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, 2025
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: 01-32665

BOARDWALK PIPELINE PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware	**20-3265614**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

9 Greenway Plaza, Suite 2800
Houston, Texas 77046
(866) 913-2122
(Address and Telephone Number of Registrant's Principal Executive Office)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
NONE	**NONE**	**NONE**

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the 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 ☒ 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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

Boardwalk Pipeline Partners, LP meets the conditions set forth in General Instructions I(1) (a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format.

Documents incorporated by reference. None.

2025 FORM 10-K

BOARDWALK PIPELINE PARTNERS, LP

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PART I

Item 1. Business

Unless the context otherwise requires, references in this Annual Report on Form 10-K to "we," "our," "us" or like terms refer to the business of Boardwalk Pipeline Partners, LP and its consolidated subsidiaries.

Introduction

We are a Delaware limited partnership formed in 2005. Our business, which is conducted by our primary subsidiary, Boardwalk Pipelines, LP (Boardwalk Pipelines) and its operating subsidiaries (together, the operating subsidiaries), consists of integrated pipeline and storage systems for natural gas and natural gas liquids, olefins and other hydrocarbons (herein referred to together as NGLs). All of our operations are conducted by the operating subsidiaries of Boardwalk Pipelines. As of December 31, 2025, Boardwalk Pipelines Holding Corp. (BPHC), a wholly owned subsidiary of Loews Corporation (Loews), owned directly or indirectly, 100% of our capital.

Our Business

We operate in the midstream portion of the natural gas and NGLs industry, providing transportation and storage for those commodities. We also provide ethane supply and transportation services for petrochemical customers in Louisiana and Texas. We own approximately 14,275 miles of natural gas and NGLs pipelines and underground storage caverns having aggregate capacity of approximately 199.5 billion cubic feet (Bcf) of working natural gas and 31.2 million barrels (MMBbls) of NGLs. Our integrated natural gas pipeline and storage systems are located in the Gulf Coast region, Oklahoma, Arkansas, Tennessee, Kentucky, Illinois, Indiana and Ohio, and our NGLs pipelines and storage facilities are located in Louisiana and Texas.

We serve a broad mix of customers, including electric power generators, producers and marketers of natural gas, local distribution companies (LDCs), industrial and petrochemical users, exporters of liquefied natural gas (LNG), and interstate and intrastate pipelines. We provide a significant portion of our natural gas pipeline transportation and storage services through firm contracts under which our customers pay monthly capacity reservation fees, which are fixed fees based on the quantity of capacity reserved, regardless of use. Other fees are based on actual utilization of the capacity under firm contracts and contracts for interruptible services. Contracts for our NGLs services are generally fee-based or contain a minimum volume commitment (MVC), while others are dependent on actual volumes transported, stored or delivered. For the year ended December 31, 2025, approximately 87% of our revenues were derived from capacity reservation fees under firm contracts or from contracts with MVCs, approximately 5% of our revenues were derived from fees based on utilization under firm contracts and approximately 8% of our revenues were derived from interruptible transportation, interruptible storage, parking and lending (PAL), ethane supply and other services.

The maximum applicable rates we can charge for most of our natural gas transportation services, as well as the general terms and conditions of those services, are established by, and subject to review and revision by, the Federal Energy Regulatory Commission (FERC). These rates are based upon certain assumptions to allow us the opportunity to recover the cost of providing these services and earn a reasonable return on equity. However, it is possible that we may not recover all of our costs or earn a return. We are authorized to charge market-based rates for the majority of our natural gas storage capacity pursuant to authority granted by the FERC. The FERC also has jurisdiction over the rates, charges and terms and conditions of service for transportation on our interstate ethane pipeline. The Surface Transportation Board (STB) regulates the rates we charge for interstate service on our ethylene pipeline systems. The Louisiana Public Service Commission (LPSC) regulates the rates we charge for intrastate service within the state of Louisiana on our NGLs pipelines. The STB and LPSC require that our transportation rates are reasonable and that our practices cannot unreasonably discriminate among our shippers.

Business Segments

We have two reportable segments - Natural Gas and Natural Gas Liquids. The following contains a detailed discussion of each of our segments.

Natural Gas

Our Natural Gas segment, which provides transportation, storage and PAL services for natural gas customers, consists of integrated interstate and intrastate natural gas pipelines and storage facilities. We own and operate approximately 13,420 miles of interconnected natural gas pipelines, directly serving customers in thirteen states and indirectly serving customers throughout the northeastern and southeastern United States (U.S.) through numerous interconnections with unaffiliated pipelines. In 2025, our natural gas pipeline systems transported approximately 3.9 trillion cubic feet of natural gas. Average daily throughput on our natural gas pipeline systems during 2025 was approximately 10.7 Bcf. Our natural gas storage facilities are comprised of fourteen underground storage fields located in four states with aggregate working gas capacity of approximately 199.5 Bcf.

The principal sources of supply for our natural gas pipeline systems are regional supply hubs and market centers located in the Gulf Coast and Mid-Continent regions, including offshore Louisiana, the Perryville, Louisiana, area, the Henry Hub in Louisiana and the Carthage, Texas, area. Our pipelines in the Carthage, Texas, area provide access to natural gas supplies from the Barnett and Haynesville Shales and other natural gas producing regions in eastern Texas and northern Louisiana. The Henry Hub serves as the designated delivery point for natural gas futures contracts traded on the New York Mercantile Exchange. Our pipeline systems also have access to supply basins such as the Woodford and Scoop/Stack Shales in Oklahoma, the Fayetteville Shale in Arkansas, the Eagle Ford Shale in southern Texas and wellhead supplies in northern and southern Louisiana and Mississippi, and we also receive gas in the Lebanon, Ohio, area from the Marcellus and Utica Shales located in the northeastern U.S.

Following is a summary of the primary subsidiaries comprising our Natural Gas segment:

Gulf South Pipeline Company, LLC (Gulf South): Our Gulf South pipeline system is located along the Gulf Coast in the states of Oklahoma, Texas, Louisiana, Mississippi, Alabama and Florida. The on-system markets directly served by the Gulf South system are generally located in eastern Texas, Louisiana, southern Mississippi, southern Alabama and the Florida Panhandle. Gulf South also services the Perryville Exchange. These markets include LNG export markets in the Freeport, Texas, area, electric power generators, LDCs and municipalities located across the system, including New Orleans, Louisiana; Jackson, Mississippi; Mobile, Alabama; Houston, Texas; and Pensacola, Florida, and other end-users located across the system, including those located in the Baton Rouge to New Orleans industrial corridor and Lake Charles, Louisiana. Gulf South also has indirect access to off-system markets through numerous interconnections with affiliated and unaffiliated interstate and intrastate pipelines and storage facilities. These pipeline interconnections provide access to markets throughout the northeastern, midwestern and southeastern U.S.

Gulf South has ten natural gas storage facilities. The two natural gas storage facilities located in Bistineau, Louisiana, and Jackson, Mississippi, have approximately 78.0 Bcf of working gas storage capacity from which Gulf South offers firm and interruptible storage service, including no-notice service (NNS), and are used to support pipeline operations. Gulf South also owns and operates eight high deliverability salt-dome natural gas storage caverns in Forrest County, Mississippi, having approximately 46.0 Bcf of total storage capacity, of which approximately 29.6 Bcf is working gas capacity, and owns undeveloped land which is suitable for up to five additional storage caverns.

Gulf South is regulated by the FERC.

Texas Gas Transmission, LLC (Texas Gas): Our Texas Gas pipeline system is a bi-directional pipeline located in Louisiana, East Texas, Arkansas, Mississippi, Tennessee, Kentucky, Indiana and Ohio, with smaller diameter lines extending into Illinois. Texas Gas directly serves LDCs, municipalities and electric power generators in its market area, which encompasses seven states in the South and Midwest and includes the Memphis, Tennessee; Louisville, Kentucky; Cincinnati and Dayton, Ohio; and Evansville and Indianapolis, Indiana, metropolitan areas. Texas Gas also has indirect market access to, and receives supply from, the Northeast through interconnections with unaffiliated pipelines. A large portion of the gas delivered by the Texas Gas system is used for heating during the winter months, but Texas Gas also supplies gas for cooling needs during the summer months.

Texas Gas owns nine natural gas storage fields, of which it owns the majority of the working and base gas. Texas Gas uses this gas to meet the operational requirements of its transportation and storage customers and the requirements of its NNS customers. Texas Gas also uses its storage capacity to offer firm and interruptible storage services.

Texas Gas is regulated by the FERC.

Other: We have minor intrastate and Hinshaw pipeline assets in South Texas and the Lake Charles area serving end-use, electric power generator and industrial customers. We also own natural gas salt-dome storage capacity in our Choctaw Hub in the Mississippi River corridor area of Louisiana.

The following table provides information for our Natural Gas segment assets we owned and operated as of December 31, 2025:

Assets	Miles of Pipeline	Average Daily Throughput (Bcf/d) (1)	Peak-day Delivery Capacity (Bcf/d)	Working Gas Storage Capacity (Bcf)
Gulf South	7,140	7.1	10.9	107.6
Texas Gas	6,000	3.4	6.4	84.3
Other Natural Gas	280	0.2	—	7.6

(1) Bcf per day (Bcf/d)

Natural Gas Liquids

Our Natural Gas Liquids segment, which provides transportation and storage services for NGLs and supply services for ethane and brine customers, consists primarily of NGLs pipelines, salt-dome storage facilities and brine infrastructure. We own and operate approximately 855 miles of NGLs pipelines in Louisiana and Texas. In 2025, our Natural Gas Liquids pipeline systems transported approximately 144.2 MMBbls of NGLs. Our NGLs storage facilities consist of eleven salt-dome caverns located in Louisiana with an aggregate storage capacity of approximately 31.2 MMBbls. We also own ten salt-dome caverns and related brine infrastructure located in Louisiana for use in providing brine supply services and to support the NGLs storage operations. Our NGLs pipeline systems access the Gulf Coast petrochemical industry through our operations at our Choctaw Hub in the Mississippi River corridor area of Louisiana and our Sulphur Hub in the Lake Charles, Louisiana, area. We access ethylene supplies at Port Neches, Texas, which we deliver to petrochemical-industry customers in Louisiana. We purchase ethane at Mont Belvieu, Texas, and various locations in Louisiana and utilize our NGLs pipelines to supply ethane to customers in Texas and Louisiana. The majority of our Natural Gas Liquids segment's customers are industrial and petrochemical end-users.

Following is a summary of the primary subsidiaries comprising our Natural Gas Liquids segment:

Boardwalk Louisiana Midstream, LLC (Louisiana Midstream): Louisiana Midstream provides transportation and storage services for NGLs, primarily ethylene, and brine supply services for producers and consumers of petrochemicals through two hubs in southern Louisiana - our Choctaw Hub in the Mississippi River corridor area and our Sulphur Hub in the Lake Charles area. These assets have approximately 31.2 MMBbls of salt-dome storage capacity; significant brine supply infrastructure; and approximately 300 miles of pipeline assets, including an extensive ethylene distribution system.

Louisiana Midstream's Choctaw pipeline network is a common carrier pipeline system situated along the Mississippi River Corridor that serves chemical complexes throughout southeastern Louisiana and provides connectivity to producers and consumers of ethylene. Through interconnections with Boardwalk Petrochemical Pipeline, LLC's (Boardwalk Petrochemical) Evangeline Pipeline and other third-party pipelines, the system links ethylene producers in Texas and the Lake Charles area to the Mississippi River Corridor. Louisiana Midstream offers storage services for ethylene, ethane, propylene and ethane-propane mix at our Choctaw Hub, and has the ability to modify its existing product storage configuration to meet market demand. Louisiana Midstream also owns eight salt-dome caverns and related brine infrastructure located at our Choctaw Hub for use in providing brine supply services and supporting its NGLs storage operations.

Louisiana Midstream's Sulphur pipeline network is located near Lake Charles, Louisiana, and is connected to local ethylene producers and consumers and area refineries. Its pipeline infrastructure supports local industry by connecting their facilities to our Sulphur Hub storage terminal as well as the Boardwalk Petrochemical pipeline. At our Sulphur Hub, Louisiana Midstream owns and operates five active storage caverns, which are currently in ethylene, ethane and propane service.

Boardwalk Petrochemical: Boardwalk Petrochemical owns and operates the Evangeline Pipeline, an approximately 180-mile bi-directional, common carrier, interstate ethylene pipeline that is capable of transporting approximately 4.8 billion pounds of ethylene per year between Port Neches, Texas, and Baton Rouge, Louisiana, and interconnects with Louisiana Midstream's ethylene distribution system and storage facilities at our Sulphur and Choctaw Hubs. The Evangeline Pipeline links ethylene producers and consumers from Port Neches, Texas, to the Mississippi River Corridor, near Baton Rouge, Louisiana.

Boardwalk Ethane Pipeline Company, LLC (Bayou Ethane): Bayou Ethane owns and operates the Bayou Ethane Pipeline, an approximately 375-mile pipeline system originating in Mont Belvieu, Texas, that transports ethane to Southeast Texas and to the Mississippi River corridor in Louisiana. The Bayou Ethane Pipeline provides common carrier, interstate and intrastate transportation services and interconnects with Louisiana Midstream's storage facilities at our Sulphur and Choctaw Hubs. The Bayou Ethane Pipeline has the ability to deliver approximately 55.0 MMBbls of ethane per year to customers in Texas and Louisiana. Bayou Ethane provides ethane supply and transportation services for petrochemical customers in Louisiana and Texas. In providing ethane supply services, Bayou Ethane purchases ethane at Mont Belvieu and various locations in Louisiana and utilizes its pipeline to deliver supply to its customers.

The following table provides information for our Natural Gas Liquids segment assets we owned and operated as of December 31, 2025:

Assets	Miles of Pipeline	Annual Throughput (MMBbls)	Liquids Storage Capacity (MMBbls)
Louisiana Midstream	300	60.8	31.2
Boardwalk Petrochemical	180	38.9	—
Bayou Ethane	375	44.5	—

Current Growth Projects

We regularly review opportunities to expand our existing facilities and footprint to meet growing demand for transportation and storage services. The recent growth of LNG export and power generation demand has led to the announcement of additional growth projects for us. Through the date of this filing, we have growth projects for which we have executed precedent or long-term firm transportation agreements that are expected to increase capacity on our pipeline systems by an aggregate of 4.2 Bcf/d and our storage working gas capacity by 10 Bcf at an expected aggregate cost of approximately $3.3 billion and are scheduled to be completed through 2030. As of December 31, 2025, we have spent $134.5 million on these growth projects. These projects remain contingent upon, among other things, the receipt of required regulatory approvals and permits and are subject to construction risk.

These projects have lengthy planning and construction periods and, as a result, will not contribute to our earnings and cash flows until they receive the required regulatory approvals and permits and are constructed and placed into service over the next several years. Our cost and timing estimates for these projects are based on a variety of inputs such as contractor indicative bids, quotes on materials and internally-developed financial models, metrics and timelines and are subject to a variety of risks and uncertainties, including obtaining timely regulatory and permit approvals and the cost thereof, adverse weather conditions during construction, our ability to acquire and the cost of obtaining rights to construct and operate on land not owned by us, delays in obtaining and shortages and price increases for key materials (including pipe, compressor facilities and related equipment), tariff implications and shortages and increased costs of qualified labor. Factors in the estimates include, among other things, those related to pipeline costs based on mileage, size and type of pipe, materials, including compressors and related equipment, land, engineering and construction costs and timely receipt of all necessary permits and approvals. Actual costs and timing of in-service dates for our growth projects may differ, perhaps materially, from our estimates. In addition, failure to timely meet development milestones may result in, among other things, contractual counterparties having the ability to terminate contracts with us. Refer to Part I, Item 1A, Risk Factors of this Annual Report on Form 10-K for additional risks associated with our growth projects and the related financing.

Our more significant growth projects are listed and described below:

	Expected in-service date	Expected incremental capacity added to system (Bcf/d)
Eunice - Iowa[(1)]	Third quarter 2026	0.1
Carnation Project[(2)]	Fourth quarter 2027	0.2
Northeast Texas Power Plant Project[(3)]	Fourth quarter 2027	0.3
Kosciusko Junction project (Kosci project)[(3)]	First half 2028	1.2
Ohio Power Plant Project[(3)]	First half 2028	0.3
Southeast Compression for Utility Reliability Expansion project (SECURE project)[(3)]	First half 2028	0.3
Parks Line Upgrade and Sorrento Station Project (PLUSS project)[(4)]	First half 2028	0.2
Texas Gateway Project[(5)]	Second half 2029	1.5
Petal Gas Storage Expansion[(6)]	Second half 2030	[(6)]

(1) This project has received approval from FERC and is in construction.

(2) This project remains subject to FERC approval and receipt of environmental permits and authorizations.

(3) These projects remain subject to FERC approval, acquisition of land rights, and receipt of environmental permits and authorizations.

(4) This project received FERC approval in December 2025 and is expected to start construction in the first half of 2026.

(5) This project remains subject to FERC approval, acquisition of land rights, receipt of environmental permits and authorizations and other conditions precedent.

(6) This project remains subject to FERC approval and is expected to add 10 Bcf of storage working gas capacity.

Eunice – Iowa: This project is expected to increase the capacity of our pipeline system by the addition of compression facilities to the Lake Charles, Louisiana area and is supported by precedent and long-term firm transportation agreements to serve industrial and power markets.

Carnation Project: This project is expected to increase the capacity of our pipeline system in Hamilton County, Ohio, through the installation of a compressor unit and auxiliary equipment. This project is supported by a precedent agreement with an LDC and is expected to support regional energy needs.

Northeast Texas Power Plant Project: This project is expected to increase the delivery capacity of our pipeline system in Northeast Texas, through the construction of 16 miles of natural gas pipeline and a delivery meter connected to a power plant. The project is supported by a precedent agreement with a utility customer.

Kosci project: The Kosci project is expected to increase the capacity of our pipeline system through the addition of compression facilities, the installation of 110 miles of natural gas pipeline, and other system modifications. The capacity for this project is supported by precedent agreements with utility customers. This project is designed to connect supply from the Haynesville, Utica/Marcellus, and Fayetteville basins to markets in the southeast U.S. that are either tied into our existing pipeline systems or will be served through third-party pipeline interconnects.

Ohio Power Plant Project: This project is expected to increase the delivery capacity of our pipeline system in Hamilton County, Ohio, through the construction of seven miles of natural gas pipeline and a delivery meter connected to a power plant. The project is supported by a precedent agreement with a utility customer.

SECURE project: We executed two precedent agreements for the SECURE project, which is expected to provide additional transportation from west to east across our pipeline systems. This project is expected to increase the peak-day transmission capacity by increasing the horsepower at three existing compressor stations and constructing a new compressor station. This project supports growing energy demand and power generation needs.

PLUSS project: The PLUSS project is supported by precedent agreements to serve industrial and power markets in the Mississippi River corridor. As part of the project, we intend to add compression facilities, modify our pipelines and perform other system modifications on our pipeline systems.

Texas Gateway Project: This project is expected to increase the capacity of our pipeline system through the construction of approximately 155 miles of natural gas pipeline and the addition of compression facilities. This project is designed to connect supply from the Katy and Carthage, Texas, hubs for delivery to growing demand in Southwest Louisiana near Gillis and increase liquidity, supply security and flow assurance for LNG exporters, electric utilities, industrial users and natural gas producers.

Petal Gas Storage Expansion Project: This project is supported by precedent agreements and is expected to increase the working gas storage capacity of our Petal storage field by drilling and constructing a new natural gas storage cavern in Forrest County, Mississippi.

In addition to growth projects for which we have executed precedent agreements, we regularly consider other potential growth projects at earlier stages of development, and we are currently evaluating additional growth projects involving substantial capital commitments. We may from time to time make public disclosures regarding these potential projects, for instance, through announcements of open seasons for potential future capacity. In addition to the risks, uncertainties and contingencies described above regarding the growth projects for which we have executed precedent agreements, these potential growth projects at earlier stages of development are subject to a variety of additional risks and uncertainties as we have not reached final investment decisions or secured executed precedent agreements for them. Therefore, these potential growth projects at earlier stages of development may not be consummated as contemplated in any such public disclosures or at all.

Refer to *Liquidity and Capital Resources* in Part II, Item 7. of this Annual Report on Form 10-K for further discussion of capital expenditures and financing.

Nature of Contracts

We contract with our customers to provide transportation, storage and ethane supply services on both a firm and interruptible basis. We also provide bundled firm transportation and storage services, such as NNS, interruptible PAL services, brine supply services for certain petrochemical customers and fractionation services.

Transportation Services: We offer transportation services on both a firm and interruptible basis. Our customers choose, based upon their particular needs, the applicable mix of services depending upon the availability of pipeline capacity, the price of services and the volume and timing of customer requirements. Our firm transportation customers reserve a specific amount of pipeline capacity at specified receipt and delivery points on our system. The transaction price for firm service contracts is comprised of a fixed fee based on the quantity of capacity reserved, regardless of use (capacity reservation fee), plus variable fees in the form of a usage fee paid on the volume of commodity actually transported or injected and withdrawn from storage. Capacity reservation revenues derived from a firm service contract are generally consistent during the contract term, but can be higher in winter periods than the rest of the year, especially for NNS agreements. Firm transportation contracts can range from one to twenty years, although we may enter into shorter- or longer-term contracts. In providing interruptible services to customers, we agree to transport natural gas or NGLs for a customer when capacity is available. Interruptible service customers pay a commodity charge only for the volume of gas actually transported, plus a fuel charge. Interruptible transportation agreements have terms ranging from day-to-day to multiple years, with rates that change on a daily, monthly or seasonal basis. Our NGLs transportation services are generally fee-based or contain an MVC.

Storage and Parking and Lending Services: We offer natural gas and NGLs storage services on both a firm and interruptible basis. Firm storage customers reserve a specific amount of storage capacity, including injection and withdrawal rights, while interruptible customers receive storage capacity and injection and withdrawal rights when available. Similar to firm transportation customers, firm storage customers generally pay fees based on the quantity of capacity reserved plus an injection and withdrawal fee. Firm storage contracts typically range in term from one to ten years. Interruptible storage customers pay for the volume of gas actually stored plus injection and withdrawal fees. Generally, interruptible storage agreements are for monthly terms. We are able to charge market-based rates for the majority of our natural gas storage capacity pursuant to authority granted by the FERC. Our NGLs storage rates are market-based, and the contracts for NGLs services are typically fixed-price arrangements with escalation clauses. PAL is an interruptible service offered to customers, providing them the ability to park (inject) or borrow (withdraw) natural gas into or out of our pipeline systems at a specific location for a specific period of time. Customers pay for PAL services in advance or on a monthly basis, depending on the terms of the agreement.

No-Notice Services: NNS consist of a combination of firm natural gas transportation and storage services that allow customers to inject or withdraw natural gas from storage with little or no notice. Customers pay a reservation charge based upon the capacity reserved plus a commodity and a fuel charge based on the volume of gas actually transported. In accordance with its tariff, Texas Gas loans stored gas to certain of its no-notice customers who are obligated to repay the gas in-kind.

Ethane Supply Services: We offer ethane supply services on a firm basis, typically with an MVC or a stated volume with any requested additional volumes supplied based on availability. The pricing contained in the purchase and sales agreements associated with our ethane supply services is generally based on the same ethane commodity index, plus a fixed delivery fee. As a result, except for possible timing differences that may occur when volumes are purchased in one month and sold in another month, we have little to no direct commodity price exposure.

Other Product Sales: We occasionally sell natural gas, propane and ethylene based upon our available inventory for sale and market conditions.

Customers and Markets Served

We contract directly with end-use customers, including electric power generators, LDCs, industrial and petrochemical users and exporters of LNG. We also contract with other customers, including producers and marketers of natural gas, and interstate and intrastate pipelines, who, in turn, provide transportation and storage services for end-users. Excluding product sales, based upon our 2025 transportation, storage, PAL and other revenues, net of fuel, our customer mix was as follows: electric power generators (23%), marketers (22%), natural gas producers (18%), LDCs (15%), industrial and petrochemical end-users (15%) and exporters of LNG (7%). Excluding product sales, based upon our 2025 transportation, storage, PAL and other revenues, net of fuel, our deliveries were as follows: pipeline interconnects (31%), electric power generators (18%), LDCs (15%), industrial and petrochemical end-users (14%), storage activities (13%), exporters of LNG (7%) and others (2%). Our deliveries related to our ethane supply services were to petrochemical end-users. One customer comprised 10% or more of our operating revenues in 2025.

Electric Power Generators: Our natural gas pipelines are directly connected to 45 natural-gas-fired electric power generation facilities in seven states. The demand of the power generating customers generally peaks during the summer cooling season, which is counter to the winter season peak demands of the LDCs, although demand from electric power generators remains strong in the winter months as well, due to the overall increase in the use of natural gas over other sources, such as coal, to generate electricity. Additionally, the rise in data centers has led to increased demand for our power generating customers. Our electric power generating customers can use a combination of NNS, firm and interruptible transportation services.

Natural Gas Marketers: Natural gas marketing companies utilize our services to provide services to our other customer groups as well as to customer groups in off-system markets. The services may include combined gas transportation and storage services to support the needs of other customer groups. Some of the marketers are sponsored by LDCs or producers.

Natural Gas Producers: Producers of natural gas use our services to transport gas supplies from producing areas, including shale natural gas production areas, to supply pools and other customers on and off of our systems. Producers contract with us for storage services to store excess production and to optimize the ultimate sales prices for their gas.

Local Distribution Companies: Most of our LDC customers use firm natural gas transportation services, including NNS. We serve 165 LDCs at nearly 300 delivery locations across our pipeline systems. The demand of these customers peaks during the winter heating season.

Industrial and Petrochemical End-Users: We provide approximately 210 industrial and petrochemical facilities with a combination of firm and interruptible natural gas and NGLs transportation, storage and ethane supply services. Our pipeline systems are directly connected to industrial or petrochemical facilities in the Baton Rouge to New Orleans industrial corridor; Lake Charles, Louisiana; Mont Belvieu, Texas; Mobile, Alabama; Ingleside, Texas; and Pensacola, Florida. We can also access the Houston Ship Channel through third-party natural gas pipelines.

Exporters of LNG: LNG exporters use our natural gas firm transportation services to reach LNG liquefaction and export facilities. We provide 1.4 Bcf/d of firm natural gas transportation service directly to the Freeport LNG liquefaction and export facility in Freeport, Texas.

Our natural gas delivery markets continue to diversify, with increased deliveries to our end-use customers, whereas historically, our natural gas delivery markets were primarily to other pipelines who then delivered to the end-use customers. As of December 31, 2025, we had approximately $19.6 billion of projected operating revenues under committed firm agreements, of which our deliveries are expected to be as follows: pipeline interconnects (33%), exporters of LNG (28%), electric power generators (20%), industrial and petrochemical end-users (7%), LDCs (7%), storage activities (4%) and others (1%).

Government Regulation

Federal Energy Regulatory Commission: The FERC regulates our interstate natural gas transmission operating subsidiaries under the Natural Gas Act of 1938 (NGA) and the Natural Gas Policy Act of 1978 (NGPA). The FERC regulates, among other things, the rates and charges for the transportation and storage of natural gas in interstate commerce and the construction, extension, enlargement or abandonment of facilities under its jurisdiction. Where required, our interstate natural gas pipeline subsidiaries hold certificates of public convenience and necessity issued by the FERC covering certain of their facilities, activities and services. The FERC also prescribes accounting treatment for our interstate natural gas pipeline subsidiaries, which is separately reported pursuant to forms filed with the FERC. The regulatory books and records and other activities of our subsidiaries that operate under the FERC's jurisdiction may be periodically audited by the FERC.

The maximum applicable rates that our FERC-regulated operating subsidiaries may charge for all aspects of the natural gas transportation services they provide are established through the FERC's cost-based rate-making process; however, the FERC also allows for discounted or negotiated rates as an alternative to cost-based rates. Key determinants in the FERC's cost-based rate-making process are the costs of providing service, the volumes of gas being transported, the rate design, the allocation of costs between services, the capital structure and the rate of return a pipeline is permitted to earn. The maximum applicable rates that we may charge for storage services on Texas Gas, except for services associated with a portion of the working gas capacity on that system, are also established through the FERC's cost-based rate-making process. The FERC has authorized us to charge market-based rates for firm and interruptible storage services for the majority of our other natural gas storage facilities. None of our FERC-regulated entities currently have an obligation to file a new rate case.

Some of our other subsidiaries transport natural gas in intrastate commerce under the rules and regulations established by the Texas Railroad Commission and in interstate commerce that is subject to FERC jurisdiction under Section 311 of the NGPA. The maximum rates for services are established under Section 311 of the NGPA and are generally subject to review every five years by the FERC. The rates and terms of service on our interstate ethane transportation pipeline are also subject to regulation by the FERC under, among other statutes, the Interstate Commerce Act and the Energy Policy Act of 1992.

Over time, the FERC may change, amend or announce that it will undertake a review of its existing policies. There were no major policy changes announced by the FERC during 2025 that materially impacted us.

The FERC has authority to impose civil penalties for violations of the NGA and NGPA and the implementing regulations thereunder, up to a maximum amount that is adjusted annually for inflation, which for 2026 is approximately $1.5 million per day per violation. Should we fail to comply with applicable statutes, rules, regulations and orders administered by the FERC, we could be subject to substantial penalties and fines, in addition to reputational damage.

Surface Transportation Board and Louisiana Public Service Commission: The STB regulates the rates we charge for interstate service on our ethylene pipeline systems. The LPSC regulates the rates we charge for intrastate service within the state of Louisiana on our petrochemical and NGLs pipelines. The STB and LPSC require that our transportation rates are reasonable and that our practices cannot unreasonably discriminate among our shippers.

U.S. Department of Transportation (DOT): We are regulated by the DOT, through the Pipeline and Hazardous Materials Safety Administration (PHMSA), under the Natural Gas Pipeline Safety Act of 1968, as amended (NGPSA), and the Hazardous Liquids Pipeline Safety Act of 1979, as amended (HLPSA). The NGPSA and HLPSA govern the design, installation, testing, construction, operation, replacement and management of interstate natural gas and NGLs pipeline facilities. We have authority from PHMSA to operate certain natural gas pipeline assets under issued permits with specific conditions that allow us to operate those pipeline assets at higher than normal operating pressures of up to 0.80 of the pipeline's Specified Minimum Yield Strength (SMYS). Operating at these pressures allows us to transport all the existing natural gas volumes we have contracted for on those facilities with our customers. PHMSA retains discretion whether to grant or maintain authority for us to operate our natural gas pipeline assets at higher pressures, and, in the event that PHMSA should elect not to allow us to operate at these higher pressures, it could affect our ability to transport all of our contracted quantities of natural gas on these pipeline assets, and we could incur significant additional costs to reinstate this authority or to develop alternate ways to meet our contractual obligations. PHMSA's regulations also require transportation pipeline operators to implement integrity management programs to comprehensively evaluate certain high-risk areas, known as high consequence areas (HCAs) and moderate consequence areas (MCAs), along pipelines and take additional safety measures to protect people and property in these areas. The HCAs for natural gas pipelines are predicated on high-population density areas (which, for natural gas transmission lines, include Class 3 and 4 areas and, depending on the potential impacts of a risk event, may include Class 1 and 2 areas), whereas HCAs along our NGLs pipelines are based on high-population density areas, areas near certain drinking water sources and unusually sensitive ecological areas.

Legislation has resulted in more stringent mandates for pipeline safety and has charged PHMSA with developing and adopting regulations that impose increased pipeline safety requirements on pipeline operators. In particular, the NGPSA and HLPSA were amended by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Act), the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (2016 Act), and, most recently, the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (2020 Act), each of which imposed increased pipeline safety obligations on pipeline operators. The 2011 Act increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. The 2016 Act, among other things, required PHMSA to complete its outstanding mandates under the 2011 Act and develop new safety standards for natural gas storage facilities. The 2020 Act reauthorized PHMSA through fiscal year 2023 and directed the agency to move forward with several regulatory initiatives, including obligating operators of non-rural gas gathering lines and new and existing transmission and distribution pipeline facilities to conduct certain leak detection and repair programs and to require facility inspection and maintenance plans to align with those requirements.

As a result of the 2011 Act, the 2016 Act and the 2020 Act, PHMSA has issued a series of significant rulemakings for onshore gas transmission pipelines (e.g., relating to maximum allowable operating pressure (MAOP) reconfirmation and exceedance reporting, the integrity assessment of additional pipeline mileage and the consideration of seismicity as a risk factor in integrity management), and hazardous liquid transmission and gathering pipelines (e.g., expanding the reach of certain of PHMSA's integrity management requirements, requiring the accommodation of in-line inspection tools by 2039 for certain pipelines, increasing annual, accident and safety-related conditional reporting requirements, and expanding the use of leak detection systems beyond HCAs). PHMSA also regulates the minimum safety requirements applicable to natural gas storage facilities, including wells, wellbore tubing and casing. In August 2022, PHMSA published a final rule that attempted to expand the Management of Change process, corrosion control requirements for gas transmission pipelines, requirements that operators ensure no conditions exist following an extreme weather event that could adversely affect the safe operation of the pipeline and repair criteria for non-HCAs. Five safety standards included in that rule were challenged by industry trade groups, and in August 2024, the U.S. Court of Appeals for the D.C. Circuit struck down four of the five challenged safety standards. These and any future regulations adopted by PHMSA have imposed and may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital and operating costs and operational delays.

Transportation Safety Administration: The Department of Homeland Security's Transportation Safety Administration (TSA) has issued a series of security directives between 2022 and 2025 applicable to major pipeline owners and operators intended to strengthen the industry's overall cybersecurity posture in light of the evolving threat landscape and its potential impacts to U.S. critical infrastructure. The security directives require, among other things, that pipeline owners and operators designate a cybersecurity coordinator; establish and implement a Cybersecurity Implementation Plan; develop, maintain and test no less than annually through tabletop exercises a Cybersecurity Incident Response Plan; and establish a Cybersecurity Assessment Plan (CAP) including a schedule for assessing and auditing the CAP. The directives also contain requirements for reporting cybersecurity incidents and the results of certain assessments and audits. We have implemented tools, policies and practices designed to comply with the security directives. Other regulators, such as PHMSA and the Securities and Exchange Commission (SEC), have also established requirements for reporting certain cybersecurity incidents.

Other: Our operations are also subject to extensive federal, state, and local laws and regulations relating to the protection of the environment and occupational health and safety. Such laws and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of various substances, including hazardous substances and waste, and in connection with spills, releases, discharges and emissions of various substances into the environment. Environmental regulations also require that our facilities, sites and other properties be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Occupational health and safety regulations establish standards protective of workers, both generally and within the pipeline industry. These laws, as amended from time to time, that our operations are subject to, include, for example:

- the Clean Air Act (CAA) and analogous state laws, which regulate air emission pollutants, greenhouse gas (GHG) emissions and reciprocating engines subject to Maximum Achievable Control Technology standards;

- the Federal Water Pollution Control Act, commonly referred to as the Clean Water Act, and analogous state laws, which establish the extent to which waterways are subject to federal or state jurisdiction and serve to regulate the discharge of wastewater from our facilities into state and federal waters;
- the Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as CERCLA, or the Superfund law, and analogous state laws, which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent hazardous substances for disposal;
- the Resource Conservation and Recovery Act (RCRA) and analogous state laws, which impose requirements for the generation, storage, treatment, transportation and disposal of solid and hazardous wastes at or from our facilities;
- the Endangered Species Act (ESA), which restricts activities that may affect federally identified endangered and threatened species or their habitats by the implementation of operating restrictions or a temporary, seasonal or permanent ban in affected areas;
- the National Environmental Policy Act (NEPA), which requires federal agencies to evaluate major agency actions having the potential to impact the environment and that may require the preparation of environmental assessments and more detailed environmental impact statements that may be made available for public review and comment; and
- the Occupational Safety and Health Act (OSHA) and analogous state laws, which establish workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances and appropriate control measures.

Many states and local governments where we operate also have, or are developing, similar environmental or occupational health and safety legal requirements governing many of the same types of activities, and those requirements can be more stringent than those adopted under federal laws and regulations. Failure to comply with these federal, state, and local laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations, the incurrence of capital expenditures, the occurrence of delays, denials or cancellations in permitting or in the development or expansion of projects and the issuance of orders enjoining performance of some or all of our operations in affected areas.

While the Biden Administration attempted to pursue additional actions to bolster environmental regulations, the Trump Administration has revised or rescinded many of these changes. For example, in January 2023, the White House's Council on Environmental Quality (CEQ) released guidance to assist federal agencies in assessing the GHG emissions and climate change effects of their proposed actions under the NEPA. In May 2024, the CEQ published a final rule revising the implementing regulations of the procedural provisions of NEPA and implementing amendments to NEPA included in the Fiscal Responsibility Act of 2023. However, in November 2024, the U.S. Court of Appeals for the D.C. Circuit held that the CEQ lacks authority to issue NEPA regulations, and pursuant to an energy-related Executive Order signed by President Trump in January 2025, in February 2025, the CEQ published an interim final rule rescinding its regulations implementing NEPA. Many federal agencies have updated or begun the process of preparing their own new or updated NEPA-implementing rules and procedures. In May 2025, the CEQ withdrew its interim guidance on considering GHG emissions and climate change under NEPA. In September 2025, the CEQ issued updated guidance and an updated template for NEPA implementation procedures to provide clarity to federal agencies and promote consistency in NEPA implementation. Notwithstanding this, the impact of changes to NEPA regulations and procedures remains uncertain. While we cannot predict the full impact of these continued developments, any legal challenges to NEPA reviews performed in connection with our projects may result in further permitting and approval delays. For more information, see Item 1A. Risk Factors—Business Risks—"*Our operations, and those of our customers, are subject to a series of risks regarding climate change.*"

Stricter environmental or worker safety laws, regulations or enforcement policies could significantly increase our operational or compliance costs and compliance with new or more stringent environmental legal requirements could delay or prohibit our ability to obtain permits for operations or require us to install additional pollution control equipment. For instance, the construction or expansion of pipelines often requires authorizations under the Clean Water Act, which authorizations may be subject to challenge. We rely on the U.S. Army Corps of Engineers (the Corps) Clean Water Act Section 404 Nationwide Permit (NWP) 12, alongside other NWPs, as blanket authority for construction, maintenance, repair and removal of pipelines. The NWP process relies upon the Clean Water Act Section 401 certification process. In September 2023, the Environmental Protection Agency (EPA) finalized its Clean Water Act Section 401 Water Quality Certification Improvement Rule, effective in November 2023, which expanded the scope of certification authority. In September 2023, several states challenged the final rule in federal court alleging that the rule exceeds the EPA's statutory authority under the Clean Water Act, and the litigation has been held in abeyance pending the administration's review of the rule and litigation. In January 2026, the EPA proposed a rule revising its regulations governing Section 401 Water Quality Certifications. The proposed rule seeks to streamline the permitting process, restrict the ability of state and tribal certifying authorities to reject federal permits, and ensure such reviews are completed within the one-year statutory deadline. A final rule is expected in Spring 2026. However, opponents of the January 2026 proposed rule are pushing back on these efforts, including the EPA's efforts to narrow the scope of state authority. If NWP 12, or the underlying Section 401 certification process, is further amended or revoked, we may be required to apply for one or more Individual Permits, which would require additional time and resources to obtain. Additionally, there continues to be uncertainty with respect to the federal government's jurisdictional reach under the Clean Water Act over "waters of the United States" (WOTUS), including wetlands, as the EPA and the Corps have pursued multiple rulemakings under different administrations since 2015 in an attempt to determine the scope of such reach. In September 2023, the EPA issued a version of the WOTUS rule that, due to injunctions in certain states, is currently in effect in only 24 states. Thus, the operative definition of WOTUS varies by state. However, in November 2025, the EPA and the Corps proposed a rule to further update and narrow the September 2023 definition of WOTUS, guided by the Supreme Court's decision in *Sackett v. EPA* (adopting the “continuous surface connection” test to determine if wetlands are WOTUS). To the extent any judicial ruling or administrative rulemaking or other action further changes the scope of the Clean Water Act's jurisdiction, we could face increased costs to comply and experience delays with respect to obtaining permits. For more information, see Item 1A. Risk Factors—Business Risks—"*Failure to comply with environmental or worker safety laws and regulations or an accidental release of pollutants into the environment may cause us to incur significant costs and liabilities."*

Historically, our environmental compliance costs have not had a material adverse effect on our results of operations, but there can be no assurance that future compliance with existing requirements will not materially affect us or that the current regulatory standards will not become more onerous in the future, resulting in more significant costs to maintain compliance and increased exposure to significant liabilities. Note 5 in Part II, Item 8. of this Annual Report on Form 10-K contains information regarding environmental compliance.

Climate Change

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional, state and local levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. Due to the nature of our business, our operations emit various types of GHGs. We seek to carefully monitor our emissions and expect to incur additional costs to mitigate emissions. New legislation or regulations could increase the costs related to operating and maintaining our facilities. Depending on the particular law, regulation or program, we could be required to incur capital expenditures for installing new monitoring equipment or emission controls on our facilities, acquire and surrender allowances for GHG emissions, pay taxes or fees related to GHG emissions and/or administer and manage a more comprehensive GHG emissions program. While we may be able to include some or all of the increased costs in the rates charged by our pipelines, recovery of costs is not certain and would require the FERC's approval of a rate mechanism designed to recover those costs.

We recognize that relative to certain other fossil fuels, natural gas has an important role in reducing GHG emissions and may act as a bridge to scaling up renewable energy or other alternative energy sources in the U.S. While we are seeking to reduce our GHG emissions, we cannot predict all risks that may be associated with climate change or other sustainability matters. For more information, please see Item 1A. Risk Factors—Business Risks—*"Our operations, and those of our customers, are subject to a series of risks regarding climate change"* and *"Increased attention to climate change, sustainability matters and conservation measures may adversely impact our business."*

Human Capital

As of December 31, 2025, we had approximately 1,315 employees, approximately 95 of whom were included under collective bargaining agreements. A satisfactory relationship exists between management and our employees.

Hiring and retaining qualified people is critical to our long-term strategic success. We have programs in place that seek to help employees build their knowledge, skills and experience, as well as to guide their career development. We believe that employing individuals with different backgrounds and experiences helps meet the diverse needs of our stakeholders.

We are part of a critical infrastructure industry whose customers and communities depend upon us to provide safe and reliable service. Our employees are essential to ensuring we continue to meet these objectives, and we consider safety in our day-to-day activities to be a primary core value.

Available Information

Our website is located at *www.bwpipelines.com*. We make available free of charge through our website our Annual Reports on Form 10-K, which include our audited financial statements, 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 Securities Exchange Act of 1934 (Exchange Act) as soon as reasonably practical after we electronically file such material with the SEC. Information on or accessible through our website is not incorporated by reference into this Report. These documents are also available on the SEC's website at *www.sec.gov*.

Item 1A. Risk Factors

Our business faces many risks and uncertainties. We have described below the material risks facing us. These risks and uncertainties could lead to events or circumstances that may have a material adverse effect on our business, financial condition, results of operations or cash flows. There may be additional risks that we do not yet know of or that we do not currently perceive to be as material that may also materially adversely affect our business, financial condition, results of operations or cash flows.

All of the information included in this Annual Report on Form 10-K and any subsequent reports we file with the SEC or make available to the public should be carefully considered and evaluated before investing in any securities issued by us.

Business Risks

Our natural gas transportation and storage operations and ethane transportation services are subject to extensive regulation by the FERC, including rules and regulations related to the rates we can charge for our services and our ability to construct or abandon facilities. We may not be able to recover the full cost of operating our pipelines or storage operations, including earning a reasonable return.

Our natural gas transportation and storage operations are subject to extensive regulation by the FERC, including with respect to the types, rates and terms of services we may offer to our customers, construction of new facilities, creation, modification or abandonment of services or facilities and recordkeeping and relationships with affiliated companies. An adverse FERC action in any of these areas could affect our ability to compete for business, construct new facilities, offer new services or recover the full cost of operating our pipelines or storage operations, including earning a reasonable return. This regulatory oversight can result in longer lead times to develop and complete any future project than competitors that are not subject to the FERC's regulations. The FERC can also deny us the right to abandon certain facilities from service.

The FERC regulates the rates we can charge for our natural gas transportation and storage and interstate ethane transportation operations. For our cost-based services, the FERC establishes both the maximum and minimum rates we can charge. The basic elements that the FERC considers are the costs of providing service, the volumes of gas being transported, the rate design, the allocation of costs between services, the capital structure and the rate of return a pipeline is permitted to earn. We may not be able to recover our costs, including certain costs associated with pipeline integrity, through existing or future rates.

The FERC and/or our customers could challenge the maximum applicable rates that any of our regulated pipelines can charge in accordance with Section 5 of the NGA. The adoption of potential legislation that would amend Section 5 of the NGA to add refund provisions could increase the likelihood of such a challenge. If such a challenge is successful for any of our pipelines or if our rates are found not to be just and reasonable, then the revenues associated with transportation and storage services the pipeline provides pursuant to cost-of-service rates could materially decrease in the future, which would adversely affect, perhaps substantially, the revenues on that pipeline going forward.

Over time, the FERC may change, amend or announce that it will undertake a review of its existing policies. There were no major policy changes announced by the FERC during 2025.

The FERC has authority to impose civil penalties for violations of the NGA and NGPA, and the implementing regulations thereunder, up to a maximum amount that is adjusted annually for inflation, which for 2026 is approximately $1.5 million per day per violation. Should we fail to comply with applicable statutes, rules, regulations and orders administered by the FERC, we could be subject to substantial penalties and fines, in addition to reputational damage.

Our actual construction and development costs could exceed our forecasts; our anticipated cash flow from construction and development projects will not be immediate and can take several years; and our construction and development projects may not be completed on time or at all.

We are and have been engaged in several construction projects involving our existing assets and the construction of new facilities for which we have expended or will expend significant capital. We expect to continue to engage in the construction of additional growth projects and modifications of our system. These projects incur significant resources, including technological and human capital, and involve logistical challenges. When we build a new pipeline or expand or modify an existing facility, the design, construction and development occurs over an extended period of time, and we will not receive any revenue or cash flow from that project until after it is placed into commercial service. On our interstate pipelines, there are several years between when the project is announced and when customers begin using the new facilities. During this period, we spend capital and incur costs without receiving any of the financial benefits associated with the projects.

The construction of new assets involves a number of risks, including risks related to regulations (federal, state, and local), landowner opposition, environmental matters, activists, legal compliance, political matters and materials and labor costs or shortages, as well as operational and other risks that are difficult to predict and some of which are beyond our control. Our cost and timing estimates for these projects are based on a variety of inputs such as contractor indicative bids, quotes on materials and internally-developed financial models, metrics and timelines and are subject to a variety of risks and uncertainties, including obtaining timely regulatory and permit approvals and the cost thereof, adverse weather conditions during construction, our ability to acquire and the cost of obtaining rights to construct and operate on land not owned by us, delays in obtaining, shortages and price increases for key materials (including pipe, compressor stations and related equipment), tariff implications and shortages and increased costs of qualified labor. Factors in the estimates include, among other things, those related to pipeline costs based on mileage, size and type of pipe, materials, including compressors and related equipment, land, engineering and construction costs and timely receipt of all necessary permits and approvals. Actual costs and timing of in-service dates for our growth projects may differ, perhaps materially, from our estimates. In addition, failure to timely meet development milestones may result in, among other things, contractual counterparties having the ability to terminate contracts with us. A project may not be completed on time or at all due to a variety of factors, may be impacted by significant cost overruns or may be materially changed prior to completion as a result of developments or circumstances that we are not aware of when we commit to the project. Any of these events could result in material, unexpected costs or have a material adverse effect on our ability to realize the anticipated benefits from our growth projects.

Changes in U.S. trade policy and the impact of tariffs may have a material adverse effect on our business and results of operations.

Our business and results of operations may be adversely affected by uncertainty and changes in U.S. trade policies, including tariffs, trade agreements or other trade restrictions imposed by the U.S. or other governments. These actions have caused uncertainty and volatility in financial markets, may result in retaliatory measures on U.S. goods and may adversely impact both the U.S. and global economies.

Our business requires access to steel and other materials to construct and maintain our pipelines. While our practice is to source steel through domestic producers in the U.S. in most instances, any imposition of or increase in tariffs on imports of steel or other materials, as well as corresponding price increases for such materials available domestically, could increase our construction costs and our costs to maintain our assets. To the extent that we are unable to pass all or any such cost increases on to our customers, such cost increases could adversely affect our returns on investment. Higher materials costs could also diminish our ability to develop new projects at acceptable returns, particularly during times of economic uncertainty, and limit our ability to pursue growth opportunities.

Tariffs or other trade restrictions may lead to continuing uncertainty and volatility in U.S. and global economies and commodity markets and inflation, and reduced demand for our and our customers' products and services. Such conditions could have a material adverse impact on our business, results of operations and cash flows. Also, disruptions and volatility in the financial markets may lead to adverse changes in the availability, terms and cost of capital. Such adverse changes could increase our costs of capital and limit our access to external financing sources to fund acquisitions, capital projects, or refinancing of debt maturities on similar terms.

Changes in the debt markets and increases in interest rates could adversely affect our business.

We expect to construct approximately \$3.3 billion of growth projects over the next five years and are evaluating additional growth projects involving substantial capital commitments. We anticipate funding our capital and other spending requirements through our available financing options, including cash generated from operations, borrowings under our revolving credit facility and issuances of additional debt. Changes in the debt markets, including market disruptions, limited liquidity, and an increase in interest rates, may increase the cost of financing for these growth projects as well as the risks of refinancing maturing debt. This may affect our ability to raise needed financing and reduce the amount of cash available to fund our operations or growth projects or refinance maturing debt. If the debt markets were not available, it is not certain if other adequate financing options would be available to us on terms and conditions that we would find acceptable.

Any disruption in the debt markets could require us to take additional measures to conserve cash until the markets stabilize or until we can arrange alternative credit arrangements or other funding for our business needs. Such measures could include reducing or delaying business activities, reducing our operations to lower expenses and reducing other discretionary uses of cash. We may be unable to execute our growth strategy or take advantage of certain business opportunities, any of which could negatively impact our business.

Failure to comply with environmental or worker safety laws and regulations or an accidental release of pollutants into the environment may cause us to incur significant costs and liabilities.

Our operations are subject to extensive federal, state, and local laws and regulations relating to protection of the environment and occupational health and safety. Such laws and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of various substances, including hazardous substances and waste, and in connection with spills, releases, discharges and emissions of various substances into the environment. These laws include, for example, the CAA, the Clean Water Act, CERCLA, the RCRA, ESA, NEPA, OSHA and analogous state laws. These laws and regulations may restrict or impact our business activities, including requiring the acquisition or renewal of permits or other approvals to conduct regulated activities, restricting the manner in which we handle or dispose of wastes, imposing remedial obligations to remove or mitigate contamination resulting from a spill or other release, requiring capital expenditures to comply with pollution control requirements and imposing safety and health criteria addressing worker protection. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, the incurrence of capital expenditures, the occurrence of delays, denials or cancellations in the permitting or performance or expansion of projects and the issuance of orders enjoining future operations in a particular area. Under certain of these environmental laws and regulations, we could be subject to joint and several strict liability for the removal or remediation of previously released pollutants or property contamination, regardless of whether we were responsible for the release or contamination or if our operations were in compliance with applicable laws. We may not be able to recover some or any of the costs incurred from insurance.

Stricter environmental or worker safety laws, regulations or enforcement policies could significantly increase our operational or compliance costs and compliance with new or more stringent environmental legal requirements could delay or prohibit our ability to obtain permits for operations or require us to install additional pollution control equipment. For instance, the construction or expansion of pipelines often requires authorizations under the Clean Water Act, which may be subject to challenge. We rely on NWP 12, alongside other NWPs, as blanket authority for construction, maintenance, repair and removal of pipelines. The NWP process relies upon the Clean Water Act Section 401 certification process, which is subject to ongoing litigation. In September 2023, the EPA finalized its Clean Water Act Section 401 Water Quality Certification Improvement Rule, effective in November 2023, which expanded the scope of certification authority. However, in September 2023, several states challenged the final rule in federal court, alleging that the rule exceeds the EPA's statutory authority under the Clean Water Act, and the litigation has been held in abeyance pending the administration's review of the rule and litigation. In January 2026, the EPA proposed a rule revising its regulations governing Section 401 Water Quality Certifications. The proposed rule seeks to streamline the permitting process, restrict the ability of state and tribal certifying authorities to reject federal permits, and ensure such reviews are completed within the one-year statutory deadline. A final rule is expected in Spring 2026. However, opponents of the January 2026 proposed rule are pushing back on these efforts, including the EPA's efforts to narrow the scope of state authority. If NWP 12, or the underlying Section 401 certification process, is further amended or revoked, we may be required to apply for one or more Individual Permits, which would require additional time and resources to obtain, and may result in increased costs and project delays. Additionally, there continues to be uncertainty with respect to the federal government's jurisdictional reach under the Clean Water Act over WOTUS, as the EPA and the Corps have pursued multiple rulemakings under different administrations since 2015 to determine the scope of such reach. In September 2023, the EPA issued a version of the WOTUS rule that, due to injunctions in certain states, is currently in effect in only 24 states. Thus, the operative definition of WOTUS varies by state. However, in November 2025, the EPA and the Corps proposed a rule to further update and narrow the September 2023 definition, guided by the Supreme Court's decision in *Sackett v. EPA* (adopting the "continuous surface connection" test to determine if wetlands are WOTUS). To the extent any judicial ruling or administrative rulemaking or other action further changes the scope of the Clean Water Act's jurisdiction, we could face increased costs to comply and experience delays with respect to obtaining permits. See Part I, Item 1. Business—*Government Regulation—Other* of this Annual Report on Form 10-K for further discussion on environmental matters.

Legislative and regulatory initiatives relating to new or more stringent pipeline safety requirements or substantial changes to existing integrity management programs or withdrawal of regulatory waivers could subject us to increased capital and operating costs and operational delays.

Our interstate pipelines are subject to regulation by PHMSA, which is part of the DOT. PHMSA regulates the design, installation, testing, construction, operation and maintenance of existing interstate natural gas and NGLs pipeline facilities. PHMSA regulation currently requires pipeline operators to implement integrity management programs, including frequent inspections, remediation of certain identified anomalies and other measures to promote pipeline safety in HCAs, MCAs, Class 1 and 2 areas (depending on the potential impacts of a risk event), Class 3 and Class 4 areas, as well as in areas unusually sensitive to environmental damage and commercially navigable waterways. PHMSA has revised its standards from time to time and recently issued a series of significant rulemakings for onshore gas distribution, transmission and gathering pipelines (e.g., relating to MAOP reconfirmation and exceedance reporting, the integrity assessment of additional pipeline mileage and the consideration of seismicity as a risk factor in integrity management), and hazardous liquid transmission and gathering pipelines (e.g., expanding the reach of certain of PHMSA's integrity management requirements, requiring the accommodation of in-line inspection tools by 2039 for certain pipelines, increasing annual, accident and safety-related conditional reporting requirements, and expanding the use of leak detection systems beyond HCAs). PHMSA also regulates safety requirements applicable to natural gas storage facilities, including wells, wellbore tubing and casing. In August 2022, PHMSA published a final rule that attempted to expand the Management of Change process and corrosion control requirements for gas transmission pipelines and add requirements that operators ensure no conditions exist following an extreme weather event that could adversely affect the safe operation of the pipeline and repair criteria for non-HCAs. Five safety standards included in that rule were challenged by industry trade groups, and in August 2024, the U.S. Court of Appeals for the D.C. Circuit struck down four of the five challenged safety standards. In January 2025, PHMSA adopted a rule enhancing the safety requirements for gas distribution pipelines and requiring updates to distribution integrity management programs, emergency response plans, operations and maintenance manuals and other safety practices. However, this new rule was withdrawn by the Trump Administration before formal publication in the Federal Register. Any future regulations adopted by PHMSA may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital and operating costs, may cause us to experience operational delays and may result in potential adverse impacts to our operations or our ability to reliably serve our customers.

States have jurisdiction over certain of our intrastate pipelines and have adopted regulations similar to existing PHMSA regulations. State regulations may impose more stringent requirements than those found under federal law that affect our intrastate operations. Compliance with these rules over time generally has resulted in an overall increase in our maintenance costs.

The imposition of new or more stringent pipeline safety rules applicable to natural gas or NGLs pipelines, or any issuance or reinterpretation of guidance from PHMSA or any state agencies, could cause us to install new or modified safety controls, pursue additional capital projects, forgo growth projects or conduct maintenance programs on an accelerated basis, any or all of which could result in us incurring increased capital and operating costs, experiencing operational delays and suffering potential adverse impacts to our operations, our ability to grow our business or our ability to reliably serve our customers. Requirements that are imposed under the 2011 Act, the 2016 Act, the 2020 Act or other pipeline safety legislation or implementing regulations may also increase our capital and operating costs or impact the operation of our pipelines. See Part I, Item 1. Business—*Government Regulation—U.S. Department of Transportation* of this Annual Report on Form 10-K for further discussion on pipeline safety matters.

We have entered into certain firm transportation contracts with shippers that utilize the design capacity of certain of our pipeline assets, based upon the authority we received from PHMSA to operate those pipelines at higher than normal operating pressures of up to 0.80 of the pipeline's SMYS under issued permits with specific conditions. PHMSA retains discretion to withdraw or modify this authority. If PHMSA were to withdraw or materially modify such authority, it could affect our ability to transport all of our contracted quantities of natural gas on these pipeline assets, and we could incur significant additional costs to reinstate this authority or to develop alternate ways to meet our contractual obligations.

A failure in our computer systems or a cybersecurity attack on any of our computer systems, devices or telecommunications networks or those of certain third parties could cause substantial and catastrophic damage and may materially adversely affect our cash flows, financial condition and ability to operate our business.

Our business is dependent upon our computer systems, devices and networks (operational and information technology), and those of our customers, suppliers and others with whom we do business, to collect, process and store the data necessary to conduct almost all aspects of our business, including the operation of our pipeline and storage facilities and the recording and reporting of commercial and financial information. Despite our security measures, the information and operational technology and infrastructure we rely on may be vulnerable to attacks by third parties, such as hackers, cybercriminals, nation-states, insiders or other third parties, or breached due to human error, malfeasance or other disruptions. Through government intelligence reports, we are aware of credible global threats to third-party, U.S. critical infrastructure sectors on which we depend, such as the telecommunications sector.

Cybersecurity threat actors have attacked and continue to threaten energy infrastructure. The U.S. government has issued public and industry-directed warnings that indicate that energy assets might be specific targets of cybersecurity attacks, which are increasing in sophistication, magnitude and frequency. Vulnerabilities in one environment may affect other interconnected systems. A cybersecurity incident that impacts a third party with whom we do business may impact us.

Some cyber incidents, such as surveillance, may go unnoticed for a long period of time. Any investigation of a cybersecurity attack or other security incident will be inherently unpredictable and complex, and it may take significant time before the completion of any investigation and availability of full and reliable information. During such time, we may not know the extent of the harm or how best to remediate it, and certain errors or actions could be repeated or compounded before they are discovered and remediated, any or all of which could further increase the costs and consequences of a cybersecurity attack or other security incident, and our remediation efforts may not be successful.

As the cybersecurity threat landscape continues to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities. Advances in computer capabilities, discoveries in the field of artificial intelligence, cryptography, inadequate facility security or other developments may result in a compromise or breach of the technology we use to safeguard our operational and information technology systems and confidential, personal, or otherwise protected information. As the breadth and complexity of the technologies we use continue to grow, including as a result of the use of mobile devices, cloud services, artificial intelligence, open-source software, social media and the increased reliance on devices connected to the internet, the potential risk of cyberattacks and cybersecurity incidents also increases. No security measure is infallible. Despite ongoing efforts to improve our ability to protect our systems from compromise, we may not be able to protect all of our diverse systems. Our efforts to improve security and protect data and our systems may also identify previously undiscovered instances of security breaches or other cyber incidents.

TSA has issued a series of security directives applicable to pipeline owners and operators, which require the implementation of a variety of cybersecurity measures and reporting. Other regulators, such as PHMSA and the SEC, have also established requirements for reporting certain cybersecurity incidents. As cybersecurity incidents continue to evolve, more legislation could be enacted to seek to mitigate cybersecurity threats. This may require us to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate vulnerabilities to cybersecurity incidents at significantly increased costs. We cannot predict the potential impact to our business of potential future legislation, regulations or orders relating to cybersecurity.

A failure, security breach, disruption or degradation impacting our operational or information technology systems or those of third parties with whom we do business could negatively affect our ability to safely and reliably operate our assets and/or result in delays in providing services for our customers, contamination or degradation of the products we transport and store, damage to or destruction of our or third-party pipelines, property or facilities, catastrophic events, injury or death to our employees or other persons, the inadvertent release of hydrocarbons or the release or destruction of confidential, proprietary or business-critical information or intellectual property, which could result in outages, reduced revenue, unexpected costs and expenses, litigation and reputational damage, any or all of which may be irreversible and may materially adversely affect our results of operations, cash flows, financial condition and ability to operate our business.

In addition, access, disclosure or other loss of information or other consequences could result in legal claims or proceedings, liability under laws that protect the privacy of personal information or personally identifiable information, regulatory penalties for divulging or failing to adequately protect such information, disruption of our operations, incident response and remediation costs, damage to our reputation, and loss of confidence in our services.

Our operations, and those of our customers, are subject to a series of risks regarding climate change.

Climate change remains a concern in the U.S. and in other countries. Numerous proposals have been made and could continue to be made at the international, national, regional, state and local levels of government to monitor, limit and eliminate both existing and future emissions of GHGs. These proposals expose our operations, as well as the operations of our fossil fuel producer customers, to a series of regulatory, political, litigation and financial risks.

In the U.S., no comprehensive climate change legislation has been implemented at the federal level, though the Inflation Reduction Act of 2022 (IRA) advanced numerous climate-related objectives. The IRA required the EPA to impose and collect a methane emissions fee that applies to excess methane emissions from certain facilities that exceed statutory methane emissions thresholds. In November 2024, the EPA issued a final rule implementing the methane emissions fee, although in February 2025, Congress repealed the rule under the Congressional Review Act. Additionally, in the One Big Beautiful Bill Act, Congress delayed the implementation of the methane emission fee until 2034. While the EPA cannot reissue its rule implementing the methane emissions fee (either in substantially the same form or in a new rule), the underlying requirement in the IRA remains unchanged. We cannot predict if the Trump Administration and/or Congress may take further actions with respect to the IRA or methane emissions fee. However, compliance with this and other air pollution control and permitting requirements has the potential to delay or increase the costs of development of our projects, which costs could be significant.

Additionally, the EPA has the authority to regulate GHGs, including methane and carbon dioxide, under the CAA and has implemented various permitting, reporting and technology-based requirements to reduce GHG emissions by the oil and gas sectors. In December 2023, the EPA finalized its methane rules for new, modified, and reconstructed facilities, known as Subpart OOOOb, as well as standards for existing sources for the first time ever, known as Subpart OOOOc. Under the final rules, states have two years to prepare and submit their plans to impose methane emission controls on existing sources. The presumptive standards established under the final rules include advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane emissions, reduction of emissions by 95% through capture and control systems, zero-emission requirements for certain devices, and the establishment of the "super emitter" response program that would allow third parties to make reports to the EPA of large methane emission events. Fines and penalties for violations of these rules can be substantial. However, in March 2025, the EPA announced plans to reconsider Subparts OOOOb and OOOOc, in line with the Trump Administration's deregulatory agenda. Additionally, in November 2025, the EPA finalized an interim rule extending the compliance deadlines for certain provisions provided in Subparts OOOOb and OOOOc. Litigation challenging the EPA's final interim final rule extending such compliance deadlines for new and existing oil and gas sources remains pending.

Governmental entities, including certain states and groups of states, have adopted or are considering legislation, regulations or other initiatives, such as GHG cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and emissions limits. At the international level, in 2021, the U.S. rejoined the Paris Agreement, which requires member nations to submit non-binding GHG emissions reduction goals every five years, and President Biden announced a new target for the U.S. to reduce GHG emissions 50%-52% from 2005 levels by 2030. However, in January 2025, President Trump signed an Executive Order once again withdrawing the U.S. from the Paris Agreement and in January 2026, announced the U.S. withdrawal from the United Nations Framework Convention on Climate Change. Additionally, President Trump revoked any purported financial commitment made by the U.S. pursuant to the same. The full impact these actions may have upon our business or financial condition remains uncertain at this time.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the U.S. The Trump Administration rescinded many of the previous administration's climate-related initiatives, which initiatives included curtailing oil and natural gas production and transportation, restricting flaring and venting during natural gas production, limiting or banning oil and gas leases on federal lands and offshore waters, increasing requirements for construction and permitting of pipeline infrastructure and LNG export facilities, and further restricting GHG emissions from oil and gas facilities. The Trump Administration has also taken a number of steps to repeal or otherwise modify several GHG regulations, including some applicable to the oil and gas industry. We cannot predict what additional actions the Trump Administration may take with respect to these matters, or others, or the timing or success of any such actions. Additionally, litigation risks are also increasing with respect to climate change, as a number of cities and other governmental entities have brought suit alleging that fossil fuel producers created public nuisances by producing fuels that contributed to global warming effects such as rising sea levels, are responsible for associated roadway and infrastructure damage, or defrauded investors or customers by failing to timely and adequately disclose adverse effects of climate change.

There have also been increasing financial risks for fossil fuel energy companies as certain investors become concerned about the potential effects of climate change and may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Some institutional lenders who provide financing to fossil fuel energy companies also have become more attentive to sustainable lending practices that favor alternative power sources (such as wind, solar, geothermal, tidal and biofuels), making those sources more attractive, and some of them may elect not to provide funding for fossil fuel energy companies, although this trend has decreased in recent times and is impacted by complex factors, including regional, political, and legal considerations. While we cannot predict how or to what extent sustainable lending and investment practices may impact us, a material reduction in the capital available to the fossil fuel industry could make it more difficult to secure funding for exploration and production or midstream energy business activities, which could adversely impact our business and operations. There have also been efforts at the federal, state and international levels seeking more fulsome disclosures relating to climate risks, targets and metrics. Any climate-related disclosure requirements imposed in the future may result in increased compliance costs and increased costs of and restrictions on access to capital. These agency or state or international regulatory actions also could increase the potential for litigation.

The adoption and implementation of new or more stringent international, federal, regional, state or local legislation, regulations or other initiatives that impose more stringent standards for GHG emissions from the oil and gas sector or otherwise restrict fossil fuel production could result in increased costs of compliance for fossil fuel use, result in litigation and reduce demand for fossil fuels, which could reduce demand for our transportation and storage services. Political, litigation and financial risks may result in our fossil fuel producer customers restricting or canceling production activities, incurring liability for infrastructure and other damages as a result of climatic changes, or impairing their ability to continue to operate in an economic manner, which also could reduce demand for our services. Moreover, the increased competitiveness of alternative energy sources could reduce demand for hydrocarbons and for our services. Finally, we may also be subject to various physical risks from climate change. For more information on these physical risks, see our risk factor titled *"Climatic conditions and events could adversely impact our operations, pipelines and facilities, or those of our customers or suppliers."*

Increased attention to climate change, sustainability matters and conservation measures may adversely impact our business.

Increased attention to climate change, societal expectations on companies to address climate change, investor and societal expectations regarding sustainability matters and disclosures, and consumer demand for alternative forms of energy may result in increased costs, reduced demand for our services, reduced profits, increased investigations and litigation, and negative impacts on our access to capital markets. Increased attention to climate change and environmental conservation, for example, may result in demand shifts for oil and natural gas products, additional governmental investigations, governmental and private litigation and other liabilities imposed against us or our customers. It is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage or to other mitigating factors.

While we may publish voluntary disclosures regarding sustainability matters from time to time, many of the statements in those disclosures may not be material and may be based on expectations and assumptions or hypothetical scenarios that may not be representative of actual risks or events or forecasts of expected risks or events. Such expectations and assumptions or hypothetical scenarios are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established approach to identifying, measuring and reporting on many sustainability matters. In addition, failure or perception of failure (whether or not valid) to pursue or implement sustainability strategies or achieve (or make progress against) sustainability goals or commitments, including GHG reduction goals or commitments, could result in private litigation and damage to our reputation.

Organizations that provide information to investors on corporate governance and related matters have developed rating and proxy voting recommendation processes for evaluating companies on their approach to sustainability matters, and many of these processes are inconsistent with each other. Such ratings and proxy advisory services are used by some investors to inform their investment and voting decisions. While such ratings and services do not impact all investors' investments or voting decisions, unfavorable ratings or recommendations could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our access to and costs of capital.

In addition, other stakeholders, including customers, employees, regulators, credit rating agencies and suppliers, have also been focused on sustainability matters. Companies that do not adapt to or comply with investor or other stakeholder expectations and standards, or that are perceived to have not responded appropriately to the concerns regarding sustainability issues, may suffer from reputational damage and other adverse consequences. Additionally, to the extent sustainability matters negatively impact our reputation, we may not be able to compete as effectively to recruit or retain employees, which may adversely affect our operations.

Certain public statements with respect to sustainability matters, such as emissions reduction goals, other environmental targets, or other commitments addressing certain social issues, are becoming increasingly subject to heightened scrutiny from public and governmental authorities, as well as other parties, related to the risk of potential "greenwashing," *i.e.*, misleading information or false claims overstating potential sustainability benefits. For example, federal and state regulators have taken enforcement action against companies for sustainability-related misconduct, including greenwashing. Such regulators, as well as non-governmental organizations and other private actors have also filed lawsuits under various securities and consumer protection laws alleging that certain sustainability-related statements, goals, or standards were misleading, false, or otherwise deceptive.

Additionally, certain employment or business practices and social initiatives are the subject of scrutiny by both those calling for the continued advancement of such policies, as well as those who believe they should be curbed, including government actors, and the complex regulatory and legal frameworks applicable to such initiatives continue to evolve. We cannot be certain of the impact of such regulatory, legal and other developments on our business. As a result, we may face increased litigation risks from private parties and governmental authorities related to any sustainability efforts.

Climatic conditions and events could adversely impact our operations, pipelines and facilities, or those of our customers or suppliers.

Climatic events can cause disruptions to, delays in or suspension of our services by interrupting our operations, causing loss of or damage to our facilities or equipment, or having similar impacts on our customers or third-party suppliers. In general, our operations could be significantly impacted by climatic conditions such as increased frequency and severity of storms, floods and wintry conditions. Our pipeline operations along coastal waters and offshore could be adversely impacted by climatic conditions such as rising sea levels, subsidence and erosion, which could result in serious damage to our facilities and affect our ability to provide transportation services. Such damage could result in leakage, migration, releases or spills from our operations and could result in liability, remedial obligations or otherwise have a negative impact on operations. Such climatic conditions could also impact our customers' ability to utilize our services and third-party suppliers' ability to provide us with the products and services necessary to maintain operation of our facilities. We may incur significant damages as well as costs to repair or maintain our facilities, which could adversely affect our operations and the financial health of our business. In recent years, local governments and landowners in Louisiana have filed lawsuits against energy companies, including us, alleging that their operations contributed to increased coastal rising seas and erosion and are seeking, or have been awarded, substantial damages. Changing meteorological conditions, particularly temperature, may affect the amount, timing, or location of demand for energy or the products we transport, which may impact demand for our services.

We are subject to reputational risks and risks related to public opinion.

Our business, operations and financial condition may be adversely impacted as a result of negative public opinion. We operate in an industry that receives negative portrayals and opposition to development projects. Our reputation and public opinion could be impacted by the actions, activities and responses of other companies operating in the energy industry, particularly other energy infrastructure providers, over which we have no control. Our reputation could also be impacted by negative publicity related to pipeline incidents, unpopular expansion projects and opposition to the development of hydrocarbons and energy infrastructure, including projects involving resources that are considered to increase GHG emissions and contribute to climate change. Negative impacts from a compromised reputation or changes in public opinion (including with respect to the production, transportation and use of hydrocarbons generally) could include increased regulatory oversight, delays in obtaining, or challenges to, regulatory approvals with respect to growth projects, blockades, project cancellations, difficulty securing financing at reasonable terms, revenue loss or a reduction in customer base.

We may face opposition to the operation of our pipelines and facilities, construction or expansion of facilities and new pipeline projects from various groups.

We may face opposition to the operation of our pipelines and facilities, construction or expansion of our facilities and new pipeline projects from governmental officials, environmental groups, landowners, communities, tribal or local groups and other advocates. Such opposition could take many forms, including organized protests, attempts to block or sabotage our operations, acts of eco-terrorism, 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. For example, repairing our pipelines often involves securing consent from individual landowners to access their property, and one or more landowners may resist our efforts to make needed repairs, which could lead to an interruption in the operation of the affected pipeline or facility for a period of time that is significantly longer than would have otherwise been the case. Acts of sabotage or eco-terrorism could cause significant damage or injury or death to people, property or the environment and lead to extended interruptions of our operations and material damages and costs.

Market conditions, including available supply, demand and the price differentials between natural gas supplies and market locations for natural gas, may affect the transportation rates that we can charge on certain portions of our pipeline systems.

Each year, a portion of our firm natural gas transportation contracts expire and need to be replaced or renewed. As a result of market conditions, we may renew some expiring contracts at lower rates or for shorter terms than in the past. The transportation rates we are able to charge customers are heavily influenced by market trends (both short and longer term), including the continued availability of supply from key supply basins, the competition between producing basins, competition with other pipelines for supply and markets, the demand for gas by end-users such as electric power generators, petrochemical facilities, artificial intelligence data centers and LNG export facilities and the price differentials between the gas supplies and the market demand for the gas (basis differentials).

Changes in energy prices, including natural gas, oil and NGLs, impact the supply of and demand for those commodities, which impact our business.

Our customers, especially producers and certain plant operators, are directly impacted by changes in commodity prices. The prices of natural gas, oil and NGLs fluctuate in response to changes in both domestic and worldwide supply and demand, market uncertainty and a variety of additional factors, including for natural gas, the realization of potential LNG exports and demand growth within the power generation market, including as a result of increased demand from artificial intelligence (AI) data centers. Volatility in the pricing levels of natural gas, oil and NGLs could adversely affect the businesses of certain of our producer customers and could result in defaults or the non-renewal of our contracted capacity when existing contracts expire. Commodity prices could affect the operations of certain of our industrial customers, including the temporary closure or reduction of plant operations, resulting in decreased deliveries to those customers. Future increases in the price of natural gas and NGLs could make alternative energy and feedstock sources more competitive and decrease demand for natural gas and NGLs. A reduced level of demand for natural gas and NGLs could diminish the utilization of capacity on our systems and reduce the demand for our services.

We are exposed to credit risk relating to default or bankruptcy by our customers.

Credit risk relates to the risk of loss resulting from the default by a customer of its contractual obligations or the customer filing bankruptcy. We have credit risk with both our existing customers and those supporting our growth projects. Credit risk exists in relation to our growth projects because the expansion customers make long-term firm capacity commitments to us for such projects and certain of those expansion customers agree to provide credit support as construction for such projects progresses. If a customer fails to post the required credit support or defaults during the growth project process, overall returns on the project may be reduced to the extent an adjustment to the scope of the project occurs, or we are unable to replace the defaulting customer with a customer willing to pay similar rates.

Our credit exposure also includes receivables for services provided, future performance under firm agreements and volumes of gas owed by customers for imbalances or gas loaned by us to them under certain NNS and PAL services.

We rely on a limited number of customers for a significant portion of our revenues.

For 2025, one customer comprised 10% or more of our operating revenues. Additionally, as of December 31, 2025, the top ten customers under committed firm agreements comprised approximately 66% of our total projected operating revenues. If any of our significant customers have credit or financial problems that result in bankruptcy, a delay or failure to pay for services provided by us, to post the required credit support for construction associated with our growth projects or existing contracts or to repay the gas they owe us, it could have a material adverse effect on our revenues, results of operations and financial condition.

Our revolving credit facility contains operating and financial covenants that may restrict our business and financing activities.

Our revolving credit facility contains operating and financial covenants that may restrict our ability to finance future operations or capital needs or to expand or pursue business activities. Our credit agreement limits our ability to make loans or investments, make material changes to the nature of our business, merge, consolidate or engage in asset sales, or grant liens or make negative pledges. This agreement also requires us to maintain a ratio of consolidated total debt to consolidated EBITDA (as defined in the credit agreement) of not more than 5.0 to 1.0, or up to 5.5 to 1.0 for the quarter in which the consummation of a qualified acquisition occurs where the purchase price exceeds $100.0 million and the three quarters following the qualified acquisition quarter, which limits the amount of additional indebtedness we can incur to grow our business, and could require us to reduce indebtedness if our earnings before interest, income taxes, depreciation and amortization (EBITDA) decreases to a level that would cause us to breach this covenant. Future financing agreements we may enter into could contain similar or more restrictive covenants or may not be as favorable as those under our existing indebtedness.

Our ability to comply with the covenants and restrictions contained in our credit agreement may be affected by events beyond our control, including economic, financial and market conditions. If market or economic conditions or our financial performance deteriorate, our ability to comply with these covenants may be impaired. If we are not able to incur additional indebtedness, we may be required to seek other sources of funding that may be on less favorable terms. If we default under our credit agreement or another financing agreement, significant additional restrictions may become applicable. In addition, a default could result in a significant portion of our indebtedness becoming immediately due and payable, and our lenders could terminate their commitment to make further loans to us. If such an event occurs, we may not be able to obtain sufficient funds to make these accelerated payments.

Our indebtedness could affect our ability to meet our obligations and may otherwise restrict our activities.

As of December 31, 2025, we had $3.8 billion in principal amount of debt outstanding, of which $550.0 million was called for redemption on January 31, 2026. We expect to construct approximately $3.3 billion of growth projects over the next five years (and are evaluating additional growth projects involving substantial capital commitments) and anticipate having to finance a substantial portion of these capital commitments. This level of debt requires significant interest payments. Our inability to generate sufficient cash flow to satisfy our debt obligations, or to refinance our obligations on commercially reasonable terms, would have a material adverse effect on our business. Our indebtedness could have important consequences. For example, it could:

- limit our ability to borrow money for our working capital, capital expenditures, including our growth projects, debt service requirements or other general partnership purposes;
- impact our ratings received from credit rating agencies;
- increase our vulnerability to general adverse economic and industry conditions; and
- limit our ability to respond to business opportunities, including growing our business through acquisitions.

We are permitted, under our revolving credit facility and the indentures governing our notes, to incur additional debt, subject to certain limitations under our revolving credit facility and the indentures governing the notes. If we incur additional debt, our increased leverage could also result in or exacerbate the consequences described above.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets, which may affect our ability to fulfill our debt obligations.

We are a partnership holding company, and our operating subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the ownership interests in our subsidiaries. As a result, our ability to fulfill our debt obligations depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations, including FERC policies.

Pandemics or other outbreaks of contagious diseases and the measures to mitigate their spread could materially adversely affect our business, financial condition and results of operations and those of our customers, suppliers and other business partners.

The global outbreak of the COVID-19 pandemic and measures to mitigate the spread of COVID-19 caused unprecedented disruptions to the global and U.S. economies and impacted global demand for oil and petrochemical products. Future pandemics or other outbreaks of contagious diseases could result in similar or worse impacts and significant business and operational disruptions, including business closures, supply chain disruptions, travel restrictions, stay-at-home orders and limitations on the availability of workforces. Although our operations are considered essential critical infrastructure under current Cybersecurity and Infrastructure Security Agency guidelines, if significant portions of our workforce are unable to work effectively, including because of illness or quarantines or from the impacts of any potential future pandemics or other outbreaks of contagious diseases, our business could be materially adversely affected. We may also be unable to perform fully on our contracts, and our costs may increase as a result of any potential future pandemics or other outbreaks of contagious diseases. These cost increases may not be fully recoverable. It is possible that future pandemics or other outbreaks of contagious diseases could cause disruption in our customers' businesses, cause delays, or limit the ability of our customers to perform, including in making timely payments to us. Future pandemics or other outbreaks of contagious diseases could impact capital markets, which may impact our customers' financial position. Future pandemics or other outbreaks of contagious diseases may also have the effect of exacerbating several of the other risk factors contained herein.

We do not own all of the land on which our pipelines, storage and other facilities are located, which could result in disruptions to our operations.

Substantial portions of our pipelines, storage and other facilities are constructed and maintained on property owned by others pursuant to rights-of-way, easements, permits, licenses or consents, and we are subject to the possibility of more onerous terms and/or increased costs to retain necessary land use rights if we do not have valid land use rights or if such land use rights lapse or terminate. Some of the rights we obtain to construct and operate our pipelines, storage or other facilities on land owned by third parties and governmental agencies are for specific periods of time. We cannot guarantee that we will always be able to renew, when necessary, existing land use rights or obtain new land use rights without experiencing significant costs or experiencing landowner opposition. Any loss of these land use rights (or increased costs to renew) with respect to the operation of our pipelines, storage and other facilities, through our inability to acquire or renew right-of-way or easement contracts or permits, licenses, consents or otherwise (or increased costs in connection with the renewal thereof), could have a material adverse effect on our operations.

We may not be successful in executing our strategy to grow and diversify our business.

We rely primarily on the revenues generated from our natural gas transportation and storage services. Negative developments in these services have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets. Our ability to grow, diversify and increase cash flows will depend, in part, on our ability to expand our existing business lines, close and execute on accretive acquisitions and finance and construct our growth projects. We may not be successful in acquiring or developing such assets or may do so on terms that ultimately are not profitable.

Our ability to replace expiring gas storage contracts at attractive rates or on a long-term basis and to sell short-term services at attractive rates or at all are subject to market conditions.

We own and operate substantial natural gas storage facilities. The market for the storage and PAL services that we offer is impacted by the factors and market conditions discussed above for our transportation services and is also impacted by natural gas price differentials between time periods, such as winter to summer (time period price spreads), and the volatility in time period price spreads. When market conditions cause a narrowing of time period price spreads and a decline in the price volatility of natural gas, these factors adversely impact the rates we can charge for our storage and PAL services.

Our operations are subject to catastrophic losses, operational hazards and unforeseen interruptions for which we may not be adequately insured.

There are a variety of operating risks inherent in transporting and storing natural gas, ethylene and NGLs, such as leaks and other forms of releases, explosions, fires, cybersecurity attacks and mechanical problems, which could have catastrophic consequences. Additionally, the nature and location of our business may make us susceptible to catastrophic losses from hurricanes or other named storms, particularly with regard to our assets in the Gulf Coast region, cold freezes, snowstorms, windstorms, earthquakes, hail, tornados and other severe weather. Any of these or other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of life, significant damage to property, environmental pollution, impairment of our operations and substantial financial losses and reputational damage. The location of pipelines in HCAs, which includes populated areas, residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from some of these risks.

We currently possess property, business interruption, cybersecurity and general liability insurance, but proceeds from such insurance coverage may not be adequate for all liabilities or expenses incurred or revenues lost. Moreover, such insurance may not be available in the future at commercially reasonable costs and terms. The insurance coverage we do obtain may contain large deductibles or fail to cover certain events, hazards or potential losses.

Our business requires the retention and recruitment of a skilled executive team and workforce and their loss could result in the failure to implement our business plans.

Our operations and management require the retention and recruitment of a skilled executive team and workforce, including engineers, technical personnel and other professionals. In addition, several of our current employees are approaching retirement age and have significant institutional knowledge that must be transferred to other employees. If we are unable to retain our current employees, successfully complete the knowledge transfer and/or recruit new employees of comparable knowledge and experience, our business could be negatively impacted.

Our business is highly competitive.

The principal elements of competition among pipeline systems are the availability of capacity, rates, terms of service, access to gas supplies, flexibility and reliability of service. Additionally, the FERC's policies promote competition in natural gas markets by increasing the number of natural gas transportation options available to our customer base. Increased competition could reduce the volumes of product we transport or store or, in instances where we do not have long-term contracts with fixed rates, could cause us to decrease the transportation or storage rates we can charge our customers. Competition could exacerbate the negative impact of factors that adversely affect the demand for our services, such as adverse economic conditions, weather, higher fuel costs and taxes or regulatory actions that increase the cost, or limit the use, of our facilities or products we transport and store.

Possible terrorist activities or military actions could adversely affect our business.

The continued threat of terrorism and the impact of military and other action by the U.S. and its allies or other countries might lead to increased political, economic and financial market instability and volatility in prices for natural gas, which could affect the markets for our natural gas transportation and storage services. While we are taking steps that we believe are appropriate to increase the security of our assets, we may not be able to completely secure our assets or completely protect them against a terrorist attack.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

Risk Management and Strategy

Our business is dependent upon our computer systems, devices and networks (operational and information technology), and those of third parties with whom we do business, to collect, process and store the data necessary to conduct almost all aspects of our business, including the operation of our pipeline and storage facilities and the recording and reporting of commercial and financial information. We maintain a cybersecurity program, which includes people, processes, and technology aimed at defending our computer systems, devices and networks (operational and information technology) against increasingly sophisticated threats.

We recognize the importance of protecting both our information and operational control systems from threats that could disrupt our business, put our assets at risk or compromise our customer and employee data, including personally identifiable information. The effective protection of our assets and technology infrastructure is crucial to the reliability of our operations, our ability to serve our customers, the nation's energy needs and the security of our assets and data. We developed a comprehensive strategy designed to address both physical and cybersecurity threats. Additionally, as further described in Item 1. Business—*Government Regulation—Transportation Safety Administration,* TSA has issued a series of security directives that all pipeline owners and operators must include the directives in their cybersecurity planning, testing and reporting of any incidents.

Our cybersecurity program is encapsulated in our Cybersecurity Implementation Plan, Cybersecurity Incident Response Plan and CAP. Our cybersecurity program is implemented and maintained using information security tools, policies and a dedicated team responsible for monitoring our networks, providing training to our employees, analyzing the evolution of new threats and strategies for mitigating such threats and seeking to continually harden our cybersecurity posture. The program is periodically exercised, reviewed, updated, and vetted through third-party audits, assessments, and tests with the goal of validating its effectiveness in reducing risk, as well as evaluating its compliance with legal and regulatory requirements. To assess, identify and manage our material risks from cybersecurity threats, we endeavor to employ the following:

a. Identification of critical systems – we seek to identify which operational or information technology, if compromised or exploited, would result in operational disruption or harm or data compromise. We aim to protect the entire environment at an enterprise level where practical, combined with additional layered, risk-based controls designed to safeguard against cybersecurity threats where risk is higher. This strategic, defense-in-depth, and risk-based approach to cybersecurity provides a methodology designed to identify, protect, detect, respond, and recover from cybersecurity incidents.

b. Network segmentation – we use a combination of firewalls, routers and switches in an effort to provide network segmentation aimed at providing network zone protection.

c. Access controls – we leverage several security capabilities to attempt to enforce access, authorization and authentication to relevant systems, technology, and controls. A least-privilege methodology is applied for localized client workstations, servers, and applications. Security capabilities for access control include physical, administrative, and technical controls that combine to seek to provide a defense-in-depth approach designed to protect our cyber assets from unauthorized use.

d. Continuous monitoring, detection, and auditing – we employ various technologies, tactics, and procedures aimed to continuously monitor, baseline, and detect threats, and audit our network and systems. In addition, we use a combination of technology tools with outside managed security service providers designed to capture, analyze and respond to security anomalies.

e. Patch management – network vulnerability scanning tools are deployed that seek to continually scan, identify and report on asset vulnerabilities. Vulnerability scanner reports are used to drive patching and remediation efforts and are also used as a tool to evaluate the effectiveness and timeliness of patching efforts. Application and infrastructure subject matter experts subscribe to various third-party vendor security notifications to receive proactive notifications on, among other things, bugs, security flaws and mitigations, related to operational and information systems.

The above cybersecurity risk management processes are integrated into our overall risk management program. Cybersecurity threats are understood to be wide-reaching and to intersect with various other enterprise risks. In addition to assessing our own cybersecurity preparedness, we also consider cybersecurity risks associated with our use of third-party service providers based on the potential impact of a disruption of the services to our operations and the sensitivity of data shared with the service providers. We have established separate processes and procedures to oversee and identify cybersecurity risks associated with third parties.

We regularly engage independent third parties to periodically assess our cybersecurity posture. These assessments include penetration tests, purple team activities, health checks and point-specific technical cybersecurity assessments of key systems. Some of these assessments are performed independently with internal audit oversight. Certain processes are part of our CAP and are required to be tested at regular intervals, and test results may be required to be reported to TSA as requested and during inspections. We interface with industry peers, participate in information sharing and analysis centers and partner with federal, state, and local law enforcement and regulatory agencies with the goal of forming a cybersecurity threat feedback loop. Threat and mitigation information, techniques, tactics and procedures are often shared via this loop.

Impact of Risks from Cybersecurity Threats

As of the date of this Annual Report, though the Company and third parties with whom we do business have experienced certain cybersecurity incidents, we are not aware of any previous cybersecurity threats or incidents that have materially affected or are reasonably likely to materially affect us. We acknowledge that cybersecurity threats are continually evolving, and the possibility of future cybersecurity incidents remains. Despite the implementation of our cybersecurity processes, our security measures cannot guarantee that a significant cybersecurity attack will not occur. While we devote resources to our security measures designed to protect our systems and information, no security measure is infallible. See Item 1A. Risk Factors for additional information about the risks to our business associated with a breach or other compromise to our information and operational technology systems.

Governance

Our board of directors oversees the execution of our cybersecurity strategy. Our Chief Information Security Officer (CISO) oversees our cybersecurity activities and leads our team of cybersecurity professionals responsible for our cybersecurity program and is informed about and monitors the prevention, detection, mitigation and remediation of cybersecurity incidents as part of our cybersecurity programs. Our CISO, Chief Financial Officer (CFO) and other cybersecurity professionals provide updates regarding cybersecurity risks to our executive team and board of directors at least quarterly, with more frequent updates regarding cybersecurity-related situations, such as relevant intelligence indicators, as appropriate. Our CFO and CISO also attend weekly executive leadership meetings to give updates on any immediate cybersecurity threats, risks and regulatory changes, as well as any improvements or impediments to our cybersecurity posture. Our CISO has over thirty years of experience involving technology in the energy sector, with a focus over the last twenty years on helping companies, including us, improve their technology infrastructure and cybersecurity programs.

Item 2. Properties

We are headquartered in approximately 98,600 square feet of leased office space located in Houston, Texas. We also have approximately 60,000 square feet of leased office space in Owensboro, Kentucky. Our operating subsidiaries own their respective pipeline and storage systems in fee. However, substantial portions of these systems are constructed and maintained on property owned by others pursuant to rights-of-way, easements, permits, licenses or consents. *Natural Gas* and *Natural Gas Liquids*, in Part I, Item 1. of this Annual Report on Form 10-K, contains additional information regarding our material property, including our pipelines and storage facilities.

Item 3. Legal Proceedings

Refer to Note 5 in Part II, Item 8. of this Annual Report on Form 10-K for a discussion of our legal proceedings.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Not applicable.

Item 6. [Reserved]

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

Overview

We operate in the midstream portion of the natural gas and NGLs industry, providing transportation and storage for those commodities. We also provide ethane supply and transportation services for petrochemical customers in Louisiana and Texas. Refer to Part I, Item 1. Business, of this Annual Report on Form 10-K for further discussion of our operations and business. We are not in the business of buying and selling natural gas and NGLs other than for system management purposes and to facilitate our ethane supply operations, but changes in natural gas and NGLs prices may impact the volumes of natural gas or NGLs transported and stored by our customers or the ethane supply requirements on our systems. The pricing contained in the purchase and sales agreements associated with our ethane supply services is generally based on the same ethane commodity index, plus a fixed delivery fee. As a result, except for possible timing differences that may occur when volumes are purchased in one month and sold in another month, our ethane supply services, like our other businesses, have little to no direct commodity price exposure. Due to the capital-intensive nature of our business, our operating costs and expenses typically do not vary significantly based upon the volume of products transported, with the exception of fuel consumed at our compressor stations and not included in a fuel tracker. Refer to Part I, Item 1. Business, for further discussion of the services that we offer and our customer mix. Our operations are reported under two business segments: Natural Gas and Natural Gas Liquids.

Firm Agreements

A substantial portion of our transportation and storage capacity is contracted for under firm agreements. For the year ended December 31, 2025, approximately 87% of our revenues were derived from capacity reservation fees under firm contracts or from contracts with MVCs. The table below shows a rollforward of projected operating revenues under committed firm agreements in place as of December 31, 2024, to December 31, 2025, including agreements for transportation, storage, ethane supply and other services, over the remaining term of those agreements (in millions):

Total projected operating revenues under committed firm agreements as of December 31, 2024	$	14,184.0
Adjustments for:		
Actual revenues recognized from firm agreements in 2025(1)		**(1,639.5)**
Firm agreements entered into in 2025(2)		**7,011.0**
Total projected operating revenues under committed firm agreements as of December 31, 2025	**$**	**19,555.5**

(1) As of December 31, 2024, we expected our 2025 revenues from fixed fees under firm agreements to be approximately $1,512.0 million, including agreements for transportation, storage and other services. Our actual 2025 revenues recognized from fixed fees under firm agreements were approximately $1,639.5 million, an increase of $127.5 million from 2024, primarily resulting from contract renewals at higher rates that occurred in 2025.

(2) During 2025, we entered into approximately $7.0 billion of new firm agreements, of which approximately 82% were associated with new growth projects executed in 2025.

For firm agreements associated with new growth projects, the associated assets may not be placed into commercial service until sometime in the future. The table above includes $9.9 billion of estimated revenues that are anticipated under executed precedent or long-term firm transportation agreements for growth projects that are contingent upon, among other things, receipt of required regulatory approvals and permits and are subject to construction risk. Each year, a portion of our firm transportation and storage agreements expire. The rates we are able to charge customers are heavily influenced by market trends (both short and longer term), including the available supply, geographical location of natural gas production, the competition between producing basins, competition with other pipelines for supply and markets, the demand for gas by end-users such as electric power generators (including as a result of increased demand by AI data centers), petrochemical facilities and LNG export facilities and the price differentials between the gas supplies and the market demand for the gas (basis differentials). Refer to Part I, Item 1. Business and Item 1A. Risk Factors of this Annual Report on Form 10-K for further information. As of December 31, 2025, our top ten customers under committed firm agreements comprised approximately 66% of our total projected operating revenues and the credit profile associated with our customers comprising the total projected operating revenues under committed firm agreements was 87% rated as investment grade, 2% rated as non-investment grade and 11% not rated. Note 3 in Part II, Item 8. of this Annual Report on Form 10-K contains more information regarding the revenues we expect to earn from fixed fees under committed firm agreements.

Pipeline System Maintenance and GHG Emission Reduction Initiatives

We incur substantial costs for ongoing maintenance of our pipeline systems and related facilities, including those incurred for pipeline integrity management activities, equipment overhauls, general upkeep and repairs. These costs are not dependent on the amount of revenues earned from our transportation services. PHMSA's regulations require transportation pipeline operators to implement integrity management programs to comprehensively evaluate certain high-risk areas, known as high consequence areas (HCAs) and moderate consequence areas (MCAs), along pipelines and take additional safety measures to protect people and property in these areas. These regulations have resulted in an overall increase in our ongoing maintenance costs, including maintenance capital and maintenance expense. Refer to Part I, Item 1. Government Regulation, for further discussion of these regulations.

Due to the nature of our business, our operations emit various types of GHGs. We seek to monitor our emissions and expect to incur additional costs to mitigate emissions. New legislation or regulations could increase the costs related to operating and maintaining our facilities. Depending on the particular law, regulation or program, we could be required to incur capital expenditures for installing new monitoring equipment or emission controls on our facilities, acquire and surrender allowances for GHG emissions, pay taxes or fees related to GHG emissions and/or administer and manage a more comprehensive GHG emissions program.

We have been focused on seeking to meet and, in certain instances, pursuing projects aimed at exceeding, regulatory obligations (such as those found in the CAA) by working to reduce emissions of regulated air pollutants, including methane, associated with our pipeline transportation and storage assets.

PHMSA regulations and efforts to reduce GHG emissions have caused our capital and operating costs to increase since 2021. Those costs are expected to stabilize for the foreseeable future, though PHMSA regulations and such efforts may cause us to experience operational delays and may result in potential adverse impacts to our ability to grow our business and reliably serve our customers. Additionally, any changes to these regulations could cause our costs to increase in the future. See Part I, Item 1. Business and Item 1A. Risk Factors of this Annual Report on Form 10-K for further information.

Maintenance costs may be capitalized or expensed, depending on the nature of the activities. For any given reporting period, the mix of projects that we undertake will affect the amounts we record as property, plant and equipment on our Consolidated Balance Sheets or recognize as expenses, which impact our earnings. In 2026, we expect to spend approximately $530.0 million to maintain our pipeline systems, comply with regulations and monitor, control and reduce our GHG emissions, of which approximately $225.0 million is expected to be maintenance capital. In 2025, we spent $516.1 million on these matters, of which $194.2 million was recorded as maintenance capital. Refer to *Capital Expenditures* for more information regarding certain of our maintenance costs.

Consolidated Results of Operations

Note 2 in Part II, Item 8. of this Annual Report on Form 10-K contains a summary of our revenue contracts and the related revenue recognition policies. A significant portion of our revenues are fee-based, being derived from capacity reservation charges under firm agreements with customers, which do not vary significantly period to period, but are impacted by longer-term trends in our business, such as changes in pricing on contract renewals and other factors discussed elsewhere in this Annual Report on Form 10-K. The pricing contained in the purchase and sales agreements associated with our ethane supply services is generally based on the same ethane commodity index, plus a fixed delivery fee. As a result, except for possible timing differences that may occur when volumes are purchased in one month and sold in another month, our ethane supply services, like our other businesses, have little to no direct commodity price exposure. Our operating costs and expenses do not vary significantly based upon the volume of products transported, with the exception of costs recorded in *Costs associated with service revenues*. Our operation and maintenance expenses are impacted by our compliance with the requirements of, among other regulations, pipeline integrity maintenance regulations and our efforts to monitor, control and reduce emissions, as further discussed in this Annual Report on Form 10-K.

We use EBITDA, a measure not included in accounting principles generally accepted in the U.S. (GAAP), as a financial measure to assess our operating and financial performance and return on invested capital. We believe that some investors may find this measure useful in evaluating our performance as EBITDA is a commonly used metric within the midstream industry.

The following table presents a reconciliation of net income to EBITDA (in millions):

	For the Year Ended December 31,	
	2025	2024
Net income	**$ 594.7**	$ 510.9
Income taxes	**1.7**	1.1
Depreciation and amortization	**438.9**	424.8
Interest expense	**161.2**	182.9
Interest income	**(13.8)**	(31.1)
EBITDA	**$ 1,182.7**	$ 1,088.6

Please refer to the disclosures in this Item 7. and Item 1A. Risk Factors of this Annual Report on Form 10-K of items that have impacted, or could impact in the future, our results of operations.

2025 Compared with 2024

Our net income for the year ended December 31, 2025, increased $83.8 million, or 16%, to $594.7 million compared to $510.9 million for the year ended December 31, 2024. Our EBITDA increased $94.1 million, or 9%, to $1,182.7 million for the same period. Our net income and EBITDA increased primarily due to the factors discussed below.

Operating revenues for the year ended December 31, 2025, increased $277.7 million, or 14%, to $2,305.8 million, compared to $2,028.1 million for the year ended December 31, 2024. Our transportation revenues increased $104.3 million, primarily due to re-contracting at higher rates, recently completed growth projects and higher utilization-based revenue; our storage and PAL revenues increased $35.3 million due to favorable market conditions which allowed for contracting at higher rates; and our product sales revenues increased $137.0 million primarily from higher volumes from the sale of ethane due to a customer outage in 2024, which impacted 2024 volumes, and higher ethane pricing in 2025.

Operating costs and expenses for the year ended December 31, 2025, increased $195.5 million, or 14%, to $1,565.9 million, compared to $1,370.4 million for the year ended December 31, 2024, primarily from: higher product costs associated with increased ethane product sales; higher employee-related and maintenance project costs; increased depreciation and amortization expense; higher property taxes due to higher assessments and an increased asset base; and a 2024 gain from a contract settlement.

Our interest income and expense for the year ended December 31, 2025, as compared to the same period in the prior year, were impacted by the following items:

- decreased interest expense of $21.7 million due to the pre-financing of a December 2024 debt maturity; and
- decreased interest income of $17.3 million due to income earned from cash invested in short-term investments in 2024 from the pre-financing of a December 2024 debt maturity.

Segment Results

We report our operations under two business segments: Natural Gas and Natural Gas Liquids. While our segments provide similar services, their results of operations are primarily organized and managed according to product lines – that of Natural Gas and that of Natural Gas Liquids. Management uses Segment EBITDA as a basis to assess segment financial performance and allocate resources, which financial information is contained in Note 17 in Part II, Item 8. of this Annual Report on Form 10-K.

The following table provides our Total Segment EBITDA and a reconciliation to EBITDA (in millions):

	For the Year Ended December 31,	
	2025	2024
Natural Gas	**$ 967.1**	$ 874.7
Natural Gas Liquids	**215.6**	213.9
Total Segment EBITDA	**$ 1,182.7**	$ 1,088.6
EBITDA [(1)]	**$ 1,182.7**	$ 1,088.6

(1) Refer to the reconciliation of net income to EBITDA in the table under Consolidated Results of Operations.

2025 Compared with 2024

Natural Gas Segment

The Natural Gas segment's operating revenues for the year ended December 31, 2025, increased $149.4 million, or 10%, to $1,591.5 million, compared to $1,442.1 million for the year ended December 31, 2024. Segment operating costs and expenses increased $57.0 million in 2025, or 10%, to $624.4 million, compared to $567.4 million in 2024. EBITDA increased by $92.4 million to $967.1 million in 2025.

EBITDA for 2025, as compared to 2024, was primarily impacted by the following items:

- transportation revenues increased by $100.5 million primarily due to re-contracting at higher rates, recently completed growth projects and higher utilization-based revenue;
- storage and PAL revenues increased by $47.2 million primarily due to favorable market conditions which allowed for re-contracting at higher rates;
- operation and maintenance costs increased by $20.5 million primarily due to higher maintenance project, employee-related, pipeline legal and utility costs;
- administrative and general costs increased by $11.8 million primarily due to higher employee-related and outside service costs;
- other taxes increased by $8.3 million primarily due to higher property tax assessments and an increased asset base; and
- a 2024 gain from a contract settlement of $6.8 million.

Natural Gas Liquids Segment

The Natural Gas Liquids segment's operating revenues for the year ended December 31, 2025, increased $129.6 million, or 20%, to $765.0 million compared to $635.4 million for the year ended December 31, 2024. Segment operating costs increased $127.9 million in 2025, or 30%, to $549.4 million, compared to $421.5 million in 2024. EBITDA increased by $1.7 million to $215.6 million in 2025.

EBITDA for 2025, as compared to 2024, was primarily impacted by the following items:

- transportation revenues increased by $3.8 million primarily due to higher volumes;
- ethane product sales increased by $144.9 million primarily due to higher volumes, partially offset by increased product costs related to ethane product sales of $137.0 million;
- propane and ethylene product sales decreased by $5.2 million; and
- operation and maintenance costs decreased by $8.9 million primarily due to environmental accruals recorded in 2024 and lower outside service costs.

Liquidity and Capital Resources

We are a partnership holding company and derive all of our operating cash flow from our operating subsidiaries. Our principal sources of liquidity include cash generated from operating activities, our revolving credit facility and debt issuances. Our operating subsidiaries use cash from their respective operations to fund their operating activities and maintenance capital requirements, service their indebtedness and make advances or distributions to Boardwalk Pipelines. Boardwalk Pipelines uses cash provided from the operating subsidiaries and, as needed, borrowings under our revolving credit facility to service outstanding indebtedness and make distributions or advances to us. In 2025, we paid $500.0 million of distributions to BPHC and Boardwalk GP, LP, our general partner.

At December 31, 2025, we had $499.2 million of cash on hand and $351.3 million of short-term investments, no outstanding borrowings under our revolving credit facility, and the full borrowing capacity under our revolving credit facility of $1.0 billion available to us. As of December 31, 2025, we have $5.2 billion of contractual cash payment obligations under firm agreements, of which $4.8 billion represents principal and interest payments related to our debt. We have $550.0 million of 5.95% Notes maturing in June 2026 (2026 Notes). In January 2026, we notified the holders of the 2026 Notes of our intent to redeem the notes on March 1, 2026, at a redemption price equal to par plus accrued and unpaid interest. In November 2025, we issued $550.0 million aggregate principal amount of Boardwalk Pipelines 5.375% notes due February 2036, the proceeds of which will be used to redeem the 2026 Notes. In November 2025, we amended and restated our $1 billion revolving credit facility, extending the term to November 2030. Additionally, as of December 31, 2025, we have future capital commitments comprised of binding commitments under purchase orders for materials ordered but not received totaling approximately $354.5 million, which are expected to be settled through 2028. As of February 6, 2026, we have an effective shelf registration statement on file with the SEC, which expires in September 2026, under which we may publicly issue up to $350.0 million of debt securities, warrants or rights from time to time. We intend to update our shelf registration statement and access the debt markets to fund some or all capital expenditures for growth projects or acquisitions, to refinance maturing debt or for general partnership purposes. We believe that our existing capital resources, including our cash, cash equivalents and short-term investments, revolving credit facility and our cash flows from operating activities, will be adequate to fund our anticipated obligations over the next twelve months. Note 11 in Part II, Item 8. of this Annual Report on Form 10-K contains more information regarding our debt and financing activities and Notes 4 and 5 contain more information about our other commitments.

Credit Ratings

Most of our senior unsecured debt is rated by independent credit rating agencies. The credit ratings affect our ability to access the public and private debt markets, as well as the terms and the cost of our borrowings. Our ability to satisfy financing requirements or fund planned growth capital expenditures will depend upon our future operating performance and our ability to access the capital markets, which are affected by economic factors in our industry as well as other general economic, financial and business factors, some of which are beyond our control. As of February 6, 2026, our credit ratings for our senior unsecured notes (including those issued by Boardwalk Pipelines) and that of our operating subsidiary having outstanding rated debt were as follows:

Rating agency	Rating (Us/Operating Subsidiary)	Outlook (Us/Operating Subsidiary)
Standard and Poor's	BBB/BBB	Stable/Stable
Moody's Investor Services	Baa2/Baa1	Stable/Stable
Fitch Ratings, Inc.	BBB/BBB	Stable/Stable

Credit ratings reflect the view of a rating agency and are not a recommendation to buy, sell or hold any security, and may be revised or withdrawn at any time by the rating agency if it determines that the facts and circumstances warrant such a change. Each credit agency's rating should be evaluated independently of any other credit agency's rating.

Guarantee of Securities of Subsidiaries

Our debt is primarily issued at Boardwalk Pipelines, our wholly owned subsidiary, although we have historically also issued debt at our operating subsidiaries. As of December 31, 2025, all of the outstanding notes issued by Boardwalk Pipelines (Subsidiary Issuer) and the full amount of the revolving credit facility were guaranteed by us (Parent Guarantor). The purpose of the guarantees is to help simplify our reporting and capital structure.

We guarantee amounts borrowed under the revolving credit facility, but any amounts borrowed under the revolving credit facility are not subject to the reporting requirements of Rule 13-01 of Regulation S-X (Rule 13-01). As of December 31, 2025, there were no outstanding borrowings under the revolving credit facility. The following table identifies our principal amounts outstanding for the debt that is subject to the disclosure rules of Rule 13-01 (in millions):

		As of December 31, 2025
Principal amounts guaranteed by Boardwalk Pipeline Partners and subject to Rule 13-01 [(1)]	$	3,700.0
Principal amounts not guaranteed [(2)]		100.0
Other [(3)]		(18.6)
Total debt and finance lease obligation	$	3,781.4

(1) This represents principal amounts of all outstanding debt at Boardwalk Pipelines subject to the disclosure rules of Rule 13-01 (the Guaranteed Notes), including $550.0 million of outstanding Guaranteed Notes that have been classified as current.

(2) This represents principal amounts of outstanding debt at Texas Gas.

(3) This represents amounts related to a finance lease and unamortized debt discount and issuance costs.

The Guaranteed Notes are fully and unconditionally guaranteed by the Parent Guarantor on a senior unsecured basis. The guarantees of the Guaranteed Notes rank equally with all of our existing and future senior debt, including our guarantee of indebtedness under our revolving credit facility. The guarantees will be effectively subordinated in right of payment to all of our future secured debt to the extent of the value of the assets securing such debt. There are no restrictions on the Subsidiary Issuer's ability to pay dividends or make loans to the Parent Guarantor. The guaranteed obligations will be terminated with respect to any series of notes if that series has been discharged or defeased.

Our operating assets, operating liabilities, operating revenues, expenses and other comprehensive income either exist at or are generated by our operating subsidiaries. The Parent Guarantor and the Subsidiary Issuer have no material assets, liabilities or operations independent of their respective financing activities, which includes the Guaranteed Notes and interest expense of $154.7 million for the year ended December 31, 2025, and includes advances to and from each other, and their investments in the operating subsidiaries. For these reasons, we meet the criteria in Rule 13-01 to omit the summarized financial information from our disclosures.

Capital Expenditures

We expect total capital expenditures to be approximately $845.0 million in 2026, including approximately $225.0 million for maintenance capital and $620.0 million related to growth projects. As described in *Current Growth Projects* in Part I, Item 1. Business of this Annual Report on Form 10-K, we are currently engaged in growth projects for which we have executed precedent or long-term firm transportation agreements. Through the date of this filing, the expected aggregate construction costs associated with these agreements is approximately $3.3 billion, which is expected to be spent through 2030. As of December 31, 2025, we have spent $134.5 million on these growth projects. The majority of the capital expenditures for each of these projects is expected to be spent upon receiving FERC approval to begin construction, which is generally 12-18 months prior to the project's expected in-service date. We are also evaluating additional growth projects involving substantial capital commitments. We expect to finance our growth projects through a combination of operating cash flows and the issuance of long-term debt, including borrowings under our revolving credit facility. Our cost and timing estimates for our growth projects are subject to a variety of risks and uncertainties, and are based on the factors, described in *Current Growth Projects* in Part I, Item 1. Business of this Annual Report on Form 10-K. Actual costs and timing of in-service dates for our growth projects may differ, perhaps materially, from our estimates. Refer to Part I, Item 1A. Risk Factors of this Annual Report on Form 10-K for additional risks associated with our growth projects and the related financing.

The nature of our existing growth projects will require us to enhance or modify our existing assets to accommodate increased operating pressures or changing flow patterns. We consider capital expenditures associated with the modification or enhancement of existing assets in the context of a growth project to be growth capital to the extent that the modification would not have been made in the absence of the growth project without regard to the condition of the existing assets.

Maintenance capital expenditures for the years ended December 31, 2025, 2024 and 2023, were $194.2 million, $202.4 million and $164.5 million. Refer to *Pipeline System Maintenance and GHG Emission Reduction Initiatives* for further information about factors impacting our maintenance capital spending.

Growth capital expenditures for the years ended December 31, 2025, 2024 and 2023, were $159.7 million, $190.0 million and $217.9 million. During the year ended December 31, 2023, we acquired Bayou Ethane for $355.0 million.

Critical Accounting Estimates and Policies

Our significant accounting policies are described in Note 2 in Part II, Item 8. of this Annual Report on Form 10-K. The preparation of these consolidated financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities. Estimates are based on historical experience and on various other assumptions that are believed to be reasonable under the circumstances. The result of this process forms the basis for making judgments about the carrying amounts of assets and liabilities and related disclosures of contingent assets and liabilities that are not readily apparent from other sources. We review our estimates and assumptions on a regular, ongoing basis. Changes in facts and circumstances may result in revised estimates and actual results may differ materially from those estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the periods in which the facts that give rise to the revisions become known.

The following accounting policies and estimates are considered critical due to the potentially material impact that the estimates, judgments and uncertainties affecting the application of these policies might have on our reported financial information.

Goodwill

Goodwill represents the excess of the cost of an acquisition over the fair value of the net identifiable assets acquired and liabilities assumed. Goodwill is tested for impairment at the reporting unit level at least annually, as of November 30, or more frequently when events occur and circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. Accounting requirements provide that a reporting entity may perform an optional qualitative assessment on an annual basis to determine whether events occurred or circumstances changed that would more likely than not reduce the fair value of a reporting unit below its carrying amount. If an initial qualitative assessment identifies that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, or the optional qualitative assessment is not performed, a quantitative analysis is performed. The quantitative goodwill impairment test is performed by calculating the fair value of the reporting unit and comparing it to the reporting unit's carrying amount. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not impaired. However, if the carrying amount of a reporting unit exceeds its fair value, an impairment loss is recognized in an amount equal to that excess, limited to the total amount of goodwill recorded on the reporting unit.

In 2025, we reorganized our legal entity structure, which impacted our reporting units for purposes of goodwill. Goodwill was reallocated based on the relative fair value approach, resulting in $4.5 million of goodwill being allocated to a third reporting unit, which has increased the number of reporting units for goodwill testing to three. As of December 31, 2025, our Texas Gas reporting unit had $163.5 million of goodwill, our Gulf South and other natural gas businesses reporting unit had $4.5 million of goodwill and our Natural Gas Liquids reporting unit had $69.4 million of goodwill.

As of November 30, 2025, our annual goodwill testing date, we elected to perform qualitative tests on our Gulf South and other natural gas businesses and Natural Gas Liquids reporting units as a result of the proximity in timing of the quantitative tests performed as of February 28, 2025, noted below, and taking into account expected future performance and the operating environment. These qualitative assessments included our consideration of, among other things, overall macroeconomic conditions, industry and market considerations, current discount rates and valuation multiples, overall financial performance, including operating revenues, and other relevant company specific events. Based on the assessment of these items, we concluded that it is more likely than not that the fair value of these two reporting units exceeded their respective carrying amounts. Accordingly, there were no indicators of impairment and the quantitative impairment test was not performed on these reporting units as of November 30, 2025.

Quantitative tests were performed on our Texas Gas reporting unit as of November 30, 2025, and on the Natural Gas Liquids and Gulf South and other natural gas businesses reporting units as of February 28, 2025. The quantitative analysis measured whether the fair values of our reporting units were less than their carrying amounts. The fair value measurements of the reporting units were derived based on judgments and assumptions we believe market participants would use in assessing the fair value of the reporting units. These judgments and assumptions included the valuation premise, use of a discounted cash flow model to estimate fair value under an income approach and inputs to the valuation model. The inputs included our five-year financial plan operating results, including operating revenues, the long-term outlook for growth in natural gas, NGLs and petrochemical demand, measures of the risk-free rate, equity premium and systematic risk used in the calculation of the applied discount rate under the capital asset pricing model and views regarding future market conditions, among others. The reasonableness of fair value estimates under the income approach was supported by a market approach under which we applied EBITDA multiples derived from publicly available information to each reporting unit's EBITDA. The results of the quantitative goodwill impairment tests for 2025 indicated that the fair values of the reporting units exceeded their carrying amounts and no goodwill impairment charges were recognized. The use of alternate judgments and assumptions, including changes in the risk-free rate, could change the results of our goodwill impairment analysis, including the potential recognition of an impairment charge in our Consolidated Financial Statements.

The qualitative goodwill tests for 2024 and the quantitative tests for 2023 also did not result in any goodwill impairment charges for our reporting units.

Impairment of Long-Lived Assets (including Tangible and Definite-Lived Intangible Assets)

We evaluate whether the carrying amounts of our long-lived and intangible assets have been impaired when circumstances indicate the carrying amount of those assets may not be recoverable. The carrying amount is not recoverable if it exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. If the carrying amount is not recoverable, an impairment loss is measured as the excess of the asset's carrying amount over its fair value. We recognized asset impairment charges of $0.9 million, $2.4 million and $0.4 million for the years ended December 31, 2025, 2024 and 2023.

Forward-Looking Statements

Certain statements contained in this Annual Report on Form 10-K, as well as some statements in our other filings with the SEC and periodic press releases and some statements made by our officials, us and our subsidiaries in presentations about us, are "forward-looking." Forward-looking statements include, without limitation, any statement that may project, indicate or imply future results, events, performance, intentions or achievements, and may contain the words "expect," "intend," "plan," "anticipate," "estimate," "believe," "will likely result" and similar expressions. In addition, any statement concerning future financial performance (including future revenues, earnings or growth rates), ongoing business strategies or prospects and possible actions by us or our subsidiaries, are also forward-looking statements.

Forward-looking statements are based on current expectations and projections about future events and their potential impact on us. While management believes that these forward-looking statements are reasonable as and when made, there is no assurance that future events affecting us will be those that we anticipate. All forward-looking statements are inherently subject to a variety of risks and uncertainties, many of which are beyond our control, which could cause actual results to differ materially from those anticipated or projected. These include, among others, the impacts of legislative and regulatory initiatives, including tariffs, or the implementation thereof, our ability to complete growth projects that we have commenced or will commence at budgeted amounts and within the projected timeframes, the costs of maintaining and ensuring the integrity and reliability of our pipeline systems, the impacts of climate change, sustainability matters and pipeline safety requirements and initiatives, recontracting at acceptable rates, the risk of a failure in computer systems or cybersecurity attack, successful negotiation, consummation and completion of contemplated transactions, projects and agreements, risks and uncertainties related to the impacts of volatility in energy prices and our exposure to credit risk relating to default or bankruptcy by our customers. Developments in any of these areas could cause our results to differ materially from results that have been or may be anticipated or projected. Forward-looking statements speak only as of the date they are made and we expressly disclaim any obligation or undertaking to update these statements to reflect any change in our expectations or beliefs or any change in events, conditions or circumstances on which any forward-looking statement is based.

Refer to Part I, Item 1A. of this Annual Report on Form 10-K for additional risks and uncertainties regarding our forward-looking statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

With the exception of our revolving credit facility, for which the interest rates are periodically reset, our debt has been issued at fixed rates. For fixed-rate debt, changes in interest rates affect the fair value of the debt instruments but do not directly affect our earnings or cash flows. The following table presents market risk associated with our fixed-rate debt at December 31, 2025 and 2024 (in millions, except interest rates):

	2025	2024
Carrying amount of fixed-rate debt	**$ 3,785.2**	$ 3,236.5
Fair value of fixed-rate debt	**$ 3,786.5**	$ 3,129.7
100 basis point increase in interest rates and resulting fair value of debt decrease	**$ 155.6**	$ 133.0
100 basis point decrease in interest rates and resulting fair value of debt increase	**$ 167.4**	$ 141.9
Weighted-average interest rate	**5.03 %**	4.95 %

At December 31, 2025 and 2024, we had no outstanding debt under variable-rate agreements.

Commodity Risk

For the natural gas and NGLs (other than ethane supply services) that our pipelines transport and store, we do not take title to these products; therefore, we do not assume the related commodity price risk associated with these products. For our ethane supply services, which require us to enter into ethane sales and purchase agreements and take title to those products, the pricing contained in those purchase and sales agreements is generally based on the same ethane commodity index, plus a fixed delivery fee. As a result, except for possible timing differences that may occur when volumes are purchased in one month and sold in another month, our ethane supply services, like our other businesses, have little to no direct commodity price exposure.

Credit Risk

Our credit exposure generally relates to receivables for services provided, as well as volumes owed by customers for imbalances or gas lent by us to them, generally under PAL and certain firm services. Natural gas price volatility can materially increase credit risk related to gas loaned to customers. We also have credit risk related to customers supporting our growth projects. If any significant customer of ours should have credit or financial problems resulting in a delay or failure to pay for services provided by us or repay gas they owe to us, this could have a material adverse effect on our business, financial condition, results of operations and cash flows.

As of December 31, 2025, the amount of gas owed to our operating subsidiaries due to gas imbalances and gas loaned under PAL and certain firm service agreements was approximately 13.1 trillion British thermal units (TBtu). Assuming an average market price during December 2025 of $3.90 per million British thermal unit (MMBtu), the market value of that gas was approximately $51.1 million. As of December 31, 2025, there were no outstanding NGLs imbalances owed to our operating subsidiaries. As of December 31, 2024, the amount of gas owed to our operating subsidiaries due to gas imbalances and gas loaned under PAL and certain firm service agreements was approximately 9.8 TBtu. Assuming an average market price during December 2024 of $2.98 per MMBtu, the market value of that gas was approximately $29.2 million. As of December 31, 2024, the amount of NGLs owed to our operating subsidiaries due to imbalances was less than 0.1 million barrels, which had a market value of approximately $0.3 million. As of December 31, 2025 and 2024, there were no amounts of ethylene owed to our operating subsidiaries under exchange agreements.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Boardwalk GP, LLC and the Partners of Boardwalk Pipeline Partners, LP

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Boardwalk Pipeline Partners, LP and subsidiaries (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of income, comprehensive income, changes in partners' capital, and cash flows, for each of the three years in the period ended December 31, 2025, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, 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 audits. 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 audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting 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.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit council and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Goodwill — Natural Gas Liquids and Texas Gas Reporting Units - Refer to Notes 2 and 8 to the financial statements

Critical Audit Matter Description

Goodwill is tested for impairment at the reporting unit level at least annually, as of November 30, or more frequently when events occur and circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. Quantitative tests were performed on the Company's Texas Gas reporting unit as of November 30, 2025 and on the Natural Gas Liquids reporting unit as of February 28, 2025. The quantitative analysis measured whether the fair value of the reporting units was less than their carrying amounts. If the carrying amount of a reporting unit exceeds its fair value, an impairment loss is recognized in an amount equal to that excess, limited to the total amount of goodwill recorded on the reporting unit.

The fair value measurements of the reporting units were derived based on judgments and assumptions the Company believes market participants would use in assessing the fair value of the reporting units. The inputs included the Company's five-year financial plan operating results, including operating revenues, the long-term outlook for growth in natural gas, NGLs and petrochemical demand, measures of the risk-free rate, equity premium and systematic risk used in the calculation of the applied discount rate, and views regarding future market conditions. The use of alternate judgments and assumptions, including changes in the risk-free rate, could change the results of the Company's goodwill impairment analysis, including the potential recognition of an impairment charge in the Company's Consolidated Financial Statements. The results of the quantitative goodwill impairment tests for 2025 indicated that the fair value of the reporting units exceeded their carrying amounts and no goodwill impairment charges were recognized.

We identified goodwill for the Natural Gas Liquids and Texas Gas reporting units as a critical audit matter because of the significant judgments made by management to estimate the fair value of the reporting units. This required a high degree of auditor judgment and an increased extent of effort, including the need to involve fair value specialists, when performing audit procedures to evaluate the reasonableness of management's judgments and assumptions related to the applied discount rate, the long-term outlook for growth in natural gas and NGLs and petrochemical demand, and the Company's future estimated operating revenues within the five-year financial plan operating results.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's assumptions underlying the applied discount rates, the long-term outlook for growth in natural gas and NGLs and petrochemical demand, and the Company's future estimated operating revenues within the five-year financial plan operating results included the following, among others:

- We tested the effectiveness of controls over management's annual goodwill impairment test, including controls over management's estimate of the applied discount rate, the long-term outlook for growth in natural gas and NGLs and petrochemical demand, and the future estimated operating revenues.
- We evaluated management's ability to accurately forecast future operating revenues by comparing actual results to management's historical forecasts for the reporting units.
- We evaluated the reasonableness of the future estimated operating revenues within the five-year financial plan operating results by comparing the forecasts to:
    - Historical operating revenues of the reporting units' similar or existing contracts with customers and average annual growth rates.
    - Forecasted information in industry reports relevant to the reporting units.
- We evaluated contracts subject to renewal within the five-year financial plan by making a selection of contracts and assessing the reasonableness of renewal assumptions, including rates and volumes.
- We evaluated revenue agreements already contracted included in the five-year financial plan by making a selection of contracts and assessing the accuracy of calculated revenues, including rates and volumes.
- With the assistance of our fair value specialists, we evaluated the reasonableness of the applied discount rate, and the long-term outlook for growth in natural gas and NGLs and petrochemical demand used as inputs to management's goodwill impairment test of the reporting units by:
    - Comparing the Company's estimate of the long-term outlook for growth in natural gas and NGLs and petrochemical demand for the reporting units to industry reports and other market data.
    - Developing a range of independent estimates of the applied discount rate for the reporting units and comparing those to the applied discount rates selected by management for the reporting units.

/s/ *Deloitte & Touche LLP*

Houston, Texas
February 10, 2026

We have served as the Company's auditor since 2003.

BOARDWALK PIPELINE PARTNERS, LP
CONSOLIDATED BALANCE SHEETS
(Millions)

	December 31,	
ASSETS	**2025**	2024
Current Assets:		
Cash and cash equivalents	**$ 499.2**	$ 117.9
Receivables:		
Trade, net	**220.5**	210.7
Other	**27.6**	21.4
Gas transportation receivables	**22.4**	7.4
Prepayments	**30.2**	25.2
Short-term investments	**351.3**	—
Other current assets	**28.5**	18.5
Total current assets	**1,179.7**	401.1
Property, Plant and Equipment:		
Pipelines, storage and other plant	**13,835.1**	13,667.7
Construction work in progress	**289.2**	190.1
Property, plant and equipment, gross	**14,124.3**	13,857.8
Less—accumulated depreciation and amortization	**5,352.5**	5,045.1
Property, plant and equipment, net	**8,771.8**	8,812.7
Other Assets:		
Goodwill	**237.4**	237.4
Gas stored underground	**100.0**	98.3
Other	**224.5**	229.9
Total other assets	**561.9**	565.6
Total Assets	**$ 10,513.4**	$ 9,779.4

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP
CONSOLIDATED BALANCE SHEETS
(Millions)

LIABILITIES AND PARTNERS' CAPITAL	December 31, 2025	December 31, 2024
Current Liabilities:		
Payables:		
Trade	**$ 140.5**	$ 100.9
Affiliates	**0.5**	0.5
Other	**29.9**	21.7
Gas transportation payables	**14.9**	11.7
Accrued taxes, other	**73.3**	67.0
Accrued interest	**49.8**	46.7
Accrued payroll and employee benefits	**53.1**	48.6
Current portion of long-term debt	**549.6**	—
Regulatory liabilities	**29.1**	18.3
Other current liabilities	**41.1**	30.2
Total current liabilities	**981.8**	345.6
Long-term debt and finance lease obligation	**3,231.8**	3,234.4
Other Liabilities and Deferred Credits:		
Asset retirement obligations	**71.6**	70.0
Provision for other asset retirement	**108.2**	103.6
Payable to affiliate	**6.2**	4.8
Other	**121.2**	115.0
Total other liabilities and deferred credits	**307.2**	293.4
Commitments and Contingencies		
Partners' Capital:		
Partners' capital	**6,073.3**	5,978.6
Accumulated other comprehensive loss	**(80.7)**	(72.6)
Total partners' capital	**5,992.6**	5,906.0
Total Liabilities and Partners' Capital	**$ 10,513.4**	$ 9,779.4

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP
CONSOLIDATED STATEMENTS OF INCOME
(Millions)

	For the Year Ended December 31,		
	2025	2024	2023
Operating Revenues:			
Transportation	**$ 1,483.7**	$ 1,361.3	$ 1,287.0
Storage, parking and lending	**228.2**	211.0	160.9
Product sales	**515.7**	378.7	100.3
Other	**78.2**	77.1	69.5
Total operating revenues	**2,305.8**	2,028.1	1,617.7
Operating Costs and Expenses:			
Costs associated with service revenues	**34.6**	29.1	26.3
Costs associated with product sales	**441.0**	303.5	87.8
Operation and maintenance	**321.9**	310.3	281.0
Administrative and general	**199.6**	186.1	171.9
Depreciation and amortization	**438.9**	424.8	408.7
Loss (gain) on sale of assets, impairments and other	**0.2**	(5.5)	0.3
Taxes other than income taxes	**129.7**	122.1	115.5
Total operating costs and expenses	**1,565.9**	1,370.4	1,091.5
Operating income	**739.9**	657.7	526.2
Other Deductions (Income):			
Interest expense	**161.2**	182.9	155.6
Interest income	**(13.8)**	(31.1)	(12.1)
Miscellaneous other income, net	**(3.9)**	(6.1)	(4.1)
Total other deductions	**143.5**	145.7	139.4
Income before income taxes	**596.4**	512.0	386.8
Income taxes	**1.7**	1.1	0.8
Net income	**$ 594.7**	$ 510.9	$ 386.0

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Millions)

	For the Year Ended December 31,		
	2025	2024	2023
Net income	**$ 594.7**	$ 510.9	$ 386.0
Other comprehensive income (loss):			
Reclassification adjustment transferred to Net income from cash flow hedges	**0.5**	0.1	0.1
Pension and other postretirement benefit costs, net of tax	**(8.6)**	3.9	2.8
Total Comprehensive Income	**$ 586.6**	$ 514.9	$ 388.9

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)

	For the Year Ended December 31,		
	2025	2024	2023
OPERATING ACTIVITIES:			
Net income	**$ 594.7**	$ 510.9	$ 386.0
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	**438.9**	424.8	408.7
Amortization of deferred costs and other	**16.2**	13.8	18.5
Loss (gain) on sale of assets, impairments and other	**0.2**	(5.5)	0.3
Interest income from short-term investments	**(1.3)**	(19.8)	—
Changes in operating assets and liabilities:			
Trade and other receivables	**(16.0)**	(2.8)	(7.8)
Gas transportation receivables, storage assets and other product inventory	**(31.4)**	(15.2)	70.6
Prepayments and other assets	**(8.4)**	(7.7)	3.1
Trade and other payables	**14.2**	11.9	11.5
Other payables, affiliates	**—**	0.1	0.1
Gas transportation payables	**10.9**	(8.6)	(20.8)
Accrued liabilities	**12.4**	17.1	7.4
Regulatory assets and liabilities	**11.1**	2.7	(40.3)
Other liabilities	**1.1**	(21.2)	(19.9)
Net cash provided by operating activities	**1,042.6**	900.5	817.4
INVESTING ACTIVITIES:			
Capital expenditures	**(353.9)**	(392.4)	(382.4)
Proceeds from sale of operating assets	**1.0**	0.5	0.3
Acquisition of business	**—**	—	(355.0)
Purchases of short-term investments	**(350.0)**	(1,102.2)	—
Proceeds from the maturity of short-term investments	**—**	1,122.0	—
Net cash used in investing activities	**(702.9)**	(372.1)	(737.1)
FINANCING ACTIVITIES:			
Proceeds from long-term debt, net of issuance cost	**544.0**	593.5	—
Repayment of borrowings from long-term debt	**—**	(600.0)	—
Proceeds from borrowings on revolving credit facility	**—**	170.0	155.0
Repayments of borrowings on revolving credit facility, including financing fees	**(2.9)**	(195.0)	(130.6)
Principal payment of finance lease obligation	**(0.9)**	(0.9)	(0.9)
Advances from affiliates	**1.4**	1.8	0.7
Distributions paid	**(500.0)**	(400.0)	(300.0)
Net cash provided by (used in) financing activities	**41.6**	(430.6)	(275.8)
Increase (decrease) in cash and cash equivalents	**381.3**	97.8	(195.5)
Cash and cash equivalents at beginning of period	**117.9**	20.1	215.6
Cash and cash equivalents at end of period	**$ 499.2**	$ 117.9	$ 20.1

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP
CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
(Millions)

	Partners' Capital	Accumulated Other Comprehensive (Loss) Income	Total Partners' Capital
Balance December 31, 2022	$ 5,781.7	$ (79.5)	$ 5,702.2
Add (deduct):			
Net income	386.0	—	386.0
Distributions paid	(300.0)	—	(300.0)
Other comprehensive income, net of tax	—	2.9	2.9
Balance December 31, 2023	$ 5,867.7	$ (76.6)	$ 5,791.1
Add (deduct):			
Net income	510.9	—	510.9
Distributions paid	(400.0)	—	(400.0)
Other comprehensive income, net of tax	—	4.0	4.0
Balance December 31, 2024	$ 5,978.6	$ (72.6)	$ 5,906.0
Add (deduct):			
Net income	**594.7**	**—**	**594.7**
Distributions paid	**(500.0)**	**—**	**(500.0)**
Other comprehensive loss, net of tax	**—**	**(8.1)**	**(8.1)**
Balance December 31, 2025	**$ 6,073.3**	**$ (80.7)**	**$ 5,992.6**

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1: Corporate Structure

Boardwalk Pipeline Partners, LP (the Company) is a Delaware limited partnership formed in 2005 to own and operate the business conducted by its primary subsidiary Boardwalk Pipelines, LP (Boardwalk Pipelines) and its operating subsidiaries, Gulf South Pipeline Company, LLC (Gulf South), Texas Gas Transmission, LLC (Texas Gas), Boardwalk Louisiana Midstream, LLC (Louisiana Midstream), Boardwalk Louisiana Gas Transmission, LLC, Boardwalk Texas Intrastate, LLC, Boardwalk Petrochemical Pipeline, LLC (Boardwalk Petrochemical), and Boardwalk Ethane Pipeline Company, LLC (together, the operating subsidiaries), which consists of integrated pipeline and storage systems for natural gas and natural gas liquids, olefins and other hydrocarbons (herein referred to together as NGLs). All of the Company's operations are conducted by the operating subsidiaries. The Company's two reportable segments are Natural Gas and Natural Gas Liquids.

As of December 31, 2025, Boardwalk Pipelines Holding Corp. (BPHC), a wholly owned subsidiary of Loews Corporation (Loews), owned directly or indirectly, 100% of the Company's capital.

Note 2: Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S.) (GAAP).

Principles of Consolidation

The consolidated financial statements include the Company's accounts and those of its wholly owned subsidiaries after elimination of intercompany transactions.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, disclosure of contingent assets and liabilities and the fair values of certain items. The Company bases its estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, which form the basis for making judgments about the carrying amounts of assets and liabilities that are not readily apparent from other sources. Actual results could differ from such estimates.

Regulatory Accounting

Most of the Company's natural gas pipeline subsidiaries and its interstate ethane transportation pipeline are regulated by the Federal Energy Regulatory Commission (FERC). When certain criteria are met, GAAP requires that certain rate-regulated entities account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates (regulatory accounting). This basis of accounting is applicable to operations of the Company's Texas Gas subsidiary, which records certain costs and benefits as regulatory assets and liabilities in order to provide for recovery from or refunds to customers in future periods, but is not applicable to the operations associated with the Fayetteville and Greenville Laterals due to rates charged under negotiated rate agreements and a portion of Texas Gas' storage capacity due to the regulatory treatment associated with the rates charged for that capacity.

The Company also applies regulatory accounting for its fuel trackers on Gulf South, under which the value of fuel received from customers paying the maximum tariff rate and the related value of fuel used in transportation are recorded to a regulatory asset or liability depending on whether Gulf South uses more fuel than it collects from customers or collects more fuel than it uses. Other than as described for Texas Gas and for the fuel trackers on Gulf South, regulatory accounting is not applicable to the Company's other FERC-regulated operations.

The Company monitors the regulatory and competitive environment in which it operates to determine whether its regulatory assets continue to be probable of recovery. If the Company determines that all or a portion of its regulatory assets no longer meets the criteria for recognition as regulatory assets, that portion which is not recoverable will be written off, net of any regulatory liabilities.

Note 10 contains more information regarding the Company's regulatory assets and liabilities.

Fair Value Measurements

Fair value refers to an exit price that would be received to sell an asset or paid to transfer a liability in an orderly transaction in the principal market in which the reporting entity transacts based on the assumptions market participants would use when pricing the asset or liability assuming its highest and best use. A fair value hierarchy has been established that prioritizes the information used to develop those assumptions giving priority, from highest to lowest, to quoted prices in active markets for identical assets and liabilities (Level 1); observable inputs not included in Level 1, for example, quoted prices for similar assets and liabilities (Level 2); and unobservable data (Level 3), for example, a reporting entity's own internal data based on the best information available in the circumstances. The Company uses fair value measurements to account for equity securities, asset retirement obligations (ARO), pension and postretirement benefits other than pension (PBOP) assets and any impairment charges.

Notes 6 and 12 contain more information regarding fair value measurements.

Cash and Cash Equivalents

Cash equivalents are highly liquid investments with an original maturity of three months or less and are stated at cost plus accrued interest, which approximates fair value. The Company had no restricted cash at December 31, 2025 and 2024.

Short-Term Investments

The Company invests in U.S. treasury bills, considered short-term investments, from time to time. The short-term investments are classified as held-to-maturity as the Company has the intent and the ability to hold the short-term investments until they mature. The carrying amount of the U.S. treasury bills are adjusted for the accretion of discounts over the remaining life of the investment. Income related to the U.S. treasury bills is recorded in *Interest Income* on the Consolidated Statements of Income. As of December 31, 2025, the Company recorded $351.3 million of U.S. treasury bills on its Consolidated Balance Sheets, maturing in February 2026, at amortized cost with an unrecognized gain of $0.1 million.

Trade and Other Receivables

Trade and other receivables are stated at their historical carrying amount, net of allowances for doubtful accounts. The Company establishes an allowance for doubtful accounts under an expected credit loss model based on historical credit loss experience and specific facts and circumstances. Uncollectible receivables are written off when a settlement is reached for an amount that is less than the outstanding historical balance or a receivable amount is deemed otherwise unrealizable.

Gas and NGLs Stored Underground and Gas and NGLs Receivables and Payables

Certain of the Company's operating subsidiaries have underground gas in storage which is utilized for system management and operational balancing, as well as for services including firm and interruptible storage associated with certain no-notice and parking and lending (PAL) services. Gas stored underground includes the historical cost of natural gas volumes owned by the operating subsidiaries, at times reduced by certain operational encroachments upon that gas.

The operating subsidiaries provide storage services whereby they store natural gas or NGLs on behalf of customers and also periodically hold customer gas under PAL services. Since the customers retain title to the gas held by the Company in providing these services, the Company does not record the related gas on the Consolidated Balance Sheets. Certain of the Company's operating subsidiaries also periodically lend gas and NGLs to customers.

In the course of providing transportation and storage services to customers, the operating subsidiaries may receive different quantities of gas from shippers and operators than the quantities delivered on behalf of those shippers and operators. This results in transportation and exchange gas receivables and payables, commonly known as imbalances, which are primarily settled in cash or the receipt or delivery of gas in the future. Settlement of imbalances requires agreement between the pipelines and shippers or operators as to allocations of volumes to specific transportation contracts and timing of delivery of gas based on operational conditions. The receivables and payables are valued at market price for operations where regulatory accounting is not applicable and are valued at the historical value of gas in storage for operations where regulatory accounting is applicable.

Product Inventory

Product inventory, primarily ethane used in the Company's ethane supply services, is included in *Other Current Assets* on the Consolidated Balance Sheets. Product inventory is recorded at the lower of weighted-average cost or net realizable value. At December 31, 2025 and 2024, the Company held $22.2 million and $12.7 million of product inventory.

Materials and Supplies

Materials and supplies are carried at average cost and are included in *Other Assets* on the Consolidated Balance Sheets. The Company expects its materials and supplies to be used for projects related to its property, plant and equipment (PPE) and for future growth projects. At December 31, 2025 and 2024, the Company held approximately $44.8 million and $42.4 million of materials and supplies.

Property, Plant and Equipment and Repair and Maintenance Costs

PPE is recorded at its original cost of construction or fair value of assets purchased. Construction costs and expenditures for major renewals and improvements which extend the lives of the respective assets are capitalized. *Construction work in progress* is included in the financial statements as a component of PPE. Repair and maintenance costs are expensed as incurred.

Depreciation of PPE related to operations for which regulatory accounting does not apply is provided for using the straight-line method of depreciation over the estimated useful lives of the assets, which range from 3 to 35 years. The ordinary sale or retirement of PPE for these assets could result in a gain or loss being recorded in the income statement. Depreciation of PPE related to operations for which regulatory accounting is applicable is provided for primarily on the straight-line method at FERC-prescribed rates over estimated useful lives of 5 to 62 years. Reflecting the application of composite depreciation, gains and losses from the ordinary sale or retirement of PPE for these assets are not recognized in earnings and generally do not impact PPE, net.

Note 7 contains more information regarding the Company's PPE.

Goodwill and Intangible Assets

Goodwill represents the excess of the cost of an acquisition over the fair value of the net identifiable assets acquired and liabilities assumed. Goodwill is tested for impairment at the reporting unit level at least annually, as of November 30, or more frequently when events occur and circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. A reporting entity may perform an optional qualitative assessment on an annual basis to determine whether events occurred or circumstances changed that would more likely than not reduce the fair value of a reporting unit below its carrying amount. If an initial qualitative assessment identifies that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, or the optional qualitative assessment is not performed, a quantitative analysis is performed. The quantitative goodwill impairment test is performed by calculating the fair value of the reporting unit and comparing it to the reporting unit's carrying amount. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not impaired. However, if the carrying amount of a reporting unit exceeds its fair value, an impairment loss is recognized in an amount equal to that excess, limited to the total amount of goodwill recorded on the reporting unit.

Intangible assets are those assets which provide future economic benefit but have no physical substance. The Company recorded intangible assets for customer relationships obtained through its acquisitions. The customer relationships, which are included in *Other Assets* on the Consolidated Balance Sheets, have a finite life and are being amortized over their estimated useful lives, which is generally 35 years.

Note 8 contains more information regarding the Company's goodwill and intangible assets.

Impairment of Long-lived Assets (including Tangible and Definite-lived Intangible Assets)

The Company evaluates its long-lived and intangible assets for impairment when, in management's judgment, events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. When such a determination has been made, management's estimate of undiscounted future cash flows attributable to the remaining economic useful life of the asset (or asset group) is compared to the carrying amount of the asset (or asset group) to determine whether an impairment has occurred. If an impairment of the carrying amount has occurred, the amount of impairment recognized in the financial statements is determined by estimating the fair value of the assets (or asset group) and recording a loss to the extent that the carrying amount exceeds the estimated fair value.

Capitalized Interest and Allowance for Funds Used During Construction (AFUDC)

The Company records capitalized interest, which represents the cost of borrowed funds used to finance construction activities for operations where regulatory accounting is not applicable. The Company records AFUDC, which represents the cost of funds, including equity funds, applicable to regulated natural gas transmission plant under construction as permitted by FERC regulatory practices, in connection with the Company's operations where regulatory accounting is applicable. Capitalized interest and the allowance for borrowed funds used during construction are recognized as a reduction to *Interest expense* and the allowance for equity funds used during construction is included in *Miscellaneous other income, net* on the Consolidated Statements of Income. The following table summarizes capitalized interest and the allowance for borrowed funds and allowance for equity funds used during construction (in millions):

	For the Year Ended December 31,		
	2025	2024	2023
Capitalized interest and allowance for borrowed funds used during construction	**$ 4.3**	$ 5.5	$ 3.6
Allowance for equity funds used during construction	**3.2**	4.5	5.7

Income Taxes

The Company is not a taxable entity for federal income tax purposes. As such, it does not directly pay federal income tax. The Company's taxable income or loss, which may vary substantially from the net income or loss reported on the Consolidated Statements of Income, is includable in the federal income tax returns of each of its partners. The aggregate difference in the basis of the Company's net assets for financial and income tax purposes is $5.8 billion. The subsidiaries of the Company directly incur some income-based state taxes which are presented in *Income taxes* on the Consolidated Statements of Income.

Note 13 contains more information regarding the Company's income taxes.

Asset Retirement Obligations

The accounting requirements for existing legal obligations associated with the future retirement of long-lived assets require entities to record the fair value of a liability for an ARO in the period during which the liability is incurred. The liability is initially recognized at fair value and is increased with the passage of time as accretion expense is recorded, until the liability is ultimately settled. The accretion expense is included within *Operation and maintenance* costs on the Consolidated Statements of Income. An amount corresponding to the amount of the initial liability is capitalized as part of the carrying amount of the related long-lived asset and depreciated over the useful life of that asset.

Note 9 contains more information regarding the Company's ARO.

Environmental Liabilities

The Company records environmental liabilities based on management's estimates of the undiscounted future obligation for probable costs associated with environmental assessment and remediation of operating sites. These estimates are based on evaluations and discussions with counsel and operating personnel and the current known facts and circumstances related to these environmental matters.

Note 5 contains more information regarding the Company's environmental liabilities.

Defined Benefit Plans

The Company maintains postretirement benefit plans for certain employees. The Company funds these plans through periodic contributions which are invested until the benefits are paid out to the participants, and records an asset or liability based on the overfunded or underfunded status of the plan. The net benefit costs of the plans are recorded on the Consolidated Statements of Income. Any deferred amounts related to unrecognized gains and losses or changes in actuarial assumptions are recorded as either a regulatory asset or liability or recorded as a component of accumulated other comprehensive income until those gains or losses are recognized on the Consolidated Statements of Income.

Note 12 contains more information regarding the Company's pension and other postretirement benefit obligations.

Long-Term Compensation

The Company provides performance awards (Performance Awards) to certain of its employees under its 2018 Long-Term Incentive Plan (2018 LTIP). A Performance Award is a long-term incentive award with a stated target amount which is payable in cash, after certain adjustments, upon vesting based on certain specified performance criteria being met.

The Company measures the cost of an award issued in exchange for employee services based on the stated target amount for Performance Awards. All outstanding awards are required to be settled in cash and are classified as a liability until settlement. The related compensation expense, less forfeitures, is recognized over the period that employees are required to provide services in exchange for the awards, usually the vesting period.

Note 12 contains more information regarding the Company's long-term compensation.

Leases

Operating lease right-of-use assets and lease liabilities are recognized at the lease commencement date based on the present value of lease payments over the lease term. The discount rate used to determine the commencement date present value of lease payments is typically the Company's secured borrowing rate, as the implicit rate of most of the Company's leases is not readily determinable. The Company has elected not to record any leases with terms of twelve months or less on the Consolidated Balance Sheets.

Note 4 contains more information regarding the Company's leases.

Revenue Recognition

Nature of Contracts

The Company primarily earns revenues from contracts with customers by providing transportation and storage services for natural gas and NGLs on a firm and interruptible basis and providing ethane supply and transportation services for petrochemical customers in Louisiana and Texas. The Company also provides interruptible natural gas PAL services. The Company's customers choose, based upon their particular needs, the applicable mix of services depending upon availability of pipeline and storage capacity, the price of services and the volume and timing of customer requirements. The maximum applicable rates that the majority of the Company's operating subsidiaries may charge for their services are established through the FERC's cost-based rate-making process; however, the FERC also allows for discounted or negotiated rates as an alternative to cost-based rates. Under the FERC regulations, certain revenues that the Company's subsidiaries collect may be subject to possible refunds to customers. Accordingly, during a rate case, estimated refund liabilities are recorded considering regulatory proceedings, advice of counsel and estimated risk-adjusted total exposure, as well as other factors. The Company's service contracts can range from one to twenty years although the Company may enter into shorter- or longer-term contracts, and services are invoiced monthly with payment from the customer generally expected within ten to thirty days, depending on the terms of the contract. For the ethane supply contracts, the purchases and sales are with different counterparties and control transfers at different receipt and delivery points, resulting in the purchases and sales being presented on a gross basis in the Consolidated Statements of Income.

Firm Service Contracts: The Company offers firm services to its customers. The Company's customers can reserve a specific amount of pipeline capacity at specified receipt and delivery points on the Company's pipeline system (transportation service) or can reserve a specific amount of storage capacity at specified injection and withdrawal points at the Company's storage facilities (storage service). The Company accounts for firm services as a single promise to stand ready each month of the contract term to provide the committed capacity for either transportation or storage services when needed by the customer, which represents a series of distinct monthly services that are substantially the same with the same pattern of transfer to the customer. Although several activities may be required to provide the firm service, the individual activities do not represent distinct performance obligations because all of the activities must be performed in combination in order for the Company to provide the firm service.

The transaction price for firm service contracts is comprised of a fixed fee based on the quantity of capacity reserved, regardless of use (capacity reservation fee), plus variable fees in the form of a usage fee paid on the volume of commodity actually transported or injected and withdrawn from storage. Both the fixed and usage fees are allocated to the single performance obligation of providing transportation or storage service and recognized over time based upon the output measure of time as the Company completes its stand-ready obligation to provide contracted capacity and the customer receives and consumes the benefit of the reserved capacity, which corresponds with the transfer of control to the customer. The fixed fee is recognized ratably over the contract term, representative of the proportion of the committed stand-ready capacity obligation that has been fulfilled to date, and the usage fee is recognized upon satisfaction of each distinct monthly performance obligation, consistent with the allocation objective and based upon the level of effort required to satisfy the stand-ready obligation in a given month. Capacity reservation revenues derived from a firm service contract are generally consistent during the contract term, but can be higher in winter periods than the rest of the year based upon seasonal rates.

Interruptible Service Contracts: In providing interruptible services to customers, the Company agrees to transport or store natural gas or NGLs for a customer when capacity is available. The Company does not account for interruptible services with a customer as a contract until the customer nominates for service and the Company accepts the nomination based upon available pipeline or storage capacity or product availability because there are no enforceable rights and obligations until that time. The nomination and acceptance process is a daily activity and acceptance is granted based upon priority of service and availability of capacity and products. Upon acceptance, the Company accounts for interruptible services similarly to its firm services.

The transaction price for interruptible service contracts is comprised of a variable fee in the form of a usage fee paid on the volume of commodity actually transported or injected and withdrawn from storage. The transaction price is allocated to the single performance obligation of providing interruptible service. Interruptible service revenues for natural gas transportation and storage are generally recognized over time based on the output measure of volume transported or stored when services are rendered upon the successful allocation of the services provided to the customer's account, which best depicts the transfer of control to the customer and satisfaction of the promised service. Interruptible services are recognized in the month services are provided because the Company has a right to consideration from customers in amounts that correspond directly to the value that the customer receives from the Company's performance. The rates charged may vary on a daily, monthly or seasonal basis.

Minimum Volume Commitment (MVC) Contracts: Certain of the Company's transportation, storage or ethane supply contracts require customers to transport, store or purchase a minimum volume of commodity over a specified time period. If a customer fails to meet its MVC for the specified time period, the customer is obligated to pay a contractually-determined deficiency fee based upon the shortfall between the actual volumes transported, stored or purchased and the MVC for that period. MVC contracts are generally similar in nature to a firm service contract where the performance obligation is a stand-ready obligation that is a series of distinct services that are substantially the same with the same pattern of transfer to the customer. The transaction price for a MVC is a fee for the volume of commodity actually transported, stored or delivered, which is allocated to each distinct monthly performance obligation, consistent with the allocation objective and based upon the level of effort required to satisfy the obligation of the transacted activities in a given month. Revenues associated with transportation and storage services are generally recognized over time based on the output measure of volume transported or stored and revenues associated with ethane supply are generally recognized at a point in time based on barrels delivered, with the recognition of the deficiency fee in the period when it is known the customer cannot make up the deficient volume in the specified period.

Other: Certain ethane supply contracts include a stated volume that the Company supplies to customers, and any volume requested above the stated volume is based on product availability. Revenues for these ethane supply contracts are generally recognized at a point in time when each barrel is transferred to the customer because the customer is able to direct the use of, and obtain substantially all of the remaining benefits from, the product at that time. Periodically, the Company may also enter into contracts with customers for the sale of natural gas or NGLs. The Company recognizes revenues for these transactions at the point in time of the physical sale of the commodity, which corresponds with the transfer of control of the commodity to the customer and the consideration is measured as the stated sales price in the contract.

Contract Balances

The Company records contract assets primarily related to performance obligations completed but not billed, or partially billed, as of the reporting date. The Company records contract liabilities, or deferred revenue, when payment is received in advance of satisfying its performance obligations.

Note 3: Revenues

The Company contracts directly with end-use customers, including electric power generators, local distribution companies, industrial and petrochemical users and exporters of liquefied natural gas. The Company also contracts with other customers, including producers and marketers of natural gas and interstate and intrastate pipelines, who, in turn, provide transportation and storage services for end-users. The following tables present the Company's revenues disaggregated by type of service by segment (in millions):

	For the Year Ended December 31, 2025			
	Natural Gas	**Natural Gas Liquids**	**Eliminations**	**Total**
Revenues from Contracts with Customers				
Firm Service (1)	**$ 1,495.5**	**$ 609.1**	**$ (32.1)**	**$ 2,072.5**
Interruptible Service	**65.1**	**—**	**(1.1)**	**64.0**
Other revenues	**7.6**	**119.0**	**—**	**126.6**
Total Revenues from Contracts with Customers	**1,568.2**	**728.1**	**(33.2)**	**2,263.1**
Other operating revenues (2)	**23.3**	**36.9**	**(17.5)**	**42.7**
Total Operating Revenues	**$ 1,591.5**	**$ 765.0**	**$ (50.7)**	**$ 2,305.8**

(1) Revenues earned from contracts with MVCs are included in firm service given the stand-ready nature of the performance obligation and the guaranteed nature of the fees over the contract term.

(2) Other operating revenues include certain revenues earned from operating leases, pipeline management fees, intrasegment licensing fees and other activities that are not considered central and ongoing major business operations of the Company and do not represent revenues earned from contracts with customers.

	For the Year Ended December 31, 2024			
	Natural Gas	Natural Gas Liquids	Eliminations	Total
Revenues from Contracts with Customers				
Firm Service (1)	$ 1,353.9	$ 452.6	$ (31.0)	$ 1,775.5
Interruptible Service	59.1	0.1	—	59.2
Other revenues	7.6	144.9	—	152.5
Total Revenues from Contracts with Customers	1,420.6	597.6	(31.0)	1,987.2
Other operating revenues (2)	21.5	37.8	(18.4)	40.9
Total Operating Revenues	$ 1,442.1	$ 635.4	$ (49.4)	$ 2,028.1

(1) Revenues earned from contracts with MVCs are included in firm service given the stand-ready nature of the performance obligation and the guaranteed nature of the fees over the contract term.

(2) Other operating revenues include certain revenues earned from operating leases, pipeline management fees, intrasegment licensing fees and other activities that are not considered central and ongoing major business operations of the Company and do not represent revenues earned from contracts with customers.

	For the Year Ended December 31, 2023			
	Natural Gas	Natural Gas Liquids	Eliminations	Total
Revenues from Contracts with Customers				
Firm Service [(1)]	$ 1,253.1	$ 262.7	$ (26.1)	$ 1,489.7
Interruptible Service	51.6	—	—	51.6
Other revenues	3.4	36.8	—	40.2
Total Revenues from Contracts with Customers	1,308.1	299.5	(26.1)	1,581.5
Other operating revenues [(2)]	6.6	33.5	(3.9)	36.2
Total Operating Revenues	$ 1,314.7	$ 333.0	$ (30.0)	$ 1,617.7

(1) Revenues earned from contracts with MVCs are included in firm service given the stand-ready nature of the performance obligation and the guaranteed nature of the fees over the contract term.

(2) Other operating revenues include certain revenues earned from operating leases, pipeline management fees and other activities that are not considered central and ongoing major business operations of the Company and do not represent revenues earned from contracts with customers.

Contract Balances

As of December 31, 2025 and 2024, the Company had receivables recorded in *Trade Receivables, net* from contracts with customers of $220.5 million and $210.7 million, contract assets recorded in *Other Assets* from contracts with a customer of $11.9 million for each year, and contract liabilities recorded in *Other Current Liabilities* (current portion) and *Other Liabilities* (noncurrent portion) from contracts with customers of $19.1 million and $17.9 million.

As of December 31, 2025, contract liabilities are expected to be recognized through 2040. Significant changes in the contract liability balances during the year ended December 31, 2025, were as follows (in millions):

	Contract Liabilities
Balance as of December 31, 2024[(1)]	**$ 17.9**
Revenues recognized that were included in the contract liability balances at the beginning of the period	**(1.8)**
Increases due to cash received, excluding amounts recognized as revenues during the period	**3.0**
Balance as of December 31, 2025[(1)]	**$ 19.1**

(1) As of December 31, 2025 and 2024, $3.9 million and $1.8 million were recorded in *Other Current Liabilities* (current portion), and $15.2 million and $16.1 million were recorded in *Other Liabilities* (noncurrent portion).

Significant changes in the contract liability balances during the year ended December 31, 2024, were as follows (in millions):

	Contract Liabilities
Balance as of December 31, 2023[(1)]	$ 21.4
Revenues recognized that were included in the contract liability balances at the beginning of the period	(4.1)
Increases due to cash received, excluding amounts recognized as revenues during the period	0.6
Balance as of December 31, 2024[(1)]	$ 17.9

(1) As of December 31, 2024 and 2023, $1.8 million and $3.5 million were recorded in *Other Current Liabilities* (current

portion) and $16.1 million and $17.9 million were recorded in *Other Liabilities* (noncurrent portion).

Performance Obligations

The following table includes estimated operating revenues expected to be recognized in the future related to agreements that contain performance obligations that were unsatisfied as of December 31, 2025. The amounts presented primarily consist of fixed fees or MVCs which are typically recognized over time as the performance obligation is satisfied, in accordance with firm service contracts, or at a point in time as guaranteed minimum fees associated with the performance obligation are satisfied under certain ethane supply contracts. For the Company's customers that are charged maximum tariff rates related to its FERC-regulated operating subsidiaries, the amounts below reflect the current tariff rate for such services for the term of the agreements; however, the tariff rates may be subject to future adjustment. The Company has elected to exclude the following from the table: (a) unsatisfied performance obligations from usage fees associated with its firm services because of the variable nature of such services; (b) unsatisfied performance obligations from the ethane commodity indexed portion of ethane supply contracts because of the variable nature of ethane prices; and (c) consideration in contracts that is recognized in revenue as invoiced, such as for interruptible services. The estimated revenues reflected in the table include estimated revenues that are anticipated under executed precedent or long-term firm transportation agreements for growth projects that are contingent upon, among other things, receipt of required regulatory approvals and permits and are subject to construction risk.

	In millions			
	2026	**2027**	**Thereafter**	**Total**
Estimated revenues from contracts with customers from unsatisfied performance obligations as of December 31, 2025(1)(2)	$ 1,551.5	$ 1,331.0	$ 16,509.5	$ 19,392.0
Operating revenues which are fixed and determinable (operating leases)	27.5	27.5	108.5	163.5
Total projected operating revenues under committed firm agreements as of December 31, 2025	$ 1,579.0	$ 1,358.5	$ 16,618.0	$ 19,555.5

(1) In March 2024, the Company executed a 108-year firm storage agreement with a customer. The estimated annual revenue from this contract is $3.1 million with $325.4 million of unsatisfied performance obligations included in the "Thereafter" column. Per the tariff provisions, this customer was required to provide 90 days of collateral and the Company can suspend services due to non-payment.

(2) The estimated revenues from contracts with customers from unsatisfied performance obligations as of December 31, 2025, that are anticipated under executed precedent or long-term firm transportation agreements associated with the Company's growth projects are $9.9 billion.

Note 4: Leases

The Company has various operating lease commitments extending through 2058, generally covering office space and equipment rentals, some of which contain options to renew or extend the lease term. The Company also has a finance lease related to the lease of an office building in Owensboro, Kentucky, entered into in 2013, that has a fifteen-year term with two renewal options for up to twenty additional years in total.

The components of lease cost were as follows (in millions):

	For the Year Ended December 31,		
	2025	2024	2023
Operating lease cost	**$ 4.3**	$ 4.1	$ 3.8
Short-term lease cost	**3.8**	5.4	4.7
Finance lease cost:			
Amortization of right-of-use asset	**0.7**	0.7	0.7
Interest on lease liability	**0.2**	0.3	0.3
Total lease cost	**$ 9.0**	$ 10.5	$ 9.5

The following provides supplemental balance sheet information related to the Company's leases:

	As of December 31,	
	2025	2024
Right-of-use assets (in millions)		
Operating leases (recorded in *Other Assets*)	**$ 22.7**	$ 24.9
Finance lease (recorded in *Property, Plant and Equipment*)	**1.8**	2.5
Lease liabilities (in millions)		
Operating leases (recorded in *Other Liabilities*, current and noncurrent)	**24.0**	25.3
Finance lease (recorded in *Other Current Liabilities* and *Long-term debt and finance lease obligation*)	**2.7**	3.6
Weighted-average remaining lease term (years)		
Operating leases	**13.0**	13.6
Finance lease	**2.6**	3.6
Weighted-average discount rate		
Operating leases	**3.99 %**	3.95 %
Finance lease	**5.89 %**	5.89 %

The table below presents the maturities of lease liabilities (in millions):

	As of December 31, 2025	
	Operating Leases	**Finance Lease**
2026	$ 2.7	$ 1.1
2027	2.2	1.1
2028	0.9	0.7
2029	2.1	—
2030	2.9	—
Thereafter	21.7	—
Total	32.5	2.9
Less: discount	(8.5)	(0.2)
Total lease liabilities	$ 24.0	$ 2.7

Note 5: Commitments and Contingencies

Legal Proceedings and Settlements

The Company and its subsidiaries are parties to various legal actions arising in the normal course of business. Management believes the disposition of these outstanding legal actions, including the legal actions identified below, will not have a material impact on the Company's financial condition, results of operations or cash flows.

Mishal and Berger Litigation

On May 25, 2018, plaintiffs Tsemach Mishal and Paul Berger (on behalf of themselves and the purported class, Plaintiffs) initiated a purported class action in the Court of Chancery of the State of Delaware (the Trial Court) against the following defendants: the Company, Boardwalk GP, LP (Boardwalk GP), Boardwalk GP, LLC and BPHC (together, Defendants), regarding the potential exercise by Boardwalk GP of its right to purchase the issued and outstanding common units of the Company not already owned by Boardwalk GP or its affiliates (Purchase Right).

On June 25, 2018, Plaintiffs and Defendants entered into a Stipulation and Agreement of Compromise and Settlement, subject to the approval of the Trial Court (the Proposed Settlement). Under the terms of the Proposed Settlement, the lawsuit would be dismissed, and related claims against the Defendants would be released by the Plaintiffs, if BPHC, the sole member of the general partner of Boardwalk GP, elected to cause Boardwalk GP to exercise its Purchase Right for a cash purchase price, as determined by the Company's Third Amended and Restated Agreement of Limited Partnership, as amended (the Limited Partnership Agreement), and gave notice of such election as provided in the Limited Partnership Agreement within a period specified by the Proposed Settlement. On June 29, 2018, Boardwalk GP elected to exercise the Purchase Right and gave notice within the period specified by the Proposed Settlement. On July 18, 2018, Boardwalk GP completed the purchase of the Company's common units pursuant to the Purchase Right.

On September 28, 2018, the Trial Court denied approval of the Proposed Settlement. On February 11, 2019, a substitute verified class action complaint was filed in this proceeding, which, among other things, added Loews as a Defendant. The Defendants filed a motion to dismiss, which was heard by the Trial Court in July 2019. In October 2019, the Trial Court ruled on the motion and granted a partial dismissal, with certain aspects of the case proceeding to trial. A trial was held the week of February 22, 2021, and post-trial oral arguments were held on July 14, 2021.

On November 12, 2021, the Trial Court issued a ruling in the case. The Trial Court held that Boardwalk GP breached the Limited Partnership Agreement and found that Boardwalk GP was liable to the Plaintiffs for approximately $690.0 million in damages, plus pre-judgment interest (approximately $166.0 million), post-judgment interest and attorneys' fees. The Trial Court's ruling and damages award was against Boardwalk GP, and not the Company or its subsidiaries.

The Defendants believed that the Trial Court ruling included factual and legal errors. Therefore, on January 3, 2022, the Defendants appealed the Trial Court's ruling to the Supreme Court of the State of Delaware (the Supreme Court). On January 17, 2022, the Plaintiffs filed a cross-appeal to the Supreme Court contesting the calculation of damages by the Trial Court. Oral arguments were held on September 14, 2022, and on December 19, 2022, the Supreme Court reversed the Trial Court's ruling and remanded the case to the Trial Court for further proceedings related to claims not decided by the Trial Court's ruling. Briefing by the parties at the Trial Court on the remanded issues was completed in September 2023. A hearing on the remanded issues was held at the Trial Court in April 2024. In September 2024, the Trial Court ruled in favor of the Defendants on all of the remanded issues.

On October 21, 2024, the Plaintiffs appealed the Trial Court's ruling on the remanded issues to the Supreme Court. Briefing on this appeal was completed in March 2025 and a hearing on this appeal occurred in June 2025. On December 10, 2025, the Supreme Court affirmed in part and reversed in part the Trial Court's ruling. In its decision, the Supreme Court found that Boardwalk GP had breached the Limited Partnership Agreement in its exercise of the Purchase Right. In its 2022 decision, the Supreme Court had previously determined that Boardwalk GP was exculpated from damages. The remaining claims that have been remanded by the Supreme Court to the Trial Court for further proceedings are tortious interference and unjust enrichment claims related to the exercise of the Purchase Right against the non-Boardwalk GP defendants.

City of New Orleans Litigation

Gulf South, along with several other energy companies operating in Southern Louisiana, has been named as a defendant in a petition for damages and injunctive relief in state district court for Orleans Parish, Louisiana, (Case No. 19-3466) by the City of New Orleans. The case was filed on March 29, 2019. The lawsuit claims include, among other things, negligence, strict liability, nuisance and breach of contract, alleging that the defendants' drilling, dredging, pipeline and industrial operations since the 1930s have caused increased storm surge risk, increased flood protection costs and unspecified damages to the City of New Orleans. In October 2020, this case was stayed pending the outcome of a consolidated appeal to the Fifth Circuit Court of Appeals in a similar case. On August 5, 2021, the Fifth Circuit Court of Appeals ruled in favor of the oil-and-gas defendants in that consolidated appeal, finding that the two cases being appealed should be re-examined in federal district court since they involve operations that were federally overseen at the time. The ruling reverses a previous decision that allowed the cases to be heard in state court, which the plaintiffs had sought. As a result of the Fifth Circuit Court of Appeals' decision, it is anticipated that this case will be reviewed in federal district court to determine whether the case should be heard in that court. This case was settled in December 2025, which did not have a material impact to the Company's results of operations or equity.

Gulf South and Texas Gas have been named as defendants in several suits in the State of Louisiana that are similar in nature to the City of New Orleans litigation discussed above. These cases were filed in Louisiana state courts and discovery is ongoing. Two of these cases were settled in 2024, which did not have a material impact to the Company's results of operations or equity.

Louisiana Department of Wildlife and Fisheries Litigation

Gulf South, among other energy companies, has been named as a defendant in an action filed by the Louisiana Department of Wildlife and Fisheries (Department). The case was filed in the state district court for LaFourche Parish, Louisiana, on October 11, 2022 (Case No. C-145860). In this lawsuit, the Department alleges that Gulf South's operations in the Point-aux-Chenes Wildlife Management Area wetlands have contributed to hydrological changes and widening canals. The Department's claims include negligence, nuisance, breach of contract, tort and unfair trade practices. Discovery is ongoing, and the Department has issued expert reports, which include their damages models.

Environmental and Safety Matters

The Company's operating subsidiaries are subject to federal, state, and local environmental laws and regulations in connection with the operation and remediation of various operating sites. As of December 31, 2025 and 2024, the Company had an accrued liability of approximately $4.5 million and $7.0 million related to assessment and/or remediation costs associated with the historical use of polychlorinated biphenyls, petroleum hydrocarbons and mercury. The liability represents management's estimate of the undiscounted future obligations based on evaluations and discussions with counsel and operating personnel and the current known facts and circumstances related to these matters. The related expenditures are expected to occur over the next twelve to fifteen years. As of December 31, 2025 and 2024, approximately $1.7 million and $3.4 million were recorded in *Other Current Liabilities* and approximately $2.8 million and $3.6 million were recorded in *Other Liabilities and Deferred Credits*.

Clean Air Act and Climate Change

The Company's pipelines and associated facilities are subject to the Clean Air Act (CAA) and comparable state laws and regulations, which regulate the emission of air pollutants from many sources and impose various compliance monitoring and reporting requirements. Under the CAA, the Company may be required to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. The need to obtain permits has the potential to delay the development or expansion of the Company's projects. Over the next several years, the Company could be required to incur capital expenditures for air pollution control equipment or other air emissions related issues. For example, in 2015, the Environmental Protection Agency (EPA) issued a final rule under the CAA, lowering the National Ambient Air Quality Standard (NAAQS) for ground-level ozone to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare. In December 2020, the EPA published notice of a final action to retain the 2015 ozone NAAQS without revision on a going-forward basis. However, several groups filed litigation and in October 2021, the EPA announced that it would reconsider the December 2020 determination. In August 2023, the EPA announced a new review of the ozone NAAQS to ensure the standards protect public health and reflect the most current, relevant science. The EPA announced an updated reconsideration of the ozone NAAQS in March 2025. States are also expected to implement more stringent regulations that could apply to the Company's operations. Compliance with any final decision could, among other things, require installation of new emission controls on some of the Company's equipment, result in longer permitting timelines and significantly increase its capital expenditures and operating costs. Additionally, climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional, state and local levels of government to monitor and limit emissions of greenhouse gases (GHGs). These efforts have included consideration of cap-and-trade programs, carbon taxes and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources.

Commitments for Construction

The Company's future capital commitments are comprised of binding commitments under purchase orders for materials ordered but not received. As of December 31, 2025, the commitments totaled approximately $354.5 million, of which $254.9 million is expected to be settled in 2026, $64.3 million in 2027 and $35.3 million in 2028.

Pipeline Capacity and Storage Agreements

The Company's operating subsidiaries have entered into pipeline capacity and storage agreements with third-party pipelines that allow the operating subsidiaries to transport gas to off-system markets on behalf of customers or store natural gas. Additionally, the Company has assumed a pipeline capacity agreement with a third party to facilitate the transportation of ethane and an ethane storage agreement. The Company incurred expenses of $12.9 million, $11.2 million and $5.8 million related to pipeline capacity and storage agreements for the years ended December 31, 2025, 2024 and 2023. The table below presents the future commitments related to these agreements as of December 31, 2025 (in millions):

2026	$ 8.0
2027	5.7
2028	3.3
2029	3.2
2030	3.2
Thereafter	3.9
Total	$ 27.3

Note 6: Fair Value

Financial Assets and Liabilities

The Company had no assets and liabilities recorded at fair value on a recurring basis as of December 31, 2025. The Company had equity securities recorded at fair value on a recurring basis in *Other Current Assets* of $1.8 million and had no liabilities recorded at fair value on a recurring basis as of December 31, 2024. The equity securities were received as part of a settlement of a bankruptcy claim. The equity securities were valued based on quoted market prices at December 31, 2024, and were considered Level 1 investments.

Financial Assets and Liabilities Not Measured at Fair Value

The following methods and assumptions were used in estimating the fair value amounts included in the disclosures for financial assets and liabilities:

Cash and Cash Equivalents: For cash and short-term financial assets, the carrying amount is a reasonable estimate of fair value due to the short maturity of those instruments.

Short-Term Investments: The carrying amount of the U.S. treasury bills are adjusted for the accretion of discounts over the remaining life of the investment.

Debt, Current and Long-Term: The estimated fair value of the Company's publicly traded debt is based on quoted market prices at December 31, 2025 and 2024. The fair market value of the debt that is not publicly traded is based on market prices of similar debt at December 31, 2025 and 2024.

The carrying amounts and estimated fair values of the Company's financial assets and liabilities which were not recorded at fair value on the Consolidated Balance Sheets, were as follows (in millions):

As of December 31, 2025		**Estimated Fair Value**			
Financial Assets	**Carrying Amount**	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	**$ 499.2**	**$ 499.2**	**$ —**	**$ —**	**$ 499.2**
Short-term investments	**351.3**	**351.4**	**—**	**—**	**351.4**
Financial Liabilities					
Debt, current and long-term	**$ 3,785.2** (1)	**$ —**	**$ 3,786.5**	**$ —**	**$ 3,786.5**

(1) The carrying amount of debt excluded a $1.7 million long-term finance lease obligation and $5.5 million of unamortized debt issuance costs.

As of December 31, 2024		Estimated Fair Value			
Financial Assets	Carrying Amount	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$ 117.9	$ 117.9	$ —	$ —	$ 117.9
Financial Liabilities					
Long-term debt	$ 3,236.5 (1)	$ —	$ 3,129.7	$ —	$ 3,129.7

(1) The carrying amount of long-term debt excluded a $2.7 million long-term finance lease obligation and $4.8 million of unamortized debt issuance costs.

Note 7: Property, Plant and Equipment

The following table presents the Company's PPE as of December 31, 2025 and 2024 (in millions):

Category	**2025 Amount**	**2025 Weighted-Average Useful Lives (Years)**	2024 Amount	2024 Weighted-Average Useful Lives (Years)
Depreciable plant:				
Transmission	**$ 11,937.1**	**39**	$ 11,750.7	38
Storage	**1,027.1**	**39**	1,002.1	39
Gathering	**115.5**	**18**	108.8	25
General, intangibles and other	**508.0**	**19**	557.7	20
Total utility depreciable plant	**13,587.7**	**38**	13,419.3	38
Non-depreciable:				
Construction work in progress	**289.2**		190.1	
Storage	**195.8**		196.8	
Land	**51.6**		51.6	
Total non-depreciable assets	**536.6**		438.5	
Total PPE, gross	**14,124.3**		13,857.8	
Less: accumulated depreciation and amortization	**5,352.5**		5,045.1	
Total PPE, net	**$ 8,771.8**		$ 8,812.7	

The non-depreciable assets were not included in the calculation of the weighted-average useful lives.

For the years ended December 31, 2025, 2024 and 2023, depreciation expense for PPE was $436.0 million, $421.9 million and $406.5 million and was recorded in *Depreciation and amortization* on the Consolidated Statements of Income.

The Company holds undivided interests in certain assets, including the Mobile Bay Pipeline, of which the Company owns 64%, and offshore and other assets, comprised of pipeline and gathering assets in which the Company holds various ownership interests. In addition, the Company owns 83% of two ethylene wells and supporting surface facilities in Choctaw, Louisiana, and certain ethylene and propylene pipelines connecting Louisiana Midstream's storage facilities in Choctaw to chemical manufacturing plants in Geismar, Louisiana.

The proportionate share of investment associated with these interests has been recorded as PPE on the Consolidated Balance Sheets. The Company records its portion of direct operating expenses associated with the assets in *Operation and maintenance* expense. The following table presents the gross PPE investment and related accumulated depreciation for the Company's undivided interests as of December 31, 2025 and 2024 (in millions):

	2025		2024	
	Gross PPE Investment	**Accumulated Depreciation**	Gross PPE Investment	Accumulated Depreciation
Mobile Bay Pipeline	**$ 16.2**	**$ 9.2**	$ 15.4	$ 8.8
NGLs pipelines and facilities	**55.1**	**16.6**	55.1	15.1
Offshore and other assets	**7.7**	**5.9**	7.5	5.7
Total	**$ 79.0**	**$ 31.7**	$ 78.0	$ 29.6

Asset Impairments

The Company recognized asset impairment charges of $0.9 million, $2.4 million and $0.4 million for the years ended December 31, 2025, 2024 and 2023.

Note 8: Goodwill and Intangible Assets

Goodwill

As of December 31, 2025 and 2024, goodwill of $237.4 million was recorded on the Consolidated Balance Sheets. As of December 31, 2025 and 2024, $168.0 million and $163.5 million was attributable to the Natural Gas reportable segment and $69.4 million and $73.9 million to the Natural Gas Liquids reportable segment. In 2025, the Company reorganized its legal entity structure which impacted its reporting units for purposes of goodwill. Goodwill was reallocated based on the relative fair value approach, resulting in $4.5 million of goodwill being transferred from Natural Gas Liquids to Natural Gas and increasing the number of reporting units for goodwill testing to three. As of December 31, 2025, the Texas Gas reporting unit had $163.5 million of goodwill, the Gulf South and other natural gas businesses reporting unit had $4.5 million of goodwill and the Natural Gas Liquids reporting unit had $69.4 million of goodwill.

As of November 30, 2025, the Company performed a qualitative annual goodwill impairment test on its Gulf South and other natural gas businesses and Natural Gas Liquids reporting units as a result of the proximity in timing of the quantitative tests performed as of February 28, 2025, noted below and taking into account expected future performance and operating environment. The qualitative assessments included the Company's consideration of, among other things, the overall macroeconomic conditions, industry and market considerations, current discount rates and valuation multiples, overall financial performance, including operating revenues, and other relevant company specific events. Based on the assessment of these items, the Company concluded that it is more likely than not that the fair value of these two reporting units exceeded their respective carrying amounts. Accordingly, there were no indicators of impairment and quantitative impairment tests were not performed for the two reporting units as of November 30, 2025.

Quantitative tests were performed on the Texas Gas reporting unit as of November 30, 2025, and on the Gulf South and other natural gas businesses and Natural Gas Liquids reporting units as of February 28, 2025. The fair value measurements of the reporting units were derived based on judgments and assumptions the Company believes market participants would use in assessing the fair value of the reporting units. These judgments and assumptions included the valuation premise, use of a discounted cash flow model to estimate fair value under an income approach and inputs to the valuation model. The inputs included the Company's five-year financial plan operating results, including operating revenues, the long-term outlook for growth in natural gas, NGLs and petrochemical demand, measures of the risk-free rate, equity premium and systematic risk used in the calculation of the applied discount rate under the capital asset pricing model and views regarding future market conditions, among others. The reasonableness of fair value estimates under the income approach was supported by a market approach under which the Company applied earnings before interest, income taxes, depreciation and amortization (EBITDA) multiples derived from publicly available information to each reporting unit's EBITDA. The results of the quantitative goodwill impairment tests for 2025 indicated that the fair values of the reporting units exceeded their carrying amounts.

As of November 30, 2024, the Company elected to perform qualitative assessments for its annual goodwill impairment tests. There were no indicators of impairment and quantitative impairment tests were not performed.

No impairment charges related to goodwill were recorded for any of the Company's reporting units during 2025, 2024 or 2023.

Intangible Assets

The following table contains information regarding the Company's intangible assets, which include customer relationships acquired as part of its acquisitions (in millions):

	As of December 31,	
	2025	2024
Gross carrying amount	**$ 92.9**	$ 92.9
Accumulated amortization	**(27.1)**	(24.2)
Net carrying amount	**$ 65.8**	$ 68.7

For the years ended December 31, 2025, 2024 and 2023, amortization expense for intangible assets was $2.9 million, $2.9 million and $2.2 million, and was recorded in *Depreciation and amortization* on the Consolidated Statements of Income. Amortization expense for the next five years and in total thereafter as of December 31, 2025, is expected to be as follows (in millions):

2026	$ 2.9
2027	2.9
2028	2.9
2029	2.9
2030	2.9
Thereafter	51.3
Total	$ 65.8

The weighted-average remaining useful life of the Company's intangible assets as of December 31, 2025, was 24 years.

Note 9: Asset Retirement Obligations

The Company has identified and recorded legal obligations associated with the abandonment of certain pipeline and storage assets, brine ponds and offshore facilities and the abatement of asbestos, consisting of removal, transportation and disposal when removed from certain compressor stations and meter station buildings. Legal obligations exist for the main pipeline and certain other Company assets; however, the fair value of these obligations cannot be determined because the lives of the assets are indefinite. As a result, cash flows associated with retirement of the assets cannot be estimated with the degree of accuracy necessary to establish a liability for the obligations.

The following table summarizes the aggregate carrying amount of the Company's ARO (in millions):

	As of December 31,	
	2025	2024
Balance at beginning of year	**$ 72.2**	$ 74.1
Liabilities recorded	**1.0**	5.0
Liabilities settled	**(3.2)**	(9.9)
Accretion expense	**1.9**	2.1
Revision of estimates	**—**	0.9
Balance at end of year	**71.9**	72.2
Less: Current portion of ARO	**(0.3)**	(2.2)
Long-term ARO	**$ 71.6**	$ 70.0

For the Company's operations where regulatory accounting is applicable, depreciation rates for PPE are comprised of two components. One component is based on economic service life (capital recovery) and the other is based on estimated costs of removal (as a component of negative salvage) which is collected in rates and does not represent an existing legal obligation.

The Company has reflected $108.2 million and $103.6 million as of December 31, 2025 and 2024, on the Consolidated Balance Sheets as *Provision for other asset retirement* related to the estimated cost of removal collected in rates.

Note 10: Regulatory Assets and Liabilities

The amounts recorded as regulatory assets and liabilities on the Consolidated Balance Sheets as of December 31, 2025 and 2024, are summarized in the table below. The table also includes amounts related to unamortized debt issuance costs and unamortized discount on debt, which while not regulatory assets and liabilities, are a component of the embedded cost of debt financing utilized in Texas Gas' rate proceedings. The tax effect of the equity component of AFUDC represents amounts recoverable from rate payers for the tax recorded in regulatory accounting. Certain amounts in the table are reflected as a negative, or a reduction, to be consistent with the regulatory books of account. The period of recovery for the regulatory assets included in rates varies from one to eighteen years. The remaining period of recovery for regulatory assets not yet included in rates would be determined in future rate proceedings. None of the regulatory assets shown below were earning a return as of December 31, 2025 and 2024 (in millions):

	As of December 31,	
	2025	2024
Regulatory Assets:		
Pension	**$ 7.0**	$ 8.0
Tax effect of AFUDC equity	**0.1**	0.1
Fuel tracker	**0.5**	—
Other	**0.5**	0.5
Total regulatory assets	**$ 8.1**	$ 8.6
Regulatory Liabilities:		
Cashout and fuel tracker	**$ 29.1**	$ 18.3
Provision for other asset retirement	**108.2**	103.6
Unamortized debt issuance costs	**(0.4)**	(0.7)
Unamortized discount on debt	**(0.1)**	(0.1)
Postretirement benefits other than pension	**66.6**	62.8
Total regulatory liabilities	**$ 203.4**	$ 183.9

Note 11: Financing

Debt

The following table presents all debt issuances outstanding (in millions):

	As of December 31, 2025	As of December 31, 2024
Notes and Debentures:		
Boardwalk Pipelines		
5.95% Notes due 2026 (Boardwalk Pipelines 2026 Notes)	**$ 550.0**	$ 550.0
4.45% Notes due 2027	**500.0**	500.0
4.80% Notes due 2029	**500.0**	500.0
3.40% Notes due 2031	**500.0**	500.0
3.60% Notes due 2032	**500.0**	500.0
5.625% Notes due 2034	**600.0**	600.0
5.375% Notes due 2036	**550.0**	—
Texas Gas		
7.25% Debentures due 2027	**100.0**	100.0
Total notes and debentures	**3,800.0**	3,250.0
Finance lease obligation	**1.7**	2.7
	3,801.7	3,252.7
Less:		
Unamortized debt discount	**(14.8)**	(13.5)
Unamortized debt issuance costs	**(5.5)**	(4.8)
Total Debt and Finance Lease Obligation	**3,781.4**	3,234.4
Less:		
Current portion of long-term debt	**549.6**	—
Total Long-Term Debt and Finance Lease Obligation	**$ 3,231.8**	$ 3,234.4

Maturities of the Company's debt for the next five years and in total thereafter are as follows (in millions):

2026	$ 550.0
2027	600.0
2028	—
2029	500.0
2030	—
Thereafter	2,150.0
Total debt	$ 3,800.0

The Company has classified the Boardwalk Pipelines 2026 Notes which mature in less than one year as current on its Consolidated Balance Sheets as of December 31, 2025. In January 2026, the Company notified the holders of the Boardwalk Pipelines 2026 Notes of its intent to redeem the notes on March 1, 2026.

Notes and Debentures

As of December 31, 2025 and 2024, the weighted-average interest rates of the Company's notes and debentures were 5.03% and 4.95%.

For the twelve months ended December 31, 2025, the Company completed the following debt issuance (in millions, except interest rates):

Date of Issuance	Issuing Subsidiary	Amount of Issuance	Purchaser Discounts and Expenses	Net Proceeds	Interest Rate	Maturity Date	Interest Payable
November 2025	Boardwalk Pipelines	$ 550.0	$ 6.0	$ 544.0 (1)	5.375 %	February 15, 2036	February 15 and August 15

(1) The net proceeds of this offering will be used to redeem the Boardwalk Pipelines 2026 Notes. In January 2026, the Company notified the holders of the Boardwalk Pipelines 2026 Notes of its intent to redeem the notes on March 1, 2026, at a redemption price equal to par plus accrued and unpaid interest.

The Company's notes and debentures are redeemable, in whole or in part, at the Company's option at any time, at a redemption price equal to the greater of 100% of the principal amount of the notes to be redeemed or a "make whole" redemption price based on the remaining scheduled payments of principal and interest discounted to the date of redemption at a rate equal to the U.S. Treasury rate plus 20 to 50 basis points depending upon the particular issue of notes, plus accrued and unpaid interest, if any. Other customary covenants apply, including those concerning events of default.

The indentures governing the notes and debentures have restrictive covenants which provide that, with certain exceptions, neither the Company nor any of its subsidiaries may create, assume or suffer to exist any lien upon any property to secure any indebtedness unless the debentures and notes shall be equally and ratably secured. All of the Company's debt obligations are unsecured. As of December 31, 2025, the Company and its subsidiaries were in compliance with their covenants under the indentures.

Revolving Credit Facility

In November 2025, the Company entered into a Fourth Amended and Restated Revolving Credit Agreement (Amended Credit Agreement) with Wells Fargo Bank, N.A., as administrative agent, having aggregate lending commitments of $1.0 billion, a maturity date of November 10, 2030, and including Boardwalk Pipelines, Texas Gas and Gulf South as borrowers (Borrowers). Interest is determined, at the Company's election, by reference to (a) the base rate, plus an applicable margin from 0.00% to 0.75% based on the individual Borrower's credit rating, which base rate is the highest of (1) the prime rate, (2) the federal funds rate plus 0.50% and (3) the one month term Secured Overnight Financing Rate plus 1.00%, or (b) the term Secured Overnight Financing Rate, plus an applicable margin from 1.00% to 1.75% based on the individual Borrower's credit rating. The Amended Credit Agreement provides for a quarterly commitment fee charged on the average daily unused amount of the revolving credit facility ranging from 0.10% to 0.25% which is determined based on the individual Borrower's credit rating from time to time.

The Amended Credit Agreement contains various restrictive covenants and other usual and customary terms and conditions, including restrictions regarding the incurrence of additional debt, the sale of assets and sale-leaseback transactions. The financial covenants under the Amended Credit Agreement require the Company and its subsidiaries to maintain, among other things, a ratio of consolidated total debt to consolidated EBITDA (as defined in the Amended Credit Agreement) measured for the previous twelve months of not more than 5.0 to 1.0, or up to 5.5 to 1.0 for (i) the quarter in which the consummation of a qualified acquisition occurs where the purchase price exceeds $100.0 million and (ii) the three quarters following the qualified acquisition quarter. The Company and its subsidiaries were in compliance with the covenants under the Amended Credit Agreement as of December 31, 2025.

As of December 31, 2025 and 2024, the Company had no outstanding borrowings under its revolving credit facility and had the full borrowing capacity of $1.0 billion available.

Cash Distributions

The Company paid to BPHC and Boardwalk GP cash distributions of $500.0 million, $400.0 million and $300.0 million for the years ended December 31, 2025, 2024 and 2023.

Note 12: Employee Benefits

Retirement Plans

Defined Benefit Retirement Plans (Retirement Plans)

Texas Gas employees hired prior to November 1, 2006, are covered under a non-contributory, defined benefit pension plan (Pension Plan). The Texas Gas Supplemental Retirement Plan (SRP) provides pension benefits for the portion of an eligible employee's pension benefit under the Pension Plan that becomes subject to compensation limitations under the Internal Revenue Code. Collectively, the Company refers to the Pension Plan and the SRP as Retirement Plans. The Company uses a measurement date of December 31 for the Retirement Plans.

As a result of the Texas Gas rate case settlement in 2006, the Company is required to fund the amount of annual net periodic pension cost associated with the Pension Plan, including a minimum of $3.0 million, which is the amount included in rates. In 2025 and 2024, the Company funded $3.0 million and $3.2 million to the Pension Plan and expects to fund an additional $3.0 million to the plan in 2026. In 2025 and 2024, no SRP payments were made.

The Company recognizes in expense each year the actuarially determined amount of net periodic pension cost associated with the Retirement Plans, including a minimum amount of $3.0 million related to its Pension Plan, in accordance with the 2006 rate case settlement. Texas Gas is permitted to seek future rate recovery for amounts of annual Pension Plan costs in excess of $6.0 million and is precluded from seeking future recovery of annual Pension Plan costs between $3.0 million and $6.0 million. As a result, the Company would recognize a regulatory asset for amounts of annual Pension Plan costs in excess of $6.0 million and would reduce its regulatory asset to the extent that annual Pension Plan costs are less than $3.0 million. Annual Pension Plan costs between $3.0 million and $6.0 million will be charged to expense.

Postretirement Benefits Other Than Pension

Texas Gas provides postretirement medical benefits and life insurance to retired employees who were employed full time, hired prior to January 1, 1996, and have met certain other requirements. In each of the years 2025 and 2024, the Company contributed $0.2 million to the PBOP plan. The PBOP plan is in an overfunded status; therefore, the Company does not expect to make any contributions to the plan in 2026. The Company does not anticipate that any plan assets will be returned to the Company during 2026. The Company uses a measurement date of December 31 for its PBOP plan.

Projected Benefit Obligation, Fair Value of Assets and Funded Status

The projected benefit obligation, fair value of assets, funded status and the amounts not yet recognized as components of net periodic pension and postretirement benefits cost for the Retirement Plans and PBOP were as follows (in millions):

	Retirement Plans		PBOP	
	For the Year Ended December 31,		For the Year Ended December 31,	
	2025	2024	**2025**	2024
Change in benefit obligation:				
Benefit obligation at beginning of period	**$ 83.1**	$ 88.0	**$ 21.3**	$ 23.4
Service cost [1]	**1.8**	1.9	**8.8**	—
Interest cost	**3.6**	4.0	**1.1**	1.1
Plan participants' contributions	**—**	—	**0.9**	1.0
Actuarial loss (gain)	**4.3**	(2.1)	**0.9**	(0.1)
Benefits paid	**(0.5)**	(0.5)	**(4.0)**	(4.1)
Settlements	**(13.5)**	(8.2)	**—**	—
Benefit obligation at end of period	**$ 78.8**	$ 83.1	**$ 29.0**	$ 21.3
Change in plan assets:				
Fair value of plan assets at beginning of period	**$ 84.4**	$ 83.3	**$ 82.5**	$ 82.3
Actual return on plan assets	**9.7**	6.6	**5.2**	3.1
Company's contribution	**3.0**	3.2	**0.2**	0.2
Plan participants' contributions	**—**	—	**0.9**	1.0
Benefits paid	**(0.5)**	(0.5)	**(4.0)**	(4.1)
Settlements	**(13.5)**	(8.2)	**—**	—
Fair value of plan assets at end of period	**$ 83.1**	$ 84.4	**$ 84.8**	$ 82.5
Funded status	**$ 4.3**	$ 1.3	**$ 55.8**	$ 61.2
Items not recognized as components of net periodic cost:				
Net actuarial loss	**$ 4.5**	$ 6.8	**$ 0.9**	$ 2.5

(1) As of December 31, 2025, PBOP service cost increased by $8.8 million as a result of changes to the plan effective January 1, 2026, that eliminated contributions from plan participants.

Components of Net Periodic Benefit Cost

Components of net periodic benefit cost for both the Retirement Plans and PBOP were as follows (in millions):

	Retirement Plans			PBOP		
	For the Year Ended December 31,			For the Year Ended December 31,		
	2025	2024	2023	**2025**	2024	2023
Service cost	**$ 1.8**	$ 1.9	$ 1.9	**$ —**	$ —	$ —
Interest cost	**3.6**	4.0	4.1	**1.1**	1.1	1.2
Expected return on plan assets	**(4.1)**	(3.9)	(3.6)	**(2.7)**	(2.6)	(2.4)
Amortization of prior service cost	**0.1**	0.1	0.1	**—**	—	—
Amortization of unrecognized net loss	**0.1**	0.3	1.2	**—**	—	—
Settlement charge	**0.9**	0.7	1.3	**—**	—	—
Regulatory asset decrease	**0.9**	0.1	—	**—**	—	—
Net periodic benefit cost (credit)	**$ 3.3**	$ 3.2	$ 5.0	**$ (1.6)**	$ (1.5)	$ (1.2)

Due to the Texas Gas rate case settlement in 2006, Texas Gas is permitted to seek future rate recovery for amounts of annual Pension Plan costs in excess of $6.0 million.

Estimated Future Benefit Payments

The following table shows benefit payments, which reflect expected future service, as appropriate, which are expected to be paid for both the Retirement Plans and PBOP (in millions):

	Retirement Plans	PBOP
2026	$ 16.1	$ 3.1
2027	11.3	2.9
2028	8.7	2.7
2029	7.3	2.5
2030	5.4	2.2
2031-2035	15.8	8.5

Weighted-Average Assumptions

Weighted-average assumptions used to determine benefit obligations were as follows:

	Retirement Plans				**PBOP**	
	For the Year Ended December 31,				**For the Year Ended December 31,**	
	2025		2024		**2025**	2024
	Pension	**SRP**	Pension	SRP		
Discount rate	**4.80 %**	**4.65 %**	5.35 %	5.25 %	**5.50 %**	5.60 %
Expected return on plan assets	**5.50 %**	**5.50 %**	5.50 %	5.50 %	**3.37 %**	3.37 %
Rate of compensation increase	**5.00 %**	**5.00 %**	4.00%-4.50%	4.00%-4.50%	**— %**	— %

Weighted-average assumptions used to determine net periodic benefit cost for the periods indicated were as follows:

	Retirement Plans						**PBOP**		
	For the Year Ended December 31,						**For the Year Ended December 31,**		
	2025		2024		2023		**2025**	2024	2023
	Pension	**SRP**	Pension	SRP	Pension	SRP			
Discount rate	**(1)**	**5.25 %**	(1)	5.25 %	(1)	4.90 %	**5.60 %**	5.10 %	5.40 %
Expected return on plan assets	**5.50%**	**5.50 %**	5.00%	5.00 %	5.00%	5.00 %	**3.37 %**	3.25 %	2.99 %
Rate of compensation increase	**4.00% - 4.50%**	**4.00% - 4.50%**	3.00% - 3.50%	3.00% - 3.50%	3.00% - 4.50%	3.00%- 4.50%	**— %**	— %	— %

(1) Pension expense was remeasured quarterly in 2025, 2024 and 2023. The quarterly remeasurements for each quarter in 2025, 2024 and 2023 were as follows: Quarter 1: 5.00%, 5.25% and 5.35%; Quarter 2: 5.15%, 5.40% and 5.15%; Quarter 3: 4.90%, 4.80% and 5.45%; and Quarter 4: 4.80%, 5.35% and 4.90%.

In determining the discount rate assumption, current market and liability information is utilized, including a discounted cash flow analysis of the pension and postretirement obligations. In particular, the basis for the discount rate selection was the yield on indices of highly rated fixed income debt securities with durations comparable to that of the Company's plan liabilities. The yield curve was applied to expected future retirement plan payments to adjust the discount rate to reflect the cash flow characteristics of the plans. The yield curves and indices evaluated in the selection of the discount rate were comprised of high-quality corporate bonds that are rated AA by an accepted rating agency.

The expected long-term rate of return for plan assets is determined based on widely-accepted capital market principles, long-term return analysis for global fixed income and equity markets as well as the active total return oriented portfolio management style. Long-term trends are evaluated relative to market factors such as inflation, interest rates and fiscal and monetary policies, in order to assess the capital market assumptions as applied to the plan. Consideration of diversification needs and rebalancing is maintained.

Pension Plan and PBOP Asset Allocation and Investment Strategy

Pension Plan

The Pension Plan assets are held in the Texas Gas Trust, established by Texas Gas, which manages and administers the Pension Plan. The Texas Gas Trust assets are measured at fair value. Equity securities are publicly traded securities which are valued using quoted market prices and are considered Level 1 investments under the fair value hierarchy. Short-term investments that are actively traded or have quoted prices, such as money market funds or treasury bills, are considered Level 1 investments. Fixed income mutual funds include highly liquid government securities and exchange traded bonds, valued using quoted market prices, and are considered Level 1 investments. Tax-exempt securities are valued using a methodology based on information generated by market transactions involving identical or comparable assets, a discounted cash flow methodology or a combination of both when necessary. Common inputs for these securities, which are considered Level 2 investments, include pricing for similar securities, marketplace quotes, benchmark yields, spreads off benchmark yields, interest rates, U.S. Treasury or swap curves and other pricing models utilizing observable inputs.

The following table sets forth, by level within the fair value hierarchy, a summary of the Texas Gas Trust's assets measured at fair value on a recurring basis at December 31, 2025 (in millions):

	Pension Plan Trust Assets			
	Level 1	**Level 2**	**Level 3**	**Total**
Equity securities	**$ 34.4**	**$ —**	**$ —**	**$ 34.4**
Short-term investments	**17.4**	**—**	**—**	**17.4**
Fixed income mutual funds	**31.3**	**—**	**—**	**31.3**
Total assets	**$ 83.1**	**$ —**	**$ —**	**$ 83.1**

The following table sets forth, by level within the fair value hierarchy, a summary of the Texas Gas Trust's assets measured at fair value on a recurring basis at December 31, 2024 (in millions):

	Pension Plan Trust Assets			
	Level 1	Level 2	Level 3	Total
Equity securities	$ 35.9	$ —	$ —	$ 35.9
Short-term investments	8.4	—	—	8.4
Fixed income mutual funds	40.1	—	—	40.1
Total assets	$ 84.4	$ —	$ —	$ 84.4

PBOP

The PBOP plan assets are held in a trust and are measured at fair value. Short-term investments and other assets that are actively traded or have quoted prices, such as money market or mutual funds, are considered Level 1 investments. Fixed income securities, such as tax-exempt securities and corporate bonds, and asset-backed securities are valued using a methodology based on information generated by market transactions involving identical or comparable assets, a discounted cash flow methodology or a combination of both when necessary. Common inputs for these securities, which are considered Level 2 investments, include pricing for similar securities, marketplace quotes, benchmark yields, spreads off benchmark yields, interest rates, U.S. Treasury or swap curves and other pricing models utilizing observable inputs. Other assets and other liabilities are primarily pending sale and purchase transactions for certain investments that were executed on the last day of the year and not settled until the following year.

The following table sets forth, by level within the fair value hierarchy, a summary of the PBOP trust investments measured at fair value on a recurring basis at December 31, 2025 (in millions):

	PBOP Trust Assets			
	Level 1	**Level 2**	**Level 3**	**Total**
Short-term investments	**$ 6.4**	**$ —**	**$ —**	**$ 6.4**
Other assets	**1.6**	**—**	**—**	**1.6**
Asset-backed securities	**—**	**0.4**	**—**	**0.4**
Corporate bonds	**—**	**45.1**	**—**	**45.1**
Tax-exempt securities	**—**	**32.0**	**—**	**32.0**
Total assets	**$ 8.0**	**$ 77.5**	**$ —**	**$ 85.5**
Other liabilities	**(0.7)**	**—**	**—**	**(0.7)**
Total liabilities	**$ (0.7)**	**$ —**	**$ —**	**$ (0.7)**

The following table sets forth, by level within the fair value hierarchy, a summary of the PBOP trust investments measured at fair value on a recurring basis at December 31, 2024 (in millions):

	PBOP Trust Assets			
	Level 1	Level 2	Level 3	Total
Short-term investments	$ 1.6	$ —	$ —	$ 1.6
Other assets	15.7	—	—	15.7
Asset-backed securities	—	0.5	—	0.5
Corporate bonds	—	47.8	—	47.8
Tax-exempt securities	—	34.9	—	34.9
Total assets	$ 17.3	$ 83.2	$ —	$ 100.5
Other liabilities	(18.0)	—	—	(18.0)
Total liabilities	$ (18.0)	$ —	$ —	$ (18.0)

Investment Strategy

Pension Plan: The Company employs a total-return approach using a mix of equities and fixed income securities designed to maximize the long-term return on plan assets for a prudent level of risk and generate cash flows adequate to meet plan requirements. The intent of this strategy is to minimize plan expenses by generating investment returns that exceed the growth of the plan liabilities over the long run. Risk tolerance is established through careful consideration of the plan liabilities, plan funded status and corporate financial conditions. The target allocation of plan assets is 85% of the investment portfolio to equity and fixed income securities, with the remainder primarily invested in cash. Investment risk is monitored through annual liability measurements, periodic asset and liability studies and quarterly investment portfolio reviews.

PBOP: The investment strategy for the PBOP assets is to reduce the volatility of plan investments while protecting the initial investment given the overfunded status of the plan. The Company uses a broad array of public and private assets and investment vehicles to achieve a return that is targeted to meet or exceed the plan blended benchmark indices. At December 31, 2025 and 2024, the investment portfolio contained a diversified blend of fixed income securities, such as tax-exempt securities and corporate bonds, asset-backed securities, short-term securities and other assets.

Defined Contribution Plan

Texas Gas employees hired on or after November 1, 2006, and all other employees of the Company are provided retirement benefits under a defined contribution plan, which also provides 401(k) plan benefits to its participants. Costs related to the Company's defined contribution plan were $15.9 million, $14.7 million and $14.0 million for the years ended December 31, 2025, 2024 and 2023.

Long-Term Incentive Compensation Plans

The 2018 LTIP provides for grants of Performance Awards to selected employees of the Company. A Performance Award is a long-term incentive award with a stated target amount which is payable in cash, after adjustments, upon vesting based on certain specified performance criteria being met. In the case of retirement, any outstanding and unvested awards would become fully vested upon retirement and the Performance Awards will be paid at the original vesting date. In 2025 and 2024, the Company granted to certain employees $15.0 million and $17.2 million of Performance Awards. The Company recorded compensation expense of $15.9 million, $17.1 million and $14.2 million related to Performance Awards for the years ended December 31, 2025, 2024 and 2023, and had $10.2 million and $10.5 million of remaining unrecognized compensation expense related to Performance Awards as of December 31, 2025 and 2024.

Note 13: Income Taxes

The Company is not a taxable entity for federal income tax purposes. The following is a summary of the provision for income taxes (in millions):

	For the Year Ended December 31,		
	2025	2024	2023
Current expense:			
State	**$ 1.2**	$ 0.8	$ 0.8
Deferred provision:			
State	**0.5**	0.3	—
Income taxes	**$ 1.7**	$ 1.1	$ 0.8

The Company's tax years 2022 through 2025 remain subject to examination by the Internal Revenue Service and the states in which it operates. There were no differences between the provision at the statutory rate to the income tax provision at December 31, 2025, 2024 and 2023. As of December 31, 2025 and 2024, there were no significant deferred income tax assets or liabilities.

Note 14: Credit Risk

Major Customers

For the year ended December 31, 2025, the Company earned $237.5 million of operating revenues from one customer which represented approximately 10% of total operating revenues. For the years ended December 31, 2024 and 2023, no customer comprised 10% or more of the Company's operating revenues.

Gas and NGLs Loaned to Customers

Natural gas price volatility can cause changes in credit risk related to gas and NGLs loaned to customers. As of December 31, 2025, the amount of gas owed to the Company's operating subsidiaries due to gas imbalances and gas loaned under PAL and certain firm service agreements was approximately 13.1 trillion British thermal units (TBtu). Assuming an average market price during December 2025 of $3.90 per million British thermal unit (MMBtu), the market value of that gas was approximately $51.1 million. As of December 31, 2025, there were no outstanding NGLs imbalances owed to the Company's operating subsidiaries. As of December 31, 2024, the amount of gas owed to the Company's operating subsidiaries due to gas imbalances and gas loaned under PAL and certain firm service agreements was approximately 9.8 TBtu. Assuming an average market price during December 2024 of $2.98 per MMBtu, the market value of that gas was approximately $29.2 million. As of December 31, 2024, the amount of NGLs owed to the Company's operating subsidiaries due to imbalances was less than 0.1 million barrels, which had a market value of approximately $0.3 million. As of December 31, 2025 and 2024, there were no amounts of ethylene owed to the Company's operating subsidiaries under exchange agreements. If any significant customer should have credit or financial problems resulting in a delay or failure to pay for services provided or repay the gas owed to the operating subsidiaries, it could have a material adverse effect on the Company's financial condition, results of operations and cash flows.

Note 15: Related Party Transactions

Loews provides a variety of corporate services to the Company under services agreements, including risk management, finance and accounting, legal, tax and corporate development services, and charges the Company for allocated overheads. The Company incurred charges related to these services of \$6.0 million, \$5.4 million and \$4.3 million for the years ended December 31, 2025, 2024 and 2023, which were recorded in *Administrative and general* on the Consolidated Statements of Income.

Total distributions paid to BPHC and Boardwalk GP were \$500.0 million, \$400.0 million and \$300.0 million for the years ended December 31, 2025, 2024 and 2023.

Note 16: Supplemental Disclosure of Cash Flow Information (in millions):

	For the Year Ended December 31,		
	2025	2024	2023
Cash paid during the period for:			
Amounts included in the measurement of operating lease liabilities	**$ 3.3**	$ 4.2	$ 4.9
Amounts included in the measurement of finance lease liability	**1.1**	1.1	1.1
Interest (net of amount capitalized)	**150.7**	162.1	147.3
Income taxes, net	**1.6**	0.8	0.7
Non-cash investing activities:			
Accounts payable and PPE	**63.8**	30.4	47.7
Right-of-use asset obtained in exchange for lease obligations	**1.0**	9.9	3.4
Gas stored underground and PPE	**—**	—	47.8

Note 17: Reportable Segments

Identification of Segments

The Company determines its operating and reportable segments based on how the Chief Operating Decision Maker (CODM), who is the Chief Executive Officer, reviews and manages the business, including determining how to allocate resources and assess performance. Every year, the Company completes an assessment of its segment reporting based on information provided to the CODM. Based on this assessment, the Company identified three operating segments in accordance with *ASC 280, Segment Reporting* (ASC 280), consisting of (1) Texas Gas; (2) Gulf South and the Company's other natural gas businesses; and (3) Louisiana Midstream, Boardwalk Petrochemical and Boardwalk Ethane Pipeline Holdco, LLC (collectively, Natural Gas Liquids).

The Company aggregated the Texas Gas operating segment and the Gulf South and the Company's other natural gas businesses operating segment into one reportable segment in accordance with ASC 280, because the Company concluded that: (1) both operating segments had similar economic characteristics; (2) both operating segments had similar product and service lines, customer base, production processes, distribution methods and regulatory environments; and (3) aggregation would be consistent with the objectives and basic principles of ASC 280.

The Company has the following two reportable segments, which comprise 100% of the Company's operating revenues. The segments are generally organized and managed according to products.

- *Natural Gas* (Texas Gas, Gulf South and the Company's other natural gas businesses): This segment consists of the ownership and operation of the Company's interstate and intrastate natural gas pipelines and storage facilities. This segment earns revenues from contracts with customers by providing transportation and storage services for natural gas on a firm and interruptible basis.

- *Natural Gas Liquids:* This segment consists of the ownership and operation of the Company's interstate and intrastate NGLs pipelines and storage facilities and the operations of brine supply services and NGLs marketing activities, which primarily consist of purchases and sales of ethane under supply service agreements. This segment earns revenues from contracts with customers by providing transportation and storage services for NGLs on a firm basis as well as providing brine and ethane supply services.

Measures of Segment Profit or Loss Used

The CODM uses EBITDA to assess each of the Company's segments performance and to determine how to allocate resources. EBITDA is used in the annual budget process and the CODM considers budget-to-actual variances of the segments, which is reviewed at least quarterly, when making decisions about the allocation of operating and capital resources for the segments of the Company. The CODM uses this measure, together with other non-financial measures, such as safety, emissions and reliability initiatives, commercial opportunities and compliance with the Company’s rules and regulations, when assessing performance of the Company and establishing management's compensation.

Segment Expenses and Other Segment Items

The Company provides segment expenses to its CODM on the same basis as the expenses are provided in the Company's income statement and used to calculate EBITDA. The Company accounts for intrasegment sales and transfers as if the sales or transfers were to third parties, or at fair market value.

Information about Reportable Segments

The below tables provide information about the Company's reportable segments as provided to the CODM, including information about segment operating revenues; EBITDA, the performance measure of the Company's segments; significant segment expenses; segment asset information and segment capital expenditures. Interest expense and interest income are not allocated to nor used in the performance measures of the Company's reportable segments. The Company's segments pipeline, storage and other fixed assets are all operated and located within the U.S. and follow the accounting policies as described in Note 2.

Financial information by segment (in millions):

	For the Year Ended December 31, 2025		
	Natural Gas	Natural Gas Liquids	Total
Revenues			
Revenue from external customers	$ 1,540.8	$ 765.0	$ 2,305.8
Intrasegment revenues	50.7	—	50.7
	$ 1,591.5	$ 765.0	$ 2,356.5
Reconciliation of revenues:			
Elimination of intrasegment revenues			(50.7)
Total consolidated revenues			$ 2,305.8
Less:			
Costs associated with service revenues	$ 48.5	$ 19.3	
Costs associated with product sales	—	441.0	
Operation and maintenance	273.6	48.3	
Administrative and general	188.7	28.4	
Taxes other than income taxes	117.3	12.4	
Loss on sale of assets, impairments and other	0.2	—	
Miscellaneous other income, net	(3.9)	—	
Segment EBITDA	$ 967.1	$ 215.6	$ 1,182.7
Reconciliation of profit or loss:			
Depreciation and amortization			$ 438.9
Interest expense			161.2
Interest income			(13.8)
Consolidated income before income taxes			$ 596.4

	For the Year Ended December 31, 2024		
	Natural Gas	Natural Gas Liquids	Total
Revenues			
Revenue from external customers	$ 1,392.7	$ 635.4	$ 2,028.1
Intrasegment revenues	49.4	—	49.4
	$ 1,442.1	$ 635.4	$ 2,077.5
Reconciliation of revenues:			
Elimination of intrasegment revenues			(49.4)
Total consolidated revenues			$ 2,028.1
Less:			
Costs associated with service revenues	$ 41.1	$ 19.0	
Costs associated with product sales	—	303.5	
Operation and maintenance	253.1	57.2	
Administrative and general	176.9	27.6	
Taxes other than income taxes	109.0	13.1	
(Gain) loss on sale of assets, impairments and other	(6.6)	1.1	
Miscellaneous other income, net	(6.1)	—	
Segment EBITDA	$ 874.7	$ 213.9	$ 1,088.6
Reconciliation of profit or loss:			
Depreciation and amortization			$ 424.8
Interest expense			182.9
Interest income			(31.1)
Consolidated income before income taxes			$ 512.0

	For the Year Ended December 31, 2023					
	Natural Gas		Natural Gas Liquids		Total	
Revenues						
Revenue from external customers	$	1,284.7	$	333.0	$	1,617.7
Intrasegment revenues		30.0		—		30.0
	$	1,314.7	$	333.0	$	1,647.7
Reconciliation of revenues:						
Elimination of intrasegment revenues						(30.0)
Total consolidated revenues					$	1,617.7
Less:						
Costs associated with service revenues	$	37.1	$	15.3		
Costs associated with product sales		—		87.8		
Operation and maintenance		229.1		51.9		
Administrative and general		151.7		24.1		
Taxes other than income taxes		106.1		9.4		
Loss on sale of assets, impairments and other		0.3		—		
Miscellaneous other income, net		(4.0)		(0.1)		
Segment EBITDA	$	794.4	$	144.6	$	939.0
Reconciliation of profit or loss:						
Depreciation and amortization					$	408.7
Interest expense						155.6
Interest income						(12.1)
Consolidated income before income taxes					$	386.8

Segment assets include *Property, plant, and equipment – net, Intangible assets – net of accumulated amortization* and *Goodwill*. The following table reflects segment assets and a reconciliation to *Total Assets* (in millions):

	As of December 31,			
	2025		2024	
Natural Gas	**$**	**7,591.2**	$	7,490.1
Natural Gas Liquids		**1,483.8**		1,628.7
Total Segment Assets		**9,075.0**		9,118.8
Total current assets		**1,179.7**		401.1
Gas stored underground and Other assets		**258.7**		259.5
Total Assets	**$**	**10,513.4**	$	9,779.4

The following table reflects capital expenditures by segment (in millions):

	For the Year Ended December 31,					
	2025		2024		2023	
Natural Gas	**$**	**320.3**	$	340.6	$	321.5
Natural Gas Liquids		**33.6**		51.8		60.9
Total	**$**	**353.9**	$	392.4	$	382.4

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedure*s*

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. Our disclosure controls and procedures are designed to allow timely decisions regarding required disclosure and to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2025, at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended December 31, 2025, that have materially affected or that are reasonably likely to materially affect our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting for us. Our internal control system was designed to provide reasonable assurance regarding the preparation and fair presentation of our published financial statements.

There are inherent limitations to the effectiveness of any control system, however well designed, including the possibility of human error and the possible circumvention or overriding of controls. 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. Management must make judgments with respect to the relative cost and expected benefits of any specific control measure. The design of a control system is also based in part upon assumptions and judgments made by management about the likelihood of future events, and there can be no assurance that a control will be effective under all potential future conditions. As a result, even an effective system of internal control over financial reporting can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2025. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework (2013*). Based on this assessment, our management believes that, as of December 31, 2025, our internal control over financial reporting was effective.

Item 9B. Other Information

Not applicable.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

We are omitting disclosure under this item because we meet the conditions set forth in General Instructions I(1) (a) and (b) of Form 10-K.

Item 11. Executive Compensation

We are omitting disclosure under this item because we meet the conditions set forth in General Instructions I(1) (a) and (b) of Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

We are omitting disclosure under this item because we meet the conditions set forth in General Instructions I(1) (a) and (b) of Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

We are omitting disclosure under this item because we meet the conditions set forth in General Instructions I(1) (a) and (b) of Form 10-K.

Item 14. Principal Accountant Fees and Services

Audit Fees and Services

Deloitte & Touche LLP (Deloitte & Touche) (PCAOB ID No. 34) has served as our auditor since our inception in 2005 and our predecessors' auditor from 2003 to 2005. The following table presents fees billed by Deloitte & Touche and its affiliates for professional services rendered to us and our subsidiaries in 2025 and 2024 by category as described in the notes to the table (in millions):

	2025	2024
Audit fees [1]	**$ 3.3**	$ 3.1
Audit related fees [2]	**—**	—
Total	**$ 3.3**	$ 3.1

(1) Includes the aggregate fees and expenses for annual financial statement audit and quarterly financial statement reviews, including comfort letters.

(2) Includes the aggregate fees and expenses for services that were reasonably related to the performance of the financial statement audits or reviews described above and not included under Audit fees above.

Auditor Engagement Pre-Approval Policy

We are a wholly owned indirect subsidiary of Loews, and the Loews Audit Committee has responsibility for the appointment, compensation and oversight of the independent external audit firm retained to audit our financial statements and the audit fee negotiations associated with their retention. To assure the continued independence of our independent auditor, Deloitte & Touche, the Loews Audit Committee has adopted a policy requiring its pre-approval of all audit and non-audit services performed for us and our subsidiaries by the independent auditor. Under this policy, the Loews Audit Committee annually pre-approves certain limited, specified recurring services that may be provided by Deloitte & Touche, subject to maximum dollar limitations. All other engagements for services to be performed by Deloitte & Touche are specifically pre-approved by the Loews Audit Committee or a designated committee member to whom this authority had been delegated.

Under that policy, the Loews Audit Committee, or a designated member, pre-approved all engagements by us and our subsidiaries for services of Deloitte & Touche during 2025, including the terms and fees thereof, and the Loews Audit Committee concluded that all such engagements were compatible with the continued independence of Deloitte & Touche in serving as our independent auditor.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1. Financial Statements

Included in Item 8 of this Annual Report on Form 10-K:

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets at December 31, 2025 and 2024

Consolidated Statements of Income for the years ended December 31, 2025, 2024 and 2023

Consolidated Statements of Comprehensive Income for the years ended December 31, 2025, 2024 and 2023

Consolidated Statements of Cash Flows for the years ended December 31, 2025, 2024 and 2023

Consolidated Statements of Changes in Partners' Capital for the years ended December 31, 2025, 2024 and 2023

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules

Schedule II not material.

(a) 3. Exhibits

The following documents are filed or furnished as exhibits to this report:

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Boardwalk Pipeline Partners, LP (Incorporated by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on August 16, 2005).
3.2	Fourth Amended and Restated Agreement of Limited Partnership of Boardwalk Pipeline Partners, LP dated as of July 19, 2018 (Incorporated by reference to Exhibit 3.2 to the Registrant's Annual Report on Form 10-K filed on February 13, 2019).
4.1	Indenture dated July 15, 1997, between Texas Gas Transmission Corporation (now known as Texas Gas Transmission, LLC) and The Bank of New York, as Trustee (Incorporated by reference to Exhibit 4.1 to Texas Gas Transmission Corporation's Registration Statement on Form S-3, Registration No. 333-27359, filed on May 19, 1997).
4.2	Fifth Supplemental Indenture to the indenture dated August 21, 2009, among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on May 20, 2016).
4.3	Sixth Supplemental Indenture to the indenture dated August 21, 2009, by and among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to Boardwalk Pipeline Partners, LP's Current Report on Form 8-K, filed on January 12, 2017).
4.4	Seventh Supplemental Indenture to the indenture dated August 21, 2009, by and among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to Boardwalk Pipeline Partners, LP's Current Report on Form 8-K, filed on May 6, 2019).
4.5	Eighth Supplemental Indenture to the indenture dated August 21, 2009, by and among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to Boardwalk Pipeline Partners, LP's Current Report on Form 8-K, filed on August 12, 2020).
4.6	Ninth Supplemental Indenture to the indenture dated August 21, 2009, by and among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to Boardwalk Pipeline Partners, LP's Current Report on Form 8-K, filed on February 17, 2022).
4.7	Tenth Supplemental Indenture, dated February 15, 2024, by and among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to Boardwalk Pipeline Partners, LP’s Current Report on Form 8-K, filed on February 16, 2024).
4.8	Eleventh Supplemental Indenture, dated November 24, 2025, by and among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to Boardwalk Pipeline Partners, LP’s Current Report on Form 8-K, filed on November 24, 2025).
10.1	Services Agreement dated as of May 16, 2003, by and between Loews Corporation and Texas Gas Transmission, LLC (Incorporated by reference to Exhibit 10.8 to Amendment No. 3 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on October 24, 2005). (1)

Exhibit Number	Description
10.2	Fourth Amended and Restated Revolving Credit Agreement, dated as of November 10, 2025, among Boardwalk Pipelines, LP, Texas Gas Transmission, LLC and Gulf South Pipeline Company, LLC, as borrowers, Boardwalk Pipeline Partners, LP, as guarantor, the several lenders and issuers party thereto, Wells Fargo Bank, N.A., as administrative agent, Barclays Bank PLC, Citibank, N.A., JPMorgan Chase Bank, N.A., MUFG Bank, Ltd., Regions Bank, Truist Bank, U.S. Bank National Association, Bank of America, N.A., and Sumitomo Mitsui Banking Corporation, as co-syndication agents, and Wells Fargo Securities, LLC, Barclays Bank PLC, Citibank, N.A., J.P. Morgan Chase Bank, N.A., MUFG Bank, Ltd., Regions Capital Markets, a division of Regions Bank, Truist Securities, Inc., U.S. Bank National Association, BOFA Securities, Inc., and Sumitomo Mitsui Banking Corporation, as joint lead arrangers and joint bookrunners (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on November 12, 2025).
*22.1	Subsidiary Issuers and Guarantors of Registered Securities.
*23.1	Consent of Independent Registered Public Accounting Firm.
*31.1	Certification of Scott A. Hallam, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities and Exchange Act of 1934, as amended.
*31.2	Certification of Steven A. Barkauskas, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities and Exchange Act of 1934, as amended.
**32.1	Certification of Scott A. Hallam, Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**32.2	Certification of Steven A. Barkauskas, Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
*101.SCH	Inline XBRL Taxonomy Extension Schema Document
*101.CAL	Inline XBRL Taxonomy Calculation Linkbase Document
*101.DEF	Inline XBRL Taxonomy Extension Definitions Document
*101.LAB	Inline XBRL Taxonomy Label Linkbase Document
*101.PRE	Inline XBRL Taxonomy Presentation Linkbase Document
*104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

* Filed herewith
** Furnished herewith

(1) The Services Agreements between Gulf South Pipeline Company, LP (now known as Gulf South Pipeline Company, LLC) and Loews Corporation and between Boardwalk Pipelines, LP (formerly known as Boardwalk Pipelines, LLC) and Loews Corporation are not filed because they are identical to Exhibit 10.1 except for the identities of Gulf South Pipeline Company, LLC and Boardwalk Pipelines, LLC and the date of the agreement.

Item 16. Form 10-K Summary

We are omitting disclosure under this item as it is provided elsewhere in this Report.

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.

Boardwalk Pipeline Partners, LP

By: Boardwalk GP, LP
its general partner

By: Boardwalk GP, LLC
its general partner

Dated: February 10, 2026 By: *<u>/s/ Steven A. Barkauskas</u>*

Steven A. Barkauskas
Senior Vice President, Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

Dated: February 10, 2026	*<u>/s/ Scott A. Hallam</u>* Scott A. Hallam President, Chief Executive Officer and Director (principal executive officer)
Dated: February 10, 2026	*<u>/s/ Steven A. Barkauskas</u>* Steven A. Barkauskas Senior Vice President, Chief Financial Officer and Director (principal financial officer)
Dated: February 10, 2026	*<u>/s/ Christine Fernandez</u>* Christine Fernandez Vice President, Controller and Chief Accounting Officer (principal accounting officer)
Dated: February 10, 2026	*<u>/s/ Michael E. McMahon</u>* Michael E. McMahon Senior Vice President, Chief Legal and Regulatory Officer and Director
Dated: February 10, 2026	*<u>/s/ Kenneth I. Siegel</u>* Kenneth I. Siegel Director, Chairman of the Board
Dated: February 10, 2026	*<u>/s/ Marc A. Alpert</u>* Marc A. Alpert Director
Dated: February 10, 2026	*<u>/s/ Stanley C. Horton</u>* Stanley C. Horton Director
Dated: February 10, 2026	*<u>/s/ Benjamin J. Tisch</u>* Benjamin J. Tisch Director
Dated: February 10, 2026	*<u>/s/ Jane Wang</u>* Jane Wang Director

EXHIBIT 22.1

Subsidiary Issuers and Guarantors of Registered Securities

Subsidiary Issuer	**Guarantor**
Boardwalk Pipelines, LP 5.95% Notes due 2026	Boardwalk Pipeline Partners, LP
Boardwalk Pipelines, LP 4.45% Notes due 2027	Boardwalk Pipeline Partners, LP
Boardwalk Pipelines, LP 4.80% Notes due 2029	Boardwalk Pipeline Partners, LP
Boardwalk Pipelines, LP 3.40% Notes due 2031	Boardwalk Pipeline Partners, LP
Boardwalk Pipelines, LP 3.60% Notes due 2032	Boardwalk Pipeline Partners, LP
Boardwalk Pipelines, LP 5.625% Notes due 2034	Boardwalk Pipeline Partners, LP
Boardwalk Pipelines, LP 5.375% Notes due 2036	Boardwalk Pipeline Partners, LP

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-274067 on Form S-3 of our report dated February 10, 2026, relating to the financial statements of Boardwalk Pipeline Partners, LP appearing in this Annual Report on Form 10-K for the year ended December 31, 2025.

/s/ *Deloitte & Touche LLP*
Houston, Texas
February 10, 2026

EXHIBIT 31.1

I, Scott A. Hallam, certify that:

1) I have reviewed this Annual Report on Form 10-K of Boardwalk Pipeline Partners, LP;
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.

Dated: February 10, 2026

<u>/s/ Scott A. Hallam</u>
Scott A. Hallam
President and Chief Executive Officer

EXHIBIT 31.2

I, Steven A. Barkauskas, certify that:

1) I have reviewed this Annual Report on Form 10-K of Boardwalk Pipeline Partners, LP;
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.

Dated: February 10, 2026 *<u>/s/ Steven A. Barkauskas</u>*

Steven A. Barkauskas

Senior Vice President, Chief Financial Officer

EXHIBIT 32.1

Certification by the Chief Executive Officer
of
Boardwalk GP, LLC
pursuant to 18 U.S.C. Section 1350
(as adopted by Section 906 of the Sarbanes-Oxley Act of 2002)

Pursuant to 18 U.S.C. Section 1350, the undersigned chief executive officer of Boardwalk GP, LLC hereby certifies, to such officer's knowledge, that the annual report on Form 10-K for the year ended December 31, 2025, (the Report) of Boardwalk Pipeline Partners, LP (the Company) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 10, 2026

/s/ Scott A. Hallam
Scott A. Hallam
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.2

Certification by the Chief Financial Officer
of
Boardwalk GP, LLC
pursuant to 18 U.S.C. Section 1350
(as adopted by Section 906 of the Sarbanes-Oxley Act of 2002)

Pursuant to 18 U.S.C. Section 1350, the undersigned chief financial officer of Boardwalk GP, LLC hereby certifies, to such officer's knowledge, that the annual report on Form 10-K for the year ended December 31, 2025, (the Report) of Boardwalk Pipeline Partners, LP (the Company) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 10, 2026

/s/ Steven A. Barkauskas
Steven A. Barkauskas
Senior Vice President, Chief Financial Officer
(principal financial officer)