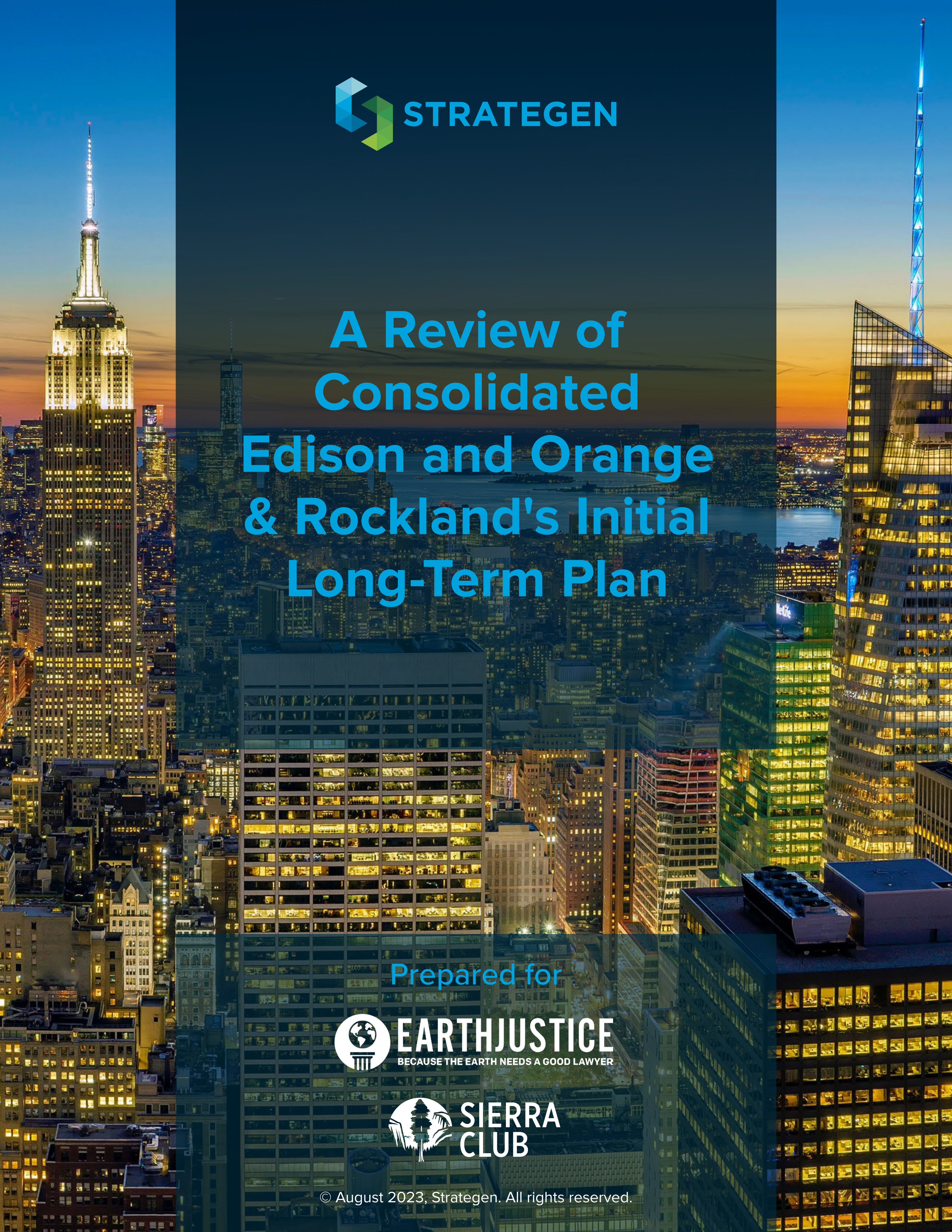

STRATEGEN

A Review of Consolidated Edison and Orange & Rockland's Initial Long-Term Plan

Prepared for

EARTHJUSTICE
BECAUSE THE EARTH NEEDS A GOOD LAWYER

SIERRA CLUB

Introduction

Strategen Consulting has prepared these comments on the initial Long-Term Plan ("LTP") of Consolidated Edison Company of New York ("Con Edison") and Orange and Rockland Utilities ("O&R"), jointly "the Companies," on behalf of its clients, Sierra Club and Earthjustice. Sierra Club and Earthjustice asked Strategen to review the Companies' proposed pathways and outcomes of the modeling in the LTP. Specifically, Strategen reviewed the Companies' alternative fuel assumptions that are a core feature of the Hybrid pathway, capital forecasts, technological assumptions for electrification technologies, and implementation of non-pipeline alternatives ("NPAs").

After review of the LTP, Strategen recommends the Companies adopt the Deep Electrification pathway and recommends adjustments to the LTP to ensure that the Deep Electrification pathway results in the equitable decarbonization of the gas system.

Contents

I. Background

In July 2019, New York State passed the Climate Leadership and Community Protection Act (CLCPA), which set ambitious climate requirements to reduce economy-wide greenhouse gas emissions by 40% by 2030 and no less than 85% by 2050 from 1990 levels.[1] In May 2022, the New York Public Service Commission (the "Commission") issued the Order Adopting Gas System Planning Process ("Gas Planning Order"),[2] which requires each gas distribution company to file a 20-year Long-Term Plan to show, among other things, that the gas utility's planning is consistent with the CLCPA mandates. On May 31, 2023, the Companies filed their Initial Long-Term Plan with the Commission. In the context of the CLCPA emissions reduction targets, the Companies' LTP outlines several measures to support the reduction of their Scope 2 and 3 emissions over the next 20 years, including methane leak reduction, energy efficiency, electrification, and low-carbon fuels like renewable natural gas ("RNG") and green hydrogen. The LTP includes three preliminary pathways. First, the Company determined a "Reference" pathway, which represents business-as-usual forecasts without meeting State or local emission reduction goals.[3] The Company also examined two alternative pathways that take substantive measures toward meeting emissions goals: a "Hybrid" pathway and a "Deep Electrification" pathway.

The Hybrid pathway assumes that low-carbon fuels are critical for decarbonizing the gas system. In the near-term, emissions reductions are driven by some electrification and the adoption of "certified natural gas," which the Companies describe as natural gas with fewer upstream emissions.[4] However, over the planning horizon, RNG plays a central role and, along with hydrogen and synthetic natural gas ("SNG"), the three alternative fuels may enable the Companies to reach 2050 emissions reduction goals. The Hybrid Scenario results in a 61% reduction in emissions through 2042.[5]

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[1] *Progress to Our Goals*, N.Y. State, https://climate.ny.gov/our-impact/our-progress/ (last visited Aug.11, 2023).
[2] Order Adopting Gas System Planning Process, NY PSC Case No. 20-G0131 (May 12, 2022) (hereinafter "Gas Planning Order").
[3] Gas System Long-Term Plan at 54, NY PSC Case No. 22-G-0147 (May 31, 2023) (hereinafter "LTP").
[4] LTP at 67.
[5] *Id*. at 4, fig. 2.

The Deep Electrification pathway, on the other hand, meets CLCPA and local emissions targets largely through the electrification of the gas system. This pathway assumes a 62% reduction in gas customer counts and a 78% reduction in gas throughput by 2042.[6] The measures taken in the Deep Electrification pathway result in an 82% reduction in emissions over the plan period, the greatest reduction of the three pathways the Companies presented.[7]

The Companies have opted not to identify a preferred pathway in the LTP and, instead, intend to pursue both pathways at the present time.[8] Considering the significant differences in decarbonization approaches, it is unclear how the utility's capital investment strategy could align with both pathways.

The natural gas utility industry is beginning a fundamental transformation, driven primarily by cost-competitive electric alternatives and decarbonization policies. As gas utility customers either partially or fully electrify, gas utility annual throughput will correspondingly decline. All else equal, if the fixed costs of the gas utility system have to be recovered over fewer therms of gas, customers will experience rate increases. Indeed, the Companies are already experiencing declining throughput, largely through energy efficiency and, to a lesser extent, electrification. In a July 2023 Order approving a rate case settlement for Con Edison, the Commission found that significant reductions in forecasted gas sales volumes, as compared to the previous gas rate plan, was the most significant rate driver since the 2020 rate plan.[9] Accelerating electrification over the planning horizon will exacerbate the Company's rate pressure.

Given the uncertain planning environment, the Companies should focus on making investments that minimize costs and regret. As the Companies acknowledge in their LTP, the future availability and cost of alternative fuels is highly uncertain. Electrification, however, is a mature, cost-effective technology that immediately locks in emissions reductions for decades. Investing in electrification is the least cost, least risk approach.

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[6] DPS-3-77 Att. 1. Note that Figure 2 of the LTP displays a 76% reduction.
[7] LTP at 4, fig. 2.
[8] The LTP states that the Companies will seek input from stakeholders to determine the best course of action. *Id.* at 4. However, the Companies stated in a stakeholder session that they intend to pursue both pathways.
[9] Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans with Additional Requirements at 111, NY PSC Case Nos. 22-E-0064 & 22-G-0065 (July 20, 2023).

II. Summary of Recommendations

Strategen evaluated the Hybrid and Deep Electrification pathways, analyzing the risk, cost, and emissions reductions forecasted by the Companies. Strategen concludes that, of the two pathways presented by the Companies, the decarbonization strategy described in the Deep Electrification pathway presents the least-cost, least-risk conceptual approach to decarbonization.

Despite being the more reasonable conceptual approach, the investments identified in the Deep Electrification pathway must do even more to protect customers, and especially customers in disadvantaged communities, from gas rate increases during the planning horizon. The Companies should modify the Deep Electrification pathway before adoption in its final LTP. Strategen proposes several recommendations to the Deep Electrification pathway to mitigate increases in customer rates, including a reduction in capital spending and greater adoption of non-pipeline alternatives.

The overarching goal of Strategen's recommended modifications to the Deep Electrification pathway is for the Companies to reduce capital investments such that the size of the gas system scales in alignment with customer counts and throughput. The Companies forecast $7 billion in system investments in the Deep Electrification pathway through 2030 and $9.4 billion through the planning period.[10] Due to these significant investments, the Companies project the rate base to be roughly the same in 2042 as in 2023 despite a loss of over 62% of its customers.[11] The Companies' Deep Electrification pathway investments do not align with the energy demands of their customers and are fundamentally incompatible with the methodological approaches outlined in the Deep Electrification. The scale of the Companies' capital investments, if not modified, will increase customer energy burden.

To resolve the issues in the Deep Electrification pathway, Strategen recommends the Companies adopt a general policy that prioritizes infrastructure repair over replacement, as well as the significant expansion of NPA programs. These modifications to the Deep Electrification pathway should occur immediately since the billions in capital investments that the Companies

[10] DPS-3-77 Att. 1.
[11] *Id.*

forecast in the short term will significantly increase the rate base and customer rates. By prioritizing NPAs, the Companies would avoid installing new gas infrastructure that will most likely become stranded. Demand-side NPA measures such as electrification are inherently consistent with the Deep Electrification pathway's methodological approach to decarbonization and can greatly reduce gas infrastructure spending. Similarly, when NPAs are not a viable solution, pipeline patching and repairs of gas assets reduce gas system investments costs. Repairs can safely extend the serviceable lives of gas assets to match the expected usage periods of those assets and reduce the rate base.[12]

Finally, Strategen recommends the Companies provide detailed cost and load impact forecasts for electrification measures in a revised LTP, if feasible, and in future LTPs. For example, the Companies did not model specific costs and adoption rates for electrification measures such as heat pumps. Rather, the Companies assume electrification occurs at a level that is consistent with meeting CLCPA targets. Electrification measure details are integral to properly assessing the societal costs and electric system demands imposed by the Deep Electrification pathway.

	Companies' LTP	**Strategen Recommendation for LTP**
Preferred Pathway	The Companies intend to pursue both pathways.	The Companies should pursue an approach consistent with the Deep Electrification pathway to maximize emissions reductions and minimize risk.
Deep Electrification CapEx Forecast	The Companies forecast a 24% increase in rate base	The Companies should limit capital investment spending in the short term

[12] Bob Ackley, Nathan Phillips, Wash. D.C. Dep't Energy Env't, Strategic Electrification in Washington, D.C.: Neighborhood Case Studies of Transition from Gas to Electric-based Building Heating (Dec. 14, 2022), https://edocket.dcpsc.org/apis/api/Filing/download?attachId=186471&guidFileName=a9254ec8-d08f-46ed-af0e-31b28d707139.pdf.

	Companies' LTP	Strategen Recommendation for LTP
	from 2023-2030 in the Deep Electrification pathway.	by adopting a policy that prioritizes NPAs when feasible, then pipeline repairs and patching over replacement.
NPA Implementation	The Companies do not provide an NPA budget or forecast. In O&R's Deep Electrification capital forecast, NPAs account for only 3% of spending through 2030.	In addition to detailing ongoing NPA assessments and completed projects, the revised LTP should prioritize identifying new NPA opportunities and demonstrate analytical review. NPAs should be assessed as the primary option over replacement.
Certified Gas	The Companies assume emissions reductions from certified gas at a cost of $0.10 per dekatherm.	Emission reductions from certified gas should not be factored into the LTP until evidence of avoided fugitive methane is accurately measured and the cost is known.
Electrification Assumptions	Electrification assumptions are based on floorspace data. The Company provides no individual measure counts, costs, or load data.	The Companies should provide detailed assumptions regarding electric measure unit costs, performance, and impact on the electric grid in its revised LTP, if feasible, or in the revised LTP. Similar data should be provided for all energy efficiency measures.

	Companies' LTP	Strategen Recommendation for LTP
Benefits to Disadvantaged Communities	No Disadvantaged Community benefits identified.	In the revised LTP and future LTPs, the Companies should provide specific programmatic details for how they will deploy at least 35% of clean energy program benefits for Disadvantaged Communities per the CLCPA.

III. The Deep Electrification Pathway Provides a Model for Gas Sector Decarbonization

The Deep Electrification pathway envisions a steady reduction in gas utility customers and gas consumption. The Companies forecast a 93% reduction in throughput and a 98% reduction in throughput by 2050 for O&R and Con Edison, respectively.[13] In this pathway, the Companies would rely on heat pumps and other electric appliances to meet climate policy goals. The Deep Electrification pathway assumes minimal use of alternative fuels, limited to renewable natural gas.

A) The Deep Electrification Pathway Meets Climate Goals at Low Risk

The Deep Electrification pathway is more consistent with State targets and establishes a method for building sector emission reductions. While the Companies' LTP lacks the detail to assess specific volumes of electrified assets, it is evident that the Deep Electrification pathway relies on the implementation of heat pumps and other electric assets for compliance with State targets. The CLCPA mandates an 85% reduction in 1990 emissions by 2050.[14] Specific to the building sector, the Climate Action Council recommends that 85% of homes and commercial

[13] LTP at 72.
[14] ECL § 75-0107(1)(a)–(b).

space be electrified through heat pumps and thermal energy networks by 2050.[15] The Companies' Deep Electrification pathway takes the first steps toward these goals. Additionally, the Deep Electrification pathway appears to comply with New York City's Local Law 154, which effectively requires that new buildings under seven stories be all-electric by 2024 and that new developments seven stories or greater be all-electric by July 2027.[16]

Not only is the Deep Electrification pathway consistent with State targets and local laws, but it also presents a lower-risk approach for decarbonization. The Deep Electrification pathway relies on existing and mature electrification technologies, like heat pumps, which have several advantages as a decarbonization solution relative to alternative fuels. First, heat pumps are up to three times more efficient than fossil fuel-powered furnaces and electric resistance heating. All-electric new construction has already been shown to be more cost-effective than new, mixed-fuel homes. A Rocky Mountain Institute study found that, over 15 years, all-electric new buildings saved households as much as $6,800 and resulted in 81% fewer emissions than mixed-fuel homes.[17] A California Energy Commission report found that new all-electric single-family and multi-family homes are comparable in cost to mix-fuel homes and result in an average of 0.67 metric tons of annual CO_2 savings per home.[18]

Second, federal law, including the Inflation Reduction Act ("IRA"), provides significant support for efficient electric appliances, including heat pumps. The IRA boosts the heat pump market by providing flat $2,000 in tax credits and rebates up to $8,000 for income-qualified households.[19] This funding will only further accelerate heat pump adoption rates, which have recently surpassed gas furnace sales.

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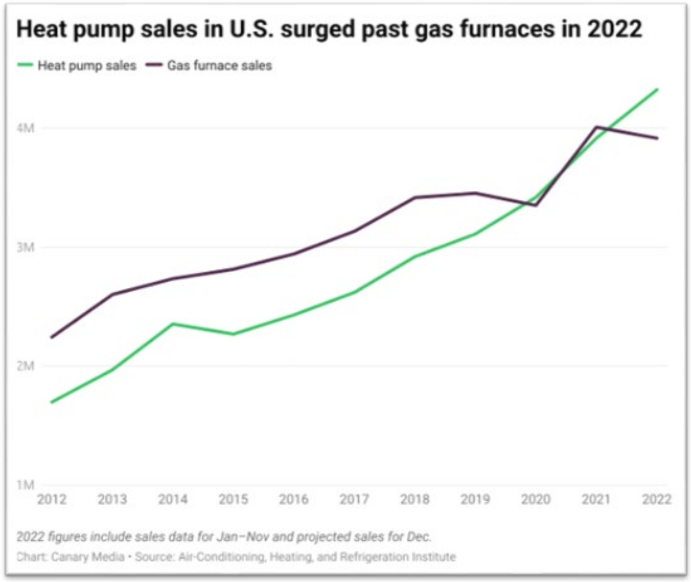
[15] N.Y. State Climate Action Council, Scoping Plan, 180 (Dec. 2022), https://climate.ny.gov/-/media/project/climate/files/NYS-Climate-Action-Council-Final-Scoping-Plan-2022.pdf.
[16] 24 New York City Admin. Code §24-177.1 (Am. Legal Publ'g, 2021).
[17] Claire McKenna, et al., *All-Electric New Homes: A Win for the Climate and the Economy*, Rocky Mountain Inst. (Oct. 15, 2020), https://rmi.org/all-electric-new-homes-a-win-for-the-climate-and-the-economy/.https://rmi.org/all-electric-new-homes-a-win-for-the-climate-andthe-economy/.
[18] Max Wei, et al., *Approaches to Zero Net Energy Cost Effectiveness in New Homes*, Cal. Energy Comm'n, CEC-500-2021-025, at 5 (Apr. 12, 2021), https://www.energy.ca.gov/sites/default/files/2021-05/CEC-500-2021-025.pdf.
[19] Inflation Reduction Act, Pub. L. No. 117-169, 136 STAT. 1818 (2022).

Figure 1: Sales of Heat Pumps and Gas Furnaces[20]



Third, it is likely that the performance and cost-effectiveness of heat pumps will only increase as manufacturers and governments invest in further research and development ("R&D"). In 2021, the US Department of Energy ("DOE") launched a Residential Cold Climate Heat Pump Challenge to develop more efficient cold climate heat pumps.[21] In November 2022, Trane, a heat pump manufacturer, announced that its newest prototype exceeded DOE targets by performing at temperatures as low as -23 degrees Fahrenheit.[22] Several countries in the European Union have also invested public funds into early-stage development.[23] The benefits are evident; heat pump sales have grown by an average of 20% from 2019 to 2021.[24] Seeking to benefit from the rise in heat pump demand, manufacturers are investing in R&D. For example, in April 2020,

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[20] Maria Virginia Olano, *Chart: Americans Bought More Heat Pumps than Gas Furnaces Last Year*, Canary Media (Feb. 10, 2023), https://www.canarymedia.com/articles/heat-pumps/chart-americans-bought-more-heat-pumps-than-gas-furnaces-last-year.

[21] U.S. Dep't Energy, *Residential Cold-Climate Heat Pump Challenge*, (Feb. 2022), https://www.energy.gov/eere/buildings/articles/residential-cold-climate-heat-pump-technology-challenge-fact-sheet

[22] *Trane Passes Heat Pump Challenge*, Cooling Post (Nov. 4, 2022), https://www.coolingpost.com/world-news/trane-passes-heat-pump-challenge/.

[23] Euro. Comm'n, *Heat Pumps*, https://energy.ec.europa.eu/topics/energy-efficiency/heat-pumps_en.

[24] Lorcan Lyons et al., *Clean Energy Technology Observatory: Heat Pumps in the European Union – 2022 Status Report on Technology Development, Trends, Value Chains and Markets*, Joint Rsch. Center Eur. Union, (Nov. 3, 2022), https://publications.jrc.ec.europa.eu/repository/handle/JRC130874.

Carrier, one of the largest heat pump manufacturers, announced a new, $16-million R&D center to focus on sustainable heating solutions.[25] In aggregate, the European Commission estimates that EU investment in heat pumps, including repurposing and building new factories, will total €3.3 billion between 2022 and 2025.[26] These investments will likely lead to improvements in heat pump coefficients of performance ("COP"), and enhance the cost-effectiveness of heat pumps, especially in colder weather.

Finally, New York's mandate of zero-emissions electricity by 2040 ensures that electrified assets will provide significant and long-term emissions reductions. The zero-emissions electricity requirement reduces the risk of the Deep Electrification pathway since it provides a clear pathway to meeting State and local emissions reduction targets. Utilities can decarbonize the building sector through electrification without relying on technological leaps and can initiate necessary actions today.

B) Heat Pumps Perform Better than the Companies' Assumptions

The Companies make three overly conservative assumptions about the efficacy of heat pumps, thereby biasing the LTP against the technology. More specifically, the Companies' LTP heat pump COP estimates are not in line with the best available data. First, the LTP assumes lower heat pump COP values than other relevant and available studies. For example, the consulting firm E3 modeled cold climate heat pump COP values using the Northeast Energy Efficiency Partnerships ("NEEP") Product Specification, which sets qualifying requirements for cold source heat pumps, shown in Figure 2 below.

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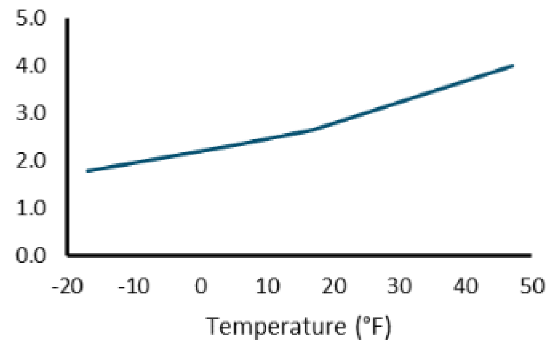
[25] Press Release, Carrier, *Carrier to Invest $16 Million in Research & Development Center of Excellence in Italy*, (Apr. 4, 2022), https://www.carrier.com/commercial/en/eu/news/news-article/carrier-to-invest--16-million-in-research---development-center-of-excellence-in-italy.html.

[26] Lorcan Lyons et al., *supra* note 24.

Figure 2: Cold Climate Heat Pump COP[27]



Temperature (° F)	COP
10	2.45
0	2.21
-10	1.97
-20	1.72

The Companies identify a peak design day temperature at 0 degrees Fahrenheit[28] and assume a heat pump COP range of 1.4–2.1 during these winter peaks.[29] However, E3's study of using NEEP product specifications, as shown in Figure 2, finds that the COP value exceeds 2.0 at 0 degrees Fahrenheit.[30]

Second, the Companies assume a range of 2–2.9 for heat pump COP on average.[31] Considering that the COP values in Figure 2 exceed 3.0 at 30 degrees Fahrenheit, the Companies' range is far too low. The range the Companies provide is so wide that the impact of modeling with values on either bound would significantly alter any analysis. NEEP's Version 4 specifications require a COP of above 2.25 at 17 degrees Fahrenheit for units producing under 135 MBtu per hour.[32] While temperatures in the Companies' service territory do drop below

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[27] Tory Clark et al., *BGE Integrated Decarbonization Strategy*, Energy & Env't Econ., 70 (Oct. 2022), https://www.ethree.com/wp-content/uploads/2022/10/BGE-Integrated-Decarbonization-White-Paper_2022-11-04.pdf.
[28] LTP at 37.
[29] *Id.* at 61.
[30] Response to Sierra Club Data Request 5, SCDR05-07, Md. PSC Case No. 9692 (May 15, 2023).
[31] LTP at 72, fig. 49.
[32] Northeast Energy Efficiency P'ship, *Cold Climate Air Source Heat Pump Specification (Version 4.0)*, 6 (Jan. 1, 2023), neep.org/sites/default/files/media-files/cold_climate_air_source_heat_pump_specification_-_version_4.0_final.pdf.

freezing, not a single month's average low-temperature drops below 26 degrees Fahrenheit.[33] The average temperature across the winter season is above 30 degrees in New York City,[34] indicating that a value at or above the Companies' upper bound is likely to be more accurate.

Finally, the Companies do not appear to assume any increase in the performance of heat pumps throughout the planning horizon. Forecasting no change in heat pump performance over the next two decades is an unreasonable assumption that is incongruous with the historical development of heat pump technology, which has steadily improved over the last fifty years. A 2001 National Renewable Energy Laboratory ("NREL") report on air source heat pumps detailed a performance "one-and-a-half to two times greater than those available 30 years ago."[35] And over the last twenty years, heat pump efficiencies have continued to rise. In 2001, models with a Heating Seasonal Performance Factor ("HSPF") of 7 or greater earned the Energy Star label.[36] Now, models must achieve at least an 8.1 HSPF rating for ducted systems and an 8.5 HSPF rating for non-ducted systems to qualify for the Energy Star label,[37] while NEEP Version 4 specifications require HSPF ratings to be 10 or greater for non-ducted systems.[38] The ability of heat pumps to accommodate cold weather heating needs will be accelerated due to the influx of public and private funding for technological innovation, described earlier. Given the historic trend of improved performance and R&D investments committed by governments and corporations, the Companies should project an increase in heat pump performance throughout the planning period.

Modifying the LTP to reflect more accurate COP values and to reflect the assumption that customers adopt cold climate heat pumps would alter the crossover temperature at which backup systems, such as electrical resistance or gas furnaces, would begin to operate. The Companies

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[33] See New York City monthly data at https://www.ncei.noaa.gov/access/metadata/landing-page/bin/iso?id=gov.noaa.ncdc%3AC00332.
[34] *Id.*
[35] "30 years ago" being 1970. Nat'l Renewable Energy Lab'y, *Air-Source Heat Pumps*, U.S. Dep't of Energy, 4 (June, 2001), https://www.nrel.gov/docs/fy01osti/28037.pdf.
[36] *Id.* at 3.
[37] Energy Star®, *Heat Pump Equipment and Central Air Conditioners Key Product Criteria,* https://www.energystar.gov/products/heating_cooling/heat_pumps_air_source/key_product_criteria (last visited Aug. 11, 2023).
[38] Northeast Energy Efficiency P'ship, *supra* note 32 at 3.

assume that cold climate heat pumps would cross over to backup resistance heating at 5 degrees Fahrenheit,[39] but NEEP specs indicate that the crossover temperature should be much lower. Considering that the Companies' design day temperature is 0 degrees Fahrenheit, backup systems should not be needed to support cold climate heat pumps in the Companies' service territory. Revising COP assumptions will therefore reduce the contribution of all-electric systems during peak demand. A lower crossover temperature would also reduce the reliance on natural gas furnaces operating as backups, lowering emissions and reducing gas system throughput during peak periods.

C) Strategen Recommendations

The Companies Should Adopt the Deep Electrification Pathway

Strategen recommends that the Companies adopt the Deep Electrification pathway since it aligns with policy goals and relies on proven and cost-effective technology. The targets laid out in the LTP, including a 82% reduction in emissions by 2042 and a 98% reduction in throughput across Con Edison's system by 2050, present a commitment to decarbonization and electrification.

The LTP Should Expand on Electrification Assumptions

To better determine the impact on customers, Strategen recommends that the Companies include additional data in the revised LTP as well as subsequent LTPs. This first iteration of the LTP includes few details on the cost and approach the Companies will use to support electrification. The Companies did not include any electrification measure quantities and costs, which are critical data for NPA analyses. Rather, the Companies relied on New York City Mayor's Office floorspace data.[40] Consequently, the Companies were unable to and did not quantify the societal costs and benefits of electrification.[41]

Moreover, it appears that the Companies provided misleading information on the impacts of building electrification to the electric system. The Companies included transportation

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[39] SC and EJ 2-16 Att. 1
[40] SC and EJ 3-25
[41] SC and EJ 3-23

electrification in the electrification load growth models.[42] While electric system impacts due to transportation electrification is useful information, it should not factor into the comparison of pathways without context and its inclusion in summary tables, such as Figure 2 of the LTP,[43] misleads the reader into believing that building electrification results in greater electrical system impacts than the Companies actually forecasted.

Strategen recommends that the LTP include more substantive assumptions by class, specifically regarding the following:

- Electrification measures cost curve
- Electrification measures energy use and performance in accordance with NEEP specifications
- Heat pump performance increase over the planning horizon
- Electrification incentive costs
- Electrification measure ramp rates
- Energy efficiency measure costs
- Energy efficiency measures energy savings
- Energy efficiency measures ramp rates

Furthermore, the LTP should more comprehensively quantify the impacts of the Deep Electrification pathway on the electric system. Strategen recommends that the Company provide the following projections:

- Electricity price forecast
- Annual electricity demand forecasts
- Peak demand forecasts for every summer and winter season

Finally, Strategen recommends revising heat pump estimates to reflect the latest cold climate heat pump performance specification detailed by NEEP.

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[42] SC and EJ 3-20
[43] LTP at 4, fig. 2.

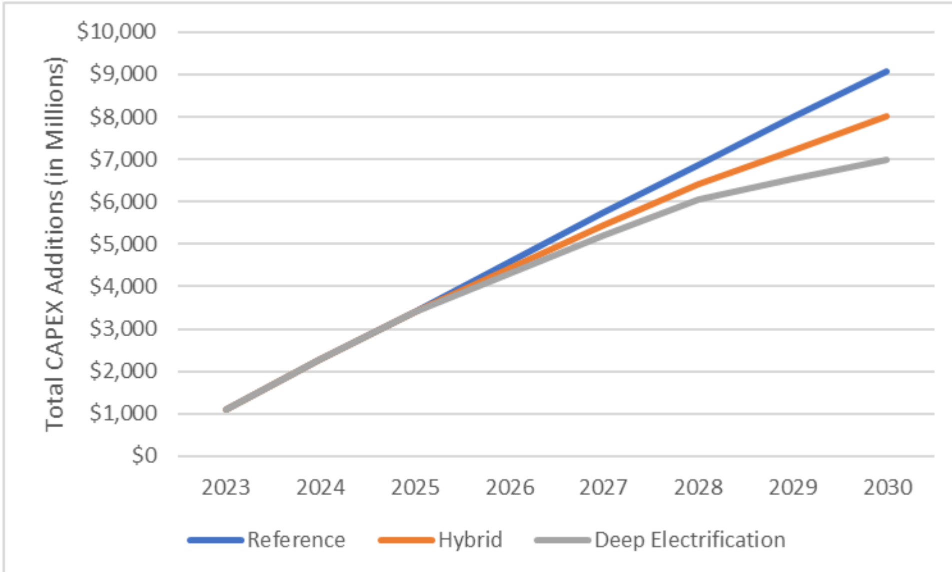
IV. The Companies Should Modify their Deep Electrification Capital Spending to Ensure an Equitable Energy Transition

A) The Companies' Capital Investments Will Likely Become Stranded and Cause Rate Increases

Although Strategen recommends the Companies pursue a decarbonization strategy in line with the Deep Electrification pathway, we are concerned with the proposed level of capital expenditures associated with the pathway. The Companies forecast significant spending over the next decade in all the examined scenarios, including the Reference, Hybrid, and Deep Electrification pathways. However, the need for extensive delivery system infrastructure in the Deep Electrification pathway is incongruous with forecasted demand. From 2023 to 2042, the Companies forecast a 62% reduction in customers in the Deep Electrification pathway and a 78% reduction in throughput.[44] Such significant reductions should be accompanied by a reduction in the size of the system, yet the Companies forecast their rate base to stay nearly level from 2023 to 2042.[45] This is largely due to significant investments over the next decade. In the Deep Electrification pathway, the Companies forecast $7 billion in new capital investments through 2030.[46] For comparison, the Companies forecast $9 billion over that same period in the Reference pathway, which assumes only a 22% reduction in throughput through 2042.[47]

[44] DPS-3-77 Att. 1.
[45] *Id.*
[46] *Id.*
[47] *Id.*

Figure 3: Forecasted CapEx Additions Through 2030 by Pathway[48]



The forecasted system investments lead to the Companies' rate base **increasing by 24%** from 2023 to 2030 in the Deep Electrification pathway.[49]

These capital investments will have two major impacts: 1) gas customers will face rate increases as a smaller set of customers will be responsible for greater fixed costs, and 2) many of the investments could become stranded. Gas assets are long-lasting, especially main lines that depreciate over a period of 85 years. Pipelines placed into service over the next five years will likely not be paid off for decades. The Companies' Deep Electrification pathway projects a 93% and 98% reduction in gas volumes for O&R and Con Edison, respectively, by 2050.[50] A contraction in gas system usage should be accompanied by a reduction in capital investments to keep rates, and customer bills, reasonable. It is highly concerning that the Companies forecast otherwise. If such investments are ultimately placed into service, customers will pay rapidly increasing rates for assets that will likely become underused or unused.

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[48] *Id.*
[49] *Id.*
[50] LTP at 72.

The Companies appear to acknowledge this issue by modeling a version of the Deep Electrification pathway with accelerated depreciation.[51] While not reducing the risk of stranding investments, accelerated depreciation seeks to alleviate customer rate pressure by frontloading asset cost recovery when more customers are still part of the gas system. This alternative does little to reduce the risk of stranded assets and does not meaningfully reduce customer rates. Instead of seeking policy methods to shift the timing of the rate impacts, the Companies should focus on scaling back their investments.

B) The Companies' Short Term Capital Investments Do Not Align with the Deep Electrification Pathway

Gas utility business models and the traditional cost-of-service regulatory framework have traditionally assumed perpetual growth for gas systems. The energy transition challenges this assumption. Utilities can no longer replace pipelines and other infrastructure with the assumption that assets will be useful throughout their projected lifespans. According to the Companies' Deep Electrification pathway, by 2050, most of their system will be depreciated. System enhancements should no longer be optimized to last 50 to 80 years, but to serve customers for a shorter horizon, perhaps 10 to 25 years. Therefore, the Companies should prioritize the repair, rather than replacement, of system infrastructure when NPAs are not feasible. By focusing on opportunities for repairing assets, the Companies will reduce their capital expenditures and will better align the longevity of assets with the useful period that is outlined in the Deep Electrification pathway. A Washington D.C. Department of Energy and Environment study found that repairing leaks rather than replacing pipes can be a "cost-effective strategy to manage gas pipelines for retirement."[52] The report found that the utility's action to repair the largest leaks in the study resulted in "the one-time cost of these repairs to ratepayers to be between one tenth and one hundredth of the cost of pipeline replacement on that street."[53] Applying a similar proportion to the Companies' proposed capital expenditures, the Companies' proposed $7 billion in investments through 2030

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[51] LTP at 78.
[52] Bob Ackley, Nathan Phillips, Wash. D.C. Dep't Energy Env't, *supra* note 12 at 2.
[53] *Id.*

could be reduced to between $70 and 700 million. Such cost savings are critical in reducing customer rate impacts.

The Deep Electrification capital forecast also does not align with the projected lifespan of its system. The Companies' capital spending does not indicate a focus on repairs and minimization of long-lived assets. Through 2030, Con Edison forecasts several billion dollars in distribution pipeline replacements and upgrades and nearly a billion dollars in transmission projects.

Figure 4: Subset of CECONY Capital Investments 2023-2030 (In Billions)[54]

Capital Investment Program Type	**Total**
Leak Prone Main Replacement Program (MRP/GIRRP)	$2.28 B
Service Replacement	$0.59 B
Transmission/Generation Projects	$0.82 B
System Reinforcement Program/Winter Load Relief	$0.23 B
Public Improvement	$1.15 B

The Companies assume that, for their Deep Electrification pathway, "main replacement programs end by 2031 (Con Edison and O&R); routine CapEx in rate case through 2024 (O&R) and 2025 (Con Edison) then proportional to main mileage."[55]

The Companies should not wait until 2025 to begin taking meaningful action to reduce the sizes of their investments. The Companies can begin by drastically scaling back the scope of its main replacement programs through 2031. Historically, Con Edison has targeted 10 miles per year of "High Risk" main replacements through its Main Replacement Program.[56] However, in its 2023–2025 Gas Operations Capital Programs budget, the Company states its intentions to replace 80 miles through 2025, or approximately 27 miles per year.[57] The LTP states that the Main Replacement Program will continue through 2031.[58] The Companies increasingly aggressive Main Replacement Program is risky when, according to the Companies' forecasts,

[54] DPS-1-26 Att. 1.
[55] LTP at 72.
[56] 2023–2025 Gas Operations Capital Programs/Projects at 8, NY PSC Case No. 22-G-0065 (Jan. 28, 2022).
[57] *Id.* at 7.
[58] LTP at 72.

there will be almost no natural gas demand by 2050. While some main replacement will be necessary, the program, with its specific replacement targets initiated before the CLCPA, overestimates the amount of replacement that is necessary to maintain a safe system in the short-term. Instead, the Companies should be making every effort to repair pipelines or seek other alternatives that prevent further pipeline investments.

Strategen recommends the Companies focus on three areas for reducing capital spending: pipeline replacements, transmission investments, public improvement projects, and oil-to-gas conversions.

a. Pipeline Replacement

While some pipeline replacements may be necessary for safety and reliability, required replacements may be far less extensive than what the Company forecasts in the next decade. Con Edison's capital forecast after 2031 may provide a better sense of the minimum investments needed to ensure the safety of the gas system. For many of these capital program types, the long-run investment projections are significantly smaller than near-term projections. As demonstrated in Figure 5 below, Con Edison's capital expenditures are significantly greater in the next eight years than the following eight across several CapEx categories related to pipeline replacements and upgrades. This suggests that significant short-term investments could be avoided through repairs.

Figure 5: Comparison of Average Annual Con Edison Capital Investment (in Millions)[59]

Capital Investment Program Type	2023-2031	2032-2040
Leak Prone Main Replacement Program (MRP/GIRRP)	$266	$15
Service Replacement	$68	$4
System Reinforcement Program/Winter Load Relief	$26	$0
Non-Leak-Prone Main Replacement Program (DIME)	$6	$1

b. Transmission Investments

Annual transmission pipeline investments remain consistent at over a hundred million per year through 2035, before dropping to $5 million a year for the rest of the planning horizon.[60] These costs are likely related to the 2019 Pipeline and Hazardous Materials Safety Administration's Maximum Allowable Operating Pressure Reconfirmation regulation ("MAOP rule"), which requires reconfirmation of all transmission pipeline segments that do not have "traceable, verifiable, and complete" records (50% must be reconfirmed by 2028).[61] Utilities must reconfirm all pipelines subject to the regulation through a reconfirmation process that can be accomplished through six methods, including a pressure test, pressure reduction, engineering critical assessment, pipe replacement, pressure reduction for pipeline segments, and alternative technology.[62] Some utilities have opted for reconfirmation through transmission pipeline replacements, which can cost millions per mile. With throughput projected to rapidly decline in the Deep Electrification pathway, Con Edison should seek to avoid spending hundreds of millions on transmission projects by focusing on reconfirmation through lower-cost options in the short term (such as pipeline derating) while examining options for the retirement of segments that are scheduled to be reconfirmed in the next decade.

[59] DPS-1-26 Att. 1.
[60] *Id.*
[61] 49 CFR §§ 191, 192.
[62] *Id.* § 192.624(c).

c. Public Improvement Projects

Public improvement projects that result in the construction of new pipelines are triggered by other entities, such as local governments, and present another significant cost. Unlike other programs, public improvement projects continue to be extensive throughout the planning horizon. To a certain extent, the utility has less control over these CapEx costs since it cannot plan as far in advance. The Companies still can seek alternative solutions to rebuilding pipelines and should leverage NPAs, discussed in Section V, to decommission segments that need to be replaced, where appropriate. Decommissioning segments will become increasingly viable towards the end of the planning horizon when a significant portion of customers have already exited the gas system and once the NPA process has been refined and streamlined.

d. Oil to Gas Conversions

The Deep Electrification pathway still allows for another five years of oil-to-gas conversions. Oil customers converting to gas will ultimately need to electrify and a short stint on the gas network will raise customer costs since extension costs are unlikely to be fully recovered. The infrastructure needed to convert customers from oil to gas will almost certainly become stranded. While the utility is still obligated to serve customers seeking to convert from oil to gas, the utilities, and the Commission, should heavily incentivize oil customers to electrify.

C) Disadvantaged Communities Will Likely Be More Greatly Impacted by Unnecessary Spending

In each of the scenarios modeled in the LTP, including the Reference case and the Hybrid scenario, the Companies forecast decreasing customer counts and decreasing throughput. As stated in these comments, the decline in demand is highest in the Deep Electrification pathway. A shrinking customer base will cause the smaller, remaining set of customers to pay for a fixed system that, according to the Companies' capital forecast, will remain relatively flat over the planning horizon. Rising gas rates will catalyze a transition to electrification, further raising rates for remaining customers. Low-income and disadvantaged communities have the fewest resources to fuel switch and are the most likely to remain on the dwindling gas system. Unnecessary spending in the short term is likely to lead to inequitable outcomes for gas system customers. Despite identifying high concentrations of disadvantaged communities in the Bronx, Queens, and

Brooklyn,[63] the Companies have not detailed efforts to reduce energy burdens for those communities in this LTP. Beyond existing affordability programs, the Companies do not describe how they intend to direct at least 35% of clean energy program benefits to disadvantaged communities, as directed in the CLCPA.

D) Strategen Recommendations

The Companies Should Seek to Repair Rather than Replace Pipelines

Strategen recommends that, when NPAs are not feasible, repairs, rather than replacements, should become the default solution for segments of leak-prone pipe and other gas infrastructure in need of upgrades. With the Companies projecting almost no throughput by 2050 in the Deep Electrification pathway, replacements will have a useful life of one to two decades. To reduce ratepayer burdens, the Companies should seek to extend the lifespan of existing pipelines through repairs whenever possible.

The Deep Electrification pathway capital forecast is essentially identical to the Reference pathway through 2025. Spending in 2024 and 2025 is not set in stone and the Deep Electrification pathway should not assume that business remains as usual for another two-and-a-half years. While the Reference pathway assumes continued use of the gas system, the Deep Electrification pathway does not, and, therefore, the Company should take immediate steps to prevent further investment in a contracting system. Main replacements scheduled in the coming years should be assessed for repair. Although repairs may not be feasible in all circumstances, the Deep Electrification capital forecast should factor substantially less spending associated with replacements than the Reference and Hybrid pathways. As mentioned earlier, the Deep Electrification capital forecast from 2032–2040 may signal the minimum necessary investment needed to maintain a safe gas network. Those lower costs suggest that fewer pipelines need to be replaced if they only need to operate reliably for another decade. This signifies that repairs could suitably extend the lifespan of pipelines in the short term.

[63] LTP, at 17, fig. 11.

The Companies Should Provide a Thorough Explanation of How They Will Ensure at Least 35% of Clean Energy Program Benefits Go to Disadvantaged Communities

A policy of repair over replacement, even if not concentrated in disadvantaged communities, will directly benefit disadvantaged communities that are least able to electrify. However, the Companies should do more to protect these communities from rising energy burdens. Strategen recommends that the Companies provide a more robust assessment in the revised LTP detailing how they will deploy at least 35% of clean energy program benefits for disadvantaged communities, per the CLCPA.

V. The Companies Should Scale Non-Pipeline Alternatives to Avoid Infrastructure Capital Spending

Non-pipeline alternatives are critical for avoiding unnecessary gas system investments. NPAs in the gas sector are the equivalent of the electric sector's "non-wires alternatives" and refer to activities or investments that delay, reduce, or avoid the need to build or upgrade traditional gas system infrastructure such as pipelines, storage, and peaking resources.[64] NPA solutions are composed of a variety of strategies, programs, and technologies on both the demand side and supply side, including demand response, energy efficiency, electrification, thermal storage, behavioral changes, liquefied natural gas ("LNG") peaking storage, and mobile pipeline injection. In practice, NPAs are typically a portfolio of solutions that offset pipeline gas demand.

The three main benefits of NPA are cost reduction, risk reduction, and emissions reductions. NPAs can be less expensive than traditional utility capital investments such as pipeline replacements, leading to cost savings for ratepayers. This is especially pertinent if pipeline replacements are at risk of being stranded and recovered through a dwindling customer base, as is the case in the Companies' Deep Electrification pathway. Implementing NPAs instead of pipeline solutions reduces the risk of asset under-recovery and customer rate shocks. Additionally, demand-side NPAs reduce gas consumption, thus enabling emissions reductions and compliance with the New York climate goals.

[64] Advanced Energy Econ., *Non-Pipeline Alternatives (NPAs)*, 1 (Oct. 2022), https://info.aee.net/hubfs/Sarah%20S%20uploads/NPAs.pdf.

A) Con Edison's NPA Framework

The Company's framework identifies three investment types that are suitable for NPAs: load relief, regulator station upgrade programs, and main replacement programs.

- Load relief: designed to reduce demand in areas where the Company may not be able to meet peak day demand. To be successful, NPAs should offset capacity expansion projects and maintain system reliability.[65]
- Regulator station upgrade programs: designed to avoid the installation of new piping and regulator station vaults. To be successful, NPAs should sufficiently reduce demand to maintain system reliability.[66]
- Main replacement programs: designed to avoid the replacement of leak-prone gas mains. To be successful, NPAs should enable the full electrification of customers served by the eliminated pipeline.[67]

B) The Companies' LTP Does Not Reflect a Commitment to NPAs

While Con Edison's NPA framework specifies capital investments that can be avoided with NPAs and establishes evaluation criteria, the Companies' capital forecasts do not reflect significant use of NPAs. As discussed earlier, Con Edison forecasts $2.28 billion in leak-prone pipe replacements and nearly a quarter of a billion dollars in system reinforcement spending through 2030 in the Deep Electrification pathway.[68] O&R forecasts over a quarter of billion dollars in main replacements and reliability investments through 2030 in the Deep Electrification pathway, or 75% of its capital budget over that span.[69] Over that same period, O&R forecasts $10 million towards NPAs, only 3% of its capital spending. From 2031–2042, NPA spending accounts for 2% of O&R's capital spending, despite a considerable decrease in overall

[65] Proposal for Use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure at 11, NY PSC Case No. 19-G-0066 (Sept 15, 2020).
[66] *Id*. at 12.
[67] *Id.*
[68] DPS-1-26 Att. 1.
[69] *Id.*

spending.[70] The Companies' capital forecasts in each pathway reflect considerable pipeline investments and negligible commitments to NPAs.

The LTP does not expand on the NPA framework adopted in other dockets and does not establish goals, such as miles of leak-prone pipe avoided or spending targets, for Con Edison. This lack of information is especially concerning since NPAs are an integral part of cost-effectively implementing the Deep Electrification pathway. Electrification, a demand-side NPA measure, is the central component of the Deep Electrification pathway. To maintain affordability for customers that remain on the gas system, the Companies should target electrification measures, often paired with other demand- and supply-side measures, such that pipeline investments can be avoided. The NPA programs provide the framework for avoiding gas system spending and accomplishing the goals identified in the Deep Electrification pathway.

C) NPA Programs Should be Prioritized for Immediate Implementation

The process of developing a request for proposals ("RFP"), evaluating proposals, and implementing an NPA solution takes significant time. Con Edison's NPA framework sets a timeline of over 36 months for large projects (over $2 million).[71] If the Companies delay NPA programs or identify a narrow set of potential projects, significant reliability and safety issues will inevitably be resolved with pipeline solutions, which will add to the rate base and will likely become stranded. Inaction regarding NPAs will directly lead to unnecessary capital spending and threaten customers with rate increases. Figure 5 of the LTP, which models gas system rates, displays dramatic rate increases in the Deep Electrification pathway.[72] The modeled rate increases are, in part, a result of the Companies' failure to comprehensively implement NPAs in the Deep Electrification pathway (and repair infrastructure as discussed in Section IV).

The Companies' capital spending totals in the Deep Electrification pathway are similar to those of the Reference scenario through 2030. If the Companies begin assessments in earnest now, NPAs should have a significant impact starting in 2025 for projects under $2 million and

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[70] *Id.*
[71] Proposal for Use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure, *supra* note 65 at 17.
[72] LTP at 7, fig. 5.

starting in 2026 for projects over $2 million. In 2026, Con Edison forecasts $277 million in leak-prone pipe replacements and $42 million in system reinforcement programs.[73] Given the lead time necessary to implement NPA projects, the Companies should conduct reliability projections several years in advance to identify high-risk areas before a pipeline solution is required. The Companies may need to address some reliability concerns before a NPA portfolio can be evaluated and implemented. In those scenarios, utilities should consider compressed natural gas as a bridge to long-term, demand-side NPAs. Compressed natural gas can temporarily resolve reliability concerns during peak periods while enabling the utility to implement a long-term NPA solution. All of the leak-prone pipe replacements and system reinforcement projects that would occur in 2026 or later should be automatically reassessed for NPAs. Other capital programs, such as service replacements, Maximum Allowable Operating Pressure rule replacements, and public improvement projects—in which there is ample time to implement an NPA solution—should also be automatically assessed.

D) Strategen Recommendations

NPAs Should Be a Principal Component of the Revised LTP

Strategen recommends that the Companies provide a comprehensive report of all NPA activities and significantly enhance their NPA strategy in the revised LTP. Specifically, the Companies should provide data quantifying the number of NPA projects assessed, the number of NPA projects implemented, and the individual project costs since this first iteration of the LTP. Additionally, the Companies should provide a list of ongoing NPA assessments and forecasts of planned NPA assessments for the next three years.

The NPA strategy outlined in the revised LTP should set goals for the number of pipeline miles replaced and avoid capital spending. The Companies should clearly identify how their NPA approach seeks to minimize infrastructure spending. Moreover, the strategy should detail measures the Companies have taken to ensure that disadvantaged communities are prioritized in NPA assessments and implementations.

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[73] DPS-1-26 Att. 1.

VI. The Hybrid Pathway Is Risky and Does Not Meet Electrification Goals

The Companies' Hybrid pathway is primarily a pipeline approach to decarbonization that relies heavily on low-carbon fuels, with modest electrification measures, to reduce emissions. By 2042, the Companies project that the Hybrid pathway would reduce emissions by 61%, compared to 21% in the reference pathway and 82% in the deep electrification pathway.[74] A significant portion of emissions reductions are due to the use of large quantities of RNG and questionable assumptions related to certified gas. Since the Hybrid pathway is a pipeline-based approach, the Companies project $15.2 billion in CapEx spending through 2042, only $3.8 billion less than the reference pathway.[75]

A) The Hybrid Pathway Does Not Meet State and Local Targets

The Hybrid pathway does not comply with local laws, will not meet electrification targets, and may not position the Companies to meet State emissions reduction mandates. The hybrid pathway assumes continued customer growth through 2030,[76] even though New York City local law 154 effectively bans fossil fuel use in new buildings in 2024 for buildings under seven stories and in 2027 for buildings seven stories or greater.[77] The State of New York has passed a similar fossil ban, although the prohibitions on fossil fuel use in new buildings begin several years later than under New York City's ordinance.[78]

Additionally, the Final Scoping Plan recommends that 85% of home and commercial building space be electrified with heat pumps and thermal energy networks by 2050.[79] The Hybrid pathway will not meet those targets since it primarily relies on low-carbon fuels, not electrification, for emissions reductions. Furthermore, the Hybrid approach falls behind the State's emission reduction mandates. The CLCPA's emissions reduction requirements of 40% by

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[74] LTP at 4.
[75] DPS-3-77 Att. 1.
[76] LTP at 61, fig. 40.
[77] 24 New York City Admin. Code §24-177.1 (Am. Legal Publ'g, 2021).
[78] FY 2024 New York State Executive Budget: Transportation, Economic Development and Environmental Conservation Article VII Legislation, at 254 (Jan. 31, 2023), https://www.budget.ny.gov/pubs/archive/fy24/ex/artvii/ted-bill.pdf.
[79] N.Y. State Climate Action Council, *Scoping Plan*, *supra* note 15 at 180.

2030 and 85% by 2050 apply economywide, so at present do not apply directly to the Companies. However, if future policies apply sector-based requirements, the Companies risk non-compliance. For example, the New York State Department of Environmental Conservation is developing an economy-wide cap-and-invest program. The program could impose sector-specific limitations that apply to the building sector, which could necessitate deeper reductions than would be achieved under the Hybrid pathway.

B) Alternative Fuels Are Costly and Carry Too Much Risk

The feasibility and cost-efficacy of the Hybrid pathway hinges on alternative fuels materializing in sufficient quantities and at a low price point, which is a risky premise. Unlike the Deep Electrification pathway which relies on existing, cost-effective electrification technologies for emissions reductions, the Hybrid pathway gambles that technological innovations allow low-carbon fuels to be widely available and cost-effective. The Companies are aware of this risk, stating in their LTP that, "If, however, [low-carbon fuels] do not materialize in a meaningful way, the gas system will need to be phased out in the long-term to achieve carbon neutrality."[80] The Hybrid pathway is especially risky because the cost-effectiveness and availability of low-carbon fuels will remain unclear for many years. Pursuing a Hybrid pathway would entail the Companies operating largely business-as-usual for the next decade while waiting for technological innovations to materialize. If they do not, which the Companies acknowledge is a possibility, then the Companies will need to electrify, and critical time will have been lost. During that lost time, the Companies will have made significant investments in their delivery systems that are likely to become stranded and will not have made the investments necessary for other decarbonization pathways.

SNG, RNG, and green hydrogen all play a role in the Hybrid pathway, and each presents a significant risk for the Companies and their customers in meeting emissions reduction goals. The risks of each are discussed in depth below.

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[80] LTP at 61.

a. Green Hydrogen

Con Edison forecasts acquiring 6.4 TBtu of hydrogen by 2042 in the Hybrid pathway, roughly equating to a 15% blend by volume.[81] Similarly, O&R forecasts roughly 15% blending by volume in 2042 in the Hybrid pathway,[82] signifying that, through this pathway, the utility would significantly invest in system upgrades and increase operations and maintenance spending to ensure the safe delivery of hydrogen.[83] Although hydrogen holds promise as a decarbonization fuel for hard-to-decarbonize sectors of the economy, the gas delivery system is a poor use case for green hydrogen due to blending limitations and its relative cost as compared to alternatives.

Hydrogen cannot be substituted for natural gas on a 1:1 basis without a complete overhaul of the gas distribution system and customer end-use equipment. While low volumes of hydrogen blends in the distribution system can offset gas consumption, these blends can come with increased risk. Hydrogen has a far greater risk of leakage, given its smaller molecule size, compared to natural gas.[84] A recent California Public Utilities Commission study shows that the greater the hydrogen concentration in the gas network, the more significant leaks become.[85] Hydrogen leakage increases safety risk given hydrogen's lower minimum ignition energy than natural gas, meaning hydrogen leaks can ignite without any apparent ignition sources present.[86] The alternative fuel also has three times less energy content than natural gas by volume, meaning that introducing hydrogen to the natural gas system without reducing energy output requires an increase in pipeline capacity (pressure-associated or volumetric), leading to additional costs and potential risk to pipeline safety (due to embrittlement and leakage). [87] Hydrogen leakage can reduce the alternative fuel's climate benefits, as hydrogen acts as an indirect greenhouse gas in

[81] LTP at App. C-7.
[82] *Id.*
[83] Calculated using values in LTP Appendix C-7 and the assumption that hydrogen is three times less energy dense than natural gas.
[84] Miroslav Penchev et al., *Hydrogen Blending Impacts Study Final Report*, Univ. of Cal., Riverside (July, 18, 2022), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.
[85] *Id*.
[86] *Id*.
[87] *Id.*

the atmosphere, increasing the amounts of other gases such as methane and dampening some of the near-term emissions reductions gained by a switch to green hydrogen.[88]

Research on the level of hydrogen blending possible without significant system retrofits varies. Some research indicates hydrogen blends may be possible up to 20% by volume (meaning 7% by energy since hydrogen has less energy content),[89] and one-off demonstrations have even exceeded this blending level at power plants.[90] However, multiple recent studies suggest that safety concerns can render blends above even 5% by volume infeasible without a distribution system and end-customer investment.[91] Hydrogen blending literature also emphasizes that feasible blending levels may differ significantly between pipeline network systems and should be determined on a case-by-case basis. As a result, researchers at NREL concluded that introducing any level of hydrogen blending in the gas system "would require extensive study, testing, and modifications to existing pipeline monitoring and maintenance practices" (e.g., additional leak detection technology, more frequent maintenance inspections) which would add additional costs.[92] These costs would apply even if the Companies' proposed hydrogen blend required no other significant system retrofits. With higher blends, further costs will be incurred, including replacing or retrofitting pipelines and other distribution system equipment to be hydrogen ready. Thus, the 15% blend that the Companies propose would almost certainly require large system upgrades, with significant financial investment, to maintain system integrity and safety.

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[88] Ilissa B. Ocko and Steven P. Hamburg, *Climate Consequences of Hydrogen Emissions*, Env't Def. Fund (July 20, 2022), https://acp.copernicus.org/articles/22/9349/2022/acp-22-9349-2022.pdf; Maria Sand et al., *A Multi-model Assessment of the Global Warming Potential of Hydrogen*, 4 Communications Earth & Env't (2023), https://doi.org/10.1038/s43247-023-00857-8.

[89] Kevin Topolski et al., *Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology*, Nat'l Renewable Energy Lab'y (Oct. 2022), https://www.nrel.gov/docs/fy23osti/81704.pdf

[90] Emma Penrod, *Constellation Sets Hydrogen-gas Plant Blending Record, But More Advances Needed for Utility-scale Use: Experts*, UtilityDive (June 5, 2023), https://www.utilitydive.com/news/constellation-energy-hydrogen-blending-test-hillabee-power-plant/652000/.

[91] Press Release, Cal. Pub. Util. Comm'n, *CPUC Issues Independent Study on Injecting Hydrogen into Natural Gas Systems* (July, 21, 2022), www.cpuc.ca.gov/news-and-updates/all-news/cpuc-issues-independent-study-on-injecting-hydrogen-into-natural-gas-systems; Kevin Topolski et al., *supra* note 89.

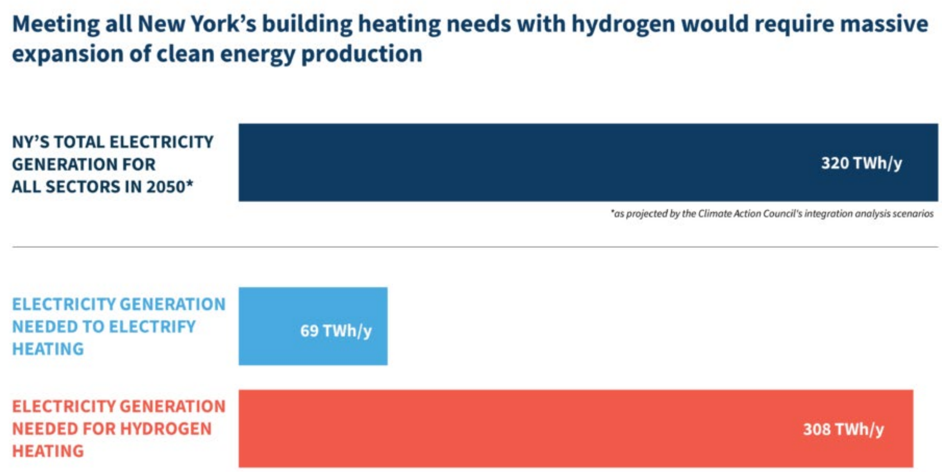
[92] M.W. Melaina et al., *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*, Nat'l Renewable Energy Lab'y (Mar. 2013), https://www.nrel.gov/docs/fy13osti/51995.pdf.

Hydrogen blends at higher volumes may also be incompatible with end-use appliances. Studies suggest that some appliances cannot tolerate even the slightest blends and would require modifications to function properly.[93] The widespread blending of hydrogen in gas lines could thus require the abrupt retrofit of home appliances, likely well before the end of many installed appliances' useful lives. The Companies' LTP does not discuss the costs to customers for the retrofit of end-use appliances.

Green hydrogen is also an expensive fuel as compared to other building heating alternatives. The LTP projects hydrogen prices to drop to $9.31/MMBtu by 2031.[94] This goal is sourced from DOE's Hydrogen Shot, an ambitious plan to reduce the cost of clean hydrogen to $1/kg by 2031,[95] which the DOE itself says is "based on stretch R&D goals."[96] In addition to the cost of the fuel, the Companies have estimated the incremental cost of blending hydrogen to be **BEGIN CONFIDENTIAL INFORMATION** <xxxxxxxxxxxxxxxxxxxxxxx[97]xxxxxxxxxxx xxxxxxxxxxxxxxxxx>[98] **END CONFIDENTIAL INFORMATION**. The added system costs render the overall cost of hydrogen far less competitive. Given the uncertainty in these cost projections, relying on a plan that hopes that hydrogen blending will be a cost-competitive decarbonization resource for the gas delivery system is risky for customers. This risk might be understandable if hydrogen were the only alternative to fossil gas, but that is far from true. Cost-effective alternatives to hydrogen, like electrification, are readily available. Regardless of how much green hydrogen's cost declines, it is inherently less cost-effective than electricity since the green hydrogen production process requires electricity as an input. Energy is lost in the chemical reaction that produces hydrogen; therefore, a significant expansion in electric generation would be necessary to supply the hydrogen quantities the Companies forecast in the Hybrid pathway.

[93] *Id*.; Miroslav Penchev et al., *supra* note 84.
[94] LTP at App. C-6.
[95] *Hydrogen Shot*, U.S. Dep't Energy, https://www.energy.gov/eere/fuelcells/hydrogen-shot (last visited Aug 11, 2023).
[96] U.S. Dep't Energy, *Pathways to Commercial Liftoff: Clean Hydrogen*, 2 (Mar. 2023), https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.
[97] Calculated using DPS-2-65
[98] *Id.*

Figure 6: Efficiency of Electricity in Direct Use Versus Conversion to Green Hydrogen[99]



Hydrogen blending also exposes customers to unknown and potentially severe air pollution and health risks. Hydrogen blending has the potential to increase nitrogen oxide (NOx) pollution because hydrogen burns hotter than methane, and NOx is formed under high-temperature conditions during combustion. While it is possible to reduce hydrogen's NOx emissions by adjusting hydrogen's combustion temperature, designing combustors to minimize exposure to nitrogen in the air, or after-treating exhaust to remove NOx, these approaches mainly apply to hydrogen combustion at large scales (e.g., power plants, industrial facilities).[100] Addressing NOx emissions associated with blending hydrogen for combustion in residential and commercial properties (e.g., in boilers and stoves) is both more complex and less cost-effective than at centralized facilities.[101] Research on NOx emissions in these consumer-facing hydrogen applications shows the need for a greater understanding of hydrogen's impacts before deployment. A recent study measuring NOx emission from hydrogen blends in household assets

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[99] Olivia Prieto & Mike Henchen, *Low-Carbon Fuels Have a Limited Role to Play in New York's Buildings*, Rocky Mountain Institute (May 25, 2022), https://rmi.org/low-carbon-fuels-have-a-limited-role-to-play-in-new-yorks-buildings/.

[100] Christina Cilento, *Fueling a Low-Carbon Future in Utah: The Role of Hydrogen*, Ctr. Climate & Energy Solutions, 8 (June, 2022), https://www.c2es.org/wp-content/uploads/2022/07/Fueling-a-low-carbon-future-in-utah-the-role-of-hydrogen.pdf.

[101] Alastair C. Lewis, *Optimizing Air Quality Co-benefits in a Hydrogen Economy: A Case for Hydrogen-specific Standards for NOx Emissions*, Env't Sci.: Atmospheres, 201, 203, (2021), https://pubs.rsc.org/en/content/articlepdf/2021/ea/d1ea00037c.

revealed "a huge range of possible changes in NOx emissions from H2-[natural gas] fuel blends," with possible emission increases of 7% to 30%.[102] NOx emissions from hydrogen blends may pose health concerns that should be thoroughly assessed before the widespread implementation of hydrogen.[103]

While investing in system upgrades and end-customer retrofits to enable hydrogen use for residential and small commercial applications is unlikely to be more cost-effective than electrification, some large commercial and industrial ("C&I") customers face significant challenges decarbonizing via electrification and may provide more natural use cases for hydrogen. Any safe and cost-effective use of hydrogen in the Companies' system is likely limited to blending in designated transmission pipelines to these C&I customers. Focusing on these priority applications can help reduce emissions from hard-to-electrify industrial processes (e.g., industries with high heat needs) and large commercial businesses, while also minimizing the system costs and safety risks associated with blending hydrogen in the sprawling gas distribution system. These C&I transmission pipelines should be islanded from the distribution system to reduce safety risks. Only small quantities of hydrogen would be necessary to satisfy this use case, far less than the 7.3 TBtu that the Companies project in 2042.[104]

b. Renewable Natural Gas

The Companies' LTP forecasts significant use of renewable natural gas, including 37% of 2042 supply in the Hybrid pathway.[105] Comparatively, the Companies forecast that RNG makes up only 13% of 2042 supply in the Deep Electrification scenario.[106] Although RNG can displace fossil gas on a 1:1 basis, RNG supply is limited, there is competition for its use, and it is a relatively expensive resource. RNG is significantly more expensive than fossil gas according to

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[102] Madeleine L. Wright & Alastair C. Lewis, *Emissions of NOx from Blending of Hydrogen and Natural Gas in Space Heating Boilers*, Elementa: Sci. Anthropocene, 2022, https://doi.org/10.1525/elementa.2021.00114 at 7, 11.
[103] *A Review of the Evidence: Public Health and Gas Stoves*, Multnomah County, 10 (Nov. 2022), https://www.multco.us/review-evidence-public-health-and-gas-stoves.
[104] LTP at App C-7.
[105] *Id.* at 4.
[106] *Id.*

the Companies' LTP, ranging from $11.29/MMBtu to $34.56/MMBtu, depending on the feedstock.[107]

While RNG is a low-carbon fuel with potential applications in hard-to-electrify sectors, the scale of RNG acquisition for the Companies' delivery system in the Hybrid pathway is unrealistic. The Companies assume they can purchase "the full amount produced by anaerobic digestion in our service territories" and "their representative share of RNG produced by anaerobic digestion from the Mid-Atlantic and the rest of the Eastern U.S."[108] The Companies essentially assume that they will be able to monopolize the RNG supply in their service territory and claim RNG from regions across the Eastern United States. Specifically, in the Hybrid pathway, Con Edison forecasts that it will source 43.1 TBtu of RNG in 2042 while O&R forecasts 6.4 TBtu.[109] However, the Companies' analysis determines there to be only 10.3 TBtu of achievable RNG in New York City and Westchester (Con Edison's territory) and 1.3 TBtu of achievable RNG in O&R's territory.[110]

It is highly concerning for the Companies to forecast such high acquisition rates from locally sourced RNG and from the Mid-Atlantic. If other gas utilities were to forecast similar adoption of RNG, the Companies would fall well short of their RNG needs. Nor would monopolizing available RNG be sufficient. Acquiring all the RNG within the Companies' service territories would not even provide 10% of the Companies' projected 2042 fuel needs in the Hybrid pathway.[111]

Furthermore, natural gas utilities are not the only industries vying for RNG, which will impact both the available supply and the cost. The transportation sector is the predominant customer of RNG, consuming an estimated 75% of the RNG produced, due to federal and state policies such as the federal renewable fuel standard and California, Oregon, and Washington's

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[107] SC and EJ-2-11 Att. 1.
[108] LTP at 50.
[109] *Id.* at App. C-7. Note: SC and EJ-2-11 Attachment 1 displays different RNG usage than LTP Appendix C-7 (39.3 TBtu for Con Edison and 5.7 TBtu for O&R in the Hybrid Pathway)
[110] SC and EJ-2-11 Att. 1.
[111] Calculated using LTP at App. C-7

low carbon fuel standards.[112] The competition for RNG suggests that the Companies will not be able to monopolize the RNG supply in their territory and will face challenges acquiring sources outside their territory. There are other industries interested in RNG as well, including the power sector (i.e., gas-fuel generation plants), maritime shipping, and other sectors. Competition from these industries for limited supplies of RNG may drive up prices, ultimately leaving customers to bear the risks of low-carbon fuel price increases and volatility.

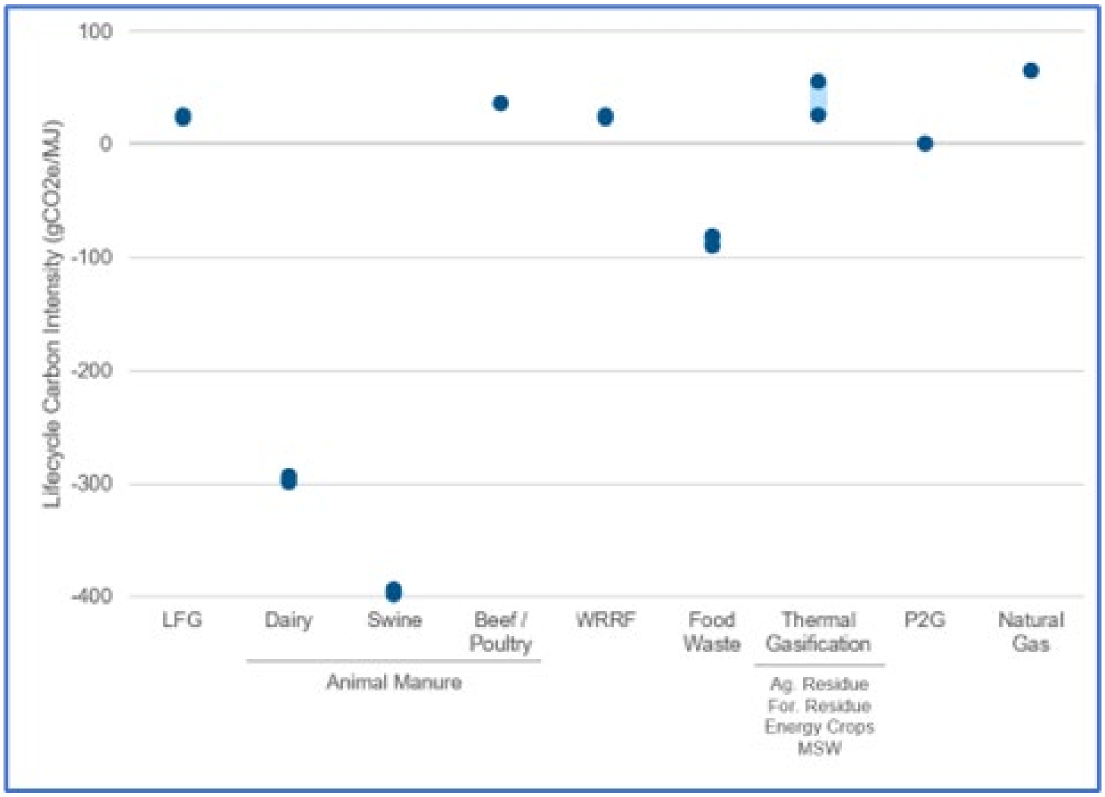
Furthermore, the Companies also assume the acquisition of RNG feedstocks that require thermal gasification for production, a resource that is not commercially available today. A 2019 American Gas Foundation report stated that "[t]here is considerable uncertainty around the costs for thermal gasification of feedstocks, as the technology has only been deployed at pilot scale to date or in the advanced stages of demonstration at pilot scale."[113] Along with RNG, the thermal gasification process produces tar, a substance that damages methanation equipment.[114] There is no mechanism that effectively prevents the buildup of tar, ultimately preventing the commercialization of thermal gasification.[115] Within the Companies' service territory, 7.1 TBtu of RNG feedstock, or 61% of the total supply, requires thermal gasification for conversion to fuel.[116] Therefore, the Companies gamble not only on the availability of RNG but also on technological advances in thermal gasification that allow for the cost-effective procurement of RNG sources within their territories.

Finally, RNG acquired through thermal gasification still produces emissions. An ICF study found that thermal gasification from all feedstocks results in positive lifecycle

[112] Bentham Paulos, *Analysis: Why Utilities Aren't Doing More with Renewable Natural Gas,* Energy News Network, (Feb. 14, 2019), https://energynews.us/2019/02/14/analysis-why-utilities-arent-doing-more-with-renewable-natural-gas/.
[113] ICF, *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment,* Am. Gas Found., 56 (Dec. 2019), https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.
[114] ICF, *Michigan Renewable Natural Gas Study,* Mich. Pub. Serv. Comm'n, 19 (Sep. 22, 2022), https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/RenewableNaturalGas/MI-RNG-Study-Final-Report-9-23-22.pdf.
[115] *Id.*
[116] SC and EJ 2-11 Att. 1.

emissions,[117] meaning that the RNG the Companies intend to source will still produce emissions. The positive lifecycle emissions of thermal gasification may prevent the Companies from achieving emission reductions goals and it is unclear whether the Companies' have factored lifecycle emissions into their calculations in the LTP.

Figure 7: Lifecycle Emissions of RNG Sources[118]



c. Synthetic Natural Gas

Although the LTP does not model any synthetic natural gas during the planning period, the Hybrid pathway indicates that SNG will be critical in achieving emissions reductions beyond 2042.[119] Due to supply and technical limitations, the Companies cannot solely rely on hydrogen

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[117] ICF, *Michigan Renewable Natural Gas Study – Draft Final Report v1,* Mich. PSC (June 7, 2022), https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/RenewableNaturalGas/MI-RNG-Study-Final-Report-9-23-22.pdf.
[118] *Id.* at 113.
[119] LTP at 3.

and RNG to meet customer demands in the Hybrid pathway. SNG is the only solution that allows the Companies to decarbonize their entire gas networks through low-carbon fuels.

However, relying on advancements in SNG as the long-term solution for decarbonization is a risky gamble since it is in the early stages of technological development. Synthetic gas is produced through a process called methanation that combines green hydrogen, produced from renewable-powered electrolyzers, with carbon dioxide ("CO_2"), sourced from carbon capture technology. None of these processes operate at scale today and only a handful of small-scale methanation pilots exist worldwide. For synthetic gas to be available and cost-competitive before mid-century, several technological leaps must occur. The failure of one of these technologies to materialize or be cost-competitive threatens the viability of the Companies' Hybrid pathway. Decarbonization via the Hybrid pathway relies on four core assumptions related to synthetic gas, the combination of which demonstrates that the fuel is speculative, risky, and likely unrealistic. The four assumptions are:

1. Green hydrogen becomes cost competitive.
2. Carbon capture becomes cost competitive.
3. The methanation process becomes cost competitive.
4. Electricity prices are low.

i. Green Hydrogen

As discussed earlier, green hydrogen, along with the system investments needed to safely enable blending, is likely to be significantly more expensive than fossil gas through 2050. The outlook for carbon capture and methanation appears to be worse.

ii. Carbon Capture

After hydrogen, the second feedstock needed to produce synthetic methane is CO_2. While CO_2 is abundant, its economic viability as a feedstock depends on the concentrations of CO_2 in the source stream. Sourcing CO_2 from an ethylene oxide stream, a byproduct in chemical manufacturing, costs between \$25–\$35/ton due to the high concentration of CO_2.[120] The

[120] Adam Baylin-Stern & Niels Berghout, *Is Carbon Capture Too Expensive?*, IEA (Feb. 17, 2021), https://www.iea.org/commentaries/is-carbon-capture-too-expensive.

Companies could acquire CO_2 from several high-concentration sources, but these supplies must be co-located with methanation plants for maximum cost-effectiveness. Piping CO_2 from chemical plants to a methanation plant would generate infrastructure costs, therefore location is an important consideration. Given the New York decarbonization mandates, there may be too few industrial and commercial sources of CO_2 in the region to supply a steady stream needed to make synthetic gas. Direct air capture technology provides another CO_2 source that can be more easily co-located with a methanation plant, but acquisition costs range between $134–$342/ton due to low concentrations in the air.[121] These high costs currently make direct air capture unviable, and despite significant tax credits enacted for direct air capture projects as part of 2022's IRA,[122] it is likely to be years before these projects operate at the scale needed to supply meaningful quantities of CO_2.[123] Relying on carbon capture to cost-effectively provide a feedstock is thus risky and unreasonable.

iii. Methanation

Methanation combines hydrogen and CO_2 feedstocks into methane or synthetic natural gas. Only a handful of methanation pilot projects exist worldwide, and this is for good reason; as discussed earlier, both feedstocks are not commercially available. Since the requisite inputs are costly, research and development in methanation is thus extremely expensive. As a result, current pilot projects are quite small, such as Uniper's plant in Germany which only produces 600kW/hr of methane.[124] It is challenging to forecast the reduction in methanation costs since the technology is nascent.

iv. Electricity Prices

Since each part of the synthetic methane production process relies on electricity, the cost-competitiveness of the fuel is highly dependent on the price of electricity. According to the International Renewable Energy Agency, "The largest single cost component for on-site

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[121] *Id.*
[122] Inflation Reduction Act, Pub. L. No. 117-169, 136 STAT. 1818 (2022).
[123] Maximus L.L. Beaumont, *Making Direct Air Capture Affordable; Technology, Market and Regulatory Approaches*, 4 Frontiers Climate, 2022, https://www.frontiersin.org/articles/10.3389/fclim.2022.756013/full at 2.
[124] *'Green' Methane Pilot Plant Starts Up*, Chem. Processing, (July 3, 2018), https://www.chemicalprocessing.com/processing-equipment/reaction-synthesis/article/11312596/green-methane-pilot-plant-starts-up.

production of green hydrogen is the cost of the renewable electricity needed to power the electrolyser unit.… A low cost of electricity is therefore a necessary condition for producing competitive green hydrogen."[125] The production of green hydrogen, the capture of CO_2, and methanation all experience energy losses. Using electricity directly, such as through heat pumps and other electric appliances, is thus inherently more energy efficient than the production of synthetic gas. Regardless of how cheap electricity prices become, synthetic gas will always be more expensive than the direct use of electricity, and the higher the price of electricity, the greater the disparity becomes. In other words, synthetic gas requires inefficient use of electricity in an attempt to solve an issue already solved by electrification. For comparison, Uniper's power-to-gas pilot achieved 53 percent efficiency.[126] It is far cheaper and less risky to use the existing electric system to decarbonize than to rely on technological breakthroughs.

In summary, there are significant technical and economic obstacles before SNG is commercially available. Banking on unknown technology to play a major role in decarbonization strategy significantly increases the risk of the Hybrid pathway.

C) Certified Gas Is Not a Solution to Decarbonizing the Gas System

The Companies forecast the adoption of certified gas as a means for decarbonization in both the Hybrid and Deep Electrification pathways. Certified gas is fossil gas but with the promise of fewer upstream emissions. The end-use combustion of certified gas results in the same amount of emissions as fossil gas. The Hybrid pathway assumes that certified gas becomes 100% of the fossil gas supply by 2033.[127] The Companies state that "[c]ertified gas reduces the upstream emissions factor associated with natural gas usage by 47%"[128] and only costs a premium of $0.10 per MMBtu,[129] a small fraction of the total cost of gas.

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[125] Int'l Renewable Energy Agency, *Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal* (2020), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf.
[126] Sonal Patel, *WindGas Falkenhagen: Pioneering Green Gas Production*, POWER (Sep. 1, 2020), https://www.powermag.com/windgas-falkenhagen-pioneering-green-gas-production/.
[127] LTP at App. C-7.
[128] *Id.* at 67.
[129] *Id.* at 52.

However, there is no guarantee that certified gas reduces emissions cost-effectively. Con Edison is currently piloting a certified gas project that will allow the Company to "determine if the certified natural gas market has developed enough to provide meaningful and verifiable emission reductions upstream of our gas distribution system at a reasonable cost to customers."[130] The Companies do not acknowledge in the LTP that the emissions reductions and cost-effectiveness of certified gas are still highly opaque. There is also uncertainty as to the maturity of the reliability of emissions reduction claims associated with certified gas. To start, there is no agreed-upon national standard for the certification process. A recent report suggests that certified gas programs are highly unreliable and ineffective due to inadequate detection of pollution events.[131] Second, the Companies' assumed cost premium for certified gas is $0.10/Dt and was "based on initial phone discussions with suppliers and pricing ranges reported in industry publications."[132] An initial phone screening is not a reliable source of information. Given the significant uncertainty related to the cost and benefits of certified gas, the Company's assumptions are not reasonable for inclusion in this LTP. Should the Company seek to rely on certified gas in future LTPs, the Companies need reliable cost estimates—such as official responses from a Company solicitation—and demonstration that the Company is working with a third-party that uses a rigorous standard for determining emissions reductions. To minimize potential appearances of conflicts, the Companies should consider working with LTP stakeholders and the Department of Public Service Staff for evaluating and selecting an appropriate third-party.

D) Strategen Recommendations

The Companies Should Not Adopt the Hybrid Pathway

Strategen recommends that the Companies do not adopt the Hybrid pathway. The risks associated with alternative fuels are too significant for the Companies to pursue the Hybrid pathway. There are significant unknowns regarding the availability, technological readiness, and

[130] Gas Infrastructure, Operations and Supply Panel Rebuttal Testimony at 62–64, NY PSC Case No. 22-G-006 (June 17, 2022).
[131] Josh Eisenfel et al., *Certified Disaster: How Project Canary & Gas Certification Are Misleading Markets & Governments*, Earthworks & Oil Change Int'l (Apr. 2023), https://earthworks.org/resources/certified-disaster/.
[132] SC and EJ 3-22.

price of hydrogen, RNG, and SNG. Alternative fuels are likely to be important in certain hard-to-decarbonize sectors of the economy, where electrification is too costly or infeasible. There is a relatively small chance that alternative fuels will be ubiquitous and cost-competitive, particularly synthetic natural gas, and it will take a decade or more to ultimately determine if it is a viable alternative. During that period, the Companies will have continued investing in pipeline solutions and preparing their systems for alternative fuels. If these technologies do not materialize, which the Companies acknowledge in their LTP, the Companies will need to electrify. Given the cost-competitiveness and technological maturity of electrification, pursuing a Hybrid pathway that may ultimately result in a pivot to electrification regardless is too risky. Moreover, customers, and not the Companies, bear the risk of the Hybrid pathway. Customers carry the risk of failed emissions reduction achievements, volatile fuel prices, and expensive infrastructure upgrades.

Relying on certified gas is not a long-term path for achieving meaningful emissions reductions. Although a factor in all pathways, certified gas plays the largest role in the Hybrid pathway. Certified gas is still fossil gas, and the upstream methane reductions from certified gas are not conclusive. Until the Companies produce conclusive evidence that certified gas will support climate efforts, Strategen recommends that certified gas not be factored into emissions reduction calculations.

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