SHALE INVESTMENT DASHBOARD IN OHIO Q3 AND Q4 2021

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November 2022

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LIST OF TABLES

LIST OF FIGURES

Executive Summary

This report presents findings from an investigation into shale-related investment in Ohio. The investment estimates are cumulative from July through December of 2021. Prior investments have been included in previous reports that are available from Cleveland State University.[1] Subsequent reports will estimate additional investment since the date of this report. Investment in Ohio into the Utica during the second half of 2021 can be summarized as follows:

Total Estimated Upstream Utica Investment: July – December 2021

Lease Renewals and New Leases	$116,565,000
Drilling	$701,760,000
Roads	$10,223,000
Lease Operating Expenses	$151,785,000
Royalties	$1,162,989,000
Total Estimated Upstream Investment	**$2,143,322,000**

Total Estimated Midstream Investment: July – December 2021

Gathering Lines	$39,827,000
Gathering System Compression and Dehydration	$34,434,000
Total Estimated Midstream Investment	**$74,261,000**

Total Estimated Downstream Investment: July – December 2021

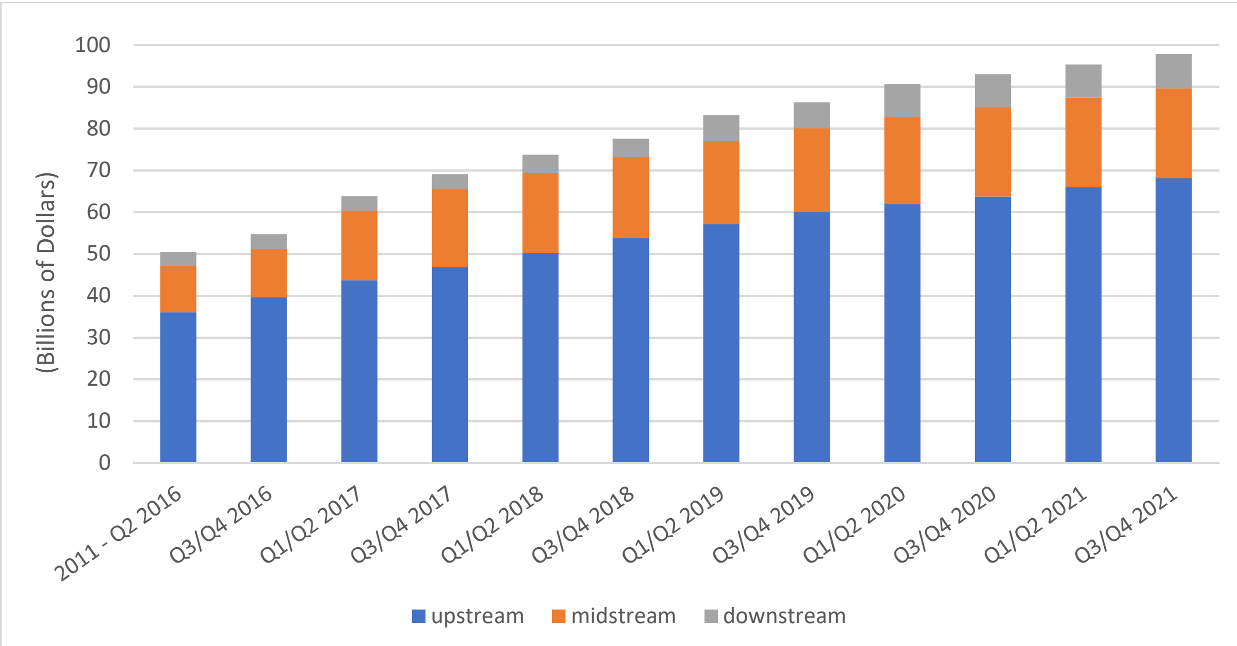
CHP Plants	$289,900,000
Total Estimated Downstream Investment	**$289,900,000**

Total investment from July through December 2021 was approximately $2.5 billion, including upstream, midstream, and downstream. Indirect downstream investment, such as development of new manufacturing as a result of lower energy costs, was not investigated as part of this Study. Together with previous investment to date, cumulative oil and gas investment in Ohio through December of 2021 is estimated to be around $97.8 billion. Of this, $68.1 billion has been in upstream, $21.4 billion in midstream, and $8.3 billion in downstream industries.[2] Figure 1 shows the growth in cumulative shale-related investment for Ohio since the release of the first Shale Dashboard.

[1] The eleven previous reports on shale investment in Ohio up to June 2021 can be found at https://engagedscholarship.csuohio.edu/urban_enpolc/

[2] Numbers may not add up precisely due to rounding.

Figure 1: Cumulative Shale Investment in Ohio Over Time



Overall upstream investments were down by about $78 million in the second half of 2021 compared to the first half of 2021, reflecting continued improving cost efficiencies for drilling. As determined from Ohio Department of Natural Resources Division of Oil and Gas (ODNR) data for shale well drilling, 86 new wells were drilled during the third and fourth quarters of 2021, 12 greater than the number drilled in the first half of 2021. ODNR production data also indicated that the total volume of gas-equivalent shale production in the second half of 2021 was 2% greater than overall production in the first half of 2021. Jefferson County had the highest number of new wells with 23, followed by Belmont and Carroll Counties, which each had 16 new wells, and Columbiana County, which had 13 new wells. No other county had more than 10 new wells drilled for the second half of 2021.

Ascent and EAP Ohio were the top producers for Q3 and Q4 of 2021, having produced 429 and 202 billion cubic feet equivalent (Bcfe), respectively. Gulfport was third in production at 168 Bcfe. SWN Production (Southwestern) and Rice Drilling produced 106 Bcfe and 105 Bcfe, respectively.[3] Antero had the sixth highest production during the Study period at 45 Bcfe. These six companies represented a little over 90% of total production in Ohio for the second half of 2021.

While producers in other shale plays consider refracturing existing wells as hydrocarbon prices rise,[4] there is little evidence of Utica operators having done so yet. A review of the DOE-supported FracFocus chemical disclosure registry suggests that no more than 5 wells have been

[3] SWN Production's Utica assets include wells formerly belonging to Eclipse and Montage Resources.
[4] *See* https://finance.yahoo.com/news/refracs-boost-u-shale-output-000000821.html

re-fractured in Ohio since 2011.[5] This compares to approximately 50 and 70 wells being refractured in the Marcellus (PA) and Eagle Ford (TX) shale plays, respectively, over this time frame.

The second half of 2021 saw midstream investment start to recover from a COVID-related downturn for this segment. While no major pipeline development or processing capacity expansion occurred during the Study period, the $74.3 million spent on gathering lines and compression represented a 73% increase in gathering system buildout compared to the first half of 2021. A further $243 million in midstream investment—primarily in the form of the $160 million Ohio Valley Connector Expansion project to increase takeaway capacity out of the region—was actively under development as of November 2022.

In downstream developments, major equipment installation for the combined heat and power (CHP) plant at Ohio State University's main campus took place in the second half of 2021. This 105.5 MW facility represents a $289.9 million investment. Future investment for natural gas-based power generation will include $1.2 billion for the Trumbull Energy Center, for which financing was secured in late 2022. A final investment decision for the proposed ethane cracker in Belmont County remains on hold. The Study Team will continue tracking these and other downstream activities in the state for future reports, including natural gas use for transportation and hydrogen production.

1. INTRODUCTION

This is the twelfth CSU study reporting investment resulting from oil and gas development in Ohio related to the Utica and Point Pleasant formations (hereinafter, the "Utica").[6] This analysis looks at investments made in Ohio between July 1 and December 31, 2021, separately considering the upstream, midstream, and downstream portions of the industry. For the upstream part, the Study Team estimated spending primarily based upon the likely costs of drilling new and operating existing wells, together with royalties and lease bonuses.

For midstream estimates, the Study Team looked at new infrastructure built during the relevant time period downstream of production, from gathering to the point of hydrocarbon distribution. This included pipelines, processing, natural gas liquid storage, and intermodal transloading facilities.

[5] *See* https://www.fracfocus.org. The FracFocus database lists *job start* and *job end* dates for when fracturing fluid was used on a given well, along with the API number for that well. A well was considered refractured if it had more than one *job start* date associated with it, and if those dates were separated by at least 6 months.
[6] This and other Investment Dashboard reports include drilling into the Marcellus and other shale units, but these comprise a very small portion of shale development in Ohio to date. This will be revisited as necessary in future iterations of the Investment Dashboard reports.

For the downstream analysis, the Study Team considered those industries that directly consume large amounts of oil, natural gas or natural gas liquids. Since hydrocarbon consumption may or may not be related to shale development, the examination of downstream investment has been limited to those projects that have been deemed by the Study Team to be dependent on, or directly the result of, the large amount of oil and gas being developed in the region as a result of the Marcellus and Utica shale formations.

This twelfth Study includes as Appendix A the cumulative investment made in Ohio resulting from shale development, based upon all previous reports that tracked total investment from early 2011 through December 2021.[7] The methodology for determining the investments is set forth in Appendix B, and has been updated since the last report. Subsequent reports will include incremental spending on a six-month basis.

2. SHALE INVESTMENT UPDATES

A. UPSTREAM DEVELOPMENT

1. Overview.

A total of 86 new wells were listed by the Ohio Department of Natural Resources as "drilled," "drilling," or "producing" during the period of July 1 to December 31, 2021.[8] This represents a 16.2% increase in new well development compared to the first half of 2021. The total number of producing wells in the Utica was 2,790 on December, 2021, a 3.3% increase from the end of July 2021. Total shale-related oil and gas production in billion cubic feet equivalent (Bcfe) for this period was 1,167 Bcfe, led by Belmont County with 354 Bcfe. Jefferson County was second with 294 Bcfe, followed by Monroe County with 228 Bcfe.[9]

The Ohio Department of Natural Resources (ODNR) Division of Oil and Gas Resources Management issues weekly reports on well status and quarterly reports on production. The ODNR production reports for the third and fourth quarters of 2021 provide the foundation for the upstream analyses presented in this Study.

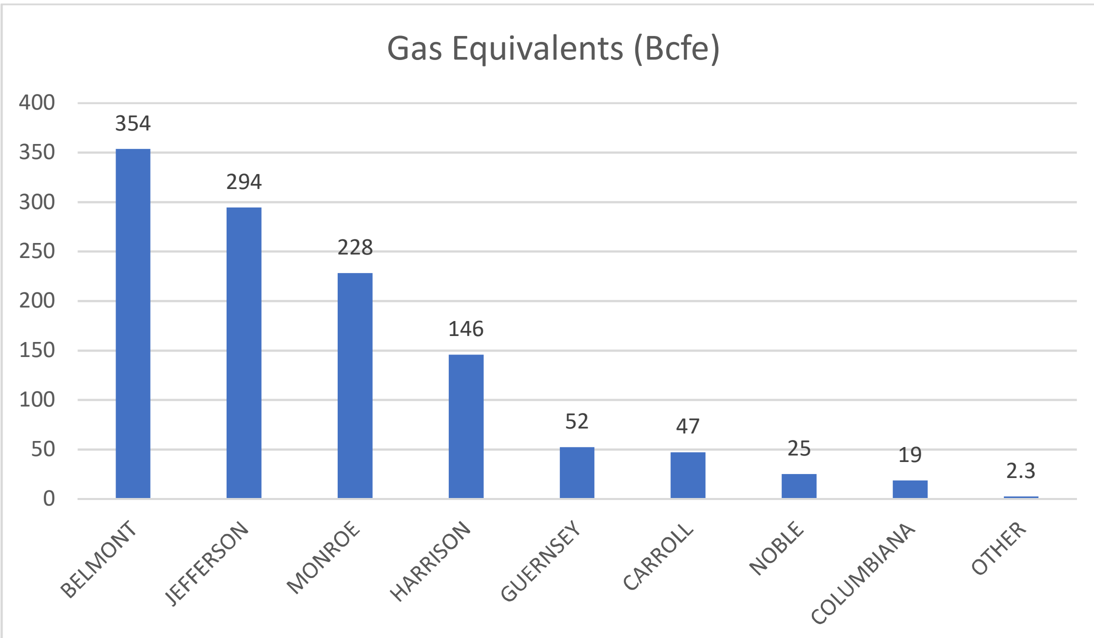
[7] *See fn 1, supra*.

[8] The number of new wells was determined using ODNR Cumulative Permitting Activity reports for the beginning and end of the 6-month period (*see* http://oilandgas.ohiodnr.gov/shale). Wells are assigned an American Petroleum Institute API number, which is included in the ODNR reports. Wells were considered new if they had a status of drilled, drilling, or producing at the end of the 6-month period but did not have any one of these status designations at the beginning of it.

[9] Production is reported to the ODNR at the wellhead as gas measured in thousands of cubic feet (Mcf) and as oil measured in barrels (bbl). The Utica also produces significant volumes of natural gas liquids (NGLs) such as ethane, propane, butane and natural gasoline. These NGLs are separated from the natural gas stream at midstream cryogenic and fractionation plants and not included in the ODNR production reports. For the purposes of this Study, oil and gas production is combined as gas equivalents (Mcfe) based on the energy content of oil and gas, measured as British thermal units (Btu). Gas equivalents were calculated using the following formula: Gas Equivalents (Mcfe) = Oil (bbl) x 5.659 Mcf/bbl + Gas (Mcf).

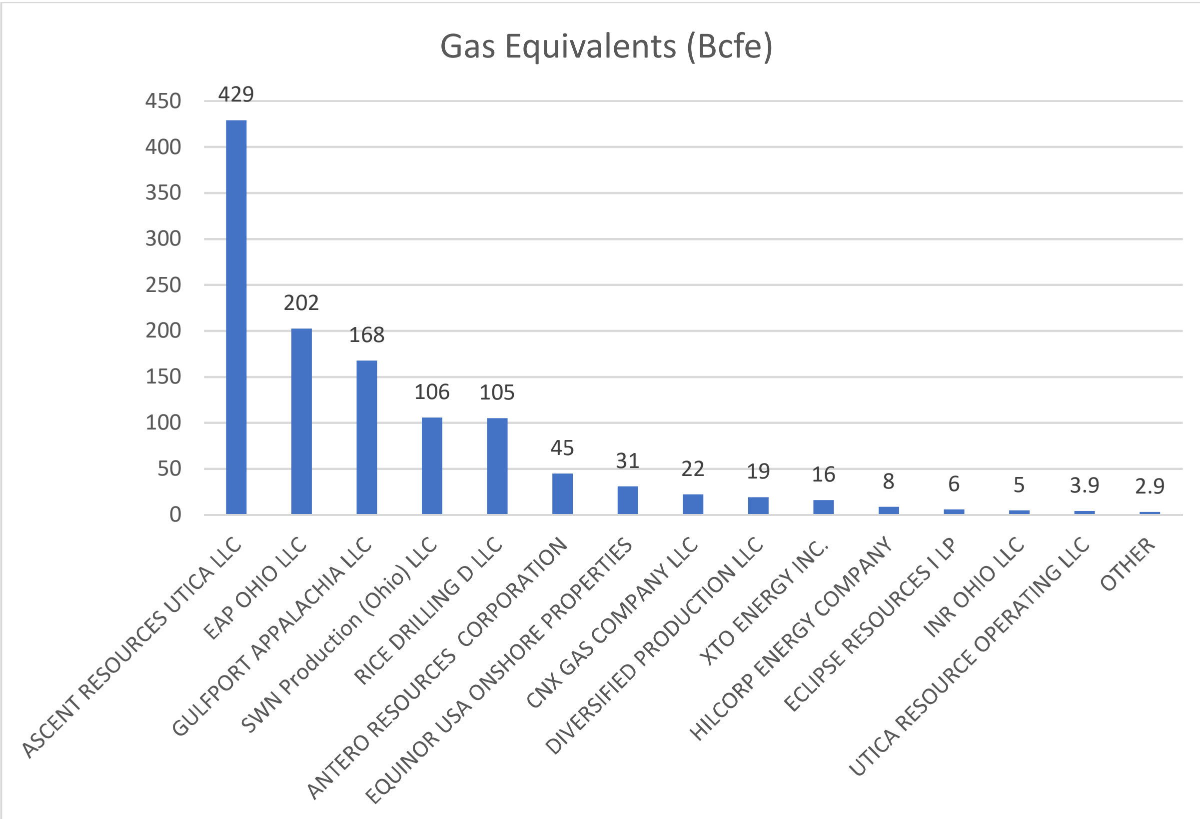
The Utica is currently identified by the ODNR as producing in eighteen eastern Ohio counties with the vast majority (over ninety-eight percent) of producing wells located in eight counties, stretching from Columbiana in the north, to Monroe and Noble at the southern end of the play. Total production in quarters 3 and 4 for 2021 is set forth by county and operator in Figures 2 and 3 below. Total cumulative production in billions of cubic feet equivalent (Bcfe) by county and by operator through December 2021 can be found in Appendix A as Figures 8 and 9.

Figure 2: Production by County for Q3 and Q4 of 2021



Data Source: ODNR (2022).

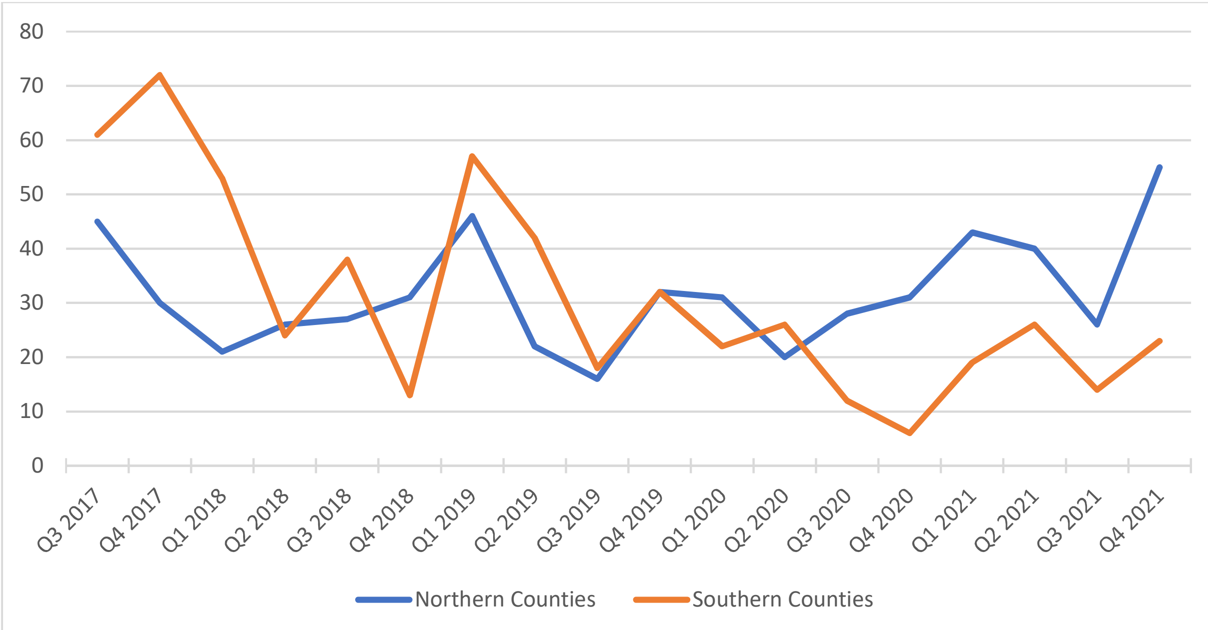
Figure 3: Production by Operator for Q3 and Q4 of 2021



Data Source: ODNR (2022).

Over the last few reports, we have tracked the relatively higher growth in shale well development for more northerly counties than southern ones, as indicated by ODNR permitting activity for Utica wells. A review of these permits suggests that this trend continued in the second half of 2021. As shown in Figure 4, by Q4 2021 there were more than twice as many permits issued for Utica oil and gas wells in the most active northern counties compared to the number of permits issued for the most active southern counties. (The four most active northern counties for drilling and production have been Jefferson, Harrison, Columbiana, and Carroll, while the four most active southern counties have been Belmont, Monroe, Guernsey, and Noble). As a result, we can expect that drilling investment will be concentrated more in the northern counties over the next two years.

Figure 4: Permits Issued for Shale Wells in Northern and Southern Counties Since 2017



Data Source: ODNR (2022).

2. Production Analysis.

Production can be summarized using tables that show gas equivalent production measured in billions of cubic feet equivalent as a function of time. This summary, for both production in the third and fourth quarters of 2021, and also for cumulative production since 2011, is set forth in Table 1. Table 2 sets forth production by county for the second half of 2021. Figure 5 sets forth the geographic distribution of production for the same period.

Table 1: Ohio's Shale Production by Reporting Period

Year	Quarter	Production Wells	Gas (Mcfe)	Oil (bbl)	Gas Equivalents (Mcfe)	Gas Production (% Change from Previous Quarter)
2021	4	2,817	576,496,677	3,912,593	598,638,041	5.2
2021	3	2,764	547,540,443	3,781,319	568,938,927	-0.6
2021	2	2,805	549,211,398	4,154,041	572,332,375	-0.2
2021	1	2,752	548,129,151	4,543,462	573,417,606	-6.4
2020	4	2722	586,878,969	4,625,639	612,624,813	-1.3
2020	3	2688	588,630,465	5,713,477	620,431,107	3.6
2020	2	2643	569,396,136	5,182,481	598,723,796	-2.6
2020	1	2573	581,634,083	5,887,032	614,948,797	-14.1
2019	4	2524	677,685,505	6,818,682	716,272,426	0.2
2019	3	2470	673,962,146	7,200,304	714,708,666	10
2019	2	2365	614,218,362	5,813,755	647,118,402	1.4
2019	1	2277	609,452,391	5,073,536	638,163,531	-8.4
2018	4	2201	663,534,323	5,810,484	696,415,852	9.3
2018	3	2198	605,716,125	5,545,536	637,098,313	9.9
2018	2	2002	554,306,916	4,488,104	579,705,097	4.7
2018	1	1906	531,291,017	3,942,251	553,600,215	5.1
2017	4	1866	503,066,907	4,193,562	526,784,387	8.7
2017	3	1769	460,844,826	4,207,674	484,656,053	18.1
2017	2	1646	387,725,175	4,019,281	410,512,053	4.7
2017	1	1530	369,913,713	3,877,717	391,904,993	2.5
2016	4	1492	362,107,422	3,568,077	382,364,866	-0.2
2016	3	1442	360,681,356	3,954,095	383,057,580	5.9
2016	2	1382	334,257,982	4,839,792	361,646,365	0.3
2016	1	1328	329,537,838	5,485,854	360,582,286	7.0
2015	4	1248	301,486,508	6,248,451	336,846,492	39.1
2015	3	989	216,974,492	4,439,258	242,096,253	-4.5
2015	2	992	221,862,582	5,578,255	253,429,927	21.5
2015	1	907	183,585,256	4,432,195	208,667,049	12.8
2014	4	810	164,815,008	3,558,836	184,954,459	25.7
2014	3	688	130,282,395	2,984,534	147,171,872	45.0
2014	2	535	87,773,834	2,422,179	101,480,943	30.1
2014	1	415	67,095,693	1,928,076	78,006,674	53.5
2013	4	371	42,693,774	1,433,731	50,807,259	24.7
2013	3	269	33,255,706	1,323,812	40,747,160	126.2
2013	2	186	14,863,645	556,437	18,012,520	79.1
2013	1	117	8,237,177	321,439	10,056,202	-38.8
2012	ANNUAL	82	12,831,292	635,874	16,429,703	481.9
2011	ANNUAL	9	2,561,524	46,326	2,823,683	--
Total		**54,199**	**12,950,501,092**	**144,854,239**	**13,768,599,775**	--

Source: ODNR (2022).

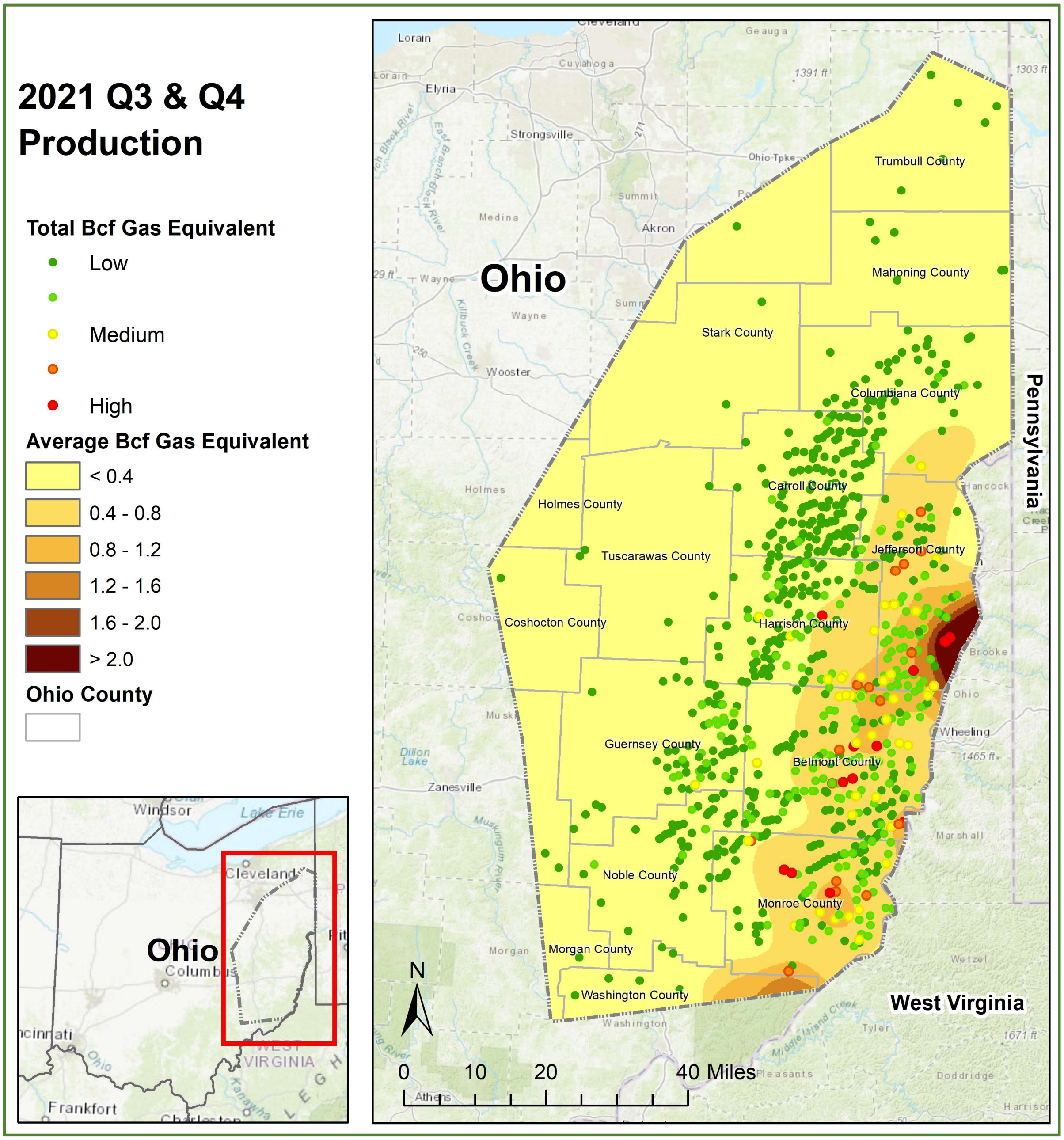
Table 2: Production by County for July – December 2021

County	Gas (Mcfe)	Oil (bbl)	Gas Equivalents (Mcfe)	Production Wells[10]
BELMONT	352,963,717	126,497	353,679,564	612
CARROLL	40,227,400	1,211,313	47,082,220	477
COLUMBIANA	18,658,819	11,241	18,722,432	87
COSHOCTON	9,341	-	9,341	1
GUERNSEY	34,560,482	3,151,204	52,393,145	252
HARRISON	129,962,369	2,794,114	145,774,260	452
JEFFERSON	294,262,115	1	294,262,121	294
MAHONING	478,514	3,481	498,213	11
MONROE	227,052,595	201,952	228,195,441	405
MORGAN	68,310	2,586	82,944	2
MUSKINGUM	267,997	11,933	335,526	2
NOBLE	24,211,219	164,026	25,139,442	173
PORTAGE	30,560	136	31,330	2
STARK	29,686	351	31,672	1
TRUMBULL	213,440	745	217,656	6
TUSCARAWAS	170,581	7,100	210,760	6
WASHINGTON	842,731	7,232	883,657	11
WAYNE	27,244	-	27,244	1
Total	1,124,037,120	7,693,912	1,167,576,968	2,791

Source: ODNR (2022).

[10] Represents the average number of production wells for the third and fourth quarters of 2021.

Figure 5: Distribution of Gas Equivalent Production for July – December 2021



Of the 3,008 total wells identified from the ODNR records for cumulative drilling activity as of December 2021, 138 were in the process of drilling, 80 wells had been drilled and were awaiting markets, and 2,790 were in the production phase.[11] (*See* Table 3, Ohio Utica Well Status.) Belmont County continued to lead in total wells (*see* Table 4).

[11] The discrepancy between the number of "Producing" wells in Table 3 and "Production" wells in Table 2 is due to how wells are reported in the ODNR's *Shale Well Drilling & Permitting* and *Well Production* spreadsheets. For a particular point in time, a given well may be classified as non-producing in the spreadsheet for cumulative activity yet have a record of production in the well production spreadsheet.

Table 3: Ohio Utica Well Status as of December 2021

Well Status	No. of Wells
Drilled	80
Drilling	138
Producing	2,790
Total	**3,008**

Source: ODNR (2022)

Table 4: Well Status by County (December 2021)

County	Drilled	Drilling	Producing	Total
BELMONT	15	22	615	652
CARROLL	2	18	478	498
HARRISON	4	20	449	473
MONROE	19	9	387	415
JEFFERSON	1	29	302	332
GUERNSEY	4	11	253	268
NOBLE	1	6	174	181
COLUMBIANA	13	21	86	120
MAHONING	1	0	12	13
TRUMBULL	3	1	7	11
WASHINGTON	0	0	11	11
PORTAGE	7	1	1	9
TUSCARAWAS	2	0	7	9
STARK	4	0	2	6
COSHOCTON	1	0	1	2
MORGAN	0	0	2	2
MUSKINGUM	0	0	2	2
ASHLAND	1	0	0	1
KNOX	1	0	0	1
MEDINA	1	0	0	1
WAYNE	0	0	1	1
Total	**80**	**138**	**2,790**	**3,008**

B. UPSTREAM INVESTMENT ESTIMATES

Upstream investments have been broken down into four areas: investments into drilling, including road construction associated with well development; lease operating (post-production) expenses; new lease and lease renewal bonuses; and royalties on hydrocarbon production. The methodology used for each calculation is set forth in Appendix B. Average drilling costs were updated for this study, based upon reports from publicly traded operating companies. Previous shale reports differentiated between northern and southern counties with respect to drilling costs based on the greater vertical depths and horizontal lengths of wells developed in southern counties, on average. However, a recent review of ODNR drilling surveys indicated that there is no longer a significant difference in average well depth and horizontal length between northern and southern counties. Based on an average lateral length of 13,600 ft. for the eight most active shale-producing counties in Ohio over the last two years, and average drilling and completion costs of $600 per lateral foot for operators in the Utica during 2021, we assumed an average drilling cost of $8.2 million per well for *all* horizontal wells.[12]

This section covers upstream investments between July and December 2021. Cumulative upstream investments to date in Ohio, including 2011 through the second half of 2021, are set forth in Table 17 of Appendix A.

1. Investments into Drilling.

The following tables set forth estimated investments for the study period made into drilling shale wells in Ohio. Jefferson County was the leader in new upstream investment, with 23 new wells and an investment of around $190.4 million between July and December 2021. Belmont and Carroll counties were second and third, with 16 new wells each, to go along with $132.5 million invested per county. (*See* Table 5.) Road-related investments for this version of the Shale Investment Dashboard reflect average road costs per well determined from three sources: The Ohio Oil and Gas Association's (OOGA) 2017 report *Ohio's Oil & Gas Industry Road Improvement Payments*; OOGA's *2022 Community Impact/Sustainability Report*; and spending in 2021 on Road Use Maintenance Agreements (RUMAs) by companies in Monroe, Noble, and Carroll Counties as reported to the Study Team by the engineer's office for those counties.[13] Based on information from these sources, road costs related to drilling were assumed to be $119,000 per well.

[12] *See* Upstream Methodology in Appendix B.

[13] OOGA's 2017 report indicated that oil and gas companies in Ohio had spent approximately $300 million on roads from 2011 through 2017. OOGA's 2022 report indicated that cumulative spending by the industry on roads had reached approximately $400 million by the end of 2021. This suggests that $100 million was spent on roads from 2018 through 2021. The Study Team has tracked 846 new wells over that period for the bi-annual shale dashboards. This suggests an average expenditure per well on roads of around $118,200. Independent of this estimate, the 2021 RUMA-based improvement totals as gathered by the engineer's office in Monroe, Noble, and Carroll counties and shared with the Study Team tallied about $3.825 million. Based on the 32 new wells the Study Team tracked for those three counties last year, this comes out to $119,500 per well. The two estimates were averaged and rounded to the nearest $1,000 to yield the rule of thumb for spending on roads.

Ascent was the leading operator-investor during the six-month period, with 35 new wells and an estimated $289.8 million. EAP Ohio recorded the second highest investment, with 22 new wells and an estimated $182.1 million investment. Hilcorp Energy and Gulfport Appalachia invested $107.6 million and $58.0 million in 13 and 7 wells, respectively. (*See* Table 6.)

Table 5: Estimated Upstream Shale Investment by County, July – December 2021

County	No. of New Wells	Drilling ($)	Roads ($)	Total Amount ($)
JEFFERSON	23	$187,680,000	$2,734,000	$190,414,000
BELMONT	16	$130,560,000	$1,902,000	$132,462,000
CARROLL	16	$130,560,000	$1,902,000	$132,462,000
COLUMBIANA	13	$106,080,000	$1,545,000	$107,625,000
GUERNSEY	7	$57,120,000	$832,000	$57,952,000
HARRISON	7	$57,120,000	$832,000	$57,952,000
MONROE	4	$32,640,000	$475,000	$33,115,000
Total	**86**	**$701,760,000**	**$10,223,000**	**$711,983,000**

Source: The Authors (2021)

Table 6: Estimated Upstream Shale Investment in Ohio by Company, July – December 2021

Operators	No. of Wells	Drilling ($)	Roads ($)	Total Amount ($)
ASCENT RESOURCES UTICA LLC	35	$285,600,000	$4,160,000	$289,760,000
EAP OHIO LLC	22	$179,520,000	$2,615,000	$182,135,000
HILCORP ENERGY COMPANY	13	$106,080,000	$1,545,000	$107,625,000
GULFPORT APPALACHIA LLC	7	$57,120,000	$832,000	$57,952,000
INR OHIO LLC	3	$24,480,000	$357,000	$24,837,000
UTICA RESOURCE OPERATING LLC	3	$24,480,000	$357,000	$24,837,000
ANTERO RESOURCES CORP.	1	$8,160,000	$119,000	$8,279,000
ECLIPSE RESOURCES I LP	1	$8,160,000	$119,000	$8,279,000
EOG RESOURCES INC	1	$8,160,000	$119,000	$8,279,000
Total	**86**	**$701,760,000**	**$10,223,000**	**$711,983,000**

Source: The Authors (2021)

2. Lease Operating Expenses.

Post-production investments have been estimated on a half-year basis, assuming an average cost of $0.13/Mcf-equivalent.[14] This estimate is based upon recent operator reports.[15] These investments are set forth below. Belmont County and Jefferson County led the lease operating expense investment, with an estimated $46.0 million and $38.3 million invested, respectively.

Table 7: Estimated Lease Operating Expenses for July – December 2021 by County

County	Gas Equivalents (Mcfe)	Lease Operating Expense for Period
BELMONT	353,679,564	$45,978,343
JEFFERSON	294,262,121	$38,254,076
MONROE	228,195,441	$29,665,407
HARRISON	145,774,260	$18,950,654
GUERNSEY	52,393,145	$6,811,109
CARROLL	47,082,220	$6,120,689
NOBLE	25,139,442	$3,268,127
COLUMBIANA	18,722,432	$2,433,916
OTHER	2,328,343	$302,685
TOTAL	**1,167,576,968**	**$151,785,006**

Table 8: Estimated Lease Operating Expenses for July – December 2021 by Operator

Operator	Gas Equivalents (Mcfe)	Lease Operating Expense for Period
ASCENT RESOURCES UTICA LLC	428,934,327	$55,761,463
EAP OHIO LLC	202,427,390	$26,315,561
GULFPORT APPALACHIA LLC	167,540,477	$21,780,262
SWN Production (Ohio) LLC	105,649,976	$13,734,497
RICE DRILLING D LLC	104,824,584	$13,627,196
ANTERO RESOURCES CORPORATION	44,778,758	$5,821,239
EQUINOR USA ONSHORE PROPERTIES	30,756,545	$3,998,351
CNX GAS COMPANY LLC	22,059,282	$2,867,707
DIVERSIFIED PRODUCTION LLC	19,037,877	$2,474,924
XTO ENERGY INC.	15,947,966	$2,073,236
HILCORP ENERGY COMPANY	8,446,677	$1,098,068
ECLIPSE RESOURCES I LP	5,677,117	$738,025
INR OHIO LLC	4,670,289	$607,138
UTICA RESOURCE OPERATING LLC	3,895,281	$506,387
OTHER	2,930,421	$380,955
TOTAL	**1,167,576,968**	**151,785,006**

[14] Previous reports relied on a per-well rule-of-thumb to calculate lease operating expenses, which attributed an equal amount to both low- and high-producing wells. A production-based rule of thumb more accurately captures the expenses that companies are likely to incur while operating wells.

[15] The per-Mcfe rule-of-thumb for lease operating expenses is based on average production costs for Ascent's and Gulfport's Utica operations in 2021 as reported in annual financial statements for both companies. *See* Appendix B.

3. Royalties.

Royalty investments have been estimated on a per quarter basis, assuming the formulas set forth in Appendix B. Total estimated royalties spent on Ohio properties between July and December 2021 were nearly $1.2 billion, about 14% higher than the amount dispersed in the first half of 2021. The breakdown by quarter for oil, residue gas (gas left after extracting liquids) and natural gas liquids is set forth in Tables 9, 10, and 11 below. The average price for natural gas was $4.02/MMBtu during the second half of 2021, up from $3.66 in the first half of 2021.[16] Regional oil prices increased from an average of $60.02/bbl during the third quarter of 2021 to $67.11/bbl for the fourth quarter.[17] For comparison, regional oil prices averaged $47.91 and $56.14 per barrel in the first and second quarters of 2021, respectively.

Table 9: Total Royalties from Oil, July – December 2021 (in millions)

Year	Quarter	Oil Price $/bbl	Oil Royalty (20%) $/bbl	Royalty ($mm)
2021	4	$67.11	$13.42	$52.52
2021	3	$60.02	$12.00	$45.39
			Subtotal	**$97.91**

Table 10: Total Royalties from Residue Gas, July – December 2021 (in millions)

Year	Quarter	Residue Gas Price $/Mcf	Residue Gas Royalty (20%) $/Mcf	Royalty ($mm)
2021	4	4.58	$0.92	$464.92
2021	3	4.27	$0.85	$411.26
			Subtotal	**$876.18**

Table 11: Total Royalties from Natural Gas Liquids, July – December 2021 (in millions)

Year	Quarter	NGL Price $/bbl	NGL Royalty (20%) $/bbl	Royalty ($mm)
2021	4	20.13	4.03	$102.14
2021	3	18.01	3.60	$86.75
			Subtotal	**$188.90**

[16] Reflects average Appalachia regional natural gas prices over the respective periods. *See* https://www.naturalgasintel.com/chesapeake-builds-natural-gas-rich-marcellus-portfolio-with-chief-tug-hill-purchase/.

[17] *See* https://ergon.com

4. Lease Renewals and New Leases.

New leases and lease renewal investments have been estimated for the Utica region based upon the drilling activity of the top six drilling companies in the region. These six companies have together drilled over 85% of the Utica wells to date, and it is assumed that they likewise control over 85% of the leases. The estimated investments into new leases and lease renewals are set forth below in Table 12.

There are several potential sources of error in these estimates. Because operators do not report lease bonus information, the Study Team was required to estimate investments into lease bonuses based upon some industry rules of thumb, together with information found in public leases. One important rule of thumb we deployed in estimating lease bonus investment is that "primary" lease terms average about 5 years. The primary term is that period of time during which the operator may conduct drilling operations but hold the lease without producing. Once a lease is drilled and production begins, the lease moves into its "secondary term," and may be thereafter "held by production" (HBP) for the life of that production. Using this rule of thumb, we determined that each operator will, on average, every year replace about 20% of its undeveloped acreage that is not HBP.

However, it is possible to hold undeveloped acreage without producing it. This can be done through the process of unitization. An operator may, for instance, have a 750-acre unit that is designed to drain a reservoir by 3 wells draining 250 acres each. The operator may drill the first well and begin to pay royalties therefrom to all the unit leases, thereby moving all the unit leases into HBP status, even though only one third of the reservoir is actually producing. Under this scenario, 500 acres would be classified as "undeveloped acreage," while 250 acres would be "developed acreage."

Most operators report undeveloped acreage.[18] However, they generally do not distinguish what portions of their undeveloped acreage are HBP or under primary term. Some do, however, report what percentage of their overall acreage is HBP, and this number can be used to estimate the likely acreage of leases that required bonuses. Based on the most recent annual financial reports for Antero, Ascent, and Gulfport, the Study Team found that on average 19% of a Utica operator's net Utica acreage was not classified as "Held-By-Production." Accordingly, for purposes of this Study, and using the 5-year primary term assumption, we assumed that operators, on average, paid lease bonuses on 20% of such non-HBP acreage for the year, and 10% over the half-year study period (i.e., 5% of total acreage each year).

[18] *Undeveloped acreage* is defined by operators as that acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether the acreage contains proved reserves. *See e.g.,* Chesapeake Energy Corporation. (2018). 2017 annual report. https://www.sec.gov/Archives/edgar/data/0000895126/000089512618000060 /chk-20171231_10k.htm. Accordingly, undeveloped acreage can have a wide range of meaning, ranging from highly speculative to proven. Operators use a different, more rigorous classification system to account for proven or potential reserves.

Another important assumption is the lease bonus rate. For this Study, we have assumed bonuses to average $5000/acre lease for renewals and new leases. From 2013-2019, this was a pretty conservative number in the Utica, and therefore likely to still be conservative for renewals of older leases. There is evidence that in 2020 new lease bonus rates were depressed due to sustained low natural gas prices. More recent publicly reported information on lease bonuses suggests, however, that $5000/acre continues to be a reasonable estimate. In May 2022, for example, the Muskingum Watershed Conservancy District leased mineral rights for $5,500/acre for a 5-year primary term on acreage in Harrison County.[19]

One additional factor that may make the lease bonus estimate inaccurate is the use of only "net" non-HBP lease acreage data to avoid possible double counting of leases. Operating companies often collaborate on development with non-operators but report only their own portion of the lease. However, bonuses must be paid on the "gross" lease acreage. So long as the non-operators are among the top six operators (which is commonly the case), their own net acreage reports will capture all the acreage. But if they are not, the acreage will not be captured, and the bonuses estimated herein will be under reported.

Table 12: Total Estimated Investments into New Leases and Lease Renewals July – December 2021 (in millions)

Operator	Acreage not held for production	Estimated Bonus Investment ($mm)
ANTERO RESOURCES CORPORATION[20]	21,590	7.6
ASCENT RESOURCES UTICA HOLDINGS, LLC	84,232	33.4
EAP OHIO LLC[21]	246,831	28.9
Southwest Energy Company[22]	58,840	13.8
GULFPORT ENERGY CORPORATION	48,216	18.7
Rice Drilling D LLC (EQT)	35,755	14.2
Total	**495,464**	**116.6**

[19] *See MWCD Negotiates Oil and Gas Lease with Encino Energy* (May 20, 2022). https://www.mwcd.org/news/2022/05/20/mwcd-negotiates-oil-and-gas-lease-with-encino-energy

[20] While Antero's FY2021 10-K did not distinguish Ohio Utica Shale from Marcellus Shale for the company's holdings in the Appalachian basin, its FY2019 10-K did. For FY2019, 90,814 of the company's 541,447 total net acres were in Ohio, or 16.8%. Applying this percentage to Antero's Appalachian basin holdings for FY2021 of 501,656 total net acres yields an estimated 84,140 total net acres in Ohio for 2021. According to the company's FY2021 10-K, 18% of its net Appalachian Basin acreage was not held by production.

[21] Fitch Solutions' coverage of privately held EAP's successful $700 million bond offering in 2021 indicates that the operator has 300,000 net Utica acres. *See* https://www.fitchratings.com/research/corporate-finance/fitch-affirms-encino-acquisition-partners-llc-idr-at-b-outlook-revised-to-stable-20-04-2021

[22] Southwest's acreage in the Appalachian Basin—encompassing parts of Ohio, Pennsylvania, and West Virginia—was not itemized by state in its FY2021 10-K report. The company's Ohio acreage was estimated by importing a map of its Appalachian operations into a geographic information system (GIS) software application. *See* https://www.swn.com/operations/appalachia/

C. Estimated Midstream Investments

Midstream investment includes natural gas processing and fractionation facilities, including rail and transloading facilities for storing and handling natural gas liquids. Midstream also includes transmission and gathering pipelines, storage facilities, compressor stations (including compressor engines), dehydration units, and generators installed as part of these stations.

Pipeline investments were estimated using mileage and size information from the Public Utilities Commission of Ohio, and cost information from the Interstate Natural Gas Association of America (INGAA). Similarly, compressor station investments were based on estimated cost per unit of power output for the region as obtained from the INGAA. A full description of the methodology can be found in Appendix B.

Additional investment information was collected from midstream company investor presentations, news reports, and other sources including Ohio EPA permits. Table 13 summarizes midstream investments identified by the Study Team for the second half of 2021. Some costs related to these projects may have occurred outside the six-month window for this study. However, because the investments cannot easily be separated and tracked while construction is ongoing, the investments are treated as though made entirely during the Study period if construction on the project was begun then.

Table 13: Midstream Gathering System Investment, July – December 2021

Company	Additions to Infrastructure	Total Amount ($mm)
Airstream Compression LLC (Encino)	• 5,000 hp of compression at Applegath Booster Station in Jefferson County	$19.4
Antero Midstream Partners	• 1.77 miles of 20" pipeline	$7.1
Aspire Energy	• 524 hp of compression in Guernsey County	$2.1
Blue Racer Midstream LLC	• 1.91 miles of 8.63" pipeline • 3,360 hp of compression at stations in Noble and Harrison Counties	$16.3
Cardinal Gas Services (Williams)	• 0.49 miles of 8.63" pipeline • 1.20 miles of 12.75" pipeline • 4.91 miles of 16" pipeline	$19.6
Utica Gas Services (Williams)	• 3.07 miles of 16" pipeline	$9.8
	Total	**$74.3**

Source for Gathering Line Mileage and Diameter Data: PUCO Gathering Construction Reports (2022)

Midstream investments were up more than 70% during the second half of 2021 compared to the first half of the year, totaling around $74 million. While this is considerably less than the $400 million in midstream spending tracked during the second half of 2020, it is consistent with this segment entering a post-COVID phase of steady recovery.

Near-term midstream investment in Ohio will likely not be directed toward gas processing. Midstream operators in the Utica have considerable capacity (>40%) available to utilize for gas processing, fractionation, and de-ethanization as a result of recent investments that have been identified in previous shale reports.[23]

It is more likely that this segment will see spending directed towards pipeline projects. Takeaway capacity out of the Appalachian Basin is "effectively maxed out," with average utilization rates on transmission lines averaging anywhere from 90-100% over the past few years.[24] This constraint has contributed to a more than $1/MMBtu discount as of late on Utica and Marcellus production relative to the Henry Hub.[25] Equitrans' $161 million Ohio Valley Connector Expansion Project, currently before FERC, could alleviate part of this bottleneck.[26] This and other midstream projects to be tracked for future shale reports are listed in Table 14.

Table 14: Future Ohio Midstream Projects

Project	Description	Est. Investment ($mm)
Ohio Valley Connector Expansion[27]	Takeaway capacity out of Appalachia (exclusive to Ohio)	$161.0
Rover North Coast Interconnect[28]	Allow for delivery of nat. gas supplies from Rover to North Coast Trans. system	$1.0
NGL Supply Co. Ltd. propane rail terminal[29]	180,000-gallon rail terminal in Sycamore, OH for propane from Utica/Marcellus	$5.3
Gathering system buildout[30]	23 miles of pipeline with avg. diameter of 11"; 6,090 hp of compression	$75.8

[23] *See* MPLX's Form 10-K for FY2021. https://ir.mplx.com/CorporateProfile/sec-filings.
[24] *See* https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/083122-appalachias-autumn-2022-natural-gas-basis-discounts-deepen-as-capacity-concerns-mount
[25] *Id. See also*, https://www.eia.gov/todayinenergy/detail.php?id=45037
[26] *See* https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx. The Ohio Valley Connector Expansion Project is designed to add transportation capacity to allow natural gas to move from the central Appalachian Basin into the interstate pipeline grid though interconnects to the Rockies Express and Rover systems.
[27] *Id.*
[28] *Id.*
[29] *See following*: 1) https://www.wyandotcountyeconomicdevelopment.com/ngl-to-construct-new-transload-facility; 2) https://www.lpgasmagazine.com/ngl-supply-co-ltd-opens-ohio-rail-terminal/; 3) https://marcellusdrilling.com/2022/03/new-ohio-lng-rail-terminal-fed-by-marcellus-utica-propane/
[30] Pipeline estimate reflects construction starts through the end of July 2022 as gathered from the PUCO's Gathering Construction Reports. Compression estimate reflects projects receiving Final Issuance of Permit-to-

D. DOWNSTREAM DEVELOPMENT

1. Combined Heat and Natural Gas Power Plants

Over the past eleven reports, we have noted 10 new natural gas-powered power plants in Ohio that were in the planning, construction, or newly operational stages since 2015. There were no new construction starts for these plants during the second half of 2021. However, in November 2022 financing was secured for the $1.2 billion Trumbull Energy Center.[31] Investment related to this 940 MW natural gas-fired power plant—which has been in development since 2015—will be included in a future shale report. The 485 MW Long Ridge Energy Terminal—investment for which was included in a previous report—concluded construction and began operations in the second half of 2021.[32] Construction on the $1 billion Harrison Power Plant had not started as of November 2022.[33]

Installation of major equipment (e.g., e.g., heat recovery steam generators, gas turbine generators, and steam turbine generators) for the 105.5 MW CHP plant at Ohio State University's main campus began in the summer of 2021 and was completed by November 2021.[34] Investment related to this $289.9 million project is included in this report.[35] The 10 current and projected natural gas-powered facilities across 8 locations, along with the CHP project at Ohio State, including their current status, are set forth in Figure 6 below.

Install and Operate from Ohio EPA as of July 31, 2022. *See* Appendix B for methodology used to calculate total dollar amount.

[31] https://www.vindy.com/news/local-news/2022/11/trumbull-energy-center-secures-financing/

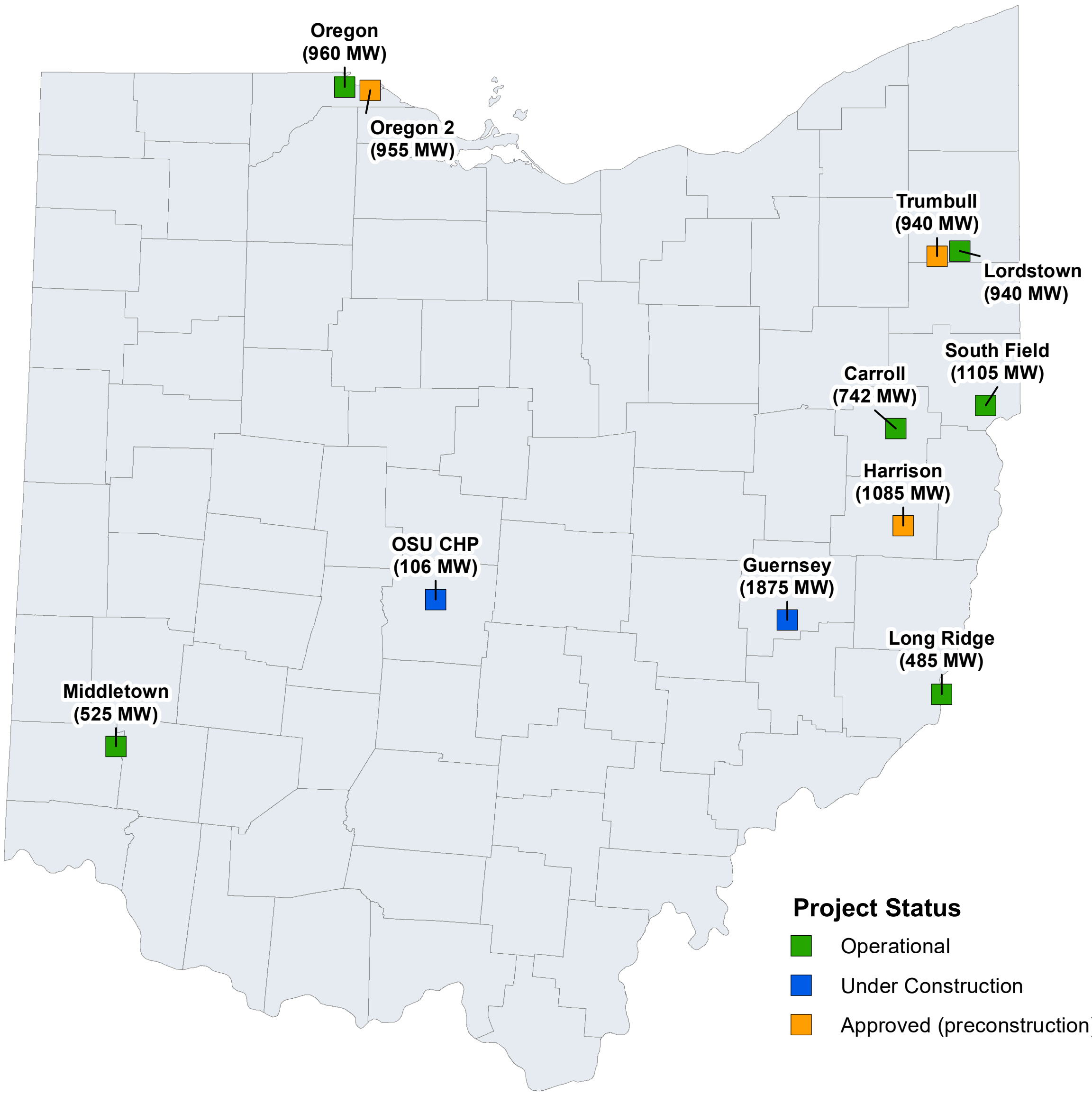
[32] https://highlandcountypress.com/Content/In-The-News/Headlines/Article/Long-Ridge-Energy-Terminal-developing-Data-Center-Campus-in-Hannibal/2/73/71484

[33] No construction notice had been filed with the Ohio Power Siting Board as of this writing.

[34] *See* https://trustees.osu.edu/sites/default/files/documents/2021/05/PUBLIC_MATERIALS_MPF_May_2021.pdf; *see also* https://trustees.osu.edu/meeting/2021/11/master-planning-nov-2021

[35] Buildout for distributing heating and cooling from the CHP plant at Ohio State is currently ongoing and planned for completion in the second half of 2023. *See* https://trustees.osu.edu/sites/default/files/documents/2022/08/Public_Materials_MPF_August22.pdf

Figure 6: Existing and Projected Natural Gas Power Plants



Source: Ohio Power Siting Board (2022)

2. Other Downstream Investment

No other downstream investments were identified for the study period. In February 2022, Solvay announced plans for major expansion at its U.S. facilities, including a 25% capacity increase for sulfone polymer production at the company's Marietta site.[36] Also, Nutrien plans to expand production capacity of Urea Ammonium Nitrate (a natural gas derivative) in 2023 at its Lima complex as part of $260 million in spending toward organic growth projects across five North American sites.[37] These petrochemical investments will be tracked and included in a future shale report.

There have been no recent developments on PTTGC America's ethane cracker in Belmont County. While it searches for an investment partner on that multi-billion-dollar project, PTTGC has more recently sought to affirm its long-term commitment to operating in the state through other activities, including a June 2022 announcement that it plans to construct and operate a plastics recycling complex near Columbus.[38]

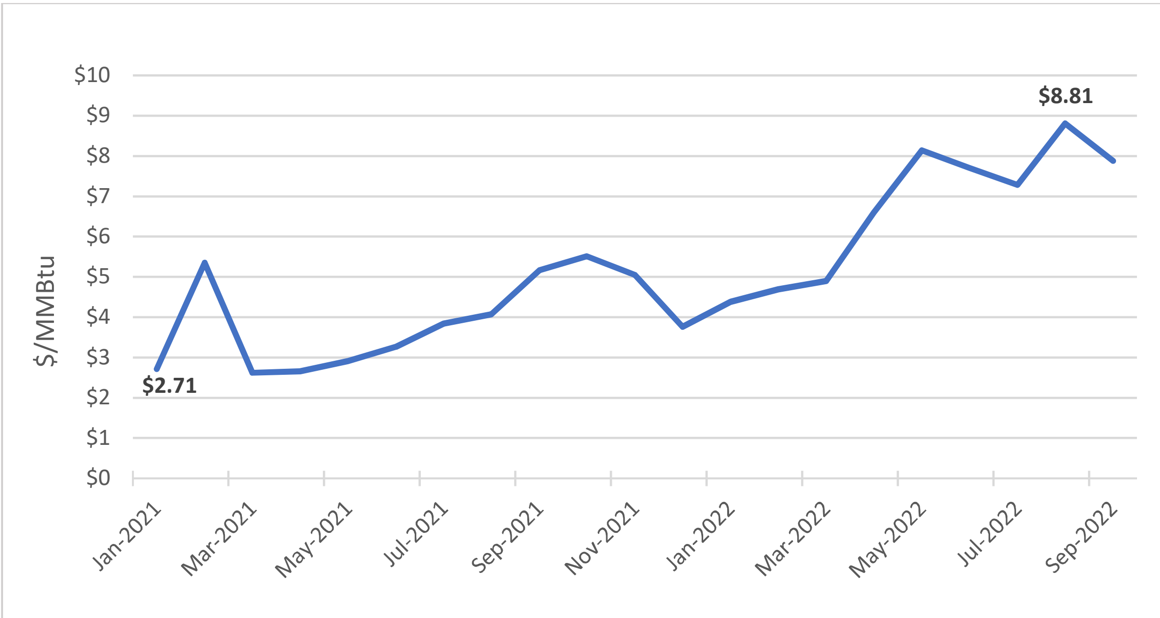
Altogether, $289.9 million in downstream investment was attributed to the second half of 2021. Cumulative downstream investments reported to date in Ohio, including 2011 through the second half of 2021, are set forth in Table 19 in Appendix A. An outline of the key products and processes for this sector within the shale gas value chain is set forth in Appendix B.

3. CONCLUSION

Total upstream shale investment in Ohio was down slightly (-3.5%) in the second half of 2021 compared to the first half of 2021. This decline is largely attributable to the continued fall in per-unit drilling costs due to increased operator efficiency. Wells drilled, production, and royalties all increased in the second half of 2021 over first half totals, and should increase further for the next shale report given the surge in energy prices during 2022 (*see* Figure 7).

[36] https://www.solvay.com/en/press-release/solvay-expands-its-us-based-sulfone-polymers-business
[37] https://nutrien-prod-asset.s3.us-east-2.amazonaws.com/s3fs-public/uploads/2022-06/2022%20Investor%20Update%20Presentation_0.pdf
[38] https://wasteadvantagemag.com/pttgc-america-chooses-central-ohio-for-recycling-project/

Figure 7: Recent Monthly Average Henry Hub Natural Gas Spot Price ($/MMBtu)



Data Source: EIA (2022)

Improvements in upstream operational efficiency have coincided with regular upward revisions to the volume of remaining technically recoverable resources (rTRR) in the Utica.[39] A 2019 U.S. Geological Survey assessment estimated that 117.2 trillion cubic feet (tcf) of natural gas remain in the Utica.[40] EIA's most recent assessment is that, as of January 2020, the Utica contains 257.6 tcf of rTRR.[41] However, a 2021 evaluation by the National Energy Technology Laboratory (NETL) indicates that these assessments are too conservative. NETL estimates that the Utica holds between 478.9 and 786.7 tcf of rTRR, which would make it the third largest gas accumulation in the world.[42]

For the Study period, Belmont County led all counties in production, while more northerly Jefferson County again had the highest number of new wells developed. This suggests that drilling activities continue to be focused more northward. Indeed, 69% of new well development occurred in northern counties during the second half of 2021.[43] Altogether, upstream shale investment totaled more than $2.1 billion for the second half of 2021.

[39] Remaining technically recoverable resources are also called "undiscovered" or "unproved" technically recoverable resources by the USGS and EIA, respectively.
[40] https://pubs.usgs.gov/fs/2019/3044/fs20193044.pdf
[41] https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf
[42] *See* https://www.osti.gov/servlets/purl/1805223. *See also* https://www.realclearenergy.org/articles/2022/04/04/americas_natural_gas_juggernaut_825258.html
[43] The four most active northern counties for drilling and production have been Jefferson, Harrison, Columbiana, and Carroll, while the four most active southern counties have been Belmont, Monroe, Guernsey, and Noble.

Midstream investments stabilized in the second half of 2021 after a downturn in the first half of the year. Among the investments that occurred during the Study period were $74 million in gathering system buildout, including $40 million for pipelines and $34 million for compression. The Study Team has already tracked at least this much in actual midstream spending for the first half of 2022. Additional expenditures toward the end of 2022 or beginning of 2023 could possibly include at least $160 million in pipeline investment to increase takeaway capacity out of the region and into the interstate transmission system.

Downstream investment picked up during the second half of 2021, thanks largely to the installation of major equipment for the CHP plant at Ohio State University's main campus. This project represents a $290 million investment.

In addition to the more than $2 billion in natural gas power generation that will likely be developed in Harrison and Trumbull Counties, future downstream investment in the region is also likely to include spending on natural gas-based hydrogen production. The DOE, as part of its Regional Clean Hydrogen Hub Funding Opportunity Announcement (FOA), plans to award $400 million to $1.25 billion to between 6 and 10 hubs to produce clean hydrogen, with cost share requirements doubling this amount.[44] The FOA stipulates that at least two hydrogen hubs must be located in regions with abundant natural gas resources.[45] Given this, and also given that more than ¼ of the groups projected to apply for funding as a natural gas-based hydrogen hub include partners from Ohio, there is a strong chance that a hydrogen hub will be developed within serviceable proximity from the Utica.[46]

Altogether, shale-related investment in Ohio for the second half of 2021, including upstream, midstream, and downstream, was around $2.5 Billion. Cumulative total shale related investment since 2012 is around $97.8 billion.

[44] The DOE's Clean Hydrogen Production Standard targets 4.0 kgCO2e/kgH2 for lifecycle (i.e., "well-to-gate") greenhouse emissions associated with hydrogen production. For natural gas-based hydrogen production, this requires a strategy for carbon capture, utilization, and storage (CCUS). For the DOE's Regional Clean Hydrogen Hub Funding Opportunity Announcement, *see* https://oced-exchange.energy.gov/FileContent.aspx?FileID=e159ff1f-5572-437e-b02d-b68acb461893. For information on the DOE's Clean Hydrogen Production Standard, *see* https://www.energy.gov/eere/fuelcells/articles/clean-hydrogen-production-standard

[45] *Id*.

[46] *See* https://www.csis.org/analysis/hydrogen-hubs-proposals-guideposts-future-us-hydrogen-economy

About the Study Team

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About the Energy Policy Center

The Energy Policy Center is housed within the Maxine Goodman Levin College of Urban Affairs at Cleveland State University. The mission of the EPC is to help overcome social and institutional barriers to the implementation of solutions to energy challenges by providing an objective channel for the free exchange of ideas, the dissemination of knowledge, and the support of energy related research in the areas of public policy, economics, law, business and social science. For more information, go to http://urban.csuohio.edu/epc/.

4. APPENDICES

APPENDIX A. CUMULATIVE OHIO SHALE INVESTMENT

Figure 8: Total Utica Production in Bcfe (Gas Equivalence) by County through December 2021

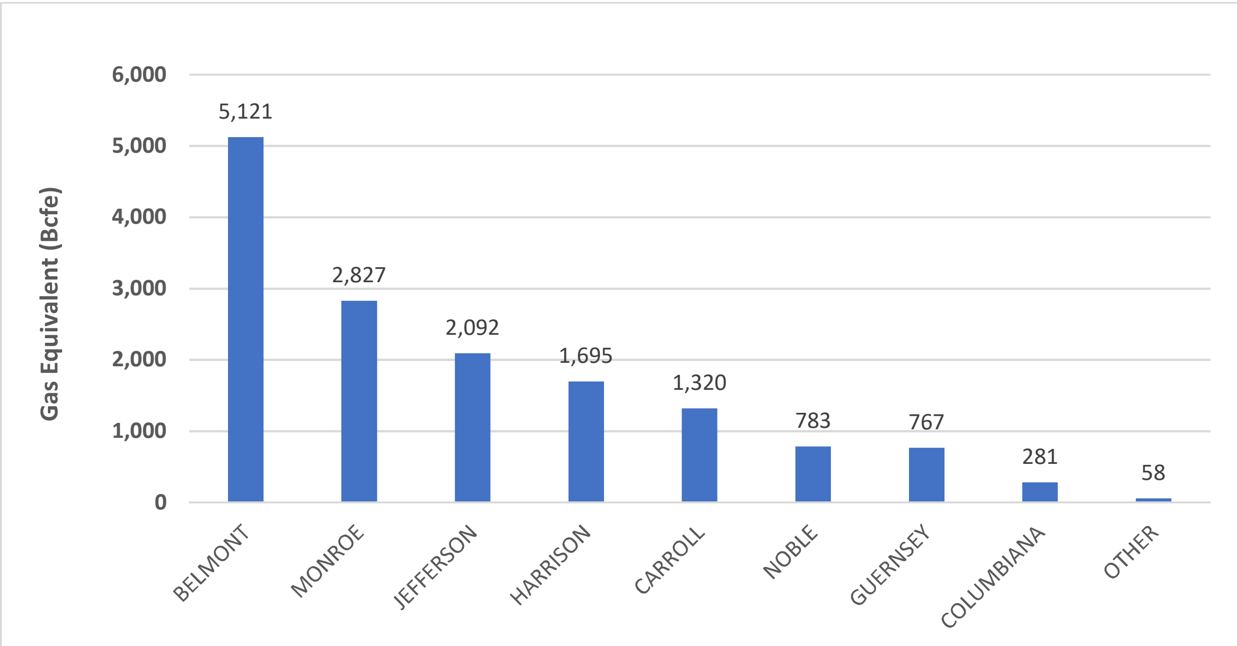


Figure 9: Total Utica Production in Bcfe by Operator through December 2021

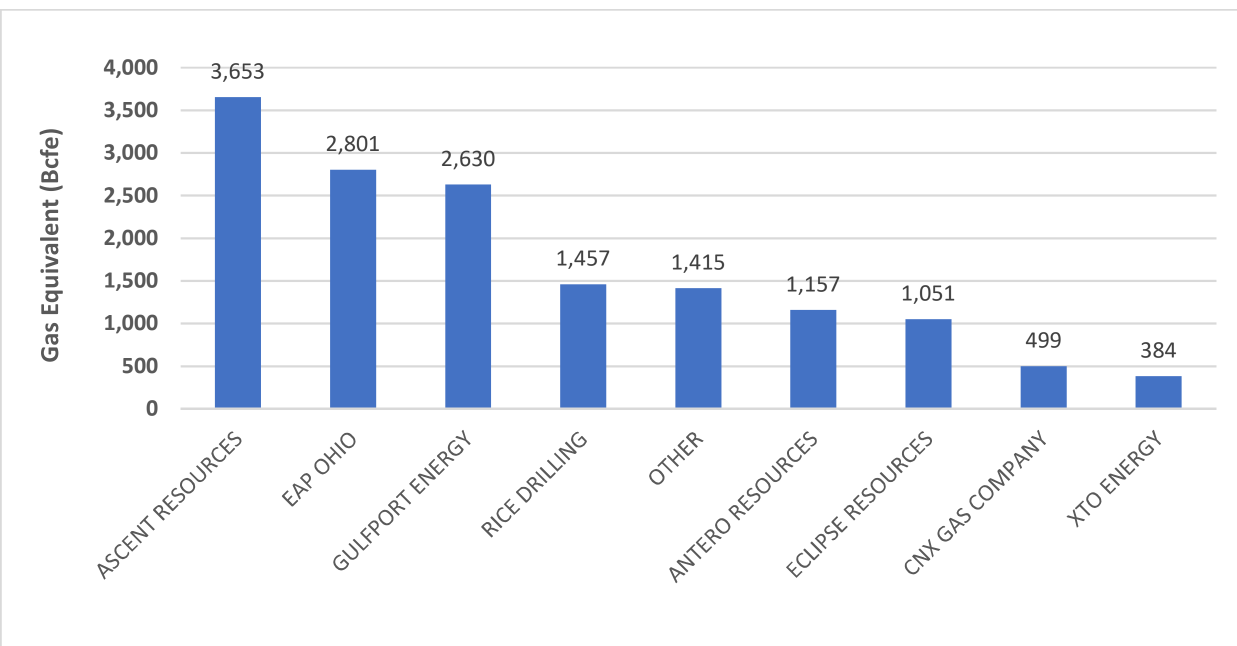
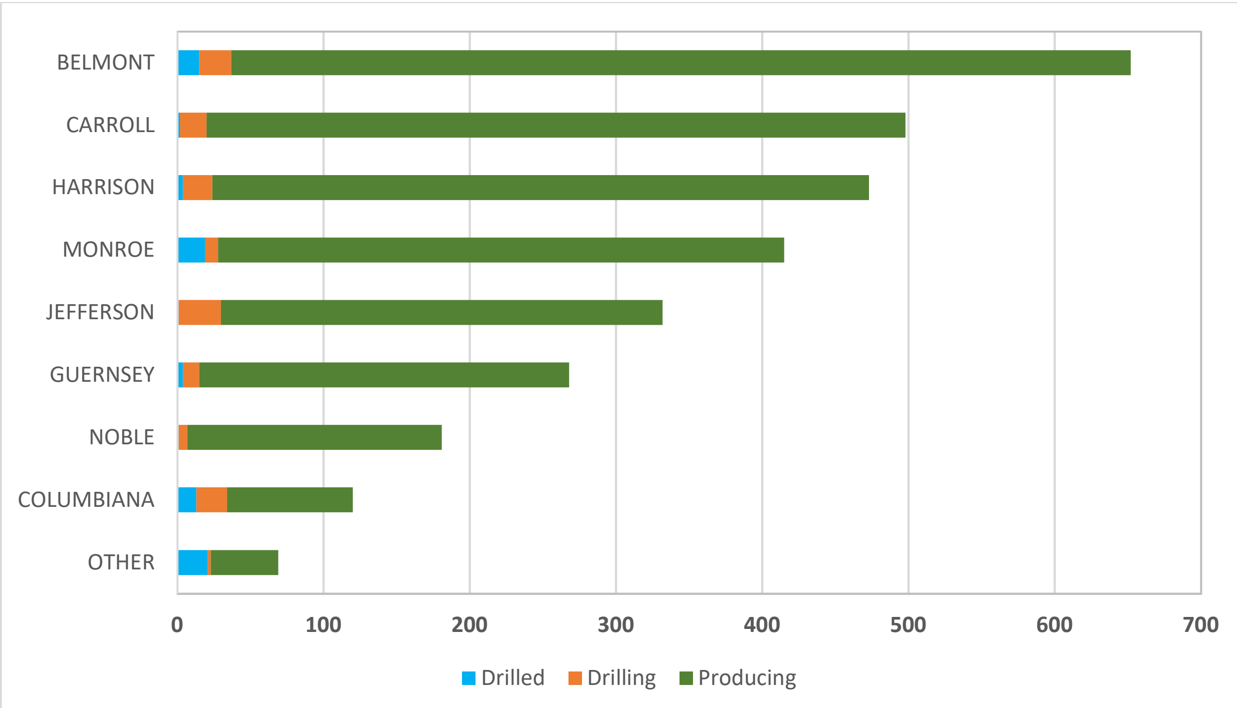


Figure 10: Cumulative Number of Wells by County through December 2021



Source: Ohio Department of Natural Resources (December 2021)

Figure 11: Distribution of Gas Equivalent Production for 2011 through December 2021

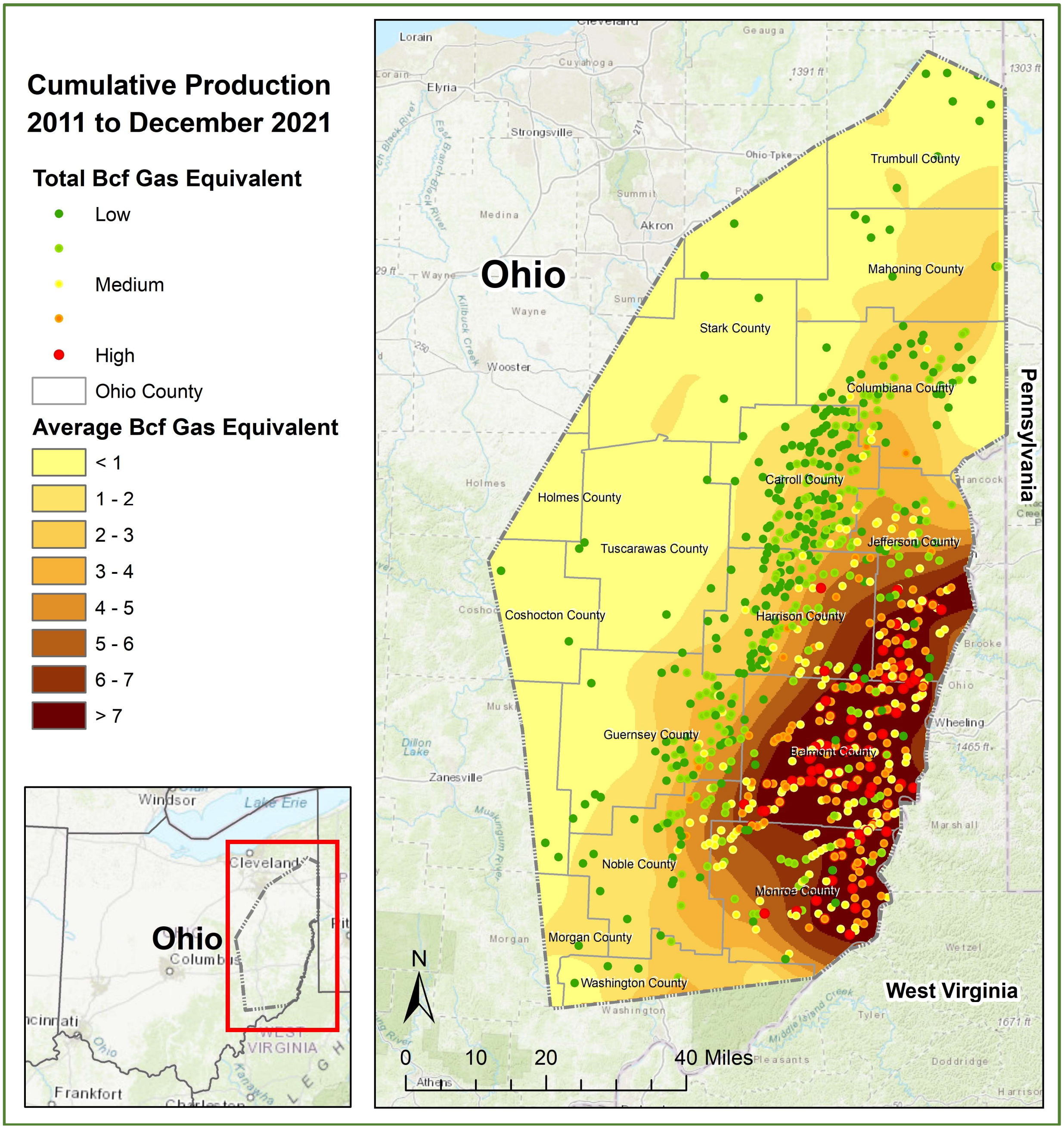


Figure 12: Distribution of Utica Wells by Status as of December 2021

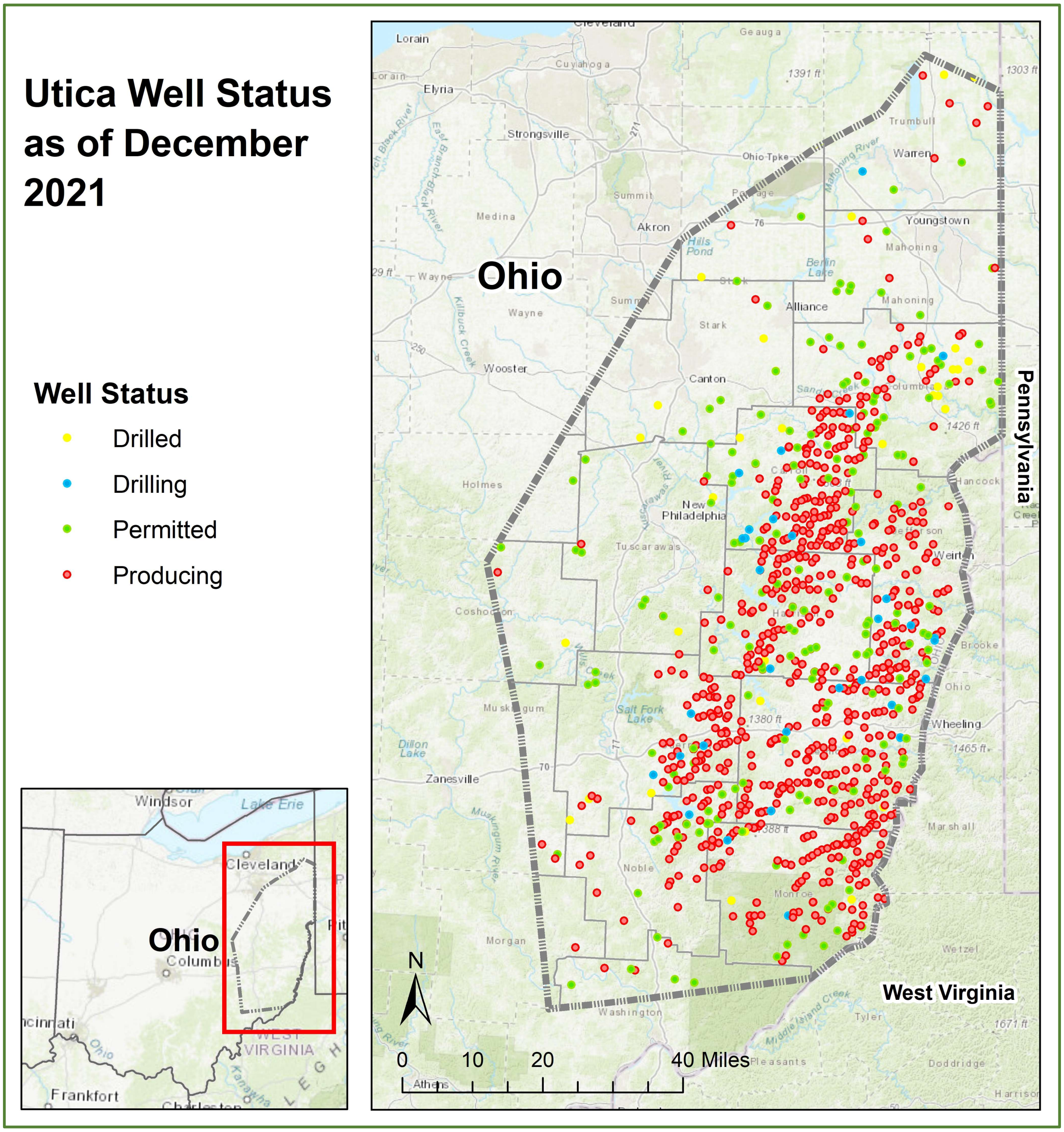


Table 15: Utica Upstream Companies Drilling in Ohio as of December 2021

Operator	Cumulative no. of Wells
EAP OHIO LLC	900
ASCENT RESOURCES UTICA LLC	702
GULFPORT APPALACHIA LLC	426
ANTERO RESOURCES CORPORATION	239
SWN Production (Ohio) LLC	195
RICE DRILLING D LLC	149
XTO ENERGY INC.	58
HILCORP ENERGY COMPANY	47
CNX GAS COMPANY LLC	46
INR OHIO LLC	43
EQUINOR USA ONSHORE PROPERTIES INC.	42
UTICA RESOURCE OPERATING LLC	37
PIN OAK ENERGY PARTNERS LLC	33
DIVERSIFIED PRODUCTION LLC	25
GEOPETRO LLC	17
GULFPORT ENERGY CORPORATION	12
ARTEX ENERGY GROUP LLC	9
NORTHWOOD ENERGY CORP	6
SUMMIT PETROLEUM INC	6
CHESAPEAKE EXPLORATION LLC	3
DEVON ENERGY PRODUCTION CO LP	3
BRAMMER ENGINEERING INC	2
ECLIPSE RESOURCES I LP	2
EQT PRODUCTION COMPANY	2
AMERICAN ENERGY UTICA LLC	1
BP AMERICA PRODUCTION COMPANY	1
EOG RESOURCES INC	1
TRIAD HUNTER LLC	1
Grand Total	**3,008**

Note: Cumulative Number of Wells are calculated based upon the total number Drilled, Drilling, and Producing. Source: ODNR (December 25, 2021).

Table 16: Total Lease Operating Expenses through December 2021 (in millions)

Year	Period	Production Wells	Lease Operating Expenses for Period ($mm)
2021	Q3 and Q4	2,791	151.8
2021	Q1 and Q2	2,700	205.7
2020	Q3 and Q4	2,705	206.1
2020	Q1 and Q2	2,772	266.2
2019	Q3 and Q4	2,497	262.2
2019	Q1 and Q2	2,173	228.0
2018	Q3 and Q4	2,200	231.0
2018	Q1 and Q2	1,874	191.2
2017	Q3 and Q4	1,818	121.8
2017	Q1 and Q2	1,588	141.3
2016	Q3 and Q4	1,467	101.2
2016	Q1 and Q2	1,355	97.6
2015	Annual	1,034	148.9
2014	Annual	612	88.1
2013	Annual	237	34.1
2012	Annual	82	3.0
2011	Annual	9	0.3
		Total	**2,478.5**

Table 17: Cumulative Utica-Related Upstream Investments in Ohio through December 2021

Estimated Investments	Total Amount
Mineral Rights	$25,653,135,000
Drilling	$29,052,360,000
Roads	$1,102,683,000
Lease Operating Expenses	$2,478,537,000
Royalties	$9,800,250,000
Total	**$68,086,965,000**

Table 18: Cumulative Utica-Related Midstream Investments in Ohio through December 2021

Estimated Investments	Total Amount
Midstream Gathering	$7,776,448,000
Processing Plants	$1,259,300,000
Fractionation Plants	$1,697,360,000
NGL Storage	$261,000,000
Rail Loading Terminals	$145,000,000
Transmission Pipelines	$10,303,128,000
Total	**$21,442,236,000**

Table 19: Cumulative Utica-Related Downstream Investments in Ohio through Dec. 2021

Estimated Investments	Total Amount
Petrochemical Plants and Refineries	$635,443,000
Other Industrial Plants	$760,000,000
Natural Gas Refueling Stations	$78,675,000
Natural Gas Power Plants	$6,442,500,000
Combined Heat and Power (CHP) Plants	$377,370,000
Total	**$8,293,988,000**

APPENDIX B. METHODOLOGY

1. Upstream Methodology.

Investment into the upstream for this fourth report has been broken down into four categories.

a. Wells and Related Roads. The first category is investment into wells and includes one-time investments into drilling and road construction related to well development. They were estimated as:

- Drilling:
  - Drilling and completion costs of $8.2 mm/well. [47]
  - Equivalent true vertical depth (TVD) for wells in all counties.
  - Average drilling and completion costs of $600 per lateral foot.[48]
  - Average lateral length of 13,600 ft.[49]
- Roads: average investments - approximately $119,000 per well based on recent OOGA reports and data for 2021 from engineer's office in Carroll, Noble, and Monroe counties.[50]

The number of new wells developed in the study period, used as a basis for these calculations, were accounted for by subtracting the number of wells in the drilled, drilling and producing categories as of July 1, 2021, from the number existent as of December 31, 2021. This information was downloaded from the ODNR's weekly *Combined Utica/Point Pleasant Shale Permitting Report*.[51]

b. Lease Operating Expense. The second estimated upstream cost identified by operators is the "lease operating expense." This includes post-production costs such as the storage, processing and disposal of produced water, among other expenses. Lease operating expenses

[47] Previous shale reports distinguished between drilling costs for northern counties (Carroll, Harrison, Jefferson, Columbiana, Trumbull, Mahoning and Tuscarawas) and southern counties (Noble, Guernsey, Belmont, Monroe and Washington) based on the assumption that the Utica is deeper in the south, requiring more expensive drilling in over-pressured formations. The Study Team conducted a review of drilling surveys associated with ODNR completion reports for new wells drilled since January 2020 and found a difference in mean true vertical depth between northern and southern counties of less than 500 ft., which would likely not lead to significant cost differences. Also, the same review of drilling surveys indicated that laterals for new wells in southern counties were not longer on average than for those in the north, contrary to prior analyses of lateral lengths by county. Indeed, laterals for wells in northern counties were found to be about 600 feet longer on average than those in the south, although this difference would likely not lead to significant cost differences.

[48] Based on Ascent Resources' and Antero Resources' estimated drilling costs per lateral foot in the Appalachian Basin during the second half of 2021. *See* https://www.prnewswire.com/news-releases/ascent-resources-utica-holdings-llc-reports-fourth-quarter-and-year-end-2021-operating-and-financial-results-and-issues-initial-2022-guidance-301500382.html. *See also* https://www.anteroresources.com/news-media/press-releases/detail/200/antero-resources-reports-fourth-quarter-results-announcesduring the . Ascent is active in both northern and southern counties. *See* https://oklahoman.com/article/5626621/ascent-resources-reports-growth-in-utica-shale-field-during-2018

[49] Calculated using well completion reports obtained from the ODNR's *Ohio Oil & Gas Well Database*.

[50] *See fn 13, supra.*

[51] https://ohiodnr.gov/business-and-industry/energy-resources/oil-and-gas-wells/horizontal-wells

for Utica wells were estimated to be a production-based $0.13/Mcf-equivalent. This average expense was developed by the Study Team based on analysis of Ascent's and Gulfport's lease operating expenses in the Utica for 2021 as reported in their annual financial statements.[52]

c. Oil and Gas Production Royalties. A third area of upstream investment, royalty calculation, is more complicated. The estimate is based upon the total production over the six-month period and the likely price received for sales of the hydrocarbon during that same period. However, because much of the natural gas has been processed, Ohio Department of Natural Resources production records cannot be readily converted to royalty payments. Accordingly, a number of assumptions are required to estimate the royalties paid. These include estimating the local market conditions at the time hydrocarbons were sold. Royalties were estimated on a per quarter basis for Utica production based upon the hydrocarbon content for a typical Utica well.

To estimate the royalties, the following assumptions were made based upon industry interviews, industry investor presentations, and Energy Information Agency reports:

- Production for each well was similar to that found in the wet gas region, and not the dry gas or condensate regions. This represents the average situation.
- The average production shrinkage after processing was 12%, thereby making the residue gas volume 88% of the total natural gas production. [53]
- The residue energy content was around 1.1 MMBtu/Mcf.[54]
- Residue gas in the Utica was selling at an average price of $3.88/MMBtu for Q3 and $4.17/MMBtu for Q4.[55] This price for the Appalachian basin was used to estimate royalties.
- Around 44 barrels of liquids were recovered per million cubic feet of gas produced.[56]
- Natural gas liquids were selling for around 30% of the listed price for Marcellus-Utica light crude oil.[57]
- Oil in the Utica region was selling for $60.02 and $67.11per barrel, on average, during the third and fourth quarters of 2021, respectively.[58]
- Royalty rates are 20% of gross production.

[52] *See* https://storage.googleapis.com/ascent-resources.appspot.com/documents/2021_Consolidated_Financial_Statements__Ascent_Resources_Utica_Holdings_LLC.pdf. *See also* https://www.gulfportenergy.com/investors/sec-filings/all-sec-filings/content/0001628280-22-004445/0001628280-22-004445.pdf
[53] Based on industry interviews, experts citing API 12.3, Manual of Petroleum Measurements and Standards
[54] The EIA estimates that the average conversion should be 1.037 MMBtu/Mcf (*see:* www.eia.gov/tools/faqs /faq.php?id=45*)*. However, industry interviews suggest 1.1 is closer to the average conversion for the Utica Shale.
[55] https://www.naturalgasintel.com/chesapeake-builds-natural-gas-rich-marcellus-portfolio-with-chief-tug-hill-purchase/.Hub prices reflect the delivered price of natural gas and so do not require further deductions for transportation costs. *See* https://www.eia.gov/todayinenergy/detail.php?id=18391
[56] Based on industry data.
[57] Based on industry interviews.
[58] *See* Marcellus/Utica prices for light crude at http://ergon.com/prices. More than 95% of Ohio oil production is light crude by API gravity. *See* https://www.eia.gov/petroleum/production/xls/api-history.xlsx

d. New and Renewal Lease Bonuses. Finally, a fourth form of upstream investment was estimated: new and renewal lease bonuses. For this purpose, we assumed that the average new lease or renewal bonus paid was $5000/acre, and that the typical lease has a five-year primary term. In prior studies, based upon the assumption that most undeveloped acreage was in the primary term of the least, we assumed that approximately 20% of the undeveloped acreage identified will need to be renewed each year or is otherwise new.[59] Since this Study covered six months, we assumed that half of this 20% was renewed or new during the Study period. However, as units have developed in the Utica, we have changed this estimate going forward to assume that 25% of the operator's total acreage is in its primary term, and that 20% of this acreage must be renewed or replaced very year (10% for a six-month period). This estimate may be high insofar as companies are not renewing or replacing all their primary term acreage. However, it may also be low insofar as the studies have only identified net acreage for the top six to nine operators in Ohio and may not be capturing all of the non-operator net acreage. (Acreage status is typically reported in company 10-K and other financial statements).

2. Midstream Methodology.

Midstream investments include pipeline construction (intrastate, gathering lines and inter-state), processing plants (compression, dehydration, fractionation, and others), natural gas liquid storage facilities, and railroad terminals and transloading facilities. Midstream expenditures were estimated based upon a combination of midstream company investor reports, media reports, and industry "rules of thumb" obtained from industry interviews, government reports, and industry trade journals. Estimated investments were then compared against investor presentations and other information gleaned from public sources to confirm their accuracy. Interviews were also used to confirm ranges of expenditures.

a. Processing plants. Processing plant information was obtained by searching a wide range of resources including EPA permit databases, news agencies, and company web sites and presentations. For purposes of estimating the investments for midstream processing plants, rules of thumb were developed based upon facility throughput capacities. These rules of thumb were applied to the processing plants that have been built in Ohio, using the throughput capacity estimates cited in permit documents, or made available from public literature. Likewise, rules of thumb based upon throughput capacity were used to estimate investments downstream of the processing plants, such as storage facilities and loading terminals. Dehydration processing plants were estimated using average cost per Mcf capacity for similarly designed and recently built plants in the Appalachian region.

Compressor station investments were calculated based on the horsepower rating listed in Ohio EPA air permit data and estimated construction costs per horsepower of $3,876 for the Midwest Region as obtained from the INGAA, as projected for 2021.[60]

[59] This estimate was confirmed through industry interviews. New operator undeveloped acreage reports are likely to be made available over time that may suggest these estimates could be either too high or too low.
[60] https://www.ingaa.org/File.aspx?id=34658

The approximate capital cost for TEG dehydration units based on throughput was obtained from Carroll's *Natural Gas Hydrates: A Guide for Engineers* (2014, 3rd ed.). Facilities receiving a final permit-to-install or permit-to-install-and operate were assumed to be constructed during the same 6-month period in which the permit was issued by the Ohio EPA.

The following assumptions were used to estimate midstream-related investments:

- Processing Plants.
    - $400,000 per MMcf/d throughput
    - $80 MM per 200 MMcf/d plant (typical skid size)
- Fractionation Plants: $3,542 per bbl/d[61]
- Storage Tankage: $80 MM for 1 Bcf/d throughput
- Rail Loading Terminals: $40 MM for 1 Bcf/d throughput

b. Pipelines. Pipeline investments were estimated by applying "inch-mile" cost estimates to known pipeline diameter and length for both inter- and intrastate projects. Interstate pipeline diameters and mileage can be determined from Federal Energy Regulatory Commission data these estimates were confirmed from investor presentations, when available. Intrastate mileage and diameter were determined using data for gathering system construction that was obtained from the Public Utilities Commission of Ohio.[62]

For this report, up-to-date cost projections for natural gas transmission and gathering line pipelines, per inch-mile, was obtained from the Interstate Natural Gas Association of America (INGAA).[63] The estimated cost for natural gas pipelines for the Midwest Region as used in this analysis was $199,915 per inch-mile, which included labor, raw materials, and permitting costs, as projected by the INGAA for 2021.

No investments into distribution lines were included in the Study since it is assumed that these have not grown as a direct result of shale development. For pipelines carrying liquids, the

[61] The Study Team reviewed the published investment costs and throughput capacities of eight different fractionation facilities that have been developed since 2018, all of which are in Texas. The assumed unit cost for fractionation reflects the median investment per barrel of processing capacity per day for these eight facilities. *See* the following examples: Targa Resources Inc.'s Mont Belvieu fractionation facilities (https://www.naturalgasintel.com/targa-building-two-new-fractionation-trains-at-mont-belvieu/); Phillip 66's Sweeny fractionation facilities (https://s22.q4cdn.com/128149789/files/doc_presentations/2019/11/Investor-Day-Slides-for-Website-11.06.2019-vF.pdf).

[62] that the data currently used supersedes data used in previous reports for study periods through June 30, 2017. Newer data suggests that the previously used assumption of 4 miles of gathering line per well pad was about twice as high as what midstream companies actually deploy in the field on average. Additionally, oil and gas companies can accommodate more than three times the 3-wells-per-pad that the Study Team assumed in prior studies. Earlier iterations of this dashboard assumed companies would drill three wells per pad on average, move on to other locations, and then come back later to infill. As the Utica play becomes more mature, we can expect that there will be a greater number of wells per pad, and therefore fewer gathering pipeline miles per well.

[63] The INGAA Foundation, Inc. (2018). *North America Midstream Infrastructure through* 2035. https://www.ingaa.org/File.aspx?id=34703.

investment assumption is that expenditures will be comparable to those seen for gas pipelines. These were also corroborated by industry investor reports.

3. Downstream Methodology.

For estimating downstream expenditures, the Study Team relied upon publicly available reports gathered from news media, trade association publications, company websites and investor presentations. The Study Team also used interviews, and Ohio EPA permits and public notices to identify projects and support investment estimates. Search terms included identified company names, and key words associated with specific facility types and industries.

As of this report, downstream investment is categorized into eight categories:

- Natural Gas Power Plants
- Combined Heat and Power Plants
- Ethane Cracker Plants
- Methanol Plants
- Refineries
- Natural Gas refueling stations
- Petrochemical Plants
- Other industrial plants with natural gas inputs

NAICS codes used to generate keywords for searches included the following:
3251 – Basic Chemical Manufacturing
3252 – Resin, Synthetic Rubber, and Artificial and Synthetic Fibers and Filaments Manufacturing
3253 – Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing
3255 – Paint, Coating, and Adhesive Manufacturing
3259 – Other Chemical Product and Preparation Manufacturing
3261 – Plastics Product Manufacturing

Downstream activities include the deployment of processes that turn hydrocarbons— natural gas (methane) and natural gas liquids (ethane, propane, butanes)—into higher-valued fuels and petrochemicals. Shale gas may be monetized into numerous resulting value-added products. Figure 13 shows the primary intermediates and products that can be manufactured from the main hydrocarbon components in shale gas as part of downstream production.[64]

[64] *See* https://www.energy.gov/sites/prod/files/2020/06/f76/Appalachian%20Energy%20and%20Petrochemical%20Report_063020_v3.pdf

Figure 13: Shale/Natural Gas Value Chain for Petrochemicals