DAVID S. LAPP
PEOPLE'S COUNSEL

WILLIAM F. FIELDS
DEPUTY PEOPLE'S COUNSEL

JOSEPH G. CLEAVER
DEPUTY PEOPLE'S COUNSEL

OPC

OFFICE OF PEOPLE'S COUNSEL
State of Maryland

6 ST. PAUL STREET, SUITE 2102
BALTIMORE, MARYLAND 21202
WWW.OPC.MARYLAND.GOV

BRANDI NIELAND
DIRECTOR, CONSUMER
ASSISTANCE UNIT

GAIL V. TUCKER
ADMINISTRATIVE
PROGRAM MANAGER

Comments on draft *Building Energy Transition Plan*

We appreciate the efforts of the Mitigation Working Group and E3. The draft plan and E3 report provide valuable insights into how Maryland can meet its greenhouse gas reduction goals, and we agree with many of its conclusions and most of its recommendations. Our comments below focus on our concerns about certain E3 assumptions. Our technical comments, provided under a separate cover, highlight serious flaws with certain technical components of E3's analysis.

Because of the problems noted below and in light of Synapse's review, we do not support the MWG recommendations that flow from E3's finding that the Electrification with Fuel-Backup (EFB) scenario is the lowest cost and lowest risk of the three scenarios analyzed. Rather, we support amending the buildings plan to be consistent with the High Electrification case, with allowances for retaining limited continued use of gas for certain customers when adequately supported by objective analysis.

Our comments make the following five points:

- The E3 analysis does not reflect the reality of current gas utility investment strategies, nor does it reflect the legal and practical realities of utility ratemaking and planning.
- The Electrification with Fuel-Backup scenario risks delaying a much-needed plan to curb costly natural gas infrastructure investments.
- Consumers—especially low-and-moderate-income customers—are most vulnerable to the adverse consequences of the EFB scenario.
- Additional policy considerations weigh against the EFB scenario.
- Implementation of all-electric building standards should not be delayed until 2027.

September 29, 2021

1. The E3 analysis does not reflect the reality of current gas utility investment strategies, nor does it reflect the legal and practical realities of utility ratemaking and planning.

a. E3 appears to incorrectly assume that the gas utilities' revenue requirements will drop significantly around 2035.

The E3 study relies on assumptions about slowed growth in gas utility revenue requirements that do not justify its conclusions. For example, E3 slide 30, on the most favorable "structured" transition, states: "Capital related expenditure and pipeline maintenance costs become flat after 2030, which reflects half of the reinvestment level compared to today." These statements are difficult—if not impossible—to reconcile with the gas utilities' ongoing and planned investments and the application of utility ratemaking to the gas utilities' plans to replace infrastructure. At the very least, they appear misleading. Below, we first summarize the gas utilities' current and planned investments. We then explain how those investments are paid for through customer rates.

i. Gas utility infrastructure investments

The gas utilities are in the midst of major infrastructure plans, including extending service to new customers and replacing most of their infrastructure built up over the last 100 years. These are long-term investments. BGE, the state's largest gas utility, last year proposed in its multi-year plan spending $411.6 million in 2021, $450.1 million in 2022, and $421.4 million in 2023, for a total of $1.28 billion over just three years. In its order on BGE's plan issued on December 16, 2020, the PSC approved most all of this spending, and earlier this BGE submitted compliance filings showing planned gas infrastructure spending over these three years of $1.26 billion. Because the EFB scenario anticipates that gas service will not be extended to new buildings, below we focus mostly on gas utility investments under the STRIDE program, which represents less than half of BGE's 2021-2023 spending plans.

The following table shows *actual* expenditures for STRIDE I; PSC-approved expenditures for STRIDE II; and the gas utilities' anticipated expenditures on STRIDE through 2043, according to the most recent plans the utilities have filed with the PSC.

Figure 1a:
STRIDE Investment Plans of Maryland's 3 Largest Gas Utilities

(in millions of dollars)	**BGE**	**WGL**	**Columbia**
Total spent STRIDE I (actual 2014-2018)	$513.1	$205.4	$63.3
Actual/Authorized budget STRIDE II (2019-2023)	$793.9	$471.0	$84.7
STRIDE III (2024-2028) budget, utility plans assume annual 3% increase	$693	$378	$99
STRIDE IV (2029-2033) budget, utility plans assume annual 3% increase	$804	$166	$67
STRIDE V (2034-2038) budget, utility plans assume annual 3% increase	$932	$74	$0
STRIDE VI (2039-2043) budget, utility plan assumes annual 3% increase	$1,034	$0	$0
Totals (millions)	**$4,771**	**$1,294**	**$313**
Total for MD's 3 major gas utilities (replacement infrastructure only)	**$6,378**		

Of the $6.4 billion in overall planned STRIDE costs shown above, approximately 75%, or $4.8 billion, is for STRIDE projects that have not yet started:

Figure 1b:
Future STRIDE Investments of Maryland's 3 Largest Gas Utilities

(in millions of dollars)	**BGE**	**WGL**	**Columbia**
Stride 2022-2023	$329.1	$177.3	$35.6
STRIDE III-VI	$3,463.6	$617.9	$165.1
Total future spending each utility (post 2021)	**$3,792.7**	**$795.3**	**$200.7**
Total future planned spending of three major MD gas utilities (post 2021)	**$4,788.6**		

The gas utilities' current STRIDE programs thus will *not* be completed by 2035 or earlier, as the E3 study shows, but (for BGE) in 2043.[1] If STRIDE investments were to be accelerated for earlier completion, the already significant rate impacts of STRIDE would be even greater. Further, in 2043, the early STRIDE investments (those begun in 2014) will be aging, and we should expect the utilities to argue that at least some of that infrastructure will need to be replaced again, in 2043 or soon thereafter. (Perhaps new and safer gas-pipe technologies will be available.) Gas utilities are incentivized to invest in this new capital because such investments benefit shareholders. To assume the utilities will forever end their infrastructure replacements—even if only to maintain their existing systems—is impractical and unrealistic.

More significantly, the investments in the chart cover only STRIDE-qualifying replacement infrastructure; they do not include other—even more significant—utility infrastructure long-term capital investments. BGE's STRIDE investments for 2021-2023, for example, represent only about *40%* of its total infrastructure investments.[2] Investments in new infrastructure are not slowing; rather, proposals before the Commission (such as BGE's pending new "pay-it-forward" proposal) would facilitate greater gas expansion to new customers. Without strong policies to address gas infrastructure connecting new gas customers, the total infrastructure investments made by the gas utilities by 2043 could be more than double the planned STRIDE investments. (These estimates also do not include the investments of smaller Maryland gas utilities.)

ii. How these investments are recovered in rates

All this spending is capital investment that is recovered from the utility's (largely captive) customers over time—often more than 30 years and as long as 70 years—as it depreciates and is removed from rate base. (This is the case for both investments made as part of the STRIDE program and other utility investments.)

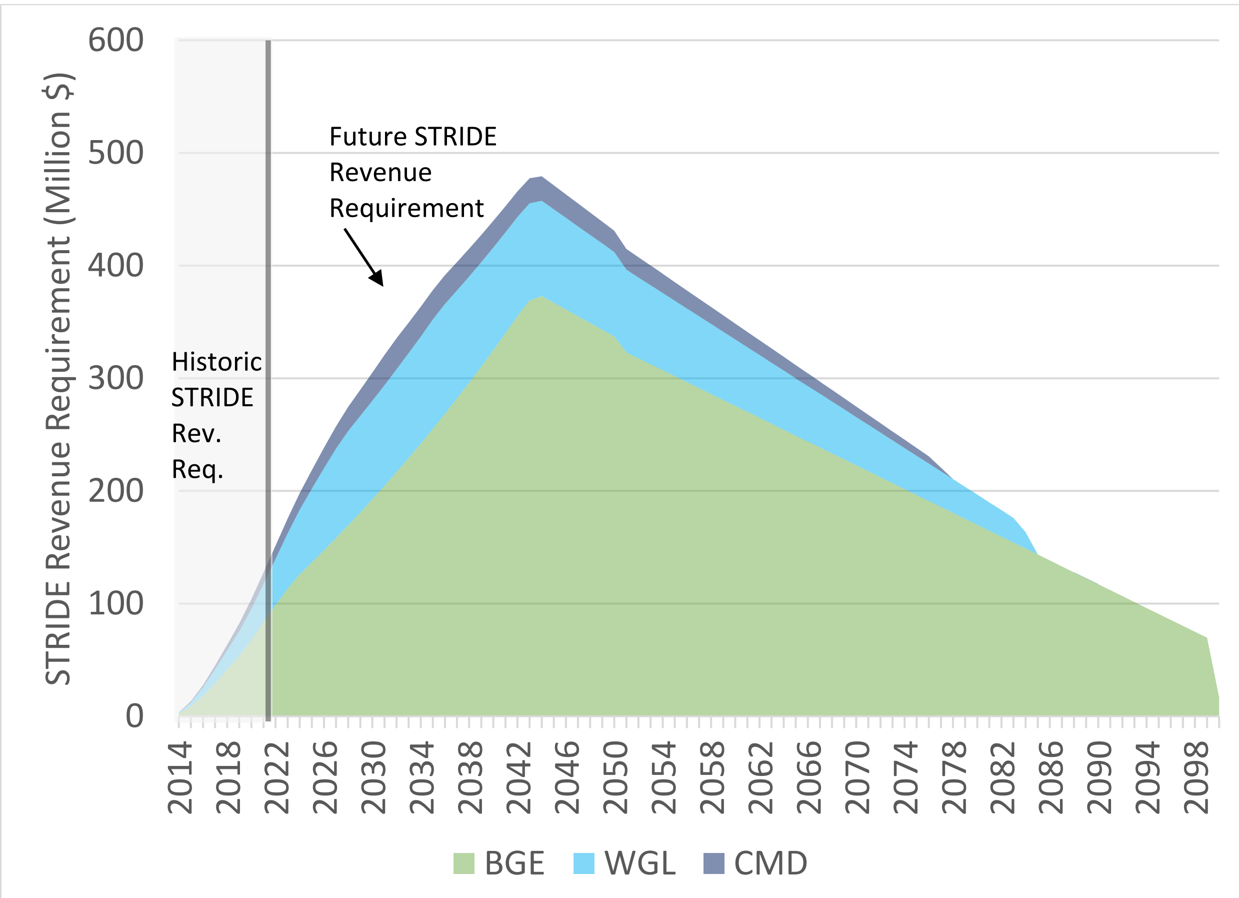
The following table shows that it will take the gas utilities *until 2099* to recover their currently planned STRIDE investments. Figure 3 immediately below shows the end dates for the three major Maryland gas utilities' (Baltimore Gas & Electric, Washington Gas & Light, and Columbia Gas Maryland) recovery of their STRIDE programs. The data is based on the utilities' own submissions from their most recent

[1] The 2030 GGRA plan implies that STRIDE will be complete in 2037, which is inconsistent with the utilities' plans submitted to the PSC. In any case, E3 cites the GGRA for the assumption that STRIDE will end two years earlier, in 2035. It is not clear why E3 uses the 2035 date.

[2] As reflected in BGE's multi-year plan, for years 2021, 2022, and 2023, STRIDE investments comprised 39%, 38%, and 40%, respectively, of the percentages of BGE's planned capital investments.

filings with the PSC. It shows that the utilities will complete their STRIDE recovery in 2099 (BGE), 2084 (WGL), and 2077 (Columbia). Figure 2 also illustrates how most of the STRIDE investments—and the consequential increased utility annual revenue requirements—have not yet occurred.

Figure 2:
STRIDE-Only Annual Revenue Requirements Under Plans of 3 Largest Maryland Gas Utilities



While the utilities' plans could change at the margins, without fundamental changes (likely requiring legislative action), it is not disputed that the costs of STRIDE investments will continue long into the future. When its first STRIDE plan was before the PSC in 2013, BGE's vice president testified that customers would be paying for STRIDE investments until *2103*, four years later than the graph above indicates (2099).[3]

[3] Testimony of Mark Case, BGE's Vice President of Regulatory and Strategy, in PSC Case 9331,

Consequently, curtailing STRIDE or ending it a few years earlier would still mean that STRIDE costs would not be fully recovered for many decades.

The scope of these STRIDE investments cannot be understated. The future increases in the gas delivery price for BGE that will be needed to recover these investments illustrates that scope. Today, BGE's residential volumetric delivery price—that is used to recover both STRIDE and non-STRIDE investments plus a large portion of operating expenses—is $0.6632/therm. When its STRIDE revenue requirement peaks in 2044, the average delivery cost per therm for STRIDE only will be approximately $0.73/therm—greater than the current residential volumetric charge. This, however, assumes the unlikely scenario that BGE's sales in 2044 will be the same as 2020. Should sales drop, by say 40 percent, then this average delivery costs would be $1.83 or almost double the current residential volumetric delivery charge.

Despite how ratemaking applies to capital investments, E3's report inexplicably states (slides 3, 86) that the growth in *the rate* of the gas utilities' revenue requirements will be halved when STRIDE ends. This emphasis on the "revenue requirement growth rate" makes little sense, since—as the graph shows—the gas utilities' revenue requirements will continue to be high long after STRIDE ends and will only gradually decrease.

E3 seems to acknowledge the issues with its assumptions. E3 states (slide 30) that its structured gas transition scenario "does not address the question of how utilities would reduce the revenue requirement or who would bear the cost gap between reduced revenue requirement and unavoidable costs for the remaining gas system." Not addressing how the "cost gap" will be paid for is, in our view, fatal to its analysis. We do not think one can properly evaluate the costs of the EFB scenario without addressing the elephant in the room—how the utilities' revenue requirements will be met or who will bear all the costs associated with the EFB scenario.

E3 further assumes (slide 24) that reduced gas throughput in the EFB scenario will result in "much lower system costs and less wide cost ranges." This assumption that reduced throughput "results in much lower" gas system costs is highly questionable. While reduced throughput theoretically could reduce certain O&M costs, it will not reduce the rate base or fixed annual O&M costs, and without low annual gas usage, rates will increase for customers remaining on the system to pay for the costs of providing service.

Tr. Vol. 2 at 452 lines 3-5.

To summarize: The E3 analysis assumes the continuation of two systems of energy to meet future energy needs. Although we have not seen E3's underlying data, the analysis ignores the extraordinary gas system annual revenue requirements through the end of the century under current utility STRIDE plans. Further, these STRIDE infrastructure replacement plans represent only a fraction of the capital investments utilities are making. Those investments also are recovered over the long term, creating additional costs that could be stranded or imposed on customers.

b. E3's assumption of efficient prices signals doesn't reflect the legal and practical realities of utility ratemaking.

E3 assumes a high level of precision and predictability in utility rate setting:

> "Achieving the Electrification with Fuel Backup pathway would require careful policy design that incentivizes consumers to employ dual fuel heating systems For example, *the current ratemaking model likely needs to be revisited, so that the right price signals are reflected in gas and electric rates and incentive consumers to switch* to fuel backups during cold hours."[4]

The EFB would require coordinating rate setting for not one, but two, utilities. This expectation of precision rate setting is both legally and practically unrealistic.

Rate setting is a complex, time-consuming task involving multi-competing issues and interacting factors. As the Supreme Court has observed, ratemaking is not an "exact science." It requires consideration of each individual utility's existing rate base, rate of return, capital structure, and cost of debt, among many other factors. It is affected by more than 100 years of constitutional, federal and state laws and regulations. In some areas, federal law preempts state law. Rates cannot be set too high, or they will not be just and reasonable for customers; they cannot be set too low or they will be confiscatory to the utilities. The process of setting rates involves competing experts with diverging views of all these considerations, often with the utilities controlling the best information and the issue-framing.

In our view it is unwise to pursue a policy path that depends on high levels of precision rate setting to accomplish customer switching between different fuel sources from two different utilities. OPC has participated in numerous utility workgroups and

[4] Slides 38 (emphasis added).

proceedings on how to influence customer behavior within a single utility's business—whether it be investing in energy efficiency, peak-load shaving, or other policies. These efforts involve both quantitative and qualitative considerations, and no one thinks they are easy. They deal with individual utility programs. But the effort under the EFB scenario would require coordinating the price signals of two utilities with competing interests. These utilities will not agree on the proper price signals. Based on our experience, this assumption of efficient rate setting across utilities is not realistic, legally or practically.

Even if this level of precision and coordination could occur, the rates designed on a policy basis as envisioned by E3 would fail to collect enough money to fund the continuation of the gas system. E3 points out that with low usage and high costs, the traditional methodologies for setting utility rates would result in very high rates, which would incent customers to leave the system. Customers would only remain on the system if the rate, based on "careful policy design," were lowered. But since the costs of the gas system would be high because of all the infrastructure investment that needs to be paid for, some other form of revenue would be necessary to supplement the rates paid by customers.

In a similar vein, draft recommendation 5 would have the General Assembly direct the PSC to instruct gas and electric utilities to develop a "unified plan" for achieving a net-zero emissions sector. While a unified plan may be necessary and desirable under any of the scenarios, without significant guidance from the General Assembly, this recommendation likely will fall far short. To the extent it succeeds, it would likely result in a unified plan highly detrimental to customers, creating high revenues and growth for two utilities instead of one. Put simply, a gas utility is not likely to agree on a plan under which it shrinks and its shareholders lose value. Rather, the General Assembly should provide the PSC clear guidance on the size and scope of the future gas system.[5]

Specifically, the General Assembly should make the fundamental choices regarding the future of Maryland's natural gas utilities and have the PSC implement those choices. Historically, the PSC's core role is to evaluate and rule on a single utility's rates and plans, with the input of parties such as OPC. Its role has not been to hear and decide upon the futures of competing utilities. The General Assembly must provide

---

[5] Further, the PSC has shown a historical reluctance to make challenging policy decisions. Rather, it often sends such issues to working groups with instructions to attempt to reach consensus. When consensus is unattainable and the PSC is asked to decide the issue, it often defers, sending the issue back to the working group. Within the context of the EmPOWER program, this pattern has played out over the years, leaving issues unresolved with respect to cost recovery, financing, and low-income goals, among other issues.

clear guidance on the future path for natural gas in Maryland's buildings.

2. The EFB scenario risks delaying a much-needed plan to curb costly natural gas infrastructure investments.

The spending on gas infrastructure described above is occurring despite its apparent inconsistency with the decreased role of gas under the most likely scenarios for meeting the state's climate goals. This spending exposes customers (and potentially taxpayers and investors) to the risk of stranded costs. With investments on depreciation schedules that extend as far out as 50 years or longer, but with fewer and fewer gas customers and less gas throughout, many of these investments will prove uneconomic. Washington Gas Light, in a recent consultant's report (ICF 2020) for the District of Columbia, contended that high electrification would result in stranded assets of "around $1.5 to $2.1 billion in unrecovered rate base in 2020, as well as distribution system decommissioning costs that have not been estimated." Applying the D.C. report to Maryland yields anywhere from $3.6 to $5.1 billion in stranded costs—for just one of Maryland's gas utilities.[6]

The best way to avoid stranding an investment is not to make the investment in the first place. Once the investment is made, the uneconomic costs of that investment must be absorbed. Providing a safe and reliable gas system under the EFB scenario means knowingly investing in gas infrastructure that will become uneconomic. Moreover, it likely will be viewed, at least implicitly, as condoning the continued *expansion* for the near future of new gas infrastructure for the purpose of connecting new customers.

3. Consumers—especially low-and-moderate-income customers—are most vulnerable to the adverse consequences of the Electrification with Fuel-Backup Scenario.

The flaws in E3's analysis outlined above (and those detailed in OPC's technical comments from Synapse) leave utility customers highly vulnerable for significant increases in gas infrastructure and commodity costs. Even with its highly questionable assumption that utility annual revenue requirements will go down under the EFB, E3 acknowledges that gas rates will be high. Higher-income customers will have options to avoid the costs by quickly replacing heating systems and appliances, but low-to-moderate-income customers will remain vulnerable.

[6] The figure is calculated based on the relative percentages of WGL's rate base (42.6% MD, 39.9% VA, 17.4% DC).

Under basic ratemaking principles, as the number of gas customers shrinks, remaining customer costs must rise for the utility to recover its revenue requirement to pay for infrastructure that was built and put into rate base, sometimes a half century earlier. Stated otherwise, a viable gas market depends on delivery costs being amortized over a sufficient volume of service such that the total cost for delivery of gas and the gas itself can compete with other energy sources.

Under the EFB scenario, the delivery costs of gas will need to increase substantially to maintain the gas infrastructure for use during only peak hours. This will entail dramatic increases in gas utility volumetric charges, customer charges, or both. In turn, this will cause increasing numbers of customer defections, in what is commonly called the death spiral. Low-to-moderate customers will bear the brunt of the death spiral. While all efforts must be made to address LMI customers under any clean energy scenario, the scale of stranded costs under the EFB scenario of maintaining two energy systems risks astronomic levels of stranded costs. Properly addressing these impacts would require massive public expenditures to expand the scope of existing energy assistance programs, which now serve only the severely impoverished and often fail to reach eligible recipients.

In sum, the transition toward a clean energy system will require significant efforts to address equity impacts, but maintaining two systems will significantly exacerbate inequities. It is undisputed that maintaining the gas system for backup use requires substantial increases in the rates for gas delivery. The high electrification case requires no backup fuels, thus obviating the need for the massive capital investments that have yet to be made to maintain the gas infrastructure. The E3 analysis expressly avoids addressing the critical issue of the "cost gap between reduced revenue requirement and unavoidable costs for the remaining gas system." In our view, failing to consider the extraordinary gas system costs in the queue would be a big mistake.

4. Additional policy considerations weigh against the EFB scenario.

The EFB scenario raises other issues that lead us to question the recommendations that flow from E3's study.

a. *Levels of GHG reductions*. While each scenario meets the goal of net-zero building emissions by 2045, E3's analysis shows that the high electrification scenario yields a higher reduction in cumulative GHG emissions than either of the other scenarios. It would thus reduce pressures for identifying reductions in other segments of the economy and create headroom should the State decide to pursue more aggressive GHG reductions. Further, technological uncertainties inherent in the scenarios could result in fewer GHG reductions materializing than predicted, creating an additional gap to fill. A pathway that overshoots the target provides more of a buffer to address such shortfalls.

b. *Technology costs*. The EFB scenario relies on conservative estimates for better heat pump technology. The estimate is inconsistent with NREL's Electrification Futures study, which assumes that the efficiency of residential heat pumps will increase by 45% by 2050. E3's assumptions regarding future heat pump efficiency for commercial buildings are similarly lower than NREL's estimates. (See OPC's Technical Comments for further discussion.)

c. *Price of synthetic gas.* On the other hand, the EFB scenario appears optimistic about the price of low-carbon substitutes and the infrastructure that may be necessary. Further, substantial uncertainty exists about the overall carbon footprint of synthetic natural gas, creating additional risk for the EFB scenario.[7]

d. *Safety and health issues.* A fuel-based system based on combustion—even for backup purposes—creates higher safety risks for Maryland's residential customers. Further, recent studies show that natural gas use in the home results in indoor air pollution with health impacts. A 2017 Johns Hopkins study focusing on Baltimore residents highlighted this concern.

5. Implementation of all-electric building standards should not be delayed until 2027.

As noted above, the best way to avoid stranding an investment is not to make the investment in the first place. Once the investment is made, the uneconomic costs of that investment must be absorbed. This means that new buildings standards should be put in place as soon as possible. The 2024 start date for the all-electric construction code should be maintained or accelerated. Delaying the start until 2027 will lead to new (not replacement) gas infrastructure investments that, as explained above, will become uneconomic before they are fully paid for.

[7] See Sebastian Timmerberg, Martin Kaltschmitt, and Matthias Finkbeiner, "Hydrogen and hydrogen-derived fuels through methane decomposition of natural gas –GHG emissions and costs. Energy Conversion and Management: X. Vol. 7 (2020). Available at https://www.sciencedirect.com/science/article/pii/S2590174520300155.