Michigan Renewable Natural Gas Study

Final Report

September 23, 2022

Submitted to:
Michigan Public Service
Commission

Submitted by:
ICF Resources, L.L.C.
9300 Lee Highway
Fairfax, VA 22031

Table of Contents

Executive Summary **1**
- RNG Production Potential in Michigan 2
- RNG Production Costs 6
- Greenhouse Gas Emission Reductions From RNG 7
- Opportunities and Barriers for RNG Production in Michigan 10

1. Introduction **13**
- Overview of Biogas in Michigan 13
- Biogas and RNG: A Market in Transition 15
- Study Objective and Study Overview 16
- Stakeholder Engagement 17

2. RNG Production **17**
- Anaerobic Digestion 18
- Thermal Gasification 19

3. RNG Feedstock Inventory **21**
- RNG Feedstocks 21
- Inventory Methodology 22
- RNG: Anaerobic Digestion of Biogenic or Renewable Resources 24
- RNG: Thermal Gasification of Biogenic or Renewable Resources 34
- Feedstock Summary 43

4. RNG Supply Scenarios **45**
- Summary of RNG Potential 46
- Summary of RNG Potential by Scenario 47
- RNG: Anaerobic Digestion of Biogenic or Renewable Resources 50
- RNG: Thermal Gasification of Biogenic or Renewable Resources 56

5. RNG Production Cost Assessment **61**
- RNG Production Costs via Anaerobic Digestion 63
- RNG Production Costs via Thermal Gasification 69
- Combined Supply-Cost Curve for RNG 71

6. GHG Emission Reductions and Cost-Effectiveness **73**
- GHG Emissions from RNG Production Potential 75
- RNG and Decarbonization 79
- RNG Cost-Effectiveness 80
- Summary of GHG Emission Reductions from RNG Supply Scenarios 80

7. GHG Abatement Cost Comparison **82**
- Renewable Hydrogen Blending 84
- Building Electrification 86
- Electricity Generation 90
- Transportation Electrification 91
- Abatement Cost Comparison 93

8. Opportunities and Barriers to RNG Production in Michigan **95**

Technical ... 95
Market ... 99
Regulatory and Policy ... 101
Environmental Impacts ... 104
Appendix A ... 106
Understanding the Current RNG Value Stack ... 106
Rise of Non-Transportation Demand ... 111
Appendix B ... 113
Common Applications of GHG Emission Accounting for RNG ... 113
Lifecycle GHG Emissions Accounting ... 116
Appendix C ... 121
State-Level RNG Polices ... 121

List of Figures

Figure 1-1. LFGE facilities and installed capacity (MW) deployed in Michigan 14
Figure 2-1. RNG Production Process via Anaerobic Digestion and Thermal Gasification 18
Figure 3-1. Michigan Prosperity Regions 23
Figure 3-2. Maximum RNG Production Potential by Region (tBtu/y) 24
Figure 4-1. Achievable Scenario Annual RNG Production in Michigan, 2025-2050 (tBtu/y) 48
Figure 4-2. Achievable Scenario RNG Production by Region in 2050 (tBtu/y) 48
Figure 4-3. Feasible Scenario Annual RNG Production in Michigan, 2025-2050 (tBtu/y) 49
Figure 4-4. Feasible Scenario RNG Production by Region in 2050 (tBtu/y) 49
Figure 4-5. Annual RNG Production Potential from Animal Manure in Michigan (tBtu/y) 50
Figure 4-6. Annual RNG Production Potential from Food Waste in Michigan (tBtu/y) 51
Figure 4-7. Annual RNG Production Potential from Landfill Gas in Michigan (tBtu/y) 54
Figure 4-8. Annual RNG Production Potential from WRRFs in Michigan (tBtu/y) 56
Figure 4-9. Annual RNG Production Potential from Agricultural Residues in Michigan (tBtu/y) 57
Figure 4-10. Annual RNG Production Potential from Energy Crops in Michigan (tBtu/y) 58
Figure 4-11. Annual RNG Production Potential from Forestry Residues in Michigan (tBtu/y) 59
Figure 4-12. Annual RNG Production Potential from MSW in Michigan (tBtu/y) 60
Figure 5-1. Combined Supply-Cost Curve for Michigan in 2030, Achievable ($/MMBtu) 72
Figure 5-2. Combined Supply-Cost Curve for Michigan in 2050, Achievable ($/MMBtu) 72
Figure 6-1. Boundary Conditions of GHG Emission Account Approaches for RNG Production 74
Figure 6-2. Michigan RNG Emission Reduction Potential by Scenario (MMtCO$_2$e) 77
Figure 6-3. Michigan Energy-Related CO$_2$ Emissions, 2019 (MMtCO$_2$e) 77
Figure 6-4. GHG Emissions from Natural Gas Consumption by Sector in Michigan 78
Figure 7-1. Installed Capacity Cost of Electrolyzers, $/kW, 2020-2050 85
Figure 7-2. GHG Abatement Costs, Selected Measures ($/tCO$_2$e) 93
Figure A-1. Overview of the Federal RFS Program 107
Figure A-2. Carbon Intensity of delivered RNG to California used as CNG, 2014-2021 109
Figure B-1. Scopes for Categorizing Emissions Under the 2019 GHG Protocol 115
Figure B-2. Boundary Conditions of Lifecycle GHG Emissions Accounting for RNG 116

List of Tables

Table 3-1. RNG Feedstock Types 21
Table 3-2. List of Data Sources for RNG Feedstock Inventory 22
Table 3-3. Key Parameters for Animal Manure Resource RNG Potential 26
Table 3-4. Animal Manure Resource RNG Potential 27
Table 3-5. Maximum Food Waste Potential in 2040 28
Table 3-6. Landfill Gas Constituents and Corresponding Upgrading Technologies 29
Table 3-7. Michigan Landfills by Region 30
Table 3-8. Large Landfills in Michigan 30
Table 3-9. RNG Potential from Landfills by Region 32
Table 3-10. WRRFs by Existing Flow and Region 34
Table 3-11. Heating Values for Agricultural Residues 36
Table 3-12. Agricultural Residue Production Potential in 2040 by Region (dry tons) 36
Table 3-13. Agricultural Residue RNG Production Potential in 2040 by Region (tBtu/y) 37
Table 3-14. Heating Values for Energy Crops 38
Table 3-15. Energy Crop Production Potential in 2040 by Region (dry tons) 38

Table 3-16. Energy Crop RNG Production Potential in 2040 by Region (tBtu/y) 39
Table 3-17. Heating Values for Forestry and Forest Product Residues 40
Table 3-18. Forestry and Forest Product Residue Production Potential in 2040 by Region (dry tons)....41
Table 3-19. Forestry and Forest Product Residue RNG Potential in 2040 by Region (tBtu/y)....41
Table 3-20. Heating Values for MSW Components 42
Table 3-21. MSW Production Potential in 2040 by Geography and Price (dry tons)....42
Table 3-22. RNG Production Potential from MSW in 2040 by Region and Price (tBtu/y) 43
Table 3-23. Maximum RNG Production Potential by Feedstock (tBtu/y)....43
Table 4-1. Estimated Annual RNG Production in Michigan by 2050 (tBtu/y) 46
Table 4-2. Estimated Annual RNG Production by Region in 2050 (tBtu/y) 46
Table 4-3. Landfills included in Scenario Analysis by Region 52
Table 4-4. EPA Candidate Landfills in Michigan....53
Table 4-5. WRRFs by Existing Flow and Geography 54
Table 4-6. Large WRRFs in Michigan....55
Table 5-1. Illustrative ICF RNG Cost Assumptions....61
Table 5-2. Summary of Cost Ranges by Feedstock Type 63
Table 5-3. Cost Consideration in LCOE Analysis for RNG from Animal Manure 64
Table 5-4. Example Facility-Level Cost Inputs for RNG from Animal Manure....64
Table 5-5. Cost Consideration in LCOE Analysis for RNG from Food Waste Digesters....65
Table 5-6. Example Facility-Level Cost Inputs for RNG from Food Waste 65
Table 5-7. Average Tipping Fee by Region ($/ton)....66
Table 5-8. Cost Consideration in LCOE Analysis for RNG from Landfill Gas 67
Table 5-9. Example Facility-Level Cost Inputs for RNG from LFG....68
Table 5-10. Cost Consideration in LCOE Analysis for RNG from WRRFs....68
Table 5-11. Example Facility-Level Cost Inputs for RNG from WRRFs 69
Table 5-12. Thermal Gasification Cost Assumptions....70
Table 5-13. Example Facility-Level Cost Inputs for RNG from Thermal Gasification....70
Table 7-1. Summary of Abatement Costs for Emission Reduction Measures....83
Table 8-1. Illustrative Quality Considerations for RNG Injection....97
Table A-1. RNG Value Stack as a Transportation Fuel in California....106
Table A-2. Nested Categories of Renewable Fuels in the RFS Program....107
Table A-3. Forecasted D3 RIN Pricing to 2030 ($2022)....108
Table A-4. Forecasted LCFS Credit Pricing to 2030 ($2022)....110
Table B-1. Estimated CI Values for RNG from Different Feedstocks (MI specific)....119

List of Abbreviations

AD	Anaerobic digestion
AGF	American Gas Foundation
ATB	Advanced Technology Baseline
CAFO	Concentrated animal feeding operation
CCST	California Council on Science and Technology
CH4	Methane
CI	Carbon intensity
CNG	Compressed natural gas
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CWC	Cellulosic Waiver Credit
CWNS	Clean Watersheds Needs Survey
DGE	Diesel gallon equivalent
DOE	United States Department of Energy
EFI	Energy Futures Initiative
EIA	Energy Information Administration
EPA	United States Environmental Protection Agency
EREF	Environmental Research & Education Foundation
gCO_2e/MJ	grams of CO_2e per megajoule
GHG	Greenhouse gas
H2S	Hydrogen sulfide
HHV	Higher heating value
IOU	Investor-Owned Utilities
KDF	Bionergy Knowledge Discovery Framework
LCFS	Low Carbon Fuel Standard
LCOE	Levelized cost of energy
LFG	Landfill gas
LFGE	Landfill gas to electricity
LMOP	Landfill Methane Outreach Program
M&HDV	Medium- and heavy-duty vehicle
MGD	Million gallons per day
MMBtu	Million British thermal units
$MMtCO_2e$	Million metric tons of CO_2e
MOU	Municipally-Owned Utilities
MSW	Municipal solid waste
N_2	Nitrogen
NGV	Natural gas vehicle
O_2	Oxygen
P2G	Power to gas
PA-CAP	Pennsylvania Climate Action Plan
PEM	Proton exchange membrane
POLYSYS	Policy Analysis System
REC	Renewable Energy Certificate

RFS	Renewable Fuel Standard
RIN	Renewable Identification Number
RNG	Renewable natural gas
RPS	Renewable Portfolio Standard
RVO	Renewable Volume Obligations
SCFM	Standard cubic feet per minute
tBtu	Trillion British thermal units
tCO_2e	Metric ton of CO_{2e}
Tpd	Tons per day
USDA	United States Department of Agriculture
WRI	World Resources Institute
WRRF	Water resource recovery facilities
ZEV	Zero emission vehicle

Executive Summary

This study is in response to the directives of Michigan Public Act 87 of 2021, which requires the Michigan Public Service Commission to conduct a study into the potential for renewable natural gas development in the state. ICF developed this study to provide data and accompanying analysis regarding renewable natural gas production potential in Michigan to help inform policymakers and decisionmakers. Stakeholder engagement included hosting three public meetings dedicated to receiving stakeholder input, soliciting peer-reviewed studies that would enrich this study, providing multiple documents that were used to develop the study's structure and findings for stakeholder review, providing stakeholders an opportunity to submit comments regarding the methodologies and assumptions employed in this study, and providing stakeholders an opportunity to submit comments regarding the draft version of this study.[1] Furthermore, the Michigan Public Service Commission accommodated multiple meeting requests from stakeholders regarding this study and incorporated stakeholder comments throughout the process.

The timing of this report is critical as the market for biogas and renewable natural gas is in transition. Biogas already plays a role in Michigan's renewable energy landscape, most notably by generating electricity to help comply with Michigan's Renewable Portfolio Standard. Michigan benefits from a variety of investments that have been made to capture biogas for beneficial use. Today, about 40 Michigan landfills have installed more than 135 megawatts of electricity generation, and five landfills in Michigan have so-called direct use applications, which uses biogas in boilers or other direct thermal uses.

As a result of policy changes at the federal level, however, the biogas market has undergone significant changes over the last eight years. During that time, investments in biogas-to-electricity projects slowed and the market shifted towards producing renewable natural gas for pipeline injection. Rather than using biogas to generate electricity for use on-site or selling it into electricity markets, that biogas is now upgraded and processed so that it can be injected into common carrier pipelines as renewable natural gas.

Today, there are at least six operational renewable natural gas projects at Michigan landfills, with two to three more expected to be online by early 2023. Similarly, there are at least four operational anaerobic digesters in Michigan that produce renewable natural gas from the capture of methane emitted from animal manure, and at least another three that have broken ground and will be fully operational towards the end of 2022. While most of the renewable natural gas produced in Michigan today is used as a transportation fuel, there is emerging demand for renewable natural gas in non-transportation applications.

In this study, ICF characterizes the potential for renewable natural gas as a greenhouse gas emission reduction strategy in the State of Michigan, including a review of how much renewable natural gas could be produced from in-state resources, the associated cost of producing renewable natural gas, an assessment of how renewable natural gas compares to other potential abatement strategies, and a review of the opportunities and barriers that exist to renewable natural gas production, including environmental impacts.

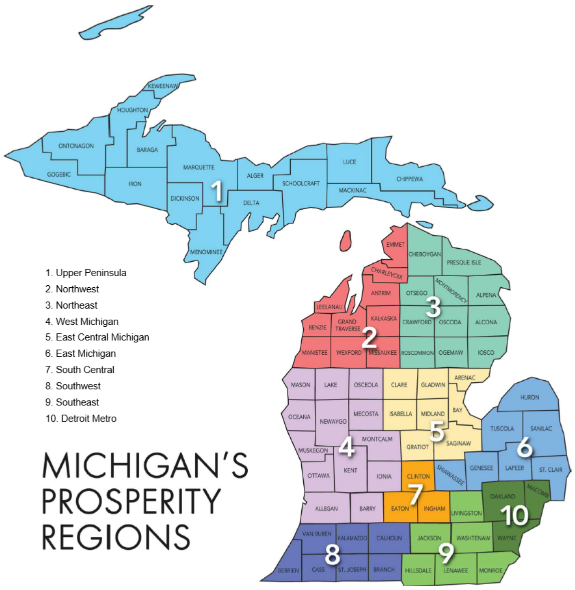
---

[1] Stakeholder comments are available on the MPSC's Renewable Natural Gas Study Workgroup website.

Public Act 87 of 2021 defines renewable natural gas as “a biogas that has been processed or upgraded to be interchangeable with conventional natural gas and to meet pipeline quality standards or transportation fuel grade requirements.” Because renewable natural gas is a ‘drop-in’ replacement for natural gas, it can be safely employed in any end use typically fueled by natural gas, including space heating and cooling, industrial applications, transportation, and electricity production.

RNG Production Potential in Michigan

ICF developed three resource potential scenarios by considering renewable natural gas production from nine feedstocks and two production technologies. The feedstocks include landfill gas, animal manure, water resource recovery facilities, food waste, agricultural residues, forestry and forest product residues, energy crops, and the biogenic fraction of municipal solid waste. These feedstocks were assumed to be processed using anaerobic digesters or thermal gasification systems. ICF used a mix of existing studies, government data, and industry resources to estimate the current and future supply of the feedstocks for renewable natural gas production.



ICF estimated renewable natural gas potential at the county level across Michigan and included facility-level information for relevant feedstocks where available (e.g., for landfills and water resource recovery facilities). While the underlying data is collected for all 83 counties in Michigan, in this report we aggregate and present the data based on Michigan’s ten prosperity regions.[2] ICF developed a maximum renewable natural gas potential for each feedstock and production technology in Michigan, reported in trillion British thermal units per year (tBtu/y). The renewable natural gas potential includes different variables for each feedstock, but ultimately reflects the most aggressive options available to achieve maximum renewable natural gas production potential.

---

[2] https://www.michigan.gov/images/mshda/MI-prosperity-regions-map-LG_616814_7.png

ICF also developed renewable natural gas supply curves for two additional scenarios for each feedstock and region included in the renewable natural gas inventory. The renewable natural gas potential scenarios included in the supply curves are based on an assessment of resource availability. In a competitive market, that resource availability is a function of multiple factors, including but not limited to demand, renewable natural gas costs, technological development, and the policies in place that might support renewable natural gas project development. ICF assessed the renewable natural gas resource potential of the different feedstocks that could be realized, given the necessary market considerations (without explicitly defining what those are). The two supply scenarios are characterized as achievable and feasible:

- **Achievable** represents a low level of feedstock utilization, with utilization levels depending on feedstock, with a range from 20% to 50% of technically available feedstocks that were converted to renewable natural gas using anaerobic digestion technologies. The utilization rate of feedstocks for thermal gasification in this scenario is 30%, at lower biomass prices. Overall, the Achievable scenario captures 18% of the renewable natural gas feedstock resource in Michigan.
- **Feasible** represents balanced assumptions regarding feedstock utilization, with a range from 60% to 85% for feedstocks that were converted to renewable natural gas using anaerobic digestion technologies. The utilization rates of feedstocks for thermal gasification in this scenario ranges from 40% to 50% at moderate biomass prices. Overall, the Feasible scenario captures 47% of the renewable natural gas feedstock resource available in Michigan.

The table below includes renewable natural gas supply estimates for 2050 from in-state resources using the constraints that ICF developed for the Achievable and Feasible scenarios; the last column shows the maximum development potential for each feedstock in 2050 based on the feedstock inventory developed (reported in units of trillion British thermal units per year).

Maximum Renewable Natural Gas Production Potential by Feedstock (tBtu/y)

RNG Feedstock		Scenario		
		Achievable	Feasible	Inventory
Anaerobic Digestion	Animal Manure	4.6	9.3	39.0
	Food Waste	1.2	1.8	3.0
	LFG	31.5	53.5	67.8
	Water Resource Recovery Facilities	1.5	2.3	3.5
Thermal Gasification	Agricultural Residue	3.8	30.3	69.9
	Energy Crops	9.6	42.0	112.3
	Forestry and Forest Product Residue	3.5	5.9	11.8
	Municipal Solid Waste	1.5	3.1	6.1
Total		**57.2**	**148.0**	**313.4**
Percentage of Total Available Feedstock[3]		**18%**	**47%**	**100%**

The renewable natural gas resources in Michigan are diverse, including significant potential from landfills, municipal solid waste, animal manure, and energy crops. The variety in renewable natural gas feedstocks is driven by the diverse nature of Michigan's renewable resources, including the mix of rural areas with agricultural activity and significant population centers that provide a source of biomass-based waste. For the sake of reference, Michigan consumed an average of 673 tBtu of natural gas in residential, commercial, and industrial, and vehicle sectors from 2016 to 2020, with a minimum of 642 tBtu in 2020 and a maximum of 713 tBtu in 2019.[4] In other words, ICF's estimates for renewable natural gas deployment in Michigan for the Achievable and Feasible scenarios amount to 8.5% and 22.0% of the average annual natural gas consumption in relevant sectors for the last five years for which there are data available.

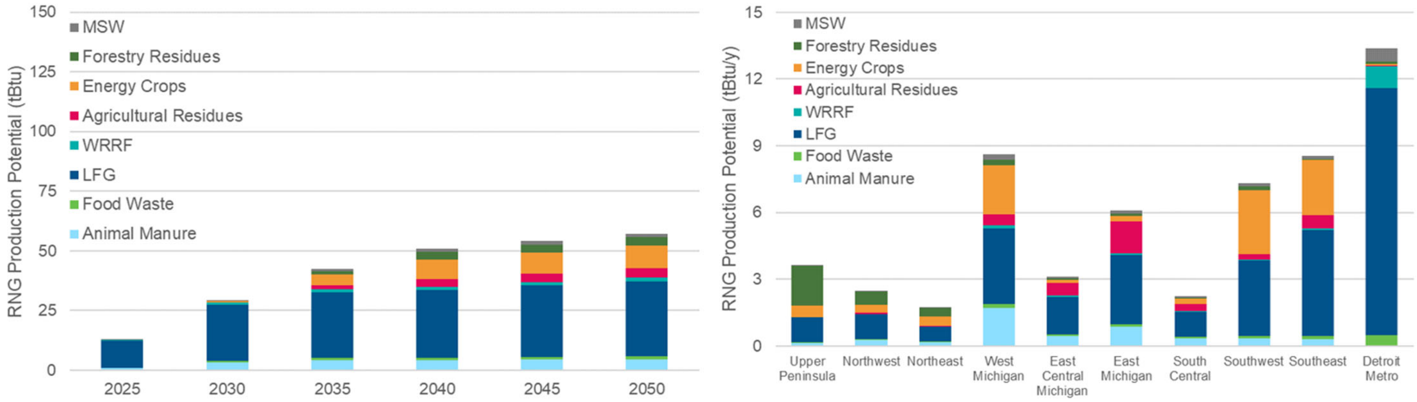
The figure below shows four graphs, outlining the renewable natural gas production potential for each feedstock out to 2050, and the corresponding renewable natural gas production potential for each region in 2050. The top two graphs correspond to the Achievable scenario, whereas the bottom two graphs correspond to the Feasible scenario.

---

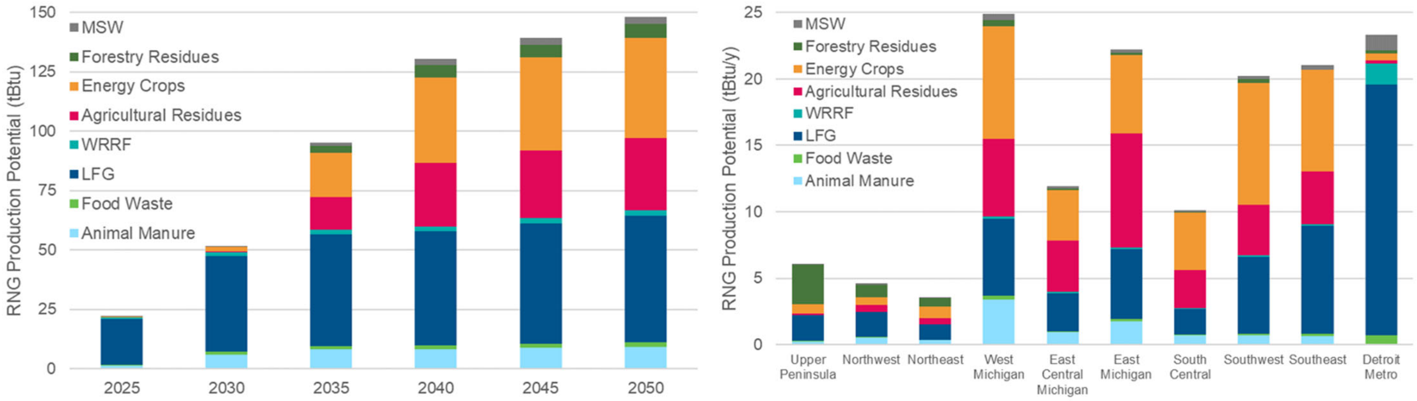
[3] Total feedstock reflects the maximum volume of RNG feedstocks available in Michigan, including all facilities and all biomass, and no restrictions are applied.

[4] Based on ICF analysis of data reported by the EIA regarding *Natural Gas Consumption by End Use*, available online at https://www.eia.gov/dnav/ng/NG_CONS_SUM_DCU_SMI_A.htm. ICF excluded natural gas used in electric power generation in our consideration here because RNG is unlikely to displace natural gas used in electricity production given its higher cost.

Achievable Scenario



Feasible Scenario



In the Achievable scenario, renewable natural gas from anaerobic digestion feedstocks represent the majority of overall production potential, with landfill gas and animal manure making up a large proportion out to 2050. Commercial deployment of the thermal gasification production technology after 2030 sees the increased deployment of feedstocks that utilize that technology, with energy crops and to a lesser degree agricultural residue and forestry residue contributing larger shares of overall potential. Consistent with the statewide timeseries, regions in Michigan with high feedstock potential from landfills and animal manure are the main sources of renewable natural gas production potential in the Achievable scenario. For example, the Detroit Metro has significant potential from landfills, while West Michigan has significant potential from animal manure.

Similar to the Achievable scenario, the Feasible scenario shows an early penetration of renewable natural gas from anaerobic digestion feedstocks, with an increased penetration of renewable natural gas from thermal gasification feedstocks taking place post-2030. With the higher deployment of energy crops and agricultural residues in the Feasible scenario, regions with large agricultural-based industries contribute a higher share to statewide renewable natural gas potential, such as West Michigan, East Michigan, Southeast and Southwest.

RNG Production Costs

ICF developed assumptions for the capital expenditures and operational costs for renewable natural gas production from the various feedstock and technology pairings discussed previously. ICF characterizes costs based on a series of assumptions regarding the production facility sizes (as measured by gas throughput), gas upgrading and conditioning and upgrading costs (depending on the type of technology used, the contaminant loadings, etc.), compression, and interconnect for pipeline injection. We also include operational costs for each technology type.

ICF presents the costs used in our analysis as well as the levelized cost of energy or LCOE for renewable natural gas in different end uses. The LCOE is a measure of the average net present cost of renewable natural gas production for a facility over its anticipated lifetime. ICF estimates that renewable natural gas can be produced from various feedstocks in a cost range of less than $10/MMBtu to upwards of $50/MMBtu. Anaerobic digestion feedstocks, notably from landfill gas and water resources recovery facilities, tend to be more cost-effective in the short-term future, whereas renewable natural gas from thermal gasification feedstocks is more expensive, largely reflecting the immature state of thermal gasification as a technology, and the associated uncertainties around cost and feedstock availability.

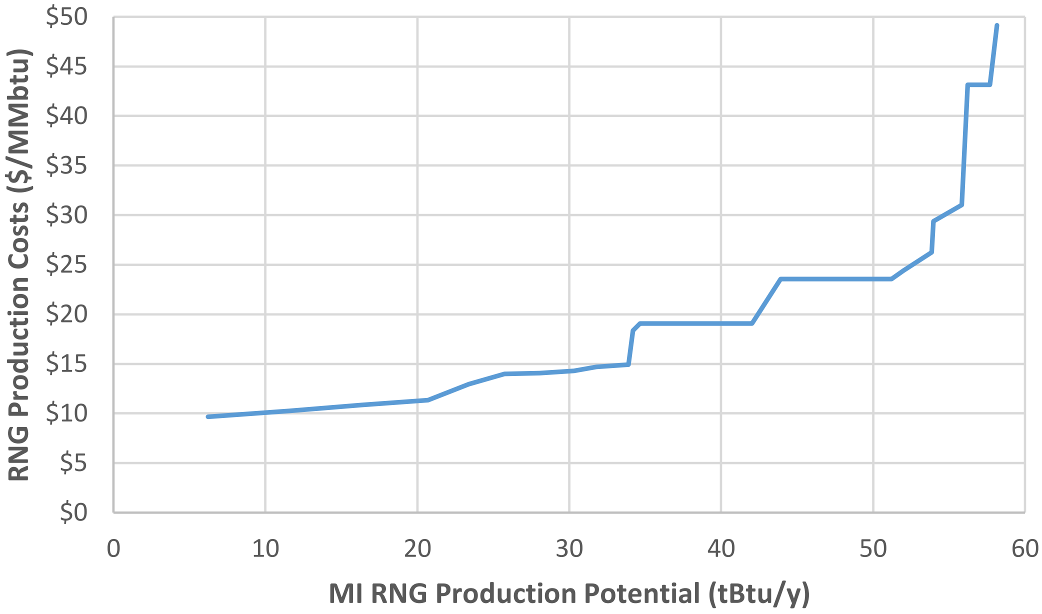
The table below summarizes the range of renewable natural gas production costs, broken down by feedstock. The range for each feedstock reflects variations in considerations associated with scale of individual renewable natural gas production facilities.

	Feedstock	Cost Range ($/MMBtu)
Anaerobic Digestion	Animal Manure	$14.53 – $49.17
	Food Waste	$18.35 – $29.39
	Landfill Gas	$9.92 – $26.85
	Water Resource Recovery Facilities	$10.90 – $70.86
Thermal Gasification	Agricultural Residues	$19.07 – $43.13
	Energy Crops	$19.07 – $43.13
	Forestry and Forest Residues	$19.07 – $43.13
	Municipal Solid Waste	$19.07 – $43.13

ICF notes that our cost estimates are not intended to replicate a developer's estimate when deploying a renewable natural gas project. Furthermore, these cost estimates do not reflect the potential value of the environmental attributes associated with renewable natural gas, nor the current markets and policies that value these environmental attributes.

The figure below shows the estimated supply-cost curve for renewable natural gas in Michigan in 2050 for the Achievable Scenario (along the x-axis) and the estimated cost to deliver that renewable natural gas (along the y-axis).

Combined Supply-Cost Curve for Michigan in 2050, Achievable ($/MMBtu)



The front end of the supply curve is comprised of landfill gas and water resource recovery facilities. ICF expects the larger thermal gasification systems are expected to be cost competitive in the 2040 to 2050 timeline. The more immediately available opportunities from the anerobic digestion of animal manure and food waste are likely available in the range of middle of the cost range shown in the figure above, whereas the back-end of the supply curve is driven by higher costs of anaerobic digestion at smaller facilities (e.g., farms) and smaller thermal gasification facilities.

Greenhouse Gas Emission Reductions From RNG

When applying a combustion accounting framework for greenhouse gas emissions, ICF estimates that 3 to 8 million metric tons of greenhouse gas emissions could be reduced per year in 2050 in Michigan through the deployment of renewable natural gas based on the Achievable and Feasible scenarios. For the sake of comparison, Michigan's energy-related greenhouse gas emissions were 159 million metric tons of carbon dioxide equivalents in 2019, with about 55 million metric tons attributable to the use of natural gas (or 35% of the total).

It is unlikely that renewable natural gas will be used to displace conventional natural gas in the electric power generation sector because of its higher costs. As such, we focus on the other three main end uses for natural gas: residential, commercial, and industrial. Excluding natural gas used for power generation, the average annual greenhouse gas emissions from natural gas consumption in these three sectors is about 36 million metric tons of greenhouse gas emissions. If RNG was used to displace conventional natural gas in these three sectors, it could decrease emissions from current levels in these sectors from 8% to 22%.

The greenhouse gas emission reduction potential for renewable natural gas is best understood in the context of cost-effectiveness or in units of dollars per ton of emissions reduced. The reasoning is simple: absent cost reductions in renewable natural gas production technology, there will always be a potential "sticker shock" associated with renewable natural gas when framed using traditional metrics, like dollars per unit of energy (e.g., $/MMBtu). However, the cost-effectiveness of renewable natural gas deployment is a better metric to contextualize the opportunities for and barriers to broader renewable natural gas deployment as part of deep decarbonization considerations. For abatement cost estimates, renewable natural gas under $10/MMBtu is equivalent to about $130/tCO$_2$e, while renewable natural gas at $25/MMBtu has an estimated cost-effectiveness of about $400/tCO$_2$e.

Although ICF did not develop new analysis and modeling that estimates abatement costs for emission reduction measures beyond RNG, such as residential electrification and renewable hydrogen, this study does provide a first order comparison to other GHG abatement strategies. ICF analysis included renewable hydrogen blending, building electrification, electricity generation (including renewable electricity generation and nuclear electricity generation), and transportation electrification. The table below and the figure that follows summarizes the estimated abatement cost ranges for the four groupings of abatement measures.

Summary of Abatement Costs for Emission Reduction Measures

Emission Reduction Measure	**Abatement Cost ($/tCO$_2$e)**	
	Low	**High**
Renewable Natural Gas (this study)	**$132**	**$510**
Renewable Hydrogen Blending Range	**$183**	**$296**
ICF Production Cost Estimates in 2050	$183	$296
Comparisons (Columbia Center on Global Energy Policy and US DOE)	$85	$791
Building Electrification Range	**$0**	**$1,000**
Pennsylvania Climate Action Plan[5]	-	$502
Energy Futures Initiative (EFI): California Deep Decarbonization[6]	$380	$540
University of Texas, Carnegie Mellon & University of Michigan[7]	$0	$1,000
Electricity Generation	**$69**	**$446**
E3: PJM 80-100% RPS 2050 (2020)[8]	$69	$220

---

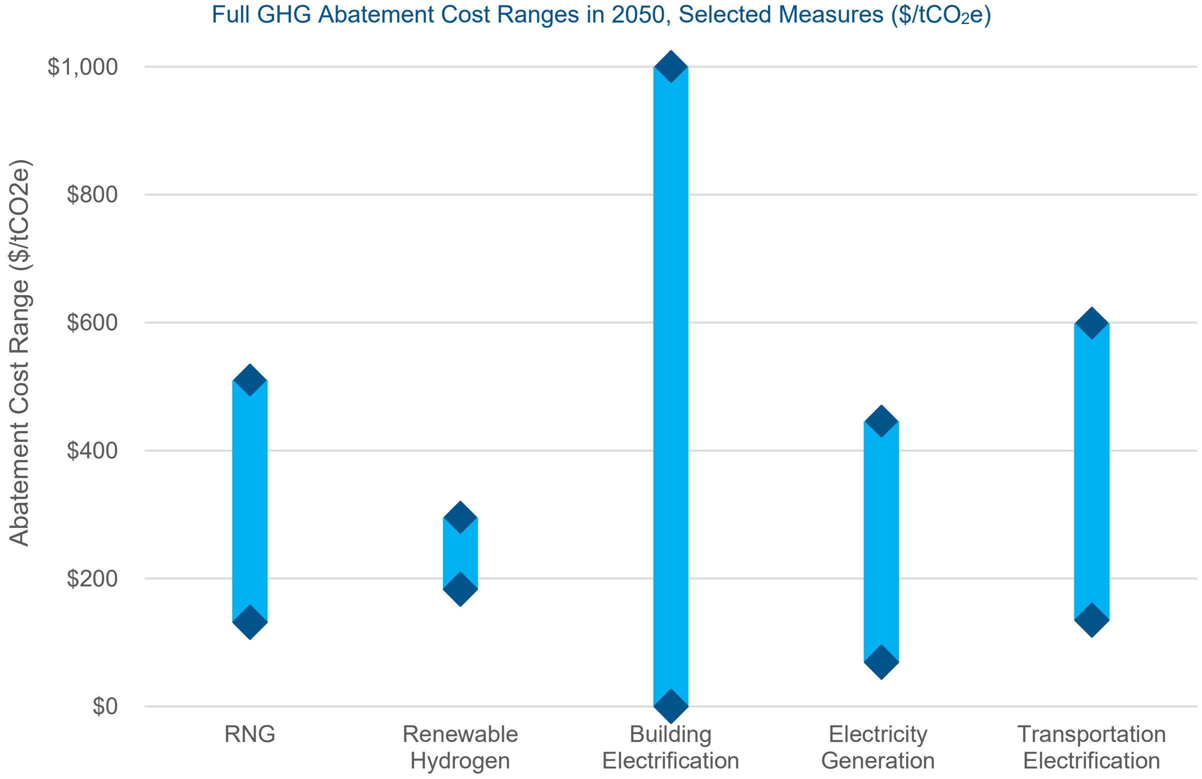
[5] Pennsylvania Department of Environmental Protection, 2021. Pennsylvania Climate Action Plan, https://www.dep.pa.gov/Citizens/climate/Pages/PA-Climate-Action-Plan.aspx

[6] EFI, 2019. Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California, https://energyfuturesinitiative.org/efi-reports

[7] Thomas A Deetjen *et al* 2021 *Environ. Res. Lett.* 16 084024. US residential heat pumps: the private economic potential and its emissions, health, and grid impacts, https://iopscience.iop.org/article/10.1088/1748-9326/ac10dc#erlac10dcs6.

[8] E3, 2020. Least Cost Carbon Reduction Policies in PJM, https://www.ethree.com/least-cost-carbon-reduction-in-pjm/.

Emission Reduction Measure	Abatement Cost ($/tCO₂e)	
	Low	High
EFI & E3: New England Net Zero (2020)[9]	-	$446
Transportation Electrification	**$135**	**$599**
ICF Comparison of Medium and Heavy-Duty Truck Technologies10	$135	$400
E3: Deep Decarbonization in a High Renewables Future[11]	$359	$599



Across all the selected measures, there are broad ranges of abatement costs. These large ranges reflect the unique circumstances and factors involved with the practical and detailed implementation of each greenhouse gas emission reduction measure. Costs and emission reductions are greatly influenced by technology costs, efficiencies and availability, climate and geography, practical infrastructure constraints, whether local or system-wide, and the interconnected nature of emission reduction trends across the economy.

---

[9] E3 and EFI, 2020. Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future, https://www.ethree.com/new-study-evaluates-deep-decarbonization-pathways-in-new-england/.

[10] ICF updated analysis of Comparison of Medium- and Heavy-Duty Technologies in California. Available online at https://efiling.energy.ca.gov/GetDocument.aspx?tn=236878.

[11] California Energy Commission, 2018. Deep Decarbonization in a High Renewables Future, https://www.energy.ca.gov/publications/2018/deep-decarbonization-high-renewables-future-updated-results-california-pathways.

These abatement cost ranges make direct comparisons across emission reduction measures challenging, particularly if there is a lack of rigorous analysis designed for specific circumstances, such as in the context of Michigan. However, the abatement cost estimates for renewable natural gas developed as part of this study can be used as a starting point to enable effective comparisons across emission reduction options. It is clear based on the abatement costs shown that renewable natural gas is potentially cost-competitive as an emission reduction approach, compared to other options relevant to the end-use of renewable natural gas.

Opportunities and Barriers for RNG Production in Michigan

There are multiple opportunities for renewable natural gas deployment to continue to be an effective GHG emission reduction measure in Michigan. The physical and environmental characteristics of renewable natural gas make for high development potential in Michigan, particularly in the context of ambitious long-term climate objectives. However, barriers and challenges remain, including limited capacity in current end-use markets, environmental impacts and social justice issues for some renewable natural gas feedstocks, and a limited policy structure. These barriers would need to be appropriately and adequately addressed through a robust, transparent and fair policy and regulatory environment that is not just limited to RNG, but for climate action more broadly.

The deployment of, and end-use demand for renewable natural gas is nascent but growing. With the ongoing expansion of the renewable natural gas market, there is increasing attention given to the opportunities and barriers associated with renewable natural gas production, delivery and end-use. In this section, ICF considers the highest-value opportunities and the corresponding challenges to realizing the potential of these opportunities in the renewable natural gas market. While the technical, market, regulatory, and environmental drivers for renewable natural gas are inextricably linked, we have distinguished between the key opportunities and challenges across these broad areas.

The table below summarizes the opportunities and barriers across the dimensions ICF considered in the analysis: technical, market, regulatory and policy, and environmental impacts.

RNG Deployment	Opportunities	Challenges
Technical	▪ RNG fulfills current definitions of a renewable resource in Michigan with carbon neutral characteristics using a combustion accounting framework for greenhouse gas emissions. Greenhouse gas emissions from RNG are lower than conventional natural gas across the board. The introduction of RNG has the potential to reduce greenhouse gas emissions significantly from the natural gas system. ▪ RNG utilizes the same existing infrastructure as conventional natural gas. When conditioned and upgraded to pipeline specifications, RNG can use the same extensive system of pipelines for the transmission and distribution of natural gas. Improved and continuous monitoring of potential harmful constituents from RNG production can decrease the technical risks of contamination in the pipeline.	▪ Feedstock location and accessibility will constrain RNG production potential. The location and availability of RNG feedstocks is mismatched with traditional demand centers for natural gas consumption. ▪ Competition for feedstocks will constrain RNG production potential. There is a diverse array of feedstocks available for RNG production yet accessing some of those feedstocks can be difficult or prohibitive. ▪ Gas quality and gas composition for RNG remains an engineering concern. There is no existing industrywide standard for RNG gas quality and gas composition, and with limited operational data, some concerns remain regarding RNG injection into a pipeline system. ▪ Seasonal variability in Michigan’s natural gas systemwide demand may require the RNG production market to adapt. Like other regions with colder winters, Michigan’s natural gas system sees a significant winter peak, largely driven by space heating demand.
Market	▪ RNG can deliver cost-effective greenhouse gas emission reductions for decarbonization. RNG can play an important role in helping to achieve decarbonization out to 2050. ▪ RNG helps maximize the utilization of evolving waste streams. The anaerobic digestion of biomass, including at landfills and water resource recovery facilities, helps maximize the use of waste. ▪ RNG markets are evolving to reflect utilities and corporations with climate and sustainability goals. There is increasing activity and interest in RNG outside of the transportation sector, and beyond jurisdictions where carbon constraining policies are influential. ▪ RNG helps give suppliers and consumers a viable decarbonization option in an evolving market and policy environment.	▪ Changes in existing programs may negatively impact the economic feasibility of existing Michigan-based RNG projects or limit the near-term growth potential for RNG projects in Michigan. ▪ Markets for RNG beyond transportation fuel are nascent. The long-term growth potential for RNG is dependent on transitioning to end uses other than transportation. ▪ RNG production and processing costs need to be reduced to improve cost-competitiveness. ▪ There is limited availability of qualified and experienced RNG developers to expand RNG production in the near-term future.

RNG Deployment	Opportunities	Challenges
		▪ The value of RNG is dependent on appropriately valuing environmental benefits compared to conventional alternatives. ▪ Interconnection costs for RNG suppliers and developers can be high.
Regulatory	▪ Conditioning and Interconnection Tariffs can help decrease the costs to developers of biogas conditioning and upgrading, and thereby providing more competitive pricing to consumers. ▪ Emergence of legislation and regulations for both mandatory and voluntary programs can help spur investment. ▪ Complementary policies could facilitate RNG feedstock collection (e.g., waste diversion and management), that help improve the accessibility of feedstocks while improving project development economics.	▪ The pathway for policies and incentives promoting RNG in market segments other than transportation is unclear and not uniform. ▪ The industry will face limits as technical and market constraints emerge in the near- to mid-term future, and the pathway for cost recovery may become less clear as incentives from out-of-state programs become less effective at promoting RNG deployment.
Environmental Impacts	▪ Investments in RNG production can yield positive environmental impacts upstream from the gas system and beyond greenhouse gas emissions. These include reducing or avoiding methane emissions from certain biomass feedstocks, helping to achieve waste management targets (e.g., waste diversion and waste utilization), supporting sustainable management practices in the agricultural and forestry sectors, and reducing the environmental impacts of concentrated animal feeding operations. ▪ If new policies are implemented to support RNG deployment in Michigan, they should ensure no back-sliding on other environmental indicators and avoid environmental injustices that have historically impacted at-risk communities.	▪ As with the natural gas industry more broadly, RNG development will face scrutiny as it relates to fugitive methane emissions, which occur along the entire natural gas supply chain—during processing, transmission, and distribution. ▪ There are a variety of environmental impacts of concentrated animal feeding operations, which represent one of the key feedstocks for RNG production in Michigan. At present, there is no clear indication that RNG policies or RNG production will impact industry trends related to concentrated animal feeding operations or contribute to the expansion of concentrated animal feeding operations in Michigan. However, it is important that there are controls put in place to ensure that RNG development would not lead to increased environmental harms or increase the risk of exposure to environmental injustices in at risk communities.

1. Introduction

Long-term environmental and energy policies for the state of Michigan are currently under development to meet aggressive long-term objectives to reduce greenhouse gas (GHG) emissions. Governor Gretchen Whitmer signed Executive Order 2020-182 and Executive Directive 2020-10 to create the MI Healthy Climate Plan. This plan establishes a pathway for Michigan to become carbon-neutral by 2050. To achieve these ambitious objectives, Michigan's policymakers, decision makers and stakeholders will need a solid evidence base for all available abatement options to make informed decisions on the most appropriate path forward. Renewable natural gas (RNG) has the potential to be a key contributor to this path to reach net zero carbon by 2050.

There is a key distinction to be made between the terms RNG and biogas. Typically, biogas refers to a mixture of gases, primarily consisting of methane (CH_4), carbon dioxide (CO_2), and hydrogen sulfide (H_2S) produced from the anaerobic digestion of renewable resources such as landfill waste, agricultural waste, animal manure, food waste, and other biomass. Biogas is captured to help avoid methane emissions, which are particularly harmful in the context of climate change because of methane's high global warming potential. When biogas is captured, it can either be a) flared to ensure the destruction of methane via combustion, emitting the less harmful carbon dioxide or b) used for beneficial energy end uses. Biogas has a methane content in the range of 45-75%. This methane content is adequate for biogas-to-electricity pathways. In most cases, biogas is used as fuel in combustion engines, which convert it to mechanical energy, powering an electric generator to produce electricity. The electric generator produces alternating current electricity, and the technology is well developed and widely available. The other beneficial use of the biogas is to condition it, which entails the removal of various constituents (like H2S, nitrogen, and oxygen), and upgrade it, which yields a high energy product that can be injected into a pipeline. This pathway yields RNG, which is a pipeline-quality gas that is fully interchangeable with conventional natural gas. As a point of reference, Act 87 of Michigan Public Acts of 2021 uses the following definition for RNG:[12]

> *a biogas that has been processed or upgraded to be interchangeable with conventional natural gas and to meet pipeline quality standards or transportation fuel grade requirements.* [13]

Overview of Biogas in Michigan

Biogas already plays a role in Michigan's renewable energy landscape, most notably via the Renewable Portfolio Standard (RPS). Michigan enacted its RPS in 2008, referred to as the Clean, Renewable, and Efficient Energy Act (Public Act 295). The original RPS required the state's investor-owned utilities (IOUs) and other electricity suppliers (e.g., municipally owned electric utilities, MOUs) to generate 10% of their retail electricity sales from renewable energy resources by 2015. This was subsequently increased to 15% by 2021 when Public Act 342 of 2016 was signed in December 2016.[14] The RPS identifies landfill gas, municipal solid waste (MSW), and biomass as eligible technologies, noting that biomass "means any organic matter that is not derived from fossil fuels, that can be converted to usable fuel for the production of energy, and that replenishes over a human, not a geological, time frame."[15] According to the most recent information available from the Public Service Commission (PSC), Michigan electric providers retired nearly 13 million renewable energy certificates (RECs) in 2019, equivalent to roughly 13% of retail sales. Of the 13 million RECs, landfill gas, MSW, and biomass represented 9%, 4%, and 13%, respectively.

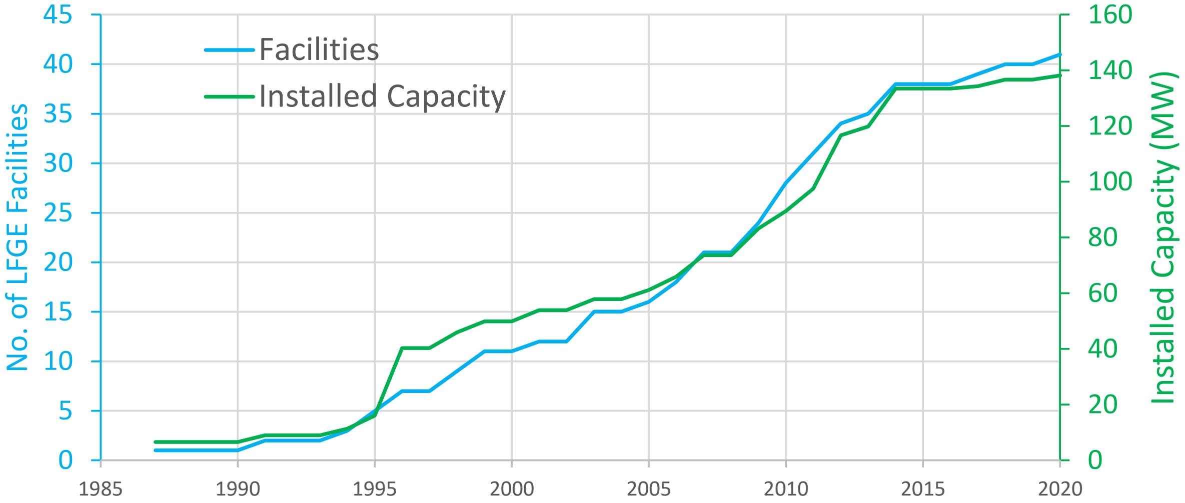
---

[12] Michigan Public Acts of 2021, Act No.87, https://www.legislature.mi.gov/documents/2021-2022/publicact/htm/2021-PA-0087.htm

[13] ICF notes that this is a useful definition but excludes RNG produced from the thermal gasification technology. The thermal gasification of sustainable biomass-based feedstocks delivers lower greenhouse gas emissions than geological natural gas and is interchangeable with natural gas and RNG. As a result, RNG from thermal gasification is included as a resource in this study.

Based on ICF's research, it appears that Michigan's first biogas-to-electricity project was deployed at the Riverview Land Preserve, a landfill in Wayne County, in 1987 as a 6.6 MW system using a gas turbine. This landfill gas to electricity (LFGE) project is common in Michigan; as of 2020, for instance, 41 of these projects have been deployed across the state with a cumulative installed capacity of 138.2 MW (see graph below). Michigan's expansion of LFGE projects continued in earnest, with the most consistent growth between 1995 and 2013.

Figure 1-1. LFGE facilities and installed capacity (MW) deployed in Michigan



Michigan benefits from a variety of investments that have been made to capture biogas for beneficial use. In addition to the 41 landfills that have installed more than 135 MW of electricity generation, 5 landfills in Michigan have so-called direct use applications, which uses biogas in boilers or other direct thermal uses.

---

[14] Michigan's two largest investor-owned utilities, DTE Electric and Consumers Energy, have additional obligations beyond those of other utilities.

[15] Biomass includes agricultural crops and crop wastes, short-rotation energy crops, herbaceous plants, trees and wood (with sustainable management practices in place), paper and pulp products, precommercial wood thinning waste, brush or yard waste, wood wastes and residues from the processing of wood products or paper; animal wastes, wastewater sludge or sewage; aquatic plants, food production and processing waste, and organic by-products from the production of biofuels.

Biogas and RNG: A Market in Transition

Figure 1-1 above illustrates more than just the expansion of the LFGE market; the slowdown in the rate of LFGE project developments in the 2013 timeframe coincided with a significant market shift as it relates to biogas and RNG. LFGE and other biogas-to-electricity projects (e.g., at WRRFs) tend to sell into competitive wholesale electricity markets to generate revenue (also via the sale of renewable energy certificates [RECs] into RPS markets) or for on-site purposes to offset retail power purchases.

The market for biogas started to change in 2014 when the United States (US) Environmental Protection Agency (EPA) determined that RNG qualifies as an eligible renewable fuel for the Renewable Fuel Standard (RFS) program. In 2015, the EPA subsequently determined that RNG sourced from landfills qualifies as a cellulosic biofuel, meeting a GHG emission reduction threshold and cellulosic content requirement, and therefore qualified as a D3 RIN,[16] which ultimately meant that the product delivered more value to eligible RNG consumed in the transportation sector. In other words, the market responded to incentives that favored the upgrading of biogas to make RNG (discussed in more detail below) for pipeline injection, rather than using it to make electricity.

The EPA's determination and associated environmental crediting value led to the rapid expansion of RNG projects for pipeline injection and subsequent RNG use as a transportation fuel in natural gas vehicles (NGVs). As NGVs can be fueled with RNG with no changes to equipment, fueling infrastructure, or vehicle performance, RNG production for use as a transportation fuel has increased nearly six-fold in the last five years. California's Low Carbon Fuel Standard (LCFS) also helped to contribute to expanding the RNG market, with a focus on lifecycle GHG emission reductions, the program provides a premium on the lowest-emitting fuel via a carbon intensity determination, which is a measure of GHG emissions per unit of energy (reported in units of grams of carbon dioxide equivalents per megajoule, gCO_2e/MJ).[17]

This market transition of biogas-to-electricity projects to RNG for transportation is exemplified by the aforementioned Riverview landfill, Michigan's oldest LFGE project. In February 2022, the City of Riverview's City Council voted to approve a modification to the contract with Riverview Energy Systems (RES) that operates the LFGE facility, and it will now produce RNG for pipeline injection and use as a transportation fuel instead of electricity.[18] There are five other operational RNG projects at landfills in Michigan, with a sixth slated to be operational in early 2023.[19] The other market trend is an increased deployment of anaerobic digesters at dairy farms to capture methane from animal manure. For instance, there are four operational dairy digesters in Michigan that produce RNG, and at least another three that have broken ground and will be fully operational towards the end of 2022.

---

[16] Renewable Identification Numbers (RINs) are the currency of the RFS program, and are discussed in more detail in the body of the report.

[17] Based on the accounting framework in place for the LCFS program, RNG derived from the anaerobic digestion of animal manure yields more value than RNG from landfill gas.

[18] Based on information reported online at https://www.thenewsherald.com/2022/02/05/project-that-converts-landfill-gas-into-natural-gas-will-benefit-riverview/ on February 5, 2022.

[19] Based on data from the Landfill Methane Outreach Program at the U.S. EPA (updated March 2022).

As of 2021, about 60-65% of the natural gas used in transportation is now RNG because of these markets. ICF anticipates that the market for RNG in the transportation sector will be saturated in the next 2-4 years. And over that same timeframe, the next transition for RNG will continue: The increased demand for RNG in non-transportation markets. The mix of regulatory and voluntary decarbonization commitments by corporate stakeholders, gas utilities, and other key actors have helped to grow the demand for RNG over the last several years, and this increase in demand to date is modest compared to the ultimate potential; however, there are barriers to expanded deployment that may constrain the RNG market.

Study Objective and Study Overview

The objective of this study is to provide data and the accompanying analysis regarding RNG production potential in Michigan that can help to inform policymakers and decisionmakers. The core components of the study include the following:

- Section 2 RNG Production. ICF provides an overview of RNG production and the production technologies that were included in ICF's analysis.
- Section 3 RNG Feedstock Inventory. ICF developed a bottom-up inventory of the various feedstocks in Michigan that can be used to make RNG, including landfills, water resource recovery facilities (WRRFs), food waste, municipal solid waste (MSW), animal manure, energy crops, agricultural residue, and forestry and forest residue products.
- Section 4 RNG Supply Scenarios. ICF used the feedstock inventory to develop RNG production potential estimates consistent with the characteristics of three scenarios: theoretical, feasible, and achievable. These scenarios reflect a variety of constraints regarding accessibility to feedstocks, the time that it would take to deploy projects, the development of technology that would be required to achieve higher levels of RNG production, and the consideration of likely project economics—with the assumption that the most economic projects will come online first.
- Section 5 RNG Production Cost Assessment. ICF developed an RNG supply-cost curve, based on assumptions for the capital expenditures and operational costs for RNG production from the various feedstock and technology combinations.
- Section 6 GHG Emission Reductions and Cost-Effectiveness. For each RNG production potential scenario quantified, ICF quantified the corresponding GHG emission reductions. ICF used these GHG emission reduction potentials and the production costs to determine the GHG cost-effectiveness of RNG production, in a dollar per ton of CO_2 equivalent metric. ICF also provided a first order comparison to alternatives including blending renewable hydrogen, building electrification, transportation electrification, and renewable electricity generation (inclusive of nuclear electricity generation).
- Section 7 GHG Abatement Cost Comparison. ICF compares the GHG cost-effectiveness of RNG deployment in Michigan to other GHG abatement strategies, including renewable hydrogen blending, building electrification, renewable electricity production, and transportation electrification.
- Section 8 Opportunities and Barriers to RNG Production in Michigan. In this section, ICF reviews the technical, market, and regulatory drivers for RNG, how they are linked, and the key opportunities and challenges across these three broad areas.

Stakeholder Engagement

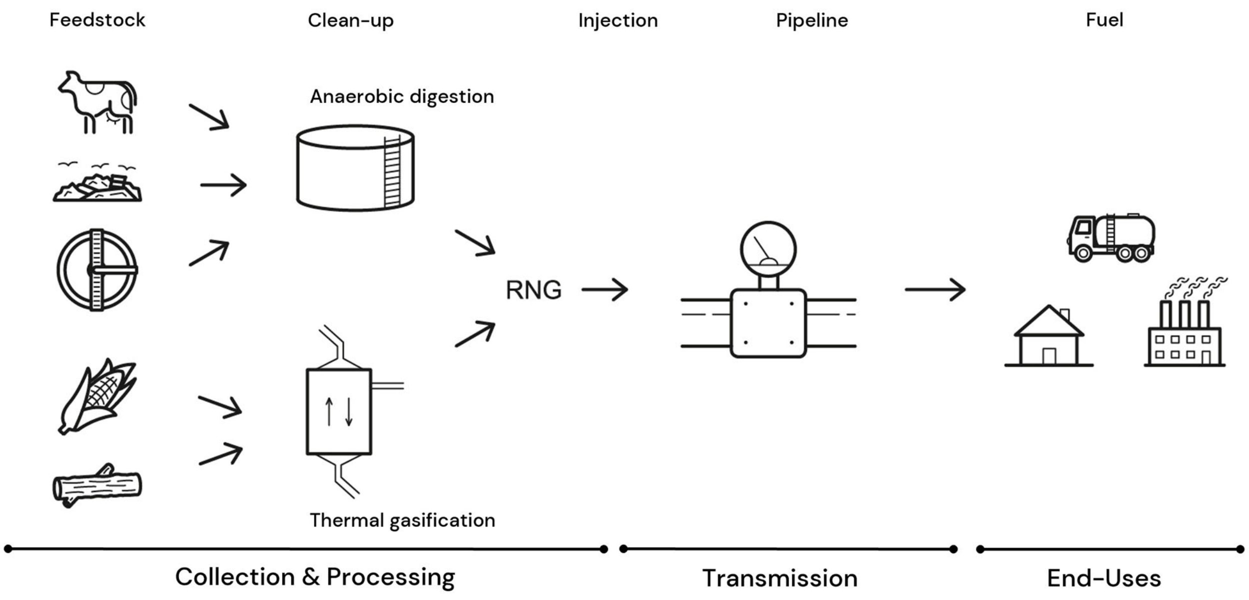
ICF worked in partnership with the Michigan Public Service Commission (MPSC) to conduct stakeholder engagement as part of this study. There were multiple opportunities for stakeholder engagement throughout this study. ICF and MPSC appreciate and value stakeholder efforts and input. All information submitted during the stakeholder engagement process was considered during the completion of this study. ICF and MPSC conducted the following stakeholder engagement in the process of finalizing this study:

- MPSC developed the Renewable Natural Gas Study Workgroup page on the MPSC website and used this site to post and update information relating to the study which includes:
  - Documents and resources
  - Actions to date (including stakeholder comments received)
  - Next steps
  - Information on stakeholder meetings (including agenda, presentations, and a recording of each)
- MPSC created a Renewable Gas Study Workgroup Mailing List that interested stakeholders could sign up for to receive email updates about key dates and information.
- MPSC posted an outline of the proposed study in December 2021 for stakeholder review.
- MPSC hosted and ICF led or participated in three public meetings. In the first public meeting in January 2022, ICF reviewed the scope of work and the key elements of the strategy to complete that scope of work. At the second public meeting in April 2022, ICF reviewed the assumptions and methodology that were used to develop the study assumptions. A background document was provided in advance of the meeting and posted publicly. Stakeholders also presented during the second meeting. In the third and final public meeting in June 2022, ICF reviewed the key findings of the study.
- In March 2022, MPSC issued a request for input from stakeholders concerning existing GHG emission reduction studies, especially those that quantify GHG abatement costs of comparable technologies. Ultimately, a list of resources received was posted online and each of these were considered for incorporation into the report (see Section 7).
- MPSC posted the draft version of this study for review on June 8, which allowed three weeks for review in advance of the June 29 meeting. ICF responded to subsequent data requests issued by stakeholders in July 2022, and MPSC extended the deadline for submission of public comments to August 3, 2022.

2. RNG Production

RNG is produced over the series of steps shown in Figure 2-1 including collection of a feedstock, delivery to a processing facility for biomass-to-gas conversion, gas conditioning, compression, and injection into the pipeline.

Figure 2-1. RNG Production Process via Anaerobic Digestion and Thermal Gasification



In this study ICF considers two production technologies: anaerobic digestion and thermal gasification.

Anaerobic Digestion

The most common way to produce RNG today is via anaerobic digestion (AD), whereby microorganisms break down organic material in an environment without oxygen. The four key processes in anaerobic digestion are hydrolysis, acidogenesis, acetogenesis, and methanogenesis. Hydrolysis is the process whereby longer-chain organic polymers are broken down into shorter-chain molecules like sugars, amino acids, and fatty acids that are available to other bacteria. Acidogenesis is the biological fermentation of the remaining components by bacteria, yielding volatile fatty acids, ammonia, carbon dioxide, hydrogen sulfide, and other byproducts. Acetogenesis of the remaining simple molecules yields acetic acid, carbon dioxide, and hydrogen. Lastly, methanogens use the intermediate products from hydrolysis, acidogenesis, and acetogenesis to produce methane, carbon dioxide, and water, where the majority of the biogas is emitted from anaerobic digestion systems.

The process for RNG production generally takes place in a controlled environment, referred to as a digester or reactor, including landfill gas facilities. When organic waste, biosolids, or livestock manure is introduced to the digester, the material is broken down over time (e.g., days) by microorganisms, and the gaseous products of that process contain a large fraction of methane and carbon dioxide. The biogas requires capture and then subsequent conditioning and upgrade before pipeline injection. The conditioning and upgrading helps to remove any contaminants and other trace constituents, including siloxanes, sulfides and nitrogen, that cannot be injected into common carrier pipelines, and increases the heating value of the gas for injection.

Thermal Gasification

Biomass-like agricultural residues, forestry and forest produce residues, and energy crops have high energy content and are ideal candidates for thermal gasification. The thermal gasification of biomass to produce RNG occurs over a series of steps:

- Feedstock pre-processing in preparation for thermal gasification (not in all cases).
- Gasification, which generates synthetic gas (syngas), consisting of hydrogen and carbon monoxide (CO).
- Filtration and purification, where the syngas is further upgraded by filtration to remove remaining excess dust generated during gasification, and other purification processes to remove potential contaminants like hydrogen sulfide, and carbon dioxide.
- Methanation, where the upgraded syngas is converted to methane and dried prior to pipeline injection.

Biomass gasification technology is at an early stage of commercialization, with the gasification and purification steps presenting challenges. The gasification process typically yields a residual tar, which can foul downstream equipment. Furthermore, the presence of tar effectively precludes the use of a commercialized methanation unit. The high cost of conditioning the syngas in the presence of these tars has limited the potential for thermal gasification of biomass. For instance, in 1998, Tom Reed[20] concluded that after “two decades” of experience in biomass gasification, “‘tars’ can be considered the Achilles heel of biomass gasification.”

Over the last several years, however, a few commercialized technologies have been deployed to increase syngas quantity and prevent the fouling of other equipment by removing the residual tar before methanation. There are a handful of technology providers in this space, including Haldor Topsoe’s tar-reforming catalyst. Frontline Bioenergy takes a slightly different approach and has patented a process producing tar-free syngas (referred to as TarFreeGas™).

More recently, a handful of thermal gasification projects are in the late stages of planning and development in North America. For example, REN is proposing to build a modular thermal gasification facility in British Columbia using wood waste to produce pipeline-quality RNG for the local natural gas utility, FortisBC.[21] Sierra Energy’s thermal gasification and biorefinery facility in Nevada produces RNG and liquid fuels using municipal solid waste as a feedstock.[22] West Biofuels have a number of demonstration and research projects using biomass to produce RNG, as well as commercialized thermal gasification facilities producing other renewable fuels.[23] Further afield there are demonstration and early-commercialization thermal gasification projects across Europe, including Sweden, France and Austria.[24]

---

[20] NREL, Biomass Gasifier “Tars”: Their Nature, Formation, and Conversion, November 1998, NREL/TP-570-25357. Available online at https://www.nrel.gov/docs/fy99osti/25357.pdf.

[21] FortisBC, 2020. Filing of a Biomethane Purchase Agreement between FEI and REN Energy International Corp, https://www.bcuc.com/Documents/Proceedings/2020/DOC_57461_B-1-FEI-REN-Sec-71-BPA-Application-Confidential-Redacted.pdf.

[22] Sierra Energy, 2020. https://sierraenergy.com/projects/fort-hunter-liggett/

[23] West Biofuels, 2020. http://www.westbiofuels.com/projects?filter=research

[24] Thunman, H. et al, 2018. Advanced biofuel production via gasification - lessons learned from 200 years man-years of research activity with Chalmers' research gasifier and the GoBiGas demonstration plant. Energy Science & Engineering, 29.

ICF notes that biomass, particularly agricultural residues, are often added to anaerobic digesters to increase gas production (by improving carbon-to-nitrogen ratios, especially in animal manure digesters). It is conceivable that some of the feedstocks considered here could be used in anaerobic digesters. For simplicity, ICF did not consider any multi-feedstock applications in our assessment; however, it is important to recognize that the RNG production market will continue to include mixed feedstock processing in a manner that is cost-effective.

3. RNG Feedstock Inventory

RNG Feedstocks

RNG can be produced from a variety of renewable feedstocks, as described in the table below.

Table 3-1. RNG Feedstock Types

Feedstock for RNG		Description
Anaerobic Digestion	Animal manure	Manure produced by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses.
	Food waste	Commercial, industrial and institutional food waste, including from food processors, grocery stores, cafeterias, and restaurants.
	Landfill gas (LFG)	The anaerobic digestion of organic waste in landfills produces a mix of gases, including methane (40–60%).
	Water resource recovery facilities (WRRF)	Wastewater consists of waste liquids and solids from household, commercial, and industrial water use; in the processing of wastewater, a sludge is produced, which serves as the feedstock for RNG.
Thermal Gasification	Agricultural residue	The material left in the field, orchard, vineyard, or other agricultural setting after a crop has been harvested. Inclusive of unusable portion of crop, stalks, stems, leaves, branches, and seed pods.
	Energy crops	Inclusive of perennial grasses, trees, and annual crops that can be grown to supply large volumes of uniform and consistent feedstocks for energy production.
	Forestry and forest product residue	Biomass generated from logging, forest and fire management activities, and milling. Inclusive of logging residues, forest thinnings, and mill residues. Also materials from public forestlands, but not specially designated forests (e.g., roadless areas, national parks, wilderness areas).
	Municipal solid waste (MSW)	The biogenic fraction of waste that would be landfilled after diversion of other waste products (e.g., food waste or other organics), including paper and paperboard and yard trimmings.

While this resource assessment applies these biomass feedstock categories as a framework to assess RNG potential, ICF notes that these categories are not necessarily discrete, and that RNG production facilities can utilize multiple feedstock and waste streams. For example, food waste is often added to anaerobic digester systems at WRRFs to augment biomass and overall gas production. In addition, current wastes streams can potentially be diverted from one feedstock category to another, such as MSW or food waste that is currently landfilled being diverted away from landfills and LFG facilities.

To avoid the potential double counting of biomass, LFG potential is derived from current waste-in-place estimates and does not include any projections of waste accumulation or the introduction of waste diversion. This likely underestimates the potential of RNG from LFG, but additional biomass that could potentially be used to produce RNG is captured in other feedstock categories, such as MSW and food waste.

Inventory Methodology

ICF used a mix of existing studies, government data, and industry resources to estimate the current and future supply of the feedstocks. The table below summarizes some of the resources that ICF drew from to complete our resource assessment, broken down by RNG feedstock:

Table 3-2. List of Data Sources for RNG Feedstock Inventory

Feedstock for RNG	Potential Resources for Assessment
Animal manure	▪ U.S. Environmental Protection Agency (EPA) AgStar Project Database ▪ U.S. Department of Agriculture (USDA) Census of Agriculture ▪ Michigan Department of Environment, Great Lakes and Energy Concentrated Animal Feeding Operation Database
Food waste	▪ U.S. Department of Energy (DOE) 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework (KDF)
LFG	▪ U.S. EPA Landfill Methane Outreach Program ▪ Environmental Research & Education Foundation (EREF) ▪ Michigan Department of Environment, Great Lakes and Energy Concentrated Solid Waste Facilities Database
WRRFs	▪ U.S. EPA Clean Watersheds Needs Survey (CWNS) ▪ Water Environment Federation
Agricultural residue	▪ U.S. DOE 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework
Energy crops	▪ U.S. DOE 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework
Forestry and forest product residue	▪ U.S. DOE 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework
MSW	▪ U.S. DOE 2016 Billion Ton Report ▪ Waste Business Journal

This RNG feedstock inventory does not take into account resource availability—in a competitive market, resource availability is a function of factors, including but not limited to demand, feedstock costs, technological development, and the policies in place that might support RNG project development. ICF assessed the RNG resource potential of the different feedstocks that could be realized given the necessary market considerations (without explicitly defining what those are), outlined in Section 3.

Consistent across all feedstocks, ICF estimates RNG potential at the county level across Michigan. Where possible, ICF includes facility-level information for relevant feedstocks, notably landfill gas facilities and WRRFs. While the underlying RNG data is collected for all 83 counties in Michigan, in this report we aggregate and present the data based on Michigan's ten prosperity regions,[25] shown in Figure 3-1 below.

---

[25] https://www.michigan.gov/images/mshda/MI-prosperity-regions-map-LG_616814_7.png

Figure 3-1. Michigan Prosperity Regions

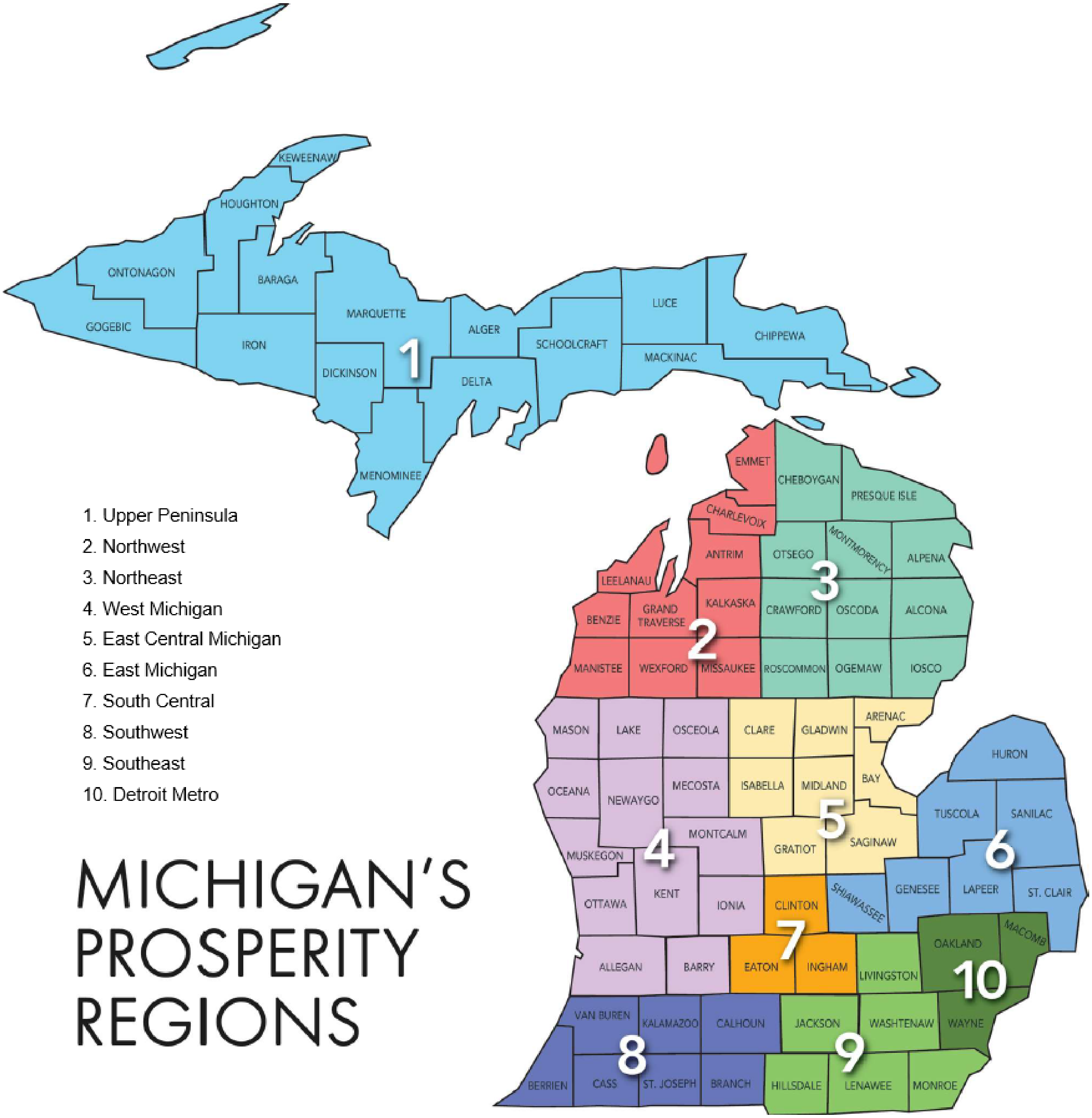
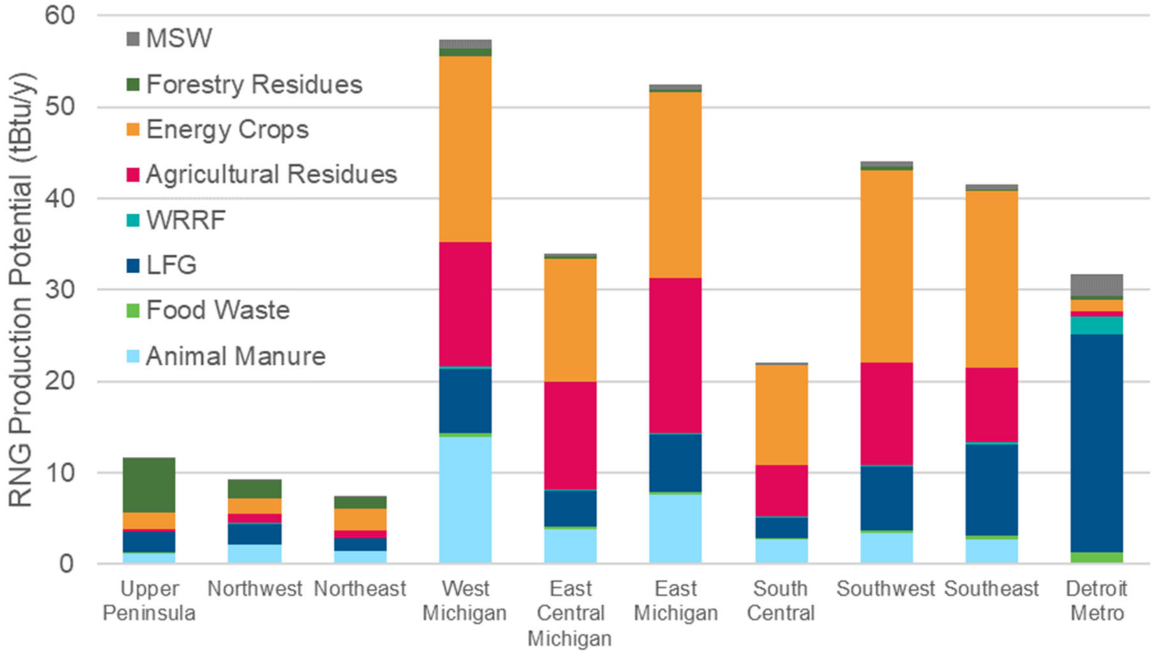

1. Upper Peninsula
2. Northwest
3. Northeast
4. West Michigan
5. East Central Michigan
6. East Michigan
7. South Central
8. Southwest
9. Southeast
10. Detroit Metro
MICHIGAN'S PROSPERITY REGIONS
1
2
3
4
5
6
7
8
9
10
KEWEENAW
HOUGHTON
ONTONAGON
BARAGA
GOGEBIC
IRON
MARQUETTE
DICKINSON
ALGER
DELTA
MENOMINEE
SCHOOLCRAFT
LUCE
MACKINAC
CHIPPEWA
EMMET
CHARLEVOIX
CHEBOYGAN
PRESQUE ISLE
LEELANAU
ANTRIM
OTSEGO
MONTMORENCY
ALPENA
BENZIE
GRAND TRAVERSE
KALKASKA
CRAWFORD
OSCODA
ALCONA
MANISTEE
WEXFORD
MISSAUKEE
ROSCOMMON
OGEMAW
IOSCO
MASON
LAKE
OSCEOLA
CLARE
GLADWIN
ARENAC
HURON
OCEANA
NEWAYGO
MECOSTA
ISABELLA
MIDLAND
BAY
TUSCOLA
SANILAC
MUSKEGON
MONTCALM
GRATIOT
SAGINAW
OTTAWA
KENT
IONIA
CLINTON
SHIAWASSEE
GENESEE
LAPEER
ST. CLAIR
OAKLAND
MACOMB
ALLEGAN
BARRY
EATON
INGHAM
LIVINGSTON
VAN BUREN
KALAMAZOO
CALHOUN
JACKSON
WASHTENAW
WAYNE
BERRIEN
CASS
ST. JOSEPH
BRANCH
HILLSDALE
LENAWEE
MONROE

Figure 3-2 below shows the maximum RNG production potential broken out by region. Regions with large and concentrated land sector-based industries, such as West Michigan and East Michigan, have the greatest RNG production potential, reflecting significant volumes of feedstocks including animal manure, agricultural residue, and energy crops. Regions with large populations, such as Southeast and Detroit Metro, have the highest potential from population-based waste streams, including landfills, wastewater and food waste.

Figure 3-2. Maximum RNG Production Potential by Region (tBtu/y)



RNG: Anaerobic Digestion of Biogenic or Renewable Resources

Animal Manure

Animal manure as an RNG feedstock is produced from the manure generated by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses. The U.S. EPA lists a variety of benefits associated with the anaerobic digestion of animal manure at farms as an alternative to traditional manure management systems, including but not limited to:[26]

- Diversifying farm revenue: the biogas produced from the digesters has the highest potential value. Digesters can also provide revenue streams via "tipping fees" from non-farm organic waste streams that are diverted to the digesters, organic nutrients from the digestion of animal manure, and displacement of animal bedding or peat moss by using digested solids.
- Conservation of agricultural land: digesters can help to improve soil health by converting the nutrients in manure to a more accessible form for plants to use and help protect the local water resources by reducing nutrient run-off and destroying pathogens.

---

[26] More information available online at https://www.epa.gov/agstar/benefits-anaerobic-digestion.

- Promoting energy independence: the RNG produced can reduce on-farm energy needs or provide energy via pipeline injection for use in other applications, thereby displacing conventional natural gas.
- Bolstering farm-community relationships: digesters help to reduce odors from livestock manure, improve growth prospects by minimizing potential negative impacts of farm operations on local communities, and help forge connections between farmers and the local community through environmental and energy stewardship.

The main components of anaerobic digestion of manure include manure collection, the digester, effluent storage (e.g., a tank or lagoon), and gas handling equipment. There are a variety of livestock manure processing systems that are employed at farms today, including plug-flow or mixed plug-flow digesters, complete-mixed digesters, covered lagoons, fixed-film digesters, sequencing-batch reactors, and induced-blanked digesters. Most dairy manure projects today, including those in Michigan, use the plug-flow or mixed plug-flow digesters.

ICF considered animal manure from a variety of animal populations, including beef and dairy cows, broiler chickens, layer chickens, turkeys, and swine. Animal populations were derived from the United States Department of Agriculture's (USDA) National Agricultural Statistics Service. ICF used information provided from the most recent census year (2017) and extracted total animal populations on a county and state level.[27] Based on this information, ICF identified animal populations for Michigan by county.

ICF developed the maximum RNG potential using animal manure production and the energy content of dried manure taken from a California Energy Commission report prepared by the California Biomass Collaborative.[28] These inputs are summarized in Table 3-3 below, with the formula and an example calculation of a 10,000-head dairy farm included for reference:

$$number\ of\ livestock\ \times volatile\ solids\ \times heating\ value\ = RNG\ production\ potential$$

$$10{,}000\ head\ \times 3{,}020\ \frac{kg\ (dry)}{head}\ \times 16{,}111\ \frac{Btu}{kg\ (dry)}\ \times \frac{1}{1.0^6} = 486{,}491\ MMBtu$$

---

[27] USDA, 2017. 2017 Census of Agriculture, https://www.nass.usda.gov/AgCensus/index.php

[28] Williams, R. B., B. M. Jenkins and S. Kaffka (California Biomass Collaborative). 2015. An Assessment of Biomass Resources in California, 2013 – DRAFT. Contractor Report to the California Energy Commission. PIER Contract 500-11-020. Available online here.

Table 3-3. Key Parameters for Animal Manure Resource RNG Potential

Animal Type	Volatile Solids (kg/head/year)	Higher Heating Value (HHV) (Btu/kg, dry basis)
Dairy	3,020	16,111
Beef:		
- Cattle	1,674	16,345
- Other	750	16,345
Swine	149	15,077
Poultry:		
- Layer Chickens	8.3	14,689
- Broiler Chickens	9.1	15,077
- Turkeys	25.0	14,830
Sheep & Goats	242	9,362

The U.S. EPA AgStar database indicates that there are eight operational anaerobic digesters at farms in Michigan, with another four under construction.[29]

The animal manure inventory does not identify specific facilities or locations where RNG will likely be produced. However, concentrated animal feeding operations (CAFOs) provide an indication of where RNG from animal manure could be produced. For example, of the eight operational anaerobic digesters at farms in Michigan, six are also licensed CAFOs.

The existing accumulation of animal manure at CAFOs located near pipeline infrastructure could conceivably increase the productive potential of animal manure as an RNG feedstock. The Michigan Department of Environment, Great Lakes and Energy (EGLE) reports that there are 290 CAFOs in Michigan.[30]

The table below shows the volume of animal feedstock available and maximum RNG potential in Michigan and for each prosperity region. Note that the maximum RNG potential does not take into account the numerous limiting factors that would constrain the volume of RNG that could be produced from animal manure. The significant animal head count figure for the West Michigan region reflects large poultry farms in counties such as Allegan, Ionia and Ottawa, including the operations of Herbuck's Poultry Ranch, a leading producer in the state.

---

[29] U.S. EPA, 2020. AgStar Database, https://www.epa.gov/agstar/livestock-anaerobic-digester-database.

[30] Michigan EGLE, 2021. CAFO Database, https://www.michigan.gov/egle/0,9429,7-135-3313_71618_3682_3713-96774--,00.html.

Table 3-4. Animal Manure Resource RNG Potential

Region	Animal Head Count (millions)	Maximum RNG Potential (tBtu)
Region 1 – Upper Peninsula	0.1	1.2
Region 2 – Northwest	0.1	2.1
Region 3 – Northeast	0.1	1.4
Region 4 – West Michigan	23.1	13.9
Region 5 – East Central Michigan	0.5	3.9
Region 6 – East Michigan	0.4	7.6
Region 7 – South Central	0.1	2.7
Region 8 – Southwest	1.7	3.4
Region 9 – Southeast	0.2	2.8
Region 10 – Detroit Metro	0.0	0.1
Michigan Total	**26.5**	**39.0**

Food Waste

Food waste includes biomass sources from commercial, industrial and institutional facilities, including from food processors and manufacturers, grocery stores, cafeterias, and restaurants. Food waste from residential sources is not reflected in this analysis, but could be an additional resource for food waste biomass with the implementation of effective waste diversion policies.

Food waste is a significant component of MSW—accounting for about 15% of MSW streams. More than 75% of food waste is landfilled. Food waste can be diverted from landfills to a composting or processing facility where it can be treated in an anaerobic digester. ICF limited consideration to the potential for utilizing the food waste that would otherwise be landfilled as a feedstock for RNG production via AD, thereby excluding the 25% of food waste that is recycled or directed to waste-to-energy facilities. In addition, food waste that is potentially diverted from landfills in the future is not included in the landfill gas analysis (outlined in more detail below), thereby avoiding any issues around double counting of biomass from food waste.

As food waste is generated from population centers and typically diverted at waste transfer stations rather than delivered to landfills, it is challenging to identify specific facilities or projects that will generate RNG from food waste. However, food waste can potentially utilize existing or future AD systems at LFG and WRRF facilities.

ICF extracted county-level information from the U.S. DOE's Bioenergy Knowledge Discovery Framework (KDF), which includes information collected as part of U.S. DOE's Billion Ton Report (updated in 2016). The Bioenergy KDF includes food waste at tipping fee price points ranging from $70/ton to $100/ton. ICF assumed a high heating value of 12.04 MMBtu/ton (dry). Note that the values from the Bioenergy KDF are reported in dry tons, so the moisture content of the food waste has already been accounted for in the DOE's resource assessment.

The table below shows the maximum volume of food waste available, and the maximum RNG potential for the ten prosperity regions, and the state as a whole, noting that no limiting factors were applied to the RNG potential.

Table 3-5. Maximum Food Waste Potential in 2040

Region	Maximum Production (dry tons)	Maximum RNG Potential (tBtu)
Region 1 – Upper Peninsula	8,690	0.1
Region 2 – Northwest	6,755	0.1
Region 3 – Northeast	5,205	0.1
Region 4 – West Michigan	38,790	0.5
Region 5 – East Central Michigan	14,505	0.2
Region 6 – East Michigan	21,898	0.3
Region 7 – South Central	11,807	0.1
Region 8 – Southwest	19,678	0.2
Region 9 – Southeast	25,064	0.3
Region 10 – Detroit Metro	97,687	1.2
Michigan Total	**250,079**	**3.0**

Landfill Gas

The Resource Conservation and Recovery Act of 1976 (RCRA, 1976) sets criteria under which landfills can accept municipal solid waste and nonhazardous industrial solid waste. Furthermore, the RCRA prohibits open dumping of waste, and hazardous waste is managed from the time of its creation to the time of its disposal. Landfill gas (LFG) is captured from the anaerobic digestion of biogenic waste in landfills and produces a mix of gases, including methane, with a methane content generally ranging 45%–60%. The landfill itself acts as the digester tank—a closed volume that becomes devoid of oxygen over time, leading to favorable conditions for certain micro-organisms to break down biogenic materials.

The composition of the LFG is dependent on the materials in the landfill, and other factors, but is typically made up of methane, carbon dioxide (CO_2), nitrogen (N_2), hydrogen, carbon monoxide (CO), oxygen (O_2), sulfides (e.g., hydrogen sulfide or H_2S), ammonia, and trace elements like amines, sulfurous compounds, and siloxanes. RNG production from LFG requires advanced treatment and upgrading of the biogas via removal of CO_2, H_2S, siloxanes, N_2, and O_2 to achieve a high-energy (Btu) content gas for pipeline injection. The table below summarizes landfill gas constituents, the typical concentration ranges in LFG, and commonly deployed upgrading technologies in use today.

Table 3-6. Landfill Gas Constituents and Corresponding Upgrading Technologies

LFG Constituent	Typical Concentration Range	Upgrading Technology for Removal
Carbon dioxide, CO_2	40% – 60%	▪ High-selectivity membrane separation ▪ Pressure swing adsorption (PSA) systems ▪ Water scrubbing systems ▪ Amine scrubbing systems
Hydrogen sulfide, H_2S	0 – 1%	▪ Solid chemical scavenging ▪ Liquid chemical scavenging ▪ Solvent adsorption ▪ Chemical oxidation-reduction
Siloxanes	<0.1%	▪ Non-regenerative adsorption ▪ Regenerative adsorption
Nitrogen, N_2 Oxygen, O_2	2% – 5% 0.1% – 1%	▪ PSA systems ▪ Catalytic removal (O_2 only)

To estimate the feedstock potential of LFG, ICF used outputs from the LandGEM model, which is an automated tool with a Microsoft Excel interface developed by the U.S. EPA to estimate the emissions rates for landfill gas and methane based on user inputs including waste-in-place (WIP), facility location and climate conditions, and waste received per year. The estimated LFG output was estimated on a facility-by-facility basis. About 1,150 facilities report methane content; for the facilities for which no data were reported, ICF assumed the median methane content of 49.6%.

To develop the RNG potential from LFG, ICF extracted data from the Landfill Methane Outreach Program (LMOP) administered by the U.S. EPA, which included more than 2,000 landfills, with 60 in Michigan and included in the inventory. The U.S. EPA's LMOP database shows that there are 35 landfills in Michigan which have operational LFG-to-energy projects.[31] ICF cross-checked the U.S. EPA LMOP database with Michigan EGLE Department's solid waste facilities database and confirmed that the list of facilities was consistent across the two datasets.[32]

The U.S. EPA currently estimates that there are 15 candidate landfills in Michigan that could capture LFG for use as energy—the U.S. EPA characterizes candidate landfills as those that are accepting waste or have been closed for five years or less, have at least one million tons of WIP, and do not have operational, under-construction, or planned projects. Candidate landfills can also be designated based on actual interest by the site.

---

[31] Some landfills have multiple landfill-to-gas energy projects, with 41 projects in total across the 35 landfills.

[32] Michigan EGLE Department Solid Waste Facilities, 2021. https://www.michigan.gov/egle/0,9429,7-135-3312_4123-9894--,00.html

Table 3-7. Michigan Landfills by Region[33]

Region	Landfills	Landfill-to-Energy Projects	EPA Candidate Landfills
Region 1 – Upper Peninsula	7	-	6
Region 2 – Northwest	4	1	2
Region 3 – Northeast	3	1	2
Region 4 – West Michigan	8	5	1
Region 5 – East Central Michigan	6	5	-
Region 6 – East Michigan	8	5	2
Region 7 – South Central	2	2	-
Region 8 – Southwest	6	4	1
Region 9 – Southeast	6	4	1
Region 10 – Detroit Metro	10	8	-
Michigan Total	**60**	**35**	**15**

There are 47 large landfills in Michigan that have more than one million tons of WIP, with the largest 30 shown in the table below. Due to the minimal and declining methane production of waste after 25 years in landfills, ICF typically only considers RNG potential from landfills that are either currently open or were closed post-2000.

Of the 47 large landfills, nine do not have landfill gas collection systems in place and are identified by the U.S. EPA as candidate landfills. The remaining 38 landfills all have existing gas collection systems, with 31 having LFG-to-energy projects in place. LFG-to-energy projects typically use unprocessed biogas (the feedstock for RNG) to power reciprocating engines to produce electricity, or fuel cogeneration or boiler systems.

Table 3-8. Large Landfills in Michigan

Landfill	County	LFG Collection Project Type	RNG Potential (MMBtu/year)
Arbor Hills Landfill Inc.	Washtenaw	Electricity (combined cycle)	6,217,557
Woodland Meadows Landfill	Wayne	RNG for pipeline injection	5,380,443
Carleton Farms Landfill	Wayne	Electricity (reciprocating engine)	4,760,141
Pine Tree Acres LF Inc.	Macomb	Electricity (reciprocating engine)	4,343,810
Ottawa County Farms LF	Ottawa	Electricity (reciprocating engine)	2,688,298
Sauk Trail Hills Landfill	Wayne	RNG for pipeline injection	2,341,448
Forest Lawn Landfill	Berrien	Flared (candidate landfill)	2,324,167
Riverview Land Preserve	Wayne	Electricity & RNG	2,260,223

---

[33] Based on data from the LMOP at the U.S. EPA (updated March 2022).

Landfill	County	LFG Collection Project Type	RNG Potential (MMBtu/year)
Vienna Junction Landfill	Monroe	Boiler	2,102,949
Oakland Heights Landfill	Oakland	Boiler	1,773,192
Brent Run Landfill	Genesee	Electricity (reciprocating engine)	1,697,294
C&C Landfill	Calhoun	Electricity (reciprocating engine)	1,584,403
Citizens Disposal Landfill	Genesee	Electricity (cogeneration)	1,520,132
Westside Recycling Facility	St. Joseph	RNG for pipeline injection	1,401,147
Granger Wood Street LF	Clinton	RNG for pipeline injection	1,396,661
Autumn Hills Facility	Ottawa	Electricity (reciprocating engine)	1,392,323
Eagle Valley RDF	Oakland	Electricity (reciprocating engine)	1,329,123
People's Landfill, Inc.	Saginaw	Electricity (reciprocating engine)	1,187,972
Venice Park Facility	Shiawassee	Electricity (reciprocating engine)	1,155,545
City of Midland Sanitary LF	Midland	Electricity (cogeneration)	1,028,101
Smiths Creek Landfill	St. Clair	Electricity (reciprocating engine)	992,838
Kent County South Kent LF	Kent	Electricity (reciprocating engine)	915,719
Central Sanitary LF	Montcalm	Electricity (reciprocating engine)	894,786
Granger Grand River LF	Clinton	Electricity (reciprocating engine)	887,075
Adrian Landfill	Lenawee	Electricity (reciprocating engine)	861,493
Orchard Hill SLF	Berrien	Electricity (reciprocating engine)	741,651
Southeast Berrien County LF	Berrien	Electricity (reciprocating engine)	724,194
Manistee County LF	Manistee	Flared (candidate landfill)	667,793
Waters Landfill	Crawford	Boiler	659,205
Menominee Landfill	Menominee	No collection (candidate landfill)	658,622
Wexford County Landfill	Wexford	Flared (candidate landfill)	566,898
Whitefeather Landfill	Bay	Electricity (reciprocating engine)	553,972
Glen's Sanitary Landfill Inc.	Leelanau	Boiler	550,732
Northern Oaks Facility	Clare	Electricity (reciprocating engine)	548,748
Cedar Ridge Facility	Charlevoix	No collection	504,560
Muskegon County SWF	Muskegon	Boiler	469,621
Tri-City RDF	Sanilac	Flared (candidate landfill)	447,593
Hastings Sanitary Landfill	Barry	Flared (candidate landfill)	435,283
K&W LF	Ontonagon	No collection (candidate landfill)	382,241
Montmorency-Oscoda-Alp. LF	Montmorency	No collection (candidate landfill)	376,232
Huron Landfill	Huron	No collection (candidate landfill)	358,248
McGill Road Landfill	Jackson	Flared (candidate landfill)	346,746
Dafter Sanitary Landfill Inc	Chippewa	No collection (candidate landfill)	330,171

Landfill	County	LFG Collection Project Type	RNG Potential (MMBtu/year)
Elk Run Sanitary Landfill	Presque Isle	No collection (candidate landfill)	317,718
Delta County Landfill	Delta	Flared (candidate landfill)	309,862
Wood Island Waste LF	Alger	No collection (candidate landfill)	309,174
Marquette County SWL	Marquette	No collection (candidate landfill)	272,805

The table below shows overall maximum RNG potential from LFG facilities for Michigan, as well as the potential at landfills that do not have landfill-to-energy projects. ICF notes that the RNG potential from unutilized landfills in Michigan is likely an underestimation, as while the majority of LFG is already utilized in existing LFG-to-energy projects, many of the systems operate at maximum capacity, with excess gas flared. In addition, there is a growing trend for landfill operators to convert existing energy projects to produce RNG, driven by regulatory incentives as well as a higher-value end product.

Table 3-9. RNG Potential from Landfills by Region

Region	Landfills	Unutilized LFG Potential[34] (tBtu/y)	Maximum RNG Potential (tBtu/y)
Region 1 – Upper Peninsula	7	2.3	2.3
Region 2 – Northwest	4	1.7	2.3
Region 3 – Northeast	3	0.7	1.4
Region 4 – West Michigan	8	0.8	7.2
Region 5 – East Central Michigan	6	0.6	4.0
Region 6 – East Michigan	8	1.1	6.4
Region 7 – South Central	2	-	2.3
Region 8 – Southwest	6	2.7	7.1
Region 9 – Southeast	6	0.6	10.3
Region 10 – Detroit Metro	10	2.3	24.6
Michigan Total	**60**	**12.7**	**67.8**

Water Resource Recovery Facilities

Wastewater is created from residences and commercial or industrial facilities, and it consists primarily of waste liquids and solids from household water usage, from commercial water usage, or from industrial processes. Depending on the architecture of the sewer system and local regulation, it may also contain storm water from roofs, streets, or other runoff areas. The contents of the wastewater may include anything which is expelled (legally or not) from a household and enters the drains. If storm water is included in the wastewater sewer flow, it may also contain components collected during runoff: soil, metals, organic compounds, animal waste, oils, and solid debris such as leaves and branches.

---

[34] Unutilized LFG reflects RNG potential from landfills that do not have existing landfill-to-energy projects.

Processing of the influent to a large water resource recovery facility (WRRF) is comprised typically of four stages: pre-treatment, primary, secondary, and tertiary treatments. These stages consist of mechanical, biological, and sometimes chemical processing.

- Pre-treatment removes all the materials that can be easily collected from the raw wastewater that may otherwise damage or clog pumps or piping used in treatment processes.
- In the primary treatment stage, the wastewater flows into large tanks or settling bins, thereby allowing sludge to settle while fats, oils, or greases rise to the surface.
- The secondary treatment stage is designed to degrade the biological content of the wastewater and sludge, and is typically done using water-borne micro-organisms in a managed system.
- The tertiary treatment stage prepares the treated effluent for discharge into another ecosystem, and often uses chemical or physical processes to disinfect the water.

The treated sludge from the WRRF can be landfilled, and during processing it can be treated via anaerobic digestion, thereby producing methane which can be used for beneficial use with the appropriate capture and conditioning systems put in place.

To determine the WRRFs in Michigan, ICF used the Clean Watersheds Needs Survey (CWNS) conducted in 2012 by the U.S. EPA, an assessment of capital investment needed for wastewater collection and treatment facilities to meet the water quality goals of the Clean Water Act, and includes more than 14,500 WRRFs. ICF distinguishes between facilities based on location and facility size as a measure of average flow (in units of million gallons per day, MGD). ICF also reviewed more than 1,200 facilities that are reported to have anaerobic digesters in place, as reported by the Water Environment Federation.

To estimate the amount of RNG produced from wastewater at WRRFs, ICF used data reported by the U.S. EPA,[35] a study of WRRFs in New York State,[36] and previous work published by AGF.[37] ICF used an average energy yield of 7.003 MMBtu/MG of wastewater.

There are 393 WRRFs in Michigan, with a total flow of over 1,360 MGD. Of the 393 WRRFs, 59 have AD systems with a total flow of 166 MGD, or 12% of Michigan's total flow. These existing AD systems collect biogas and generally use it to produce electricity (which is eligible for REC generation) or direct heat applications. The table below summarizes WRRFs by flow and RNG potential for the ten regions and the entire state.

---

[35] US EPA, Opportunities for Combined Heat and Power at Wastewater Treatment Facilities, October 2011. Available online here.

[36] Wightman, J and Woodbury, P., Current and Potential Methane Production for Electricity and Heat from New York State Wastewater Treatment Plants, New York State Water Resources Institute at Cornell University. Available online here.

[37] AGF, The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality, September 2011.

Table 3-10. WRRFs by Existing Flow and Region

Region	Large Facilities (>7 MGD)	Small Facilities (<7 MGD)	Total Flow (MGD)	RNG Potential (tBtu/y)
Region 1 – Upper Peninsula	-	53	27.5	0.07
Region 2 – Northwest	-	23	12.4	0.03
Region 3 – Northeast	-	18	8.5	0.02
Region 4 – West Michigan	4	63	137.8	0.35
Region 5 – East Central Michigan	4	32	71.6	0.18
Region 6 – East Michigan	3	60	92.2	0.24
Region 7 – South Central	2	24	40.0	0.10
Region 8 – Southwest	3	33	65.8	0.17
Region 9 – Southeast	4	48	91.9	0.23
Region 10 – Detroit Metro	5	14	816.7	2.09
Michigan Total	**25**	**368**	**1,364.3**	**3.49**

RNG: Thermal Gasification of Biogenic or Renewable Resources

The biomass feedstocks for RNG production potential via thermal gasification include agricultural residues, energy crops, forestry and forest product residues, and the non-biogenic fraction of MSW. Given that biomass gasification technology is at an early stage of commercialization, RNG production potential for these feedstocks cannot be determined to a facility-specific level, in contrast to other feedstocks such as LFG and WRRFs. However, sources of thermal gasification feedstocks can be approximated at a regional level based on existing land use patterns and population levels. The specific approach for each feedstock is outlined below.

To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems. This factor is based in part on the 2011 AGF Report on RNG, indicating a range of thermal gasification efficiencies in the range of 60% to 70%, depending upon the configuration and process conditions. The report authors also used a conversion efficiency of 65% in their assessment. More recently, GTI estimated the potential for RNG from the thermal gasification of wood waste in California, and assumed a conversion efficiency of 60%.[38]

---

[38] GTI, Low-Carbon Renewable Natural Gas from Wood Wastes, February 2019, available online at https://www.gti.energy/wp-content/uploads/2019/02/Low-Carbon-Renewable-Natural-Gas-RNG-from-Wood-Wastes-Final-Report-Feb2019.pdf

Agricultural Residues

Agricultural residues include the material left in the field, orchard, vineyard, or other agricultural setting after a crop has been harvested. More specifically, this resource is inclusive of the unusable portion of crop, stalks, stems, leaves, branches, and seed pods. Agricultural residues (and sometimes crops) are often added to anaerobic digesters.

ICF extracted information from the U.S. DOE Bioenergy KDF, including the following agricultural residues relevant to Michigan: corn stover, noncitrus residues, tree nut residues, and wheat straw. These estimates are based on modeling undertaken as part of the 2016 Billion Ton Study, and utilizes the Policy Analysis System (POLYSYS), a policy simulation model of the U.S. agricultural sector. The POLYSYS modeling framework simulates how commodity markets balance supply and demand via price adjustments based on known economic relationships, and is intended to reflect how agricultural producers respond to new and different agricultural market opportunities, such as for biomass. Available biomass is constrained to not exceed the tolerable soil loss limit of the USDA Natural Resources Conservation Service and to not allow long-term reduction of soil organic carbon.

POLYSYS simulates exogenous price changes introduced as a farmgate price, which then solves for biomass supplies that may be brought to market in response to these prices. The farmgate price is held constant nationwide in all counties over all years of the simulation to allow farmers to respond by changing crops and practices gradually over time.[39]

Agricultural residue volumes are then derived from these estimates at a county level, and reflect total aboveground biomass produced as byproducts of conventional crops, and then limited by sustainability and economic constraints. Not all agricultural residues are made available, as crop residues often provide important environmental benefits, such as protection from wind and water erosion, maintenance of soil organic carbon, and soil nutrient recycling.

In the simulations no land use change is assumed to occur, except within the agricultural sector (i.e. forested land is not converted to agricultural land for agricultural residue or energy crop purposes).

To summarize, the DOE modeling approach attempts to capture the economic and environmental potential of biomass over time, reflected through the introduction of escalating economic incentives to collect and aggregate various agricultural residues at a granular (farm) level. An increase in economic incentive (measured in dollars per dry ton of biomass) leads to the rising availability of biomass, which in turn could be directed towards RNG production (among other productive end uses). ICF extracted data from the Bioenergy KDF modeling at $10 price point increments, from $30/ton to $100/ton, that showed variation in production potential for agricultural residue biomass from 2025 out to 2040.

The table below lists the energy content on a higher heating value (HHV) basis for the various agricultural residues included in the analysis. The energy content is based on values reported by the California Biomass Collaborative.

---

[39] DOE, 2016. 2016 Billion Ton Report, https://www.energy.gov/eere/bioenergy/2016-billion-ton-report.

Table 3-11. Heating Values for Agricultural Residues

Agricultural Component	MMBtu/ton, dry
Corn stover	15.174
Noncitrus residues	15.476
Tree nut residues	17.194
Wheat straw	15.054

The volume of agricultural residue was extracted at the county level in Michigan. The table below shows an annotated summary of the maximum agricultural residue potential at biomass prices that showed significant variation in 2040, broken down by region.

Table 3-12. Agricultural Residue Production Potential in 2040 by Region (dry tons)

Region	Biomass Price $40	Biomass Price $60	Biomass Price $80	Biomass Price $100
Region 1 – Upper Peninsula	963	25,336	28,254	38,782
Region 2 – Northwest	20,318	97,618	96,374	90,641
Region 3 – Northeast	15,595	97,414	85,264	82,692
Region 4 – West Michigan	166,328	1,184,611	1,352,845	1,369,436
Region 5 – East Central Michigan	199,670	791,660	1,104,265	1,197,744
Region 6 – East Michigan	486,766	1,738,713	1,692,419	1,723,393
Region 7 – South Central	105,621	579,306	595,868	574,760
Region 8 – Southwest	81,133	773,274	1,032,552	1,140,187
Region 9 – Southeast	201,398	801,103	862,653	829,372
Region 10 – Detroit Metro	9,352	55,855	51,748	49,838
Michigan Total	**1,287,144**	**6,144,890**	**6,902,242**	**7,096,845**

Using the heating values outlined above and assuming a 65% efficiency for thermal gasification systems, ICF estimated the RNG production potential from agricultural residue feedstocks at the different biomass prices in 2040, broken down by the different geographies.

Table 3-13. Agricultural Residue RNG Production Potential in 2040 by Region (tBtu/y)

Region	Biomass Price $40	Biomass Price $60	Biomass Price $80	Biomass Price $100
Region 1 – Upper Peninsula	0.01	0.25	0.28	0.38
Region 2 – Northwest	0.20	0.97	0.95	0.90
Region 3 – Northeast	0.15	0.96	0.84	0.81
Region 4 – West Michigan	1.64	11.68	13.35	13.51
Region 5 – East Central Michigan	1.95	7.79	10.87	11.80
Region 6 – East Michigan	4.76	17.11	16.66	16.97
Region 7 – South Central	1.03	5.70	5.87	5.66
Region 8 – Southwest	0.80	7.63	10.19	11.25
Region 9 – Southeast	1.97	7.89	8.49	8.17
Region 10 – Detroit Metro	0.09	0.55	0.51	0.49
Michigan Total	**12.63**	**60.53**	**68.01**	**69.95**

Energy Crops

Energy crops are inclusive of perennial grasses, trees, and some annual crops that can be grown specifically to supply large volumes of uniform, consistent quality feedstocks for energy production. Energy crop estimates are based on the same modeling framework used to derive the agricultural residue estimates, outlined in the previous section. With respect to land use, rather than shifting existing agricultural production (e.g. corn and soy) to energy crop production, DOE's modeling also shows that energy crops are largely grown on idle or available pasture lands, particularly at lower farmgate prices. Similar to agricultural residues, in the simulations no land use change is assumed to occur, except within the agricultural sector (i.e., forested land is not converted to agricultural land for agricultural residue or energy crop purposes).

To summarize, the DOE modeling approach attempts to capture the economic and environmental potential of biomass over time, reflected through the introduction of escalating economic incentives to grow energy crops at a granular (farm) level. An increase in economic incentive (measured in dollars per dry ton of biomass) leads to the rising availability of biomass, which in turn could be directed towards RNG production (among other productive end uses). ICF extracted data from the Bioenergy KDF modeling at $10 price point increments, from $30/ton to $100/ton that showed variation in production potential for energy crops from 2025 out to 2040. The table below lists the energy content on an HHV basis for the various energy crops relevant to Michigan.

Table 3-14. Heating Values for Energy Crops

Energy Crop	Btu/lb, dry	MMBtu/ton, dry
Biomass sorghum	7,240	14.48
Miscanthus	7,900	15.80
Poplar	7,775	15.55
Switchgrass	7,929	15.86
Willow	8,550	17.10

The volume of energy crops was extracted at the county level in Michigan. The table below shows the maximum energy crop production potential broken down by region at biomass prices with significant variation in 2040.

Table 3-15. Energy Crop Production Potential in 2040 by Region (dry tons)

Region	Biomass Price $40	Biomass Price $60	Biomass Price $80	Biomass Price $100
Region 1 – Upper Peninsula	181,279	189,140	189,267	179,214
Region 2 – Northwest	99,342	121,046	132,954	161,510
Region 3 – Northeast	126,570	195,393	203,129	228,662
Region 4 – West Michigan	657,442	1,981,729	1,602,460	1,953,107
Region 5 – East Central Michigan	38,866	894,677	1,503,020	1,280,928
Region 6 – East Michigan	78,961	1,389,039	1,594,457	1,944,888
Region 7 – South Central	77,120	1,016,716	937,507	1,040,974
Region 8 – Southwest	864,296	2,160,014	1,832,502	2,013,347
Region 9 – Southeast	763,023	1,790,265	1,510,526	1,864,410
Region 10 – Detroit Metro	17,148	122,345	111,982	123,596
Michigan Total	**2,904,047**	**9,860,364**	**9,617,804**	**10,790,636**

Using the heating values outlined above and assuming a 65% efficiency for thermal gasification systems, ICF estimated the RNG production potential from energy crop feedstocks at the different biomass prices in 2040, broken down by region.

Table 3-16. Energy Crop RNG Production Potential in 2040 by Region (tBtu/y)

Region	Biomass Price $40	Biomass Price $60	Biomass Price $80	Biomass Price $100
Region 1 – Upper Peninsula	1.92	1.98	1.95	1.84
Region 2 – Northwest	1.06	1.29	1.40	1.68
Region 3 – Northeast	1.37	2.10	2.16	2.38
Region 4 – West Michigan	7.31	21.17	16.91	20.34
Region 5 – East Central Michigan	0.43	9.42	15.95	13.41
Region 6 – East Michigan	0.88	14.76	16.61	20.24
Region 7 – South Central	0.86	10.83	9.93	10.86
Region 8 – Southwest	9.61	22.99	19.13	20.93
Region 9 – Southeast	8.31	19.12	15.84	19.34
Region 10 – Detroit Metro	0.19	1.30	1.18	1.29
Michigan Total	**31.92**	**104.96**	**101.07**	**112.30**

Forestry and Forest Product Residues

Forestry and forest product residues includes biomass generated from logging, forest and fire management activities, and milling. Logging residues (e.g., bark, stems, leaves, branches), forest thinnings (e.g., removal of small trees to reduce fire danger), and mill residues (e.g., slabs, edgings, trimmings, sawdust) are also considered in the analysis. This includes materials from public forestlands (e.g., state, federal), but not specially designated forests (e.g., roadless areas, national parks, wilderness areas) and includes sustainable harvesting criteria as described in the U.S. DOE Billion Ton Update. The updated DOE Billion Ton study was altered to include additional sustainability criteria. Some of the changes included: [40]

- Alterations to the biomass retention levels by slope class (e.g., slopes with between 40% and 80% grade included 40% biomass left on-site, compared to the standard 30%).
- Removal of reserved (e.g., wild and scenic rivers, wilderness areas, USFS special interest areas, national parks) and roadless designated forestlands, forests on steep slopes and in wet land areas (e.g., stream management zones), and sites requiring cable systems.
- The assumptions only include thinnings for over-stocked stands and did not include removals greater than the anticipated forest growth in a state.
- No road building greater than 0.5 miles.

These additional sustainability criteria provide a more realistic assessment of available forestland than other studies.

ICF extracted information from the U.S. DOE Bioenergy KDF, which includes information on forest residues such as thinnings, mill residues, and different residues from woods (e.g., mixedwood, hardwood, and softwood). The Bioenergy KDF estimates are based on ForSEAM, a linear programming model constructed to estimate forestland production over time, including both traditional forest products but also products that meet biomass feedstock demands. The model assumes that projected traditional timber demands will be met and estimates costs, land use, and competition between lands. The forestry and forest product residue estimates also reflect a cost minimization framework that minimizes the total costs (harvest costs and other costs) under a production target goal in addition to land, growth, and other constraints. The cost minimization framework includes the POLYSYS model as well as IMPLAN, an input-output model that estimates impacts to the economy.[41]

---

[40] DOE, 2011. *2011 Billion Ton Update – Assumptions and Implications Involving Forest Resources*, http://web.ornl.gov/sci/ees/cbes/workshops/Stokes_B.pdf

To summarize, the DOE modeling approach attempts to capture the economic and environmental potential of biomass over time, reflected through the introduction of escalating economic incentives to collect and aggregate various forestry residues at a granular level. An increase in economic incentive (measured in dollars per dry ton of biomass) leads to the rising availability of biomass, which in turn could be directed towards RNG production (among other productive end uses). ICF extracted data from the Bioenergy KDF modeling at price points, from $30/ton to $100/ton, although the price points did not show any variation in production potential for forest and forest product residue biomass from 2025 out to 2040.

The table below lists the energy content on an HHV basis for the various forest and forest product residue elements considered in the analysis. To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems.

Table 3-17. Heating Values for Forestry and Forest Product Residues

Forestry and Forest Product	Btu/lb, dry	MMBtu/ton, dry
Other forest residue	8,597	17.19
Primary mill residue		
Secondary mill residue		
Mixedwood, residue	6,500	13.00
Hardwood, lowland, residue		
Softwood, natural, residue		
Softwood, planted, residue		

The table below shows the maximum forestry and forest product residue potential broken down by region.

---

[41] DOE, 2016. 2016 Billion Ton Report, https://www.energy.gov/eere/bioenergy/2016-billion-ton-report

Table 3-18. Forestry and Forest Product Residue Production Potential in 2040 by Region (dry tons)

Region	Biomass (dry tons)
Region 1 – Upper Peninsula	716,074
Region 2 – Northwest	202,669
Region 3 – Northeast	147,139
Region 4 – West Michigan	84,554
Region 5 – East Central Michigan	21,438
Region 6 – East Michigan	40,129
Region 7 – South Central	5,027
Region 8 – Southwest	49,917
Region 9 – Southeast	8,768
Region 10 – Detroit Metro	35,829
Michigan Total	**1,311,544**

Using the heating values outlined above and assuming a 65% efficiency for thermal gasification systems, ICF estimated the RNG production potential from forestry and forest product residue feedstocks in 2040, broken down by region.

Table 3-19. Forestry and Forest Product Residue RNG Potential in 2040 by Region (tBtu/y)

Region	RNG Potential (tBtu/y)
Region 1 – Upper Peninsula	6.11
Region 2 – Northwest	1.73
Region 3 – Northeast	1.31
Region 4 – West Michigan	0.93
Region 5 – East Central Michigan	0.21
Region 6 – East Michigan	0.37
Region 7 – South Central	0.06
Region 8 – Southwest	0.55
Region 9 – Southeast	0.10
Region 10 – Detroit Metro	0.40
Michigan Total	**11.76**

Municipal Solid Waste

MSW represents the trash and various items that household, commercial, and industrial consumers throw away—including materials such as glass, construction and demolition (C&D) debris, food waste, paper and paperboard, plastics, rubber and leather, textiles, wood, and yard trimmings. About 25% of MSW is currently recycled, 9% is composted, and 13% is combusted for energy recovery, with the roughly 50% balance landfilled.

ICF limited consideration to biogenic MSW types not covered in other feedstock categories – paper and paperboard, and yard trimmings. We further limited MSW to only the potential for utilizing MSW that would otherwise be landfilled as a feedstock for thermal gasification; this excludes MSW that is recycled or directed to waste-to-energy facilities. To be clear, ICF assumes that this MSW would not be landfilled so as to avoid any double counting of RNG production potential associated with the capture of landfill gas.

ICF extracted information from the U.S. DOE’s Bioenergy KDF, which includes information collected as part of U.S. DOE’s Billion Ton Report (updated in 2016). The Bioenergy KDF includes the following waste residues: construction and demolition (C&D) debris, paper and paperboard, plastics, rubber and leather, textiles, wood, yard trimmings, and other. ICF extracted data from the Bioenergy KDF at price points between $30/ton and $60/ton.

The table below lists the energy content on an HHV basis for the various components of MSW relevant to Michigan. To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems.

Table 3-20. Heating Values for MSW Components

MSW Component	Btu/lb, dry	MMBtu/ton, dry
Paper and paperboard	7,642	15.28
Yard trimmings	6,448	12.90

The table below shows the maximum MSW potential broken down by region at prices of $30/ton and $60/ton.

Table 3-21. MSW Production Potential in 2040 by Geography and Price (dry tons)

Region	Biomass Price $30	Biomass Price $60
Region 1 – Upper Peninsula	17,618	22,067
Region 2 – Northwest	13,698	17,157
Region 3 – Northeast	10,554	13,218
Region 4 – West Michigan	78,653	98,507
Region 5 – East Central Michigan	29,414	36,839
Region 6 – East Michigan	44,404	55,612
Region 7 – South Central	23,940	29,983
Region 8 – Southwest	39,900	49,972
Region 9 – Southeast	50,822	63,651
Region 10 – Detroit Metro	198,073	248,074
Michigan Total	**507,076**	**635,080**

Using the heating values outlined above and assuming a 65% efficiency for thermal gasification systems, ICF estimated the RNG production potential from MSW at prices of $30/ton and $60/ton, broken down by region.

Table 3-22. RNG Production Potential from MSW in 2040 by Region and Price (tBtu/y)

Region	Biomass Price $30	Biomass Price $60
Region 1 – Upper Peninsula	0.17	0.21
Region 2 – Northwest	0.14	0.17
Region 3 – Northeast	0.10	0.13
Region 4 – West Michigan	0.78	0.95
Region 5 – East Central Michigan	0.29	0.35
Region 6 – East Michigan	0.44	0.53
Region 7 – South Central	0.24	0.29
Region 8 – Southwest	0.40	0.48
Region 9 – Southeast	0.50	0.61
Region 10 – Detroit Metro	1.97	2.39
Michigan Total	**5.04**	**6.11**

Feedstock Summary

The following table summarizes the maximum RNG potential for each feedstock and production technology in Michigan, reported in trillion British thermal units (tBtu) per year (tBtu/y). The RNG potential includes different variables for each feedstock, but ultimately reflects the most aggressive options available, such as the highest biomass price and the utilization of all feedstocks at all facilities, including existing RNG production in the state of Michigan.

ICF emphasizes that the estimates included in the table below are based on the theoretical maximum RNG production potential from all feedstocks, and does not apply any economic or technical constraints on feedstock availability. An assessment of resource availability is addressed in Section 4.

Table 3-23. Maximum RNG Production Potential by Feedstock (tBtu/y)

RNG Feedstock	Michigan
Animal Manure	39.0
Food Waste	3.0
Landfill Gas[42]	67.8
Water Resource Recovery Facilities	3.5

---

[42] Landfill gas estimate includes RNG production potential from landfills with existing landfill-to-energy projects, such as biogas collected and used for heat or electricity.

RNG Feedstock	Michigan
Anaerobic Digestion Sub-Total	*113.3*
Agricultural Residue	69.9
Energy Crops	112.3
Forestry & Forest Product Residue	11.8
Municipal Solid Waste	6.1
Thermal Gasification Sub-Total	*200.1*
Total	**313.4**

4. RNG Supply Scenarios

ICF developed economic supply curves for two separate scenarios for each feedstock and region included in the RNG inventory in Section 3. The RNG potential included in the supply curves are based on an assessment of resource availability. In a competitive market, that resource availability is a function of multiple factors, including but not limited to demand, feedstock costs, technological development, and the policies in place that might support RNG project development. ICF assessed the RNG resource potential of the different feedstocks that could be realized, given the necessary market considerations (without explicitly defining what those are).

For the RNG market more broadly, ICF assumed that the national market would grow at a compound annual growth rate slightly higher than we have seen over the last five years—a rate of about 35%.[43] ICF applied a logistic function to model the growth potential of the RNG production, whereby the initial stage of growth is approximated as an exponential, and thereafter growth slows to a linear rate and then approaches a plateau (or limited to no growth) at maturity.

In addition to the RNG inventory, ICF developed two scenarios for each feedstock, with varying assumptions that influence the level of feedstock utilization relative to the RNG inventory.

- **Achievable** represents a low level of feedstock utilization, with utilization levels depending on feedstock, with a range from 20% to 50% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rate of feedstocks for thermal gasification in this scenario is 30%, at lower biomass prices. Overall, the Achievable scenario captures 18% of the RNG feedstock resource in Michigan, based on the inventory developed in Section 3.
- **Feasible** represents balanced assumptions regarding feedstock utilization, with a range from 60% to 85% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rates of feedstocks for thermal gasification in this scenario ranges from 40% to 50% at moderate biomass prices. Overall, the Feasible scenario captures 47% of the RNG feedstock resource available in Michigan.

In the following sub-sections, ICF outlines the potential for RNG for pipeline injection, broken down by the feedstocks presented previously and considering the potential for RNG growth over time, with 2050 being the final year in the analysis. ICF presents the Achievable and Feasible RNG production scenarios, varying both the assumed utilization of existing resources as well as the rate of project development required to deploy RNG at the volumes presented. Consistent with Section 3, we present the RNG potential scenarios for Michigan as a whole, as well as the ten regions.

---

[43] ICF estimates that nationally there was about 17 tBtu of RNG produced for pipeline injection in 2016 and that there was about 70 tBtu of RNG produced for pipeline injection at the end of 2021—this yields a compound annual growth rate in excess of 30%.

Summary of RNG Potential

The following subsections summarize the RNG potential for each feedstock and production technology by scenario and geography of interest.

Table 4-1 below includes estimates for Michigan for the Achievable and Feasible scenarios and shows the development potential of each feedstock in 2050, reported in units of tBtu per year. For reference, the table also shows the RNG inventory from Section 3.

Table 4-1. Estimated Annual RNG Production in Michigan by 2050 (tBtu/y)

RNG Feedstock		Scenario		
		Achievable	Feasible	Inventory
Anaerobic Digestion	Animal Manure	4.6	9.3	39.0
	Food Waste	1.2	1.8	3.0
	LFG	31.5	53.5	67.8
	WRRFs	1.5	2.3	3.5
Thermal Gasification	Agricultural Residue	3.8	30.3	69.9
	Energy Crops	9.6	42.0	112.3
	Forestry and Forest Product Residue	3.5	5.9	11.8
	Municipal Solid Waste	1.5	3.1	6.1
Total		**57.2**	**148.0**	**313.4**
Percentage of Total Available Feedstock[44]		**18%**	**47%**	**100%**

Table 4-2. Estimated Annual RNG Production by Region in 2050 (tBtu/y)

Region	Scenario		
	Achievable	Feasible	Inventory
Region 1 – Upper Peninsula	3.6	6.1	11.7
Region 2 – Northwest	2.5	4.6	9.4
Region 3 – Northeast	1.8	3.6	7.5
Region 4 – West Michigan	8.6	24.9	57.6
Region 5 – East Central Michigan	3.1	11.9	34.0
Region 6 – East Michigan	6.1	22.2	52.6
Region 7 – South Central	2.2	10.1	22.1
Region 8 – Southwest	7.3	20.2	44.2
Region 9 – Southeast	8.6	21.0	41.8

---

[44] Total feedstock reflects the maximum volume of RNG feedstocks available in Michigan, including all facilities and all biomass, and no restrictions are applied.

Region	Scenario		
	Achievable	Feasible	Inventory
Region 10 – Detroit Metro	13.4	23.3	32.6
Michigan	**57.2**	**148.0**	**313.4**

The RNG resources in Michigan are diverse, including significant potential from landfills, MSW, animal manure, and energy crops, among other feedstocks. The variety in RNG feedstocks is driven by the diverse nature of Michigan, including predominantly rural areas as well as significant population centers that provide a source of biomass-based wastes.

For the sake of reference, Michigan consumed an average of 673 tBtu of natural gas in residential, commercial, and industrial, and vehicle sectors from 2016 to 2020, with a minimum of 642 tBtu in 2020 and a maximum of 713 tBtu in 2019.[45] In other words, ICF's estimates for RNG deployment in Michigan for the Achievable and Feasible scenarios amount to 8.5% and 22.0% of the average annual natural gas consumption in relevant sectors for the last five years for which there are data available.

Summary of RNG Potential by Scenario

Figure 4-1 through Figure 4-4 below show the total RNG potential for each feedstock by scenario in Michigan from 2025 out to 2050, as well as RNG potential by region in 2050.

In the Achievable scenario (Figure 4-1), RNG from anaerobic digestion feedstocks dominate overall potential, with landfill gas and animal manure making up a large proportion out to 2050. Commercial deployment of the thermal gasification production technology after 2030 sees the increased deployment of feedstocks that utilize that technology, with energy crops and to a lesser degree agricultural residue and forestry residue contributing larger shares of overall potential.

Consistent with the statewide timeseries, regions in Michigan with high feedstock potential from landfills and animal manure are the main sources of RNG production potential in the Achievable scenario (Figure 4-2). For example, the Detroit Metro has significant potential from landfills, while West Michigan has significant potential from animal manure.

Similar to the Achievable scenario, the Feasible scenario shows an early penetration of RNG from anaerobic digestion feedstocks, with an increased penetration of RNG from thermal gasification feedstocks taking place post-2030 (Figure 4-3). With the higher deployment of energy crops and agricultural residues in the Feasible scenarios, regions with large agricultural-based industries contribute a higher share to statewide RNG potential, such as West Michigan, East Michigan, Southeast and Southwest (Figure 4-4).

---

[45] Based on ICF analysis of data reported by the EIA regarding *Natural Gas Consumption by End Use*, available online at https://www.eia.gov/dnav/ng/NG_CONS_SUM_DCU_SMI_A.htm. ICF excluded natural gas used in electric power generation in our consideration here because RNG is unlikely to displace natural gas used in electricity production given its higher cost.

Achievable Scenario

Figure 4-1. Achievable Scenario Annual RNG Production in Michigan, 2025-2050 (tBtu/y)

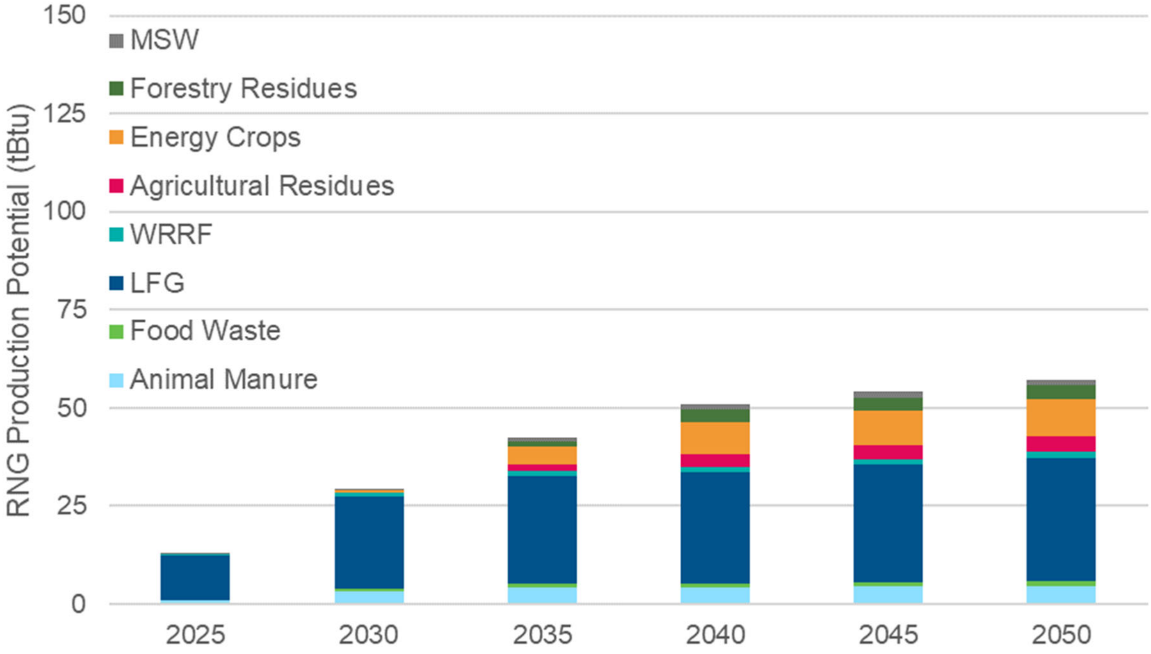
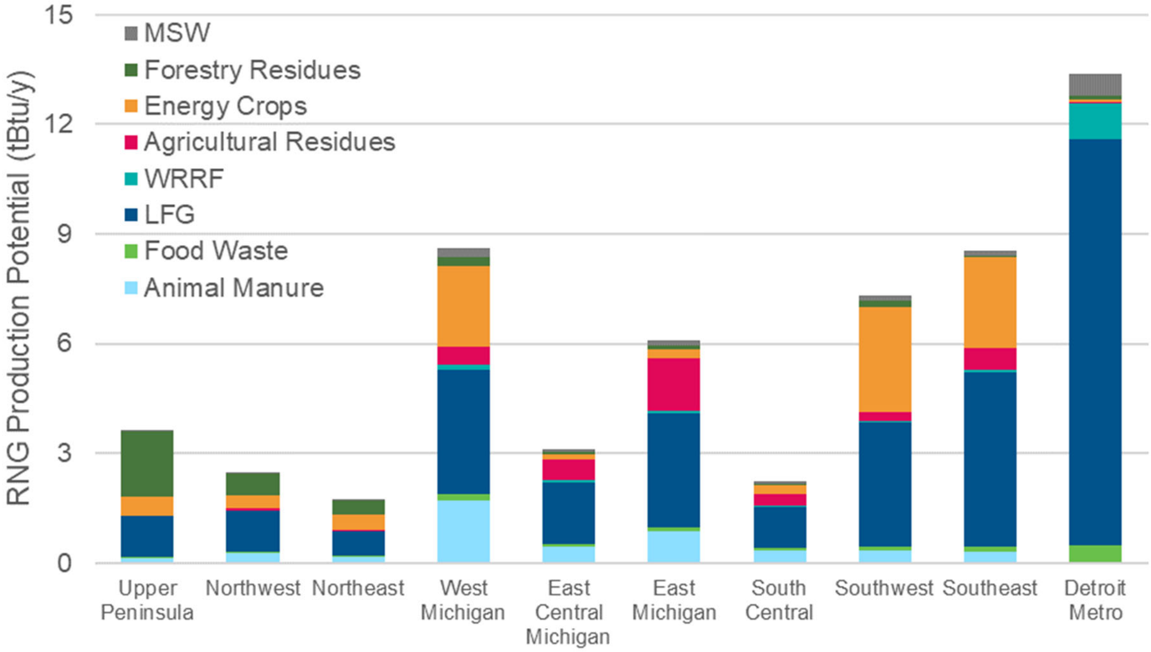


Figure 4-2. Achievable Scenario RNG Production by Region in 2050 (tBtu/y)



Feasible Scenario

Figure 4-3. Feasible Scenario Annual RNG Production in Michigan, 2025-2050 (tBtu/y)

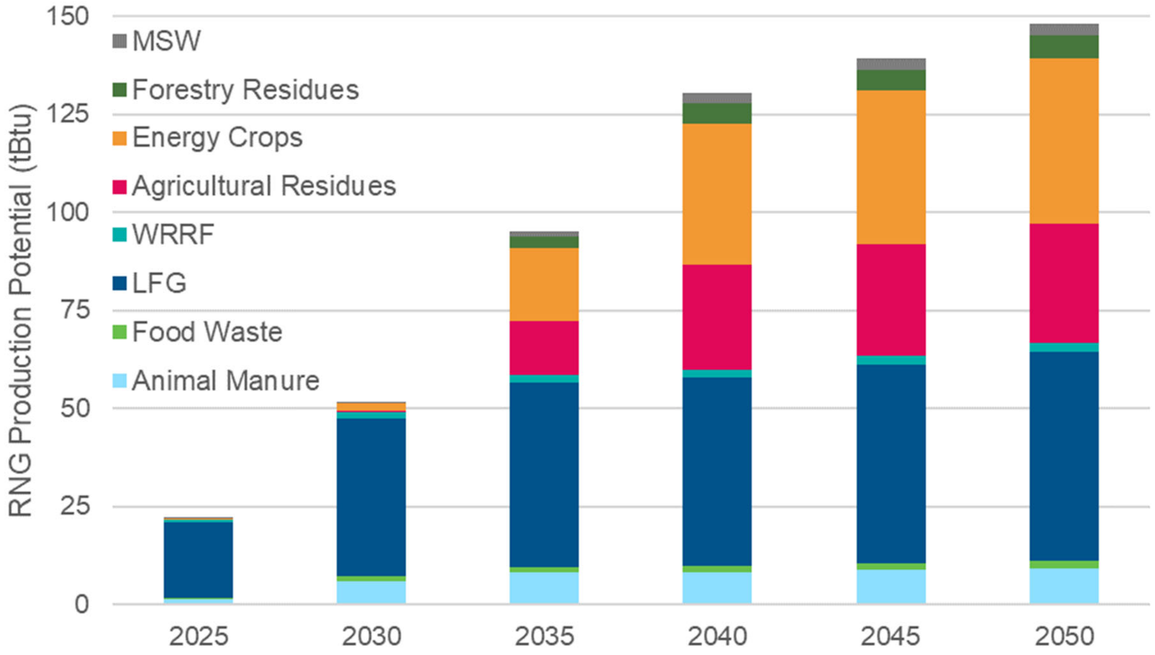
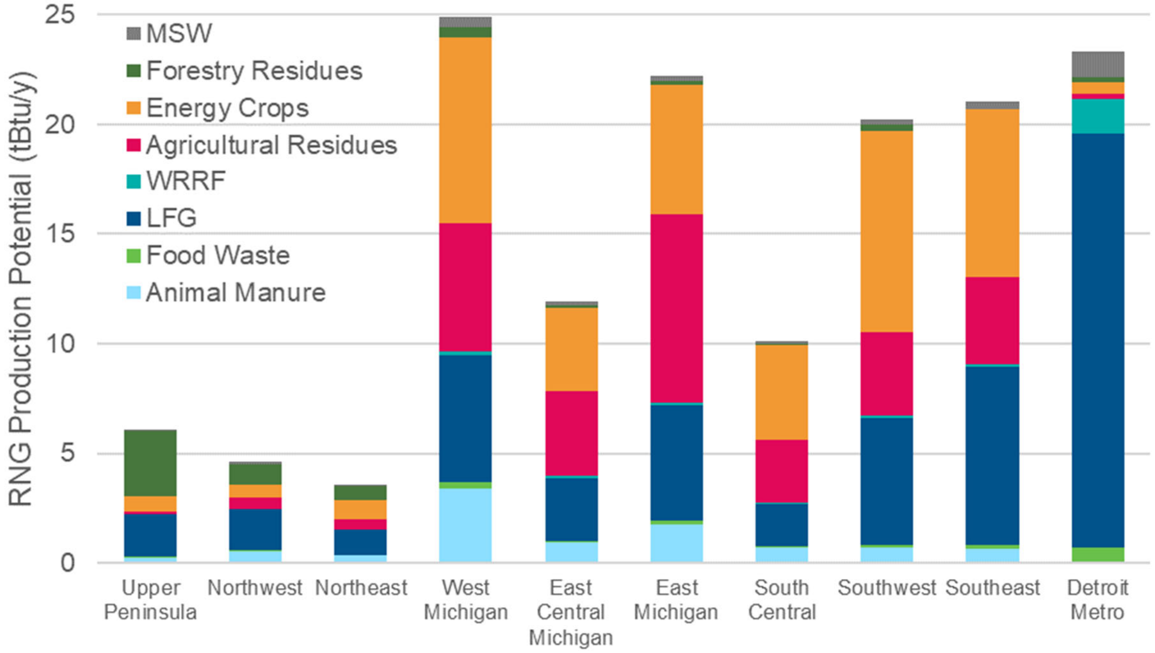


Figure 4-4. Feasible Scenario RNG Production by Region in 2050 (tBtu/y)



RNG: Anaerobic Digestion of Biogenic or Renewable Resources

Animal Manure

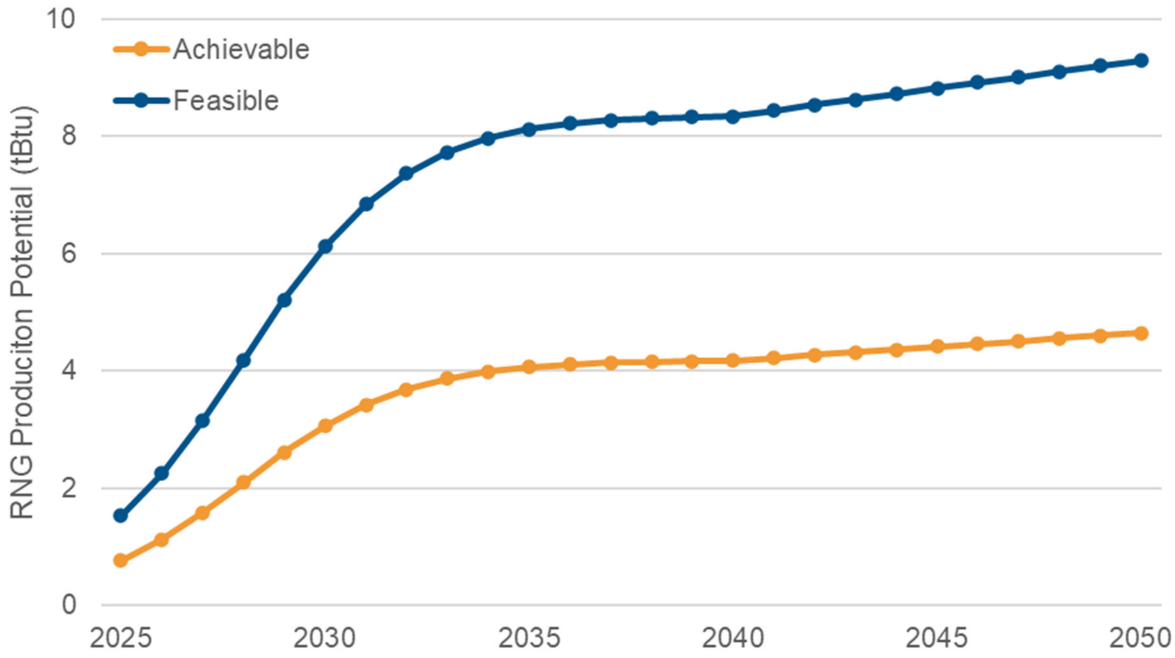
Prior to the application of economic and market constraints for animal manure as an RNG feedstock, ICF applied technical availability factors to each manure type to reflect that not all animal manure can be collected, due to practical considerations such as small farming operations and the inability to collect manure from grazing animals. After applying these technical availability factors for each animal manure type, the total available animal manure potential is reduced by over half.

ICF developed the following assumptions for resource potentials for RNG production from the anaerobic digestion of animal manure in the two scenarios.

- In the Achievable scenario, ICF assumed that RNG could be produced from 30% of the animal manure, after accounting for the technical availability factor.
- In the Feasible scenario, ICF assumed that RNG could be produced from 60% of the animal manure, after accounting for the technical availability factor.

The figure below shows the Achievable and Feasible resource potential from animal manure between 2025 and 2050 in Michigan.

Figure 4-5. Annual RNG Production Potential from Animal Manure in Michigan (tBtu/y)



Food Waste

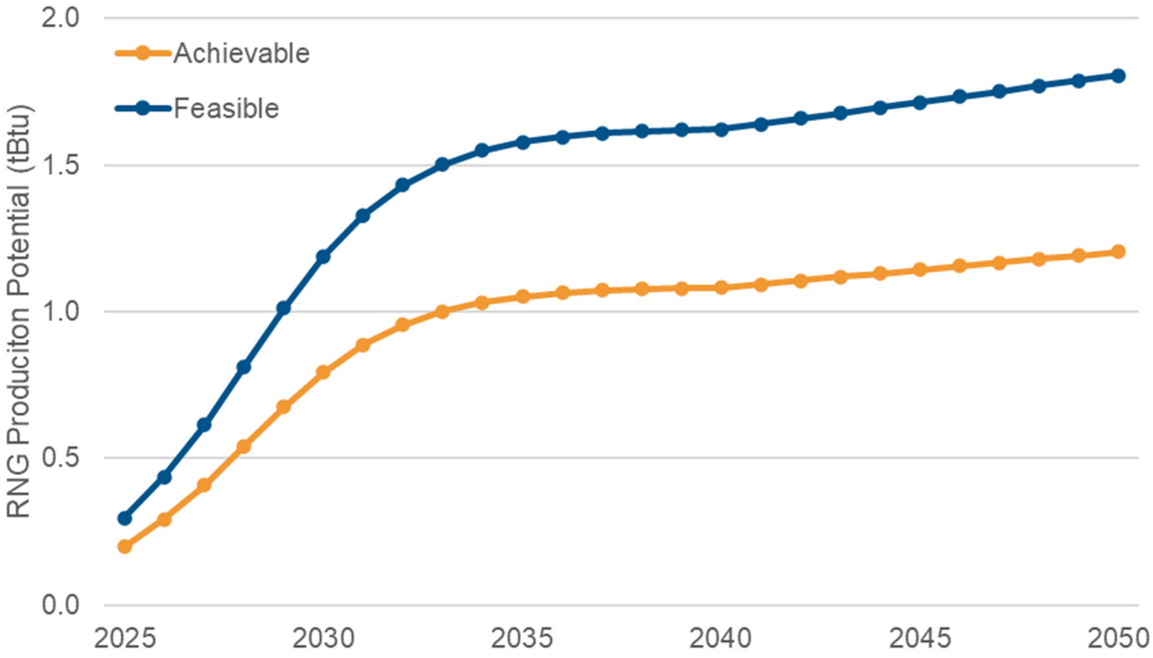
ICF developed the following assumptions for the RNG production potential from food waste in the two scenarios:

- In the Achievable scenario, ICF assumed that 40% of available food waste would be diverted to AD systems.

- In the Feasible scenario, ICF assumed that 60% of available food waste would be diverted to AD systems.

The figure below shows the Achievable and Feasible resource potential scenarios from the anaerobic digestion of food waste between 2025 and 2050 in Michigan.

Figure 4-6. Annual RNG Production Potential from Food Waste in Michigan (tBtu/y)



Landfill Gas

To develop the RNG potential from LFG, ICF extracted data from the Landfill Methane Outreach Program (LMOP) administered by the U.S. EPA, which included more than 2,000 landfills, with 60 in Michigan and included in the inventory. Due to the minimal and declining methane production of waste after 25 years in landfills, in building the scenarios ICF considered only landfills that are either open or were closed post-2000, and landfills with waste-in-place greater than one million tons. In contrast to the overall landfill inventory outlined in Section 3, and summarized in Table 3-7 and Table 3-9, these constraints reduce the number of landfills included in our scenario analysis to 47 in Michigan, summarized by category in Table 4-3 below.

Table 4-3. Landfills included in Scenario Analysis by Region[46]

Region	EPA Candidate Landfills	Landfill-to-Energy Projects	Total Landfills
Region 1 – Upper Peninsula	6	-	6
Region 2 – Northwest	2	1	3
Region 3 – Northeast	2	1	3
Region 4 – West Michigan	1	5	6
Region 5 – East Central Michigan	-	4	4
Region 6 – East Michigan	2	4	7
Region 7 – South Central	-	2	2
Region 8 – Southwest	1	4	5
Region 9 – Southeast	1	3	4
Region 10 – Detroit Metro	-	7	7
Michigan	**15**	**31**	**47**

The U.S. EPA's LMOP database shows that there are at least 31 operational LFG-to-energy projects in Michigan. 20 of the projects capture LFG and combust it in reciprocating engines to make electricity, five landfills have direct use for the energy (e.g., thermal use on-site), and six produce RNG, mostly for use in natural gas vehicles.

The U.S. EPA currently estimates that there are 15 candidate landfills in Michigan that could capture LFG for use as energy, shown in the table below. The U.S. EPA characterizes candidate landfills as those that are accepting waste or have been closed for five years or less, have at least one million tons of WIP, and do not have operational, under-construction, or planned projects. Candidate landfills can also be designated based on actual interest by the site.

---

[46] Based on data from the LMOP at the U.S. EPA (updated March 2022).

Table 4-4. EPA Candidate Landfills in Michigan

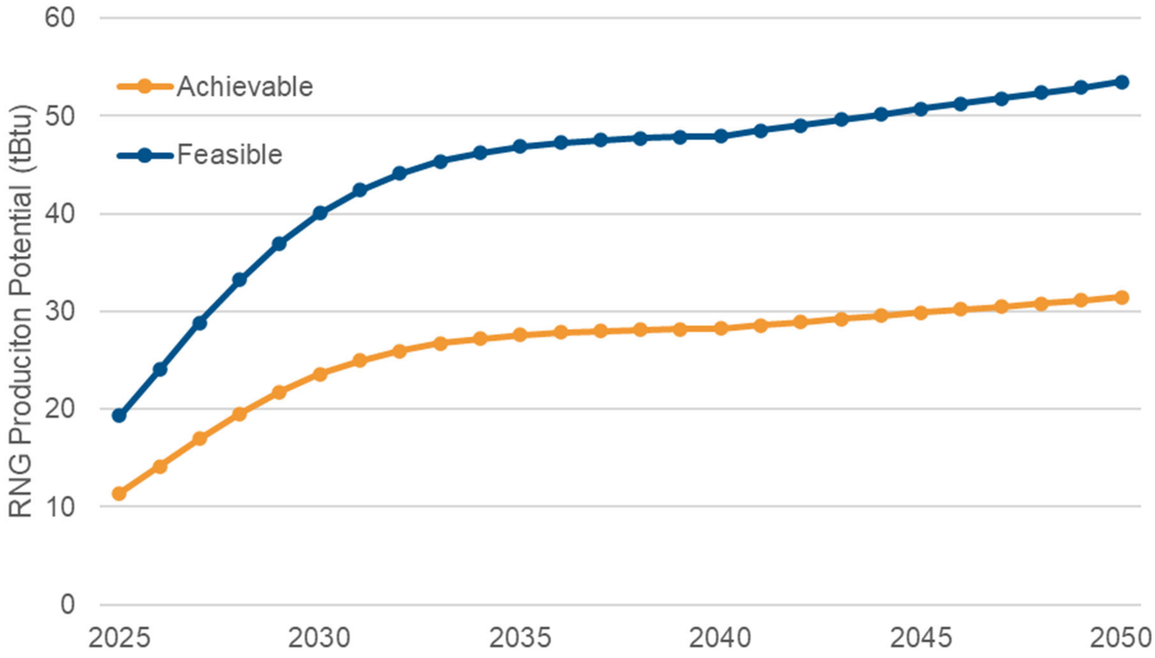
Landfill	County	LFG Collection	RNG Potential (MMBtu/year)
Forest Lawn Landfill	Berrien	Yes	2,324,167
Manistee County LF	Manistee	Yes	667,793
Menominee Landfill	Menominee	No	658,622
Wexford County Landfill	Wexford	Yes	566,898
Tri-City RDF	Sanilac	Yes	447,593
Hastings Sanitary Landfill	Barry	Yes	435,283
K&W LF	Ontonagon	No	382,241
Montmorency-Oscoda-Alpena LF	Montmorency	No	376,232
Huron Landfill	Huron	No	358,248
McGill Road Landfill	Jackson	Yes	346,746
Dafter Sanitary Landfill Inc	Chippewa	No	330,171
Elk Run Sanitary Landfill	Presque Isle	No	317,718
Delta County Landfill	Delta	Yes	309,862
Wood Island Waste Management	Alger	No	309,174
Marquette County SWL	Marquette	No	272,805

ICF developed assumptions for the resource potentials for RNG production at landfills in the two scenarios, considering the potential at LFG facilities with collection systems in place, LFG facilities that do not have collection systems in place, and candidate landfills identified by the U.S. EPA.

- In the Achievable scenario, ICF assumed that 50% of eligible LFG facilities would produce RNG.
- In the Feasible scenario, ICF assumed that 85% of eligible LFG facilities would produce RNG.

The figure below shows the Achievable and Feasible RNG resource potential from LFG between 2025 and 2050 in Michigan.

Figure 4-7. Annual RNG Production Potential from Landfill Gas in Michigan (tBtu/y)



Water Resource Recovery Facilities

There are 393 WRRFs in Michigan, with a total flow of over 1,360 MGD. Of the 393 WRRFs in Michigan, 59 have anaerobic digestion systems with a total flow of 167 MGD, or 12% of the Michigan's total flow. The table below summarizes WRRFs by flow and RNG potential by region in Michigan.

Table 4-5. WRRFs by Existing Flow and Geography

Region	Large Facilities (>7 MGD)	Small Facilities (<7 MGD)	Total Flow (MGD)	RNG Potential (tBtu/y)
Region 1 – Upper Peninsula	-	53	27.5	0.07
Region 2 – Northwest	-	23	12.4	0.03
Region 3 – Northeast	-	18	8.5	0.02
Region 4 – West Michigan	4	63	137.8	0.35
Region 5 – East Central Michigan	4	32	71.6	0.18
Region 6 – East Michigan	3	60	92.2	0.24
Region 7 – South Central	2	24	40.0	0.10
Region 8 – Southwest	3	33	65.8	0.17
Region 9 – Southeast	4	48	91.9	0.23
Region 10 – Detroit Metro	5	14	816.7	2.09
Michigan Total	**25**	**368**	**1,364.3**	**3.49**

The figures and table above illustrate the unique opportunities for Michigan associated with deploying AD systems at WRRFs: roughly 15% of WRRFs have an AD system, covering 12% of flow and RNG potential. Typically, facilities that have AD systems in place are capturing biogas for on-site electricity production rather than for pipeline injection. With an effective policy and regulatory framework, these facilities present a near-term opportunity for RNG to be directed into the pipeline, rather than for on-site electricity production.

The table below shows the 25 largest WRRFs in Michigan, with a flow greater than 7 MGD. In addition to WRRFs that have existing AD systems in place, the WRRF list shows there remains significant potential for WRRFs without AD systems.

Table 4-6. Large WRRFs in Michigan

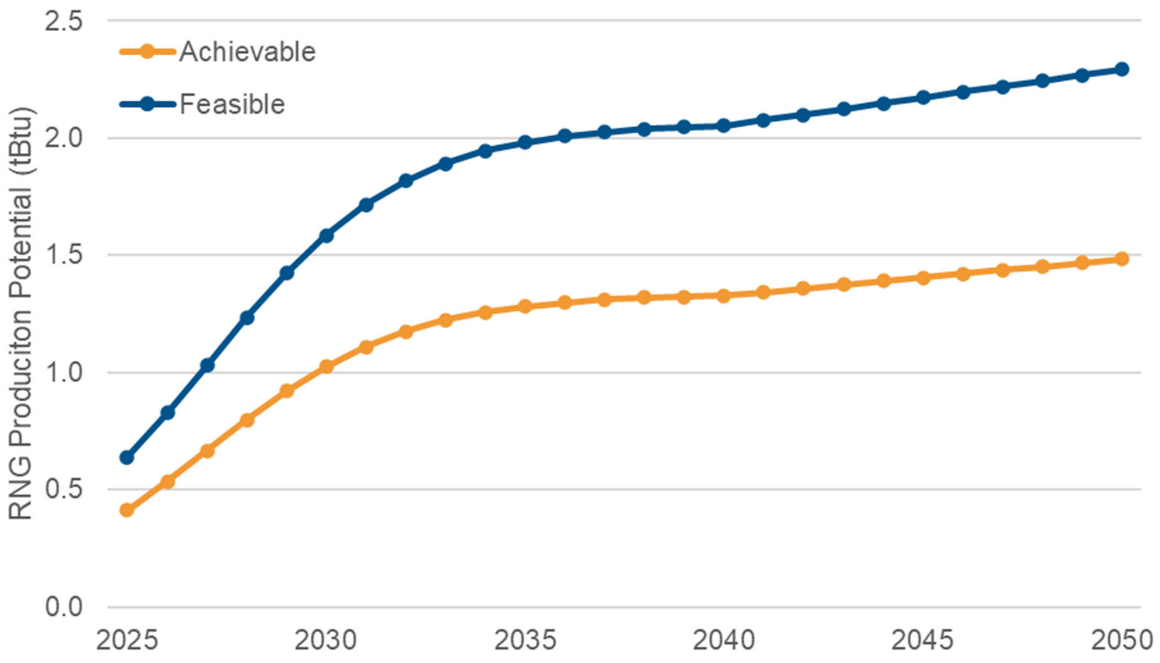
Landfill	County	Flow (MGD)	AD System	RNG Potential (MMBtu/year)
Detroit STP	Wayne	660.5	No	1,688,549
Wyandotte WWTP	Wayne	81.0	No	207,074
Grand Rapids WWTP	Kent	50.4	No	128,846
Flint WPCF	Genesee	43.3	Yes	110,695
Muskegon County STP	Muskegon	32.3	No	82,446
Warren WWTP	Macomb	30.0	No	76,694
Kalamazoo WWTP	Kalamazoo	28.0	No	71,581
Saginaw STP	Saginaw	25.0	No	63,912
YCUA WWTP	Washtenaw	24.2	No	61,953
Wyoming WWTP	Kent	16.5	No	42,182
Ann Arbor WWTP	Washtenaw	15.1	No	38,705
Ragnone DIST.#2 WWTP	Genesee	14.0	No	35,791
Huron Valley WWTP South	Wayne	14.0	No	35,791
Lansing WWTP	Ingham	13.5	No	34,589
Jackson WWTP	Jackson	13.4	Yes	34,333
East Lansing WWP	Ingham	13.4	No	34,257
Monroe Metro WWTP	Monroe	13.4	No	34,257
Battle Creek STP	Calhoun	11.0	No	28,121
Port Huron WWTP	St. Clair	11.0	No	28,121
Holland WTF	Ottawa	9.5	No	24,286
Bay City STP	Bay	9.1	No	23,264
Midland WWTP	Midland	8.5	Yes	21,730
Pontiac STP	Oakland	8.0	Yes	20,452
West Bay Regional WWTP	Bay	7.9	Yes	20,273
Benton Harbor-St Joseph	Berrien	7.2	Yes	18,432

ICF developed the following assumptions for the resource potentials for RNG production at WRRFs in the two scenarios:

- In the Achievable scenario, ICF assumed that 50% of the WRRFs with a capacity greater than 7 MGD would produce RNG.
- In the Feasible scenario, ICF assumed that 75% of the WRRFs with a capacity greater than 3.5 MGD would produce RNG.

The figure below shows the Achievable and Feasible RNG resource potential from WRRFs between 2025 and 2050 in Michigan.

Figure 4-8. Annual RNG Production Potential from WRRFs in Michigan (tBtu/y)



RNG: Thermal Gasification of Biogenic or Renewable Resources

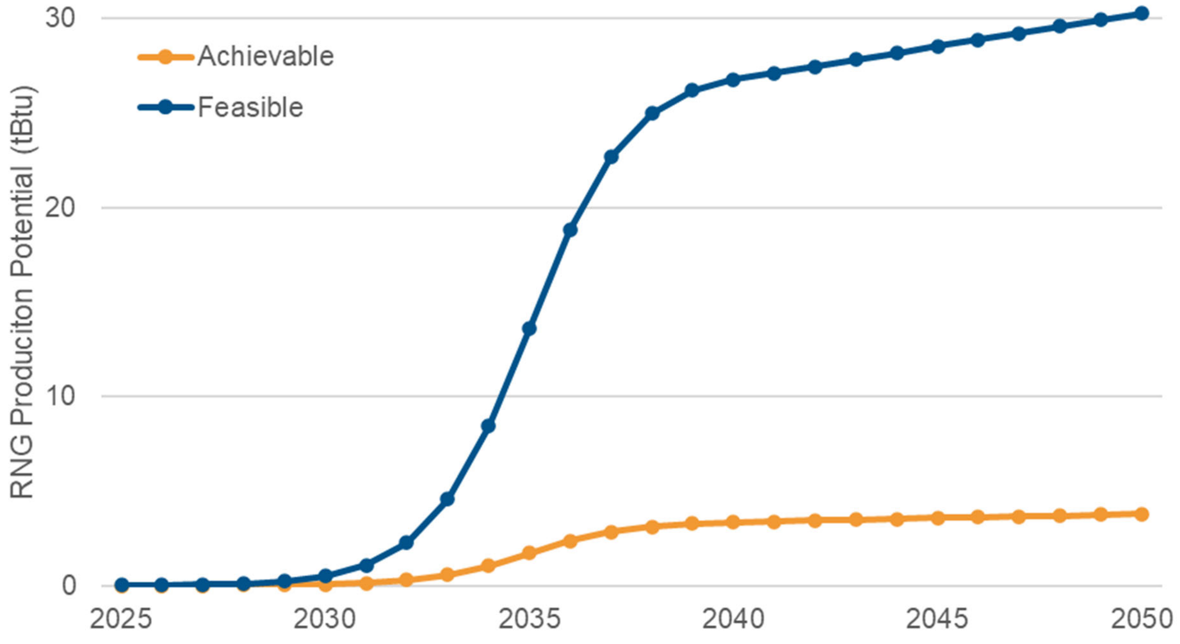
Agricultural Residues

ICF developed the following assumptions for the RNG production potential from agricultural residues in the two scenarios.

- In the Achievable scenario, ICF assumed that 30% of the agricultural residues available at $40/dry ton would be diverted to thermal gasification systems.
- In the Feasible scenario, ICF assumed 50% of the agricultural residues available at $60/dry ton would be diverted to thermal gasification systems.

The figure below shows the Achievable and Feasible RNG resource potential scenarios from the thermal gasification of agricultural residues between 2025 and 2050 in Michigan.

Figure 4-9. Annual RNG Production Potential from Agricultural Residues in Michigan (tBtu/y)



Energy Crops

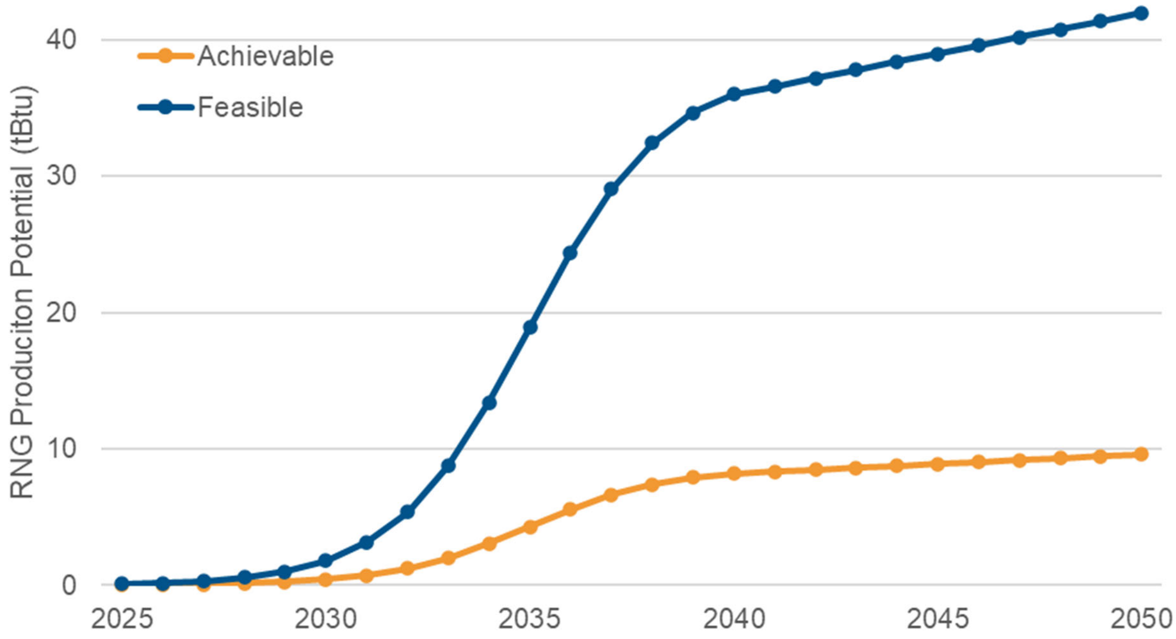
Energy crops are inclusive of perennial grasses, trees, and some annual crops that can be grown specifically to supply large volumes of uniform, consistent quality feedstocks for energy production. ICF extracted data from the Bioenergy KDF at $10 price point increments, from $30/ton to $100/ton that showed variation in production potential for energy crops from 2025 out to 2040.

ICF developed assumptions for the RNG production potential from energy crops for the two scenarios:

- In the Achievable scenario, ICF assumed that 30% of the energy crops available at $40/dry ton would be diverted to thermal gasification systems.
- In the Feasible scenario, ICF assumed that 40% of the energy crops available at $60/dry ton would be diverted to thermal gasification systems.

Figure 4-10 below shows the RNG resource potential from the thermal gasification of energy crops between 2025 and 2050 in the Achievable and Feasible scenarios in Michigan.

Figure 4-10. Annual RNG Production Potential from Energy Crops in Michigan (tBtu/y)



Forestry and Forest Product Residues

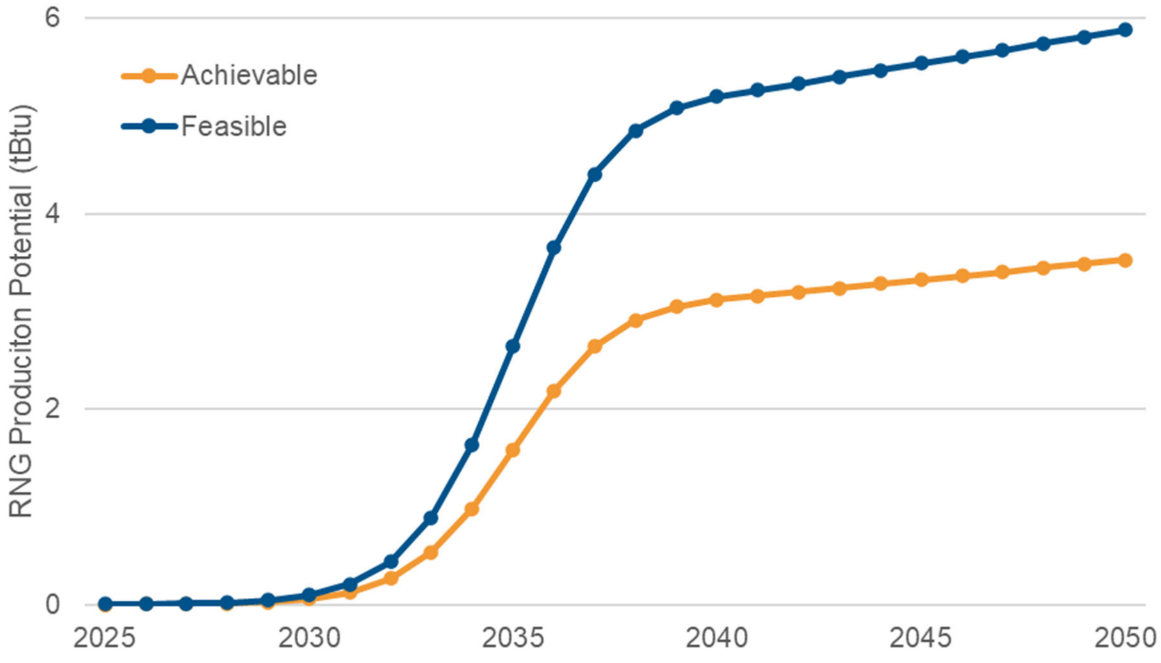
ICF extracted information from the U.S. DOE Bioenergy KDF, which includes information on forest residues such as thinnings, mill residues, and different residues from woods (e.g., mixedwood, hardwood, and softwood). ICF extracted data from the Bioenergy KDF at three price points, $30/ton and $60/ton, that showed variation in production potential for forest and forest product residue biomass from 2025 out to 2040.

ICF developed the following assumptions for the RNG production potential from forest residues in the two scenarios:

- In the Achievable scenario, ICF assumed that 30% of the forest and forestry product residues available at $40/dry ton would be diverted to thermal gasification systems.
- In the Feasible scenario, ICF assumed that 50% of the forest and forestry product residues available at $60/dry ton would be diverted to thermal gasification systems.

Figure 4-11 below shows the RNG resource potential from the thermal gasification of forestry and forest product residues between 2025 and 2050 in the Achievable and Feasible scenarios in Michigan.

Figure 4-11. Annual RNG Production Potential from Forestry Residues in Michigan (tBtu/y)



Municipal Solid Waste

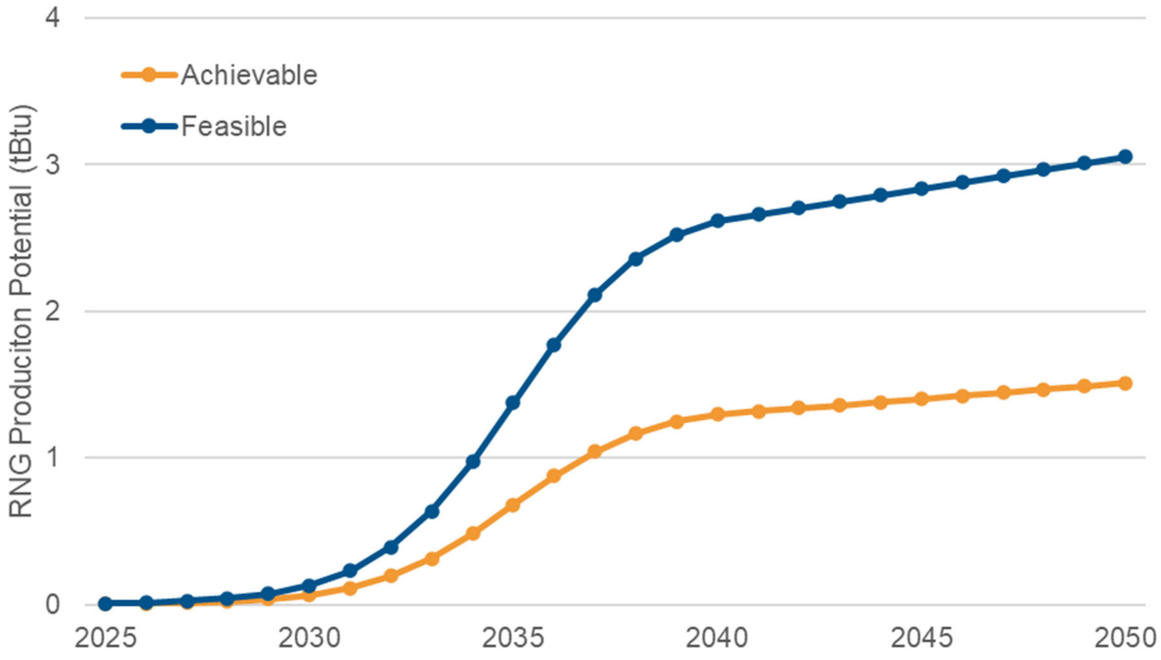
ICF extracted MSW information from the U.S. DOE's Bioenergy KDF, which includes information collected as part of U.S. DOE's Billion Ton Report. ICF limited our consideration to the potential for utilizing MSW that is currently landfilled as a feedstock for thermal gasification; this excludes MSW that is recycled or directed to waste-to-energy facilities. The MSW volumes available at different prices are derived from a variety of sources, including county-level tipping fees and costs associated with sorting.

ICF developed assumptions for the RNG production potential from MSW for the two scenarios:

- In the Achievable scenario, ICF assumed that 30% of the biogenic fraction of MSW available at $40/dry ton from the Bioenergy KDF for paper and paperboard, and yard trimmings could be gasified.
- In the Feasible scenario, ICF assumed 50% of the biogenic fraction of MSW available at $60/dry ton from the Bioenergy KDF for paper and paperboard and yard trimmings could be gasified.

The figure below shows the RNG resource potential from the thermal gasification of MSW between 2025 and 2050 in the Achievable and Feasible scenarios in Michigan.

Figure 4-12. Annual RNG Production Potential from MSW in Michigan (tBtu/y)



5. RNG Production Cost Assessment

ICF developed assumptions for the capital expenditures and operational costs for RNG production from the various feedstock and technology pairings outlined previously. ICF characterizes costs based on a series of assumptions regarding the production facility sizes (as measured by gas throughput in units of standard cubic feet per minute [SCFM]), gas upgrading and conditioning and upgrading costs (depending on the type of technology used, the contaminant loadings, etc.), compression, and interconnect for pipeline injection. We also include operational costs for each technology type. Table 5-1 below outlines some of ICF's baseline assumptions that we employ in our RNG costing model.

Table 5-1. Illustrative ICF RNG Cost Assumptions

Cost Parameter	ICF Cost Assumptions
Capital Costs	
Facility Sizing	▪ Differentiate by feedstock and technology type: anaerobic digestion and thermal gasification. ▪ Prioritize larger facilities to the extent feasible but driven by resource estimate.
Gas Conditioning and Upgrade	▪ Vary by feedstock type and technology required.
Compression	▪ Capital costs for compressing the conditioned/upgraded gas for pipeline injection.
O&M Costs	
Operational Costs	▪ Costs for each equipment type—digesters, conditioning equipment, collection equipment, and compressors—as well as utility charges for estimated electricity consumption.
Feedstock	▪ Feedstock costs (for thermal gasification), ranging from \$30 to \$60 per dry ton.
Delivery	▪ The costs of delivering the same volumes of biogas that require pipeline construction greater than 1 mile will increase, depending on feedstock/technology type, with a typical range of \$1–\$5/MMBtu.
Levelized Cost of Gas	
Project Lifetimes	▪ Calculated based on the initial capital costs in Year 1, annual operational costs discounted, and RNG production discounted accordingly over a 20-year project lifetime.

ICF presents the costs used in our analysis as well as the levelized cost of energy (LCOE) for RNG in different end uses. The LCOE is a measure of the average net present cost of RNG production for a facility over its anticipated lifetime. The LCOE enables us to compare across RNG feedstocks and other energy types on a consistent per unit energy basis. The LCOE can also be considered the average revenue per unit of RNG (or energy) produced that would be required to recover the costs of constructing and operating the facility during an assumed lifetime. The LCOE calculated as the discounted costs over the lifetime of energy producing facility (e.g., RNG production) divided by a discounted sum of the actual energy amounts produced. The LCOE is calculated using the following formula:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

where I_t is the capital cost expenditures (or investment expenditures) in year t, M_t represents the operations and maintenance expenses in year t, F_t represents the feedstock costs in year t (where appropriate), E_t represents the energy (i.e., RNG) produced in year t, r is the discount rate, and n is the expected lifetime of the production facility.

ICF notes that our cost estimates are not intended to replicate a developer's estimate when deploying a project. For instance, ICF recognizes that the cost category "gas conditioning and upgrading" actually represents an array of decisions that a project developer would have to make with respect to CO_2 removal, H_2S removal, siloxane removal, N_2/O_2 rejection, deployment of a thermal oxidizer, among other elements.

In addition, the cost assumptions attempt to strike a balance between existing or near-term capital and operational expenditures, and the potential for project efficiencies and associated cost reductions that may eventuate over time as the RNG industry expands. For example, in general construction and engineering costs may decline from present levels driven by the development and implementation of modular technology systems or facilities.

These cost estimates also do not reflect the potential value of the environmental attributes associated with RNG, nor the current markets and policies that provide credit for these environmental attributes. While this section focuses purely on the costs associated with the production of RNG, Section 0 discusses in more detail the market prices for RNG and the associated value of the environmental characteristics of RNG.

Furthermore, we understand that project developers have reported a wide range of interconnection costs, with numbers as low as $200,000 reported in some states, and as high as $9 million in other states. We appreciate the variance between projects, including those that use anaerobic digestion or thermal gasification technologies, and our supply-cost curves are meant to be illustrative, rather than deterministic. This is especially true of our outlook to 2050—we have *not* included significant cost reductions that might occur as a result of a rapidly growing RNG market or sought to capture a technological breakthrough or breakthroughs. For anaerobic digestion and thermal gasification systems we have focused on projects that have reasonable scale, representative capital expenditures, and reasonable operations and maintenance estimates.

To some extent, ICF's cost modeling does presume changes in the underlying structure of project financing, which is currently linked inextricably to revenue sharing associated with environmental commodities in the federal Renewable Fuel Standard (RFS) market and California's Low Carbon Fuel Standard (LCFS) market. Our project financing assumptions likely have a lower return than investors may be expecting in the market today; however, our cost assessment seeks to represent a more mature market to the extent feasible, whereby upward of 1,000-4,500 tBtu per year of RNG is being produced. In that regard, we implicitly assume that contractual arrangements are likely considerably different and local/regional challenges with respect to RNG pipeline injection have been overcome.

Table 5-2 provides a summary of the different cost ranges for each RNG feedstock and technology.

Table 5-2. Summary of Cost Ranges by Feedstock Type

	Feedstock	Cost Range ($/MMBtu)
Anaerobic Digestion	Animal Manure	$14.53 – $49.17
	Food Waste	$18.35 – $29.39
	Landfill Gas	$9.92 – $26.85
	Water Resource Recovery Facilities	$10.90 – $70.86
Thermal Gasification	Agricultural Residues	$19.07 – $43.13
	Energy Crops	$19.07 – $43.13
	Forestry and Forest Residues	$19.07 – $43.13
	Municipal Solid Waste	$19.07 – $43.13

RNG Production Costs via Anaerobic Digestion

Animal Manure

ICF developed assumptions for the region by distinguishing between animal manure projects, based on a combination of the size of the farms and assumptions that certain areas would need to aggregate or cluster resources to achieve the economies of scale necessary to warrant an RNG project. There is some uncertainty associated with this approach because an explicit geospatial analysis was not conducted; however, ICF did account for considerable costs in the operational budget for each facility assuming that aggregating animal manure would potentially be expensive.

Table 5-3 includes the main assumptions used to estimate the cost of producing RNG from animal manure, while Table 5-4 that follows provides example cost inputs for low cost and high animal manure facilities.

Table 5-3. Cost Consideration in LCOE Analysis for RNG from Animal Manure

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor	▪ 95%
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 15-25% of installed equipment costs ▪ 10% of installed equipment costs
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ $1.0 to $2.2 million, depending on facility ▪ $0.1 to $0.3 million, depending on facility ▪ $0.25 to $2.5 million, depending on facility
Utility Costs	▪ Electricity: 30 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ Average of 12.5 ¢/kWh for Michigan ▪ Average of $6.86/MMBtu for Michigan
Operations & Maintenance	▪ 1 FTE for maintenance ▪ Miscellany	▪ 15% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $1.5 million ▪ $2.0 million ▪ $0.1–$0.325 million
Other	▪ Value of digestate ▪ Tipping fee	▪ Valued for dairy at about $100/cow/y ▪ Excluded from analysis
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 7-10% ▪ 8%

Table 5-4. Example Facility-Level Cost Inputs for RNG from Animal Manure

Factor	High LCOE	Low LCOE
Facility size (cows	1,300	3,600
Biogas production (SCFM)	90	1,300
Capital: collection	$2.15 million	$21.59 million
Capital: conditioning (CO2/O2 removal)	$1.035 million	$2.185 million
Capital: sulfur treatment	$0.1 million	$0.3 million
Capital: nitrogen rejection	$0.25 million	$2.5 million
Capital: compressor	$0.1 million	$0.325 million
Capital: pipeline (on-site)	$2.0 million	$2.0 million
Capital: utility interconnect	$1.5 million	$1.5 million
O&M: electricity and natural gas	$0.11 million	$1.61 million
Construction and engineering: installation	$0.87 million	$1.83 million
Construction and engineering: owner's cost	$0.35 million	$0.73 million

ICF reports a range of LCOE for RNG from animal manure at $14.53/MMBtu to $49.17/MMBtu for Michigan. There are likely additional costs that RNG from animal manure will face. For instance, Michigan's dairies continue to bed animals almost exclusively on sand,[47] and while some projects may convert dairies to digestate-based bedding alternatives, this should not be assumed as a baseline for determining costs. As a result of this baseline condition, additional sand separation may be required for manure handling.

Food Waste

ICF made the simplifying assumption that food waste processing facilities would be purpose-built and be capable of processing 60,000 tons of waste per year. ICF estimates that these facilities would produce about 500 SCFM of biogas for conditioning and upgrading before pipeline injection.

In addition to the other costs included in other anaerobic digestion systems, we also included assumptions about the cost of collecting food waste and processing it accordingly (see Table 5-5). Table 5-6 that follows provides example cost inputs for low cost and high food waste facilities.

Table 5-5. Cost Consideration in LCOE Analysis for RNG from Food Waste Digesters

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor ▪ Processing capability	▪ 95% ▪ 60,000 tons per year
Dedicated Equipment	▪ Organics processing ▪ Digester	▪ $10.0 million ▪ $12.0 million
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 25% of installed equipment costs ▪ 10% of installed equipment costs
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ $2.3 to $7.0 million, depending on facility ▪ $0.3 million ▪ $1.0 million
Utility Costs	▪ Electricity: 28 kWh/MMBtu ▪ Natural Gas: 5% of product	▪ Average of 12.5 ¢/kWh for Michigan ▪ Average of $6.86/MMBtu for Michigan
Operations & Maintenance	▪ 1.5 FTE for maintenance ▪ Miscellany	▪ 15% of installed capital costs
Other	▪ Tipping fees	▪ Statewide average of $42.77
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $1.5 million ▪ $2 million ▪ $0.1–$0.325 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 7-10% ▪ 8%

Table 5-6. Example Facility-Level Cost Inputs for RNG from Food Waste

---

[47] Based on information submitted in a comment by Consumers Energy.

Factor	High LCOE	Low LCOE
Food waste processed (ton/y)	30,000	120,000
Biogas production (SCFM)	250	1,000
Capital: organics processing	$7.0 million	$12.5 million
Capital: digester	$7.2 million	$19.2 million
Capital: collection	$0.17 million	$0.44 million
Capital: conditioning (CO2/O2 removal)	$1.36 million	$3.8 million
Capital: sulfur treatment	$0.1 million	$0.5 million
Capital: nitrogen rejection	$0.3 million	$2.5 million
Capital: compressor	$0.13 million	$0.33 million
Capital: pipeline (on-site)	$2.0 million	$2.0 million
Capital: utility interconnect	$1.5 million	$1.5 million
O&M: electricity and natural gas	$0.31 million	$1.53 million
Construction and engineering: installation	$0.97 million	$2.3 million
Construction and engineering: owner's cost	$0.4 million	$0.91 million

ICF assumed that food waste facilities would be able to offset costs with tipping fees. ICF used values presented by an analysis of municipal solid waste landfills by Environmental Research & Education Foundation (EREF). The tipping fees reported by EREF for 2019, including Michigan state-wide average, are shown in Table 5-7.

Table 5-7. Average Tipping Fee by Region ($/ton)[48]

Region	Tipping Fee
Michigan, statewide average	$42.77
Midwest: IL, IN, IA, KS, MI, MN, MO, NE, OH, OH, WI	$47.85
Rest of U.S.	
Northeast: CT, DE, ME, MD, MA, NH, NJ, NY, PA, RI, VA, WV	$68.69
Mountains / Plains: CO, MT, ND, SD, UT, WY	$47.83
Pacific: AK, AZ, CA, HI, ID, NV, OR, WA	$72.03
South Central: AR, LA, NM, OK, TX	$39.66
Southeast: AL, FL, GA, KY, MS, NC, SC, TN	$46.26
National Average	***$53.72***

---

[48] Environmental Research & Education Foundation, Analysis of MSW Landfill Tipping Fees–January 2021. Retrieved from www.erefdn.org.

The values listed in Table 5-7 are generally the fees associated with tipping municipal solid waste—the tipping fees for construction and debris tend to be higher because the materials take up more space in landfills. ICF developed our cost estimates assuming that anaerobic digesters discounted the tipping fee for food waste compared to MSW landfills by 20%.

ICF reports an estimated LCOE of RNG from food waste of \$18.35/MMBtu to \$29.39/MMBtu.

Landfill Gas

ICF developed assumptions for each region by distinguishing between four types of landfills: candidate landfills[49] without collection systems in place, candidate landfills with collection systems in place, landfills[50] without collection systems in place, and landfills with collections systems in place.[51] For each region, ICF further characterized the number of landfills across these four types of landfills, distinguishing facilities by estimated biogas throughput (reported in units of SCFM of biogas).

For utility costs, ICF assumed 25 kWh per MMBtu of RNG injected and 6% of geological or fossil natural gas used in processing. Electricity costs and delivered natural gas costs were reflective of industrial rates reported at the state level by the EIA.

Table 5-8 summarizes the key parameters that ICF employed in our cost analysis of LFG, while the table that follows provides example cost inputs for low cost and high LFG facilities.

Table 5-8. Cost Consideration in LCOE Analysis for RNG from Landfill Gas

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor	▪ 95%
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 25% of installed equipment costs ▪ 10% of installed equipment costs
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ \$2.3 to \$7.0 million, depending on facility ▪ \$0.3 to \$1.0 million, depending on facility ▪ \$1.0 to \$2.5 million, depending on facility
Utility Costs	▪ Electricity: 25 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ Average of 12.5 ¢/kWh for Michigan ▪ Average of \$6.86/MMBtu for Michigan
Operations & Maintenance	▪ 1 FTE for maintenance ▪ Miscellany	▪ 10% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ \$1.5 million ▪ \$2 million ▪ \$0.13–\$0.5 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 7-10% ▪ 8%

---

[49] The EPA characterizes candidate landfills as one that is accepting waste or has been closed for five years or less, has at least one million tons of WIP, and does not have an operational, under-construction, or planned project. Candidate landfills can also be designated based on actual interest by the site.

[50] Excluding those that are designated as candidate landfills.

[51] Landfills that are currently producing RNG for pipeline injection are included here.

Table 5-9. Example Facility-Level Cost Inputs for RNG from LFG

Factor	High LCOE	Low LCOE
Biogas production (SCFM)	240	4,800
Capital: collection	$0.17 million	$3.3 million
Capital: conditioning (CO_2/O_2 removal)	$0.85 million	$7.0 million
Capital: sulfur treatment	$0.1 million	$1.0 million
Capital: nitrogen rejection	$0.75 million	$2.5 million
Capital: compressor	$0.13 million	$0.45 million
Capital: pipeline (on-site)	$2.0 million	$2.0 million
Capital: utility interconnect	$1.5 million	$1.5 million
O&M: electricity and natural gas	$0.3 million	$5.9 million
Construction and engineering: installation	$0.96 million	$3.2 million
Construction and engineering: owner's cost	$0.38 million	$1.3 million

ICF reports an estimated LCOE of RNG from LFG ranging from $9.92/MMBtu to $26.85/MMBtu.

Water Resource Recovery Facilities

ICF developed assumptions for each region by distinguishing between WRRFs based on the throughput of the facilities. The table below includes the main assumptions used to estimate the cost of producing RNG at WRRFs while the table that follows provides example cost inputs for low cost and high WRRF facilities.

Table 5-10. Cost Consideration in LCOE Analysis for RNG from WRRFs

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor	▪ 95%
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 25% of installed equipment costs ▪ 10% of installed equipment costs
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ $2.3 to $7.0 million, depending on facility ▪ $0.3 to $1.0 million, depending on facility ▪ $1.0 to $2.5 million, depending on facility
Utility Costs	▪ Electricity: 26 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ Average of 12.5 ¢/kWh for Michigan ▪ Average of $6.86/MMBtu for Michigan
Operations & Maintenance	▪ 1 FTE for maintenance ▪ Miscellany	▪ 10% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $1.5 million ▪ $2 million ▪ $0.1–$0.5 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 7-10% ▪ 8%

Table 5-11. Example Facility-Level Cost Inputs for RNG from WRRFs

Factor	High LCOE	Low LCOE
Biogas production (SCFM)	60	2,920
Capital: collection	$0.13 million	$1.98 million
Capital: conditioning (CO2/O2 removal)	$1.36 million	$8.6 million
Capital: sulfur treatment	$0.05 million	$1.2 million
Capital: nitrogen rejection	$0.20 million	$5.0 million
Capital: compressor	$0.10 million	$0.45 million
Capital: pipeline (on-site)	$2.0 million	$2.0 million
Capital: utility interconnect	$1.5 million	$1.5 million
O&M: electricity and natural gas	$0.74 million	$3.61 million
Construction and engineering: installation	$0.93 million	$4.3 million
Construction and engineering: owner’s cost	$0.37 million	$1.7 million

ICF reports an estimated LCOE of RNG from WRRFs of $10.90/MMBtu and up to $70.86/MMBtu for smaller WRRFs.

RNG Production Costs via Thermal Gasification

ICF used similar assumptions across the thermal gasification of feedstocks, including agricultural residue, forestry residue, energy crops, and MSW. There is considerable uncertainty around the costs for thermal gasification of feedstocks, as the technology has only been deployed at pilot scale to date or in the advanced stages of demonstration at pilot scale. This is in stark contrast to the anaerobic digestion technologies considered previously.

ICF reports here on a range of facilities processing different volumes of feedstock (in units of tons per day, or tpd) that we employed for conducting the cost analysis, with cost assumptions outlined in Table 5-12 and example cost inputs for low cost and high thermal gasification facilities shown in Table 5-13.

Table 5-12. Thermal Gasification Cost Assumptions

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor ▪ Processing capability	▪ 90% ▪ 1,000–2,000 tpd
Dedicated Equipment & Installation Costs	▪ Feedstock handling (drying, storage) ▪ Gasifier ▪ CO_2 removal ▪ Syngas reformer ▪ Methanation ▪ Other (cooling tower, water treatment) ▪ Miscellany (site work, etc.) ▪ Construction / Engineering	▪ $20–22 million ▪ $60 million ▪ $25 million ▪ $10 million ▪ $20 million ▪ $10 million ▪ All-in: $335 million for 1,000 tpd
Utility Costs	▪ Electricity: 30 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ Average of 12.5 ¢/kWh for Michigan ▪ Average of $6.86/MMBtu for Michigan
Operations & Maintenance	▪ Feedstock ▪ 3 FTE for maintenance ▪ Miscellany: water sourcing, treatment/disposal	▪ $30/dry ton ▪ 12% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline	▪ $2 million ▪ $1.5–$7.2 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 7-10% ▪ 8%

Table 5-13. Example Facility-Level Cost Inputs for RNG from Thermal Gasification

Factor	High LCOE	Low LCOE
Feedstock processed (tons/day)	200	2,000
Annual RNG production (MMBtu)	440,000	5,210,000
Capital: biomass handling and drying	$6.3 million	$27.3 million
Capital: gasification	$18.0 million	$86.9 million
Capital: syngas shifting	$3.15 million	$13.36 million
Capital: conditioning (CO2 removal)	$7.39 million	$34.17 million
Capital: cooling and water treatment	$2.25 million	$11.18 million
Capital: miscellaneous materials	$7.48 million	$32.01 million
Capital: methanation	$6.17 million	$27.26 million
Capital: electrical and controls	$2.88 million	$12.00 million
Capital: pipeline (on-site)	$1.5 million	$7.2 million
Capital: utility interconnect	$2.0 million	$2.0 million
O&M: electricity	$1.7 million	$16.7 million
Construction and engineering: installation	$11.0 million	$50.3 million
Construction and engineering: owner’s cost	$5.5 million	$25.1 million

ICF reports estimated levelized costs of RNG from thermal gasification of $19/MMBtu to $43/MMBtu.

Combined Supply-Cost Curve for RNG

ICF estimates that RNG will be available from various feedstocks in the range of less than $10/MMBtu to upwards of $70/MMBtu. Anaerobic digestion feedstocks, notably from LFG and WRRF, are more cost-effective in the short term. RNG from thermal gasification feedstocks are more expensive, largely reflecting the immature state of thermal gasification as a technology, and the associated uncertainties around cost and feedstock availability.

RNG is more expensive than its conventional counterpart; however, in a decarbonization framework, a more appropriate comparison for RNG is to other abatement measures that are viewed as long-term strategies to reduce GHG emissions (discussed in more detail in Section 6). In addition, ICF anticipates that over time there will be increasing opportunities for cost reductions as RNG technologies mature and the market expands.

The figures below show estimated supply-cost curves for RNG in Michigan in 2030 and in 2050, including resource potential for the Achievable Scenario (along the x-axis) and the estimated cost to deliver that RNG (along the y-axis). ICF notes that the supply-cost curves do not necessarily reflect the price for RNG available on the market today, but instead the estimated production costs for RNG as deployment escalates over time.

Both in 2030 and 2050 the front end of the supply curve is comprised of landfill gas and WRRFs, with limited thermal gasification potential in 2030, and relatively expensive. ICF expects the larger thermal gasification systems are expected to be cost competitive in the 2040 to 2050 timeline. The more immediately available opportunities from the anerobic digestion of animal manure and food waste are likely available in the range of $20-25/MMBtu in 2030. In 2050 the back-end of the supply curve is driven by higher costs of anaerobic digestion at smaller facilities (e.g., farms) and smaller thermal gasification facilities.

Figure 5-1. Combined Supply-Cost Curve for Michigan in 2030, Achievable ($/MMBtu)

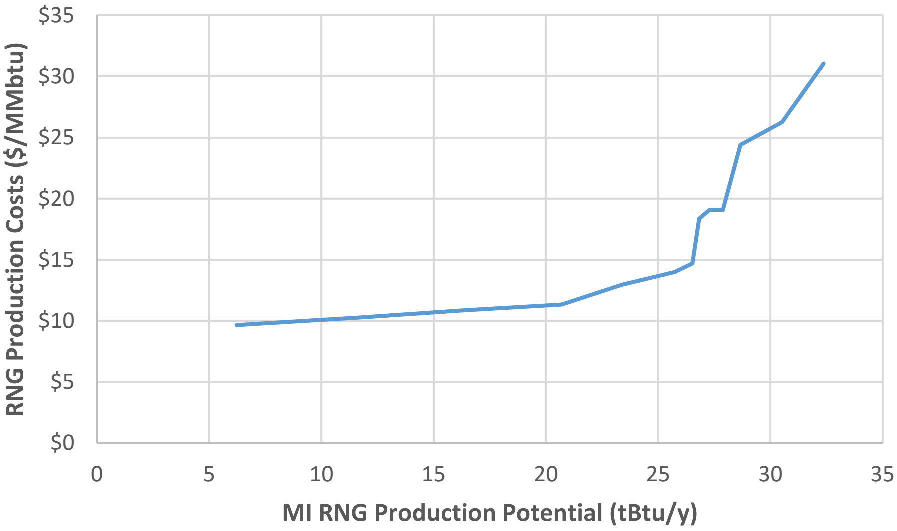
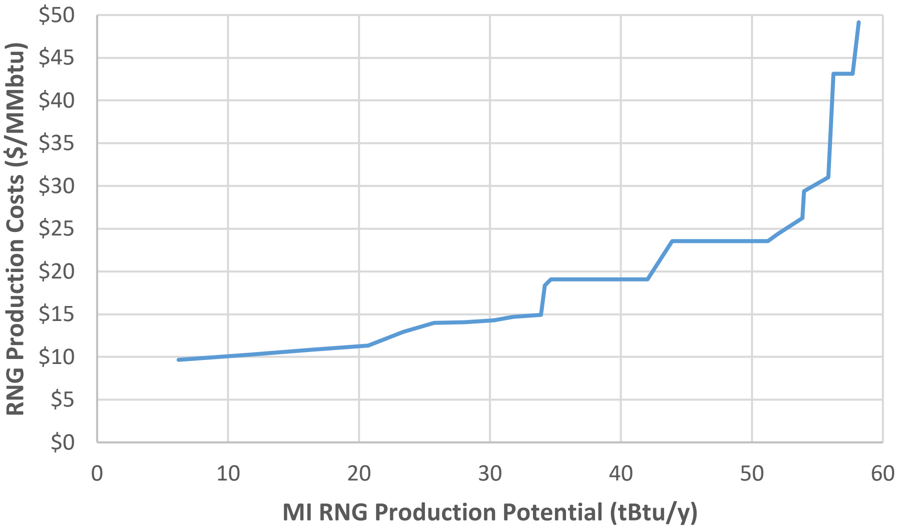


Figure 5-2. Combined Supply-Cost Curve for Michigan in 2050, Achievable ($/MMBtu)



6. GHG Emission Reductions and Cost-Effectiveness

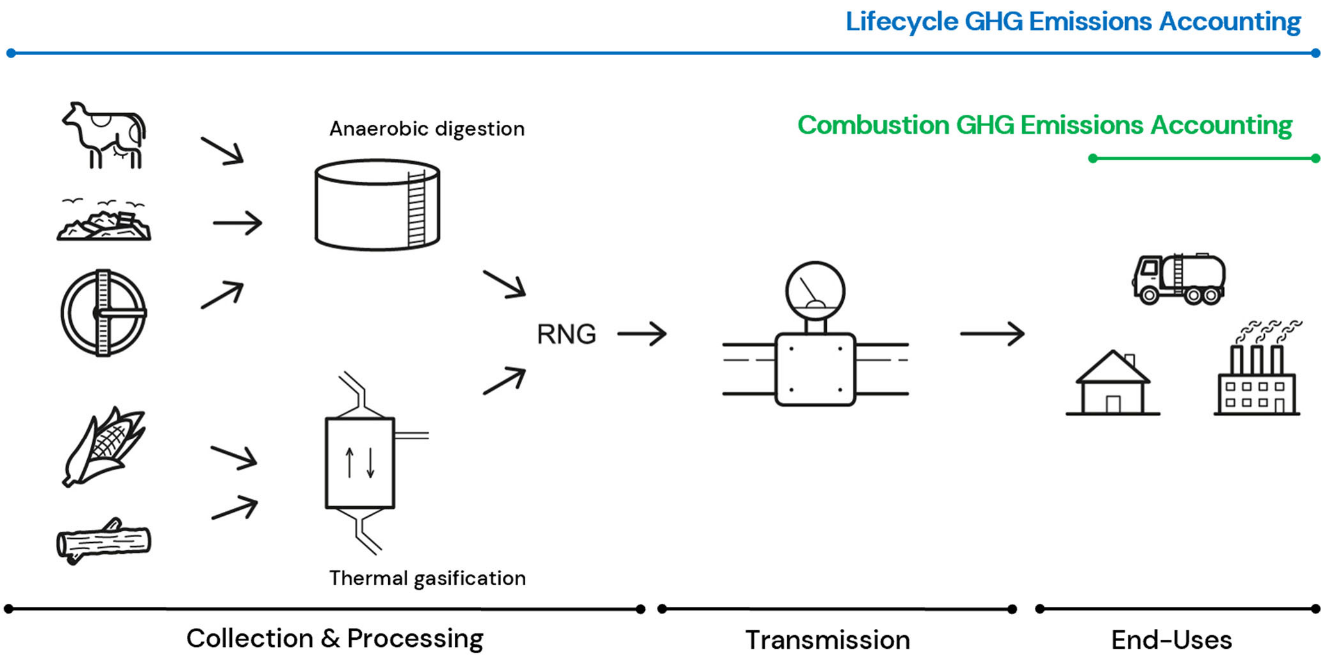
GHG emission accounting is a common practice used to evaluate the respective GHG impacts of various energy sources or fuels, and to enable comparison between them. GHG emission accounting is used in practice by regulators and private actors for a variety of reasons, including to develop GHG emission inventories, as part of broader environmental reports, and to track carbon as an environmental commodity in carbon markets. GHG emission accounting is applied in practice by multiplying a GHG emissions factor and the associated activity data for the fuel of interest. In other words, the total GHG emissions are calculated as a product of the emissions factor and the amount of energy consumed—the equation below highlights this for the case of natural gas, with the GHG emissions factor in units of kilograms of carbon dioxide equivalents per unit energy of natural gas, in units of million British thermal units ($kgCO_2e/MMBtu$) and the amount of natural gas used reported in units of MMBtu.

$$GHG\ Emissions = GHG\ Emissions\ Factor\ ^{Lifecycle}_{Combustion} \left[\frac{kgCO_2e}{MMBtu}\right] \times\ Activity\ [MMBtu]$$

As noted in the equation above (as part of the *GHG Emissions Factor*), there are two distinct GHG emission accounting approaches in use today: the combustion approach and the lifecycle approach. The framework of these two approaches is consistent across fuel types. However, the inputs vary and lead to different GHG emission profiles. These two different GHG emission accounting approaches are currently driving the conversation regarding GHG emissions associated with RNG. It is important to understand that neither accounting approach is the "correct" one to use. Rather, the fact that both accounting approaches are used frequently can create confusion.

Figure 6-1 offers a more detailed view of the various stages in RNG production, showing two different production methods and multiple feedstocks. As shown below, the stages of the combustion and lifecycle accounting approaches are broken out into three categories: Collection & Processing, Pipeline/Transmission, and End-Uses. However, the inputs considered within these stages vary between conventional natural gas and RNG, and even among different RNG feedstocks.

Figure 6-1. Boundary Conditions of GHG Emission Account Approaches for RNG Production



GHG emissions from RNG can be generated along the three stages of the RNG supply chain.

- *Collection and processing: Energy use required to produce, process, and distribute the fuel*. The energy used to produce, process, and distribute RNG is characterized here as: 1) feedstock collection and 2) digestion and processing related to anaerobic digesters, or synthetic gas (syngas) processing as it relates to thermal gasification.
- *Pipeline/transmission: Methane leaks primarily during transmission*. Methane leaks can occur at all stages in the supply chain from production through use but are generally focused on leakage during transmission. ICF limits our explicit consideration to leaks of methane as those that occur during transmission through a natural gas pipeline, as other methane losses that occur during RNG production are captured as part of efficiency assumptions.
- *End-use: RNG combustion*. The GHG emissions attributable to RNG combustion are straightforward: CO_2 emissions from the combustion of biogenic renewable fuels are considered zero, or carbon neutral. In other words, the GHG emissions are limited to CH_4 and N_2O emissions because the CO_2 emissions are considered biogenic.[52]

For the purposes of this report, ICF has opted to present the GHG emission reductions here using the combustion approach, while providing an overview of the lifecycle GHG emission reductions attributable to RNG in Appendix B. The reasoning for this is straightforward: using the combustion approach enables ICF to compare the GHG emissions reductions attributable to the RNG supply scenarios developed for this study (see Section 4) to existing GHG emission inventories developed for Michigan. Furthermore, the combustion accounting approach enables us to compare to the abatement cost of other strategies more accurately (see Section 7). More specifically, the abatement costs of other abatement strategies against which ICF is comparing RNG are uniformly reported using the combustion approach.

---

[52] IPCC guidelines state that CO_2 emissions from biogenic fuel sources (e.g., biogas or biomass based RNG) should not be included when accounting for emissions in combustion – only CH_4 and N_2O are included. This is to avoid any upstream “double counting” of CO_2 emissions that occur in the agricultural or land use sectors per IPCC guidance.

It is important to understand that ICF's presentation of results using the combustion approach is not an endorsement of one GHG emission accounting framework over another or a recommendation as it relates to a policy structure. Rather, it is an analytical and methodological decision to enable a more robust comparison and to contextualize the results of our analysis more accurately.

GHG Emissions from RNG Production Potential

ICF applied the aforementioned combustion accounting approach to estimate the GHG reduction potential across the two RNG potential scenarios for Michigan, as reported in Section 4.[53] ICF reiterates that a combustion GHG accounting framework is the standard approach for most volumetric GHG targets, developing GHG emissions inventories, and comparing mitigation measures as they are more closely tied to where the emissions physically occur. When applying the combustion approach, the emission reduction estimates for RNG consumption can be more easily compared to existing GHG emission inventories, such as Michigan's energy-related GHG emissions as shown in Figure 6-3. In particular, if RNG displaces conventional natural gas consumption in residential buildings, then the associated emission reductions can be directly attributed to the residential sector (in contrast to the lifecycle approach).

The figures below show the range of GHG emission reductions using a combustion accounting framework, in units of million metric tons of CO_2e ($MMtCO_2e$). ICF estimates that 3.0 to 7.9

---

[53] Lifecycle GHG emission factors and emission reductions are discussed in

The combination of RINs and LCFS credits have helped deliver significant volumes of RNG, especially to California. In fact, as of the end of 2021, RNG accounted for more than 90% of the market for natural gas as a transportation fuel in California. As lower carbon RNG comes on to the market, end users will likely gain additional market influence. Most of the RNG that is currently delivered to and dispensed in California is derived from landfills. ICF anticipates a shift towards lower carbon intensity RNG from feedstocks such as the anaerobic digestion of animal manure and digesters deployed at wastewater treatment plants.

Over time, these lower carbon sources will likely displace higher carbon intensity RNG from landfills. The role of RNG in the LCFS program will be determined by the market for NGVs. If steps are taken to foster adoption of NGVs, particularly in the heavy-duty sector(s), then this will be less of an issue. The introduction of the low-NOx engine (currently available as an 9L, 12L, and 6.7L engine) from Cummins may help jumpstart the market, especially with a near-term focus on NOx reductions in the South Coast Air Basin (which is in severe non-attainment for ozone standards).

$MMtCO_2e$ of emissions could be reduced per year by 2050 through the deployment of RNG projects located in Michigan, shown in Figure 6-2.

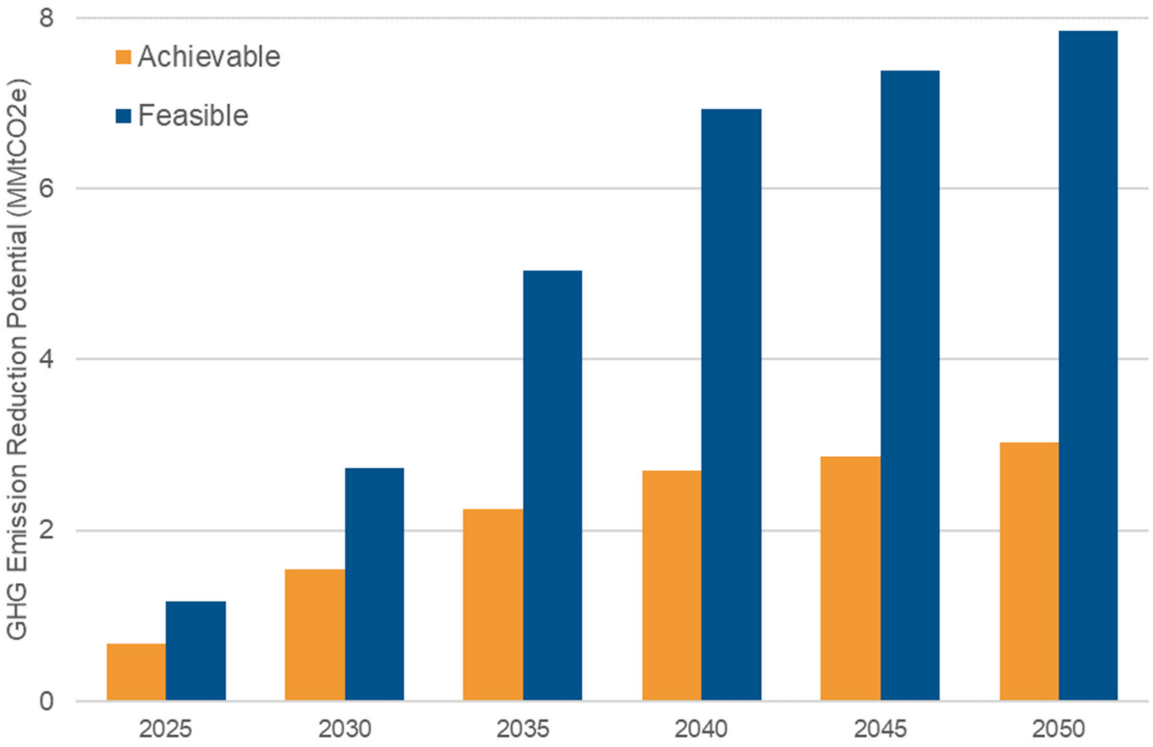
However, California has a clear focus on zero emission tailpipe solutions for the transportation sector e.g., via the Advanced Clean Truck (ACT) regulation. The ACT Regulation requires zero-emission purchase requirements for medium- and heavy-duty trucks starting in 2024. The rule seeks to "accelerate the widespread adoption of [ZEVs] in the medium- and heavy-duty truck sector." The core compliance mechanism is a minimum performance standard for ZEVs as a percentage of each major truck manufacturer's new sales in California.

While the deployment of RNG in the transportation sector has experienced massive growth in the past five years, there is a clear constraint to the overall production and use of RNG in transportation: the limited number of NGVs. With the transportation sector approaching RNG saturation, there is growing interest from policymakers, regulators and industry stakeholders to grow the production of RNG for pipeline injection and stationary end-use consumption.

As currently constructed, in general the policy framework does not encourage RNG use in stationary applications, instead directing RNG consumption to the transportation and electricity generation sectors. However, there are several emerging state-level policies in place that are helping to shape the outlook for RNG beyond transportation. The most interesting development for RNG is that there is growing interest in applying the same principles of RPS program as it relates to electricity to the natural gas sector. These are often referred to as Renewable Gas Standards. Oregon's Senate Bill 98 (SB 98), for instance, established a voluntary goal for adding as much as 30% RNG into Oregon's system by 2050. Furthermore, the law allows up to 5% of a utility's revenue requirement to be used to cover the additional cost of investments in RNG infrastructure. More specifically, the bill operates similar to a renewable portfolio standard, whereby volumetric goals have been set, and other critical parameters have been established to support cost-effective procurement. Utilities are able to invest in and own the processing and conditioning equipment required to upgrade raw biogas to pipeline quality gas, as well as the interconnection facilities to connect to the local gas distribution system. To date, NW Natural in Oregon has executed two agreements that will deliver about 2% of NW Natural's annual sales in Oregon, including agreements with a) Tyson Foods and BioCarbN to convert waste to RNG at Tyson facilities and b) Element Markets to purchase the environmental attributes from a WRRF in New York City and a mixed waste anaerobic digester in Wisconsin.

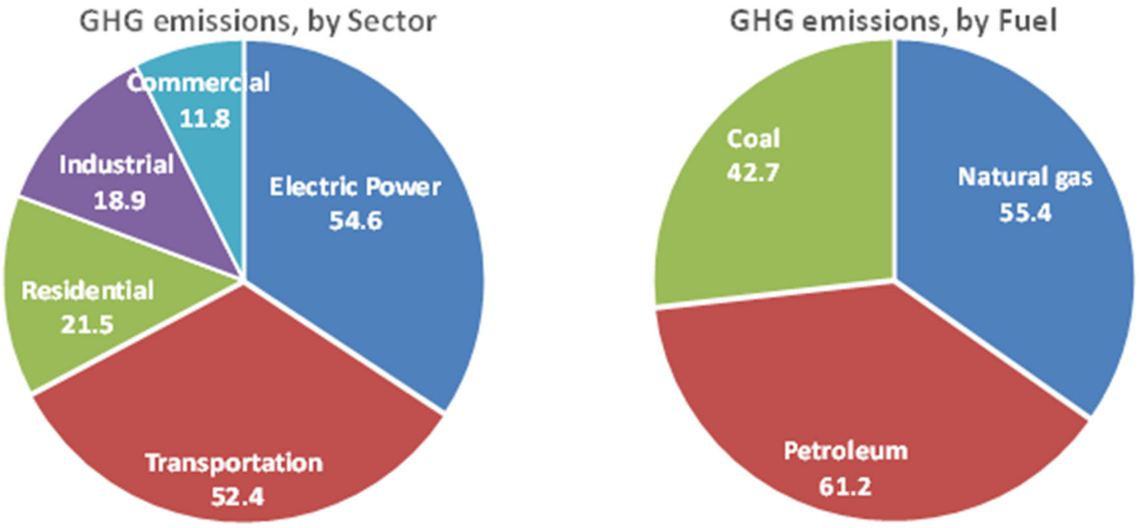
Appendix B.

Figure 6-2. Michigan RNG Emission Reduction Potential by Scenario (MMtCO$_2$e)



Michigan's energy-related CO$_2$ emissions were 159 MMtCO$_2$e in 2019, shown below by sector and fuel in Figure 6-3 below.[54]

Figure 6-3. Michigan Energy-Related CO$_2$ Emissions, 2019 (MMtCO$_2$e)

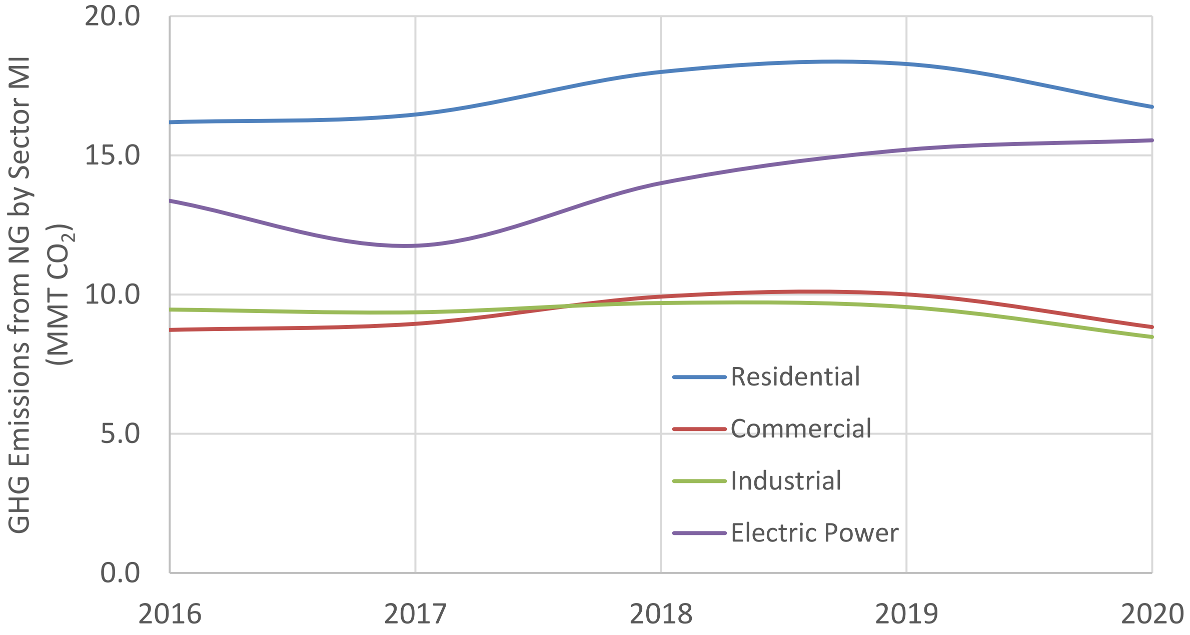


---

[54] U.S. Energy Information Agency, 2022. State energy-related carbon dioxide emissions by sector and fuel, https://www.eia.gov/environment/emissions/state/.

Because RNG is more expensive than conventional natural gas and because we generally assume that there will be a focus on energy efficiency across all sectors, ICF assumes that RNG will most likely to displace conventional natural gas consumption, as opposed to increasing natural gas consumption as a result of displacing another fuel like petroleum or coal. Natural gas currently accounts for about 35% of Michigan's energy-related carbon dioxide emissions. Natural gas is consumed across four main sectors: residential, commercial, industrial, and for electric power generation.[55] The plot below shows the GHG emissions attributable to natural gas consumption in these four sectors from 2016 to 2020 based on data from the EIA [56] and analysis by ICF.

Figure 6-4. GHG Emissions from Natural Gas Consumption by Sector in Michigan



---

[55] Natural gas is also consumed as a transportation fuel in Michigan, but it represents less than 0.1% of total consumption statewide.

[56] Natural Gas Consumption by End Use, US EIA. Available online at https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SMI_a.htm.

It is unlikely that RNG will be used to displace fossil natural gas in the electric power generation sector because that pathway will be more expensive than electric power generation from other resources. For instance, the EIA recently estimated that the LCOE of electricity produced from combined cycle power plants powered by natural gas would be about $37 per megawatt hour (MWh) in 2027, and that about $26/MWh of this cost was attributable to the variable cost, which is primarily attributable to natural gas costs. Comparatively, wind and solar electricity generation would have a LCOE of $33-38/MWh.[57] RNG would cause the variable costs of natural gas fired combined cycle plants to more than double, increasing the LCOE by at least 70%. In other words, there are likely to be more cost-effective uses of RNG than in decarbonizing electricity generation. As such, ICF focuses on the other three end uses shown in the graph above: residential, commercial, and industrial. Although RNG will be more expensive than natural gas, it will be more cost competitive with other decarbonization opportunities in these sectors, as discussed in more detail in Section 7.

The trends shown in the figure above show that average annual GHG emissions from natural gas consumption in these three sectors is about 36 MMtCO_2e. In other words, if RNG was used to displace conventional gas in these three sectors, it could decrease GHG emissions in these sectors by 8% to 21% based on current levels of consumption. ICF also notes that as efficiency improvements and other market forces that decrease the demand for natural gas in these sectors take hold, the role of RNG will be increasingly important. Consider for instance a 15% decrease from today’s levels of natural gas consumption over the same period that it takes to develop the RNG supply potential that ICF developed for the Achievable and Feasible scenarios. This would mean that RNG would decrease GHG emissions by 10% to 26% when paired with efficiency gains and/or other measures that decrease natural gas consumption.

RNG and Decarbonization

As shown by the cost estimates provided in Section 5, RNG costs more than conventional natural gas, when environmental benefits are not fully valued. However, the objective for enhanced RNG production and deployment is not to be cost-competitive to conventional natural gas on a dollars-per-MMBtu basis.

Instead, the benefit of RNG is derived from the valuable environmental attributes associated with RNG, and the GHG emission reductions when RNG displaces conventional natural gas consumption. Outside of the transportation sector, these positive environmental attributes are not currently credited, indicating a policy and regulatory framework that does not effectively value the role of RNG.

With the commitment to deep and long-term decarbonization objectives, including in Michigan, strategies and policies will need to be implemented to deliver on these ambitious goals. In contrast to the current regulatory structure, in a decarbonization framework RNG is a renewable resource with carbon-neutral (and in some cases, carbon-negative) characteristics, and the GHG emissions from RNG are lower than conventional natural gas across the board.

---

[57] EIA, Levelized Costs of New Generation Resources in the Annual Energy Outlook 2022. Available online at https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf. Values are shown in 2021 dollars per MWh.

To assess the cost-effectiveness of RNG as a GHG emission reduction measure, the relevant metric is not the commodity cost in dollars-per-MMBtu but instead GHG abatement costs. Abatement costs are measured in dollars-per-unit of GHG emission reductions, typically metric tons of carbon dioxide equivalent ($/t$CO_2$e). Estimating and comparing the cost-effectiveness of different GHG emission reduction measures is challenging and results can vary significantly across temporal and geographic considerations.

RNG Cost-Effectiveness

The GHG cost-effectiveness is reported on a dollar-per-ton basis and is calculated as the difference between the emissions attributable to RNG and conventional natural gas. For this report, ICF followed IPCC guidelines and does not include biogenic emissions of CO_2 from RNG. The cost-effectiveness calculation is simply as follows:

$$\Delta(RNG_{cost}, Fossil\ NG_{cost}) \big/ 0.05306\ MT\ CO_{2e}$$

where the RNG_{cost} is simply the cost from the estimates reported previously. For the purposes of this report, we use a conventional natural gas cost equal to the three-year rolling average Henry Hub spot price reported by the EIA for years 2019 to 2021,[58] adjusted for inflation to dollars in 2022 ($2022) and calculated as $3.11/MMBtu. ICF notes that the average spot price of natural gas via Henry Hub through April 2022 has averaged about $5.14/MMBtu or 1.65 times higher than the three-year rolling average considered in this report. If these higher prices were to persist, then it would *decrease* the abatement cost of RNG as a replacement for conventional gas in real terms, and likely the relative abatement costs of non-gas alternatives.

The front end of the supply-cost curve is showing RNG of less than $10/MMBtu, which is equivalent to about $130 per metric ton of carbon dioxide equivalent (tCO_2e). As the estimated RNG cost increases to $25/MMBtu, we report an estimated cost-effectiveness of above $400/t$CO_2$e. This range in cost for RNG can be converted to provide an equivalent range for the cost-effectiveness of RNG for GHG emission reductions, in dollars per tCO_2e.

Summary of GHG Emission Reductions from RNG Supply Scenarios

When applying a combustion accounting framework and treating CO_2 emissions from the combustion of biogenic renewable fuels as zero, ICF estimates that 3 to 9 MMtCO_2e of GHG emissions could be reduced per year in 2050 in Michigan through the deployment of RNG based on the Achievable and Feasible scenarios. For abatement cost estimates, RNG at under $10/MMBtu is equivalent to about $130/t$CO_2$e, while RNG at $20/MMBtu has an estimated cost-effectiveness of about $300/t$CO_2$e.

---

[58] EIA, Natural Gas Data, available online at https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm

The GHG emission reduction potential for RNG is best understood in the context of cost-effectiveness or in units of dollars per ton of emissions reduced. The reasoning is simple: absent unexpected cost reductions in RNG production technology, there will always be a potential “sticker shock” associated with RNG when framed using traditional metrics like dollars per unit energy (e.g., $/MMBtu). However, the cost-effectiveness of RNG deployment is a better metric to contextualize the opportunities for and barriers to broader RNG deployment as part of deep decarbonization considerations.

7. GHG Abatement Cost Comparison

As outlined in the previous section, the first step to evaluate the cost effectiveness of a GHG emission reduction measure is to estimate the abatement cost in a translatable metric, such as $\$/tCO_2e$. The second component is to compare the dollar-per-ton estimates outlined in the previous section with other GHG emission reduction measures. ICF notes that estimating the cost-effectiveness of different GHG emission reduction measures is challenging and results can vary significantly across temporal and geographic considerations.

ICF also notes that the intent of this study is not to develop new analysis and modeling that estimates abatement costs for emission reduction measures beyond RNG, such as residential electrification and renewable hydrogen. Instead, the objective is to compare the RNG abatement cost range developed in this study to the costs of other abatement measures sourced from existing research and studies.

The abatement measures within scope for cost comparison are organized into four groups:

- Renewable hydrogen blending;
- Building electrification;
- Electricity generation; and
- Transportation electrification.

Below is a summary table of the estimated abatement cost ranges for the four groupings of abatement measures, as well as the underlying source analyses for the abatement cost ranges. The following subsections provide a brief description of each analysis.

Table 7-1. Summary of Abatement Costs for Emission Reduction Measures

Emission Reduction Measure	Abatement Cost ($/tCO$_2$e) Low	Abatement Cost ($/tCO$_2$e) High
RNG (this study)	**$132**	**$510**
Renewable Hydrogen Blending Range	**$183**	**$296**
ICF Production Cost Estimates in 2050	$183	$296
Comparisons (Columbia Center on Global Energy Policy and US DOE)	$85	$791
Building Electrification Range	**$0**	**$1,000**
Pennsylvania Climate Action Plan[59]	-	$502
University of Texas, Carnegie Mellon & University of Michigan[60]	$0	$1,000
Electricity Generation	**$69**	**$446**
E3: PJM 80-100% RPS 2050 (2020)[61]	$69	$220
EFI & E3: New England Net Zero (2020)[62]	-	$446
Transportation Electrification	**$135**	**$599**
ICF Comparison of Medium and Heavy-Duty Truck Technologies[63]	$135	$400
E3: Deep Decarbonization in a High Renewables Future[64]	$359	$599

---

[59] Pennsylvania Department of Environmental Protection, 2021. Pennsylvania Climate Action Plan, https://www.dep.pa.gov/Citizens/climate/Pages/PA-Climate-Action-Plan.aspx

[60] Thomas A Deetjen *et al* 2021 *Environ. Res. Lett.* 16 084024. US residential heat pumps: the private economic potential and its emissions, health, and grid impacts, https://iopscience.iop.org/article/10.1088/1748-9326/ac10dc#erlac10dcs6.

[61] E3, 2020. Least Cost Carbon Reduction Policies in PJM, https://www.ethree.com/least-cost-carbon-reduction-in-pjm/.

[62] E3 and EFI, 2020. Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future, https://www.ethree.com/new-study-evaluates-deep-decarbonization-pathways-in-new-england/.

[63] ICF updated analysis of Comparison of Medium- and Heavy-Duty Technologies in California. Available online at https://efiling.energy.ca.gov/GetDocument.aspx?tn=236878.

[64] California Energy Commission, 2018. Deep Decarbonization in a High Renewables Future, https://www.energy.ca.gov/publications/2018/deep-decarbonization-high-renewables-future-updated-results-california-pathways.

Renewable Hydrogen Blending

Renewable hydrogen (or “green hydrogen”) in the context of this report refers to hydrogen generated from electrolysis using renewable electricity, also referred to as power-to-gas (P2G). The key process in P2G is the production of hydrogen from renewably generated electricity by means of electrolysis. Electrolyzers split water into hydrogen and oxygen, where if the electricity is sourced from renewable resources, such as wind and solar, then the resulting hydrogen is carbon neutral.

This hydrogen conversion method is not new, and there are three electrolysis technologies with different efficiencies and in different stages of development and implementation:

- Alkaline electrolysis, where two electrodes operate in a liquid alkaline solution,
- Proton exchange membrane electrolysis, where a solid membrane conducts protons and separates gases in a fuel cell, and
- Solid oxide electrolysis, a fuel cell that uses a solid oxide at high temperatures.

The hydrogen produced from P2G is a highly flexible energy product that can be:

- Stored as hydrogen and used to generate electricity at a later time using fuel cells or conventional generating technologies,
- Injected as hydrogen into the natural gas system, where it augments the natural gas supply,
- Converted to methane and injected into the natural gas system, or
- Injected into a dedicated hydrogen pipeline.

Noting the different uses for hydrogen outlined above, for this abatement cost comparison we have limited the consideration of renewable hydrogen to volumes that can be mixed directly with natural gas in existing pipeline systems without changes to infrastructure or end-use equipment. The blend limit of hydrogen in existing natural gas distribution systems is an evolving area of research and analysis, and can vary depending on the physical characteristics of the system as well as end use appliances. Despite this uncertainty, there are indications that hydrogen can be blended up to 20 percent by volume (7 percent by weight) without adverse effects to existing gas infrastructure and without significant upgrades.[65]

Based on this approach, the costs associated with the deployment of renewable hydrogen as an emission reduction measure are limited to the production cost of the hydrogen itself. ICF developed hydrogen production costs using a series of assumptions regarding the following key parameters: a) electrolyzer costs and efficiency, b) the cost of renewable electricity as a function of how it is delivered to the electrolyzer (e.g., via curtailed renewable electricity or dedicated renewable electricity), and c) the capacity factor for P2G systems.

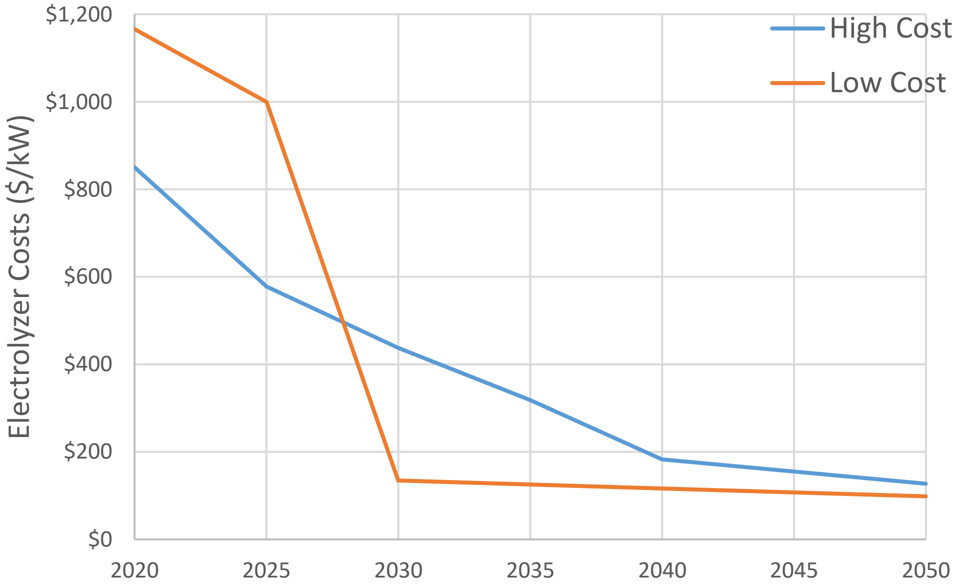
Electrolyzer Costs and Efficiency

ICF developed the installed cost of electrolyzers on a dollar per kilowatt ($/kW) basis. The graph below illustrates ICF’s assumptions regarding the installed costs of electrolyzers; we assumed that the resource base for electrolyzers would be some blend of proton exchange membrane (PEM), alkaline systems, and solid oxide systems. Rather than be deterministic about which technology will be the preferred technology, we present the cost as a blended average of the $/kW installed. This is based on ICF's review of literature and review of assumptions developed by UC Irvine[66] and by Bloomberg New Energy Finance (BNEF).[67] Using this approach, ICF's estimates an electrolyzer cost in the range of $98/kW to $127.50/kW in 2050, shown in the figure below.

---

[65] California Energy Commission, 2021. 2021 Integrated Energy Policy Report Volume III: Decarbonizing the State’s Gas System, https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report.

Figure 7-1. Installed Capacity Cost of Electrolyzers, $/kW, 2020-2050



ICF assumed improved efficiencies over time for electrolyzers consistent with the values presented in the figure below. The peak efficiency of 77% by 2050 is consistent with estimates reported by UC Irvine and BNEF.

Cost of Renewable Electricity

The levelized cost of renewable electricity is a critical parameter in the determination of the levelized cost of renewable hydrogen production. BNEF, for instance, recently reported renewable hydrogen costs based on an assumed LCOE for renewable electricity in the range of $15-20/MWh. ICF took a more nuanced view of LCOE of renewable electricity in this analysis, considering regional considerations and data from the National Renewable Energy Laboratory (NREL).

In our consideration of curtailed renewable electricity, ICF assumes that the cost would be around $40-45/MWh to cover the costs of transmission and distribution of the electricity, but that the commodity cost would be zero.

---

[66] The Challenge of Retail Gas in California's Low-Carbon Future, CEC-500-2019-055-F, available online at https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf.
[67] Hydrogen Levelized Cost Update 2021, Bloomberg New Energy Finance, Confidential.

To develop hydrogen production costs from dedicated renewables, ICF used 2021 LCOE and capacity factor estimates from NREL's Advanced Technology Baseline (ATB) data. More specifically, ICF assumed that electrolyzers used to produce green hydrogen would be powered by a mix of dedicated renewable electricity installations, including from off-shore wind, land-based wind, and utility scale solar PV.

Although curtailed renewable electricity is likely to be inexpensive, it will only be intermittently available based on supply-demand dynamics in the electricity sector. ICF made the assumption that curtailed renewable electricity will enable an electrolyzer system to operate at a maximum 10% annual capacity factor. Conversely, ICF assumed that by 2050 dedicated renewable electricity systems will be able to operate at a weighted average annual capacity factor consistent with the values reported in NREL's ATB 2021. Using these assumptions, dedicated renewables lead to better economics than curtailed renewables, and so all modeling cases assumed dedicated renewables.

To determine a low-end abatement cost for renewable hydrogen, ICF used low cost estimates for electrolyzers, the lower costs for LCOE and higher capacity estimates in our sensitivity analysis from NREL's ATB 2021. The low-end production cost for renewable hydrogen is estimated at $11.35/MMBtu or $1.70/kg in 2050.

To determine a high-end abatement cost for renewable hydrogen, ICF used high cost estimates for electrolyzers, the more conservative estimates for LCOE and capacity factors of renewable electricity from NREL's ATB 2021. The high-end production cost for renewable hydrogen is estimated at $16.78/MMBtu or $2.51/kg in 2050.

ICF's estimated costs of renewable hydrogen yield a GHG abatement cost of \$155/tCO_2e to \$258/tCO_2e in 2050.

Comparable References

The Columbia Center on Global Energy Policy estimates that the current production cost for renewable hydrogen is $6.04/kg using grid renewables, and as a high as $8.30/kg for production facilities using dedicated renewables.[68] Unlike ICF's analysis, the Columbia Center on Global Energy Policy developed the analysis based on current capital and electricity cost estimates and they did not take into account any cost reductions in the future. For instance, the U.S. Department of Energy Hydrogen Shot outlines a pathway to reduce the cost of renewable hydrogen to $1.00/kg through reductions in three crucial cost areas: input renewable electricity, capital, and operating and maintenance.[69] However, the Columbia Center on Global Energy Policy does not assume any cost reductions.

Building Electrification

Building electrification describes the strategy of shifting to use electricity for building energy uses like space heating and cooking. The biggest focus tends to be on heat pumps. In residential and commercial buildings, appliances powered by natural gas, propane, or heating oil powered appliances (e.g., furnaces and boilers) are assumed to be ground- or air-source heat pumps. Similarly, gas-powered heaters can be replaced with heat pump water heaters. Furthermore, kitchen appliances running on natural gas can be replaced with electric ranges and induction stove tops.

---

[68] Columbia Center on Global Energy Policy, 2019. Low-Carbon Heat Solutions for Heavy Industry: Sources, Options and Costs Today, https://www.energypolicy.columbia.edu/sites/default/files/file-uploads/LowCarbonHeat-CGEP_Report_100219-2_0.pdf.

[69] U.S. DOE Hydrogen Shot, 2021. https://www.energy.gov/eere/fuelcells/hydrogen-shot.

Determining the impact of building electrification (e.g., via costs and GHG emissions) relies on assumptions and sophisticated analysis regarding how renewable electrons are delivered on an as-needed basis (i.e., dispatched) to align electricity demand with renewable electricity generation.

To estimate abatement levels and the associated costs of building electrification, any analysis would need to include appliance and equipment costs, installation costs, maintenance costs, fuel costs (including electric system costs) and conversion or retrofit costs. Focusing on a subset of these costs, such as a comparison of upfront appliance costs, would not deliver a robust and complete picture of the costs and benefits of building electrification.

As noted at the start of this subsection, estimating the cost-effectiveness of emission reduction measures is challenging and results can vary significantly. Building electrification, and residential building electrification in particular, showcases this variability, with temporal and geographic considerations, combined with modeling assumptions and limitations, delivering a wide range of abatement cost estimates.

For example, a core component of building electrification is the deployment of heat pumps for space heating and cooling. Heat pumps operate as reversible air conditioners, in that they act as air conditioners in summer, and reverse the flow in winter to become heaters. In winter heat pumps absorb heat from outdoors and release it inside the building, with electricity used to do the mechanical work to move heat (rather than produce heat).

Heat pump adoption has the potential to significantly increase peak electricity demand and shift the seasonal timing of peak demand (such as from summer to winter). The operation of heat pumps is also impacted by climate and temperature, as they are less efficient and consume more energy in colder environments, exacerbating electricity demand issues as well as operation costs. For example, the Rocky Mountain Institute found that the coefficient of performance for heat pumps declined from 3.5 at 47°F to 1.4 at –13°F in Illinois and Rhode Island.[70]

In comments submitted to MPSC, stakeholders noted a variety of key factors associated with incorporating heat pumps into any building electrification analysis. For instance, one stakeholder requested that to reflect Michigan's climate, any building electrification comparison should use cold climate air source heat pumps (ccASHPs) that have higher efficiency ratings and may provide greater efficiency gains than their relative difference in Heating Season Performance Factor (HSPF) ratings. ICF notes that the two studies that are described in more detail below do not focus on ccASHPs.

---

[70] Rocky Mountain Institute, 2018. The Economics of Electrifying Buildings, https://rmi.org/insight/the-economics-of-electrifying-buildings/.

To ensure consistency with the abatement cost estimates for RNG and other measures, building electrification abatement costs used for comparison in this study need to incorporate input assumptions broadly consistent with the geography and climate of Michigan in the absence of any Michigan-specific data. The first study discussed below covers a broad range of geographies whereas the latter is focused on Pennsylvania.[71]

University of Texas, Carnegie Mellon & University of Michigan

Researchers from the University of Texas, Carnegie Mellon and University of Michigan simulated energy consumption of 400 representative single-family houses in 55 US cities both before and after heat pump adoption in an attempt to estimate the costs and benefits of increased heat pump adoption, taking into account housing stock, electric grid, energy prices, and technology.[72] ICF finds this study particularly helpful in emphasizing the significant variance in electrification costs, and associated abatement costs.

The study includes energy prices, CO_2 emissions, health damages from criteria air pollutants, and changes in peak electricity demand to quantify the costs and benefits of each house's heat pump retrofit. Cumulative costs and benefits are based on the typical life time of a heat pump, assumed to be 15 years. These costs and benefits are adjusted over this time period to account for relevant trends, such as declining emissions from the electric grid.

At a high level, the study found that roughly 20% of residential US housing stock would benefit economically by replacing existing heating with a heat pump. However, the study recognizes that climate is crucial to realizing the economic benefit of heat pump adoption, with mild climates demonstrating the greatest potential for this switch. In addition, the study found that "switching a home's heating fuel from natural gas to heat pumps rarely produces a benefit, especially in cold climates where there are almost no houses where such a switch makes sense".

The results of the study do not specifically present detailed abatement costs across climates and housing types. However, the research notes:

- 28% of US residential housing stock have abatement costs in the range of \$0/tCO_2e to \$200/tCO_2e.
- 66% of US residential housing stock have abatement costs in the range of \$200/tCO_2e to \$1,000/tCO_2e.
- 6% of US residential housing stock have abatement costs exceeding \$1,000/tCO_2e.

---

[71] ICF notes that there are studies available in the public domain that may seem relevant at first glance. For instance, ICF reviewed the *Massachusetts 2050 Decarbonization Roadmap*. That study's section on building electrification implies that building electrification has a *negative* cost per ton of emission reduction for most buildings (which implies that society yields a net benefit, not a net cost). However, this study exemplifies the challenge comparing across abatement strategies in a consistent manner. ICF ultimately excluded the study from this report because it does *not* provide an adequate estimate for building electrification. More specifically, the abatement cost estimates are limited to capital costs associated with building electrification, and *do not* include other costs such as fuel and system-wide investments required to accommodate the electrification envisioned in the study.

[72] Deetjen et al, 2021. Environmental Research Letters, 16-084024, US residential heat pumps: the private economic potential and its emissions, health, and grid impacts, https://iopscience.iop.org/article/10.1088/1748-9326/ac10dc#erlac10dcs6.

Pennsylvania Climate Action Plan

Pennsylvania's 2021 Climate Action Plan (PA-CAP)[73] outlines a pathway to reach Pennsylvania's GHG reduction goal of 80 percent by 2050 from 2005 levels. The economy-wide plan includes modeling and analysis of 18 different emission reduction strategies, including a detailed assessment of residential and commercial electrification. This electrification strategy includes incentivizing building electrification (e.g., heating and hot water) for the residential and commercial sectors, inclusive of converting fuel oil and natural gas use to electricity use in existing buildings and electrification of new buildings when there are large natural gas infrastructure costs or when fuel oil is the alternative.

The PA-CAP methodology involved an average annual energy savings potential for new and existing residential and commercial buildings to estimate energy consumption (natural gas, and fuel oil) reductions from electrification. GHG emission factors for electricity were consistent with the decarbonization of Pennsylvania's consumption to meet the 80 percent reduction target. The natural gas emissions factor reflected the PA-CAP's modeled deployment of RNG over time. Electrification conversion factors assumed a Heating Seasonal Performance Factor for residential single family and multifamily of 8.2. Electrification of commercial sector included a 18% efficiency electrification factor taken from American Council for an Energy Efficiency Economy's "Electrifying Space Heating in Existing Commercial Buildings" study. Since electrification and cold climate heat pumps are still early technology, a 1% annual improvement curve for capital costs and associated incentives was included in alignment with air source heat pump projections from NREL's "Electrification Future's Study".[74]

While the weather and climate conditions of Pennsylvania and Michigan are not identical, ICF considers that there are enough similarities in climate, and subsequent operation of electric space heating appliances, to allow for a reasonable comparison of electrification abatement costs. This is contrast to other studies of electrification measures with climate conditions distinct from Michigan, such as in California.[75] Furthermore, electric rates in Michigan and Pennsylvania are comparable, with Michigan's average price of electricity across all sectors just 16-17% higher than for Pennsylvania.[76]

The PA-CAP outlines emission reductions, in tCO_2e, and costs, in 2021$, for the suite of building electrification incentive programs included in the pathway out to 2050. From these figures the abatement cost is estimated at $502/tCO_2e.

---

[73] Pennsylvania Department of Environmental Protection, 2021. Pennsylvania Climate Action Plan, https://www.dep.pa.gov/Citizens/climate/Pages/PA-Climate-Action-Plan.aspx.

[74] National Renewable Energy Laboratory (NREL), 2017. Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050, https://www.nrel.gov/docs/fy18osti/70485.pdf.

[75] For example, abatement cost estimates included in Energy Futures Initiative's Deep Decarbonization Pathways for California is not considered pertinent given the generally different climates of California and Michigan.

[76] Based on ICF analysis of data from the Electric Power Monthly, published by the EIA, available online at https://www.eia.gov/electricity/monthly/.

Electricity Generation

The decarbonization of electricity generation encompasses a significant number of different emission reduction measures, with a large scope of measures that can be narrow, such as a single renewable electricity project, or broad, including jurisdictional emission reduction targets for electricity grids.

As noted previously, the RNG market is transitioning away from biogas to electricity projects and towards pipeline injection in part because it is not as cost-effective to generate electricity using biogas as other renewable resources. For instance, the table below is reproduced from a Waste to Energy from Municipal Solid Waste Report prepared for the DOE in 2019, and shows selected project costs of electricity in cents per kilowatt-hour, including for biogas to electricity projects.[77]

Solar PV	Onshore Wind	Offshore Wind	Natural gas, Combined Cycle	Natural gas, Combustion Turbine	Conventional Coal	Biogas
6.3	5.9	13.8	4.9	9.9	10.3	8.2-19.6

The authors conclude that “based on the limited amount of techno-economic analysis that is publicly available, MSW or biomass-based power generation can be among the most expensive options for producing electricity.”

Although not included in the table above, ICF notes that LCOE of electricity generation from nuclear power is reported in the range of 4.39 to 9.86 c/kwh depending on the discount rate employed for plants built in the 2020 to 2025 timeframe.[78]

The table above also highlights why there is such a strong focus on decarbonizing electricity generation using renewables like solar photovoltaics (PV) and wind: Their costs are competitive today with conventional alternatives and are projected to decrease over time.

New England Net-Zero

E3 and EFI conducted a detailed analysis of New England’s electricity system’s reliability in the context of reducing emissions to nearly zero. They found that meeting this dual challenge cost-effectively will involve the addition of large amounts of wind, solar, and battery storage resources, complemented by firm capacity to provide generation during extended periods of low wind and solar availability—including natural gas power plants, nuclear, hydrogen generation, or other yet-to-be commercialized options such as long-duration storage.

Under the High Electrification Scenario, E3 and EFI report marginal abatement costs relative to a reference case scenario—and that reference case scenario assumes a 50% RPS. In other words, the marginal cost is the difference between achieving a net zero emissions target compared to the GHG emissions in a 50% RPS scenario. For the sake of reference, the New

---

[77] DOE, Office of Energy Efficiency and Renewable Energy, Waste-to-Energy from Municipal Solid Wastes, August 2019. https://www.energy.gov/sites/prod/files/2019/08/f66/BETO--Waste-to-Energy-Report-August--2019.pdf.

[78] OECD IEA & NEA, Projected Costs of Generating Electricity, 2020 Edition, Table 3.13a, assuming 85% capacity factor and discount rates of 3% to 10%.

England states considered in the E3 and EFI analysis emitted about 170 MMtCO$_2$e in 2016. The marginal cost of abatement of reducing GHG emissions in the High Electrification scenario to 10 MMtCO$_2$e in 2050 was about \$125/tCO$_2$e; however, reducing it to 2.5 MMtCO$_2$e and then 0 MMtCO$_2$e in 2050 showed a marginal abatement cost of \$442/tCO$_2$e and \$446/tCO$_2$e, respectively. Importantly, the E3 and EFI analysis assumed in their High Electrification Scenario that renewable hydrogen would be available in lieu of conventional natural gas molecules for electricity generation. To achieve net zero emissions without any combustion of gaseous renewable hydrogen and relying exclusively on renewable electricity and storage would increase the marginal abatement cost to nearly \$8,000/tCO$_2$e.

Least Cost Carbon Reduction Policies in PJM
E3 evaluated least cost carbon reduction policies in the PJM region in a "least-cost, least-regrets manner." The analysis was built around different policies that would achieve decarbonization targets. By 2050, E3 reports a range of \$23-77/tCO$_2$e associated with grid decarbonization. The variation in the average abatement cost is a function of the policy. For instance, E3 report that achieving an 80% RPS for the PJM region would have an average cost of about \$69/tCO$_2$e whereas a program designed to achieve 80% GHG emission reductions is more cost-effective at \$23/tCO$_2$e. However, the lower costs in the GHG emission reduction scenario are achieved through a policy that encourages more-efficient, lower-emissions resources to replace less-efficient, higher-emitting ones (e.g., switching from coal to gas). Furthermore, the GHG emission reduction scenario enables gas power generators to use drop-in biofuels in later years. As a result of the focus on GHG emission reductions, rather than renewable electricity deployment, the GHG reduction scenarios build less renewable capacity compared to the 80% RPS case, retire the coal fleet by 2030, and keep nuclear capacity online to meet the GHG targets.

ICF limited the extraction of abatement costs to the scenarios that are tied to renewable energy production via the RPS cases, focusing on the 80% and 100% RPS cases presented in the analysis. For the 80% RPS case, E3 reports an average abatement cost of about \$69/tCO$_2$e; ICF estimates that the average abatement cost for the 100% RPS case is closer to \$220/tCO$_2$e. ICF also notes that there are average abatement costs reported, and not marginal abatement costs—at the margin, the abatement costs are closer to \$500/tCO$_2$e based on ICF's analysis of data presented in the study.

Transportation Electrification

Transportation electrification is a set of broad emission reduction measures encompassing all forms of transportation, from light-, medium- and heavy-duty vehicles through to off-road transportation types including rail. With this wide-ranging grouping, the emission reduction potential and associated costs of specific types of electrification can vary significantly.

To deliver a more targeted abatement cost comparison relevant to RNG, ICF will limit the consideration of transportation electrification types where RNG is or has the potential to be a cost-effective emission reduction measure, focused on medium- and heavy-duty vehicles (M&HDVs). RNG is already a viable option to decarbonize M&HDVs, with established vehicle technologies and pathways for RNG to be used as a transportation fuel.

In contrast to building electrification, the abatement costs associated with the electrification of M&HDVs are relatively consistent across geographies and climate (notwithstanding changes in battery efficiencies across temperatures). For this reason, transportation electrification studies and analyses considered for abatement cost comparison do not necessarily need to be Michigan specific.

ICF notes that transportation electrification and RNG are unlikely to be “competitors” or “alternatives” in Michigan in the mid- to long-term future. To be clear, RNG is not a substitute for gasoline. Rather, most RNG is used in compressed natural gas (CNG) vehicles in the medium- and heavy-duty market segments (e.g., transit buses, refuse haulers, regional haul trucks, etc.). By way of background, CNG is not consumed in significant volumes in Michigan. There are fewer than 25 CNG stations in Michigan and ICF estimates that the estimated annual consumption of CNG is about 3 to 5 million diesel gallon equivalents (DGE). Comparatively, there are about 1 billion gallons of diesel and 4.5 billion gallons of gasoline consumed in Michigan.

ICF’s Comparison of Medium- and Heavy-Duty Technologies

ICF was contracted by the California Electric Transportation Coalition and the Natural Resources Defense Council (NRDC). The study was prepared in partnership with the Union of Concerned Scientists, Earthjustice, BYD, Ceres, and NextGen Climate America, with advisory support from the University of California, Davis Policy Institute for Energy, Environment and the Economy, and East Yard Communities for Environmental Justice. ICF analyzed fourteen different types of medium- and heavy-duty vehicle classes, included a total cost of ownership calculation, an emissions impact assessment, and a macroeconomic analysis of various transportation investments required to reduce GHG emissions.

The total cost of ownership included cost components for the vehicle, operation and maintenance (e.g., fuel costs), and fueling infrastructure (e.g., charging infrastructure). When excluding incentives available in California (e.g., LCFS credits, utility incentives, and other state incentives), and depending on the vehicle class or vocation, electrification is still likely to be an appealing alternative to diesel trucks in the 2030 to 2050 timeline, assuming that battery prices continue to decrease.

ICF employed the same methodology in the previous study, including the same cost assumptions for vehicles, but updating electricity costs and non-electricity fuel costs for data specific to Michigan, and excluding any incentives or grants unique to California. ICF’s updated analysis of the total cost of ownership across the same vehicle classes presented in the previous study indicates a GHG abatement cost range of about \$135/tCO$_2$e to \$400/tCO$_2$e for medium- and heavy-duty electric vehicle segments considered.

Deep Decarbonization in a High Renewables Future

E3’s study for the California Energy Commission evaluated long-term energy scenarios to investigate options and costs for California to achieve a 40 percent reduction in GHGs emissions by 2030 and an 80 percent reduction in GHG emissions by 2050. The analysis incorporated mitigation strategies across all economic sectors.

As part of the analysis for the California Energy Commission, E3 included what they referred to as a truck portfolio, inclusive of battery electric trucks, hydrogen fuel cell vehicles, CNG vehicles, and hybridized powertrains. More specifically, E3 describes their mitigation scenario assuming

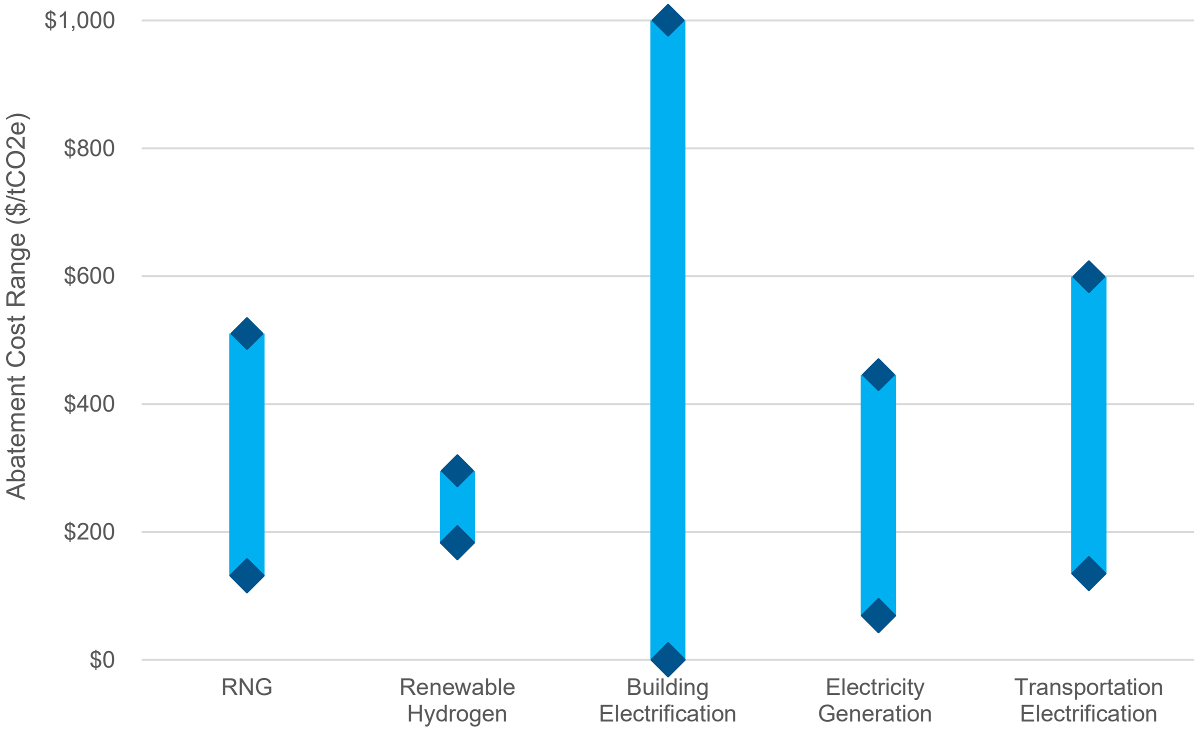
> that battery trucks can displace no more than 50% of truck vehicle miles (those used for shorter-haul distances), while fuel-cell trucks are assumed to serve longer-haul heavy duty trucking. As a result, hydrogen fuel cell heavy-duty trucks are a key “reach technology” in this scenario.

The E3 report does not specifically call out the GHG abatement costs for each of the truck technologies considered; rather the report presents a range across the truck portfolio. E3 reports a range of \$300/tCO_2e to \$500/tCO_2e for the truck portfolio in the High Renewables Future in 2016 dollars. When adjusted to 2022 dollars, this is represents a range of about \$359-599/ tCO_2e.

Abatement Cost Comparison

Figure 7-2 below shows a comparison of the selected measures as outlined in Table 7-1.

Figure 7-2. GHG Abatement Costs, Selected Measures (\$/tCO_2e)



Across all the selected measures, there are broad ranges of abatement costs. While these ranges are very broad, ICF finds that these large ranges actually reflect the unique circumstances and factors involved with the practical and detailed implementation of each emission reduction measure. Costs and emission reductions are greatly influenced by technology costs, efficiencies and availability, climate and geography, practical infrastructure constraints, whether local or system-wide, and the interconnected nature of emission reduction trends across the economy.

These abatement cost ranges make direct comparisons across emission reduction measures challenging, particularly if there is a lack of rigorous analysis designed for specific circumstances, such as in the context of Michigan. Furthermore, ICF asserts that a GHG abatement analysis conducted for each strategy included in Figure 7-2 with assumptions unique to Michigan would likely yield narrower ranges, as the analyses from other states and regions either do not include assumptions specific to Michigan or apply generalizing assumptions to reflect a broader geographic scope. However, the abatement cost estimates for RNG developed as part of this study can be used as a starting point to enable effective comparisons across emission reduction options.

In addition, it is clear based on the abatement costs shown in Figure 7-2 that RNG is potentially cost-competitive as an emission reduction approach, compared to other options relevant to the end-use of the RNG. For example, at a high level RNG is cost competitive with other low carbon gaseous fuels, such as renewable hydrogen (putting aside pipeline specifications and blending constraints).

In short, the abatement cost comparison outlined above shows that RNG can play a cost-effective role in achieving aggressive decarbonization objectives over the long-term, particularly as part of a comprehensive economy-wide strategy to reduce GHG emissions.

8. Opportunities and Barriers to RNG Production in Michigan

There are multiple opportunities for the deployment of RNG as an effective GHG emission reduction measure. The physical and environmental characteristics of RNG make for high development potential in Michigan, particularly in the context of ambitious long-term climate objectives. However, barriers and challenges remain, including limited capacity in current end-use markets, environmental impacts and social justice issues for some RNG feedstocks, and a limited policy structure. These barriers will need to be appropriately and adequately addressed through a robust, transparent and fair policy and regulatory environment that is not just limited to RNG, but for climate action more broadly.

The deployment of, and end-use demand for RNG is nascent but growing. With the ongoing expansion of the RNG market, there is increasing attention given to the opportunities and barriers associated with RNG production, delivery and end-use. In this section, ICF considers the highest-value opportunities and the corresponding challenges to realizing the potential of these opportunities in the RNG market. While the technical, market, regulatory, and environmental drivers for RNG are inextricably linked, we have distinguished between the key opportunities and challenges across these broad areas.

Technical

The technical potential for RNG over the next decade is constrained primarily by regulatory and market constraints, rather than technical ones. In large part, this is attributable to the fact that there are multiple feedstocks that can be converted to RNG using anaerobic digestion—this is a mature technology. Moving past 2025 and into a post-2030 reality, however, the technical potential for RNG will be constrained by the ability to expand beyond anaerobic digestion of feedstocks like landfill gas, animal manure, WRRFs, and food waste, and into technologies like thermal gasification. Thermal gasification is advancing rapidly, however, it should be considered in pre-commercial stages or very early commercial deployment. The transition to this type of production technology increases long-term RNG production potential substantially and can help drive down the long-term costs of RNG.

Opportunities

- **RNG fulfills current definitions of a renewable resource in Michigan with carbon neutral characteristics using a combustion accounting framework for GHG emissions.** The GHG benefits of RNG are clear: GHG emissions from RNG are lower than conventional natural gas across the board. The introduction of RNG has the potential to reduce GHG emissions significantly from the natural gas system. Furthermore, these GHG emission reductions are supported by policies that can improve waste management (e.g., landfill diversion), improve utilization of agricultural and forestry products, and generate additional revenue streams for some vulnerable parts of the economy.
- **RNG utilizes the same existing infrastructure as conventional natural gas.** When conditioned and upgraded to pipeline specifications, RNG can use the same extensive

system of pipelines for the transmission and distribution of natural gas. Improved and continuous monitoring of potential harmful constituents from RNG production can decrease the technical risks of contamination in the pipeline.

Barriers

- **Feedstock location and accessibility will constrain RNG production potential.** The location and availability of RNG feedstocks is mismatched with traditional demand centers for natural gas consumption. For example, many feedstocks are available in predominantly rural areas whereas demand is focused in urban centers. Some of these feedstocks may be difficult to access or may require substantial (and in some cases impractical) investments in infrastructure.
- **Competition for feedstocks will constrain RNG production potential.** There is a diverse array of feedstocks available for RNG production yet accessing some of those feedstocks can be difficult or prohibitive. Furthermore, as waste diversion policies improve over time, and decarbonization efforts presumably expand, biogenic and biomass feedstocks will have increasing value, thereby increasing competition for various energy production processes, including for gaseous fuels (i.e., RNG), liquid fuels (e.g., liquid biofuels like renewable diesel), and for renewable electricity. Technological advances in each of these markets will help determine the appropriate use of each feedstock, while the availability of that feedstock will still be constrained by other factors, including the rate of waste produced, agricultural outputs, and forestry outputs.
- **Gas quality and gas composition for RNG remains an engineering concern.** There is no existing industrywide standard for RNG gas quality and gas composition, and with limited operational data, some concerns remain regarding RNG injection into a pipeline system.

  For RNG to be suitable for introduction into the natural gas pipeline network, the initial raw biogas must be adequately processed to meet pipeline tariffs, state gas quality regulations, and end-use application standards. At a high level, this typically involves concentrating the methane content and removing any problematic constituents.

  While RNG is fundamentally interchangeable with conventional natural gas, different RNG feedstocks pose different challenges for gas quality and composition. For example, raw (unprocessed) biogas from a landfill facility is different than biogas from a dairy digester. Biogas constituents of classes vary by feedstock and conversion technology, and testing requirements need to be aligned to optimize results and processing requirements.

  Table 8-1 below shows Michigan’s acceptable gas quality and gas purity requirements for service.

Table 8-1. Illustrative Quality Considerations for RNG Injection

Gas Quality Term	Generally Acceptable Limit
Hydrogen Sulfide	0.3 g/100 scf
Total Sulfur	20 g/100 scf
Carbon Dioxide (CO_2)	$\leq$ 2.0%, by volume
Oxygen (O_2)	$\leq$ 5 ppm_v
Heating Value	950 – 1,100 Btu
Water Vapor	< 7 lb/MMscf

Each element has a differing impact on gas quality and safety, interchangeability, end-use reliability and pipeline integrity. If a constituent is not reasonably expected to be found above background levels at the point of interconnect for the RNG, then testing may not be necessary. An additional challenge is that while some constituents may not present a problem in isolation, the interaction between different constituents could result in negative impacts on the pipeline or end-use applications.

ICF notes that Michigan has one of the lowest allowable oxygen limits; Michigan has promulgated these oxygen standards for pipelines to prevent corrosion in equipment at Michigan's gas pipeline facilities and storage reservoirs. At least one stakeholder[79] has noted that the oxygen limits may present a barrier to RNG development because it requires

> sophisticated oxygen removal equipment must be added to the RNG upgrade unit, adding ~ $600k to $1M for each RNG project. Furthermore, periodic replacement of the precious-metal catalysts adds even more cost - approximately 25% of the capital cost for each replacement.

ICF notes that this type of barrier is not uncommon for RNG development. However, as noted in the referenced comment, the technology exists to ensure that the required oxygen levels are achieved, and it is actually a matter of cost. This is not to say that ICF does not consider this issue a barrier to RNG deployment; rather, it is a barrier that can be overcome through additional investment in existing technology. Similar cost concerns were originally raised in California related to gas interconnect being costly in California compared to other jurisdictions. In this case, ICF notes that the cost adder is non-trivial; however, the context is relevant:

- In the context of project financing, the additional capital may be a barrier. However, in the context of the multiple millions of dollars that are required for investment in RNG projects, the barrier is likely small to modest.
- In the context of the LCOE estimates using ICF's cost model, which account for the cost of the gas over the life of a project, the additional upfront capital and the additional operations and maintenance costs contemplated for more

---

[79] Based on information submitted by Quantalux.

sophisticated oxygen removal equipment could increase the LCOE by $0.08 to $0.45 per MMBtu, depending on the project size and the feedstock.

ICF also notes that in the event that RNG from a project is being injected into distribution lines, that there is a process whereby a project owner can work with a gas utility to ensure blending to meet the oxygen requirements or the utility can seek a waiver from the oxygen requirement. This is not meant to diminish the technical barrier raised by stakeholders as it relates to the oxygen requirements for gas injection. Rather, ICF notes that these types of technical barriers can be overcome through investment and will likely be reduced over time through lessons learned during project development, and through technological innovation.

Substantial research, testing and analysis has been done to better understand the composition of raw biogas from different feedstocks compared to traditional pipeline-quality natural gas delivered into the natural gas system. In parallel, significant technology advancements have been achieved in processing and treating raw biogas to address trace constituents and the concerns of pipeline operators and end users.

For example, at the direction of the California Public Utilities Commission, the California Council on Science and Technology (CCST) assessed acceptable heating values and maximum siloxane specifications for RNG. CCST found that keeping the current minimum Wobbe Number requirement for RNG while relaxing the heating value specification to a level near 970 Btu/scf would not likely impact safety or equipment reliability. In relation to siloxanes, the CCST found that some RNG feedstocks are very unlikely to harbor siloxanes (e.g. dairy waste, agricultural residues or forestry residues), and less stringent monitoring requirements would be needed. The CCST also recommended a comprehensive research program to understand the operational, health, and safety consequences of various concentrations of siloxanes, due to inconclusive evidence for other RNG feedstocks.[80]

- **Seasonal variability in Michigan's natural gas systemwide demand may require the RNG production market to adapt.** Like other regions with colder winters, Michigan's natural gas system sees a significant winter peak, largely driven by space heating demand. There is a four- to five-fold difference in natural gas demand on the system between winter and summer months, and RNG production facilities do not have the same variability. For instance, during colder periods of the year when space heating requirements increase, RNG production facilities cannot be ramped up to meet increasing natural gas demand. Similarly, during warmer periods when demand is lower, RNG production may exceed demand in certain local distribution systems. Current RNG contractual structures are driven by natural gas demand as a transportation fuel and are not designed to accommodate the type of system variation required for space heating applications. As the RNG market evolves and matures, ICF anticipates that this issue can be solved through book-and-claim accounting[81], storage, and other considerations.

---

[80] CCST, 2018. Biomethane in California Common Carrier Pipelines: Assessing Heating Value and Maximum Siloxane Specifications, https://ccst.us/reports/biomethane/.

[81] 'Book-and-claim' accounting is a common practice where an attribute or claim made by a party is separated from the physical flow of these goods.

However, as the RNG market transitions from transportation fuel use to more diverse end uses on the natural gas system, there will be growing pains.

Market

There are more than 120 projects producing RNG for pipeline injection today, compared to less than a half-dozen in 2010. In Section 3, ICF provided an outline of RNG potential for pipeline injection, broken down by feedstocks and production technologies. Based on this untapped potential, the RNG market is poised for substantial growth. The following section outlines the most significant opportunities driving the RNG market, and the most significant barriers that must be overcome.

Opportunities

- **RNG can deliver cost-effective GHG emission reductions for decarbonization.** RNG is a cost-effective GHG emission reduction measure, and relative to other GHG mitigation measures, RNG can play an important role in helping to achieve decarbonization out to 2050.
- **RNG helps maximize the utilization of evolving waste streams.** The anaerobic digestion of biomass, including at landfills and WRRFs, helps maximize the use of waste. With expanding urban populations and more pressure for landfill diversion, the anaerobic digestion of food waste and thermal gasification of MSW, for instance, has the potential to continue to increase the utilization of waste streams as renewable energy resources.
- **RNG markets are evolving to reflect utilities and corporations with climate and sustainability goals.** There is increasing activity and interest in RNG outside of the transportation sector, and also beyond jurisdictions where carbon constraining policies are influential. Driven by corporate sustainability goals and customer preferences, a growing number of utilities and large end users of natural gas are looking into RNG as an option to reduce GHG emissions.
- **RNG helps give suppliers and consumers a viable decarbonization option in an evolving market and policy environment.** There is an escalating trend for utilities and large industrial consumers to adopt ambitious decarbonization measures, while small consumers are increasingly aware of their carbon footprint and looking for ways to reduce emissions.

Barriers

- **Changes in California's LCFS or the federal RFS, may negatively impact the economic feasibility of Michigan-based RNG projects.** Although the LCFS and RFS programs have helped to drive considerable investment in RNG, including in Michigan, changes to either of these programs may impact existing RNG projects or limit the near-term growth potential for RNG projects in Michigan. Like most of the RNG market today, investments in Michigan-based projects are being driven by these policies and the value of the environmental commodities. These RNG projects carry the merchant risk of volatile environmental commodity markets, as well as the uncertainty related to programmatic changes that can be made by program administrators.

- **Markets for RNG beyond transportation fuel are nascent.** The long-term growth potential for RNG is dependent on transitioning to end uses other than transportation. Michigan's market will need to demonstrate a near-term market potential for RNG deployment to bolster stakeholder confidence in the ability of RNG to deliver cost-effective GHG emission reductions. However, absent other markets for RNG consumption, production investments will stall and the market will plateau.
- **RNG production and processing costs need to be reduced to improve cost-competitiveness.** The market for RNG will expand beyond the transportation sector through improved technology and complementary policies. However, technology and overall production costs need to decrease over time to maintain competitiveness.
- **Limited availability of qualified and experienced RNG developers to expand RNG production in the near-term.** With growing interest in RNG projects, particularly to capture near-term value in the transportation market, there is a lack of experienced project developers (perceived or real) to meet this demand. This issue will ameliorate over time, as the industry expands and project developers gain more experience on RNG projects.
- **RNG costs more than conventional natural gas, when environmental benefits are not fully valued.** The capital expenditures and operational costs associated with RNG production are higher than the commodity price for conventional natural gas, greatly restricting the potential for RNG production and consumption. However, the costs of RNG should not be compared directly with conventional natural gas without reflecting the significant GHG emission reduction benefits of RNG.
- **Interconnection costs for RNG suppliers and developers can be high.** Interconnection serves a vital role in an RNG project—it is the point at which gas quality is monitored, prevents non-compliant gas from entering the system, and meters the RNG injected. On a project-lifetime basis, interconnection costs are generally small as the cost is amortized, for instance, over a 10- to 20-year project lifetime. However, meeting interconnection costs can be a challenge for project developers.

  There is no "right cost" associated with interconnection. Instead, gas utilities need to work with regulators and project developers to ensure safety and reliability are maintained on the system, and that utilities can recover the costs associated with the system requirement. Utilities, along with regulators, have strategic roles to work with potential RNG suppliers and project developers to:

  - Research and evaluate suitable site locations;
  - Determine pipeline interconnection distances and pathways;
  - Develop engineering designs and configurations;
  - Determine appropriate flows and pressures; and
  - Conduct initial project cost estimates.

Regulatory and Policy

The aforementioned incentives for the use of RNG as a transportation fuel helped spur substantial investment in new RNG projects nationwide. However, the demand for RNG as a transportation fuel is limited and tied to the growth of NGVs. For RNG to play a role in long-term GHG mitigation strategies, a regulatory and policy structure is required to support the cost-effective use of pipeline-injected RNG.

There is growing activity outside the transportation sector, and in particular the construct of the RFS and LCFS programs, where so much attention is paid today. With deep decarbonization goals becoming more prevalent, the ability to use an existing energy system to deliver significant emission reductions is highly valuable. RNG as a decarbonization approach for stationary energy applications provides two advantages relative to other measures:

- Utilizes existing natural gas transmission and distribution infrastructure, which is highly reliable and efficient, and already paid for, and
- Allows for the use of the same consumer equipment as conventional gas (e.g., furnaces, stoves), avoiding retrofits and upgrades required for fuel-switching

For example, DTE launched a voluntary biogas program in 2013, amended and expanded in 2020 to become the Natural Gas Balance Program, which supports the development of RNG projects in Michigan. Regulators, policymakers and gas industry participants are implementing or developing RNG programs across the country:

- Minnesota HF7: allows gas utilities to file innovative resource plans, and requires the PUC to establish GHG and cost-benefit accounting frameworks to assess plans. Plans can include RNG as part of innovative resources.
- Ohio HB 166: allows gas utilities to treat RNG-related infrastructure as useful and eligible for cost recovery.
- The joint venture between Dominion Energy and Smithfield Foods is set to become the largest RNG producer in the U.S., developing animal manure-based RNG in North Carolina, Virginia, and Utah, with plans to expand to California and Arizona.
- TECO Peoples Gas in Florida had a tariff for biogas conditioning and upgrading approved in December 2017, and have since made modifications to the tariff to accommodate the receipt of RNG from biogas producers and an updated rate schedule for conditioning services.[82]
- In early 2022 the California Public Utilities Commission adopted a mandatory RNG program, where the state's largest gas utilities need to procure increasing volumes of RNG out to 2030.
- Oregon SB 98: allows natural gas utilities to make "qualified investments" and procure RNG from 3rd parties to meet portfolio targets for the percentage of gas purchased for distribution to retail customers. The RNG portfolio targets range from 5% between 2020 and 2024 to 30% between 2045 and 2050.
- Nevada SB 154: authorizes natural gas utilities to engage in RNG activities and to recover the reasonable and prudent costs of such activities, including the purchase of

---

[82] TECO Peoples, Section 7 of the tariff is available online at https://www.peoplesgas.com/company/ournaturalgassystem/tariff/.

and production of RNG. The legislation also includes voluntary procurement targets of not less than 1% of the total amount of gas sold by 2025, not less than 2% by 2030, and not less than 3% by 2035.

- Approved in 2017, Vermont Gas offers a voluntary RNG tariff program, providing retail gas customers the opportunity to purchase RNG in amounts proportionate to their monthly requirements. [83]
- FortisBC, the main gas utility in the Canadian Province of British Columbia, has had a voluntary RNG tariff program since 2011, which has spurred RNG production in the region.[84]
- National Grid's New York City Newtown Creek RNG demonstration project will be one of the first facilities in the U.S. that directly injects RNG into a local distribution system using biogas generated from a water and food waste facility.
- Southwest Gas Company (SWGC) in Arizona has a biogas services tariff enabling them to enter into a service agreement with a biogas or RNG producer, and includes requirements for access to the production facilities, interconnection facilities, and gas quality testing facilities.[85]
- Southern California Gas Company (SoCalGas) announced that they intend to have 5% RNG on their system by 2022 and 20% by 2030. SoCalGas is also seeking approval to allow customers to purchase RNG as part of a voluntary RNG tariff program. [86]

Driven by corporate sustainability goals and customer preferences, a growing number of large end users of natural gas are looking into RNG as an option to reduce GHG emissions. Global cosmetics manufacturer L'Oréal uses RNG from a nearby landfill facility at its plant in Kentucky. L'Oréal's long-term purchase commitment for the RNG was a key underwriting component that led to the financing of the LFG project.

While there is clearly a near-term focus on reaping the benefits of credits generated in the LCFS program and RINs in the RFS program, the long-term potential for increased volumes of RNG outside the transportation sector is considerably more robust than many stakeholders may realize. With appropriate incentives that fully reflect the environmental impacts of RNG, the end-use demand for RNG from stationary applications is substantial, in contrast to the limited demand in the transportation sector.

ICF notes that the majority of the measures and actions outlined above are voluntary in nature, and do not deliver binding RNG deployment targets or GHG emission reduction objectives. Voluntary programs and opt-in green tariffs provide near-term opportunities for natural gas utilities, regulators and customers to become accustomed to RNG and the RNG market, without requiring substantial and long-term commitments. Voluntary markets have been critical to the initial growth of emission reduction measures, such as renewable electricity through residential and non-residential customers voluntarily helping grow demand considerably in the early years of renewable electricity development.

---

[83] Vermont Gas, 2022. https://www.vermontgas.com/renewablenaturalgas/.

[84] FortisBC, 2022. https://www.fortisbc.com/services/sustainable-energy-options/renewable-natural-gas

[85] SWGC, Schedule No. G-65, Biogas and Renewable Natural Gas Services , available online at https://www.swgas.com/1409197529940/G-65-RNG-02262018.pdf.

[86] SoCalGas, information retrieved from https://www.socalgas.com/for-your-business/power-generation/biogas-conditioning-upgrading.

However, over the long-term, and considering the significant economy-wide emission reductions needed to meet deep decarbonization goals, the policy and regulatory framework for RNG will need to be more ambitious and comprehensive. For example, a mandatory Renewable Gas Standard for gas utilities would be relatively straightforward and mimic parallel renewable portfolio standards on the electric supply side.

Opportunities

- **Conditioning and Interconnection Tariffs.** As outlined in Section 3, the costs of biogas conditioning and upgrading can be expensive; similarly, interconnection costs can be challenging for some project developers. These costs are the primary capital outlays at the outset of a project and have a material impact on the ability of projects to obtain financing. Under a tariff structure, the producer can avoid the significant upfront capital costs that can often impede project development. Conditioning and interconnection tariffs allow utilities or LDCs to build and operate the upgrading and interconnection facilities, while recovering capital and operation and maintenance costs from the project developer at a pre-determined rate.
- **Emergence of legislation and regulations for both mandatory and voluntary programs.** Utilities may offer opt-in voluntary programs to customers to help reduce the environmental impact of their energy supply. This is more common for electric utilities, however, similar programs can be developed for gas utilities and RNG consumption.
- **Complementary policies could facilitate RNG feedstock collection (e.g., waste diversion and management).** The RNG industry could benefit considerably from complementary policies that help improve the accessibility of feedstocks while improving project development economics. This includes regulations or policies that encourage methane capture, encourage waste diversion and waste utilization, forest management and thinning requirements, etc.

Barriers

- **The pathway for policies and incentives promoting RNG in market segments other than transportation is unclear and not uniform.** Current programs in place do not provide the price and supply certainty that is required for larger volumes of RNG to be deployed, beyond the success of RNG in the transportation fuels market. While voluntary commitments and other drivers may help to increase RNG consumption in non-transportation market segments, the potential for RNG is intrinsically constrained without a strong policy signal in place. Furthermore, the programs that have been proposed or even promulgated are generally lacking or insufficient, and do not recognize or credit the environmental benefits of RNG in a manner that is consistent with the long-term potential of the technology.
- **Gas utilities are just beginning to gain cost-recovery mechanisms for RNG procurement and investments.** There has been rapid expansion of RNG production over the last several years; however, the industry will face limits as technical and market constraints limit market participants. Faced with varying pressures to decarbonize,

utilities need cost-recovery mechanisms for RNG procurement or investments, if they are to play a role in the development of these projects. In particular, natural gas utilities will need a regulatory structure that provides cost recovery for the incremental costs of RNG, interconnection facilities and equipment for RNG to comply with gas quality specifications and standards, and investment in larger facilities such as pipelines and premium gas production, supply facilities, and pipeline capacity costs that would support and facilitate the development of RNG.

Environmental Impacts

Section 6 outlines the environmental value of RNG, in the context that it can deliver GHG emission reductions as a low carbon gaseous fuel. However, to assess accurately the complete potential of RNG as a fuel in a decarbonizing economy, a broader perspective on the impacts of RNG is needed.

Opportunities

- **Investments in RNG production can yield positive environmental impacts upstream from the gas system and beyond GHG emissions.** These include reducing or avoiding methane emissions from certain biomass feedstocks, helping to achieve waste management targets (e.g., waste diversion and waste utilization), supporting sustainable management practices in the agricultural and forestry sectors, and reducing the environmental impacts of CAFOs.
- **If new policies are implemented to support RNG deployment in Michigan, they should ensure no back-sliding on other environmental indicators and avoid environmental injustices that have historically impacted at-risk communities.**

Barriers

- **RNG development will face scrutiny as it relates to fugitive methane emissions, which occur along the entire natural gas supply chain—during processing, transmission, and distribution.** This is a pressing issue for the natural gas industry and is not unique to RNG production. In the context of RNG production, most of the fugitive methane emissions would occur during transmission of the product via pipeline, however, these emissions would not be considered incremental or additional GHG emissions; rather, those same GHG emissions would have occurred if the alternative was conventional natural gas. Methane emissions are particularly harmful because of the gas's high global warming potential. Fugitive methane emissions in the natural gas supply chain have become a pressing issue for the natural gas industry over the past decade. The issue has been brought into focus in large part by a collaboration of the Environmental Defense Fund (EDF), universities, research institutions, and companies that completed 16 projects to collect data on methane emissions from the natural gas supply chain from 2013 to 2018.[87] These studies helped to demonstrate that the methane emissions from natural gas supply chains were considerably higher (up to 60%) than the estimates from the EPA's GHG emissions inventory.[88]

---

[87] EDF. 2018. Methane research series: 16 studies, accessible online at https://www.edf.org/climate/methane-research-series-16-studies.

- **There are a variety of environmental impacts of CAFOs, which represent one of the key feedstocks for RNG production in Michigan**, accounting for 18% and 14% of the RNG production potential in the Achievable and Feasible scenarios, respectively. Some of the environmental impacts attributable to CAFOs include:[89]
  - Manure contains variety of potential contaminants. Plant nutrients such as nitrogen and phosphorous, pathogens such as *E. coli*, growth hormones, antibiotics, chemicals used as additives to the manure or to clean equipment, animal blood, silage leachate from corn feed, or copper sulfate used in footbaths for cows
  - CAFOs are a source of strong odors and are known to increase insect vectors.
  - The manure often presents risks to ground and surface water quality.
  - CAFOs tend to emit air pollutants such as ammonia, hydrogen sulfide, methane, and particulate matter.
  - Left untreated or managed via digesters, CAFOs are a source of GHG emissions via the methane that is emitted

  These environmental harms lead to environmental justice concerns and impacts. The negative impact on air quality and water quality in communities surrounding CAFOs can lead to disproportionate harms like increased asthma rates. There is also evidence that CAFOs depress property prices in surrounding communities.

  At present, there is no clear indication that RNG policies or RNG production will impact industry trends related to CAFOs or contribute to the expansion of CAFOs in Michigan. To the contrary, the use of anaerobic digesters at farms is more likely to mitigate environmental harms at existing CAFOs than exacerbate them. Regardless, it is important that there are controls put in place to ensure that RNG development does not lead to increased environmental harms or increase the risk of exposure to environmental injustices in at-risk communities.

---

[88] Alvarez, R., et al., 2018, Assessment of methane emissions from the U.S. oil and gas supply chain, Science, DOI: 10.1126/science.aar7204.

[89] Understanding Concentrated Animal Feeding Operations and Their Impact on Communities, available online at https://www.cdc.gov/nceh/ehs/docs/understanding_cafos_nalboh.pdf.

Appendix A

Understanding the Current RNG Value Stack

Low carbon fuels, such as ethanol, biodiesel, renewable diesel, and RNG, that are deployed in California have the potential to earn LCFS credits in the state-level LCFS program as well as Renewable Identification Numbers (RINs) in the federal RFS program. Fuel providers can generate value in both the LCFS and the RFS programs by rule. The programs are implemented by tracking two different environmental attributes: the state-level LCFS program enables fuel providers to monetize the GHG reductions attributable to the fuel, whereas the federal-level RFS program monetizes the volumetric unit of the renewable fuel. This ability to “stack” environmental credits has led to the aforementioned significant increase in the volume of RNG consumption in California. For instance, ICF estimates that 60-65% of domestic RNG production in 2021 was delivered to California, generating both the RINs and the LCFS credits. The following subsections provide an outlook on these two markets and the role of RNG over the next 5-10 years.

The table below highlights the current value stack for RNG in 2022, assuming that the fuel is used in a NGV in California.

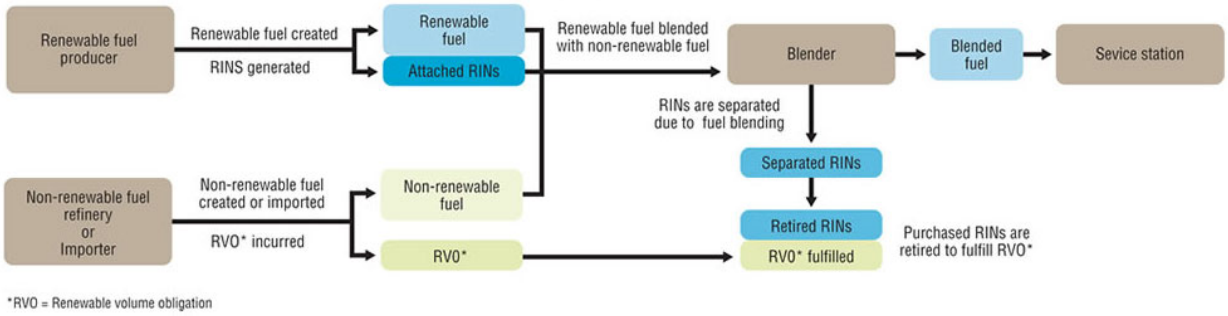
Table A-1. RNG Value Stack as a Transportation Fuel in California

RNG Value Stack ($/MMBtu)	RNG from Landfill CI: 45 g/MJ	RNG from dairy manure CI: -250 g/MJ
Commodity Value	$7.40	$7.40
D3 RIN *$3.41 per D3 RIN*	$40.00	$40.00
LCFS Credit *$115/ton*	$3.98	$36.30
Total	$51.37	$83.69

EPA Renewable Fuel Standard

The RFS mandates biofuel volumes that must be blended into transportation fuel each year from 2006 to 2022. The program was developed as part of the Energy Policy Act (EPAct) of 2005 and revised/updated by the Energy Independence and Security Act (EISA) in 2007. The program is administered by the EPA. The RFS policy mandates that producers of petroleum fuel products and blenders add in renewable fuels into their pool every year. Every gallon of renewable fuel is given a Renewable Identification Number or RIN. Among other things, the RIN identifies who made the fuel, when, and what type of fuel it is. The RINs can be sold along with the fuel or “separated” and sold to an obligated party (e.g., a petroleum refinery) separately. Typically, the RIN is sold with the volume of fuel to a blender who then sells the blended fuel to fuel outlets (e.g., retail gasoline stations). The blender then sells the “separated RIN” back to the refinery. A diagram is shown below.

Figure A-1. Overview of the Federal RFS Program


Renewable fuel producer
Renewable fuel created
RINS generated
Renewable fuel
Attached RINs
Renewable fuel blended with non-renewable fuel
Blender
Blended fuel
Sevice station
RINs are separated due to fuel blending
Separated RINs
Non-renewable fuel refinery or Importer
Non-renewable fuel created or imported
RVO* incurred
Non-renewable fuel
RVO*
Retired RINs
RVO* fulfilled
Purchased RINs are retired to fulfill RVO*
*RVO = Renewable volume obligation

Each year, the EPA estimates the volume of transportation fuel that is expected/forecasted to be consumed in the U.S., using projections from the EIA. The Renewable Volume Obligations (RVOs) are expressed as a percentage of this expected nationwide fuel consumption. EPA is required to set the standards by November 30 for the following year. Changes to the program in the EISA created four nested categories, as shown in the table below: renewable biofuels, advanced biofuels, biomass-based diesel, and cellulosic biofuels. Each category has its own volume requirement and RIN type. RINs are the currency of the RFS program and are represented by a 38-digit code representing an ethanol gallon equivalent of fuel. Each category includes a threshold of lifecycle GHG emission savings compared to petroleum products (i.e., gasoline and diesel).

Table A-2. Nested Categories of Renewable Fuels in the RFS Program

RIN Type	Description / Biofuel	Min GHG Reductions	RFS Qualifying Categories
D3	Cellulosic Biofuel	60% GHG savings	Cellulosic, Advanced or Renewable
D4	Biomass-Based Diesel	50% GHG savings	Biomass-Based Diesel, Advanced or Renewable Diesel
D5	Advanced Biofuel	50% GHG savings	Advanced or Renewable
D6	Renewable Fuel	20% GHG savings	Renewable (Corn-Based Ethanol)
D7	Cellulosic Diesel	60% GHG savings	Cellulosic or Advanced, Biomass-Based Diesel, or Renewable

Through the annual RVO setting process, the EPA has established cellulosic biofuel volumes that are lower than the statutory volumes for the years 2010 to 2020, and the proposed values for 2021 and 2022. The annual RVO setting process has recommended lower volumes than statutory volumes because available supply has been insufficient to maintain the annual RVOs at the same level as statutory volumes. Despite annual volumes being lower than statutory volumes, the supply of cellulosic biofuels has increased year-over-year, with more significant increases in the last 3-5 years. Consider the year 2020: the statutory volume for cellulosic biofuels was 10.50 billion gallons; however, the final annual RVO established by the EPA was 0.59 billion gallons. Because the annual RVO was lower than the statutory volume, the Cellulosic Waiver Credit (CWC) provision was enacted. CWCs are not allowed to be traded or banked for future use and are only allowed to be used to meet the cellulosic biofuel standard in the year for which they were offered. An obligated party can satisfy its D3 RIN obligation by either (i) purchasing a D3 RIN or (ii) paying the CWC and purchasing a D5 RIN.

- The CWC is calculated based on the formula in the regulation, which is the greater of \$0.25 or \$3.00 minus the average wholesale price of gasoline ($P_{gasoline}$). Both of the constants in the formula, \$0.25 and \$3.00, are adjusted for inflation from January 2009 (per the regulation) to June of the year in question. Fundamentally, the CWC price increases as gasoline prices decrease, and declines as gasoline prices increase.
- ICF models D5 RIN values based on lowest cost economics of advanced biofuel production and forward markets for commodities. We also note that we put maximum and minimum value on the D5 based on the nested structure of the RFS. In other words, the D5 RIN must always be less than the D4 RIN (biodiesel) and greater than the D6 RIN (corn ethanol). Forecasting RINs requires that modeling considers annual RVOs and the supply-demand of eligible advanced biofuels, and in most years, this yields a compliance pathway in which D4 RINs are the marginal unit of compliance. As such, biodiesel production economics tend to drive D5 RIN pricing.

ICF forecasts D3 RIN values as the sum of a D5 RIN and the CWC, and the product of a market-based discount factor.

For the purposes of this study, ICF assumed that the RFS regulation remains in place post-2022. Changes to the RFS post-2022 would require legislation passed by the U.S. Congress. Any price changes post 2022 reflect technological improvements and cost-competitiveness in each sector. ICF also assumed that the EPA would adjust/reduce the volume of cellulosic biofuel on an annual basis to match production volumes of eligible D3 RIN generating projects. ICF reports a range of values for the D3 RIN out to 2030.

Table A-3. Forecasted D3 RIN Pricing to 2030 (\$2022)

	2021^{A}	2022	2023	2024	2025	2026	2027	2028	2029	2030
D3 RIN	2.67	2.95-3.15	2.10-2.30	2.45-2.55	3.35-3.60	2.95-3.30	2.90-3.25	3.00-3.35	2.86-3.21	3.07-3.42

Notes:

1. 2021 Values are presented as actual values.
2. The D3 RIN value reported for 2021 is the weighted average of Q-RIN transactions.
3. Values are reported as \$/D3 RIN in Real terms using 2022 (\$2022).

ICF notes that RINs are all reported in units of ethanol gallon equivalents, and one gallon of ethanol is assumed to have 77,000 Btu. In order to determine the number of RINs generated by 1 MMBtu of natural gas, the equation is:

> 1,000,000 Btu [RNG] / 77,000 Btu [Ethanol Equivalence] x 0.903 [adjust for LHV / HHV of natural gas] = 11.727 RINs per MMBtu of RNG

In other words, a D3 RIN value of \$3.00 is equivalent to \$35.18/MMBtu.

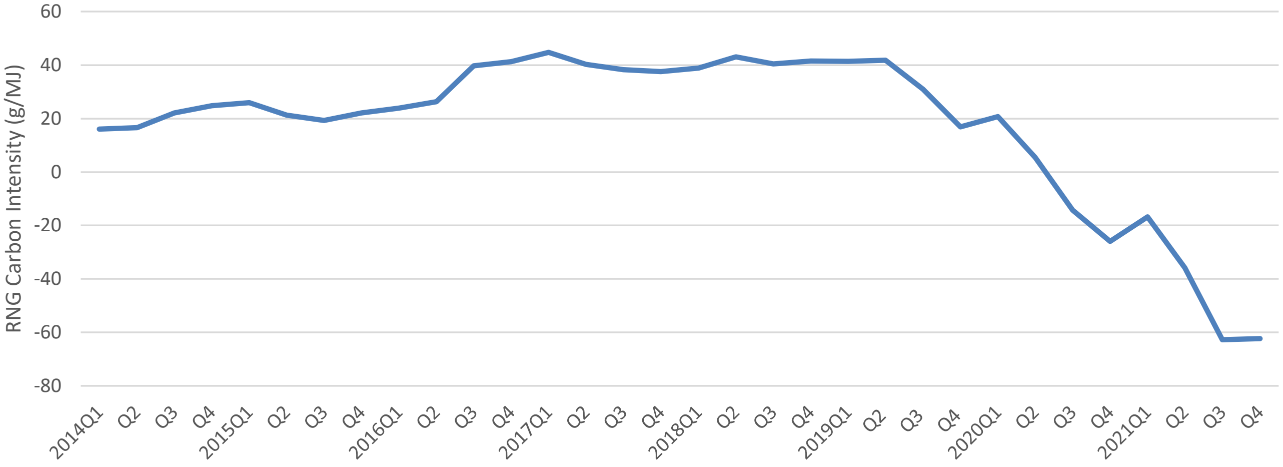
California's Low Carbon Fuel Standard

California has in law, in regulation, and in executive orders the most aggressive GHG reduction program in the world, requiring staged emissions reductions of 80% over the coming years. California's steep GHG reduction goals require emissions reductions in every sector of the economy. Transportation produces the largest portion of California's GHG emissions, 37% of total emissions. The AB 32 Scoping Plan identified California's LCFS Program as an Early Action Item. The standard required a 7.5% reduction in transportation fuel carbon intensity by 2020 and requires a 20% reduction by 2030. The program began in 2011. Carbon intensity (CI) is measured in grams of carbon dioxide equivalents (gCO_2e) per unit energy (megajoules, MJ) of fuel and is quantified on a lifecycle or well-to-wheels basis. The LCFS is the most significant emissions reduction program in the California transportation sector, delivering as much reduction as all other transportation programs combined. The reductions delivered by the LCFS are essential to achieving overall GHG goals. In 2007, Governor Schwarzenegger signed an executive order establishing the Low Carbon Fuel Standard. California Air Resources Board enacted the LCFS regulation in 2009, updated the program in 2011, and re-adopted the program in 2015. The LCFS measures the full "lifecycle" (well-to-wheels or field-to-wheels) carbon emissions of fuels.

The LCFS program operates on a simple system of deficits and credits. Petroleum-based transportation fuels (i.e., gasoline and diesel) with a CI higher than the standard generate deficits; these deficits must be offset on an annual basis by credits generated by lower carbon fuels. Unlike RINs in the RFS program, LCFS credits can be banked without holding limits and do not carry vintages.

There are about 45 registered LFG pathways in California's LCFS program, with a maximum carbon intensity of 67 g/MJ and a low of 30.5 g/MJ, and a median of 41.5 g/MJ. For illustrative purposes, ICF has included the average carbon intensity of RNG since 2014.

Figure A-2. Carbon Intensity of delivered RNG to California used as CNG, 2014-2021[90]



---

[90] Based on data released by the California Air Resources Board.

Most of the RNG that is currently delivered to and dispensed in California and Oregon is derived from landfills. However, ICF anticipates a shift towards lower carbon intensity RNG from feedstocks such as the anaerobic digestion of animal manure and from digesters deployed at WRRFs. For instance, the figure above shows a precipitous decrease in the *average* carbon intensity of RNG delivered through 2021, indicating the emergence of several low CI pathways from animal manure projects that have been increasing deliveries to California. Over time, these lower carbon sources will continue to displace substantial volumes of higher carbon intensity RNG from landfills in the California (and Oregon) market, however, these alternative sources of RNG tend to have smaller production profiles and will not be able to displace landfill gas entirely in the system.

ICF models the LCFS program using an optimization model that considers compliance strategies based on parameters including alternative fuel production costs, fuel supply chains (to California), interactions between programs, alternative fuel pricing, gasoline and diesel pricing, and GHG abatement potential. ICF developed the model to solve dynamically for the lowest-cost (and in the case of LCFS forecasting, the lowest emission) solution while considering inter-temporal trading and banking behavior on an annual basis.

ICF modifies critical parameters across multiple model runs to identify the range of compliance scenarios and identify the most likely marginal units of compliance in relevant markets (e.g., the LCFS program and the RFS program). Based on this, the model estimates the corresponding environmental commodity price (including RIN prices and LCFS credit prices) as the difference between the delivered cost of the marginal unit of compliance and the forecasted price of gasoline or diesel. As the environmental commodity prices rise, additional compliance opportunities (including additional supply of existing compliance pathways or new compliance pathways) are considered viable. However, the model is not exclusively constrained by price, it is also constrained by fuel supply and consumer behavior, and it also accounts for lag times between pricing signals and investment required to deploy alternative fuels.

In 2018, LCFS credits traded at an average of $160/ton with a range of $79/ton to $202/ton; in 2019, credits traded for an average of $192/ton with a range of $85/ton to $209/ton, credit prices increased as the stringency of the program increased, and obligated parties were facing a market with constrained low carbon fuel supply compared to the demand for credits while 2020 averaged $200/ton over the year. In 2021, however, LCFS credit prices decreased substantially but held an annual average of around $179/ton. Price decreases have continued into 2022, with an average credit price trading around $138/ton through April 2022.

For the purposes of this study, ICF assumed that the LCFS regulation is implemented as currently designed, with a 20% CI reduction by 2030. ICF reports a range of values for LCFS credits out to 2030.

Table A-4. Forecasted LCFS Credit Pricing to 2030 ($2022)

	2021[A]	2022	2023	2024	2025	2026	2027	2028	2029	2030
LCFS Credit Price	179	82-114	88-108	123-143	130-160	137-167	143-173	148-174	148-174	143-173

Notes:

1. 2021 Values are presented as actual values.
2. Values are reported as $/credit in Real terms using 2022 ($2022).

The value of LCFS credits is determined by the CI of the project. For instance, a credit price of $150/ton is worth about $7/MMBtu of RNG from landfills (with a CI of 40 g/MJ), and about $55/MMBtu for RNG sourced from dairy manure digesters (with a CI score of -250 g/MJ).

Rise of Non-Transportation Demand

The combination of RINs and LCFS credits have helped deliver significant volumes of RNG, especially to California. In fact, as of the end of 2021, RNG accounted for more than 90% of the market for natural gas as a transportation fuel in California. As lower carbon RNG comes on to the market, end users will likely gain additional market influence. Most of the RNG that is currently delivered to and dispensed in California is derived from landfills. ICF anticipates a shift towards lower carbon intensity RNG from feedstocks such as the anaerobic digestion of animal manure and digesters deployed at wastewater treatment plants.

Over time, these lower carbon sources will likely displace higher carbon intensity RNG from landfills. The role of RNG in the LCFS program will be determined by the market for NGVs. If steps are taken to foster adoption of NGVs, particularly in the heavy-duty sector(s), then this will be less of an issue. The introduction of the low-NOx engine (currently available as an 9L, 12L, and 6.7L engine) from Cummins may help jumpstart the market, especially with a near-term focus on NOx reductions in the South Coast Air Basin (which is in severe non-attainment for ozone standards).

However, California has a clear focus on zero emission tailpipe solutions for the transportation sector e.g., via the Advanced Clean Truck (ACT) regulation. The ACT Regulation requires zero-emission purchase requirements for medium- and heavy-duty trucks starting in 2024. The rule seeks to “accelerate the widespread adoption of [ZEVs] in the medium- and heavy-duty truck sector.” The core compliance mechanism is a minimum performance standard for ZEVs as a percentage of each major truck manufacturer’s new sales in California.

While the deployment of RNG in the transportation sector has experienced massive growth in the past five years, there is a clear constraint to the overall production and use of RNG in transportation: the limited number of NGVs. With the transportation sector approaching RNG saturation, there is growing interest from policymakers, regulators and industry stakeholders to grow the production of RNG for pipeline injection and stationary end-use consumption.

As currently constructed, in general the policy framework does not encourage RNG use in stationary applications, instead directing RNG consumption to the transportation and electricity generation sectors. However, there are several emerging state-level policies in place that are helping to shape the outlook for RNG beyond transportation. The most interesting development for RNG is that there is growing interest in applying the same principles of RPS program as it relates to electricity to the natural gas sector. These are often referred to as Renewable Gas Standards. Oregon’s Senate Bill 98 (SB 98), for instance, established a voluntary goal for adding as much as 30% RNG into Oregon’s system by 2050. Furthermore, the law allows up to 5% of a utility's revenue requirement to be used to cover the additional cost of investments in RNG infrastructure. More specifically, the bill operates similar to a renewable portfolio standard, whereby volumetric goals have been set, and other critical parameters have been established to support cost-effective procurement. Utilities are able to invest in and own the processing and conditioning equipment required to upgrade raw biogas to pipeline quality gas, as well as the interconnection facilities to connect to the local gas distribution system. To date, NW Natural in Oregon has executed two agreements that will deliver about 2% of NW Natural's annual sales in Oregon, including agreements with a) Tyson Foods and BioCarbN to convert waste to RNG at Tyson facilities and b) Element Markets to purchase the environmental attributes from a WRRF in New York City and a mixed waste anaerobic digester in Wisconsin.[91]

---

[91] These attributes are referred as Renewable Thermal Certificates or RTCs, and are verified and certified by the Midwest Renewable Energy Tracking System (M-RETS). In this case, each RTC is equivalent to a dekatherm or about 1 MMBtu.

Appendix B

Common Applications of GHG Emission Accounting for RNG

Through the 1990s and into the early 2000s, most biogas projects were located at landfills or dairy farms and were capturing biogas to convert it to electricity. Most of these projects were developed to support individual state Renewable Portfolio Standards (RPS). However, the advent of the federal Renewable Fuel Standard (RFS) and California's Low Carbon Fuel Standard (LCFS) shifted incentives away from biogas use in the electricity sector, and toward the upgrading of biogas into RNG use in the transportation sector as a vehicle fuel. Within a short time, projects that were using RNG feedstocks to generate electricity, transitioned to producing RNG because of the financial incentives available through the RFS and LCFS programs. Today, RNG is primarily used in the transportation sector to reduce GHG emissions, however recent regulatory programs have started to emerge that would incentivize the use of RNG in thermal applications.

The principles of GHG emission accounting methods are employed to various extents when it comes to developing and implementing policy. The intent of a policy matters, and is often influenced by political, social, or economic pressures outside the scope of GHG emission accounting methods. While a lifecycle GHG emission accounting approach or a combustion GHG emission accounting approach may provide a foundation for how a policy or regulation is implemented, it is not the only factor considered in policies that are developed to reduce GHG emissions.

Federal Renewable Fuel Standard

The federal RFS mandates biofuel volumes that must be blended into transportation fuel each year from 2006 to 2022. The program was developed as part of the Energy Policy Act (EPAct) of 2005 and revised/updated by the Energy Independence and Security Act (EISA) in 2007. The program is administered by the EPA. RNG was designated as an eligible fuel in 2014 as part of RFS rule amendments. The EPA determines the eligibility of a fuel pathway using a series of requirements outlined in statute and regulations. One of the primary requirements is that a fuel must achieve a percent reduction in GHG emissions as compared to a petroleum baseline (with a baseline year of 2005), and this is determined on a *lifecycle GHG emissions accounting basis*.

Low carbon fuel standards

A low carbon fuel standard is a performance-based program that seeks to reduce the carbon content of transportation fuels. California's LCFS program was identified as an Early Action Item as part of a broader scoping plan delivered by California regulators—the scoping plan identifies how California expects to achieve its GHG emission reduction targets in line with existing regulations. Oregon has a similar program called the Clean Fuels Program (OR CFP) and it is administered by the Oregon Department of Environmental Quality. Oregon's program operates like California's for the most part, but the carbon intensity reduction requirement differs since the program was introduced in 2016. Both the California LCFS and the Oregon CFP employ a lifecycle GHG emissions accounting method to determine the carbon intensity of eligible transportation fuels, which helps to determine the value of a particular fuel. In other words, the fuels with the lowest carbon intensity generate more credits per unit of energy and ultimately generate more value to the producer.

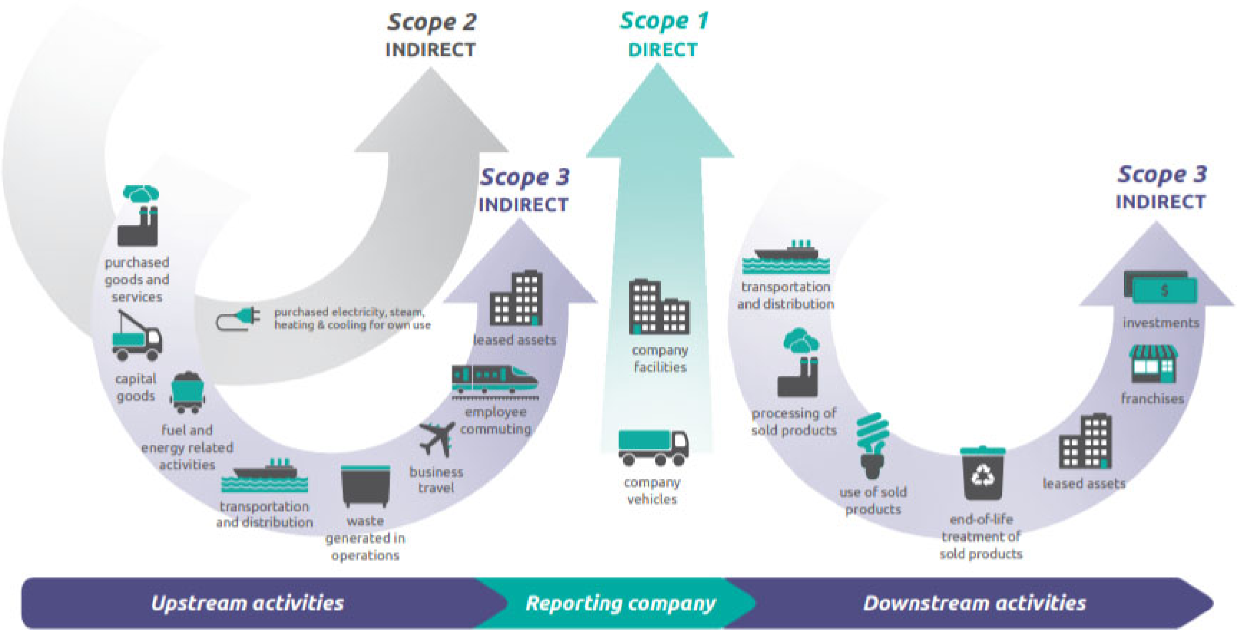
Renewable Portfolio Standards

Renewable portfolio standards seek to increase the amount of electricity generated from qualified renewable resources, including, but not limited to wind, solar, biomass, and hydro. State-level RPS programs focus on renewable electricity generation, with eligible generation technologies varying across jurisdictions including, but not limited to solar photovoltaics, wind turbines, certain geothermal electric technologies, small hydroelectric facilities, fuel cell technologies, and others. RPS programs are typically administered by placing an obligation on electricity supply companies (e.g., investor-owned utilities, municipally owned utilities, and other entities) to procure a certain share of their electricity from qualifying renewable resources. Entities that generate renewable electricity are required to be certified and tracked via RECs. These RECs are typically purchased with the electricity supplied and are subsequently retired by electricity suppliers to demonstrate compliance as part of the regulation via some regulating entity. A small number of states have incorporated different forms of RNG into their RPS programs. RPS programs do not typically employ a GHG emission reduction requirement, and as such, are generally silent on the issue of GHG emission account frameworks.

Voluntary programs

Some companies choose to prepare a voluntary GHG emission inventory for their operations. Companies do this for a variety of reasons, including to demonstrate leadership to customers, investors, and regulators, as part of a broader initiative to achieve GHG emission reduction targets, and to save money. Corporate sustainability and other Environmental, Social, and Governance (ESG) related initiatives are typically tied to the Greenhouse Gas Protocol Accounting and Reporting Standard. With the increasing number of commitments to net zero carbon emissions, including from many energy companies and investor-owned utilities, there is pressure to ensure that the GHG emission accounting approaches employed by stakeholders are consistent and transparent. The Greenhouse Gas Protocol is a commonly used set of reporting standards developed by the World Resources Institute and the World Business Council for Sustainable Development. A GHG Protocol-based approach is used by most corporations, but still incorporates many of the same sources and emission factors used by regulatory agencies. The GHG Protocol uses “Scope” levels to define the different sources and activity data included within an assessment. Instead of thinking in terms of geographic or sector-based boundaries, the GHG Protocol groups emissions in terms of direct and indirect categories through these Scopes. Figure B-1 shows how the GHG Protocol groups these emission sources by Scopes, and how they relate to an organization’s operations.

Figure B-1. Scopes for Categorizing Emissions Under the 2019 GHG Protocol


Scope 2
INDIRECT
Scope 1
DIRECT
Scope 3
INDIRECT
Scope 3
INDIRECT
purchased goods and services
capital goods
fuel and energy related activities
transportation and distribution
waste generated in operations
business travel
employee commuting
leased assets
purchased electricity, steam, heating & cooling for own use
company facilities
company vehicles
transportation and distribution
processing of sold products
use of sold products
end-of-life treatment of sold products
leased assets
franchises
investments
$
Upstream activities
Reporting company
Downstream activities

Organizations most often limit their assessment to Scope 1 and 2 emissions, which includes directly controlled assets. Scope 3 emissions reflect a lifecycle assessment approach that includes supply chain activities and associated, but not directly controlled, organizations.

There is no explicit mention of RNG in the GHG Protocol. Rather, there is guidance provided related to reporting GHG emissions from biomass fuels as a “special emissions accounting issue.” The GHG Protocol requires corporations to report the direct carbon dioxide (CO_2) emissions from the combustion of biomass separately from the three scopes; however, the methane (CH_4) and nitrous oxide (N_2O) emissions from the combustion of biomass should be accounted for in the appropriate scope. Guidance documentation in support of the GHG Protocol provide many examples of biomass materials that can be used as fuels, including multiple feedstocks or processes that characterize RNG production, including landfill gas, forestry residues, manure, and biogas (produced from digestion, fermentation, or gasification of biomass). For example, if a company replaces 50 percent of its natural gas consumption with RNG, the company should report CO_2 emissions only on the remaining 50 percent of its conventional natural gas use and would report the CO_2 emissions from RNG consumption separately. And as a result, the inventory would show a 50 percent drop in CO_2 emissions.

The World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD) initiated a process in January 2020 to develop new Greenhouse Gas Protocol guidance on accounting for land sector activities and CO_2 removals in corporate greenhouse gas inventories, building on the Corporate Standard and Scope 3 Standard.[92] WRI and WBCSD expect that draft guidance will be available for both pilot testing and review in June 2022, with final publication expected in early 2023. More specifically, the initiative seeks to update and develop new guidance on issues including land use, land use change, carbon removals and storage, bioenergy and other biogenic products, and related topics. Biogas and RNG feedstocks are included in the initiative and will be addressed accordingly. ICF anticipates that the guidance from this initiative will have a significant impact on how corporate entities conduct GHG emission accounting as it relates to RNG and its role in decarbonization strategies.

---

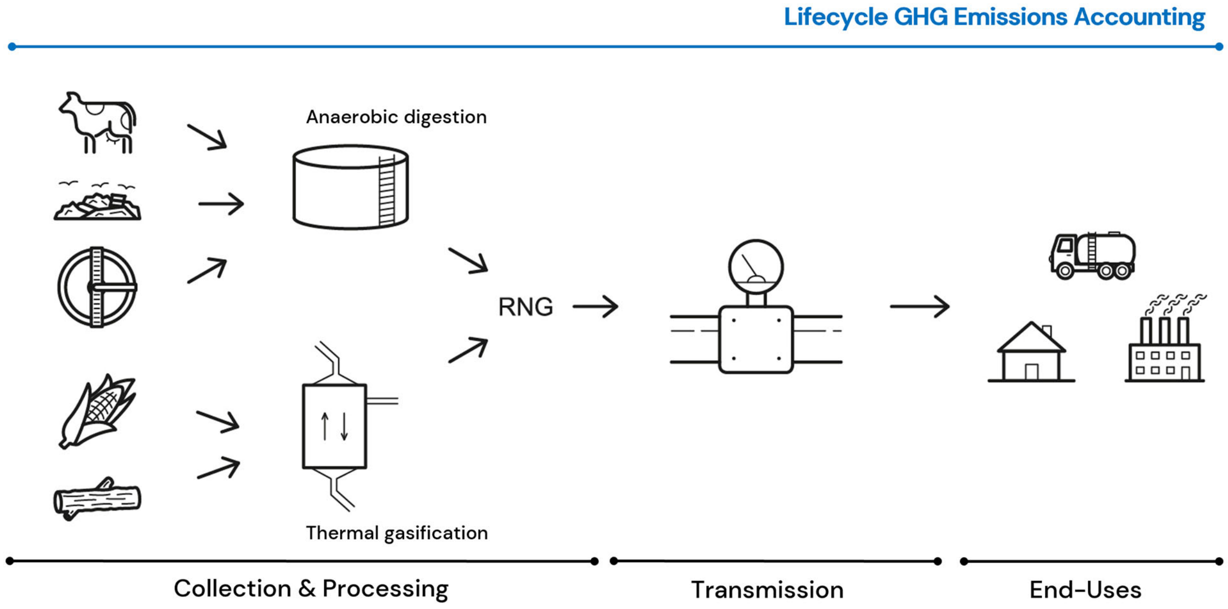
[92] GHG Protocol Land Sector and Removals Guidance, with more information available online at https://ghgprotocol.org/land-sector-and-removals-guidance.

Lifecycle GHG Emissions Accounting

As noted previously in Section 6, the lifecycle GHG emissions associated with the production of RNG vary depending on a number of factors including the feedstock type, collection and processing practices, and the type and efficiency of biogas upgrading. For the purposes of this report, ICF determined the lifecycle carbon intensity (CI) of RNG up to the point of pipeline injection. This includes feedstock transport and handling, gas processing, and any credits for the reduction of flaring or venting methane that would have occurred in absence of the RNG fuel production.

Figure B-2 (a repeat of Figure 6-1) offers a more detailed view of the various stages in RNG production, showing two different production methods and multiple feedstocks. As shown below, the stages of the combustion and lifecycle accounting approaches are broken out into three categories: Collection & Processing, Pipeline/Transmission, and End-Uses. However, the inputs considered within these stages vary between conventional natural gas and RNG, and even among different RNG feedstocks.

Figure B-2. Boundary Conditions of Lifecycle GHG Emissions Accounting for RNG



GHG emissions from RNG can be generated along the three stages of the RNG supply chain.

- *Collection and processing: Energy use required to produce, process, and distribute the fuel*. The energy used to produce, process, and distribute RNG is characterized here as: 1) feedstock collection and 2) digestion and processing related to anaerobic digesters, or synthetic gas (syngas) processing as it relates to thermal gasification.

- *Pipeline/transmission: Methane leaks primarily during transmission*. Methane leaks can occur at all stages in the supply chain from production through use but are generally focused on leakage during transmission. ICF limits our explicit consideration to leaks of methane as those that occur during transmission through a natural gas pipeline, as other methane losses that occur during RNG production are captured as part of efficiency assumptions.
- *End-use: RNG combustion*. The GHG emissions attributable to RNG combustion are straightforward: CO_2 emissions from the combustion of biogenic renewable fuels are considered zero, or carbon neutral. In other words, the GHG emissions are limited to CH_4 and N_2O emissions because the CO_2 emissions are considered biogenic.[93]

Understanding Avoided GHG Emissions

One of the key areas of confusion regarding the GHG emissions of RNG is linked to what is referred to as avoided GHG emissions—this is a concept that only occurs in lifecycle GHG emission accounting and is critical to understanding RNG's broader potential as a decarbonization strategy. Avoided GHG emissions are the GHG emissions that would have occurred under typical or business-as-usual conditions, in other words, if RNG had not been produced and used. There are three sources of GHG emissions that can be avoided:

- *Vented methane emissions.* For example, animal manure on a farm might otherwise be placed in an open lagoon that would vent or emit methane—a potent GHG. Similarly, food waste would likely be sent to a landfill where some methane would escape to the atmosphere; some would be captured and burned to convert most of the methane to carbon dioxide before it enters the atmosphere (i.e., flared).
- *Emissions displaced from the use of RNG intermediary products and coproducts*. In this case, some of the biogas produced in intermediate steps could be used to produce electricity and used to power processing equipment or other processes that require electrical energy in the RNG production supply chain, thereby displacing electricity from the grid.
- *GHG emissions attributable to combustion of conventional natural gas*. In most instances, RNG will be used as a substitute for conventional natural gas, therefore avoiding the emission that would have otherwise occurred from combusting conventional natural gas.

GHG accounting of avoided emissions can be dependent on the regulatory context. For instance, landfills above a certain size are required by federal law to collect and control landfill gas.[94] Therefore, there may be no avoided methane because landfill operators are already capturing methane that would have otherwise been emitted to the atmosphere. The avoided methane emissions are accounted by regulation. Therefore, any RNG produced via methane from a large landfill cannot count methane venting as avoided emissions in a lifecycle emissions accounting method since large landfills are required by law to capture and flare their methane emissions, as opposed to venting.

---

[93] IPCC guidelines state that CO_2 emissions from biogenic fuel sources (e.g., biogas or biomass based RNG) should not be included when accounting for emissions in combustion – only CH_4 and N_2O are included. This is to avoid any upstream "double counting" of CO_2 emissions that occur in the agricultural or land use sectors per IPCC guidance.

[94] The Clean Air Act regulations for landfills can be found in 40 CFR Part 60, Subparts Cc (https://www.ecfr.gov/current/title-40/part-60/subpart-Cc) and WWW (https://www.ecfr.gov/current/title-40/part-60/subpart-WWW)..

Avoided emissions are accounted for in a lifecycle accounting approach using negative numbers. These negative numbers simply represent the GHG emissions that were avoided—this is the appropriate convention. When determining a GHG emissions factor for RNG, there are cases when the avoided GHG emissions are greater than the GHG emissions, meaning that the GHG emissions factor is reported as a negative number. This is where the terms “carbon negative” arises from when discussing RNG from feedstocks (e.g., animal manure).

Table B-1 below shows the lifecycle carbon intensity values that ICF calculated using the GREET model for potential RNG projects in Michigan and compares that to conventional natural gas. ICF assumed that projects were located in Michigan and applied the corresponding GHG emissions factor associated with the RFC region from eGRID in the analysis. ICF did not assume that RNG projects would use on-site renewable energy to decrease the CI of the project. ICF identifies three categories in the table below:

- Extraction & Processing: This category includes the GHG emissions attributable to the energy used to operate anaerobic digesters, the energy required to upgrade biogas to RNG, and any avoided GHG emissions or displacement credits associated with a particular pathway.
- Transportation & Distribution: After the point of injection, RNG is transported through pipelines for distribution to end users. The CI of pipeline transmission depends on the distance between the gas upgrading facility and end use. GREET 2021 enables the user to choose from two approaches to fugitive methane emissions during transmission, referred to as the EPA and Hybrid approaches. These values range from 1.33 to 1.84 gCO_2e/MJ per *thousand miles* of transmission. For the sake of reference, Michigan’s Lower Peninsula is about 280 miles from north to south and 200 miles from east to west. For illustrative purposes, ICF used the Hybrid approach for fugitive methane emissions and assumed a transportation distance of about 160 miles.
- Stationary Combustion: The table also includes GHG emissions attributable to the combustion of natural gas and RNG in stationary applications. In the case of RNG, ICF assumed that the carbon dioxide emissions are biogenic and therefore zero, whereas the methane and nitrous oxide emissions are non-zero and are approximated at 0.05 g/MJ.

Table B-1. Estimated CI Values for RNG from Different Feedstocks (MI specific)

Fuel / Feedstock	Extraction & Processing	Transportation & Distribution	Stationary Combustion	Total
Conventional natural gas	8.27	4.11	50.35	62.72
Animal manure				
Dairy cows	-90.63	0.29	0.05	-90.29
Broilers & Turkeys	46.15	0.29	0.05	46.50
Beef	-12.24	0.29	0.05	-11.89
Swine	-235.00	0.29	0.05	-234.65
Food waste	-99.22	0.29	0.05	-98.87
Landfill gas	10.91	0.29	0.05	11.26
WRRF	-94.45	0.29	0.05	-94.10
Thermal gasification Agricultural residue Energy crops Forestry residue MSW	50-55	0.29	0.05	50.34-55.34

ICF notes the following about these CI estimates:

- The lowest carbon intensities are from feedstocks that prevent the release of fugitive methane, such as the collection and processing of dairy cow manure, beef manure, and swine manure, the diversion of food waste from landfills, or the beneficial use of gas from WRRFs.
- Agricultural residue, energy crops, forestry products and forestry residues, as well as MSW all have the same CI range based on the thermal gasification process required to create biogas from biomass. This is an energy-intensive process, but inclusion of renewables and co-produced electricity on-site can reduce the emissions impact of gas production.

The sensitivity of fugitive GHG emissions, particularly along gas pipelines is highlighted by comments received by stakeholders:

- Some stakeholders asserted that if RNG is produced and consumed locally, that it could eliminate or significantly reduce the use of interstate pipelines where fugitive emissions occur and that RNG development is not associated with the scale of fugitive emissions that are typical of oil and gas wells at the point of production.
- Other stakeholders noted that Michigan may have high pipeline leakage rates due to the age and materials of its pipelines.

ICF's analysis using the GREET model supports the concept that RNG has the potential to reduce fugitive GHG emissions by transport the gas over a shorter distance. ICF estimates that transportation and distribution of RNG will yield an average carbon intensity of about 0.3 g/MJ for Michigan-based projects, whereas conventional natural gas traveling longer distances yields a carbon intensity of about 4.1 g/MJ.

To be clear, these stakeholder comments were intended to emphasize the importance of using a lifecycle accounting approach as it relates to the GHG emissions of RNG. However, as stated earlier, nothing in this report should be misconstrued as an endorsement for or against one GHG emissions accounting approach over another as it relates to a policy structure.

To conduct a GHG emission reduction assessment using the lifecycle accounting approach outlined here, one would simply need to add the upstream GHG emissions factors outlined previously, determine a reasonable estimate for the average distance that RNG will be distributed through the pipeline to account for fugitive methane emissions, and include the GHG emissions at the point of combustion—which should be limited to N_2O and CH_4 emissions based on current GHG emission accounting conventions related to RNG combustion.

Appendix C

State-Level RNG Polices

Today, many state-level policies are in place that are helping to shape the outlook for RNG beyond transportation. The information included in the table on the following pages provides information on these policies, including the state in which the bill was enacted, a bill summary, and key programmatic components such as supply, production or interconnection, cost recovery for gas utilities, and end-user benefits.

State / Bill	Brief Description	Supply	Production / Interconnection	Cost Recovery	End-User Benefit
Arkansas SB 136	Amends state law related to gas rates allowing the PSC to consider utility purchase of natural gas or natural gas alternatives, such as RNG and hydrogen, as an operating expense if the purchase is in the public interest.	No reference	No reference	No reference	No reference
Colorado SB 20-013	Requires gas utilities to file a clean heat plan with the PUC. The targets are a four percent reduction below 2015 GHG emission levels by 2025 and 22 percent by 2030.	Within the overall targets, RNG may only account for one percent of the 2025 target and five percent of the 2030 target.	No reference	No reference	Reduce GHG emissions, with a focus on cost-effectiveness.
Minnesota *Natural Gas Innovation Act*	Allows a natural gas utility to submit an “innovation plan” for approval by the MN PUC to reduce natural gas use.	Eligible technologies include RNG, renewable hydrogen, energy efficiency, and other innovative technologies.	No reference	The maximum allowable cost will start at 1.75% of the utility's revenue in the state and could increase to 4% by 2033, subject to review and approval by the PUC	Reduce GHG emissions; diversify energy resources; promotes innovation; increased renewable energy consumption; and improve waste management.
Oregon SB 98	Allows natural gas utility to make “qualified investments” and procure RNG from 3rd parties to meet portfolio targets for the percentage of gas purchased for distribution to retail customers.	Establishes large/small RNG programs and to make “qualified investments” and procure RNG from 3rd parties to meet portfolio targets for the percentage of gas purchased for distribution to retail natural gas customers.	RNG infrastructure means all equipment and facilities for the production, processing, pipeline interconnection, and distribution.	PUC shall adopt rules establishing a process for utilities to fully recover costs. Cost of capital established by PUC from most recent rate case. Affiliates not prohibited from making a capital investment in a biogas production project. Restricted from making additional qualified investments without the approval of the PUC if the	Reduced emissions. RNG portfolio ranging from 5% between 2020 and 2024 to 30% between 2045 and 2050.

State / Bill	Brief Description	Supply	Production / Interconnection	Cost Recovery	End-User Benefit
				program annual costs exceed 5% of the utility's total revenue requirement in an individual year.	
Washington HB 1257	Required each gas company to offer by tariff a voluntary renewable natural gas service available to all customers.	To replace any portion of the natural gas that would otherwise be provided by the gas company. Customer charge for an RNG program may not exceed 5% of the amount charged to retail customers for natural gas.	No Reference	No Reference	Commission must assess whether the gas companies are on track to meet a proportional share of the state's GHG reduction goal.
Nevada SB 154	Authorized natural gas utilities to engage in RNG activities and to recover the reasonable and prudent costs of such activities, including the purchased of and production of RNG.	Requires a public utility to "attempt" to incorporate RNG into its gas supply portfolio. Gas which is produced by processing biogas or by converting electric energy generated using renewable energy into storable or injectable gas fuel in a process commonly known as power-to-gas or electrolysis.	Activities which may be approved: contracting with a producer of RNG to build and operate an RNG facility; extending the transmission or distribution system to interconnect with an RNG facility; purchasing gas that is produced from an RNG facility whether the gas has environmental attributes or not.	Utility applies to the Commission for approval of a reasonable and prudent RNG activity that will be used and useful. Must meet one or more: the reduction or avoidance of pollution or GHG; the reduction or avoidance of any pollutants that could impact waters in the state; the alleviation of a local nuisance within the state associated with the emission of odors.	Sell gas from RNG facility directly to the customer. Providing customers with the option to purchase gas produced from an RNG facility with or without environmental attributes. Utility shall attempt to incorporate RNG in its gas supply portfolio: By 2025, not less than 1% of the total amount of gas sold; by 2030, not less than 2%; by 2035, not less than 3%.
California SB 1440	Requires the CPUC to establish biomethane procurement goals or targets on natural gas IOUs to further decarbonize the state's natural gas sector.	Adopted a 2025 target of 17.6 BCF and a 2030 target of 72.8 BCF of RNG.	To be eligible, the biomethane needs to be delivered through a common carrier pipeline that physically flows within California, or toward the end user in California for which	Authorize procurement contracts for a minimum of 10 years and a maximum of 15 years.	A limited biomethane procurement program would help the state reduce methane and ensure that California's

State / Bill	Brief Description	Supply	Production / Interconnection	Cost Recovery	End-User Benefit
	Stipulates that the goals and targets need to be a cost-effective means of achieving reductions in short-lived climate pollutants and other GHG emission reductions.		the biomethane was produced.		climate policies are met.
California AB 1900	Established a program beginning in 2015 that provided $40M for RNG interconnection infrastructure. The bill was intended to address the barriers to allowing RNG to be injected into pipelines and break down barriers to using instate RNG—all while ensuring the supply was non-hazardous to human health.	The bill required the California EPA to compile a list of constituents of concern that could pose risks to human health and that are found in biogas at concentrations that significantly exceed the concentrations of those constituents in natural gas.	A part of this bill would require the PUC to adopt standards to ensure pipeline integrity and safety. The PUC would also adopt pipeline access rules to ensure nondiscriminatory access to all pipeline systems for physically interconnecting with the gas pipeline system and effectuating the delivery of gas.	No reference.	As a health safety initiative, the bill required the PUC to specify the maximum amount of vinyl chloride that may be found in landfill gas.
Utah HB 107	Authorizes gas utilities to establish natural gas clean air programs that promote sustainability through increasing the use of renewable natural gas if those programs are deemed to be in the public interest.	In determining whether a project is in the public interest, the Public Service Commission (PSC) shall consider to what extent the use of renewable natural gas is facilitated or expanded by the proposed project; potential air quality improvements associated with the proposed project; whether the proposed project could be provided by the private sector or would be viable without the proposed incentives; whether any proposed incentives were offered to all similarly situated	No reference.	The PSC may authorize large-scale utilities to allocate up to $10M annually to a specific sustainable transportation and energy plan. Elements include an economic development incentive rate; R&D of efficiency technologies; acquisition of non-residential natural gas infrastructure behind the utility's meter; the development of communities that can reduce GHG and NOx emissions; a natural gas renewable energy project;	Reduction of greenhouse gases and NOx emissions.

State / Bill	Brief Description	Supply	Production / Interconnection	Cost Recovery	End-User Benefit
		potential partners and recipients; and potential benefits to ratepayers.		a commercial line extension program; or any other technology program. Electric utilities were previously authorized to have similar programs. If the PSC finds that a gas corporation's request for an NGV rate/clean air programs is less than the full cost of service, remaining costs may be spread to other customers. A previous statute authorizes recovery of expenditures for the construction, operation, and maintenance of natural gas fueling stations and related facilities.	
Vermont PUC Docket# 8667	VT Public Utility Commission authorized a renewable natural gas program for the sale of RNG to customers on a voluntary basis and optional RNG tariff service.	Vermont Gas stated they were seeking to source RNG from landfill gas projects.	Supply from Lincoln and landfill gas projects outside Vermont would be received through the Trans-Canada Pipeline system.	Requires Vermont Gas to file a formal tariff including proposed rates once it has procured RNG in sufficient amounts for estimated customer demand. Adder price for each scf of RNG will be equal to the average RNG commodity cost to VGS less the average commodity cost of natural gas. Also, if Vermont Gas' RNG supply exceeds customer demand, they must first seek to sell the excess at wholesale, and if necessary may seek to flow any remaining inventory amounts through	Successful implementation can help meet the State's renewable energy policy objectives. Assessment of the voluntary program will assist in determining the feasibility of incorporating RNG as a portion of Vermont Gas' supply mix in the future.

State / Bill	Brief Description	Supply	Production / Interconnection	Cost Recovery	End-User Benefit
				a rate case as part of its cost of service.	
Tennessee SB 1959 Tennessee Natural Gas Innovation Act	Authorizes a public utility to request, and the TN PUC to authorize, a mechanism to recover the costs related to the use or development of infrastructure to facilitate use of innovative natural gas resources.	"Innovative natural gas resources" include, but are not limited to, farm gas, biogas, renewable natural gas, hydrogen, carbon capture, qualified offsets, renewable natural gas attributes, RSG, and energy efficiency resources.	No reference	Limits the incremental rate adjustment due to the investment in innovative natural gas resources at 2% of a utility's latest approved annual revenue requirement.	Reduce GHG emissions; diversify energy resources; promotes innovation; increased renewable energy consumption; and improve waste management.
Virginia HB 558	Allows utilities to make investments in eligible infrastructure costs for a variety of projects, including biogas development assuming it meets certain emissions intensity reductions.	No reference		Utilities can recover eligible infrastructure costs through the gas component of the rate structure or other recovery mechanism approved by the Commission.	