designation form is not so filed or all designated Beneficiaries predeceased such Participant, payment shall be made to his Surviving Spouse, or, in the absence of a Surviving Spouse, to his estate which shall be deemed to be his Beneficiary.

5.2 Payment of Death Benefit . Any death benefit payable under this Article V shall be paid on the Benefit Starting Date in the form of a lump sum distribution.

5.3 Non-duplication of Benefits. If any payments are made pursuant to this Article V, no payments shall be made pursuant to any other provision of this Plan.

ARTICLE VI

Administration of the Plan

6.1 Administration by Committee. The Plan shall be administered by the Committee.

6.2 Operation of the Committee.

(a) The Committee shall act by a majority of its members constituting a quorum and such action may be taken either by a vote in a meeting or in writing without a meeting. A quorum shall consist of a majority of the members of the Committee. No Committee member shall act upon any question pertaining solely to himself, and with respect to any such question only the other Committee members shall act.

(b) The Committee may allocate responsibility for the performance of any of its duties or powers to one or more Committee members or employees of the Employers.

(c) The Committee or its designee shall keep such books of account, records and other data as may be necessary for the proper administration of the Plan.

6.3 Powers and Duties of the Committee. The Committee shall be generally responsible for the operation and administration of the Plan. To the extent that powers are not delegated to others pursuant to provisions of this Plan, the Committee shall have such powers as may be necessary to carry out the provisions of the Plan and to perform its duties hereunder, including, without limiting the generality of the foregoing, the power:

(a) To appoint, retain and terminate such persons as it deems necessary or advisable to assist in the administration of the Plan or to render advice with respect to the responsibilities of the Committee under the Plan, including accountants, actuaries, administrators, attorneys and physicians.

(b) To make use of the services of the employees of the Employers in administrative matters.

(c) To obtain and act on the basis of all tables, valuations, certificates, opinions, and reports furnished by the persons described in paragraph (a) or (b) above. Any determination of Actuarial Equivalent benefits by the actuary selected by the Company or the Committee shall be conclusive and binding on the Employers, the Committee and all Participants, Former Participants and Beneficiaries.

(d) To review the manner in which benefit claims and other aspects of the Plan administration have been handled by the employees of the Employers.

(e) To determine all benefits and resolve all questions pertaining to the administration and interpretation of the Plan provisions, either by rules of general applicability or by particular decisions. To the maximum extent permitted by law, all interpretations of the Plan and other decisions of the Committee shall be conclusive and binding on all parties.

(f) To adopt such forms, rules and regulations as it shall deem necessary or appropriate for the administration of the Plan and the conduct of its affairs, provided that any such forms, rules and regulations shall not be inconsistent with the provisions of the Plan.

(g) To remedy any inequity resulting from incorrect information received or communicated or from administrative error.

(h) To commence or defend any litigation arising from the operation of the Plan in any legal or administrative proceeding.

6.4 Required Information. Any Participant or Former Participant and any Beneficiary eligible to receive benefits under the Plan shall furnish to the Committee any information or proof requested by the Committee and reasonably required for the proper administration of the Plan. Failure on the part of the Participant, Former Participant or Beneficiary to comply with any such request within a reasonable period of time shall be sufficient grounds for delay in the payment of benefits under the Plan until such information or proof is received by the Committee.

6.5 Compensation and Expenses. All expenses incident to the operation and administration of the Plan reasonably incurred, including, without limitation by way of specification, the fees and expenses of attorneys and advisors, and for such other professional, technical and clerical assistance as may be required, shall be paid by the Employers. Members of the Committee shall not be entitled to any compensation by virtue of their services as such nor be required to give any bond or other security; provided, however, that they shall be entitled to reimbursement by the Employers for all reasonable expenses which they may incur in the performance of their duties hereunder and in taking such action as they deem advisable hereunder within the limits of the authority given them by the Plan and by law.

6.6 Indemnification. To the extent provided for in the Company by-laws, each Employer shall indemnify and hold harmless each member of the Board, each member of the Committee, and each officer and employee of an Employer to whom are delegated duties, responsibilities, and authority with respect to this Plan against all claims, liabilities, fines and penalties, and all expenses reasonably incurred by or imposed upon him (including but not limited to reasonable attorney fees) which arise as a result of his actions or failure to act in connection with the operation and administration of this Plan to the extent lawfully allowable and to the extent that such claim, liability, fine, penalty, or expense is not paid for by liability insurance purchased or paid for by an Employer. Notwithstanding the foregoing, an Employer shall not indemnify any person for any such amount incurred through any settlement or compromise of any action unless the Employer consents in writing to such settlement or compromise.

6.7 Claims Procedure. The Committee as constituted and serving from time to time shall adopt, and may change from time to time, claims procedures, provided that such claims procedures and changes thereof shall conform with Section 503 of the Employee Retirement Income Security Act of 1974, as amended, and regulations promulgated thereunder. Such claims procedures, as in effect from time to time shall be deemed to be incorporated herein and made a part hereof.

ARTICLE VII
Miscellaneous

7.1 Benefits Payable by the Employers. All benefits payable under this Plan shall constitute an unfunded obligation of the Employers. Payments shall be made, as due, from the general funds of the Employers. The Employers, at their option, may maintain one or more bookkeeping reserve accounts to reflect their obligations under the Plan and may make such investments as they, or any of them, may deem desirable to assist in meeting such obligations. Any such investments shall be assets of the Employers subject to claims of general creditors. No person eligible for a benefit under this Plan shall have any right, title or interest in any such investments.

7.2 Amendment or Termination. The Committee is authorized to amend the Plan, if such amendment does not increase the costs of the Plan and the Board is authorized to amend, modify, restate or terminate the Plan; provided, however, that (i) no such action by the Committee or the Board shall reduce a Participant's Supplemental Retirement Benefit accrued as of the time thereof, and (ii) any such amendments, modifications, restatement or termination shall be effectuated in a manner which will not result in the imposition of Code Section 409A penalties. Generally, the amendment or termination of the Pre-409A Program shall be effectuated in a manner which either (A) avoids causing the "Grandfathered Benefits" to be materially modified within the meaning of Treas. Reg. 1.409A-6(a)(4); or (B) causes the Pre-409A Program to meet the requirements of Code Section 409A without the imposition of Code Section 409A penalties. In this regard, upon termination of the 409A Program due to a Change in Control, the Pre-409A Program shall be terminated either pursuant to Treas. Reg. 1.409A-6(a)(4)(iii), or pursuant to a plan termination amendment which causes the Pre-409A Program to comply with Code Section 409A. The date of such termination shall be the first business day. Payments under the 409A Program may be accelerated only to the extent permitted by Treas. Reg. 1.409A-3(j)(4). In this regard, if a Change in Control occurs, the service recipient entity that will be primarily liable immediately after the Change in Control transaction for the payment of benefits under the 409A Program shall terminate the 409A Program and all other nonaccount plans which are aggregated with the 409A Program under Treas. Reg. 1-409A-3(j)(4)(ix). The date of such termination shall be the first business day following such Change in Control and all amounts held in the Plan for any Participant shall be distributed in a lump sum within ten (10) business days after such termination.

7.3 Status of Employment. Nothing herein contained shall be deemed: (a) to give to any Participant the right to be retained in the employ of any Employer, subsidiary or affiliate; (b) to affect the right of any Employer to discipline or discharge any Participant at any time; (c) to give any Employer, subsidiary or affiliate the right to require any Participant to remain in its employ; or (d) to affect any Participant's right to terminate his or her employment at any time.

7.4 Payments to Minors and Incompetents. If a Participant, Former Participant or Beneficiary entitled to receive any benefits hereunder is a minor or is deemed by the Committee or is adjudged to be legally incapable of giving a valid receipt and discharge for such benefits, they will be paid to the duly appointed guardian of such minor or incompetent or to such other person or entity as the Committee may designate. Such payment shall, to the extent made, be deemed a complete discharge of any liability for such payment under the Plan.

7.5 Inalienability of Benefits. The right of any person to any benefit or payment under the Plan shall not be subject to voluntary or involuntary transfer, alienation or assignment, and, to the fullest extent permitted by law, shall not be subject to attachment, execution, garnishment, sequestration or other legal or equitable process. In the event a person who is receiving or is entitled to receive benefits under the Plan attempts to assign, transfer or dispose of such right, or if an attempt is made to subject said right to such process, such assignment, transfer or disposition shall be null and void.

7.6 Qualified Domestic Relations Orders. If a qualified domestic relations order is applicable to a Participant's Pension Plan Benefit, such Participant's Pension Plan Benefit shall be deemed to be the amount which would have otherwise been payable to the Participant from the Pension Plan if such qualified domestic relations order never existed. To the extent that the Committee determines, in its sole discretion, that a domestic relations order is effective with respect to a Participant’s benefit under the Plan, the benefit payable to the alternate payee under the domestic relations order, with the exception of a Death Benefit, will be paid at the same time and in the same form as the benefit that would otherwise be payable to the Participant under the Plan.

7.7 Governing Law. Except to the extent preempted by federal law, the Plan shall be governed by and construed in accordance with the laws of the State of Oklahoma.

7.8 Procedure for Adoption. Any corporation which is a contributing employer under the Pension Plan may, by resolution of such corporation's board of directors, adopt the Plan subject to such terms and conditions as may be required by the Committee consistent with the provisions of the Plan.

Executed in __ counterpart originals this 28th day of November , 2017, effective as hereinbefore provided.

THE WILLIAMS COMPANIES, INC.

By: Robyn Ewing

Exhibit 12

The Williams Companies, Inc.
Computation of Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2017	2016	2015	2014	2013
	(Millions)				
Earnings:					
Income (loss) from continuing operations before income taxes (2)	$ 535	$ (375)	$ (1,713)	$ 3,584	$ 1,080
Less: Equity earnings	(434)	(397)	(335)	(144)	(134)
Income (loss) from continuing operations before income taxes and equity earnings (2)	101	(772)	(2,048)	3,440	946
Add:					
Fixed charges:					
Interest incurred (1)	1,116	1,217	1,118	888	611
Rental expense representative of interest factor	11	11	10	9	11
Total fixed charges	1,127	1,228	1,128	897	622
Distributed income of equity-method investees	780	739	617	409	245
Less:					
Interest capitalized	(33)	(38)	(74)	(141)	(101)
Total earnings as adjusted (2)	$ 1,975	$ 1,157	$ (377)	$ 4,605	$ 1,712
Fixed charges	$ 1,127	$ 1,228	$ 1,128	$ 897	$ 622
Ratio of earnings to fixed charges	1.75	0.94	*	5.13	2.75

(1)Does not include interest related to income taxes, including interest related to liabilities for uncertain tax positions, which is included in *Provision (benefit) for income taxes* in our Consolidated Statement of Operations.

(2)Includes a $2.544 billion non-cash gain in 2014 resulting from remeasuring our previous equity-method investment in ACMP to its preliminary acquisition-date fair value due to acquiring control of ACMP on July 1, 2014.

* Earnings were inadequate to cover fixed charges by $1,505 million for 2015.

Exhibit 21

ENTITY	JURISDICTION
ACMP Finance Corp.	Delaware
Alliance Canada Marketing L.P.	Alberta
Alliance Canada Marketing LTD	Alberta
Appalachia Midstream Services, L.L.C.	Oklahoma
Aux Sable Liquid Products Inc.	Delaware
Aux Sable Liquid Products LP	Delaware
Aux Sable Midstream LLC	Delaware
Bargath LLC	Delaware
Baton Rouge Fractionators LLC	Delaware
Baton Rouge Pipeline LLC	Delaware
Black Marlin Pipeline LLC	Texas
Blue Racer Midstream, LLC	Delaware
Bluestem Gas Services, L.L.C.	Oklahoma
Caiman Energy II, LLC	Delaware
Caiman Ohio Midstream, LLC	Texas
Carbon County UCG, Inc.	Delaware
Carbonate Trend Pipeline LLC	Delaware
Cardinal Gas Services, L.L.C.	Delaware
Cardinal Operating Company, LLC	Delaware
Cardinal Pipeline Company, LLC	North Carolina
Constitution Pipeline Company LLC	Delaware
Discovery Gas Transmission LLC	Delaware
Discovery Producer Services LLC	Delaware
DMP New York, Inc.	New York
Gulfstar One LLC	Delaware
Gulfstream Management & Operating Services, L.L.C.	Delaware
Gulfstream Natural Gas System, L.L.C.	Delaware
HB Construction Company Ltd.	Alberta
HI-BOL Pipeline LLC	Delaware
Inland Ports, Inc.	Tennessee
Jackalope Gas Gathering Services, L.L.C.	Oklahoma
Laurel Mountain Midstream Operating LLC	Delaware
Laurel Mountain Midstream, LLC	Delaware
Louisiana Midstream Gas Services, L.L.C.	Oklahoma
Magnolia Midstream Gas Services, L.L.C.	Oklahoma
Marsh Resources, LLC	Delaware
Mid-Continent Fractionation and Storage, LLC	Delaware
Mockingbird Midstream Gas Services, L.L.C.	Oklahoma
Northwest Pipeline LLC	Delaware
Oklahoma Midstream Gas Services, L.L.C.	Oklahoma
Overland Pass Pipeline Company LLC	Delaware
Pacific Connector Gas Pipeline, LLC	Delaware
Pacific Connector Gas Pipeline, LP	Delaware
Parachute Pipeline LLC	Delaware
Pecan Hill Water Solutions	Delaware

Exhibit 21

ENTITY	JURISDICTION
Pennant Midstream LLC	Delaware
Pine Needle LNG Company, LLC	North Carolina
Pine Needle Operating Company, LLC	Delaware
Ponder Midstream Gas Services, L.L.C.	Delaware
Reserveco Inc.	Delaware
SCMS LLC	Delaware
Texas Midstream Gas Services, L.L.C.	Oklahoma
The Williams Companies Foundation, Inc.	Oklahoma
The Williams Companies, International Holdings B.V.	Dutch BV
Three Rivers Midstream LLC	Delaware
TransCardinal Company, LLC	Delaware
TransCarolina LNG Company, LLC	Delaware
Transco Exploration Company	Delaware
Transcontinental Gas Pipe Line Company, LLC	Delaware
TWC Holdings C.V.	Netherlands
Utica East Ohio Midstream, L.L.C.	Delaware
Utica Gas Services, L.L.C.	Oklahoma
Wamsutter LLC	Delaware
WFS - Liquids LLC	Delaware
WFS - Pipeline LLC	Delaware
WFS Enterprises LLC	Delaware
WFS Gathering Company, L.L.C.	Delaware
Williams ACM Holdings ULC	British Columbia
Williams Acquisition Holding Company LLC	New Jersey
Williams Alaska Petroleum, Inc.	Alaska
Williams Bayou Ethane Pipeline, LLC	Delaware
Williams Blu Operating LLC	Delaware
Williams Compression, L.L.C.	Oklahoma
Williams CV Holdings LLC	Delaware
Williams Energy Canada GP ULC	Alberta
Williams Energy Canada LP	Alberta
Williams Energy de Mexico, S. de. R.L. de C.V.	Mexico
Williams Energy Resources LLC	Delaware
Williams Energy Solutions LLC	Delaware
Williams Express LLC	Delaware
Williams Express, Inc.	Alaska
Williams Field Services - Gulf Coast Company, L.P.	Delaware
Williams Field Services Company, LLC	Delaware
Williams Field Services Group, LLC	Delaware
Williams Flexible Generation, LLC	Delaware
Williams Four Corners LLC	Delaware
Williams Gas Pipeline Company, LLC	Delaware
Williams Gas Processing - Gulf Coast Company, L.P.	Delaware
Williams Global Energy (Cayman) Limited	Cayman Islands
Williams Global Holdings LLC	Delaware

Exhibit 21

ENTITY	JURISDICTION
Williams Gulf Coast Gathering Company, LLC	Delaware
Williams Gulf Coast Transportation Company LLC	Delaware
Williams Headquarters Building LLC	Delaware
Williams Holdings and Manufacturing LLC	Delaware
Williams Hutch Rail Company, LLC	Delaware
Williams Information Technology LLC	Delaware
Williams International Company LLC	Delaware
Williams International El Furrial Limited	Cayman Islands
Williams International Pigap Limited	Cayman Islands
Williams International Services Company	Nevada
Williams International Venezuela Limited	Cayman Islands
Williams Laurel Mountain, LLC	Delaware
Williams Mexico Holdings B.V.	Netherlands
Williams Mexico Sub-Holdings B.V.	Netherlands
Williams Midstream Gas Services, L.L.C.	Oklahoma
Williams MLP Operating, L.L.C.	Delaware
Williams Mobile Bay Producer Services, L.L.C.	Delaware
Williams New Soda, Inc.	Delaware
Williams Ohio Valley Midstream LLC	Texas
Williams Ohio Valley Pipeline LLC	Delaware
Williams Oil Gathering, L.L.C.	Delaware
Williams Olefins Feedstock Pipelines, L.L.C.	Delaware
Williams Olefins Pipeline Holdco LLC	Delaware
Williams Pacific Connector Gas Operator, LLC	Delaware
Williams Partners Cooperatief U.A.	Netherlands
Williams Partners Finance Corporation	Delaware
Williams Partners International Holdings LLC	Delaware
Williams Partners International Sub-Holdings LLC	Delaware
Williams Partners L.P.	Delaware
Williams Partners Operating LLC	Delaware
Williams PERK, LLC	Delaware
Williams Permian Midstream, L.L.C.	Oklahoma
Williams Petroleum Services, LLC	Delaware
Williams Pipeline Services LLC	Delaware
Williams Propylene Company LLC	Delaware
Williams Purity Pipelines, LLC	Delaware
Williams Resource Center, L.L.C.	Delaware
Williams Soda Holdings, LLC	Delaware
Williams Sodium Products Company	Delaware
Williams Strategic Sourcing Company	Delaware
Williams WPC - I, LLC	Delaware
WilPro Energy Services (El Furrial) Limited	Cayman Islands
WilPro Energy Services (Pigap II) Limited	Cayman Islands
WPZ GP LLC	Delaware

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-3 Nos. 333-29185 and 333-204077) of The Williams Companies, Inc.,

(2) Registration Statement (Form S-8 No. 333-03957) pertaining to The Williams Companies, Inc. 1996 Stock Plan for Non-Employee Directors,

(3) Registration Statement (Form S-8 No. 333-85542) pertaining to The Williams Investment Plus Plan,

(4) Registration Statement (Form S-8 No. 333-85546) pertaining to The Williams Companies, Inc. 2002 Incentive Plan,

(5) Registration Statement (Form S-8 No. 333-142985) pertaining to The Williams Companies, Inc. 2007 Employee Stock Purchase Plan and The Williams Companies, Inc. 2007 Incentive Plan,

(6) Registration Statement (Form S-8 No. 333-167123) pertaining to The Williams Companies, Inc. 2007 Incentive Plan, and

(7) Registration Statement (Form S-8 No. 333-198050) pertaining to The Williams Companies, Inc. 2007 Incentive Plan and The Williams Companies, Inc. 2007 Employee Stock Purchase Plan;

of our reports dated February 22, 2018, with respect to the consolidated financial statements and schedules of The Williams Companies, Inc. and the effectiveness of internal control over financial reporting of The Williams Companies, Inc. included in this Annual Report (Form 10-K) of The Williams Companies, Inc. for the year ended December 31, 2017.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 22, 2018

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-29185 and 333-204077) and on Form S-8 (Nos. 333-03957, 333-85542, 333-85546, 333-142985, 333-167123 and 333-198050) of The Williams Companies, Inc. of our report dated February 22, 2018 relating to the financial statements of Gulfstream Natural Gas System, L.L.C., which appears in this Annual Report on Form 10-K of The Williams Companies, Inc.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 22, 2018

Exhibit 23.3

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in Registration Statement Nos. 333-03957, 333-85542, 333-85546, 333-142985, 333-167123 and 333-198050 of The Williams Companies, Inc. on Form S-8, and Registration Statement Nos. 333-29185 and 333-204077 of The Williams Companies Inc. on Form S-3 of our report dated February 22, 2017, relating to the financial statements of Gulfstream Natural Gas System, L.L.C. as of December 31, 2016 and for the years ended December 31, 2016 and 2015, appearing in this Annual Report on Form 10-K of The Williams Companies, Inc. for the year ended December 31, 2017.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 22, 2018

Exhibit 31.1

CERTIFICATIONS

I, Alan S. Armstrong, certify that:

1. I have reviewed this annual report on Form 10-K of The Williams Companies, 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(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: February 22, 2018

/s/ Alan S. Armstrong

Alan S. Armstrong
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATIONS

I, John D. Chandler, certify that:

1. I have reviewed this annual report on Form 10-K of The Williams Companies, 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(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: February 22, 2018

/s/ John D. Chandler

John D. Chandler
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of The Williams Companies, Inc. (the "Company") on Form 10-K for the period ending December 31, 2017, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned hereby certifies, in his capacity as an officer of the Company, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(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 results of operations of the Company.

/s/ Alan S. Armstrong
Alan S. Armstrong
President and Chief Executive Officer
February 22, 2018

/s/ John D. Chandler
John D. Chandler
Chief Financial Officer
February 22, 2018

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report and shall not be considered filed as part of the Report.