# New York State Oil and Gas Methane Emissions Mitigation Potential

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NEW YORK STATE | NYSERDA

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## Our Mission:

Advance clean energy innovation and investments to combat climate change, improving the health, resiliency, and prosperity of New Yorkers and delivering benefits equitably to all.

# New York State Oil and Gas Methane Emissions Mitigation Potential

***Final Report***

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# Notice



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# Abstract

The New York State Climate Leadership and Community Protection Act (Climate Act) codifies ambitious clean energy targets to drive a fundamental transition in the energy system. Under the Climate Act, New York State is required to reduce economywide greenhouse gas (GHG) emissions 40 percent by 2030 and no less than 85 percent by 2050 from 1990 levels. The goal of this project was to apply best practices identified in the literature to project future methane emissions from the oil and natural gas sector in New York State through 2050. Building off the Integration Analysis, several methane mitigation scenarios were modeled to better understand methane mitigation potential and the costs associated with mitigation. In the modeled scenarios, methane emissions in New York State could be reduced 26 to 76 percent by 2030 and 33 to 84 percent by 2050 compared to 1990 levels depending on the level of ambition. The associated mitigation costs, not considering avoided costs, range from \$15.05 to \$103.06 per $MTCO_2e$ reduced (AR5, GWP20).



# Keywords

Methane, oil, natural gas, emissions, inventory, greenhouse gas inventory, emission factors, methane inventory, downstream emissions, upstream emissions, midstream emissions, projections, natural gas production, New York State methane inventory, methane mitigation



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# Acronyms and Abbreviations

| | |
|---|---|
| AT | Accelerated Transition Away from Combustion |
| API | American Petroleum Institute |
| CAD | Canadian dollar |
| CARB | California Air Resources Board |
| CEC | Commission for Environmental Cooperation |
| $CH_4$ | methane |
| $CO_2e$ | carbon dioxide equivalent |
| EIA | Energy Information Administration |
| EPA | Environmental Protection Agency |
| FEAST | Fugitive Emissions Abatement Simulation Toolkit |
| GHG | greenhouse gas |
| IAS2 | Integration Analysis Scenario 2 |
| IAS3 | Integration Analysis Scenario 3 |
| IEA | International Energy Agency |
| IPCC | Intergovernmental Panel on Climate Change |
| LCF | low carbon fuels |
| LDAR | leak detection and repair |
| LNG | liquified natural gas |
| MW | megawatts |
| NARUC | National Association of Regulatory Utility Commissioners |
| NEB | National Energy Board |
| NPV | net present value |
| NRDC | Natural Resources Defense Council |
| NRTEE | National Round Table on the Environment and the Economy |
| NYS | New York State |
| NYSERDA | New York State Energy Research and Development Authority |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| RECS | Residential Energy Consumption Survey |
| SA | Scientific Aviation |

# Summary

In 2019, New York State (NYS) enacted the Climate Leadership and Community Protection Act (Climate Act) codifying ambitious clean energy targets to drive a fundamental transition in the energy system. Under the Climate Act, NYS is required to reduce economywide greenhouse gas (GHG) emissions 40 percent by 2030 and no less than 85 percent by 2050 from 1990 levels. NYS must also achieve 70 percent renewable generation by 2030 and a zero-emissions electricity sector by 2040. In 1990, methane emissions from the oil and natural gas sector in NYS totaled 17,400,427 $MTCO_2e$. Oil and gas methane missions would need to reduce to 10,440,256 $MTCO_2e$ or less in 2030 and oil and gas methane emissions would need to total 2,610,064 $MTCO_2e$ or less in 2050 in order to reach NYS's economywide climate goals as modeled in the Integration Analysis.

The objectives of the project discussed in this report are to:

1. Conduct a literature review on best practices for projecting future oil and gas sector methane emissions.
2. Implement a best practices approach while building off the previously developed NYS oil and natural gas methane emissions inventory to project future methane emissions from the oil and natural gas sector in NYS.
3. Develop and model methane mitigation scenarios while coordinating with NYS's Integration Analysis to help NYS make informed decisions about how best to reduce methane emissions in the oil and natural gas sector.

The methane emissions projections and mitigation options presented in this report are based on the 2020 NYS Oil and Gas Methane Inventory and 2022 integration analysis.

Total emissions over time in the different Integration Analysis scenarios are shown in Figure ES-1. From 2023 to 2050, emissions decrease steadily in the Reference case and Integration Analysis Scenario 2 and Integration Analysis Scenario 3, although at a slower rate in the Reference case. IAS–Level 1 Mitigation, IAS2–Level 2 Mitigation follow a similar pattern; there is a steep decline in emissions between 2023 and 2030 due to decommissioning, LDAR, and equipment changeout. After 2030 the achievable rate and penetration of mitigation is approached, and emissions continue to decrease only slightly to reach the 2050 emissions goal. The addition of decommissioning contributes the most to emissions reductions, as seen in Figures ES-2 and ES-3. As more equipment is decommissioned over time, LDAR contributes less to emissions reductions.

**Figure S-1. State-Level Methane Emissions from 1990 to 2050 Under Integration Analysis Scenario 2**

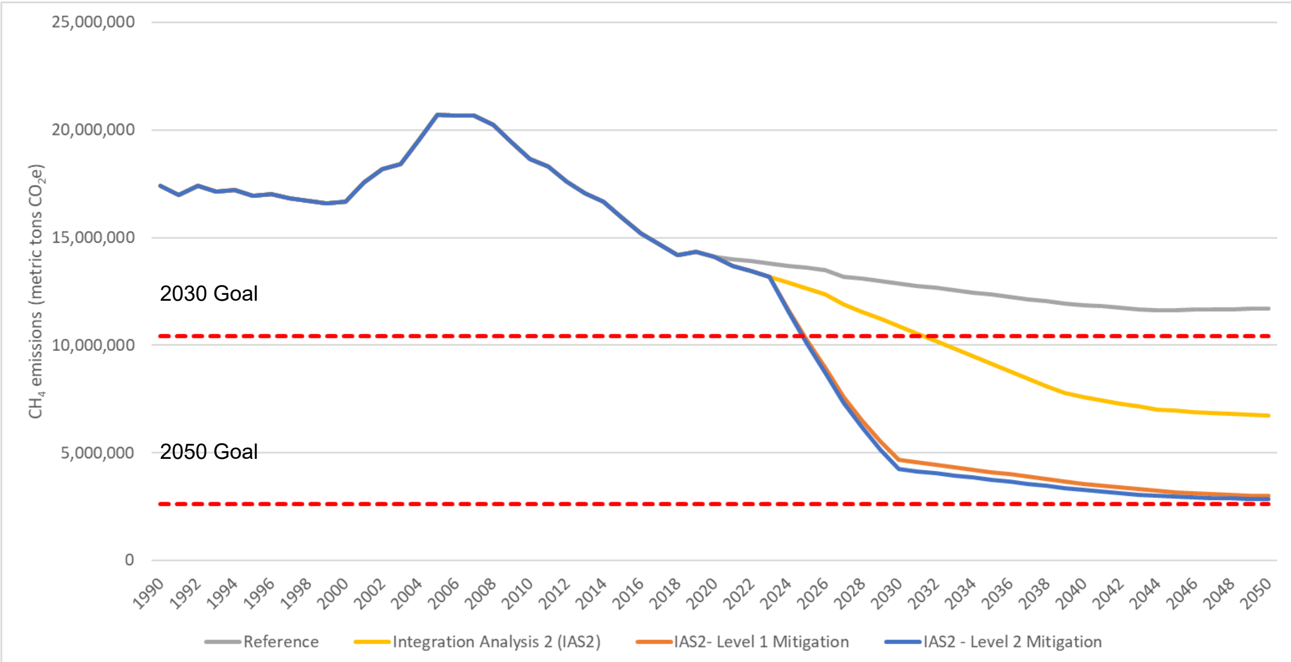



**Figure S-2. IAS2–Level 1 Mitigation Emissions Reductions by Mitigation Measure**

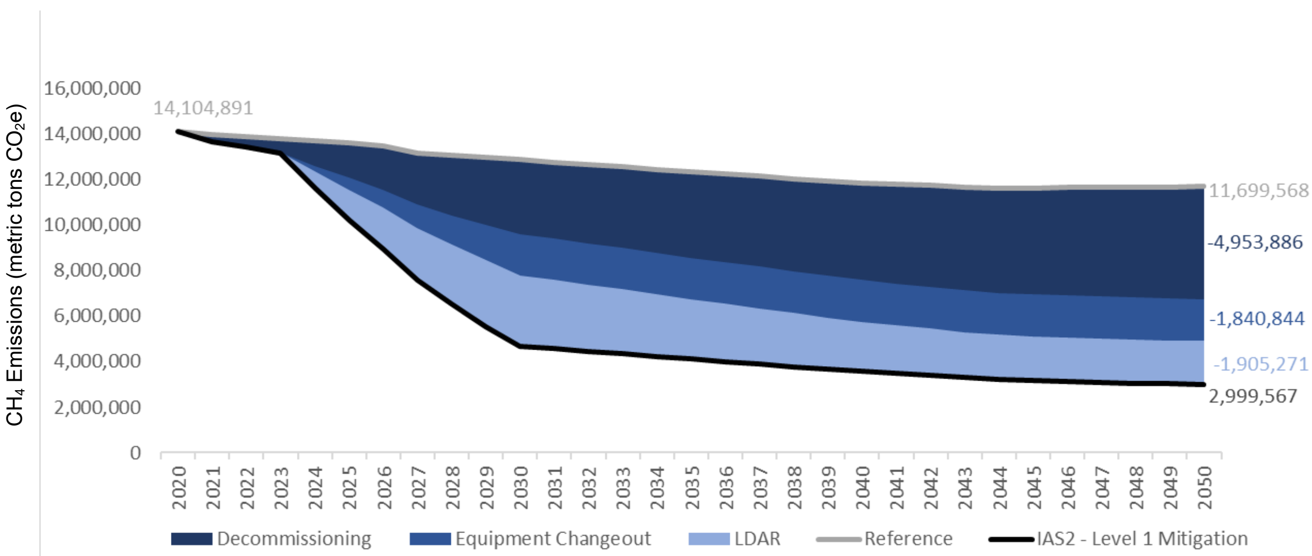
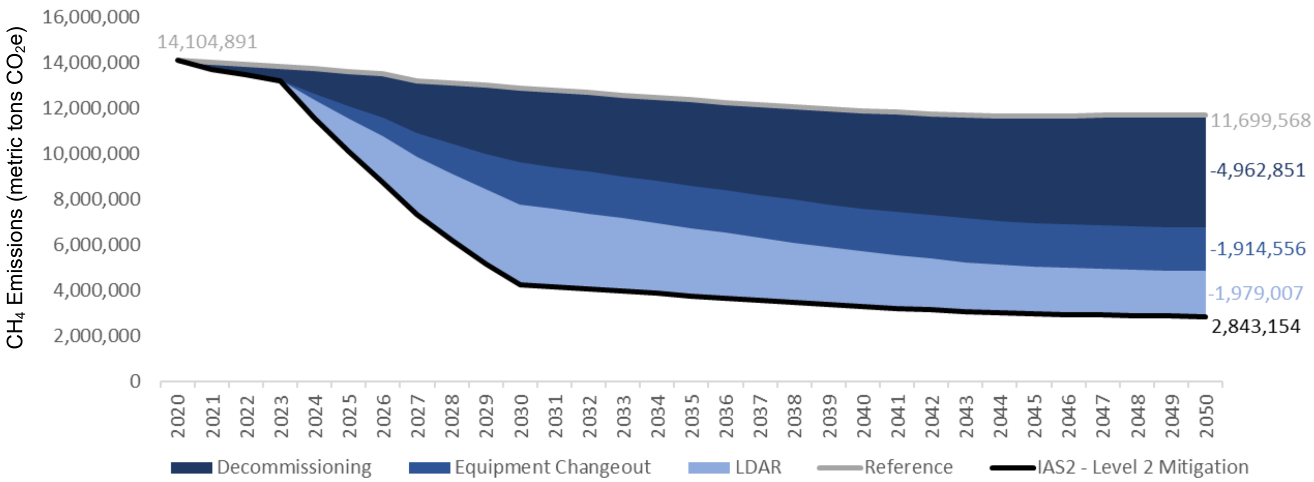


**Figure S-3. IAS2–Level 2 Mitigation Emissions Reductions by Mitigation Measure**




Results indicate that oil and gas methane emissions reductions through 2050 are more strongly correlated with building electrification than with natural gas demand, since building electrification drives natural gas infrastructure contraction (decommissioning). Depending on the integration analysis and mitigation scenarios, emissions totaling 2.7 to 11.7 $MMTCO_2e$, remain through 2050. Emissions in the reference case are reduced 26 percent by 2030 and 33 percent by 2050 compared to 1990 emissions. Emissions are reduced 37 percent by 2030 and 61 percent by 2050 in IAS2, 73 percent by 2030 and 83 percent by 2050 in IAS2–Level 1 Mitigation, and 76 percent by 2030 and 84 percent by 2050 in IAS2–Level 2 Mitigation. Emissions reductions in IAS3, IAS3–Level 1 Mitigation, and IAS3–Level 2 Mitigation are similar or slightly higher than IAS2. Therefore, oil and gas methane emissions reductions exceed alignment with NYS's 2030 economywide reduction level in IAS2–Level 1 Mitigation, IAS2–Level 2 Mitigation, IAS3–Level 1 Mitigation, and IAS3–Level 2 Mitigation, but no scenario achieves alignment with the 2050 economywide reduction level; however, since New York State's GHG limits are economywide requirements they could still be met through additional emissions reductions in other sectors.

Depending on the scenario and whether avoided costs are considered, modeling results indicate that mitigation costs range from -$25.04 to $103.06 per metric ton of $CO_2e$. When avoided costs are included, and prior to applying Level 1 Mitigation or Level 2 Mitigation, IAS2 and IAS3 result in net savings amounting to approximately $2.28 million or $2.20 million, respectively. Additionally, costs to achieve the Level 2 Mitigation emissions reductions compared to Level 1 Mitigation emission reductions are much higher because Level 2 Mitigation includes more costly strategies such as LDAR on plastic distribution pipelines. The additional costs of adding Level 1 Mitigation onto IAS2 or IAS3 are smaller as the strategies in Level 1 Mitigation are less costly. Level 2 Mitigation, while being more costly, also results in smaller emissions reductions than Level 1 Mitigation since the strategies are applied to emissions sources that are more difficult to mitigate.

# 1 Introduction

In 2019, New York State (NYS) enacted the Climate Leadership and Community Protection Act (Climate Act) codifying ambitious clean energy targets to drive a fundamental transition in the energy system. Under the Climate Act, NYS is required to reduce economywide greenhouse gas (GHG) emissions 40 percent by 2030 and no less than 85 percent by 2050 from 1990 levels. NYS must also achieve 70 percent renewable generation by 2030 and a zero-emissions electricity sector by 2040. Additionally, the Climate Act also specifies minimum targets for certain resources, including 6,000 megawatts (MW) of distributed solar resources by 2025, 3,000 MW of storage by 2030, and 9,000 MW of offshore wind generation by 2035. All this must be achieved while working toward a goal that ensures 40 percent of benefits from clean energy spending will occur in disadvantaged communities. In 1990, methane emissions from the oil and natural gas sector in NYS totaled 17,400,427 $MTCO_2e$. Oil and gas methane missions would need to reduce to 10,440,256 $MTCO_2e$ or less in 2030 and oil and gas methane emissions would need to total 2,610,064 $MTCO_2e$ or less in 2050 in order to reach NYS's economywide climate goals as modeled in the Integration Analysis.

The objectives of the project discussed in this report are to:

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3. Develop and model methane mitigation scenarios while coordinating with NYS's Integration Analysis to help NYS make informed decisions about how best to reduce methane emissions in the oil and natural gas sector.

The remainder of this document is organized by chapters and presents the results of the literature review and development of a best practices approach for projecting future methane emissions (Section 2), development of mitigation scenarios (Section 3), methodology for developing emissions projections in the baseline and reference cases (Section 4), emissions reduction potential and cost of mitigation options (Section 5), methodology for developing emissions projections in the mitigation scenarios (Section 6), results (Section 7), future improvements (Section 8), and conclusions (Section 9).

# 2 Literature Review

To inform the development of methane emissions projections and mitigation strategies, a literature review was performed to identify and define best practices for developing projections and mitigation strategies. This section outlines the information collected during the literature review.

## 2.1 Best Practices for Developing Methane Emissions Projections for the Oil and Natural Gas Sector

Emissions forecasts, or scenarios, are alternative images of how the future might unfold and are used to analyze how driving forces, such as demographic, technological, and socio-economic developments, may influence future emission outcomes and to assess the associated uncertainties in the outcomes (IPCC 2000). Scenarios can be used to determine emissions reductions goals and to identify and prioritize emissions reductions measures (IPCC 2000). However, the possibility that any single emissions path will occur as described in scenarios is highly uncertain (IPCC 2000). In general, when forecasting emissions, both a baseline scenario and mitigation scenario(s) are developed. The baseline scenario, sometimes referred to as a business-as-usual scenario, describes future greenhouse gas (GHG) emissions levels without additional mitigation efforts and policies. The mitigation scenario describes future emissions levels after additional mitigation efforts and policies.

The National Round Table on the Environment and the Economy (NRTEE) define forecasting as a depiction or model of how a system will evolve both with and without policy intervention; emissions forecasts depict the effects of policies on GHG emissions (NRTEE 2007). NRTEE has published a report of international best practices surrounding methodologies and governance in emissions forecasting. In discussing methodology, NRTEE (2007) points to the IEA's (International Energy Agency) World Energy Outlook and the EIA International Energy Outlook as best practices since they provide systematic analysis of aggregate measures and intensities (measures of economic growth, population, and energy intensity), include sections on potential errors in previous forecasts, and discuss key assumptions and sources of uncertainty. A review of additional literature, such as OECD (Organization for Economic Co-operation and Development) guidelines on baseline development (Clapp and Prag 2012) and IPCC Good Practice Guidance documents (IPCC 2006), finds that best practice guidance focuses on the following four components:

4. **Transparency.** Clear and transparent definitions of the forecasting approaches, particularly assumptions about the timeframe and details on the methods and data used. Transparency and information disclosure are essential to demonstrate the credibility of the scenarios to stakeholders.

5. **Stakeholder engagement.** Involve stakeholders in the development of the scenarios and make information about how stakeholders were consulted and how recommendations have been acted upon available publicly.
6. **Assessing uncertainty.** Identify key drivers and quantify their relative impact on emissions levels.
7. **On-going evaluation.** Continue to adjust scenarios as better data/information becomes available.

### 2.1.1 United States Environmental Protection Agency (EPA) and California Air Resources Board (CARB) Approaches to Emissions Projections

The EPA and many states in the U.S. publish greenhouse gas inventories and projections. Several GHG inventory reports were located outlining the general methods for forecasting emissions and developing emissions scenarios. In outlining the methodologies for projecting non-carbon dioxide ($CO_2$) sources, EPA describes the general approach used to project emissions (EPA 2013). As a starting point, EPA uses the most recent greenhouse gas inventory for the base year. Future changes in emissions factors are estimated based on past trends and changes expected based on policy implementation. Key elements to project emissions identified by EPA (2013) are activity drivers, scenarios, policies and measures, and technology characterization and change. Activity data projections, or activity drivers, serve as proxies, allowing the development of reasonable estimates of future year activity from base year activity levels (EPA 2013). For example, the Energy Information Administration (EIA) develops long-term energy production and consumption projections with the Annual Energy Outlook using a model that seeks to accurately represent all aspects of energy in the U.S. (EPA 2013, EIA 2020). These projections can be used to estimate activity in future years for source categories that use activity data based on energy (e.g., oil and natural gas systems) (EPA 2013). Additional activity drivers used to forecast emissions include those for population and gross domestic product from sources such as the United States Census Bureau (EPA 2013). Projection scenarios include those with currently implemented policies and measures, those that remove the effects of policies and measures, and those that include additional, planned policies and measures (EPA 2013).

The California Air Resources Board (CARB) describes the methodology used to project California's methane emissions (CARB 2016). The general approach is to multiply the base year emissions by sector- or activity-specific growth factors, which are calculated as the ratio of projected activity level for the future year to base year activity level (CARB 2016). CARB (2016) defines the base year as the average of emissions from three recent years form the statewide GHG inventory. Activity level data are parameters such as fuel consumption, electricity demand or generation, amount of material used, production data, and human population (CARB 2016). CARB (2016) describes two scenarios for projections, a baseline, and scenarios reflecting the effects of policy and regulations. CARB (2016) describes projection methods used for each sector, including energy sectors.

### 2.1.2 Recommendations for Developing Emissions Projections

When developing the baseline and mitigation scenarios, NYSERDA should focus on (1) being transparent when defining forecasting approaches; (2) involve stakeholders when possible to solicit feedback and obtain buy-in on the proposed approaches; (3) assess uncertainty by identifying key drivers of emission changes between scenarios; and (4) continue to evaluate the mitigation scenarios and adjust over time as new data/information becomes available. In addition, key activity drivers should be based on reputable, transparent sources such as the Census Bureau, the Energy Information Administration, the International Energy Agency, the EPA and New York State agencies.

## 2.2 Summary of Mitigation Options Discussed in the Literature

**Table 1. Key Takeaways from Literature Review on Mitigation Options**

| Topic | Sources | Takeaway |
|---|---|---|
| Future of Energy and O&G | EIA 2020 ; Mac Kinnon et al. 2018 ; Gillessen et al. 2019 ; Sen et al. 2019 ; Pan et al. 2020 | Natural gas production is projected to increase in most cases through 2050; only studies outside of the U.S. were located that forecasted oil and gas consumption. Natural gas could support renewable energy integration. |
| General Mitigation Strategies in O&G Sector | IEA 2020 ; Fernandez et al. 2005 | Mitigation strategies include replacing existing devices, installing new devices, and LDAR. Barriers to mitigation are lack of knowledge and information, inadequate infrastructure, lack of resources for pursuit, regulatory challenges, and misaligned investment incentives. |
| Abandoned Oil and Gas Wells | Kang et al. 2019 ; Yin et al. 2020 ; Bishop 2013 | Abandoned oil and gas wells are a source of methane and should be considered for mitigation in policies. Plugging wells costs $37,000 on average, but data from NYS estimates $5,000 per well. Methanotrophic microbes have been investigated as another mitigation strategy at abandoned wells. |
| Pipeline Replacement and Rehabilitation | Gallagher et al. 2015; NARUC 2020; Hausman and Muehlenbachs 2017 | Replacing pipelines reduces leaks and improves safety. Several plans have been submitted to modernize infrastructure in NYS. Distribution firms have been under incentivized to avoid leaks. |
| Leak Detection and Repair (LDAR) | Fox et al. 2019 ; Ravikumar and Brandt 2016 ; Ravikumar et al. 2020 ; Schwietzke et al 2019 | Emissions reduction potential increases with the number of LDAR surveys conducted. The economic benefit depends on the value of the gas and the amount that would have leaked, but the majority of leaks are economic to repair. Aerial LDAR techniques and infrared cameras have been studied at oil and gas facilities. |
| Pipeline Decarbonization | E3 2015; Speirs et al. 2018 | Decarbonizing gas, such as replacing natural gas with biomethane or hydrogen, could be more cost effective than high electrification. |
| Pipeline Decommissioning or Abandonment | Enbridge n.d.; NiGen 2018; SCS Engineers; Canada NEB 2014 | Most pipeline decommissioning involves pipeline abandonment (leaving it in place but disconnecting the line). Complete removal of pipeline has the most effect on communities and the environment. No costs were located for pipeline abandonment. |

Studies and reports identified during the preliminary literature review and summarized in Table 1, discussed the future of energy and natural gas, pipeline replacement and rehabilitation, and methane mitigation strategies in the oil and natural gas sector. EIA's Annual Energy Outlook predicts that natural gas production increases in most cases through 2050, which supports increasing consumption (EIA 2020). However, projections are sensitive to technology and resource assumptions. Several studies analyze the effectiveness of policies to reduce methane emissions in the oil and gas sector. Klemun and Trancik (2019) analyzed the magnitude and timing of methane mitigation needed to achieve climate policy goals, finding that methane emissions from the power sector would need to be reduced 30–90 percent by 2030 in order to meet a climate policy target reflecting a scenario to meet economy wide US climate policy commitments under the Paris Agreement ($CO_2$e emissions 32 percent below 2005 levels by 2030) while still relying on natural gas; expanding carbon-free sources more rapidly could meet the 2030 target without reducing natural gas leakage rates. A few studies were identified that discuss mitigating methane emissions from upstream sources; some of these studies discuss options for reducing emissions from abandoned oil and gas wells (Kang et al. 2019; Yin et al. 2020), while one study listed NYS-specific cost estimates for plugging abandoned oil and gas wells (Bishop 2013). Other studies broadly discuss options for reducing methane emissions from several sectors, including oil and gas (Hopkins et al. 2016; Karakurt et al. 2012; Nisbet et al. 2020). These studies briefly mention the need for more comprehensive monitoring programs and for repairing and replacing pipelines. Mac Kinnon et al. (2018) and Gillessen et al. (2019) analyzed the role that natural gas can play in supporting sustainable energy strategies. Two studies were identified that analyzed and projected natural gas consumption, although neither forecasted consumption in the United States; Sen et al (2019) predicted future natural gas consumption in Turkey using socio-economic indicators while Pan et al. (2020) forecasted China's oil and gas consumption under five different scenarios. The future of oil and gas consumption in China faces many uncertainties but is most impacted by national low-carbon mitigation strategies and oil prices (Pan et al. 2020). In Turkey, where most natural gas is imported, natural gas consumption is affected by gross domestic product per capita and the inflation rate (Sen et al. 2019).

IEA publishes a global methane tracker incorporating oil and gas supply data, the latest scientific literature, and measurement campaigns (IEA 2020). The report focuses on emissions from the oil and natural gas sector and provides country-level emissions estimates, abatement measures and their costs, and a database of methane policy and regulation. Abatement measures considered by IEA are replacing existing devices, installing new devices, leak detection and repair, and other measures with a total possible abatement in the United States of 8,164 kilotons methane (kt $CH_4$) (72 percent) (IEA 2020). To estimate emissions data and abatement options, emissions sources along the oil and natural gas value chain are analyzed except for those within industrial or residential buildings. The sector is divided into upstream (production and gathering and processing) and downstream (refining, transmission, and distribution) segments. Emissions that are considered for abatement are fugitive emissions, vented emissions, and incomplete flaring. The monetary value of captured methane is based on a global, societal perspective (IEA 2020). Well-head price estimates are used in each country, and a credit obtained for selling the gas applied regardless of contractual arrangements, and prices also assume that there are no domestic consumption subsidies (IEA 2020).

Estimated costs associated with abatement technologies for production sources relevant to NYS are provided in Table 2 below.

**Table 2. Emissions and Abatement Options for Fugitive Emissions Based on 2019 Emissions Estimates**

*Source: IEA 2020*

| Production Source | Abatement Technology | Possible Savings (% of source emissions) | Cost (USD/MBtu) |
|---|---|---|---|
| **Upstream** | | | |
| Onshore conventional oil | Upstream LDAR | 47.06 | -1.38 |
| Onshore conventional gas | Upstream LDAR | 47.06 | -1.38 |
| Onshore conventional oil | Upstream LDAR | 23.53 | 0.06 |
| Onshore conventional gas | Upstream LDAR | 23.53 | 0.06 |
| Onshore conventional oil | Upstream LDAR | 17.64 | 0.78 |
| Onshore conventional gas | Upstream LDAR | 17.64 | 0.78 |
| Onshore conventional oil | Upstream LDAR | 11.77 | 1.77 |
| Onshore conventional gas | Upstream LDAR | 11.77 | 1.77 |
| **Downstream** | | | |
| Downstream oil | Downstream LDAR | 47.01 | 4.83 |
| Downstream gas | Downstream LDAR | 47.06 | 4.83 |
| Downstream oil | Downstream LDAR | 23.50 | 6.11 |
| Downstream gas | Downstream LDAR | 23.53 | 6.11 |
| Downstream oil | Downstream LDAR | 17.74 | 6.76 |
| Downstream gas | Downstream LDAR | 17.65 | 6.76 |
| Downstream oil | Downstream LDAR | 11.75 | 10.67 |
| Downstream gas | Downstream LDAR | 11.76 | 10.67 |

**Table 3. Emissions and Abatement Options for Vented and Incomplete-Flare Emissions Based on 2019 Emissions Estimates**

*Source: IEA 2020*

| Production Source | Abatement Technology | Possible Savings (% of source emissions) | Cost (USD/Mbtu) |
|---|---|---|---|
| **Upstream** | | | |
| Onshore conventional oil | Blowdown capture | 100 | -2.33 |
| Onshore conventional gas | Replace pumps | 100 | -2.17 |
| Onshore conventional gas | Blowdown capture | 100 | -1.73 |
| Onshore conventional oil | Vapor recovery units | 100 | -0.46 |
| Onshore conventional oil | Replace pumps | 100 | -0.06 |
| Onshore conventional gas | Replace with instrument air systems | 100 | 1.17 |
| Onshore conventional oil | Replace with instrument air systems | 100 | 1.18 |
| Onshore conventional gas | Replace compressor seal or rod | 100 | 1.22 |
| Onshore conventional gas | Install plunger | 100 | 2.27 |
| Onshore conventional gas | Replace with electric motor | 100 | 4.25 |
| Onshore conventional oil | Early replacement of devices | 100 | 4.92 |
| Onshore conventional gas | Early replacement of devices | 100 | 4.92 |
| Onshore conventional gas | Vapor recovery units | 100 | 5.39 |
| Onshore conventional oil | Vapor recovery units | 100 | 5.42 |
| Onshore conventional oil | Other | 100 | 5.76 |
| Onshore conventional oil | Replace with electric motor | 100 | 6.10 |
| Onshore conventional oil | Install flares | 100 | 6.51 |
| Onshore conventional gas | Install flares | 100 | 10.92 |
| **Downstream** | | | |
| Downstream gas | Replace with instrument air systems | 100 | -1.62 |
| Downstream gas | Install flares | 100 | 0.23 |
| Downstream gas | Replace compressor seal or rod | 100 | 2.16 |
| Downstream oil | Vapor recovery units | 100 | 5.39 |
| Downstream gas | Vapor recovery units | 100 | 5.39 |
| Downstream oil | Install flares | 100 | 8.71 |
| Downstream gas | Other | 100 | 22.23 |

IEA states that mitigation measures are limited by three main categories of obstacles: (1) a lack of complete information regarding the problem, (2) inadequate infrastructure or underdeveloped/saturated local markets, and (3) misaligned investment incentives. In addition, United Nations Economic Commission for Europe (UNECE) categorizes barriers into four categories: knowledge, economic, regulatory, and structural barriers (UNECE 2019). Knowledge barriers feature a lack of awareness, experience, or resources to address methane emissions, including a lack of inventories. Economic barriers occur when there is a lack of human resources and capital to pursue projects. Since oil and gas operations are complex, this leads to difficulties in establishing regulations. Structural barriers occur when investors and decision makes do not benefit from gas capture.

One study found that replacing natural gas pipelines reduces methane leaks and improves safety (Gallagher et al. 2015). Gallagher et al. (2015) surveyed methane concentrations on city streets. In Manhattan, 1,050 leaks were detected corresponding to 4.25 leaks per mile. Normalized by service lines per mile of main, there are 0.0493 leaks per mile. Percent replacement candidate for mains and service lines is calculated from Pipeline and Hazardous Materials Safety Administration (PHMSA) data. NARUC (2020) reviewed the natural gas infrastructure modernization state programs at local distribution companies. Several plans have been submitted by jurisdictional local distribution companies to remove leak prone pipeline in NYS; the number of miles of pipe to be removed, costs, and cost recovery varies by the distribution company. To review cases and plans, visit the following website: http://documents.dps.ny.gov/public/Common/AdvanceSearch.aspx

Several studies were identified that estimated the component-level costs of methane mitigation. These studies are summarized in Table 4 and described below.

**Table 4. Component-level Costs of Methane Mitigation Strategies**

| Mitigation Strategy | Cost | Notes | Reference |
|---|---|---|---|
| Cap abandoned wells | \$5,000 - \$30,000 per well | Low-end value is from NYS specific data on costs of plugging abandoned wells in Allegany and Cattaraugus Counties<br>High-end value is from more recent data from Carbon Tracker | Bishop 2013<br>Carbon Tracker 2020 |
| Change high-bleed pneumatic device to low-bleed device at end of life | \$210 - \$340 per device | Natural gas savings of 50-200 Mcf per year | EPA 2006b |
| Early-replacement of high-bleed pneumatic device | \$1,850 per device | Natural gas savings of 260 Mcf per year | EPA 2006b |
| Retrofit high-bleed pneumatic device | \$675 per device | Natural gas savings of 230 Mcf per year | EPA 2006b |
| Improve maintenance practices for high-bleed pneumatic device | Negligible - \$500 per device | Natural gas savings of 45-260 Mcf per year | EPA 2006b |
| Replace wet seals with dry seals on centrifugal compressors | \$324,000 per compressor | | Ishkov et al. 2011 |
| Install electric compressors | \$6,050,000 per 4 compressors installed | Replacement of 5 reciprocating compressors with 4 electric compressors. Estimated annual methane emissions reductions of 32,800 Mcf | EPA 2011 |
| Install new transmission and storage compressors | \$2,640 per hp | Costs projected between 2014 and 2035 | Greenblatt 2015 |
| Install new gathering system compressors | \$2,800 per hp | Costs projected between 2014 and 2035 | Greenblatt 2015 |
| Directed inspection and maintenance | \$26,248 per station | | Ishkov et al. 2011 |
| Install 10” pipeline | \$600,000-\$2,100,000 per mile of pipeline | Cost depends on congestion of area | Greenblatt 2015 |
| Install 16” pipeline | \$1,100,000-\$3,200,000 per mile of pipeline | Cost depends on congestion of area | Greenblatt 2015 |
| Install 24” pipeline | \$2,000,000-\$5,200,000 per mile of pipeline | Cost depends on congestion of area | Greenblatt 2015 |
| Install 36” pipeline | \$4,000,000-\$8,900,000 per mile of pipeline | Cost depends on congestion of area | Greenblatt 2015 |
| Internal coatings for pipeline | \$2-\$8 per foot of pipeline | Cost depends on pipe diameter and type of coating | Greenblatt 2015 |
| Replace distribution pipeline | \$1,500,000-\$5,000,000 per mile of pipeline | Cost depends on diameter and other factors | Greenblatt 2015 |
| Install gathering pipeline | \$117,000 per mile of pipeline | Average diameter of 3.6 inches. Costs projected between 2014 and 2035 | Greenblatt 2015 |

**Table 4 continued**

| Mitigation Strategy | Cost | Notes | Reference |
|---|---|---|---|
| Install transmission pipeline | $4,690,000 per mile of pipeline | Average diameter of 30.5 inches. Costs projected between 2014 and 2035 | Greenblatt 2015 |
| Composite wrap repair | $5,648 per defect | Assumes a 6" defect on a 24" diameter pipe operated at 350 psig with 10 miles between shut-off valves. Estimated methane emissions reductions of 3,960 Mcf per year | EPA 2006a |
| Ground based LDAR of well pads and G&B stations | $44,891 | Includes emission detection and quantification, leak confirmation, and leak repair | Schwietzke et al. 2019 |
| LDAR of well pads and G&B stations using Kairos | $62,486 | Includes emission detection and quantification, leak confirmation, and leak repair | Schwietzke et al. 2019 |
| LDAR of well pads and G&B stations using Scientific Aviation | $47,872 | Includes emission detection and quantification, leak confirmation, and leak repair | Schwietzke et al. 2019 |
| Semiannual LDAR monitoring | $1,670 per site | | Ravikumar and Brandt 2016 |
| Valve LDAR using infrared camera | $90 | | Carbon Limits 2014 |
| Connector/connection LDAR using infrared camera | $56 | | Carbon Limits 2014 |
| Regulator LDAR using infrared camera | $189 | | Carbon Limits 2014 |

Fernandez et al. (2005) describes 25 methane emission reduction technologies and practices, including for compressors/engines. Equipment cost, operations and maintenance costs, and gas savings are estimated. Equations are also provided to calculate costs, gas savings, and payback. The technologies and practices for compressor/engines include reducing methane emissions from compressor rod packing systems, directed inspection and maintenance at compressor stations, replacing gas starters with air, replacing ignition/reduce false starts, and installing electric starters. The paper also discusses replacing high-bleed with low-bleed pneumatics, converting gas pneumatics to instrument air, and converting pneumatic controls to mechanical controls.

Several studies were located on leak detection and repair programs (LDAR). Fox et al. (2019) outlines a five-stage framework for demonstrating equivalence that combines controlled testing, simulation modeling, and field trials based on consultation with operators, regulators, academics, solution providers, consultants, and nonprofit groups from Canada and the U.S. The paper noted one modeling tool that has been used to compare costs of LDAR programs, Fugitive Emissions Abatement Simulation Toolkit (FEAST). Ravikumar and Brandt (2016) used the FEAST model to simulate methane leakage from natural gas facilities at the component level with high time resolution. Ravikumar et al. (2020) measured the effectiveness of LDAR surveys by quantifying emissions at 36 unconventional liquids-rich natural gas facilities in Alberta, Canada. The study showed that total emissions were reduced by 44 percent after one LDAR survey and that greater than 90 percent of the leaks found in their initial survey were not emitting when a follow-up survey was conducted. The study authors noted that costs of leak repair are still relatively unknown. Carbon Limits (2014) notes that the economic benefit of a LDAR program depends on the amount of gas that would have been leaked and its inherent value, along with the costs of the LDAR program which includes survey and repair costs. The study found that a majority of leaks are economic to repair once they have been identified, even when a low value of gas ($3/Mcf) was assumed. The study concluded that leaks amounting to more than 97 percent of total leak emissions were worth repairing.

Schwietzke et al. (2019) used novel aerial methane detection technologies to identify abnormally high-emitting oil and gas facilities and to guide ground-based LDAR teams. The current approach to mitigation of methane leaks from oil and gas operations relies on on-site inspections of all applicable facilities at specified frequencies, but this approach is costly and labor-intensive (Schwietzke et al. 2019). The aerial technologies used by Schwietzke et al. (2019) include Kairos Aerospace (Kairos) infrared methane($CH_4$) emission plume imaging during overflights and Scientific Aviation (SA) in situ aircraft $CH_4$ mole fraction measurements near individual facilities. The cost-effectiveness of each LDAR approach was evaluated as the total cost expended during the survey conducted April 3–8, 2017 divided by the avoided $CH_4$ emissions due to the detection of fixable emissions in that time (Schwietzke et al. 2019). The cost-effectiveness of ground-based LDAR (US $6.50–7.00 spent per thousand standard cubic feet (Mscf) $CH_4$ emissions avoided) is comparable to SA (U.S. $6.95–7.50) in the base case, and both are substantially more cost-effective than Kairos (U.S. $30.59–33.77) (Schwietzke et al. 2019).

Carbon Limits (2014) provided an empirical analysis on the costs and benefits of LDAR programs using infrared cameras at oil and natural gas facilities. For individual facilities, the study calculated the net present values (NPVs) of repairing individual leaks identified in surveys based on estimated repair costs and the value of gas conserved for sale by the repair (a negative NPV represents net costs while a positive NPV represents net gains) (Carbon Limits 2014). The average net present value of repairing leaks at well facilities was -$35, the average survey NPV at compressor stations was $3,376, and the average survey NPV at gas plants was $9,403 (Carbon Limits 2014). The study next estimated aggregated abatements costs. With the base case assumptions, well sites and well batteries have abatement costs around zero, increasing to $6/tCO$_2$e or $300/tVOC when applying the less favorable assumptions for gas price and total survey costs (Carbon Limits 2014). Overall, aggregate abatement costs for LDAR Programs at oil and gas production and processing facilities was low and program costs and emission reduction potentials are not very sensitive to program design, although aggregate abatement costs are sensitive to the survey frequency (Carbon Limits 2014). Abatement costs remain below $15/tCO$_2$e and $800/tVOC for quarterly surveys and below $55/tCO$_2$e and $3,400/tVOC for monthly surveys (Carbon Limits 2014).

Many studies and reports were found that discussed pipeline decarbonization as a methane mitigation option. One study found that decarbonizing pipeline gas could achieve California's greenhouse gas reduction goals and is possibly easier to implement in some sectors than high electrification (E3 2015). Another study analyzes the technical potentials, costs, and emissions associated with decarbonizing gas networks using biomethane and hydrogen (Speirs et al. 2018).

Hausman and Muehlenbachs (2017) analyzed leak abatement incentives at the natural gas distribution firms that deliver gas to end-user customers. Hausman and Muehlenbachs (2017) stated that reducing leaks can avert commodity losses and climate damages and that too little is spent by natural gas firms repairing leaks. The study used a panel of U.S. natural gas utilities to estimate the amount being spent on natural gas leak reductions to then test whether utilities are equating marginal abatement costs with marginal abatement benefits (Hausman and Muehlenbachs 2017). The study looked at two abatement methods, pipeline repairs involving operations and maintenance expenditures that leave pipeline infrastructure intact and pipeline replacement involving capital expenditures (Hausman and Muehlenbachs 2017). They found that, for operations and maintenance expenditures, utilities spend less for repairing leaks than the value of the lost gas itself and are therefore not taking advantage of cost-effective opportunities for leak mitigation. For capital expenditures on pipeline replacement, utilities spend more to reduce a unit of leaked gas than the cost of gas itself (Hausman and Muehlenbachs 2017).

For operations and maintenance abatement costs, they used an instrumental variables approach to estimate the cost of $0.48/Mcf for O&M-intensive leak abatement (Hausman and Muehlenbachs 2017). Hausman and Muehlenbachs (2017) stated that this indicates that there was low-hanging fruit in terms of leak mitigation opportunities that utilities were not fully incentivized historically to find. For capital expenditures, pipeline replacement, which is an intensive project that requires digging up aging pipelines and replacing them with new plastic or protected steel pipes, was considered (Hausman and Muehlenbachs 2017). Hausman and Muehlenbachs (2017) estimated the costs of abatement from pipeline main replacement and then compare to the benefit of replacement as well as the previous O&M costs of leak detection and repair. After instrumenting for pipe replacement, the cost estimate implied is a range of $607,000 to $1.2 million for the replacement of one pipeline mile (which is in line with public utility commission reports that estimate $170,000 to $3 million) (Hausman and Muehlenbachs 2017). The $/mile cost was converted to a $/Mcf cost resulting in a levelized cost of natural gas leak abatement of $48 to $103/Mcf from pipeline replacement programs, respectively (Hausman and Muehlenbachs 2017). Hausman and Muehlenbachs (2017) concluded that public utility commissions have been under incentivized to avoid leaks and historically considered lost gas a cost of doing business, generally allowing this cost to be passed on to retail customers. They also stated that pipeline replacement programs that have received more public attention have levelized costs well above the leak detection and repair O&M costs described (Hausman and Muehlenbachs 2017).

While much of literature found was on the decommissioning of offshore oil and gas pipelines, a few sources provided insight on decommissioning onshore pipelines. The process of decommissioning a pipeline usually involves pipeline abandonment or pipeline removal. A majority of onshore pipeline decommissioning is pipeline abandonment, or leaving the pipeline in place, but cleaning and disconnecting the line from the overall system and potentially segmenting the pipeline as necessary (Enbridge n.d.; NiGen 2018). Enbridge (n.d.) notes that leaving a decommissioned pipeline in place avoids costs associated with excavating and removing the pipeline.

In 2017, Santa Barbara County, California created a decommissioning plan for two crude oil pipelines through the county. The plan proposed that 99 percent of the existing pipelines be abandoned in place. The plan did note that several parcels that were transected by existing pipelines had a right-of-way clause that allowed property owners the option of requiring a pipeline be removed rather than abandoned—which could result in requiring 63 percent of the existing pipelines to be removed. The Santa Barbara County plan did not provide any cost or financial information in their plan for pipeline decommissioning (SCS Engineers 2017).

Complete removal of the pipeline increases the overall effect on communities and the environment since removal of existing pipelines requires larger subsurface grading and excavation. Abandoning pipelines in place limits stability issues and soil disturbances. Abandoned pipelines can also be used to place new pipelines in the same right-of-way to provide continued service to end users (Enbridge n.d.; SCS Engineers 2017).

In 2009, the Canadian National Energy Board (NEB) released a set of pipeline abandonment guiding principles, framework, and action plan that all pipeline companies regulated under the NEB Act were directed to comply with. Note that according to the NEB, pipeline abandonment occurs when a pipeline company decides that it will permanently stop providing services on a specific pipeline route (Canada NEB 2011). The NEB notes that it is different than decommissioning, which is when a company ceases operation of a pipeline or part of one, but the same level of service continues as a result of other lines in the system (Canada NEB 2014). The framework included base case assumptions to be used as the basis for preparing preliminary cost estimates for each pipeline company's plan for abandonment. The NEB recommended that pipeline companies use the Oil and Gas Journal Survey filed by TransCanada to develop their abandonment costs for the base case (Canada NEB 2009).

While the NEB provided documents such as a Base Case Cost Definition Grid (Table A-3; Canada NEB 2010) and an Abandonment Cost Estimates Review User Guide (Section 5.1 of the User Guide has a full table; Canada NEB 2017), no specific costs for pipeline abandonment were provided. Instead, it noted the types of cost that must be considered—e.g., engineering costs, project management costs, land access, purging and cleaning costs, mobilization/demobilization of equipment and personnel, capping and sealing pipelines, installation of plugs, etc. The actual pipeline companies conducting the pipeline abandonment were responsible for developing their own costs for pipeline abandonment. The NEB framework may be a good source of information on the types of costs that may be included in pipeline abandonment, but it is not a useful source on definitive costs to be used in the NYS model as these are determined directly by individual pipeline companies.

# 3 Modeling Scenario Nomenclature

This section describes the nomenclature for the modeling scenarios. The emissions modeling performed under this project is based on applying methane mitigation options to the oil and natural gas sector in NYS's Integration Analysis. As outlined in Figure 1, the reference case is based on the Integration Analysis and is used as the basis against which emissions reductions and cost of mitigation options are assessed. The reference case includes some electrification and is not a business-as-usual projection (NYS 2022a). Integration Analysis Scenario 2 (IAS2) reflects the Integration Analysis Strategic Use of Low Carbon Fuels (LCF) and includes more aggressive electrification and efficiency than the Reference case (NYS 2022a). Integration Analysis Scenario 3 reflects the Integration Analysis Accelerated Transition Away from Combustion (AT) and includes further electrification compared to Integration Analysis Scenario 2 (NYS 2022a). As discussed in Section 6, different mitigation strategies, such as decommissioning, equipment changeout, and leak detection and repair (LDAR) are applied to the Integration Analysis Scenarios to generate the Level 1 Mitigation and Level 2 Mitigation scenarios. Level 2 Mitigation includes additional LDAR on pipelines, compressor stations, and buildings and a faster rate of residential gas appliance upgrades compared to Level 1 Mitigation and also assumes that all production is phased out and all abandoned wells are capped. Table 5 compares the key parameters of all scenarios and levels of mitigation in the projection tool.

**Table 5. Comparison of all Scenarios and Levels of Mitigation in the Projection Tool**

| Key Parameter | Baseline Case | Reference Case | Integration Analysis Scenario 2 | Integration Analysis Scenario 3 | Level 1 Mitigation | Level 2 Mitigation |
|---|---|---|---|---|---|---|
| Natural Gas Production | 0.8% average annual increase based on regional AEO2021 natural gas projections | No change – remains constant at 2020 levels | 16.7% average annual decrease based on historical trendline from 2016-2020 | 16.7% average annual decrease based on historical trendline from 2016-2020 | LDAR on 100% of production sites upstate phased in between 2023 and 2030 (14% per year); all production but high producing oil wells phased out upstate between 2023 and 2030 (14% per year) | LDAR on 100% of production sites upstate phased in between 2023 and 2030 (14% per year); all production phased out upstate between 2023 and 2030 (14% per year) |
| Capping Abandoned Wells | 0.62% average annual decrease in uncapped abandoned oil wells and 0.82 % average annual decrease in uncapped abandoned gas wells through 2050 based on historical trendline from 1990-2020 | 0.62% average annual decrease in uncapped abandoned oil wells and 0.82 % average annual decrease in uncapped abandoned gas wells through 2050 based on historical trendline from 1990-2020 | 0.62% average annual decrease in uncapped abandoned oil wells and 0.82 % average annual decrease in uncapped abandoned gas wells through 2050 based on historical trendline from 1990-2020 | 0.62% average annual decrease in uncapped abandoned oil wells and 0.82 % average annual decrease in uncapped abandoned gas wells through 2050 based on historical trendline from 1990-2020 | No change | 100% of gas and oil wells upstate capped between 2023 and 2030 (14% per year) |
| Gathering and Boosting Stations | 0.8% average annual increase based on regional AEO2021 natural gas projections | No change – remains constant at 2020 levels | 16.7% average annual decrease based on historical trendline from 2016-2020 | 16.7% average annual decrease based on historical trendline from 2016-2020 | LDAR on 100% of stations upstate phased in between 2023 and 2030 (14% per year) | LDAR on 100% of stations upstate phased in between 2023 and 2030 (14% per year) |
| Gathering Pipeline | 0.8% average annual increase based on regional AEO2021 natural gas projections | No change – remains constant at 2020 levels | 16.7% average annual decrease based on historical trendline from 2016-2020 | 16.7% average annual decrease based on historical trendline from 2016-2020 | LDAR on 100% of pipelines upstate phased in between 2023 and 2030 | LDAR on 100% of pipelines upstate phased in between 2023 and 2030 |
| Truck Loading of Oil | 0.29% average annual decrease based on regional AEO2021 oil production projections | 0.29% average annual decrease based on regional AEO2021 oil production projections | 44.8% average annual decrease based on historical oil production trendline from 2013-2020 | 44.8% average annual decrease based on historical oil production trendline from 2013-2020 | Equipment upgrade to allow 100% vapor recovery upstate starting in 2022 | Equipment upgrade to allow 100% vapor recovery upstate starting in 2022 |

**Table 5 continued**

| Key Parameter | Baseline Case | Reference Case | Integration Analysis Scenario 2 | Integration Analysis Scenario 3 | Level 1 Mitigation | Level 2 Mitigation |
|---|---|---|---|---|---|---|
| Transmission Pipeline | hold 2020 mileage constant except for the addition of 25 miles in Ontario County in 2021 | hold 2020 mileage constant except for the addition of 25 miles in Ontario County in 2021 | Hold 2020 mileage constant except for the addition of 25 miles in Ontario County in 2021 | Hold 2020 mileage constant except for the addition of 25 miles in Ontario County in 2021 | LDAR on 100% of pipelines phased in between 2023 and 2030 (14% per year) | LDAR on 100% of pipelines phased in between 2023 and 2030 (14% per year) |
| Gas Transmission Compressor Stations | hold 2020 number of stations constant except for the addition of 1 station in Ontario County in 2021 | hold 2020 number of stations constant except for the addition of 1 station in Ontario County in 2021 | Hold 2020 number of stations constant except for the addition of 1 transmission compressor station in Ontario County in 2021 | Hold 2020 number of stations constant except for the addition of 1 transmission compressor station in Ontario County in 2021 | LDAR on 100% of stations phased in between 2023 and 2030 (14% per year) | LDAR on 100% of stations phased in between 2023 and 2030 (14% per year) |
| Gas Storage Compressor Stations | hold 2020 number of stations constant | hold 2020 number of stations constant | Hold 2020 number of stations constant | Hold 2020 number of stations constant | LDAR on 100% of stations upstate phased in between 2023 and 2030 (14% per year) | LDAR on 100% of stations upstate phased in between 2023 and 2030 (14% per year) |
| LNG Storage Compressor Stations | hold 2020 number of stations constant | hold 2020 number of stations constant | Hold 2020 number of stations constant | Hold 2020 number of stations constant | LDAR on 100% of stations downstate phased in between 2023 and 2030 (14% per year) | LDAR on 100% of stations downstate phased in between 2023 and 2030 (14% per year) |
| Natural Gas Demand | N/A; Emissions are not directly impacted by natural gas demand. Emissions are more directly connected with building electrification | N/A; Emissions are not directly impacted by natural gas demand. Emissions are more directly connected with building electrification | N/A; Emissions are not directly impacted by natural gas demand. Emissions are more directly connected with building electrification | N/A; Emissions are not directly impacted by natural gas demand. Emissions are more directly connected with building electrification | N/A; Emissions are not directly impacted by natural gas demand. Emissions are more directly connected with building electrification | N/A; Emissions are not directly impacted by natural gas demand. Emissions are more directly connected with building electrification |
| Cast Iron Distribution Pipeline: Main | 6.27% average annual decrease based on 50% of historical tend from 2010-2020 assume 20% of pipeline is too costly to replace | 6.27% average annual decrease based on 50% of historical tend from 2010-2020 assume 20% of pipeline is too costly to replace | 6.27% average annual decrease based on 50% of historical tend from 2010-2020; assume 20% of pipeline is too costly to replace | 6.27% average annual decrease based on 50% of historical tend from 2010-2020; assume 20% of pipeline is too costly to replace | LDAR on 100% of cast iron mains between 2023 and 2030 (14% per year) | LDAR on 100% of cast iron mains between 2023 and 2030 (14% per year) |

**Table 5 continued**

| Key Parameter | Baseline Case | Reference Case | Integration Analysis Scenario 2 | Integration Analysis Scenario 3 | Level 1 Mitigation | Level 2 Mitigation |
|---|---|---|---|---|---|---|
| Cast Iron Distribution Pipeline: Services | 9.5% average annual decrease based on 50% of historical trend from 2010-2020 assume 20% of pipeline is too costly to replace | 9.5% average annual decrease based on 50% of historical trend from 2010-2020 assume 20% of pipeline is too costly to replace | 9.5% average annual decrease based on 50% of historical trend from 2010-2020; assume 20% of pipeline is too costly to replace | 9.5% average annual decrease based on 50% of historical trend from 2010-2020; assume 20% of pipeline is too costly to replace | No change | LDAR on 100% of cast iron services between 2023 and 2030 (14% per year) |
| Unprotected Steel Distribution Pipeline: Main | 18.0% average annual decrease based on historical trend from 2010-2020 | 18.0% average annual decrease based on historical trend from 2010-2020 | 18.0% average annual decrease based on historical trend from 2010-2020 | 18.0% average annual decrease based on historical trend from 2010-2020 | LDAR on 100% of unprotected steel mains between 2023 and 2030 (14% per year) | LDAR on 100% of unprotected steel mains between 2023 and 2030 (14% per year) |
| Unprotected Steel Distribution Pipeline: Services | 13.3% average annual decrease based on historical trend from 2010-2020 | 13.3% average annual decrease based on historical trend from 2010-2020 | 13.3% average annual decrease based on historical trend from 2010-2020 | 13.3% average annual decrease based on historical trend from 2010-2020 | LDAR on 100% of unprotected steel services between 2023 and 2030 (14% per year) | LDAR on 100% of unprotected steel services between 2023 and 2030 (14% per year) |
| Protected Steel Distribution Pipeline: Main | hold 2020 pipeline miles constant | 0.80% average annual increase | 6.89% average annual decrease | 9.12% average annual decrease | No change | LDAR on 100% of protected steel mains between 2023 and 2030 (14% per year) |
| Protected Steel Distribution Pipeline: Services | hold 2020 pipeline miles constant | 0.69% average annual increase | 5.99% average annual decrease | 7.91% average annual decrease | No change | LDAR on 100% of protected steel services between 2023 and 2030 (14% per year) |
| Plastic Distribution Pipeline: Main | 3.03% average annual increase | 1.66% average annual increase | 6.04% average annual decrease | 8.29% average annual decrease | No change | LDAR on 100% of plastic mains between 2023 and 2030 (14% per year) |
| Plastic Distribution Pipeline: Services | 1.35% average annual increase | 1.28% average annual increase | 5.40% average annual decrease | 7.34% average annual decrease | No change | LDAR on 100% plastic services upstate (14% per year) |
| Copper Distribution Pipeline: Services | 12.1% average annual decrease | 12.1% average annual decrease | 12.1% average annual decrease | 12.1% average annual decrease | No change | LDAR on 100% of copper services between 2023 and 2030 (14% per year) |

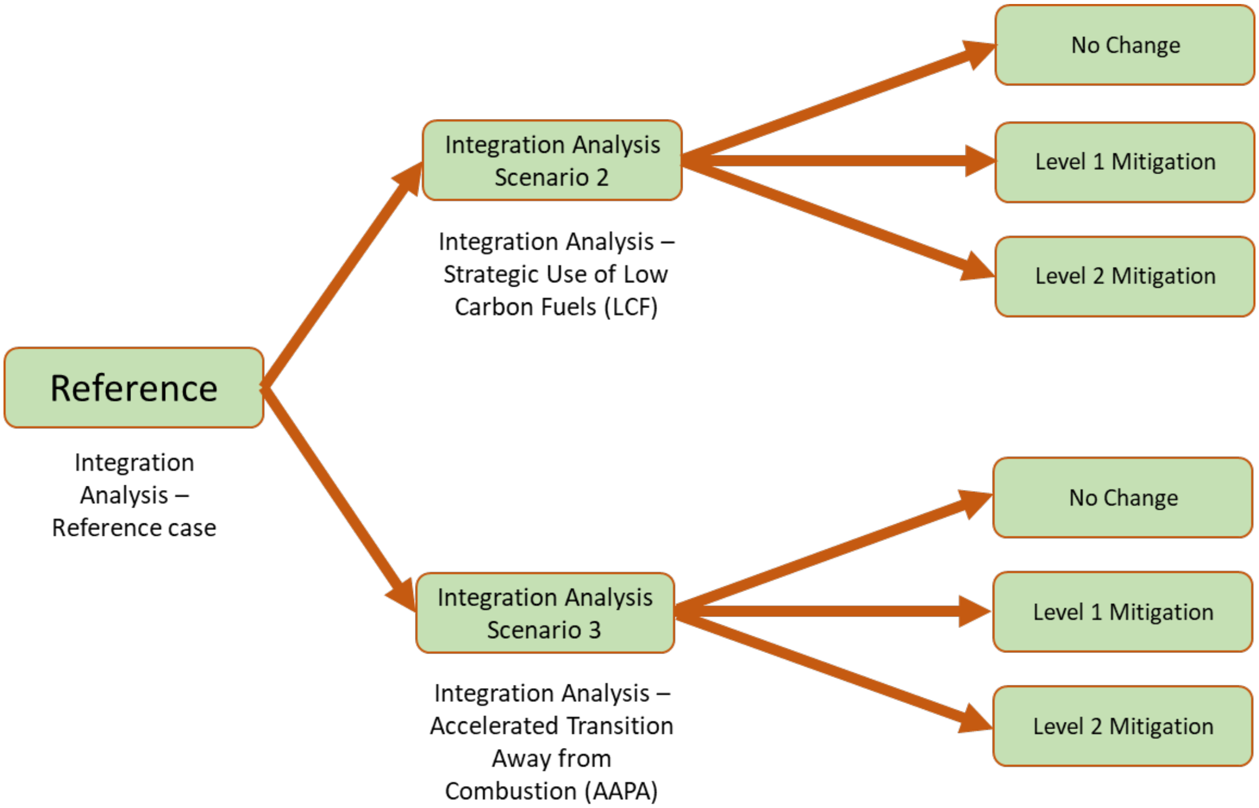
**Table 5 continued**

| Key Parameter | Baseline Case | Reference Case | Integration Analysis Scenario 2 | Integration Analysis Scenario 3 | Level 1 Mitigation | Level 2 Mitigation |
|---|---|---|---|---|---|---|
| Commercial Meters | 0.14% average annual increase (population growth) | 1.03% average annual increase (based on E3 modeling of commercial building electrification - used space heating as a surrogate to determine building electrification) | 7.73% average annual decrease | 14.48% average annual decrease | LDAR on 100% of meters phased in between 2023 and 2030 (14% per year) | LDAR on 100% of meters phased in between 2023 and 2030 (14% per year) |
| Residential Meters | 0.81% average annual increase (based on data for residential natural gas customer counts) | 0.67% average annual increase (based on E3 modeling of residential building electrification - used space heating as a surrogate to determine building electrification) | 5.38% average annual decrease | 7.34% average annual decrease | LDAR on 100% of meters phased in between 2023 and 2030 (14% per year) | LDAR on 100% of meters phased in between 2023 and 2030 (14% per year) |
| Commercial Buildings with Natural Gas Service | 0.14% average annual increase (population growth) | 1.03% average annual increase (based on E3 modeling of commercial building electrification - used space heating as a surrogate to determine building electrification) | 7.73% average annual decrease | 14.48% average annual decrease | LDAR on 100% of commercial buildings downstate 2023 and 2030 (14.3% per year) | LDAR on 100% of commercial buildings phased in between 2023 and 2030 (14.3% per year) |

**Table 5 continued**

| Key Parameter | Baseline Case | Reference Case | Integration Analysis Scenario 2 | Integration Analysis Scenario 3 | Level 1 Mitigation | Level 2 Mitigation |
|---|---|---|---|---|---|---|
| Residential Gas Appliances | 0.81% average annual increase (based on data for residential natural gas customer counts) | 0.67% average annual increase (based on E3 modeling of residential building electrification - used space heating as a surrogate to determine building electrification) | 5.38% average annual decrease | 7.34% average annual decrease | Equipment upgrade on 100% of appliances phased in between 2023 and 2043 (2% per year) | Equipment upgrade on 100% of appliances phased in between 2023 and 2043 (5% per year) |
| Residential Buildings with Natural Gas Service | 0.81% average annual increase (based on data for residential natural gas customer counts) | 0.67% average annual increase (based on E3 modeling of residential building electrification - used space heating as a surrogate to determine building electrification) | 5.38% average annual decrease | 7.34% average annual decrease | LDAR on 25% of residential buildings upstate phased in between 2023 and 2030 (14.3% per year) | LDAR on 25% of residential buildings phased in between 2023 and 2030 (14.3% per year) |

**Figure 1. Emissions Projection Scenario Architecture**




The scenarios modeled and corresponding abbreviations are provided in Table 6.

**Table 6. Modeling Scenarios and Abbreviations**

| Integration Analysis Scenario | | Abbreviation |
|---|---|---|
| Reference case | Reference case | Reference case |
| IAS2, No Change | Integration Analysis Scenario 2, No Change | IAS2-NC |
| IAS2, Level 1 Mitigation | Integration Analysis Scenario 2, Level 1 Mitigation | IAS2-Level 1 |
| IAS2, Level 2 Mitigation | Integration Analysis Scenario 2, Level 2 Mitigation | IAS2-Level 2 |
| IAS3, No Change | Integration Analysis Scenario 3, No Change | IAS3-NC |
| IAS3, Level 1 Mitigation | Integration Analysis Scenario 3, Level 1 Mitigation | IAS3-Level 1 |
| IAS3, Level 2 Mitigation | Integration Analysis Scenario 3, Level 2 Mitigation | IAS3-Level 2 |

# 4 Methodology for Developing Emissions Projections in the Baseline and Reference Cases

This section provides an overview of the methodology used for developing the emissions projections in the baseline and reference cases.

## 4.1 Baseline Case

The baseline case is based on AEO 2021 projections of energy consumption in the Atlantic region and total energy supply, historical trends, ICF Natural Gas Study data for households with natural gas, and population growth. The assumptions for the baseline case are listed below and summarized in Table 7.

### 4.1.1 Assumptions

The baseline case assumes a 0.8 percent average annual increase of natural gas production based on regional AEO natural gas projections (EIA 2021a). The projections for gathering and boosting stations and gathering pipeline are also based on AEO natural gas projections. A 0.62 percent average annual decrease in uncapped abandoned oil wells and 0.82 percent average annual decrease in uncapped abandoned gas wells is assumed based on historical trendlines. Selection of the trendline dates is based on inflection points in the historical data that indicate a change in activity. Truck loading of oil is assumed to decrease 0.29 percent annually based on regional AEO oil production projections. Transmission pipeline, gas transmission and storage compressor station, and LNG storage compressor station data is held constant at the 2020 levels except for the addition of 25 miles of pipeline and one transmission compressor station in Ontario County in 2021 for the planned and approved Empire North Expansion Project. Based on historical trends from 2010 to 2020, the following average annual decreases are expected for pipelines within the baseline case: cast iron distribution main (6.27 percent), cast iron distribution services (9.5 percent), unprotected steel distribution main (18 percent), unprotected steel distribution services (13.3 percent). Again, selection of the trendline dates is based on inflection points in the historical data that indicate a change in activity. For cast iron mains and services, it is assumed that replacement will occur at 50 percent of the historical replacement rate and that 20 percent of pipeline is too costly to replace. These assumptions are based on expert judgement and consultation with the New York State Department of Public Service. Data indicate that replacement first occurs for the most readily accessible cast iron pipes that are the least costly to replace. Due to finite resources, pipeline replacement slows as replacement costs rise. Protected steel distribution mains and services are held constant at 2020 levels, and copper distribution services are assumed to decrease 12.1 percent annually, based on the historical trendline. Commercial buildings with natural gas service and commercial meters are assumed to increase at 0.14 percent annually based on population growth (Cornell University 2018). Residential buildings with natural gas service, residential meters, residential gas appliances are assumed to increase 0.81 percent annually based on estimates of future residential natural gas customer counts considering population growth. Plastic distribution pipeline main and service mileage is assumed to increase at 3.03 percent and 1.35 percent, respectively, based on building electrification and replacement of cast iron and unprotected steel pipelines.

Trendlines were calculated using Equation 1.

**Equation 1** $$\boldsymbol{C = (AD_{2020}/AD_t)^{1/(2020-t)} - 1 \times 100}$$

Where:

$C$ = Annual percent change
$AD$ = activity data
$t$ = starting year of the trendline

The decrease in pipeline miles associated with a given pipeline material is assumed to be the result of pipeline replace with plastic pipes. Therefore, the plastic pipeline projection considers the increase in plastic pipelines due to pipeline replacement as well as the increase in plastic pipeline due to expanding distribution infrastructure. The formula for projecting plastic pipeline miles for mains and services is shown in Equation 2 below.

**Equation 2** $$\boldsymbol{L_p = (\sum D_{np}) + (L_{p,y-1}) \times (1 + GR)}$$

Where:

$L_p$ = length of plastic pipeline, miles
$D_{np}$ = decrease in non-plastic
$y$ = year
$GR$ = growth rate

The growth rate is keyed to the annual percent change in natural gas services and is equal to the annual percent change divided by 100.

## 4.2 Reference case

The reference case is based on the reference case developed for the Integration Analysis and forecasts the natural gas system in NYS through 2050 under federal and pre-Climate Act state policies, such as funded EE. The assumptions for the reference case are summarized below and in Table 7. Like the baseline case, emissions are not directly impacted by natural gas demand and are more directly correlated with building electrification.

### 4.2.1 Assumptions

Existing policies and targets including the Clean Energy Standard and 2025 and 2030 building energy efficiency targets are accounted for in the reference case. The reference case assumes the same projections as the baseline case for capping abandoned wells, gathering, and boosting stations, gathering pipeline, truck loading of oil, transmission pipeline, gas transmission compressor stations, gas storage compressor stations, LNG storage compressor stations, cast iron distribution pipeline mains and services, unprotected steel distribution pipeline mains and services, and copper distribution pipeline services.

In the reference case, no change is assumed for natural gas production from 2020 levels. Commercial buildings with natural gas service and commercial meters are assumed to increase at 1.03 percent annually based on E3 Integration Analysis reference case modeling of commercial building electrification. Residential buildings with natural gas service, residential meters, residential gas appliances are assumed to increase 0.67 percent annually based on E3 Integration Analysis reference case modeling of residential building electrification. Building electrification was determined by evaluating the change in the number of buildings with natural gas versus electric space heating. Protected steel mains and services are assumed to increase 0.89 percent and 0.69 percent annually, respectively. Plastic distribution pipeline main and service mileage, calculated using equation 2 above, is assumed to increase annually at 1.66 percent and 1.28 percent, respectively, based on replacement of cast iron and unprotected steel pipelines and the expansion of the distribution network. Due to increases in building electrification, these rates are lower than those for plastic pipelines in the baseline case.

## 4.3 Comparison of Baseline and Reference Cases

As described above, there are several assumptions that apply to both the baseline and reference cases. The key differences in assumptions between the baseline and reference cases are provided below in Table 7.

**Table 7. Baseline Case and Reference Case Assumptions**

| Key Parameter | Baseline Case | Reference Case | Same Between Baseline and Reference |
|---|---|---|---|
| Natural Gas Production | 0.8% average annual increase based on regional AEO2021 natural gas projections | No change – remains constant at 2020 levels | |
| Capping Abandoned Wells | 0.62% average annual decrease in uncapped abandoned oil wells through 2050 based on historical trendline from 1990–2020;<br>0.82% average annual decrease in uncapped abandoned gas wells through 2050 based on historical trendline from 1990–2020 | 0.62% average annual decrease in uncapped abandoned oil wells through 2050 based on historical trendline from 1990–2020;<br>0.82% average annual decrease in uncapped abandoned gas wells through 2050 based on historical trendline from 1990–2020 | X |
| Gathering and Boosting Stations | Same as natural gas production | Same as natural gas production | |
| Gathering Pipeline | Same as natural gas production | Same as natural gas production | |
| Truck Loading of Oil | 0.29% average annual decrease based on regional AEO2021 oil production projections | 0.29% average annual decrease based on regional AEO2021 oil production projections | X |
| Transmission Pipeline | hold 2020 mileage constant except for the addition of 25 miles in Ontario County in 2021 | hold 2020 mileage constant except for the addition of 25 miles in Ontario County in 2021 | X |
| Gas Transmission Compressor Stations | hold 2020 number of stations constant except for the addition of 1 station in Ontario County in 2021 | hold 2020 number of stations constant except for the addition of 1 station in Ontario County in 2021 | X |
| Gas Storage Compressor Stations | hold 2020 number of stations constant | hold 2020 number of stations constant | X |
| LNG Storage Compressor Stations | hold 2020 number of stations constant | hold 2020 number of stations constant | X |
| Natural Gas Demand | Emissions are not directly impacted by natural gas demand. Emissions are more directly connected with building electrification. | Emissions are not directly impacted by natural gas demand. Emissions are more directly connected with building electrification. | X |
| Cast Iron Distribution Pipeline: Main | 6.27% average annual decrease based on 50% of historical tend from 2010–2020<br>assume 20% of pipeline is too costly to replace | 6.27% average annual decrease based on 50% of historical tend from 2010–2020<br>assume 20% of pipeline is too costly to replace | X |
| Cast Iron Distribution Pipeline: Services | 9.5% average annual decrease based on 50% of historical trend from 2010–2020<br>assume 20% of pipeline is too costly to replace | 9.5% average annual decrease based on 50% of historical trend from 2010– 2020<br>assume 20% of pipeline is too costly to replace | X |

**Table 7 continued**

| Key Parameter | Baseline Case | Reference Case | Same Between Baseline and Reference |
|---|---|---|---|
| Unprotected Steel Distribution Pipeline: Main | 18.0% average annual decrease based on historical trend from 2010-2020 | 18.0% average annual decrease based on historical trend from 2010–2020 | X |
| Unprotected Steel Distribution Pipeline: Services | 13.3% average annual decrease based on historical trend from 2010-2020 | 13.3% average annual decrease based on historical trend from 2010–2020 | X |
| Protected Steel Distribution Pipeline: Main | hold 2020 pipeline miles constant | 0.80% average annual increase | |
| Protected Steel Distribution Pipeline: Services | hold 2020 pipeline miles constant | 0.69% average annual increase | |
| Plastic Distribution Pipeline: Main | 3.03% average annual increase | 1.66% average annual increase | |
| Plastic Distribution Pipeline: Services | 1.35% average annual increase | 1.28% average annual increase | |
| Copper Distribution Pipeline: Services | 12.1% average annual decrease | 12.1% average annual decrease | X |
| Commercial Meters | 0.14% average annual increase (population growth) | 1.03% average annual increase (based on E3 modeling of commercial building electrification - used space heating as a surrogate to determine building electrification) | |
| Residential Meters | 0.81% average annual increase (based on data for residential natural gas customer counts) | 0.67% average annual increase (based on E3 modeling of residential building electrification - used space heating as a surrogate to determine building electrification) | |
| Commercial Buildings with Natural Gas Service | 0.14% average annual increase (population growth) | 1.03% average annual increase (based on E3 modeling of commercial building electrification - used space heating as a surrogate to determine building electrification) | |
| Residential Gas Appliances | 0.81% average annual increase (based on data for residential natural gas customer counts) | 0.67% average annual increase (based on E3 modeling of residential building electrification - used space heating as a surrogate to determine building electrification) | |
| Residential Buildings with Natural Gas Service | 0.81% average annual increase (based on data for residential natural gas customer counts) | 0.67% average annual increase (based on E3 modeling of residential building electrification - used space heating as a surrogate to determine building electrification) | |

# 5 Emissions Reduction Potential and Cost of Mitigation Options

## 5.1 Methane Reduction Potential and Cost of Mitigation Options

Based on the literature review presented in section 2.2, the methane reduction potential and cost for several mitigation options including decommissioning, equipment changeout, and leak detection and repair (LDAR) were developed for each source category. All costs were converted to $2020 using the annual average Consumer Price Index research series (U.S. Bureau of Labor Statistics n.d.; U.S. Census Bureau 2020) and the value of natural gas saved was calculated using a natural gas price of $3/Mcf based on the EIA natural gas price (EIA 2021b). Table 8 below summarizes the cost and mitigation potential by source category.

For some source categories, costs were developed by using estimated labor and capital costs.
For example, pipeline LDAR was calculated using Equation 3:

**Equation 3** $$\boldsymbol{LDAR_{m,t}} = \left(\boldsymbol{L_{m,t}} \times \boldsymbol{N_{m,t}} \times \$\mathbf{8,337}\right) + \left(\$\mathbf{163} \times \boldsymbol{L_{m,t}}\right) + ((\boldsymbol{L_{m,t}} \times \mathbf{2}\ \boldsymbol{hrs})/\mathbf{1880} \times \$\mathbf{51,064})$$

Where:

$LDAR_{m,t}$ = cost of LDAR for pipeline with material $m$ and type $t$
$L_{m,t}$ = length of pipeline with material $m$ and type $t$
$N_{m,t}$ = number of leaks for pipeline with material $m$ and type $t$

Using data from Weller et al. (2020) on the number of leaks per mile and the length of pipeline by material and type, the total number of leaks are estimated. The total number of leaks is then multiplied by the composite wrap repair cost of $8,337 to estimate the cost of this repair by pipeline material and type. The cost of labor is estimated by multiplying the length of the pipeline by $163, the estimated cost of LDAR per mile of pipeline (EDF 2017). The cost of capital and training is estimated by first multiplying the length of the pipeline by the assumed labor time per mile of 2 hours (ICF 2014) to estimate the total labor time. To estimate the number of people needed to complete the labor, the total labor time is divided by 1,880, assuming one person works 1,880 hours in a year. Finally, the number of people needed is multiplied by $51,064, which is the estimated amortized capital and training for LDAR (ICF 2014).

**Table 8. Cost and Mitigation Potential of Source Categories**

| Area | Source | Mitigation | Cost per unit ($2020) | Cost Unit | Methane Emissions Reduction Potential (%) | Notes | Reference |
|---|---|---|---|---|---|---|---|
| Statewide | Low and High Producing Oil and Gas Wells | Decommissioning | $47,611.00 | per well | 100% | Inland cost estimate | CCST 2018 |
| Statewide | Low and High Producing Oil and Gas Wells | LDAR | $20.91 | per $MTCH_4$ | 40% | Assumes natural gas price of $3/Mcf; cost is converted from $/$MTCO_2e$ | ICF 2016 |
| Statewide | Abandoned Oil and Gas Wells | Decommissioning | $6,029.00 | per abandoned well | 100% | Based on NY DEC data on contracts to plug wells in Allegany and Cattaraugus counties in 2008 | Bishop 2013 |
| Statewide | Oil and Gas: Gathering and Processing | Decommissioning | $1,068.06 | per $MTCH_4$ | 100% | Lack of data - Assume 4 times cost of LDAR | Engineering judgement based on gathering pipeline data. |
| Statewide | Oil and Gas: Gathering and Processing | LDAR | $267.01 | per $MTCH_4$ | 40% | $1.51 + $4 = $5.51 per Mcf assuming no cost savings from captured natural gas; converted to $MTCH_4$ | ICF 2014; ICF 2016 |
| Statewide | Gathering Pipeline | Decommissioning | $17,263.12 | per mile | 100% | 2016 costs for pipelines from divided by total 2016 pipelines; converted CAD to US dollars using 2016 exchange rate of 0.744 | TransCanada 2016 |
| Statewide | Gathering Pipeline | Equipment Changeout | $135,017.11 | per mile | 100% | Calculated based on number of miles of pipeline and cost per mile to replace pipeline | Greenblatt 2015 |

**Table 8 continued**

| Area | Source | Mitigation | Cost per unit ($2020) | Cost Unit | Methane Emissions Reduction Potential (%) | Notes | Reference |
|---|---|---|---|---|---|---|---|
| Statewide | Gathering Pipeline | LDAR | $295.93 | per $MTCH_4$ | 60% | Value is without gas credit and converted to $MTCH_4$ | ICF 2014 |
| Statewide | Oil: Truck Loading | Decommissioning | $0.00 | per $MTCH_4$ | 100% | Assume no cost to stop truck loading since tank and pipeline decommissioning cost is associated with gathering and processing | n/a |
| Statewide | Oil: Truck Loading | Equipment Changeout | $61,853.99 | per vapor recovery unit | 95% | Data year based on inventory baseline of 2011 data; cost of vapor recovery unit | ICF 2014 |
| Statewide | Transmission Pipeline | LDAR | $530.64 | per $MTCH_4$ | 40% | $7.95 + $3 = $10.95 per Mcf assuming no cost savings from captured natural gas; converted to $MTCH_4$ | ICF 2016 |
| Statewide | Gas Transmission Compressor Stations, Gas Storage Compressor Stations, LNG Storage Compressor Stations | Equipment Changeout | $238,876.43 | per compressor | 31% | Assumes replacement of wet seal compressors with dry seal; assumes 2 wet seal compressors per station | Ishkov 2011; NRDC 2012; ICF 2016 |

**Table 8 continued**

| Area | Source | Mitigation | Cost per unit ($2020) | Cost Unit | Methane Emissions Reduction Potential (%) | Notes | Reference |
|---|---|---|---|---|---|---|---|
| Statewide | Gas Transmission Compressor Stations, Gas Storage Compressor Stations, LNG Storage Compressor Stations | LDAR | $37,049.75 | per station | 40% | Cost of leak detection program plus repair | EPA 2003 |
| Statewide | Distribution Pipeline: Main and Services (all materials) | Decommissioning | $17,263.12 | per mile | 100% | 2016 costs for pipelines from divided by total 2016 pipelines; converted CAD to US dollars using 2016 exchange rate of 0.744 | TransCanada 2016 |
| Upstate NY | Cast Iron Distribution Pipeline: Main | Equipment Changeout | $747,741.95 | per $MTCH_4$ | 100.00% | Calculated using miles of pipeline by type and size from PHMSA and replacement costs from Greenblatt 2015 | Greenblatt 2015 |
| Downstate NY | Cast Iron Distribution Pipeline: Main | Equipment Changeout | $1,552,179.30 | per $MTCH_4$ | 100.00% | | |
| Upstate NY | Cast Iron Distribution Pipeline: Main | LDAR | $60,030.25 | per $MTCH_4$ | 60.00% | Composite wrap repair cost from EPA 2006a. Leak detection labor cost EDF 2020. Capital and training cost, labor time assumptions from ICF 2014. Leaks per mile from Weller et al. 2020 | Weller et al. 2020; EPA 2006a; EDF 2020; ICF 2014 |
| Downstate NY | Cast Iron Distribution Pipeline: Main | LDAR | $46,051.51 | per $MTCH_4$ | 60.00% | | |

**Table 8 continued**

| Area | Source | Mitigation | Cost per unit ($2020) | Cost Unit | Methane Emissions Reduction Potential (%) | Notes | Reference |
|---|---|---|---|---|---|---|---|
| Upstate NY | Cast Iron Distribution Pipeline: Services | Equipment Changeout | $466,446.39 | per $MTCH_4$ | 100.00% | Calculated using miles of pipeline by type and size from PHMSA and replacement costs from Greenblatt 2015 | Greenblatt 2015 |
| Downstate NY | Cast Iron Distribution Pipeline: Services | Equipment Changeout | $988,890.38 | per $MTCH_4$ | 100.00% | | |
| Upstate NY | Cast Iron Distribution Pipeline: Services | LDAR | $66,133.37 | per $MTCH_4$ | 60.00% | Composite wrap repair cost from EPA 2006a. Leak detection labor cost from EDF 2020. Capital and training cost, labor time assumptions from ICF 2014. Leaks per mile from Weller et al. 2020 | Weller et al. 2020; EPA 2006a; EDF 2020; ICF 2014 |
| Downstate NY | Cast Iron Distribution Pipeline: Services | LDAR | $49,611.76 | per $MTCH_4$ | 60.00% | | |
| Upstate NY | Copper Distribution Pipeline: Services | Equipment Changeout | $3,460,140.55 | per $MTCH_4$ | 100.00% | Calculated using miles of pipeline by type and size from PHMSA and replacement costs from Greenblatt 2015 | Greenblatt 2015 |
| Downstate NY | Copper Distribution Pipeline: Services | Equipment Changeout | $7,335,676.32 | per $MTCH_4$ | 100.00% | | |
| Upstate NY | Copper Distribution Pipeline: Services | LDAR | $291,707.00 | per $MTCH_4$ | 60.00% | Composite wrap repair cost from EPA 2006a. Leak detection labor cost from EDF 2020. Capital and training cost, labor time assumptions from ICF 2014. Leaks per mile from Weller et al. 2020 | Weller et al. 2020; EPA 2006a; EDF 2020; ICF 2014 |
| Downstate NY | Copper Distribution Pipeline: Services | LDAR | $223,334.92 | per $MTCH_4$ | 60.00% | | |

**Table 8 continued**

| Area | Source | Mitigation | Cost per unit ($2020) | Cost Unit | Methane Emissions Reduction Potential (%) | Notes | Reference |
|---|---|---|---|---|---|---|---|
| Upstate NY | Plastic Distribution Pipeline: Main | Equipment Changeout | $13,772,562.98 | per $MTCH_4$ | 100.00% | Calculated using miles of pipeline by type and size from PHMSA and replacement costs from Greenblatt 2015 | Greenblatt 2015 |
| Downstate NY | Plastic Distribution Pipeline: Main | Equipment Changeout | $29,196,803.86 | per $MTCH_4$ | 100.00% | Calculated using miles of pipeline by type and size from PHMSA and replacement costs from Greenblatt 2015 | Greenblatt 2015 |
| Upstate NY | Plastic Distribution Pipeline: Main | LDAR | $642,147.68 | per $MTCH_4$ | 60.00% | Composite wrap repair cost from EPA 2006a. Leak detection labor cost from EDF 2020. Capital and training cost, labor time assumptions from ICF 2014. Leaks per mile from Weller et al. 2020 | Weller et al. 2020; EPA 2006a; EDF 2020; ICF 2014 |
| Downstate NY | Plastic Distribution Pipeline: Main | LDAR | $490,562.61 | per $MTCH_4$ | 60.00% | Composite wrap repair cost from EPA 2006a. Leak detection labor cost from EDF 2020. Capital and training cost, labor time assumptions from ICF 2014. Leaks per mile from Weller et al. 2020 | Weller et al. 2020; EPA 2006a; EDF 2020; ICF 2014 |
| Upstate NY | Plastic Distribution Pipeline: Services | Equipment Changeout | $180,520,175.66 | per $MTCH_4$ | 100.00% | Calculated using miles of pipeline by type and size from PHMSA and replacement costs from Greenblatt 2015 | Greenblatt 2015 |
| Downstate NY | Plastic Distribution Pipeline: Services | Equipment Changeout | $382,706,655.28 | per $MTCH_4$ | 100.00% | Calculated using miles of pipeline by type and size from PHMSA and replacement costs from Greenblatt 2015 | Greenblatt 2015 |
| Upstate NY | Plastic Distribution Pipeline: Services | LDAR | $9,037,983.45 | per $MTCH_4$ | 60.00% | Composite wrap repair cost from EPA 2006a. Leak detection labor cost from EDF 2020. Capital and training cost, labor time assumptions from ICF 2014. Leaks per mile from Weller et al. 2020 | Weller et al. 2020; EPA 2006a; EDF 2020; ICF 2014 |
| Downstate NY | Plastic Distribution Pipeline: Services | LDAR | $6,908,005.93 | per $MTCH_4$ | 60.00% | Composite wrap repair cost from EPA 2006a. Leak detection labor cost from EDF 2020. Capital and training cost, labor time assumptions from ICF 2014. Leaks per mile from Weller et al. 2020 | Weller et al. 2020; EPA 2006a; EDF 2020; ICF 2014 |

**Table 8 continued**

| Area | Source | Mitigation | Cost per unit ($2020) | Cost Unit | Methane Emissions Reduction Potential (%) | Notes | Reference |
|---|---|---|---|---|---|---|---|
| Upstate NY | Protected and Unprotected Steel Distribution Pipeline: Main | Equipment Changeout | $3,601,535.20 | per $MTCH_4$ | 100.00% | Calculated using miles of pipeline by type and size from PHMSA and replacement costs from Greenblatt 2015 | Greenblatt 2015 |
| Downstate NY | Protected and Unprotected Steel Distribution Pipeline: Main | Equipment Changeout | $7,564,751.88 | per $MTCH_4$ | 100.00% | | |
| Upstate NY | Protected Steel Distribution Pipeline: Main | LDAR | $2,904,079.77 | per $MTCH_4$ | 60.00% | Composite wrap repair cost from EPA 2006a. Leak detection labor cost from EDF 2020. Capital and training cost, labor time assumptions from ICF 2014. Leaks per mile from Weller et al. 2020 | Weller et al. 2020; EPA 2006a; EDF 2020; ICF 2014 |
| Downstate NY | Protected Steel Distribution Pipeline: Main | LDAR | $2,223,553.35 | per $MTCH_4$ | 60.00% | | |
| Upstate NY | Protected and Unprotected Steel Distribution Pipeline: Services | Equipment Changeout | $1,545,601.35 | per $MTCH_4$ | 100.00% | Calculated using miles of pipeline by type and size from PHMSA and replacement costs from Greenblatt 2015 | Greenblatt 2015 |
| Downstate NY | Protected and Unprotected Steel Distribution Pipeline: Services | Equipment Changeout | $3,276,543.92 | per $MTCH_4$ | 100.00% | | |

**Table 8 continued**

| Area | Source | Mitigation | Cost per unit ($2020) | Cost Unit | Methane Emissions Reduction Potential (%) | Notes | Reference |
|---|---|---|---|---|---|---|---|
| Upstate NY | Protected Steel Distribution Pipeline: Services | LDAR | $691,334.61 | per $MTCH_4$ | 60.00% | Composite wrap repair cost from EPA 2006a. Leak detection labor cost from EDF 2020. Capital and training cost, labor time assumptions from ICF 2014. Leaks per mile from Weller et al. 2020 | Weller et al. 2020; EPA 2006a; EDF 2020; ICF 2014 |
| Downstate NY | Protected Steel Distribution Pipeline: Services | LDAR | $529,363.89 | per $MTCH_4$ | 60.00% | | |
| Upstate NY | Unprotected Steel Distribution Pipeline: Main | LDAR | $67,920.24 | per $MTCH_4$ | 60.00% | | |
| Downstate NY | Unprotected Steel Distribution Pipeline: Main | LDAR | $51,925.09 | per $MTCH_4$ | 60.00% | Composite wrap repair cost from EPA 2006a. Leak detection labor cost from EDF 2020. Capital and training cost, labor time assumptions from ICF 2014. Leaks per mile from Weller et al. 2020 | Weller et al. 2020; EPA 2006a; EDF 2020; ICF 2014 |
| Upstate NY | Unprotected Steel Distribution Pipeline: Services | LDAR | $53,184.02 | per $MTCH_4$ | 60.00% | | |
| Downstate NY | Unprotected Steel Distribution Pipeline: Services | LDAR | $40,649.23 | per $MTCH_4$ | 60.00% | | |
| Statewide | Commercial and Residential Meters | LDAR | $122.83 | per meter | 60.00% | Assumes annual inspection and repair; assumes 25% of meters currently leak and that leaks are associated with connections to the meter and not the meters themselves | HomeAdvisor 2021 |

**Table 8 continued**

| Area | Source | Mitigation | Cost per unit ($2020) | Cost Unit | Methane Emissions Reduction Potential (%) | Notes | Reference |
|---|---|---|---|---|---|---|---|
| Statewide | Commercial Buildings | LDAR | $753.40 | per building | 40.00% | Assumes installation of smart gas detector and leak repair | HomeAdvisor 2021; CEC 2020; Con Edison Media Relations 2020 |
| Statewide | Residential Buildings | LDAR | $384.26 | per building | 40.00% | Assumes installation of smart gas detector and leak repair | CEC 2018; Con Edison Media Relations 2020; HomeAdvisor 2021 |

## 5.2 Mitigation Option Rubric

The methane mitigation cost and reduction potential were calculated by applying the cost and mitigation limits identified during the literature review to the 2020 emissions by source and geography in NYS. These values were then used to create a series of rubrics to assign a score to methane mitigation options for the oil and natural gas sector in New York State. The first rubric (Table 9) divides the mitigation cost into quartile bins and assigns a score of 1 to 4 to the bins with 1as the least costly quartile and 4 as the costliest quartile.

**Table 9. Rubric 1—Mitigation Option Cost (\$/MT$CO_2$e, AR5, GWP20)**

| Quartiles | Mitigation Cost Quartile Bin | Score |
|---|---|---|
| Min - 25% | -1.28 to 4.22 | 1 |
| 25%-50% | 4.23 to 386.96 | 2 |
| 50%-75% | 386.97 to 2,526.22 | 3 |
| >75% | 2,526.23 to 365,587.64 | 4 |

The second rubric (Table 10) divides the emissions mitigation potential (MT$CO_2$e, AR5, GWP20) into quartile bins and assigns a score of 1 to 4 to the bins with 4 being the bin with the least emissions mitigation potential and 1 having the most mitigation potential.

**Table 10. Rubric 2—Emissions Mitigation Potential (MT$CO_2$e, AR5, GWP20)**

| Quartiles | Mitigation Emissions Quartile Bin | Score |
|---|---|---|
| Min - 25% | 81 to 20,947 | 4 |
| 25%-50% | 20,948 to 45,352 | 3 |
| 50%-75% | 45,353 to 301,807 | 2 |
| >75% | 301,808 to 1,238,160 | 1 |

The third rubric (Table 11) assigns a score of 1 to 3 based on a qualitative assessment of implementation feasibility. This assessment considers the labor required and the complexity of the mitigation option, the regulatory landscape, and the level of infrastructure disruption.

**Table 11. Rubric 3—Implementation Feasibility**

| Qualitative Assessment | Score |
|---|---|
| Easy | 1 |
| Moderate | 2 |
| Hard | 3 |

Based on the summed scores of rubric 1, 2, and 3, the mitigation options are either excluded or assigned to mitigation level 1 or level 2 as shown in Table 12.

**Table 12. Mitigation Scenario Assignment**

| Mitigation Scenario | Score |
|---|---|
| Level 1 | 7 or less |
| Level 2 | 10 or less |
| Excluded | 11 |

Using this rubric, both equipment changeout and LDAR of plastic distribution pipeline services downstate are assigned a score of 11 and thus excluded. All other mitigation options considered, their scores, and which mitigation scenario they are assigned to are shown in Table 13.

**Table 13. Mitigation Cost, Emissions Mitigation Potential, Implementation Feasibility, and Total Scores of Each Mitigation Option**

| Area | Source | Mitigation | Mitigation Cost Score | Emissions Mitigation Potential Score | Implementation Feasibility Score | Total Score | Implemented in Level 1 Mitigation Scenario | Implemented in Level 2 Mitigation Scenario |
|---|---|---|---|---|---|---|---|---|
| Upstate NY | Gas Storage Compressor Stations | LDAR | 1 | 1 | 1 | 3 | Y | Y |
| Upstate NY | Gas Transmission Compressor Stations | LDAR | 1 | 1 | 1 | 3 | Y | Y |
| Upstate NY | Gas Storage Compressor Stations | Equipment Changeout | 1 | 1 | 1 | 3 | Y | Y |
| Upstate NY | Gas Transmission Compressor Stations | Equipment Changeout | 1 | 1 | 1 | 3 | Y | Y |
| Upstate NY | Gas Well: Conventional Production_Low Producing | LDAR | 1 | 1 | 2 | 4 | Y | Y |
| Downstate NY | LNG Storage Compressor Stations | LDAR | 1 | 2 | 1 | 4 | Y | Y |
| Downstate NY | Gas Transmission Compressor Stations | LDAR | 1 | 2 | 1 | 4 | Y | Y |
| Downstate NY | LNG Storage Compressor Stations | Equipment Changeout | 1 | 2 | 1 | 4 | Y | Y |
| Downstate NY | Gas Transmission Compressor Stations | Equipment Changeout | 1 | 2 | 1 | 4 | Y | Y |
| Upstate NY | Gas Well: Conventional Production_Low Producing | Decommissioning | 2 | 1 | 1 | 4 | Y | Y |
| Upstate NY | Gas Well: Conventional Production_High Producing | LDAR | 1 | 2 | 2 | 5 | Y | Y |

**Table 13 continued**

| Area | Source | Mitigation | Mitigation Cost Score | Emissions Mitigation Potential Score | Implementation Feasibility Score | Total Score | Implemented in Level 1 Mitigation Scenario | Implemented in Level 2 Mitigation Scenario |
|---|---|---|---|---|---|---|---|---|
| Upstate NY | Gas Well: Conventional Production_High Producing | Decommissioning | 1 | 2 | 2 | 5 | Y | Y |
| Upstate NY | Gas: Gathering and Processing | Decommissioning | 1 | 2 | 2 | 5 | Y | Y |
| Upstate NY | Gas: Gathering and Processing | LDAR | 1 | 3 | 1 | 5 | Y | Y |
| Upstate NY | Oil Well: Conventional Production_Low Producing | LDAR | 1 | 3 | 2 | 6 | Y | Y |
| Upstate NY | Oil: Gathering and Processing | LDAR | 1 | 4 | 1 | 6 | Y | Y |
| Upstate NY | Transmission Pipeline | LDAR | 2 | 2 | 2 | 6 | Y | Y |
| Downstate NY | Commercial Meters | LDAR | 2 | 2 | 2 | 6 | Y | Y |
| Upstate NY | Cast Iron Distribution Pipeline: Main | LDAR | 3 | 1 | 2 | 6 | Y | Y |
| Upstate NY | Unprotected Steel Distribution Pipeline: Main | LDAR | 3 | 1 | 2 | 6 | Y | Y |
| Upstate NY | Gathering Pipeline | Decommissioning | 2 | 3 | 2 | 7 | Y | Y |
| Upstate NY | Oil Well: Conventional Production_High Producing | LDAR | 1 | 4 | 2 | 7 | Y | Y |

**Table 13 continued**

| Area | Source | Mitigation | Mitigation Cost Score | Emissions Mitigation Potential Score | Implementation Feasibility Score | Total Score | Implemented in Level 1 Mitigation Scenario | Implemented in Level 2 Mitigation Scenario |
|---|---|---|---|---|---|---|---|---|
| Upstate NY | Oil: Gathering and Processing | Decommissioning | 1 | 4 | 2 | 7 | Y | Y |
| Upstate NY | Gathering Pipeline | LDAR | 1 | 4 | 2 | 7 | Y | Y |
| Upstate NY | Gathering Pipeline | Decommissioning | 2 | 3 | 2 | 7 | Y | Y |
| Upstate NY | Oil: Truck Loading | Equipment Changeout | 2 | 4 | 1 | 7 | Y | Y |
| Upstate NY | Commercial Meters | LDAR | 2 | 3 | 2 | 7 | Y | Y |
| Upstate NY | Oil Well: Conventional Production_Low Producing | Decommissioning | 3 | 2 | 2 | 7 | Y | Y |
| Downstate NY | Unprotected Steel Distribution Pipeline: Services | LDAR | 3 | 1 | 3 | 7 | Y | Y |
| Downstate NY | Cast Iron Distribution Pipeline: Main | LDAR | 3 | 1 | 3 | 7 | Y | Y |
| Downstate NY | Unprotected Steel Distribution Pipeline: Main | LDAR | 3 | 1 | 3 | 7 | Y | Y |
| Upstate NY | Unprotected Steel Distribution Pipeline: Services | LDAR | 3 | 2 | 2 | 7 | Y | Y |
| Upstate NY | Residential Meters | LDAR | 3 | 2 | 2 | 7 | Y | Y |
| Downstate NY | Residential Meters | LDAR | 3 | 2 | 2 | 7 | Y | Y |

**Table 13 continued**

| Area | Source | Mitigation | Mitigation Cost Score | Emissions Mitigation Potential Score | Implementation Feasibility Score | Total Score | Implemented in Level 1 Mitigation Scenario | Implemented in Level 2 Mitigation Scenario |
|---|---|---|---|---|---|---|---|---|
| Downstate NY | Commercial Buildings | LDAR | 3 | 2 | 2 | 7 | Y | Y |
| Upstate NY | Residential Buildings | LDAR | 3 | 2 | 2 | 7 | Y | Y |
| Upstate NY | Oil: Abandoned Wells | Decommissioning | 2 | 4 | 2 | 8 | N | Y |
| Upstate NY | Gas: Abandoned Wells | Decommissioning | 2 | 4 | 2 | 8 | N | Y |
| Upstate NY | Commercial Buildings | LDAR | 3 | 3 | 2 | 8 | N | Y |
| Downstate NY | Residential Buildings | LDAR | 4 | 2 | 2 | 8 | N | Y |
| Upstate NY | Plastic Distribution Pipeline: Main | LDAR | 4 | 2 | 2 | 8 | N | Y |
| Downstate NY | Transmission Pipeline | LDAR | 2 | 4 | 3 | 9 | N | Y |
| Upstate NY | Oil Well: Conventional Production_High Producing | Decommissioning | 3 | 4 | 2 | 9 | N | Y |
| Upstate NY | Cast Iron Distribution Pipeline: Services | LDAR | 3 | 4 | 2 | 9 | N | Y |
| Downstate NY | Plastic Distribution Pipeline: Main | LDAR | 4 | 2 | 3 | 9 | N | Y |
| Upstate NY | Protected Steel Distribution Pipeline: Services | LDAR | 4 | 3 | 2 | 9 | N | Y |

**Table 13 continued**

| Area | Source | Mitigation | Mitigation Cost Score | Emissions Mitigation Potential Score | Implementation Feasibility Score | Total Score | Implemented in Level 1 Mitigation Scenario | Implemented in Level 2 Mitigation Scenario |
|---|---|---|---|---|---|---|---|---|
| Upstate NY | Protected Steel Distribution Pipeline: Main | LDAR | 4 | 3 | 2 | 9 | N | Y |
| Downstate NY | Cast Iron Distribution Pipeline: Services | LDAR | 3 | 4 | 3 | 10 | N | Y |
| Downstate NY | Copper Distribution Pipeline: Services | LDAR | 4 | 3 | 3 | 10 | N | Y |
| Upstate NY | Copper Distribution Pipeline: Services | LDAR | 4 | 4 | 2 | 10 | N | Y |
| Downstate NY | Protected Steel Distribution Pipeline: Services | LDAR | 4 | 3 | 3 | 10 | N | Y |
| Downstate NY | Protected Steel Distribution Pipeline: Main | LDAR | 4 | 3 | 3 | 10 | N | Y |
| Upstate NY | Plastic Distribution Pipeline: Services | LDAR | 4 | 4 | 2 | 10 | N | Y |

## 5.3 Avoided Cost

Avoided costs are those costs associated with avoiding stranded assets. For example, the capital cost to install a natural gas pipeline is recovered over the average pipeline operational life. If a natural gas pipeline is installed and then not used due to the replacement of natural gas with electricity, then the pipeline becomes a liability and is considered a stranded asset. The relevant sources for which avoided costs are calculated in the model include:

- plastic mains
- plastic services
- protected steel mains
- protected steel services
- commercial meters
- residential meters
- residential buildings

For these sources, activity data in the reference case increases at a higher rate than the Integration Analysis Scenario cases indicating that some activity in the reference case is avoided in the Integration Analysis Scenario cases.

This section summarizes the literature review findings on the cost of avoided activity for the listed sources. In general, the literature review did not find any cost information published by utilities. Therefore, HomeAdvisor and HomeGuide were used to estimate costs. These sites compile millions of cost estimates to arrive at the cost to install or repair home services, including natural gas service lines, meters, house lines and appliance connections. In this analysis, the upstate cost is assumed to be 25 percent below the average cost identified in the literature and the downstate cost is assumed to be 25 percent above the average cost. Downstate costs are more expensive due to more complex natural gas infrastructure access and disturbance of existing structures in urban areas. These estimates are consistent with estimates in the literature that a pipeline in a rural area can cost five times less than a pipeline of the same length and diameter through an urban area (Parker, n.d.). The avoided costs per unit of activity are presented in Table 14.and have been updated to report all costs in 2020 dollars.

**Table 14. Summary of Avoided Costs per Unit of Activity**

| Area | Source | Avoided Cost Range ($2020) | Avoided Cost per Unit ($2020) | Cost Unit |
|---|---|---|---|---|
| Upstate NY | Plastic Distribution Pipeline: Main | $25,466–203,732 | $85,949 | Per mile |
| Downstate NY | Plastic Distribution Pipeline: Main | $25,466–203,732 | $143,249 | Per mile |
| Upstate NY | Plastic Distribution Pipeline: Services | $63,360–132,00 | $73,260 | Per mile |
| Downstate NY | Plastic Distribution Pipeline: Services | $63,360–132,00 | $122,100 | Per mile |
| Upstate NY | Protected Steel Distribution Pipeline: Main | $76,399–477,497 | $207,711 | Per mile |
| Downstate NY | Protected Steel Distribution Pipeline: Main | $76,399–477,497 | $346,185 | Per mile |
| Upstate NY | Protected Steel Distribution Pipeline: Services | $63,360–132,00 | $73,260 | Per mile |
| Downstate NY | Protected Steel Distribution Pipeline: Services | $63,360–132,00 | $122,100 | Per mile |
| Upstate NY | Commercial Meters | $500–1600 | $788 | Per building |
| Downstate NY | Commercial Meters | $500–1600 | $1,313 | Per building |
| Upstate NY | Residential Meters | $200–700 | $338 | Per building |
| Downstate NY | Residential Meters | $200–700 | $563 | Per building |
| Upstate NY | Residential Buildings | $1,273–3,416 | $1,758 | Per building |
| Downstate NY | Residential Buildings | $1,273–3,416 | $2,931 | Per building |

The remainder of this section provides details on the costs associated with stranded assets and the equations used to estimate avoided costs.

### 5.3.1 Mains

While several sources were found that described costs for pipeline installation, most estimate the costs associated with transmission pipeline projects. For instance, API (2017) estimated that through 2035, the average pipeline cost is $178,000 per inch-mile for 2016 for large transmission pipelines. Using an average of 30 inches for transmission pipelines, the cost would be $5,340,000 per mile. The study also provides a regional cost multiplier for the Northeast of 1.68.

Lively (n.d.) provides estimates per foot for installing polyethylene and steel distribution mains. The average cost per foot to install polyethylene gas distribution mains ranges from $4.00 to $32.00 depending on size, and steel gas distribution mains range from $12.00 to $75.00 (Lively n.d.) in 2008 dollars. This translates to a range of $21,120–$168,960 per mile of polyethylene mains and a range of $463,360–$396,000 per mile of steel mains. As mentioned above, to arrive at the values presented in

Table 14, the upstate cost is assumed to be 25 percent below the average cost identified in the literature and the downstate cost is assumed to be 25 percent above the average cost. For example, the average cost per mile of polyethylene mains is $95,040. Converting this cost to 2020 dollars results in an average cost of $114,599. Twenty-five percent below the average is $85,949 and 25 percent above the average is $143,249.

### 5.3.2 Services

According to HomeAdvisor, the average cost to run a new gas line (service) is $535 (HomeAdvisor 2021). HomeAdvisor estimates that it costs $15 to $25 per foot ($79,200 to $132,000 per mile) to install a new or replacement gas line, which includes labor, materials, and piping (HomeAdvisor 2021). Estimates for HomeGuide range from $12 to $25 per foot ($63,360 to $132,000 per mile) and include labor, materials, piping, and permits (HomeGuide 2021). The values from HomeGuide were used in this analysis. Similar to mains, the upstate cost is assumed to be 25 percent below the average cost and the downstate cost is assumed to be 25 percent above the average cost and the values are presented in Table 14.

### 5.3.3 Meters

According to HomeGuide, it costs between $200 and $300 to install a residential meter and between $400 and $1,000 to install a commercial meter (HomeGuide 2021). Labor costs $100 to $300 (HomeGuide 2021). HomeAdvisor estimates that it costs $100 to $300 for residential meters, $400 to $1,200 for commercial meters, and $150 to $400 for install labor (HomeAdvisor 2021). This study uses a range of $500–$1,600 for commercial meters and $200–$700 for residential meters. Similar to mains, the upstate cost is assumed to be 25 percent below the average cost and the downstate cost is assumed to be 25 percent above the average cost and the values are presented in Table 14.

### 5.3.4 Residential Buildings

HomeGuide provides estimates for several costs to add gas to a house (HomeGuide 2021). These are shown in Table 15.

**Table 15. Costs to Add Gas to a House from HomeGuide**

| Activity | Cost |
|---|---|
| Add or convert house to natural gas | $2,008 |
| New line from meter | $500–2,000 per project |
| Run lines in house | $355–743 per line |
| Connections to appliances | $46–297 per appliance |
| Standard shut off valves for appliances | $52–138 per appliance |
| Run gas line into one room house | $307 per house |
| Run gas line into 3 room house | $920 per house |

HomeGuide estimates that the average cost to add or convert a house to natural gas is $2,008 with an average range of $1,273 to $3,416 (HomeGuide 2021). The HomeGuide average range is used in this study. Similar to mains, the upstate cost is assumed to be 25 percent below the average cost and the downstate cost is assumed to be 25 percent above the average cost and the values are presented in Table 14.

### 5.3.5 Avoided Cost per Unit of Activity

The annual avoided activity is calculated using one of two equations. If the activity data in the Integration Analysis Scenario is less than the activity data in Reference case year 2020, then the annual avoided activity is the difference between the future year activity in the Reference case and the 2020 activity in the reference case. If the activity data in the Integration Analysis Scenario is greater than the activity data in the Reference case year 2020, then the annual avoided activity is the difference between the future year activity in the Reference case and the future year activity in the Integration Analysis Scenario. Next, the annual values are summed to estimate the cumulative avoided activity in the Integration Analysis Scenarios. Cumulative avoided costs are estimated by multiplying the cumulative avoided activity in the Integration Analysis Scenarios by the avoided cost per unit of activity, as shown in Equation 4a and Equation 4b.

**Equation 4a** $$\boldsymbol{AC = C \times \sum AD_{r,y} - AD_{r,2020}}$$

**Equation 4b** $$\boldsymbol{AC = C \times \sum AD_{r,y} - AD_{s,y}}$$

Where:

$AC$ = cumulative avoided cost
$C$ = cost per unit
$AD_{r,y}$ = activity in the reference case for future year $y$
$AD_{r,2020}$ = activity in the reference case for year 2020
$AD_{s,2020}$ = activity in the integration analysis scenario for future year $y$

For example, for plastic distribution pipeline mains in Integration Analysis Scenario 2, the annual activity avoided upstate is calculated as the difference between the Reference case future year activity and Integration Analysis Scenario future year activity (Equation 4b). The annual activity avoided is summed to the cumulative avoided activity upstate (2,301.01 miles). The cumulative avoided activity is then multiplied by the avoided cost per mile ($207,711.00) to estimate the cumulative avoided cost ($477,945,413.64).

## 5.4 Annualized Cost and Net Present Value

In addition to presenting non-annualized, overnight costs, annualized cost and net present value was also calculated. The equations for annualized cost and net present value are presented in Equation 5 and Equation 6 below.

**Equation 5** $$\boldsymbol{A = C_y \times IR/(1-((1+IR)^T}$$

Where:

$A$ = annualized cost
$C_y$ = cost in year $y$
$IR$ = interest rate
$T$ = loan term in years

**Equation 6** $$\boldsymbol{NPV = C_y \times (1/(1+DR))^{Y_y - Y_c}}$$

Where:

$NPV$ = net present value
$C_y$ = cost in year $y$
$DR$ = discount rate
$Y_y$ = year $y$
$Y_c$ = current year

The values used in the model are:

- Discount Rate = 3.6%
- Term of Loan = 20 years
- Interest Rate = 5%

# 6 Methodology for Developing Emissions Projections in the Mitigation Scenarios

In addition to the reference case, six mitigation scenarios were developed to model emissions projections through 2050. The first scenario, Integration Analysis Scenario 2 (IAS2), is derived from the Integration Analysis Strategic Use of Low Carbon Fuels scenario (LCF) and the second scenario, Integration Analysis Scenario 3 (IAS3), is derived from the Integration Analysis Accelerated Transition Away from Combustion (AT). No additional mitigation measures are applied to IAS2 or IAS3. Four more mitigation scenarios, IAS2–Level 1 Mitigation, IAS2–Level 2 Mitigation, IAS3–Level 1 Mitigation, and IAS3–Level 2 Mitigation, were modeled by applying varying rates of decommissioning, equipment replacement, and leak detection and repair (LDAR) at various penetration rates to IAS2 and IAS3. These mitigation measures were phased in over a 7-year time horizon, from 2023 to 2030. For upstream and midstream sources not directly modeled in the IAS2 and IAS3 scenarios, projections are based on historical trendlines. Selection of the trendline dates is based on inflection points in the historical data that indicate a change in activity (i.e., production, well capping, transmission).

## 6.1 Integration Analysis Scenario 2 (IAS2)

Integration Analysis Scenario 2 (IAS2) is based on the Integration Analysis Strategic Use of Low Carbon Fuels (LCF) scenario which represents the recommendations from each advisory panel, including aggressive electrification and efficiency relative to the Reference scenario (NYS 2022a). In addition, the IAS2 scenario includes the use of bioenergy from biogenic waste, agriculture and forestry residues, and limited purpose grown biomass, as well as green hydrogen and the conversion of industrial natural gas to hydrogen fuel in difficult to electrify end-uses. The IAS2 scenario includes limited use of negative emissions technologies. This scenario also includes increased sales of high efficiency appliances and smart devices as well as increasing sales of heat pump space heaters and water heaters in the 2020s compared to the reference case by 2030 all new sales of single-family and low-rise residential heating systems will be heat pumps with 1.5 million homes electrified with heat pumps. For multifamily and commercial heating systems, the IAS2 scenario assumes all new sales of heating systems will be heat pumps by 2035. The IAS2 scenario also assumes that by 2030, there will be 9 percent renewable natural gas blends in pipelines. By 2050, 33 percent of natural gas is assumed to be replaced with electricity.

The trends seen in IAS2 compared to the reference case are shown in Table 16. Emissions are not directly impacted by natural gas throughput but are instead more directly impacted by total building electrification. Aside from the addition of 25 miles of transmission pipeline in 2021, the number of compressor stations and transmission pipeline mileage are held constant. All other key parameters are assumed to decrease at annual rates based on historical trends.

## 6.2 Integration Analysis Scenario 3 (IAS3)

Integration Analysis Scenario 3 (IAS3) is based on the Integration Analysis Accelerated Transition Away from Combustion scenario (AT) and has a limited role for bioenergy and hydrogen but accelerates electrification of buildings and transportation (NYS 2022a). In addition, the IAS3 scenario includes additional electrification both by increasing the pace of heat pump sales in the 2020s and by including some early retirements of fossil technologies in 2028/2029, no hybrid heat pumps, electrification of industrial natural gas, low-to-no bioenergy and hydrogen combustion, and accelerated electrification of buildings and transportation. Like the IAS2 scenario, IAS3 assumes increased sales of high efficiency appliances and smart devices as well as heat pump space heaters and water heaters in the 2020s, that all new sales of single-family and low-rise residential heating systems are heat pumps by 2030 and all new sales of multifamily and commercial heating systems are heat pumps by 2035, and leak detection and repair and strategic pipeline decommissioning by 2025. The IAS3 scenario assumes that by 2030, 1.8 million homes will be electrified with heat pumps and 25 percent of all homes will have efficient shell upgrades. This scenario also assumes additional early retirement of older heating systems by 2030 and that by 2030 there will be 4 percent renewable natural gas blends in pipelines. The IAS3 scenario assumes that 83 percent of natural gas use will be electrified by 2050. The trends seen in IAS3 compared to the IAS2 and the reference case are shown in Table 16. Similar to IAS2, emissions are not directly impacted by natural gas throughput but are instead more directly impacted by total building electrification. Aside from the addition of 25 miles of transmission pipeline in 2021, the number of compressor stations and transmission pipeline mileage are held constant. All other key parameters are assumed to decrease at annual rates based on historical trends.

**Table 16. Comparison of Projections of Activity Data for the Reference Case to Integration Analysis Scenario 2 (IAS2) and Integration Analysis Scenario 3 (IAS3)**

| Key Parameter | Reference Case | Integration Analysis Scenario 2 (LCF) | Integration Analysis Scenario 3 (AT) |
|---|---|---|---|
| Natural Gas Production (+Gathering and Boosting Stations and Gathering Pipeline) | No change – remains constant at 2020 levels | 16.7% average annual decrease based on historical trendline from 2016-2020 | 16.7% average annual decrease based on historical trendline from 2016-2020 |
| Capping Abandoned Wells | 0.62% average annual decrease in uncapped abandoned oil wells through 2050 based on historical trendline from 1990-2020;<br>0.82% average annual decrease in uncapped abandoned gas wells through 2050 based on historical trendline from 1990-2020 | 0.62% average annual decrease in uncapped abandoned oil wells through 2050 based on historical trendline from 1990-2020;<br>0.82% average annual decrease in uncapped abandoned gas wells through 2050 based on historical trendline from 1990-2020 | 0.62% average annual decrease in uncapped abandoned oil wells through 2050 based on historical trendline from 1990-2020;<br>0.82% average annual decrease in uncapped abandoned gas wells through 2050 based on historical trendline from 1990-2020 |
| Truck Loading of Oil | 0.29% average annual decrease based on regional AEO2021 oil production projections | 44.8% average annual decrease based on historical oil production trendline from 2013-2020 | 44.8% average annual decrease based on historical oil production trendline from 2013-2020 |
| Transmission Pipeline | Hold 2020 mileage constant except for the addition of 25 miles in Ontario County in 2021 | Hold 2020 mileage constant except for the addition of 25 miles in Ontario County in 2021 | Hold 2020 mileage constant except for the addition of 25 miles in Ontario County in 2021 |
| Compressor Stations | Hold 2020 number of stations constant except for the addition of 1 transmission compressor station in Ontario County in 2021 | Hold 2020 number of stations constant except for the addition of 1 transmission compressor station in Ontario County in 2021 | Hold 2020 number of stations constant except for the addition of 1 transmission compressor station in Ontario County in 2021 |
| Natural Gas Throughput | Emissions are not directly impacted by natural gas throughput. | Emissions are not directly impacted by natural gas throughput. | Emissions are not directly impacted by natural gas throughput. |
| Commercial Buildings with Natural Gas Service (+Meters) | 1.03% average annual increase (based on IA modeling of commercial building electrification - used space heating as a surrogate to determine building electrification) | 7.73% average annual decrease | 14.48% average annual decrease |
| Residential Buildings with Natural Gas Service (+Meters and Appliances) | 0.67% average annual increase (based on IA modeling of residential building electrification - used space heating as a surrogate to determine building electrification) | 5.38% average annual decrease | 7.34% average annual decrease |

**Table 16 continued**

| Key Parameter | Reference Case | Integration Analysis Scenario 2 (LCF) | Integration Analysis Scenario 3 (AT) |
|---|---|---|---|
| Cast Iron : Main | 6.27% average annual decrease based on 50% of historical tend from 2010-2020; assume 20% of pipeline is too costly to replace | 6.27% average annual decrease based on 50% of historical tend from 2010-2020; assume 20% of pipeline is too costly to replace | 6.27% average annual decrease based on 50% of historical tend from 2010-2020; assume 20% of pipeline is too costly to replace |
| Cast Iron: Services | 9.5% average annual decrease based on 50% of historical trend from 2010-2020; assume 20% of pipeline is too costly to replace | 9.5% average annual decrease based on 50% of historical trend from 2010-2020; assume 20% of pipeline is too costly to replace | 9.5% average annual decrease based on 50% of historical trend from 2010-2020; assume 20% of pipeline is too costly to replace |
| Unprotected Steel: Main | 18.0% average annual decrease based on historical trend from 2010-2020 | 18.0% average annual decrease based on historical trend from 2010-2020 | 18.0% average annual decrease based on historical trend from 2010-2020 |
| Unprotected Steel: Services | 13.3% average annual decrease based on historical trend from 2010-2020 | 13.3% average annual decrease based on historical trend from 2010-2020 | 13.3% average annual decrease based on historical trend from 2010-2020 |
| Copper: Services | 12.1% average annual decrease | 12.1% average annual decrease | 12.1% average annual decrease |
| Protected Steel: Main | 0.80% average annual increase | 6.89% average annual decrease | 9.12% average annual decrease |
| Protected Steel: Services | 0.69% average annual increase | 5.99% average annual decrease | 7.91% average annual decrease |
| Plastic: Main | 1.66% average annual increase | 6.04% average annual decrease | 8.29% average annual decrease |
| Plastic: Services | 1.28% average annual increase | 5.40% average annual decrease | 7.34% average annual decrease |

## 6.3 Level 1 Mitigation

In addition to the assumptions made for IAS2 and IAS3, Level 1 Mitigation includes additional LDAR, decommissioning, and equipment changeout over Integration Analysis Scenarios between 2023 and 2030. Table 17 shows the rate and penetration of mitigation measures applied to the Level 1 Mitigation scenarios. LDAR on 100 percent of upstate production sites, upstate gathering and boosting stations, upstate gathering pipeline, statewide transmission pipeline, and statewide residential meters will be phased in at a rate of approximately 14 percent per year. LDAR will also apply to 100 percent of compressor stations, cast iron and unprotected steel mains, unprotected steel services, downstate commercial buildings, and 25 percent of upstate residential buildings at a rate of 14 percent per year. Equipment upgrades will apply to 100 percent of residential gas appliances between 2023 and 2043 at a rate of 2 percent per year. Additionally, equipment upgrades will be applied to trucks loading oil, and equipment changeout at a rate of 14 percent will be applied to compressor stations. This scenario also assumes that all upstate production except that at high producing oil wells will be phased out at a rate of 14 percent per year. This scenario assumes no well capping.

## 6.4 Level 2 Mitigation

Level 2 Mitigation also includes LDAR, decommissioning, and equipment changeout between 2023 and 2030 in addition to the assumptions included for IAS2 and IAS3; Level 2 Mitigation includes additional LDAR on pipelines, compressor stations, and buildings and a faster rate of residential gas appliance upgrades compared to Level 1 Mitigation and also assumes that all production is phased out and all abandoned wells are capped (Table 17). While the mitigation pertaining to natural gas production, gathering and boosting stations, gathering pipeline, truck loading of oil, transmission pipeline, and residential meters is the same as that applied to Level 1 Mitigation, mitigation for the other parameters occur at different rates and penetration. LDAR will also apply to 100 percent of transmission compressor stations, upstate storage compressor stations, downstate LNG storage compressor stations, cast iron mains and services, unprotected steel mains and services, protected steel mains and services, plastic mains, upstate plastic services, copper services, commercial buildings, and 25 percent of residential buildings at a rate of 14 percent per year. Equipment upgrades will apply to 100 percent of residential gas appliances between 2023 and 2043 at a rate of 5 percent per year. Additionally, equipment changeout at a rate of 14 percent will be applied to compressor stations. This scenario also assumes that all upstate production will be phased out at a rate of 14 percent per year and that all remaining wells upstate will be capped at a rate of 14 percent per year.

## 6.5 Comparison of Mitigation Scenarios

Table 17 compares the rate and penetration of mitigation measures applied to Level 1 Mitigation and Level 2 Mitigation.

**Table 17. Comparison of Mitigation Applied in Level 1 Mitigation and Level 2 Mitigation Scenarios**

| Key Parameter | Level 1 Mitigation | Level 2 Mitigation |
|---|---|---|
| Natural Gas Production | LDAR on 100% of production sites upstate phased in between 2023 and 2030 (14% per year) | |
| | All production but high producing oil wells phased out upstate between 2023 and 2030 (14% per year) | All production phased out upstate between 2023 and 2030 (14% per year) |
| Capping Abandoned Wells | No well capping | 100% of remaining wells upstate capped between 2023 and 2030 (14% per year) |
| Gathering and Boosting Stations | LDAR on 100% of stations upstate phased in between 2023 and 2030 (14% per year) | |
| Gathering Pipeline | LDAR on 100% of pipelines upstate phased in between 2023 and 2030 | |
| Truck Loading of Oil | Equipment upgrade to allow 100% vapor recovery upstate starting in 2022 | |
| Transmission Pipeline | LDAR on 100% of pipelines phased in between 2023 and 2030 (14% per year) | |
| Compressor Stations | Compressor changeout between 2023 and 2030 (14% per year) | |
| | LDAR on 100% of stations phased in between 2023 and 2030 (14% per year) | LDAR on 100% of transmission compressor stations, storage compressor stations upstate, and LNG storage compressor stations downstate phased in between 2023 and 2030 (14% per year) |
| Pipelines | LDAR on 100% of cast iron and unprotected steel mains and unprotected steel services between 2023 and 2030 (14% per year) | LDAR on 100% of cast iron mains and services, unprotected steel mains and services, protected steel mains and services, plastic mains, plastic services upstate, and copper services between 2023 and 2030 (14% per year) |
| Residential Meters | LDAR on 100% of meters phased in between 2023 and 2030 (14% per year) | |
| Buildings | LDAR on 100% of commercial buildings downstate and 25% of residential buildings upstate phased in between 2023 and 2030 (14.3% per year) | LDAR on 100% of commercial buildings and 25% of residential buildings phased in between 2023 and 2030 (14.3% per year) |
| Residential Gas Appliances | Equipment upgrade on 100% of appliances phased in between 2023 and 2043 (2% per year) | Equipment upgrade on 100% of appliances phased in between 2023 and 2043 (5% per year) |

## 6.6 Alignment with Advisory Panel Recommendations

Both the Power Generation and the Energy Efficiency & Housing Advisory panels recommended addressing methane leakage in natural gas system infrastructure (CAC 2021a, 2021b). The mitigation scenarios developed align with these recommendations by assuming there will be LDAR and decommissioning applied to sources, such as pipelines. In alignment with these recommendations, the modeled scenarios assume a transition away from natural gas to the maximum extent possible and as quickly as possible. The model also charts a path to avoid stranded assets and characterizes emissions to inform potential mitigation policies by identifying sources of emissions potentially subject to State regulation.

# 7 Results

The following section summarizes the estimated activity data, emissions, and costs of mitigation through 2050 using the emissions projection tool.

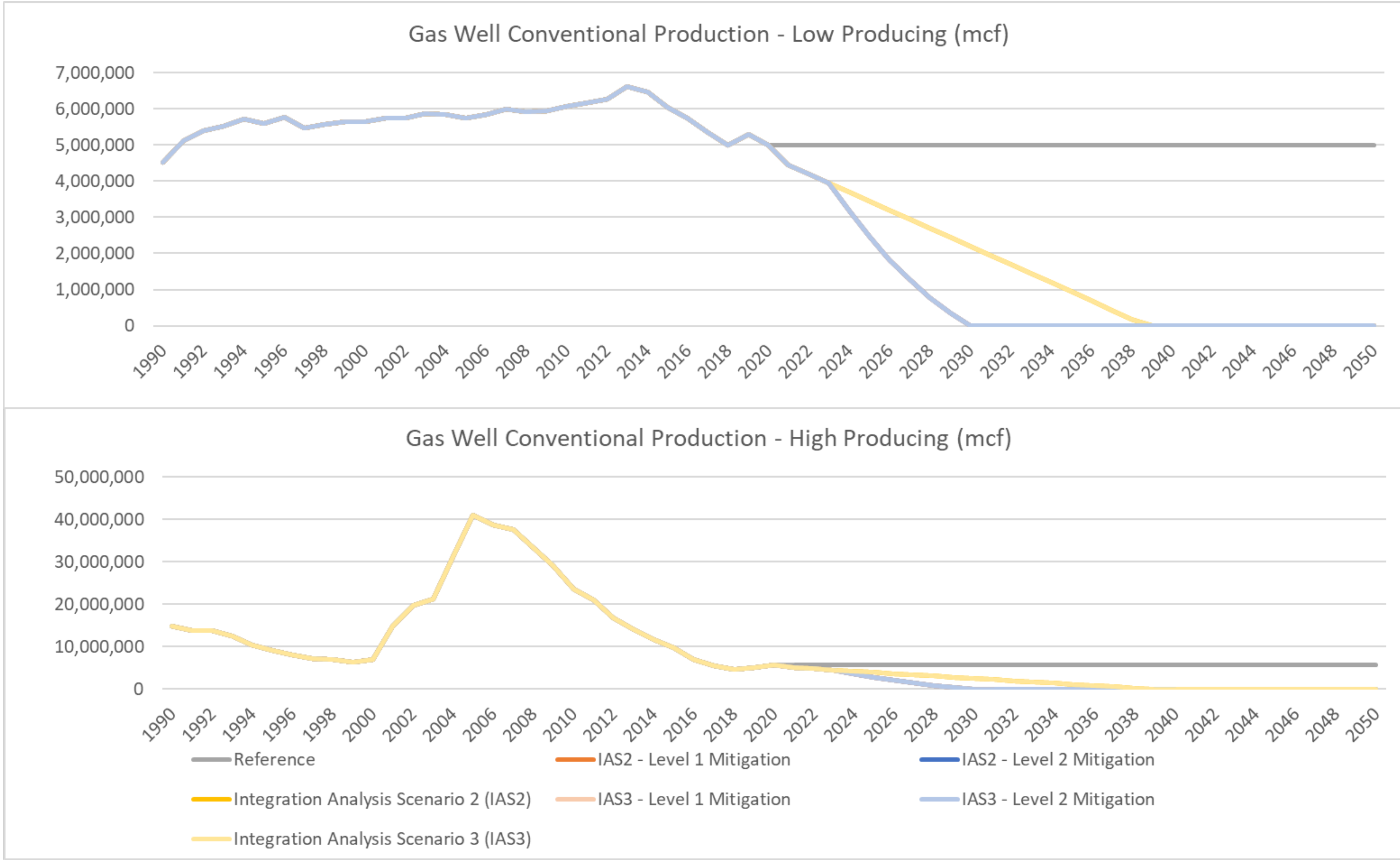
## 7.1 Activity Data

Emissions from oil and gas in NYS are driven by activity data upstream (i.e., low- and high-producing gas wells), midstream (i.e., compressor stations), and downstream (i.e., pipeline mains and services, especially cast iron and unprotected steel). Thus, differences in emissions between scenarios occur due to mitigation and changes in activity data within these sources. Differences in activity data between Integration Analysis Scenario 2 and Integration Analysis Scenario 3 only occur in downstream sources.

### 7.1.1 Upstream

In the Reference case, production at both high- and low-producing gas wells is held constant through 2050 at 5,705,846 mcf and 5,008,751 mcf, respectively. In both Integration Analysis Scenario 2 and Integration Analysis Scenario 3, there is an average annual decrease in production of 16.7 percent and production in state ceases in 2039. Production in state is phased out more quickly (14 percent per year) until ceasing in 2030 in IAS2–Level 1 Mitigation, IAS2–Level 2 Mitigation, IAS3–Level 1 Mitigation, IAS3–Level 2 Mitigation. Gas well production at high- and low-producing wells is shown in Figure 2.

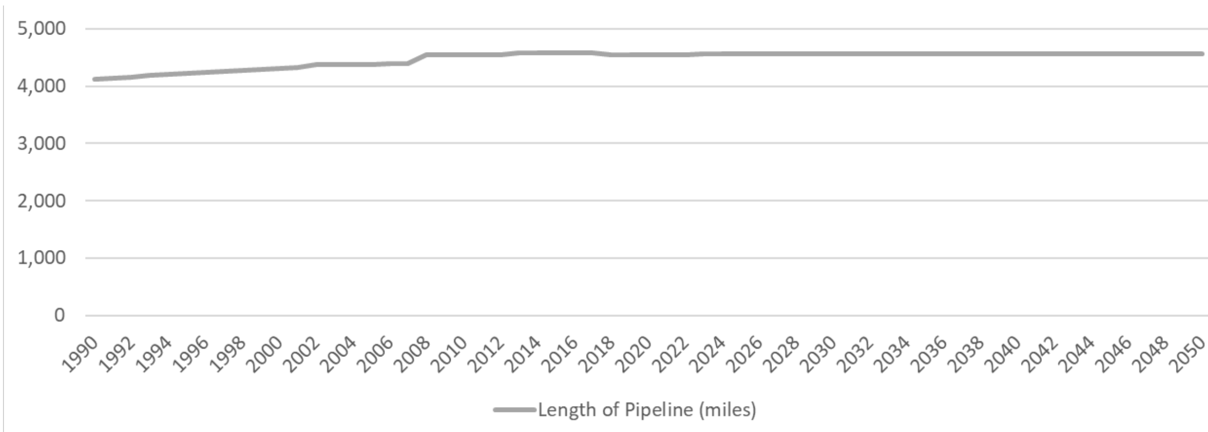
**Figure 2. Gas Well Conventional Production 1990 to 2050**



### 7.1.2 Midstream

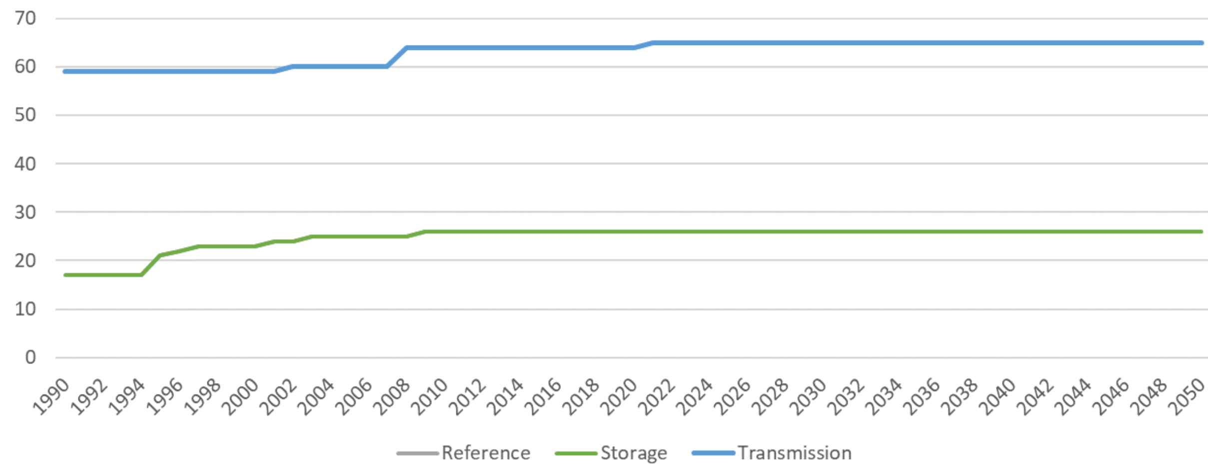
In the Reference case, Integration Analysis Scenario 2, Integration Analysis Scenario 3, and both levels of mitigation applied to Integration Analysis Scenario 2 and Integration Analysis Scenario 3, 25 miles of transmission pipeline are added to the system in 2021. The length of pipeline in 2021 (4,561 miles) remains constant through 2050 in all scenarios (Figure 3). There is no change in transmission pipeline or in compressor stations in the mitigation scenarios due to the need to continue interstate transmission.

**Figure 3. Length of Transmission Pipeline from 1990 to 2050**




In the Reference case, Integration Analysis Scenario 2, Integration Analysis Scenario 3, and both levels of mitigation applied to Integration Analysis Scenario 2 and Integration Analysis Scenario 3, the number of storage compressor stations in 2020 (26 compressor stations) is held constant; one transmission compressor station is added in 2021, and then the number of transmission compressor stations (65 compressor stations) remains constant (Figure 4).

**Figure 4. Storage and Compressor Stations from 1990 to 2050**




### 7.1.3 Downstream

The Integration Analysis Scenarios show that most residential and commercial building stock become fully electrified by 2050. In 2020, there are 3,674,764 residential buildings and 368,734 commercial buildings with natural gas services, indicating the stock of buildings with natural gas service. Beginning in 2025 in Integration Analysis Scenario 2, buildings are steadily electrified until an estimated 340,172 commercial buildings and 3,028,552 residential buildings are fully electrified by 2050 (Figure 5, Figure 6). In Integration Analysis Scenario 3, buildings are electrified at a faster rate through 2030 and more buildings are electrified; by 2050, an estimated 362,493 commercial buildings and 3,211,539 buildings are electrified.

**Figure 5. Electrification of Residential Buildings in Integration Analysis Scenario 2 and Integration Analysis Scenario 3**

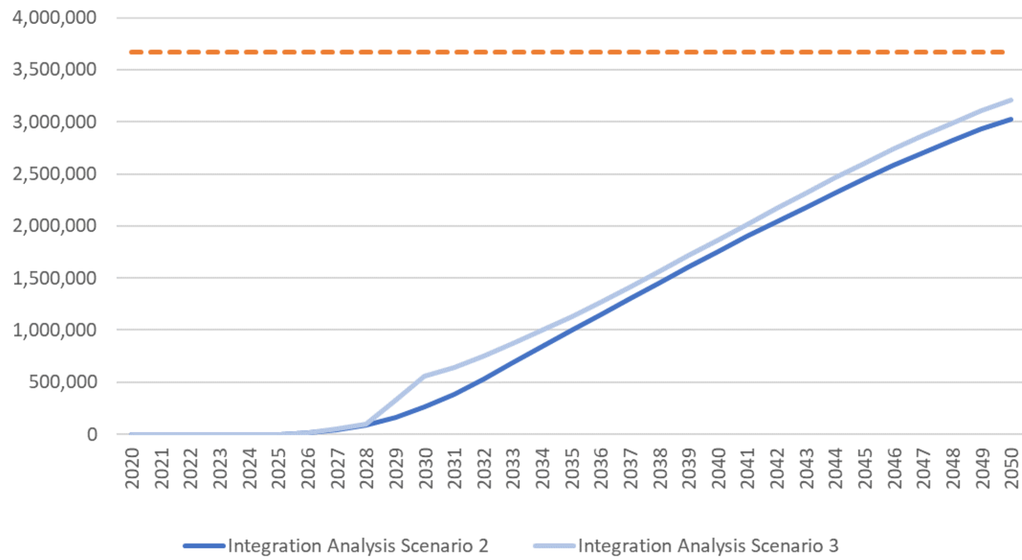
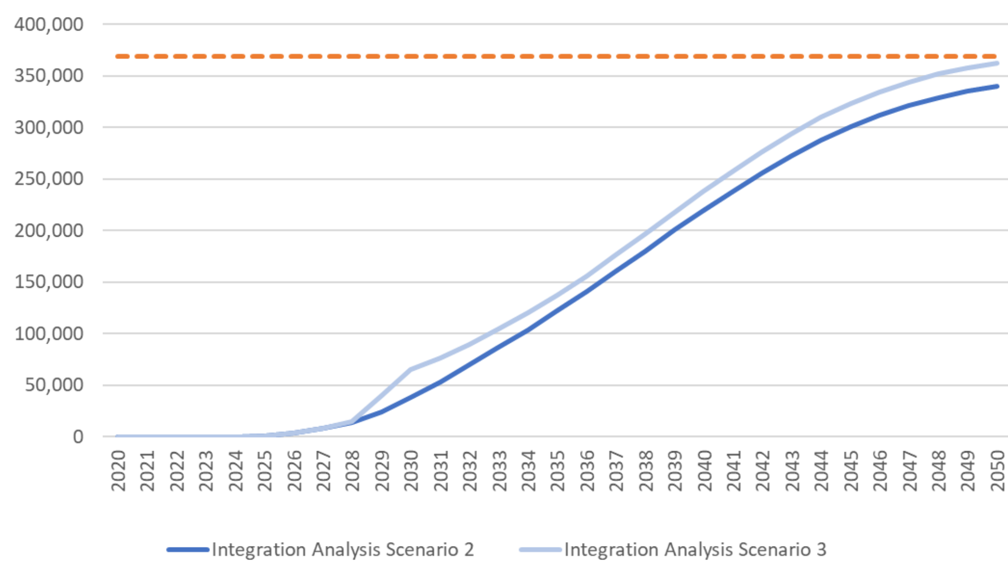
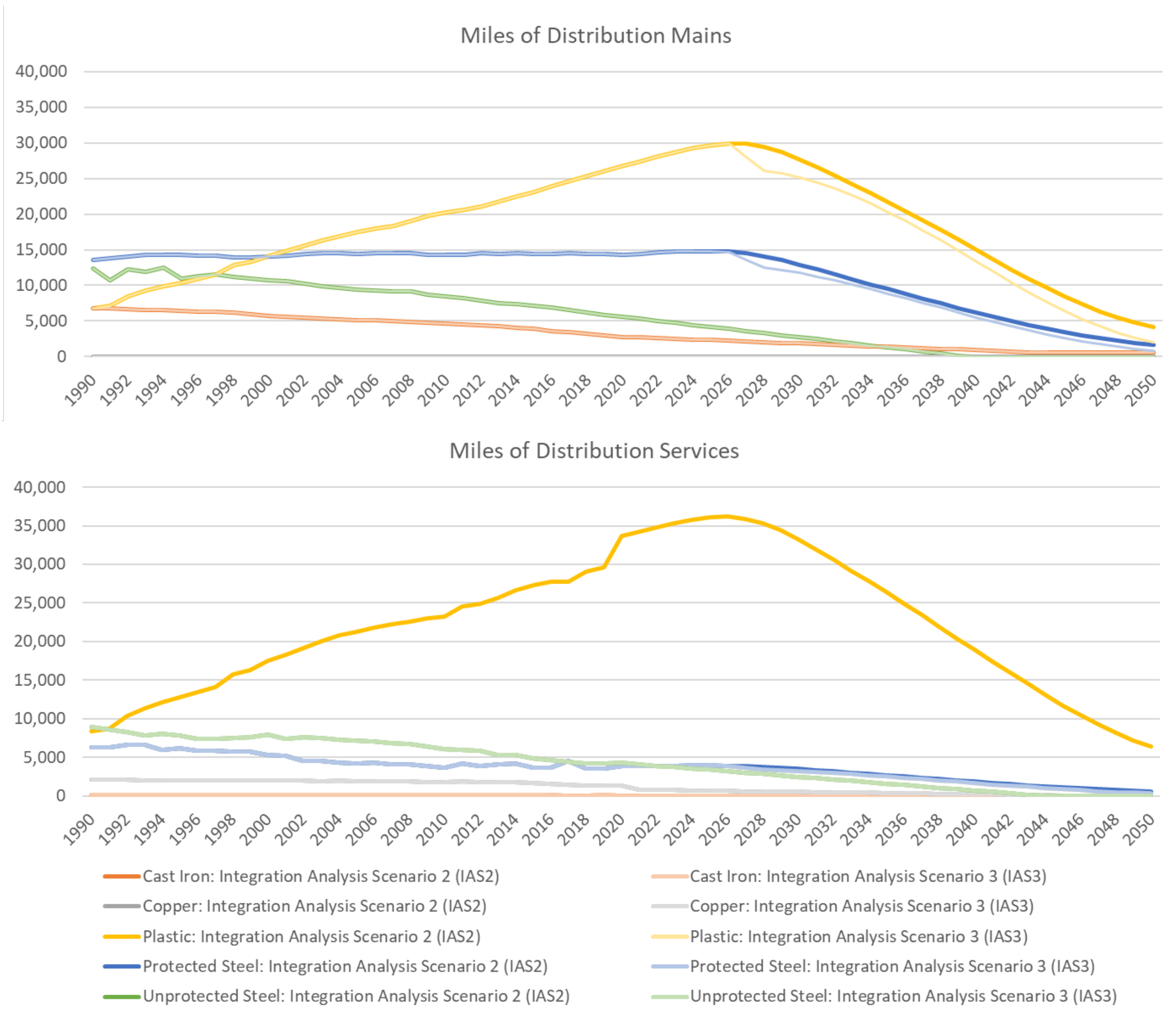



**Figure 6. Electrification of Commercial Buildings in Integration Analysis Scenario 2 and Integration Analysis Scenario 3**



In Integration Analysis Scenario 2 and Integration Analysis Scenario 3, pipeline infrastructure contracts proportionally to increased building electrification. For example, if 5 percent of buildings with natural gas heating are converted to electric heat, then the model assumes a 5 percent contraction in distribution pipeline infrastructure. Overall, older, and leak-prone pipelines are being replaced with plastic pipes. As seen in Figure 7, the rate that total pipeline miles decrease is slightly faster in Integration Analysis Scenario 3 than Integration Analysis Scenario 2.

**Figure 7. Length of Pipelines in Integration Analysis Scenario 2 and Integration Analysis Scenario 3 from 1990 to 2050**



## 7.2 Emissions

In Integration Analysis Scenario 2 and Integration Analysis Scenario 3, emissions reductions occur due to decommissioning, equipment changeout, and LDAR. In 1990, methane emissions from the oil and natural gas sector in NYS totaled 17,400,427 $MTCO_2e$. Oil and gas methane missions would need to reduce to 10,440,256 $MTCO_2e$ or less in 2030 and oil and gas methane emissions would need to total 2,610,064 $MTCO_2e$ or less in 2050 in order to reach NYS's economywide climate goals as modeled in the Integration Analysis. Table 18. summarizes emissions estimates under the different scenarios in 2030 and 2050.

Total emissions over time in the different scenarios are shown in Figure 8 and Figure 9. As seen in Figure 10 and Figure 11, emissions in all scenarios decrease slightly until 2023. From 2023 to 2050, emissions decrease steadily in the Reference case, Integration Analysis Scenario 2 and Integration Analysis Scenario 3, although at a slower rate in the Reference case. IAS–Level 1 Mitigation, IAS2–Level 2 Mitigation, IAS3–Level 1 Mitigation, and IAS3–Level 2 Mitigation follow a similar pattern; there is a steep decline in emissions between 2023 and 2030 due to decommissioning, LDAR, and equipment changeout. After 2030 the achievable rate and penetration of mitigation is approached, and emissions continue to decrease only slightly. Figure 10 through Figure 13 show emissions reductions over time by mitigation measure relative to the Reference Case in IAS2–Level 1 Mitigation, IAS2–Level 2 Mitigation, IAS3 Level 1 Mitigation, and IAS3–Level 2 Mitigation. The addition of decommissioning contributes the most to emissions reductions. As more equipment is decommissioned over time, LDAR contributes less to emissions reductions.

**Table 18. Emissions Estimates in 2030 and 2050 and Reduction Compared to 1990 for Each Scenario**

| | Reference Case | IAS2 | IAS2–Level 1 Mitigation | IAS2–Level 2 Mitigation | IAS3 | IAS3–Level 1 Mitigation | IAS3–Level 2 Mitigation |
|---|---|---|---|---|---|---|---|
| **2030 Emissions** | 12,875,243 | 10,886,728 | 4,681,246 | 4,237,326 | 10,755,992 | 4,578,150 | 4,167,452 |
| **2050 Emissions** | 11,699,568 | 6,745,682 | 2,999,567 | 2,843,154 | 6,626,739 | 2,907,014 | 2,779,692 |
| **2030 % Reduction** | 26.01% | 37.43% | 73.10% | 75.65% | 38.19% | 73.69% | 76.05% |
| **2050 % Reduction** | 32.76% | 61.23% | 82.76% | 83.66% | 61.92% | 83.29% | 84.03% |

**Figure 8. State-Level Methane Emissions from 1990 to 2050 Under Integration Analysis Scenario 2**

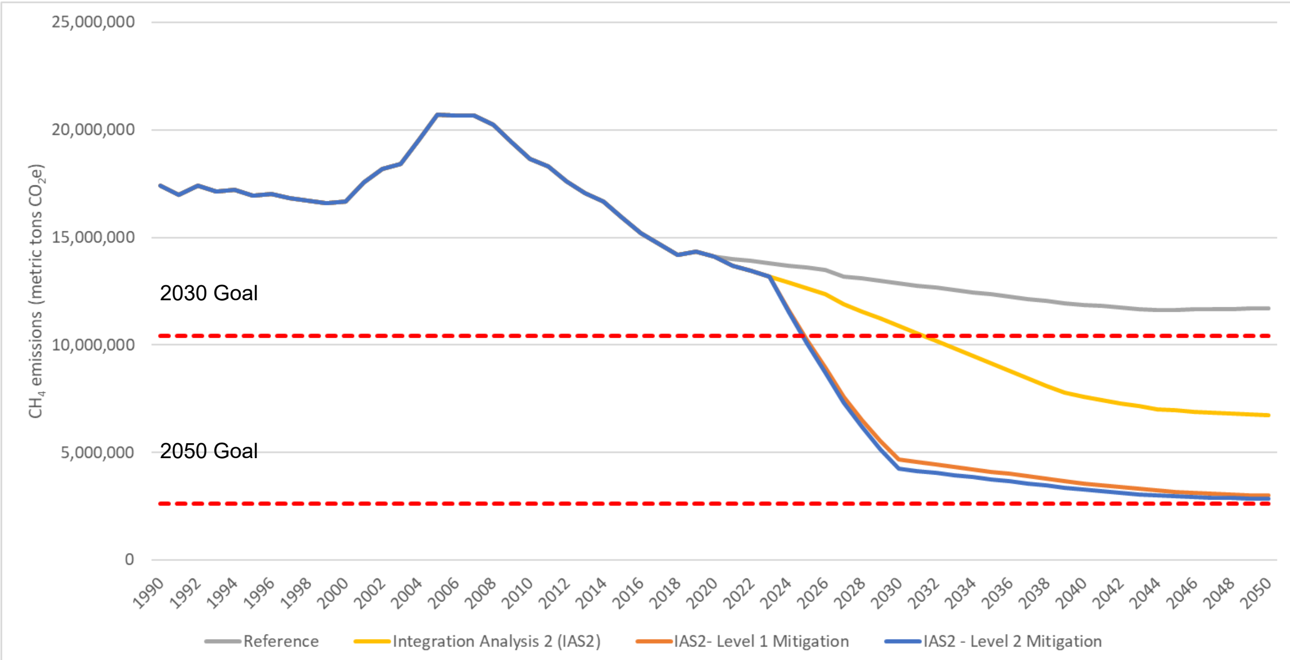



**Figure 9. State-Level Methane Emissions from 1990 to 2050 Under Integration Analysis Scenario 3**

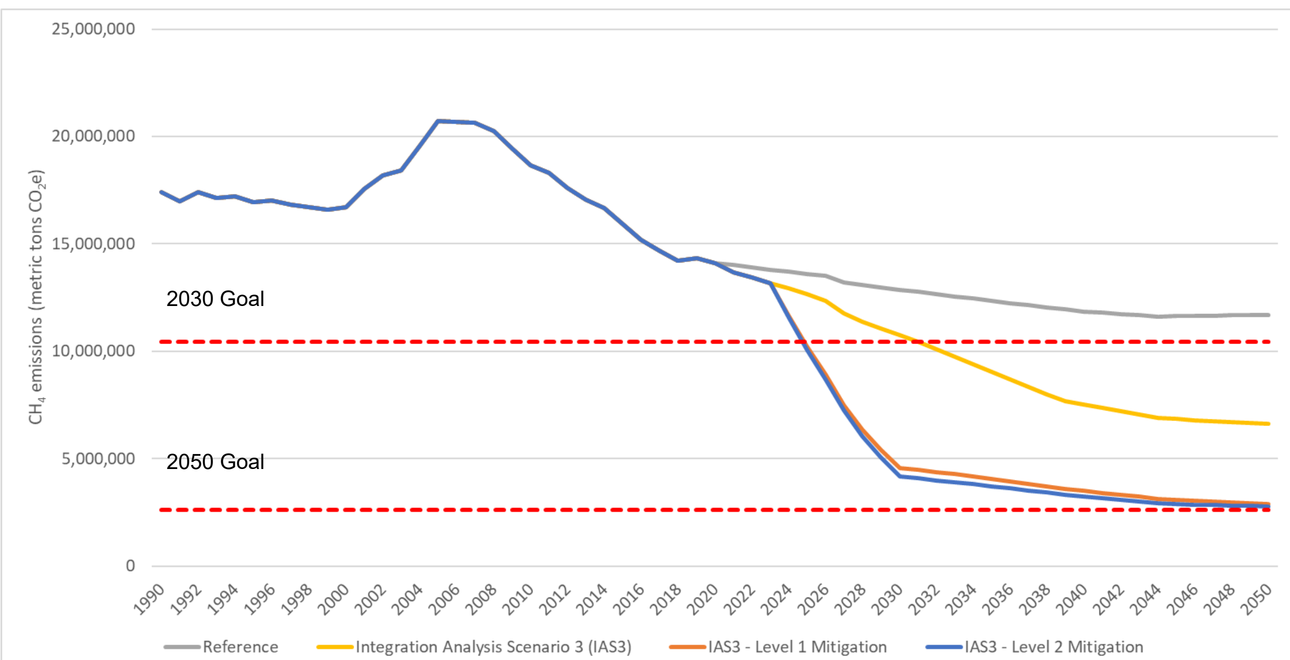


**Figure 10. IAS2–Level 1 Mitigation Emissions Reductions by Mitigation Measure**

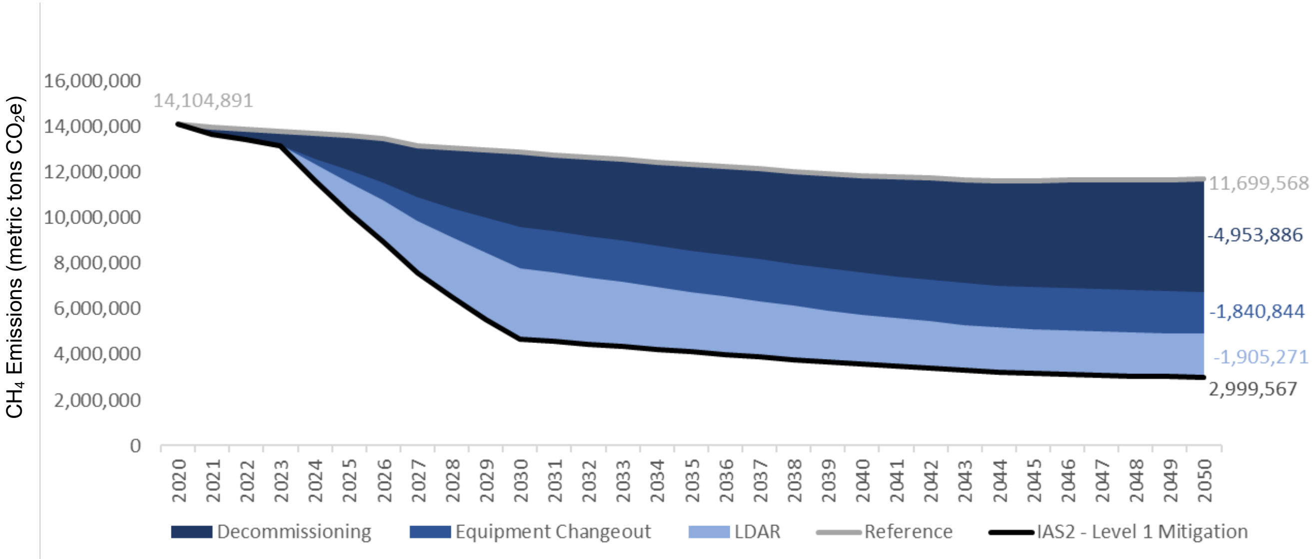



**Figure 11. IAS2–Level 2 Mitigation Emissions Reductions by Mitigation Measure**

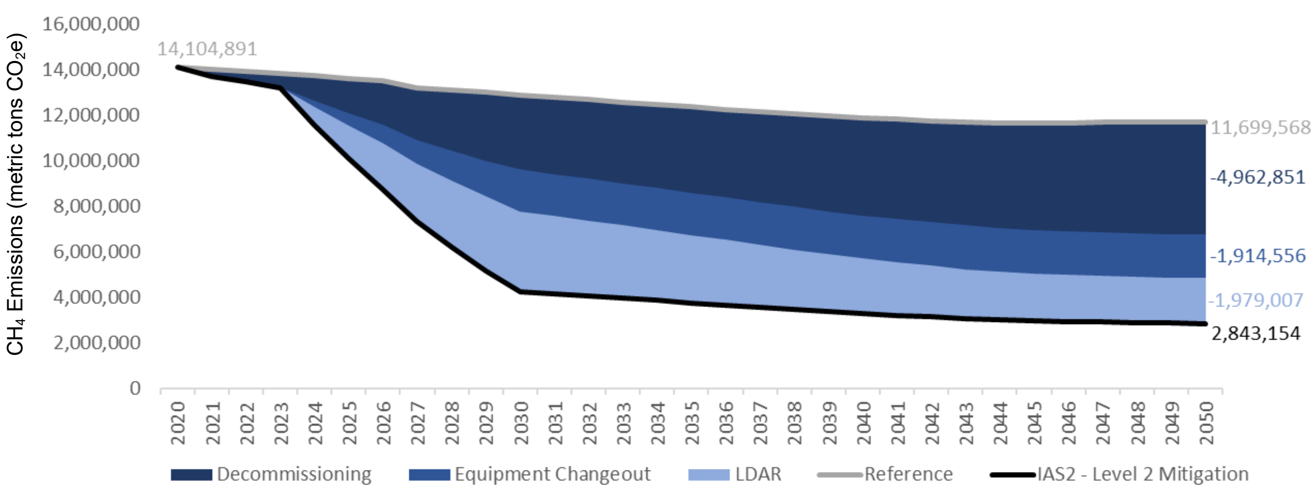


**Figure 12. IAS3–Level 1 Mitigation Emissions Reductions by Mitigation Measure**

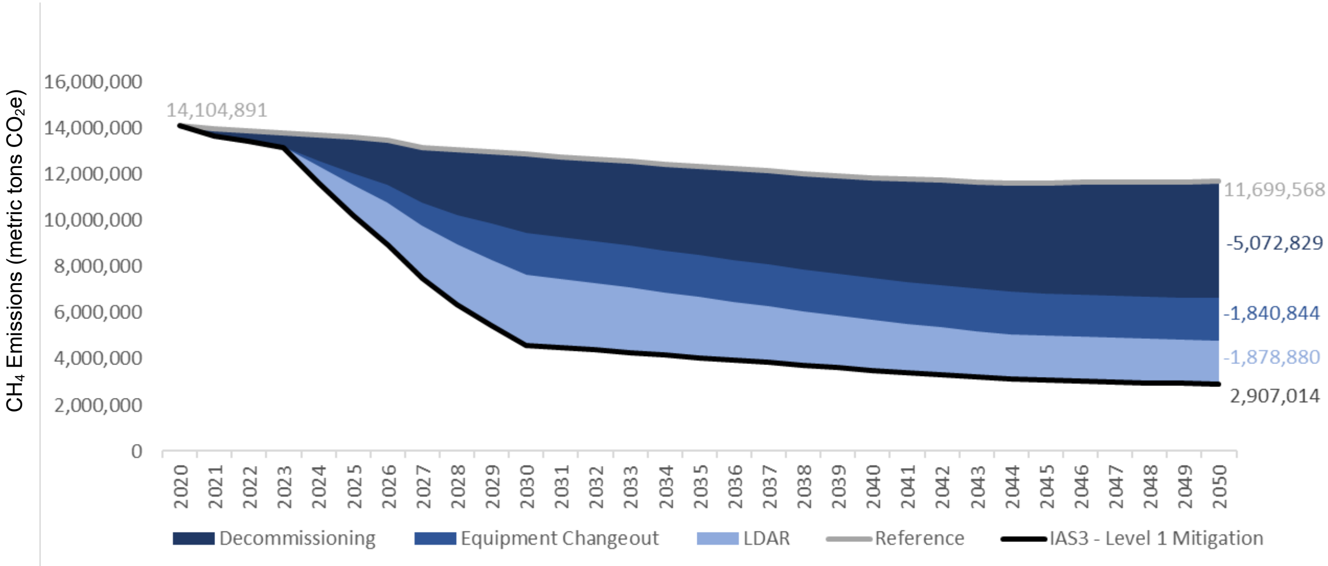
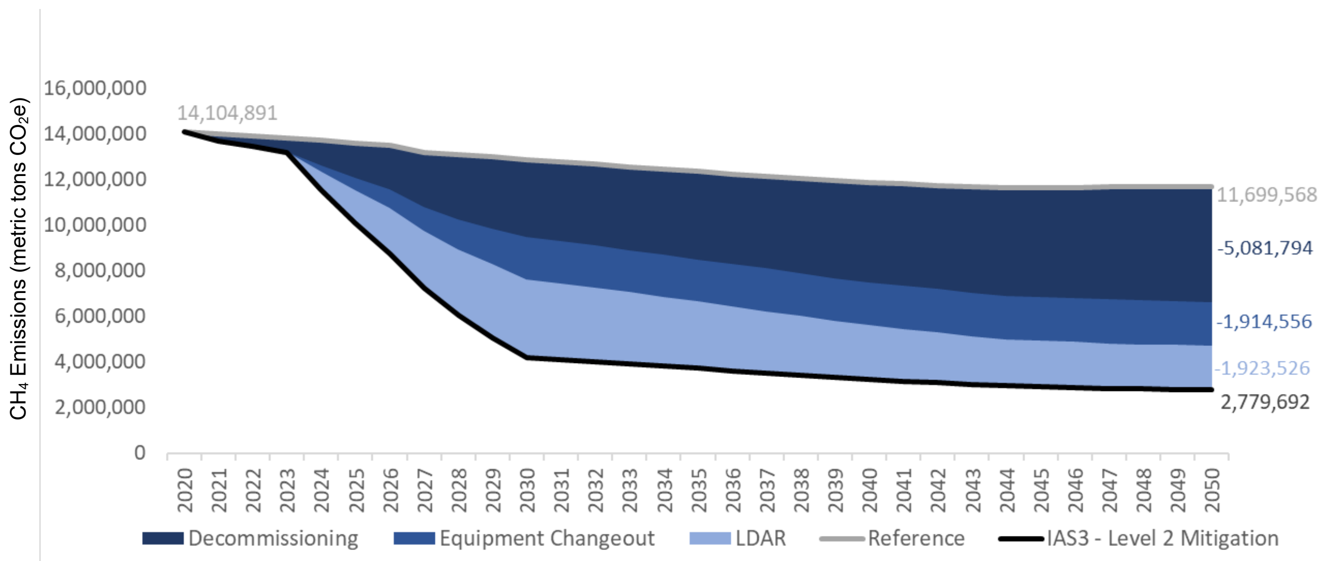



**Figure 13. IAS3–Level 2 Mitigation Emissions Reductions by Mitigation Measure**




Similar emissions reductions are seen between Integration Analysis Scenario 2 and Integration Analysis Scenario 3 relative to the Reference case (Figure 14). Emissions reductions relative to the Reference case are slightly greater in Integration Analysis Scenario 3, IAS3–Level 1 Mitigation, and IAS3–Level 2 Mitigation than in Integration Analysis Scenario 2, IAS2–Level 1 Mitigation, and IAS2–Level 2 Mitigation. For example, emissions in 2050 in Integration Analysis Scenario 2 are 47 percent lower (6,745,682 $MTCO_2e$) than the Reference case (12,648,879 $MTCO_2e$) and Integration Analysis Scenario 3 emissions are 48 percent lower (6,626,739 $MTCO_2e$).

**Figure 14. State-Level Methane Emissions ($MTCO_2e$) in 2030, 2040, and 2050 in Integration Analysis Scenario 2 and Integration Analysis Scenario 3 Compared to Reference Case**


Emissions reductions through 2050 are primarily driven by midstream and downstream compressor changeout; midstream LDAR; and downstream pipeline changeout, downstream LDAR, and building electrification. Since building electrification would result in a contraction of natural gas infrastructure, downstream emissions are affected. As seen in Figure 15 through Figure 18, the biggest differences in emissions between the reference case and IAS2–Level 1 Mitigation, IAS2–Level 2 Mitigation, IAS3–Level 1 Mitigation, and IAS3–Level 2 Mitigation in 2030 and 2050 occur in the mid-stream, followed by downstream. Reductions in emissions upstream and downstream appear to contribute to differences in overall emissions between Integration Analysis Scenario 2 and the Reference case, while emissions reductions in Level 1 Mitigation and Level 2 Mitigation are driven by reductions midstream and downstream.

Significant reductions in emissions are seen in all sources when mitigation is applied to both Integration Analysis Scenario 2 and Integration Analysis Scenario 3 (Figure 17 through Figure 20). The majority of emissions in 2050 still occur in the midstream (compressor stations, Figure 4) and downstream (plastic distribution pipelines, Figure 7). Midstream emissions account for 61 percent of emissions in the Reference case, 88 percent in Integration Analysis Scenario 2, 86 percent in IAS2–Level 1 Mitigation, 95 percent in IAS2–Level 2 Mitigation, 90 percent in Integration Analysis Scenario 3, 89 percent in IAS3–Level 1 Mitigation, and 95 percent in IAS3- Level 2 Mitigation.

**Figure 15. Emissions ($MTCO_2e$) by Scenario and Sector in 2030 (Integration Analysis Scenario 2)**

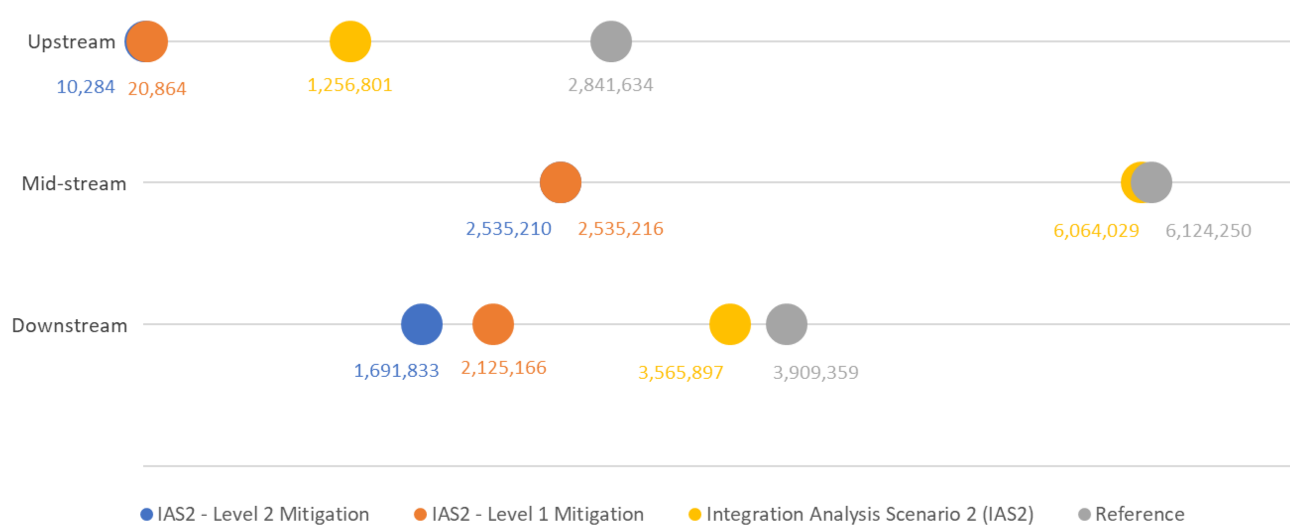



**Figure 16. Emissions ($MTCO_2e$) by Scenario and Sector in 2030 (Integration Analysis Scenario 3)**

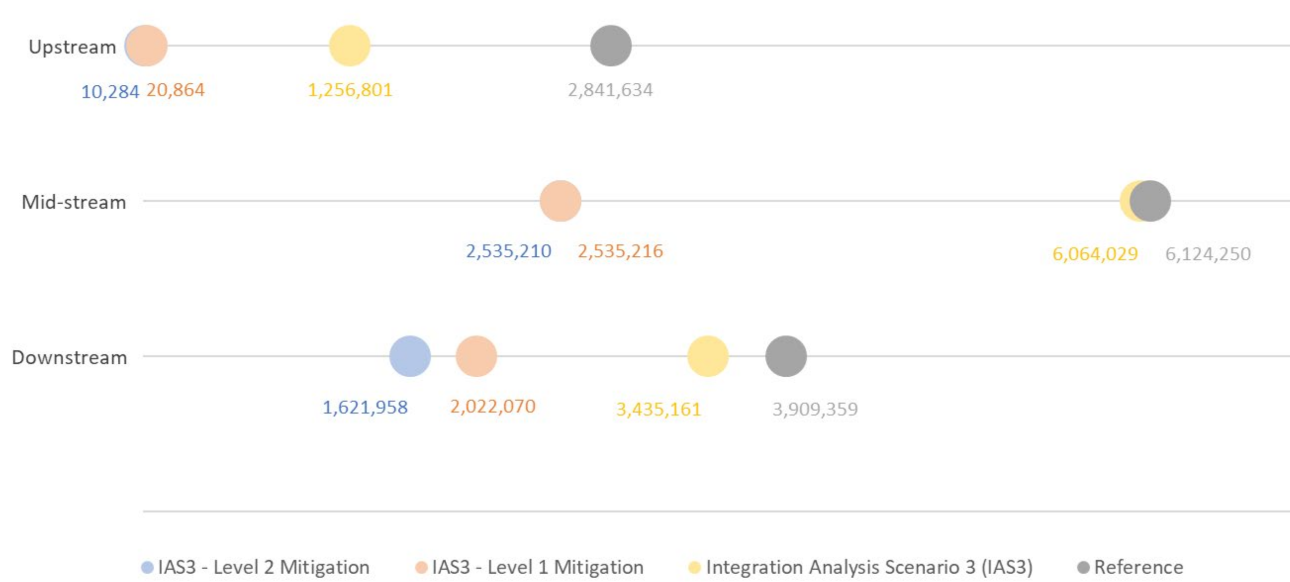


**Figure 17. Emissions ($MTCO_2e$) by Scenario and Sector in 2050 (Integration Analysis Scenario 2)**

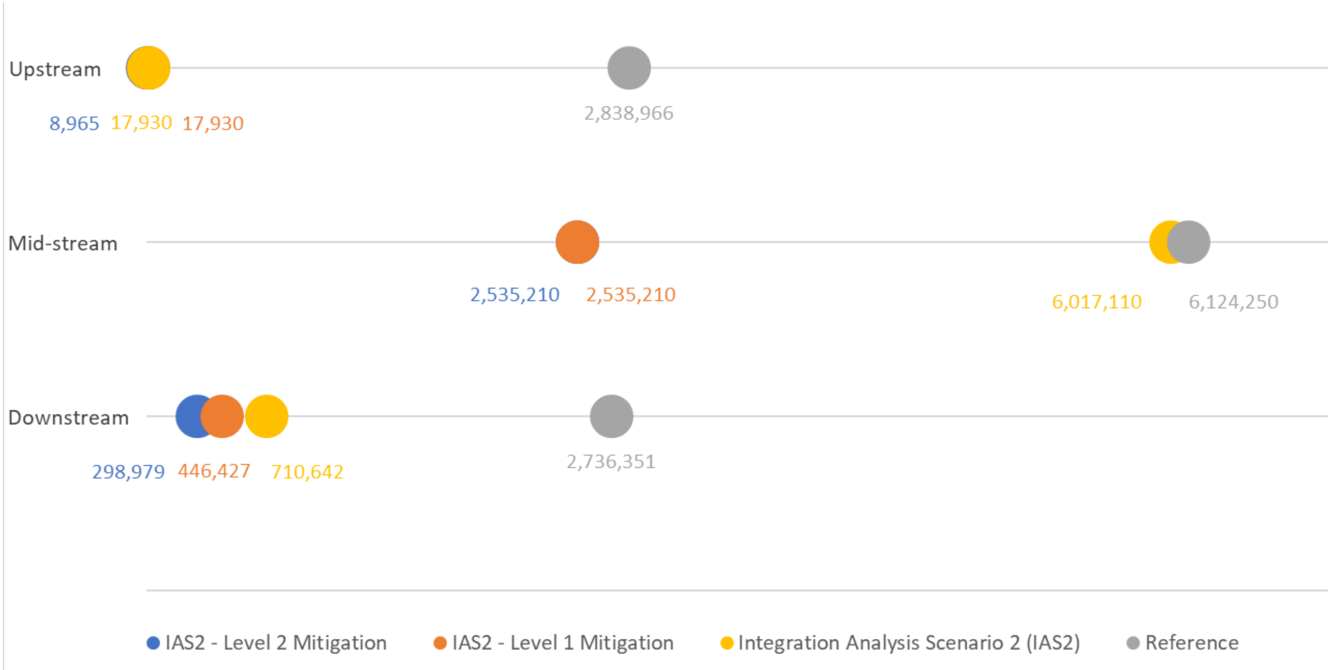



**Figure 18. Emissions ($MTCO_2e$) by Scenario and Sector in 2050 (Integration Analysis Scenario 3)**

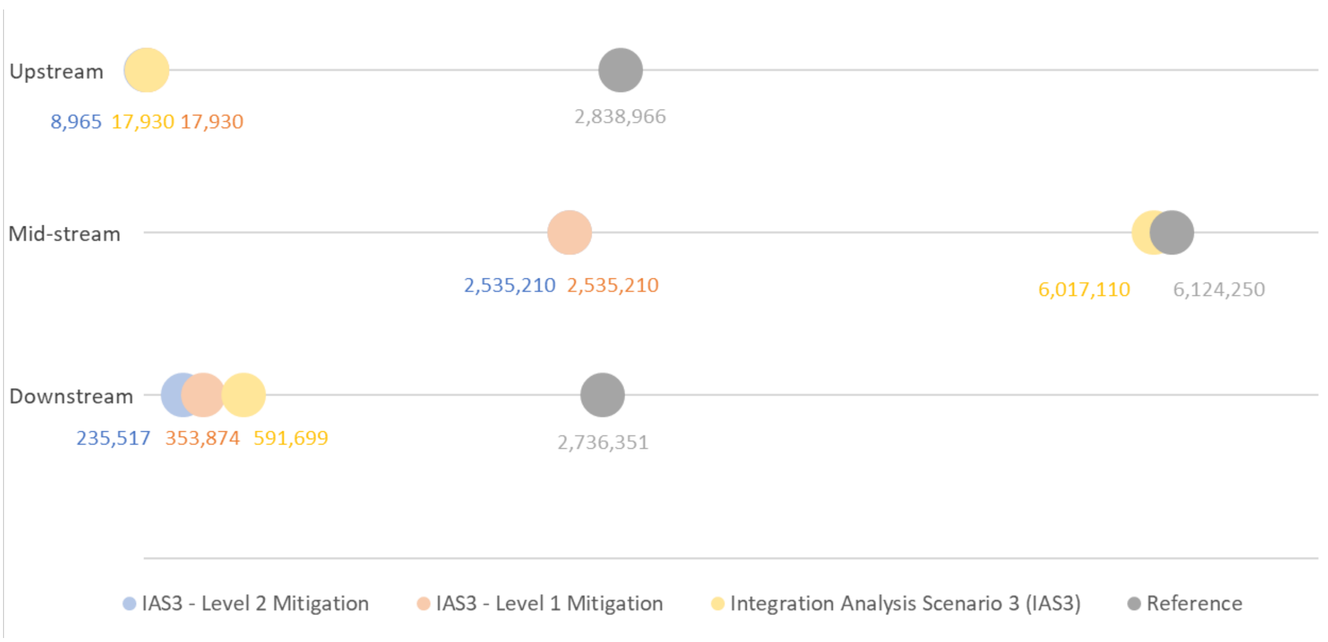


**Figure 19. Emissions by Source for Each Level of Mitigation Applied to Integration Analysis Scenario 2 in 2030 Compared to Reference Case Emissions in 1990**

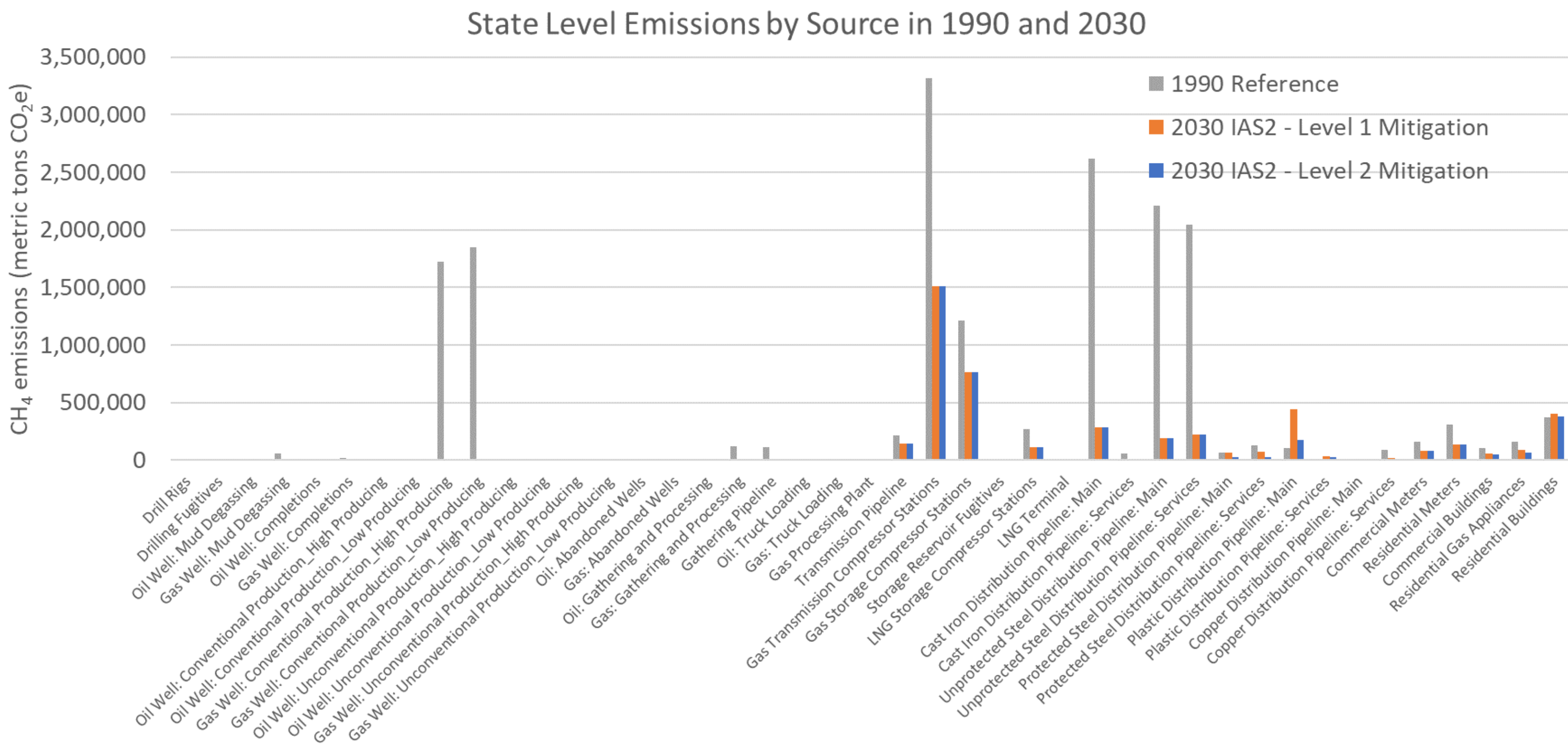


**Figure 20. Emissions by Source for Each Level of Mitigation Applied to Integration Analysis Scenario 3 in 2030 Compared to Reference Case Emissions in 1990**

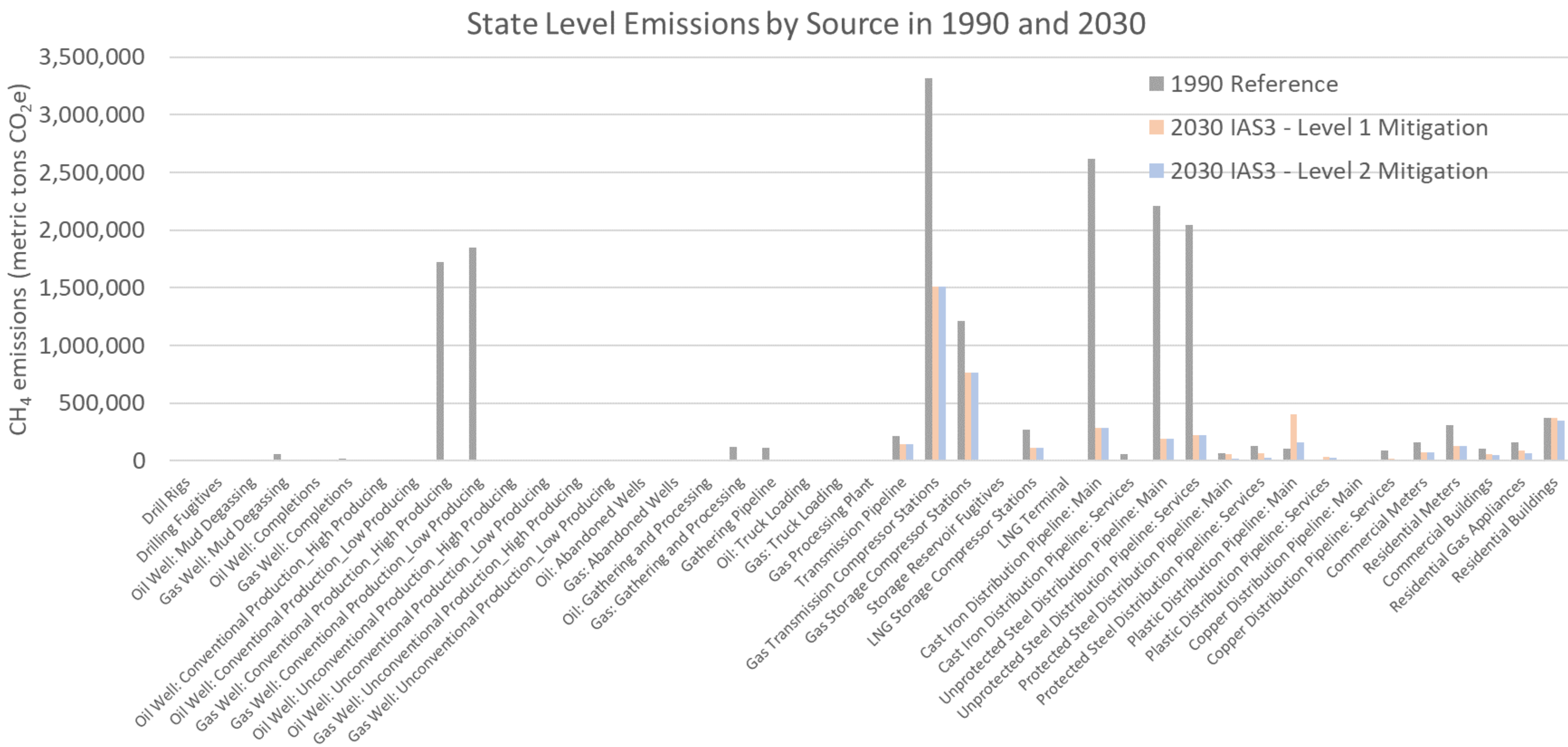


**Figure 21. Emissions by Source for Each Level of Mitigation Applied to Integration Analysis Scenario 2 in 2050 Compared to Reference Case Emissions in 1990**

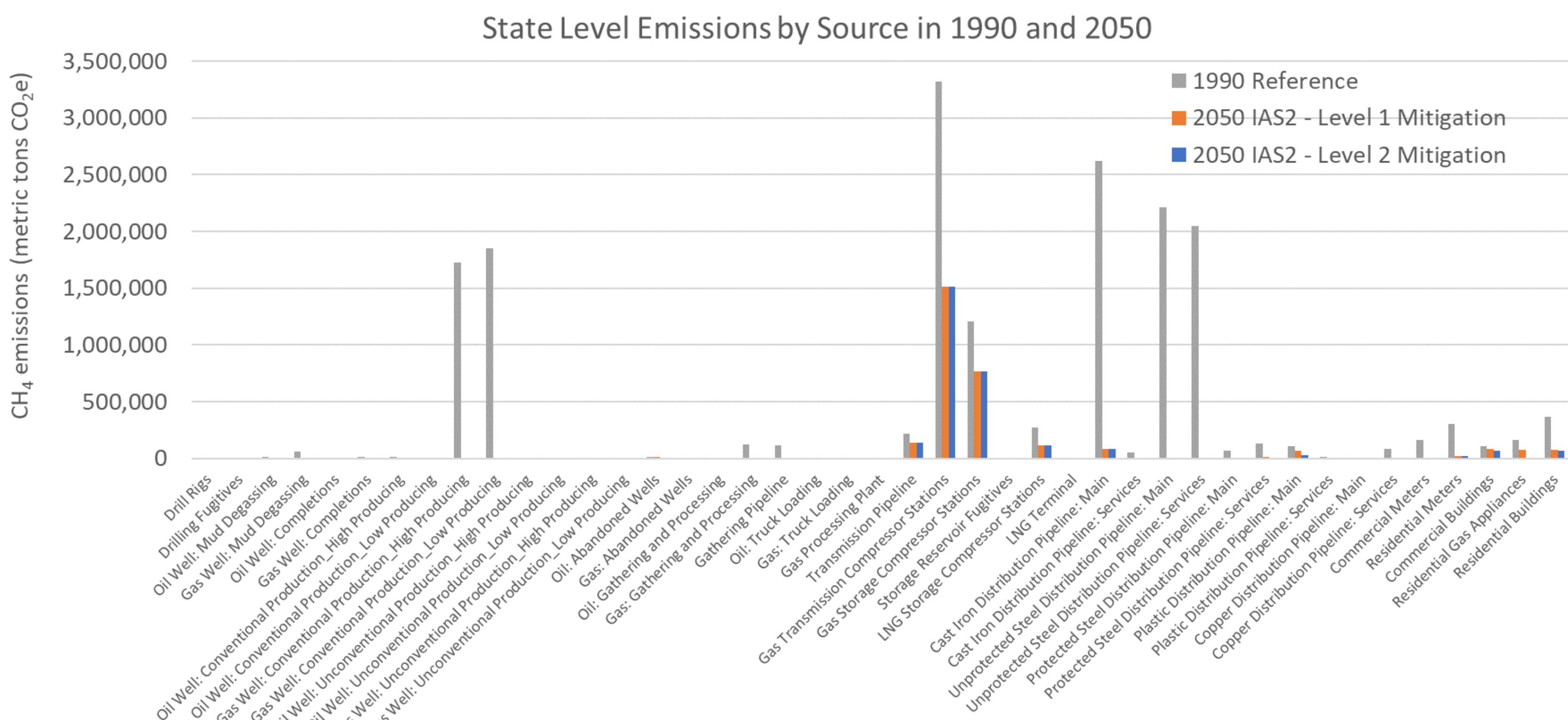
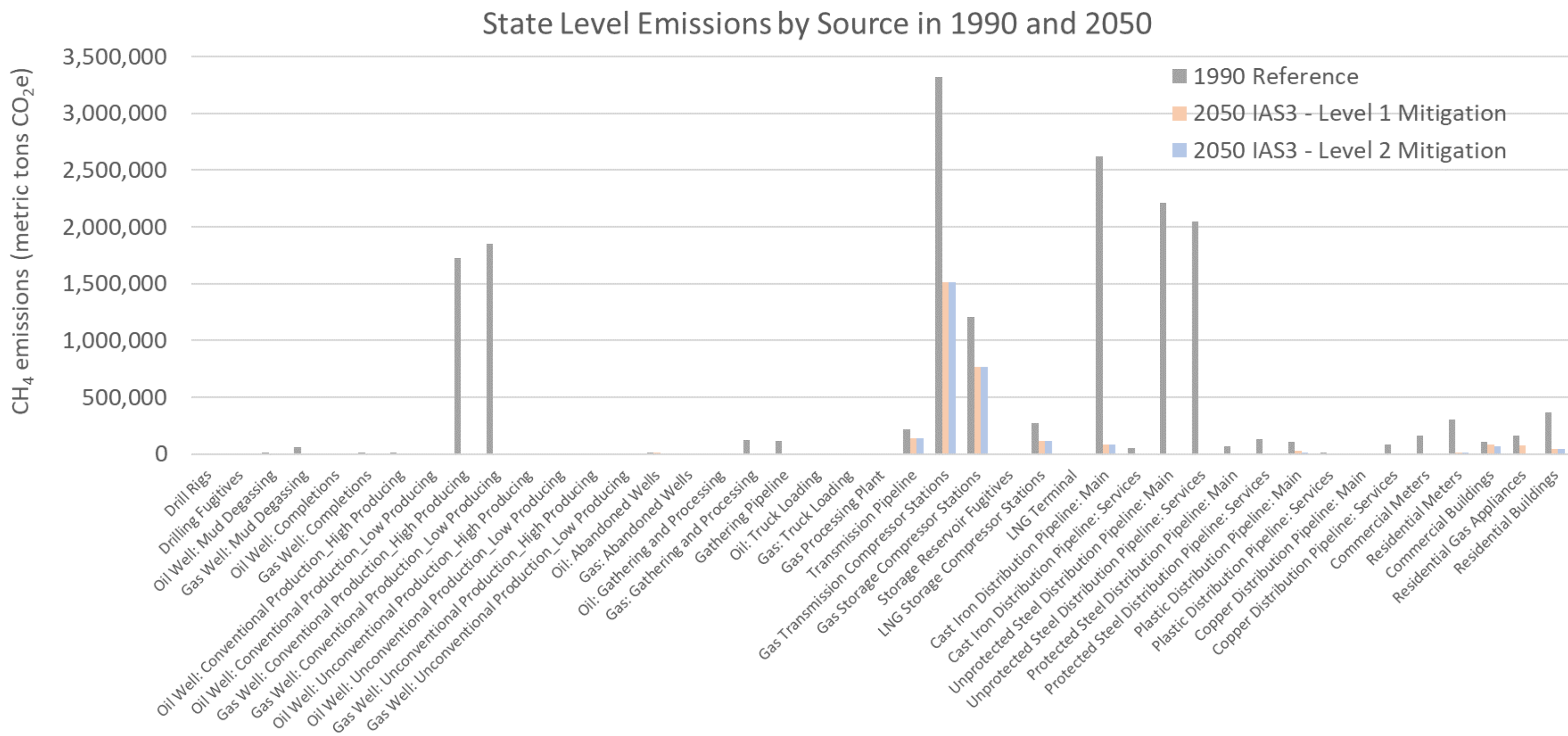


**Figure 22. Emissions by Source for Each Level of Mitigation Applied to Integration Analysis Scenario 3 in 2050 Compared to Reference Case Emissions in 1990**



## 7.3 Costs

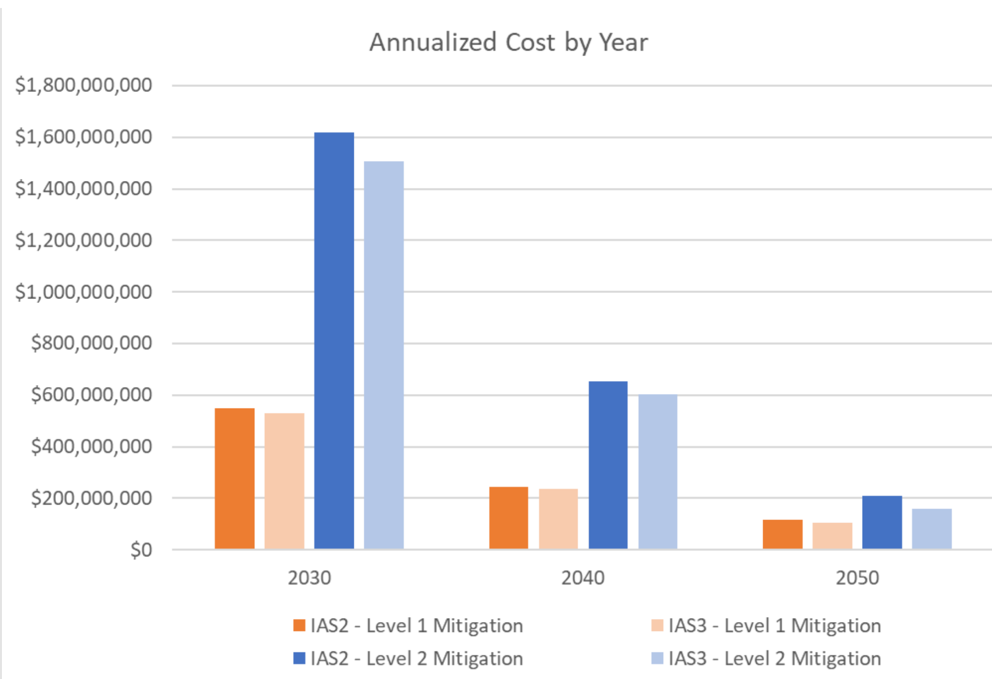
Table 19 summarizes the total costs and emissions reductions associated with each case. In Integration Analysis Scenario 3, emissions reductions are slightly higher and costs slightly lower than those in Integration Analysis Scenario 2. When avoided costs are considered in the total cost of mitigation, there is a net savings in Integration Analysis Scenario 2 and Integration Analysis Scenario 3. The cost of mitigation through 2050 in Integration Analysis Scenario 2 is $15.05 per $MTCO_2e$ (without avoided costs). The cost of mitigation increases over Integration Analysis Scenario 2 to $39.89 per $MTCO_2e$ in IAS2–Level 1 Mitigation. Total emissions reductions in IAS2–Level 1 Mitigation compared to the Reference case are nearly 115,000,000 $MTCO_2e$ more than emissions reductions in Integration Analysis Scenario 2. IAS3–Level 1 Mitigation increases the cost of mitigation over Integration Analysis Scenario 3 from $15.53 to $38.28. IAS3–Level 1 Mitigation emissions reductions compared to the Reference case are approximately 116,800,000 $MTCO_2e$ more than emissions reductions in Integration Analysis Scenario 3. The costs of IAS2–Level 1 Mitigation and IAS2–Level 2 Mitigation are $38.89 and $103.06 per $MTCO_2e$, respectively, with a much smaller difference in emissions reduction between the two levels of mitigation than is seen between Integration Analysis Scenario 2 and IAS2–Level 1 Mitigation; the difference in emissions is about 6,400,000 $MTCO_2e$. Similar differences are seen between IAS3–Level 1 Mitigation ($38.28 per $MTCO_2e$) and IAS3–Level 2 Mitigation ($95.61 per $MTCO_2e$); IAS3–Level 2 Mitigations reduces emissions by approximately 5,800,000 $MTCO_2e$ over IAS3–Level 1 Mitigation. Depending on whether avoided costs are taken into account, the mitigation cost ranges from $22.17 to $38.89 in IAS2–Level 1 Mitigation, $85.87 to $103.06 in IAS2–Level 2 Mitigation, $20.70 to $38.28 in IAS3–Level 1 Mitigation, and $78.50 to $95.61 in IAS3–Level 2 Mitigation.

Figure 23 compares the total annualized cost of IAS2–Level 1 Mitigation, IAS2–Level 2 Mitigation, IAS3–Level 1 Mitigation, and IAS3–Level 2 Mitigation in 2030, 2040, and 2050; the costs of Integration Analysis Scenario 3, IAS3–Level 1 Mitigation, and IAS3–Level 2 Mitigation are slightly lower than Integration Analysis Scenario 2, IAS2–Level 1 Mitigation, and IAS2–Level 2 Mitigation. This is the result of the more aggressive policies reducing the amount of loans needed to implement the mitigation options.

**Table 19. Total Costs, Emissions Reductions, and Cost per $MTCO_2e$**

| | Not Including Avoided Costs | | | Including Avoided Costs | | |
|---|---|---|---|---|---|---|
| Case | Total Cost ($2020) | Total Emissions Reduction ($MTCO_2e$) | $/$MTCO_2e$ | Total Cost ($2020) | Total Emissions Reduction ($MTCO_2e$) | $/$MTCO_2e$ |
| Integration Analysis Scenario 2 | $1,368,822,243 | 90,977,545 | 15.05 | -$2,278,503,541 | 90,977,545 | -25.04 |
| IAS2 – Level 1 Mitigation | $8,209,259,428 | 205,809,695 | 39.89 | $4,561,933,644 | 205,809,695 | 22.17 |
| IAS2 – Level 2 Mitigation | $21,869,422,877 | 212,196,094 | 103.06 | $18,222,097,094 | 212,196,094 | 85.87 |
| Integration Analysis Scenario 3 | $1,451,548,731 | 93,465,672 | 15.53 | -$2,201,268,522 | 93,465,672 | -23.55 |
| IAS3 – Level 1 Mitigation | $7,954,035,039 | 207,768,877 | 38.28 | $4,301,217,786 | 207,768,877 | 20.70 |
| IAS3 – Level 2 Mitigation | $20,418,493,136 | 213,566,679 | 95.61 | $16,765,675,883 | 213,566,679 | 78.50 |

**Figure 23. Total Annualized Cost in 2030, 2040, and 2050**



# 8 Future Improvements

NYSERDA is continually evaluating the literature for information to update the oil and gas methane inventory with more accurate emissions factors and activity data. For example, data on methane leaks from commercial buildings are sparse, hindering efforts to estimate emissions from the universe of commercial buildings. As of now, only emissions from hospitals and restaurants can be estimated. While emission from all commercial buildings could be estimated by using data for restaurants and hospitals as a surrogate, office buildings, schools, and other commercial buildings likely have different emissions profiles. Applying the average hospital/restaurant emissions factor to all commercial buildings indicates that emissions from universe of commercial buildings could be as high as 1,000,000 $MTCO_2e$ (AR5, $GWP_{20}$).

NYSERDA is also considering the impacts of recent legislation and regulations on the future of oil and gas methane emissions in the State, such as the Inflation Reduction Act (IRA), the U.S. EPA's supplemental proposal to reduce methane from oil and natural gas operations, and New York State's 6 NYCRR Part 203 that establishes monitoring, operational, and reporting requirements for the oil and natural gas sector statewide. In addition, Governor Hochul announced in August 2022 that New York State received $25 million as part of the Department of Interior's Initial Grant Program stemming from the Bipartisan Infrastructure Law (NYS 2022b). The funding will be used to locate and plug abandoned oil and gas wells. As these and other programs and regulatory efforts are announced, NYSERDA will continue to consider how they affect the scenarios modeled in this report.

# 9 Conclusions

Under the Climate Act, NYS is required to reduce economywide GHG emissions 40 percent by 2030 and no less than 85 percent by 2050 from 1990 levels. Under this project, NYSERDA applied best practices to develop a methane emissions projection and mitigation model for the oil and natural gas sector in NYS. NYSERDA coordinated with NYS's Integration Analysis by applying the model to better understand the impacts of methane mitigation strategies on the economywide emissions reduction requirements and to help NYS make informed decisions about how best to reduce methane emissions in the oil and natural gas sector.

Results indicate that oil and gas methane emissions reductions through 2050 are more strongly correlated with building electrification than with natural gas demand, since building electrification drives natural gas infrastructure contraction. Depending on the integration analysis and mitigation scenarios, emissions totaling 2.7 to 11.7 MMT$CO_2$e, remain through 2050. Emissions in the reference case are reduced 26 percent by 2030 and 33 percent by 2050 compared to 1990 emissions. Emissions are reduced 37 percent by 2030 and 61 percent by 2050 in IAS2, 73 percent by 2030 and 83 percent by 2050 in IAS2–Level 1 Mitigation, and 76 percent by 2030 and 84 percent by 2050 in IAS2–Level 2 Mitigation. Emissions reductions in IAS3, IAS3–Level 1 Mitigation, and IAS3–Level 2 Mitigation are similar or slightly higher than IAS2. Therefore, oil and gas methane emissions reductions exceed alignment with NYS's 2030 economywide reduction level in IAS2–Level 1 Mitigation, IAS2–Level 2 Mitigation, IAS3–Level 1 Mitigation, and IAS3–Level 2 Mitigation, but no scenario achieves alignment with the 2050 economywide reduction level; however, since New York State's GHG limits are economywide requirements they could still be met through additional emissions reductions in other sectors.

Depending on the scenario and whether avoided costs are considered, modeling results indicate that mitigation costs range from -$25.04 to $103.06 per metric ton of $CO_2$e. When avoided costs are included, and prior to applying Level 1 Mitigation or Level 2 Mitigation, IAS2 and IAS3 result in net savings amounting to approximately $2.28 million or $2.20 million, respectively. Additionally, costs to achieve the Level 2 Mitigation emissions reductions compared to Level 1 Mitigation emission reductions are much higher because Level 2 Mitigation includes more costly strategies such as LDAR on plastic distribution pipelines. The additional costs of adding Level 1 Mitigation onto IAS2 or IAS3 are smaller as the strategies in Level 1 Mitigation are less costly. Level 2 Mitigation, while being more costly, also results in smaller emissions reductions than Level 1 Mitigation since the strategies are applied to emissions sources that are more difficult to mitigate.

The methane emissions projections and mitigation options presented in this report are based on the 2020 NYS Oil and Gas Methane Inventory and 2022 integration analysis. While these analyses are helping NYS to make informed decisions about mitigation strategies, NYSERDA is continually evaluating ways to continually improve the inventory and projections to accurately assess the future of oil and gas methane emissions. Such improvements include updating emissions factors based on new research, adding new source categories as data become available, and incorporating the impacts of new legislation.

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# Appendix A. Scenario Definitions

Reference case: Emissions scenario based on the reference case developed for the Integration Analysis and that forecast the natural gas system in NYS through 2050 under federal and pre-Climate Act state policies, such as funded EE. Assumes no change in natural gas production from 2020 levels, 0.62% average annual decrease in uncapped abandoned oil wells and 0.82% average annual decrease in uncapped abandoned gas wells, 0.29% average annual decrease in truck loading of oil, the addition of 25 miles of transmission pipeline and 1 compressor station in Ontario County in 2021, 1.03% average annual increase in commercial buildings with natural gas service and commercial meters, 0.67% average annual increase in residential buildings with natural gas service and residential meters and appliances, 6.27% average annual decrease in cast iron mains (and 20% of pipeline is too costly to replace), 9.5% average annual decrease in cast iron services (and 20% of pipeline is too costly to replace), 18% average annual decrease in unprotected steel mains, 13.3% average annual decrease in unprotected steel services, 12.1% average annual decrease in copper services, 0.80% average annual increase in protected steel mains, 0.69% average annual increase in protected steel services, 1.66% average annual increase in plastic mains, and 1.28% average annual increase in plastic services.

Integration Analysis Scenario 2: Emissions scenario based on the Integration Analysis Strategic Use of Low Carbon Fuels (LCF) scenario which represents the recommendations from each advisory panel, including aggressive electrification and efficiency relative to the Reference scenario. Includes increasing sales of heat pumps in the 2020s; a greater share of heat pumps with either natural gas or oil backup; conversion of industrial natural gas to hydrogen fuel; and the use of bioenergy derived from biogenic waste, agriculture & forest residues, and limited purpose grown biomass, as well as green hydrogen, for difficult to electrify applications. Assumes 16.7% average annual decrease in natural gas production, 0.62% average annual decrease in uncapped abandoned oil wells and 0.82% average annual decrease in uncapped abandoned gas wells, 44.8% average annual decrease in truck loading of oil, the addition of 25 miles of transmission pipeline and 1 compressor station in Ontario County in 2021, 7.73% average annual decrease in commercial buildings with natural gas service and commercial meters, 5.38% average annual decrease in residential buildings with natural gas service and residential meters and appliances, 6.27% average annual decrease in cast iron mains (and 20% of pipeline is too costly to replace), 9.5% average annual decrease in cast iron services (and 20% of pipeline is too costly to replace), 18% average annual decrease in unprotected steel mains, 13.3% average annual decrease in unprotected steel services, 12.1% average annual decrease in copper services, 6.89% average annual decrease in protected steel mains, 5.99% average annual decrease in protected steel services, 6.04% average annual decrease in plastic mains, and 5.40% average annual decrease in plastic services.

Integration Analysis Scenario 3: Emissions scenario based on the Integration Analysis Accelerated Transition Away from Combustion scenario (AT). The IAS3 scenario includes additional electrification both by increasing the pace of heat pump sales in the 2020s and by including some early retirements of fossil technologies in 2028/2029; no heat pumps with fossil backup; electrification of industrial natural gas; low-to-no bioenergy and hydrogen combustion; accelerated electrification of buildings and transportation. Assumes 16.7% average annual decrease in natural gas production, 0.62% average annual decrease in uncapped abandoned oil wells and 0.82% average annual decrease in uncapped abandoned gas wells, 44.8% average annual decrease in truck loading of oil, the addition of 25 miles of transmission pipeline and 1 compressor station in Ontario County in 2021, 14.48% average annual decrease in commercial buildings with natural gas service and commercial meters, 7.34% average annual decrease in residential buildings with natural gas service and residential meters and appliances, 6.27% average annual decrease in cast iron mains (and 20% of pipeline is too costly to replace), 9.5% average annual decrease in cast iron services (and 20% of pipeline is too costly to replace), 18% average annual decrease in unprotected steel mains, 13.3% average annual decrease in unprotected steel services, 12.1% average annual decrease in copper services, 9.12% average annual decrease in protected steel mains, 7.91% average annual decrease in protected steel services, 8.29% average annual decrease in plastic mains, and 7.34% average annual decrease in plastic services.

IAS2–Level 1 Mitigation: Emissions scenario that includes additional mitigation applied to Integration Analysis Scenario 2. Also assumes LDAR on 100% of production sites upstate phased in between 2023 and 2030 (14% per year), all production but high producing oil wells phased out upstate between 2023 and 2030 (14% per year), no well capping, LDAR on 100% of gathering and boosting stations upstate phased in between 2023 and 2030 (14% per year), LDAR on 100% of gathering pipelines upstate phased in between 2023 and 2030, equipment upgrade for truck loading of oil to allow 100% vapor recovery upstate starting in 2022, LDAR on 100% of transmission pipelines phased in between 2023 and 2030 (14% per year), compressor changeout between 2023 and 2030 (14% per year), LDAR on 100% of compressor stations phased in between 2023 and 2030 (14% per year), LDAR on 100% of cast iron and unprotected steel mains and unprotected steel services between 2023 and 2030 (14% per year), LDAR on 100% of residential meters phased in between 2023 and 2030 (14% per year), LDAR on 100% of commercial buildings downstate and 25% of residential buildings upstate phased in between 2023 and 2030 (14% per year), and equipment upgrade on 100% of residential gas appliances phased in between 2023 and 2043 (2% per year).

IAS2–Level 2 Mitigation: Emissions scenario that includes additional mitigation applied to Integration Analysis Scenario 2. Also assumes LDAR on 100% of production sites upstate phased in between 2023 and 2030 (14% per year); all production phased out upstate between 2023 and 2030 (14% per year); 100% of remaining wells upstate capped between 2023 and 2030 (14% per year); LDAR on 100% of gathering and boosting stations upstate phased in between 2023 and 2030 (14% per year); LDAR on 100% of gathering pipelines upstate phased in between 2023 and 2030; equipment upgrade for truck loading of oil to allow 100% vapor recovery upstate starting in 2022; LDAR on 100% of transmission pipelines phased in between 2023 and 2030 (14% per year); compressor changeout between 2023 and 2030 (14% per year); LDAR on 100% of transmission compressor stations, storage compressor stations upstate, and LNG storage compressor stations downstate phased in between 2023 and 2030 (14% per year); LDAR on 100% of cast iron mains and services, unprotected steel mains and services, protected steel mains and services, plastic mains, plastic services upstate, and copper services between 2023 and 2030 (14% per year); LDAR on 100% of residential meters phased in between 2023 and 2030 (14% per year); LDAR on 100% of commercial buildings and 25% of residential buildings phased in between 2023 and 2030 (14% per year); and equipment upgrade on 100% of residential gas appliances phased in between 2023 and 2043 (5% per year).

IAS3–Level 1 Mitigation: Emissions scenario that includes additional mitigation applied to Integration Analysis Scenario 3. Also assumes LDAR on 100% of production sites upstate phased in between 2023 and 2030 (14% per year), all production but high producing oil wells phased out upstate between 2023 and 2030 (14% per year), no well capping, LDAR on 100% of gathering and boosting stations upstate phased in between 2023 and 2030 (14% per year), LDAR on 100% of gathering pipelines upstate phased in between 2023 and 2030, equipment upgrade for truck loading of oil to allow 100% vapor recovery upstate starting in 2022, LDAR on 100% of transmission pipelines phased in between 2023 and 2030 (14% per year), compressor changeout between 2023 and 2030 (14% per year), LDAR on 100% of compressor stations phased in between 2023 and 2030 (14% per year), LDAR on 100% of cast iron and unprotected steel mains and unprotected steel services between 2023 and 2030 (14% per year), LDAR on 100% of residential meters phased in between 2023 and 2030 (14% per year), LDAR on 100% of commercial buildings downstate and 25% of residential buildings upstate phased in between 2023 and 2030 (14% per year), and equipment upgrade on 100% of residential gas appliances phased in between 2023 and 2043 (2% per year).

IAS3–Level 2 Mitigation: Emissions scenario that includes additional mitigation applied to Integration Analysis Scenario 3. Also assumes LDAR on 100% of production sites upstate phased in between 2023 and 2030 (14% per year); all production phased out upstate between 2023 and 2030 (14% per year); 100% of remaining wells upstate capped between 2023 and 2030 (14% per year); LDAR on 100% of gathering and boosting stations upstate phased in between 2023 and 2030 (14% per year); LDAR on 100% of gathering pipelines upstate phased in between 2023 and 2030; equipment upgrade for truck loading of oil to allow 100% vapor recovery upstate starting in 2022; LDAR on 100% of transmission pipelines phased in between 2023 and 2030 (14% per year); compressor changeout between 2023 and 2030 (14% per year); LDAR on 100% of transmission compressor stations, storage compressor stations upstate, and LNG storage compressor stations downstate phased in between 2023 and 2030 (14% per year); LDAR on 100% of cast iron mains and services, unprotected steel mains and services, protected steel mains and services, plastic mains, plastic services upstate, and copper services between 2023 and 2030 (14% per year); LDAR on 100% of residential meters phased in between 2023 and 2030 (14% per year); LDAR on 100% of commercial buildings and 25% of residential buildings phased in between 2023 and 2030 (14% per year); and equipment upgrade on 100% of residential gas appliances phased in between 2023 and 2043 (5% per year).

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