INTRODUCTION AND BACKGROUND

This planning document pertains to the natural gas distribution operations of Dominion Energy, Inc. that are subject to the jurisdictions of the Utah and Wyoming Commissions. The natural gas utility providing service in Utah, Wyoming and Idaho is referred to herein as “Dominion Energy” or the “Company”.

The Company’s Utah, Wyoming, and Idaho natural gas service territories continue to experience strong customer growth of over 2% per year. The Company reached the one-million-customer mark during September of 2016.

Federal government actions have had a significant impact on the natural gas industry, and, indirectly, upon the Company. Since the beginning of his administration, President Trump has advocated for tax cuts. As a result, on December 22, 2017, the Tax Cuts and Jobs Act (TCJA) was signed into law. A major component of this act was to reduce the corporate federal income tax from 35% to 21%, starting January 1, 2018. On December 21, 2017, the Utah Commission opened Docket No. 17-057-26 to investigate the revenue requirement impact of the TCJA and ordered the Company to file comments by January 31, 2018, describing the impacts of the TCJA on the Company’s revenue requirement. The Company complied with this requirement. On Wednesday May 16, 2018 parties in this docket filed a stipulation resolving all of the issues. This stipulation was approved by the Commission on May 24, 2018. Effective June 1, 2018 rates will be reduced by $18.5 million per year to reflect the reduction in income tax expense.

In addition to the impacts on customer rates that have occurred due to tax reform, the Trump Administration will also leave its mark on the Federal Energy Regulatory Commission (FERC). The FERC regulates, among other things, the interstate natural gas pipeline system used to deliver natural gas to local distribution companies in the U.S., including those upstream pipelines that deliver supplies to the Company. The FERC consists of five members appointed by the President of the United States with the advice and consent of the Senate. By rule, not more than three members of the FERC may come from the President’s party. All have an equal vote and the President selects the Chairman. The FERC requires at least three members to operate as a quorum.

Several developments, one of which is historic, have taken place in the composition of the FERC over the last two years. In January of 2016, Commissioner Tony Clark, the lone Republican, announced that he would not seek a new term. His term ran through June of 2016 and he extended his departure date to the end of September 2016. The loss of Commissioner Clark left the FERC with three members, the minimum necessary to operate as a quorum.

During January of 2017, President Trump appointed Commissioner Cheryl LaFleur as Acting Chairman of the Commission. Also in January 2017, Chairman Norman Bay left the Commission abruptly. This left the FERC with just two members, Acting Chairman LaFleur and Commissioner Collette Honorable. For the first time in the nearly 40-year existence of the FERC, the Commission was without a quorum. Further complicating matters, Commissioner Honorable announced, on April 28, 2017, that she would not seek another term with the FERC after the expiration of her term on June 30, 2017.

Prior to the departure of Chairman Bay, the Commission expedited dozens of orders and clarified the delegated authority of Commission staff to process certain filings. During early February of 2017, Acting Chairman LaFleur canceled the regular monthly open meetings of the FERC until further notice. The lack of a quorum effectively brought to a halt the approval process necessary to provide critically needed energy infrastructure for the U.S.

On May 8, 2017, President Trump announced his intent to nominate two individuals to fill vacancies in the FERC. The nominees are Neil Chatterjee, energy advisor to Senate Majority Leader Mitch McConnell, and Robert Powelson, President of the National Association of Regulatory Utility Commissioners.[3] The Senate confirmed both nominees on August 4, 2017.[4] The confirmation of these two nominees reconstituted a quorum.

On November 2, 2017 the Senate confirmed the final two members of the FERC, Kevin McIntyre, co-leader of the global Energy Practice at the law firm Jones Day, and Richard Glick, general counsel for the Democrats on the Senate Energy and Natural Resources Committee. Mr. McIntyre serves as Chairman of the Commission.[5]

In a surprise move, on March 15, 2018 the FERC issued a Revised Policy Statement that eliminates a Master Limited Partnership's (MLP) ability to recover an income tax allowance in its cost of service. In response to this change, along with the new tax rates in the Tax Cuts and Jobs Act, the FERC proposed to require all interstate natural gas pipelines to file a section 4 rate case, reducing rates, or justifying current rates. If a pipeline chooses not to reduce rates, the FERC will consider ordering the pipeline into a section 5 rate case, requiring the pipeline to either reduce its rates or explain why it should not be required to do so.[6]

Also on March 15, 2018, Dominion Energy Overthrust Pipeline, LLC (Overthrust) was called into a Section 5 rate case. The FERC calculated Overthrust's return on equity (ROE) for years 2015 and 2016 to be 23.4 and 19.9 percent respectively. Overthrust is included in an MLP and based on the Revised Policy Statement will not be permitted to recover an income tax allowance in its cost of service in the future. The FERC recalculated Overthrust's ROE excluding the income tax allowance for 2015 and 2016. The recalculated ROEs would have been 36.4 and 30.9 percent, respectively. Based on these findings, the FERC is initiating an investigation to examine the justness and reasonableness of Overthrust's rates.[7]

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[3] "President Donald J. Trump Announces Intent to Nominate Personnel to Key Administration Posts," The White House, Office of the Press Secretary, May 8, 2017.
[4] "Senate Confirms Chatterjee, Powelson to FERC," News Releases, Federal Energy Regulatory Commission, August 4, 2017.
[5] "Senate Confirms McIntyre, Glick to FERC," News Release, Federal Energy Regulatory Commission, November 2, 2017.

[6] "Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Federal Income Tax Rate," 162 FERC ¶ 61,226, Federal Energy Regulatory Commission, March, 15 2018.
[7] "Order Instituting Investigation and Setting Matter for Hearing Procedures Pursuant to Section Five of the Natural Gas Act," 162 FERC ¶ 61,218, Federal Energy Regulatory Commission, March, 15 2018.

On March 28, 2017, in a widely expected move, the Trump Administration issued an executive order beginning the process of rescinding some of the climate-change policies of the previous administration. The order, entitled "Presidential Executive Order on Promoting Energy Independence and Economic Growth," promotes clean and safe development of U.S. energy resources. The order required all executive departments and agencies to immediately begin reviewing existing regulations that burden the development of domestic energy resources beyond the degree necessary to protect the public interest and comply with the law. Of particular interest to the energy industry is the specific requirement in the order for the U.S. Environmental Protection Agency (EPA) to review the Clean Power Plan for consistency with the presidential order.

The Clean Power Plan may have been the most ambitious initiative ever undertaken by the EPA. Regardless of the outcome of the plan, however, it is apparent that fundamental changes in the mix of power generating fuels have been taking place and will continue to take place in the U.S. That shift will move the industry generally away from the use of coal towards more environmental-friendly fuel sources.

On October 10, 2017, the EPA proposed to repeal the Clean Power Plan and a change in the legal interpretation of section 111(d) of the Clean Air Act, on which the Clean Power Plan was based. The EPA accepted comments on the proposed repeal until April 26, 2018.[8] Following the EPA's review of public comments, the repeal of the Clean Air Act will be final sometime later this year.

In a separate but related action to the proposed repeal of the Clean Power Plan, the EPA issued an Advance Notice of Proposed Rulemaking (ANPRM) to solicit public input about a potential future rulemaking to limit greenhouse gas emissions from existing power plants. The ANPRM seeks information on the roles and responsibilities of States and the EPA in regulating existing power plants for greenhouse gas emissions. It also seeks information on how to best define the "Best System of Emission Reduction" and develop emission guidelines for existing power plants.[9]

During 2017, 24 gigawatts (GW) of electric generating capacity was added to the U.S. power grid. Capacity retirements during 2017 totaled approximately 11 GW leaving a net gain of approximately 13 GW. The top three 2016 electric-capacity additions consisted of natural gas (9.3 GW), solar (8.2 GW) and wind (6.3 GW).[10]

In 2017, natural-gas-fired generation continued to exceed coal-fired generation in the U.S. on an annual basis. As a percentage of all energy sources, natural gas comprised 31.7% and coal comprised 30.1%.[11] The U.S. Energy Information Administration (EIA) expects that

[8] "Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 82 Fed. Reg. 48,035, U.S. Environmental Protection Agency, Docket EPA-HQ-OAR-2017-0355, October 10, 2017.
[9] "State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units," 82 Fed. Reg. 61,507, U.S. Environmental Protection Agency, Docket EPA-HQ-OAR-2017-0545, December 18, 2017.
[10] "Electricity generation from fossil fuels declined in 2017 as renewable generation rose," Today in Energy, U.S. Energy Information Administration, March 20, 2018.
[11] "Table ES1.B. Total Electric Power Industry Summary Statistics, Year-to-Date 2016 and 2017," Electric

additions of utility-scale natural-gas-fired generating capacity to the power grid during 2018 will total more than 20 GW, which would be the largest increase in capacity since 2004.[12]

Recent EIA data indicates that energy-related CO_2 emissions in the U.S., during calendar year 2016, totaled 5.15 billion metric tons, a decline of 0.7% from the 2016 level of 5.19 billion metric tons. Energy related CO_2 emissions peaked in 2007 at a level of 6.01 billion metric tons. The 2017 level is over 14% below the 2007 level.[13] The general decline from 2007 is largely attributed to weakness in the economy due to the recession, improving energy efficiency, increased use of renewables, and growing use of abundant natural gas. The replacement of coal-fired power generation with generation from less carbon-intensive natural gas has been fundamental to the general decline over the last nine years.[14]

Notwithstanding a recent rebound in natural gas prices, the energy price environment remains relatively weak. Natural gas prices began declining in early 2014. The average Henry Hub price during the month of February 2014 was $6.00 per Dth. By March of 2016, the average monthly Henry Hub price had declined to a low of $1.73 per Dth. By December of 2016, the average monthly Henry Hub price had recovered to $3.59 per Dth, the highest average monthly price since November of 2014. 2017 prices hovered near the average of $3.01 per Dth. The average Henry Hub price for April of 2018 stood at a level of $2.00 per Dth.

During 2017, natural gas spot prices averaged $3.01 per Dth at Henry Hub, about 50 cents higher than 2016. Overall, natural gas prices were less volatile in 2017 than in previous years. Warmer winter weather and new pipeline capacity in the Northeast contributed to the decreased volatility; however, record cold temperatures in the east during the end of December led to significant price spikes. Higher prices led to decreased natural gas consumption for power generation. This decrease was offset by increased exports to Mexico and via LNG exports.[15]

Regional prices at the Opal, Wyoming hub were also steady during 2017, hovering near the average of $2.70 per Dth. The 2017/2018 heating season reached a peak of $5.29 per Dth on January 4, 2018 due to cold weather in the Eastern United States. On May 16, 2018, the average daily mid-point price at Opal was $1.790 per Dth.

In recent months the Henry Hub natural gas futures forward curve had prices increasing from the high $2.00 per Dth range during the summer months of 2018 to the mid $3.00 per Dth range during the winter of 2018-2019. After this point in time, the forward

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Power Monthly with Data for December 2017, U.S. Energy Information Administration, Department of Energy, February 2018.

[12] "EIA forecasts natural gas to remain primary energy source for electricity generation," Today in Energy, U.S. Energy Information Administration, January 22, 2018.

[13] "March 2018 Monthly Energy Review," U.S. Energy Information Administration, U.S. Department of Energy, Released: March 27, 2018.

[14] "U.S. energy-related CO2 emissions expected to rise slightly in 2018, remain flat in 2019," Today in Energy, U.S. Energy Information Administration, February 18, 2018.

[15] "Natural gas prices, production, and exports increased from 2016 to 2017," Today in Energy, Energy Information Administration, U.S. Department of Energy, January 16, 2018.

curve is projected to swing seasonally for the next two years from the low $3.00 per Dth range during the summers to the mid $3.00 per Dth range during the winters.[16]

According to the EIA, natural gas production in the Lower 48 states increased in 2017 due to slightly higher prices. Lower-48 production averaged 82.61 Bcf/D in 2017, a 2.8% increase from 2016. This increase surpassed the all-time natural gas production record set in 2015.[17]

The recent increase in natural gas prices has had an impact on the rig count. The oil field services company, Baker Hughes, monitors and publishes drilling rig data. Since Baker Hughes began tracking rig data in 1987, the highest weekly gas-directed rotary rig count for North America occurred during August and September of 2008 when the peak reached 1,606 rigs on two occasions. On two other separate occasions during August of 2016, the gas-directed rig count dropped to an all-time low of 81 rigs. By May 11, 2018, the gas-direct rig count had recovered to a level of 199. Due to the greater economic interest in oil, the gas directed rig count at this point in time is only about 19% of the total rigs in operation[18]

According to the law firm of Haynes and Boone, from the beginning of 2015 through March 30, 2018, 144 North American oil and gas producers filed for bankruptcy. These cases involve approximately $90 billion in cumulative secured and unsecured debt. It is likely that more producer bankruptcy filings will be made during the remainder of 2018 although it appears that the filing rate is slowing this year due perhaps to improving commodity prices. During 2015, 44 oil and gas producers filed for bankruptcy, during 2016, 70 filed for bankruptcy, during 2017, 24 filed for bankruptcy, and as of March 30th, only six more companies have filed during 2018.[19]

During February of 2018, the EIA released its annual report on natural gas proved reserves for the 2016 calendar year. On February 15, 2018, the EIA reported that U.S. proved reserves of natural gas at year-end 2016 were 341.1 Tcf. This level was 16.8 Tcf higher than the 2015 level, an increase of approximately 5%. The increase in 2016 end-of-year reserves was a result of increased reserves in shale formations, including the Wolfcamp, Marcellus, Eagle Ford, Utica, Woodford, and Haynesville shales. Proved reserves are estimated volumes of natural gas from known reservoirs that geologic and engineering data demonstrate with reasonable certainty to be recoverable under existing economic and operating conditions.[20]

Total U.S. discoveries during 2016 totaled 38.4 Tcf, primarily extensions to existing natural gas fields. By source, the 38.4 Tcf discovered in 2016, can be broken down as 32.3 Tcf from shale formations (84.1%) and 6.1 Tcf from conventional and other tight formations (15.9%). Texas continues to have the largest proved natural gas reserves, followed by

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[16] "EIA expects 2018 and 2019 natural gas prices to remain relatively flat," Today in Energy, Energy Information Administration, U.S. Department of Energy, January 25, 2018.
[17] "By some measures, U.S. natural gas production set a record in 2017," Today in Energy, Energy Information Administration, U.S. Department of Energy, April 10, 2018.
[18] "North America Rig Count Current Week Data," Baker Hughes, http://www.bhge.com/, April 6, 2018.
[19] "Oil Patch Bankruptcy Monitor," Haynes and Boone, LLP, March 31, 2018.
[20] "U.S. proved reserves of natural gas up in 2016, oil reserves remained unchanged," Today in Energy, Energy Information Administration, U.S. Department of Energy, Steve Grape, February 15, 2018.

Pennsylvania, Oklahoma, West Virginia, and Wyoming. During 2016, Pennsylvania added 6.1 Tcf as a result of development in the Marcellus shale play, the largest increase of any state.[21]

Each year, the EIA tracks, throughout the country, the design capacity of natural gas storage facilities at the beginning of the traditional injection season. The total working-gas design capacity in the Lower 48 states during the period from November 2016 to November 2017 increased slightly from 4,691 Bcf to 4,725 Bcf. Since November 2013, total working-gas design capacity has been relatively flat. For the fourth consecutive year, no new underground storage facilities initiated operations in the U.S. The majority of the capacity increase was due to expansions at existing facilities in Ohio (21 Bcf) and West Virginia (8 Bcf). A facility in Colorado also expanded its capacity by 4 Bcf, increasing the total mountain region capacity to 466 Bcf.[22]

The 2017 storage injection season began in April with 2,064 Bcf in working gas storage. By the end of the traditional injection season at the end of October national working gas storage volumes were 3,817 Bcf. The traditional 2017 injection season had net injections of 1,753 Bcf. By comparison, net injections for the 2016 traditional injection season totaled 1,543 Bcf.[23] By the end of the 2017-2018 traditional withdrawal season, on March 30, 2018, the lower-48 inventory level stood at 1,383 Bcf. This level was 697 Bcf lower than the same time last year and was 347 Bcf or 20.4% below the five year average.[24]

The Company discusses its use of natural gas storage facilities in the Gathering, Transportation, and Storage section of this report.

The FERC Office of Energy Projects issues a monthly Energy Infrastructure Update. During calendar year 2017, the FERC certificated 30.8 Bcf/D of pipeline capacity, up from 18.2 Bcf/D in 2016. The miles of pipeline certificated during 2017 was 1.7 times the level certificated during 2016, and compression, in horsepower, certificated in 2017, was 2.3 times that certificated during the previous year. Pipeline capacity actually placed in service increased from 7.1 Bcf/D in 2016 to 12.0 Bcf/D in 2017. The miles of pipeline placed in service also increased from 391.7 miles in 2016 to 773.0 in 2017.[25] In explaining the differences between certificated and placed-in-service metrics, a FERC spokesperson cited the lag for construction activities (possibly two to three years). In addition, the spokesperson indicated that other holdups can occur such as those faced by Williams' Constitution Pipeline project and Dominion Energy, Inc.'s New Market Project in New York.[26]

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[21] "U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2016," U.S. Energy Information Administration, U.S. Department of Energy, February, 2018. Components may not add to totals due to independent rounding.

[22] "Underground Natural Gas Working Storage Capacity," Energy Information Administration, U.S. Department of Energy, Release Date: March 30, 2018.

[23] "Table 9. Underground natural gas storage – by season, 2016 – 2018," Natural Gas Monthly, Energy Information Administration, U.S. Department of Energy, March 2018.

[24] "Weekly Natural Gas Storage Report," Energy Information Administration, U.S. Department of Energy, For the week ending March 30, 2018, Released April 5, 2018.

[25] "Energy Infrastructure Update For December 2017," Federal Energy Regulatory Commission, Office of Energy Projects, Released February 6, 2018.

[26] "Rapid pipeline growth continues in 2016: FERC," Gas Daily, Platts McGraw Hill Financial, February 3, 2017, pages 6 and 7.

In 2017, the U.S. became a net exporter of natural gas for the first time. This trend was reinforced by the rebound of natural gas production in 2017. The EIA expects exports to continue to increase through the 2020s as more LNG export terminals come online.[27] Export capacity from the Lower 48 states increased to 2.8 billion cubic feet per day (Bcf/d) following the completion of the fourth liquefaction train at the Sabine Pass facility near the Texas/Louisiana border. The fifth train is under construction. Dominion Energy's Cove Point facility was complete in early 2018 and shipped its first commercial shipment of LNG on April 16, 2018. Other LNG facilities currently under construction are: Cheniere Energy's Corpus Christi facility in Texas, Sempra Energy's Cameron terminal in Louisiana, Freeport LNG's facility in Texas, and most recently, Kinder Morgan's Elba Island facility in Georgia.[28] As of April 2018, 15 U.S. LNG export facilities had been proposed to the FERC. Of those proposals, 12 are pending applications and 3 are projects in the pre-filing phase. One additional facility had been proposed to the U.S.-MARAD/Coast Guard in the Gulf of Mexico.[29]

The proposed Jordan Cove LNG export facility on the Oregon coast is of particular interest to the Company because the addition of this facility could impact prices in the Rockies. Veresen Inc., the developer of Jordan Cove, acquired a 50% interest in the Ruby Pipeline in 2014. The Ruby Pipeline extends from the Opal Hub in Wyoming to the Malin Hub in Oregon and crosses the Company's northern service territory. The Company regularly purchases natural gas at the Opal Hub. The Ruby Pipeline provides direct access to the Jordan Cove LNG facility through the proposed Pacific Connector Gas Pipeline.

On March 11, 2016, the FERC rejected the Pacific Connector pipeline and consequently the Jordan Cove LNG project on the grounds that the applicant had not adequately demonstrated a market need. The FERC specified that its decision was issued without prejudice and that the developers could submit a new application to construct the facilities in the future if they are able to show a market need for the project.[30] Less than two weeks after the FERC Order, Veresen announced that it had signed a long-term capacity agreement for the Jordan Cove facility with a Tokyo-based electric utility joint venture. The agreement includes the purchase of approximately one quarter of the 6 million-tons-per-annum liquefaction capacity of the facility.[31] On April 8, 2016, Veresen filed an application with the FERC requesting a rehearing related to the pipeline and LNG projects, citing recently-executed precedent agreements for more than 75% of the Pacific Connector Pipeline

[27] "U.S. Natural Gas Production and Consumption increase in Nearly All AEO 2018 Cases," Today in Energy, Energy Information Administration, U.S. Department of Energy, April 16, 2018.
[28] "U.S. Liquefied Natural Gas Exports Have Increased as New Facilities Come Online," Natural Gas Weekly, Energy Information Administration, U.S. Department of Energy, December 7, 2017.
[29] "Proposed North American LNG Export Terminals: As of April 23, 2018," Federal Energy Regulatory Commission, Natural Gas Industry, Updated April 25, 2018.
[30] "Order Denying Applications for Certificate and Section 3 Authorization," Federal Energy Regulatory Commission, Jordan Cove Energy Project, L.P., Docket No. CP13-483-000, Pacific Connector Gas Pipeline, Docket No. CP13-492-000, Issued March 11, 2016.
[31] "Jordan Cove in offtake deal with JERA," Gas Daily, Platts McGraw Hill Financial, March 24, 2016, Pages 6 and 7.

project and more than 50% of the initial design capacity of the LNG facility.[32] The FERC denied the request to reopen the record to allow the inclusion of these long-term agreements.

In early 2017, Veresen met with FERC Staff to discuss the project and its refiling plan. On January 23, 2017, Veresen submitted its Request for Approval of Pre-Filing Review for the Jordan Cove Energy Project and the Pacific Connector Gas Pipeline. Veresen indicated that it intended to file applications on or about August 30, 2017. On February 10, 2017, the FERC issued its approval of Veresen's pre-filing request.[33] On September 21, 2017, Veresen filed its applications requesting the FERC issue a Final Environmental Impact Statement by August 2018 and authorizations and waivers by November 2018 in order to meet a planned fourth quarter 2022 in-service date.[34] Veresen was subsequently purchased by Pembina Pipeline Corporation on October 2, 2017.[35]

Data from the EIA suggests that some 9.6 Bcf/D of liquefaction capacity will be available at US export facilities by the end of 2019. From February of 2017, export capacity has grown from approximately 2.1 Bcf/D to 3.6 Bcf/D in early 2018.[36] While some are concerned about an excess of capacity in the future, producers are optimistic that the world market for US LNG will continue to grow, at least in the short term. The EIA expects LNG exports to make up a growing share of natural gas exports surpassing pipeline exports of natural gas by 2020.[37]

The Company further discusses its use of interstate pipeline capacity and its interest in LNG liquefaction and storage facilities in the Gathering, Transportation, and Storage and Supply Reliability sections of this document.

Wexpro II Agreement and Gas-Producing Property Acquisitions

Over the course of approximately 35 years, the Company's customers have benefited from supplies delivered at cost-of-service to the Company pursuant to the Wexpro Agreement.[38] Beginning in the fall of 2011, the Company, Dominion Energy Wexpro (Wexpro), and regulatory agencies in Utah and Wyoming began discussing the possibility of

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[32] "Request for Rehearing of Jordan Cove Energy Project, L.P. and Pacific Connector Gas Pipeline, LP," Before the Federal Energy Regulatory Commission, Jordan Cove Energy Project, L.P. and Pacific Connector Gas Pipeline, LP, Docket No. CP13-483-000, Docket No. CP13-492-000, April 8, 2016.
[33] "Re: Approval of Pre-Filing Request," Federal Energy Regulatory Commission, Correspondence from Ann F. Miles, Director Office of Energy Projects to Elizabeth Spomer, President and CEO Jordan Cove Energy Project LP and Pacific Connector Gas Pipeline LP, February 10, 2017.
[34] "Abbreviated Application of Pacific Connector Gas Pipeline, LP for a Certificate of Public Convenience and Necessity," Before the Federal Energy Regulatory Commission, Jordan Cove Energy Project, L.P. and Pacific Connector Gas Pipeline, LP, Docket No. CP17-494-000, CP17-495-000, September 21, 2017.
[35] "Pembina Announces Closing of Business Combination with Veresen, Declares Increased Common Share Dividend and Provides Business Update," News Releases, Pembina Pipeline Corporation, October 2, 2017.
[36] "The United States Exported More Natural Gas than it Imported in 2017," Today in Energy, Energy Information Administration, U.S. Department of Energy, March 19, 2018.
[37] "Liquefied natural gas exports expected to drive growth in U.S. natural gas trade," Katie Dyl, Today in Energy, U.S. Energy Information Administration, February 22, 2017.
[38] "The Wexpro Stipulation and Agreement," Executed October 14, 1981, Approved October 28, 1981, by Public Service Commission of Wyoming and December 31, 1981, by Public Service Commission of Utah.

Wexpro acquiring oil and gas properties or undeveloped leases for the mutual benefit of the Company's customers and Wexpro, under an agreement similar to the Wexpro Agreement. This arrangement, referred to as the Wexpro II Agreement, was designed to incorporate essentially the same terms and conditions of the Wexpro Agreement (known as the Wexpro I Agreement).

On March 28, 2013, the Utah Commission issued its Report and Order approving the Company's Wexpro II Agreement[39] and on October 16, 2013, the Wyoming Commission issued its Order approving the Wexpro II Agreement.[40] Subsequently, the Utah and Wyoming Commissions approved the inclusion of the Trail Unit[41] and the Canyon Creek Unit[42] as Wexpro II properties.

On January 9, 2017, the Company filed an application with the Utah Commission requesting approval of the Vermillion Acquisition as a Wexpro II property.[43] The Company also filed an application with the Wyoming Commission on January 10, 2017.[44] The Vermillion Acquisition includes natural gas producing properties within the Vermillion Basin in the Kinney, Trail, Whiskey Canyon, and Canyon Creek Units. The Vermillion Acquisition also included certain Canyon Creek overriding royalties. The Trail and Kinney Unit properties in the Vermillion Acquisition are within the Wexpro I Development Drilling Area and therefore the Company was required to apply for Utah and Wyoming Commission approval for inclusion under the Wexpro II Agreement. The Wexpro II Agreement also allows for properties outside the Wexpro I Development Drilling Area to be submitted for inclusion under Wexpro II as was the case for the Whiskey Canyon and Canyon Creek properties in the Vermillion Acquisition.

On March 9, 2017, the Utah Commission held a hearing and issued a bench ruling approving the Vermillion Acquisition Settlement Stipulation. The Utah Commission then issued an "Order Memorializing Bench Ruling Approving Stipulation" on March 30, 2017.[45] The Wyoming Commission held a hearing on March 17, 2017, and issued a bench ruling approving the Settlement Stipulation. The Wyoming Commission issued the Order Approving the Stipulation on November 2, 2017.[46] The Kinney wells were rejected from

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39 Utah Public Service Commission, "In the Matter of the Application of Questar Gas Company for Approval of the Wexpro II Agreement," Docket No. 12-057-13, Report and Order, Issued March 28, 2013.

40 The Public Service Commission of Wyoming, "In the Matter of the Application of Questar Gas Company for Approval of the Wexpro II Agreement," Docket No. 30010-123-GA-12 (Record No. 13347), Memorandum Opinion, Findings and Order Approving the Wexpro II Agreement, Issued October 16, 2013.

41 "In the Matter of the Application of Questar Gas Company for Approval to Include a Property Under the Wexpro II Agreement," Utah Public Service Commission, Docket No. 13-057-13, January 17, 2014.

42 "In the Matter of the Application of Questar Gas Company for Approval of the Canyon Creek Acquisition as a Wexpro II Property," Utah Public Service Commission, Docket No. 15-057-10, November 17, 2015.

43 "In the Matter of the Application of Questar Gas Company for Approval of the Vermillion Acquisition as a Wexpro II Property," Utah Public Service Commission, Docket No. 17-057-01, January 9, 2017.

44 "In the Matter of the Application of Questar Gas Company for Approval of the Vermillion Acquisition as a Wexpro II Property," The Public Service Commission of Wyoming, Docket No. 30010-162-GA-17 (Record No. 14631), January 10, 2017.

45 "In the Matter of the Application of Questar Gas Company for Approval of the Vermillion Acquisition as a Wexpro II Property," Utah Public Service Commission, "Order Memorializing Bench Ruling Approving Stipulation," Docket No. 17-057-01, March 30, 2017.

46 "In the Matter of the Application of Questar Gas Company for Approval of the Vermillion Acquisition as a

inclusion in the acquisition. The Wexpro I Agreement, the Wexpro II Agreement and the stipulations in the Trail, Canyon Creek, and Vermillion dockets are collectively known as the "Wexpro Agreements."

The Wexpro Agreements provide a framework where the Company's customers can continue to receive the long-term benefits of cost-of-service production. The Company believes that the Wexpro Agreements provide a valuable long-term resource to customers.

Wyoming IRP Process

The Company has been involved in integrated resource planning in the state of Wyoming since the early 1990s. In 1992, the Wyoming Commission ordered the Company to prepare and file integrated resource plans.[47] On February 3, 2009, the Wyoming Commission issued an order initiating a rulemaking pertaining to integrated resource planning. The Commission proposed the rule to ". . . give the Commission a more formalized process for requiring the filing of integrated resource plans, in some cases, and reviewing such plans."[48] On May 12, 2009, the Wyoming Commission approved Rule 253 and on January 24, 2011 the Wyoming Commission approved the natural gas IRP guidelines.[49]

The Company filed its 2017-2018 IRP on June 14, 2017, with the Wyoming Commission. Commission Staff solicited written public comments on the IRP filing by noticing the matter on the Wyoming Commission's open meeting agendas. No public comments were received. On November 15, 2017, Commission Staff issued a report on its review of the 2017-2018 IRP. Commission Staff found no areas of concern with the results and projections in the 2017-2018 IRP, and concluded, ". . . it is evident that the Company is actively identifying, evaluating, and executing projects and plans to meet their obligation to maintain Wyoming services at safe and reliable levels."[50]

The Wyoming Commission noticed the Company's 2017-2018 IRP on its Open Meeting Agendas from June 29, 2017 through November 21, 2017 and received no comments or protests. At its regularly scheduled Open Meeting on November 21, 2017, the Wyoming Commission received a presentation from representatives of the Company which provided a summary of the sections of the 2017-2018 IRP. On November 29, 2017, the

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Wexpro II Property," Wyoming Public Service Commission, "Memorandum Opinion, Findings, and Order Approving Stipulation," Docket No. 30010-162-GA-17, November 2, 2017.

[47] "In the Matter of the Application of Mountain Fuel Supply Company to File its Integrated Resource Plan as Directed by the Commission in Docket No. 30010-GI-90-8," Findings, Conclusions and Order, Docket No. 30010-GI-91-14, May 21, 1992.

[48] Before the Public Service Commission of Wyoming, "In the Matter of the Proposed Adoption of Chapter 2, Section 253 of the Commission Procedural Rules and Special Regulations Regarding Integrated Resource Planning," Order Initiating Rulemaking, Docket No. 90000-107-XO-09 (Record No. 12032, February 3, 2009).

[49] Correspondence from the Public Service Commission of Wyoming; Alan B. Minier, Chairman, Steve Oxley, Deputy Chairman, and Kathleen "Cindy" Lewis, Commissioner, To All Wyoming Natural Gas Utilities, dated January 24, 2011.

[50] Memorandum from Michelle Bohanan and John Burbridge to Chairman Russell, Deputy Chair Brighton Fornstrom and Commissioner Sessions Cooley; Re: Docket No. 30010-167-GA-17 (Record No. 14763) In the matter of the application of Questar Gas Company D/B/A Dominion Energy Wyoming Integrated Resource Plan for Year June 1, 2017 to May 31, 2018; November 15, 2017; Page 17.

Wyoming Commission issued a letter order directing the 2017-2018 IRP be placed in the Commission's files with no further action being taken and closed the matter.[51]

Utah IRP Process

Over the previous decade, the Utah Commission has promulgated new IRP standards and guidelines. This implementation process has included numerous discussions between IRP stakeholders in public meetings and the submission of extensive comments.

On March 31, 2009, the Utah Commission issued its Report and Order on Standards and Guidelines for Questar Gas Company (2009 IRP Guidelines) to be effective starting with the Company's 2010 IRP.[52] On March 22, 2010, the Utah Commission issued an order clarifying the requirements of the 2009 IRP Standards (Clarification Order).[53]

On June 14, 2017, the Company filed its IRP for the plan year, June 1, 2017 to May 31, 2018 (2017-2018 IRP). A technical conference was held on June 27, 2017, to discuss the 2017-2018 IRP with regulatory agencies and interested stakeholders. Primary topics of discussion included the Company's plan to meet peak-hour demand and supply reliability. On August 31, 2017, the Utah Office of Consumer Services (Office) filed its IRP comments.[54] The Utah Division of Public Utilities (Division) submitted its report and recommendation on August 31, 2017.[55] On October 10, 2017, the Company filed its Reply Comments.[56]

On January 5, 2018, the Utah Commission issued its Report and Order on the 2017-2018 IRP.[57] The Utah Commission found that "with the exception of Chapter 8, Peak-Hour Demand and Reliability, Dominion's 2017 IRP generally complies with the requirements of

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[51] Letter Order, To: Jenniffer Nelson Clark, Corporate Counsel, Dominion Energy Wyoming, From: John S. Burbridge, Assistant Secretary Wyoming Public Service Commission, Re: In The Matter of the Filing of Dominion Energy Wyoming's Integrated Resource Plan for Plan Year June 1, 2017 to May 31, 2018 – Docket No. 30010-167-GA-17 (Record No. 14763), Issued: November 29, 2017.

[52] "In the Matter of the Revision of Questar Gas Company's Integrated Resource Planning Standards and Guidelines," Report and Order on Standards and Guidelines for Questar Gas Company, Docket No. 08-057-02, Issued: March 31, 2009.

[53] "In the Matter of Questar Gas Company's Integrated Resource Plan for Plan Year: May 1, 2009 to April 30, 2010," Report and Order, Docket No. 09-057-07, Issued: March 22, 2010.

[54] Memorandum titled, "Dominion Energy Utah's Integrated Resource Plan (IRP) for Plan Year: June 1, 2017 to May 31, 2018," To: The Public Service Commission of Utah, From: The Office of Consumer Services, Michele Beck, Director, Gavin Mangelson, Utility Analyst, August 31, 2017.

[55] Action Request Response, To: Utah Public Service Commission, From: Division of Public Utilities; Chris Parker, Director, Artie Powell, Manager, Energy Section, Doug Wheelwright, Technical Consultant, Carolyn Roll, Technical Consultant, Subject: Action Request Docket No. 17-057-12, Dominion Energy Utah 2017-18 Integrated Resource Plan (IRP) Report, Division's Recommendation – Acknowledgement, Date: August 31, 2017.

[56] "In the Matter of Dominion Energy Utah's Integrated Resource Plan for Plan Year: June 1, 2017 to May 31, 2018," Before the Public Service Commission of Utah, Dominion Energy Utah's Reply Comments, Docket No. 17-057-12, October 10, 2017.

[57] In the Matter of Dominion Energy Utah's Integrated Resource Plan (IRP) for Plan Year: June 1, 2017 to May 31, 2018, The Public Service Commission of Utah, Report and Order, Docket No. 17-057-12, Issued: January 5, 2018.

the 20019 IRP Guidelines." The Commission also ordered the Company to 1) monitor and report on demand-response issues; 2) initiate an IRP docket early each year; 3) modify the IRP so the action plan is readily accessible; 4) include a discussion of its interruptible customer rate structures and tariff provisions in a 2018 pre-IRP filing public meeting; and 5) provide sensitivity analysis and other information in future IRPs pertaining to all evaluated solutions for addressing perceived peak-hour deficiencies and in filings related to approval of and LNG facility.

On April 30, 2018 the Company filed an Application seeking approval for a Voluntary Resource Decision to Construct an LNG Facility with the Utah Commission in Docket 18-057-03. The Company expects that this filing will address the concerns expressed regarding the "Peak-Hour Demand and Reliability" Section of the 2017-2018 IRP. In order to comply with the Commission's Order in Docket No. 17-057-12, and given that the analysis associated with the Company's analysis includes Highly Confidential information, the Company includes the analysis contained in its Application in Docket No. 18-057-03 (and accompanying testimony and exhibits) herein by reference.

Periodically, workshops and meetings are held in the IRP process to respond to specific issues, as ordered by the Utah Commission, to receive input for the IRP process or report on the progress of the Company's planning effort. On August 2, 2017, the Utah Commission held a meeting during which the Company updated the interested parties on information pertaining to the cost-of-service gas produced by Wexpro, specifically: the five-year forward curve and cost-of-service gas production. Representatives of the Company and Wexpro also answered questions from the Public Service Commission and the Division of Public Utilities.

On February 21, 2018, the Utah Commission held an IRP technical conference in conjunction with the development of the 2018-2019 IRP. The attendees discussed the following topics:

- Review of the Utah IRP Standards and Guidelines
- Review of the Utah Commission's 2017 IRP Order
- Interruptible Tariff
- Proposed 2018-2019 IRP Outline
- Demand Response

On February 23, 2018, the Company sent the annual request for proposals (RFP) for purchased gas to potential suppliers. The deadline for responses to the RFP was March 9, 2018.

The Utah Commission held another technical conference on March 13, 2018. The attendees discussed the following topics:

- Heating Season Review
- Design-Peak Day Calculation
- Supply Reliability

On April 24, 2018, the Utah Commission held a confidential technical conference where the following topics were discussed:

- RFP Recommendations
- Wexpro Matters

The Company welcomes discussion and open dialogue and will schedule additional technical conferences to answer questions and resolve any remaining issues. The Utah Commission has scheduled a technical conference for June 26, 2018, to discuss the 2018-2019 IRP with Utah regulatory agencies and interested stakeholders.

During the course of the IRP process, the Company has maintained four main goals and objectives:

1. To project future customer requirements;

2. To analyze alternatives for meeting customer requirements from a distribution system standpoint, an upstream capacity standpoint, a gas-supply source standpoint, a reliability standpoint, and taking into consideration the inter-day load profile of each source;

3. To develop a plan using stochastic data and methods, and risk management programs that will provide customers with the most reasonable costs over the long term that are consistent with reliable service, stable prices, and are within the constraints of the physical system and available gas supply resources; and

4. To use the guidelines derived from the IRP process as a basis for creating a flexible framework for guiding day-to-day, as well as longer-term gas supply decisions, including decisions associated with cost-of-service gas, purchased gas, gathering, processing, upstream transportation, and storage.

The Company utilizes a number of models as part of its IRP processes. The complexity of the systems being analyzed necessitates the use of computer-based tools. Modeling tools are an integral part of the forecasting, gas network analysis, energy-efficiency analysis, and resource selection processes. In each section of this report where the Company has referred to modeling tools, the IRP contains a description of the functions of each model and the version utilized. The IRP also contains discussion of any material changes (logic and data) from the previous year's IRP including the reasons for those changes.

An annual IRP process coincides well with the natural cycles of the gas industry. Some of the end-of-calendar-year data is not available and fully analyzed for IRP purposes until mid-April. The utilization of this information ensures the Company is including the most current and relevant information in its IRP. The required data input assumptions utilized in IRP models are voluminous. Nevertheless, the intent of this IRP is to summarize, in a readable fashion, the Company's planning processes.