<u>NPA Working Group: NPA Framework Comment Submission</u>

On Behalf of: Energy and Ratepayer Advocacy Division, Office of the Attorney General, Massachusetts

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High Level Comments

While the Attorney General's Office ("AGO") appreciates the LDCs' constructive engagement in this NPA process, **in its current form, the NPA process will neither reduce meaningfully the risk of future stranded investment in gas infrastructure nor facilitate material progress toward the highly electrified, decarbonized future** of the building heating sector that is planned by the Commonwealth and required by its emission reduction mandates**.** As proposed by the Local Distribution Companies ("LDCs"), the NPA process is an add-on step at the end of a business-as-usual ("BAU"), traditional gas system planning process that is primarily organized by the projects and capital investments that are needed to gradually rebuild (and expand) the existing gas distribution system with new pipes. Even with some of the planning process improvements the LDCs are proposing to consider, **the NPA process envisioned will, at best, displace a minimal share of future gas pipe investments**.

For example, under the LDCs' Interim NPA processes, about 85% of 2025 GSEP projects were excluded from NPA consideration, many due to insufficient time to evaluate. Even if this temporal planning limitation could be addressed, the physical structure of a pipeline gas system ensures that the unanimous customer participation needed for electrification to remove a pipe segment under the current process will screen out most potential NPAs, considering only those few proposed infrastructure projects that can be configured to affect just a small handful of customers, and leaving most of the gas system to be rebuilt with gas pipes. Indeed, when the LDCs were asked in the NPA Working Group whether they had any expectation about what share of pipe projects (or capital investment costs) might ultimately be displaced by NPAs under the NPA Framework, they were unable to provide an estimate.

Long run gas system costs are not fixed, but are driven primarily by future capital investments that have not yet been expended. Thus, the bulk of future system costs are not sunk and may be, at least in principle, avoidable, as we illustrate below. Gas system costs (and thus potential stranded investments) will diminish considerably over time if the depreciating gas rate base is *not* replenished by new capital investments. However, with the capital investments currently planned by the LDCs (both GSEP and non-GSEP), total rate base (i.e., existing net plant plus future capital additions, net of ongoing depreciation) will increase dramatically over time. Further, the revenue requirement impacts of these rising overall costs will be magnified by throughput reductions and customer departures, which will concentrate the mounting costs on diminishing numbers of customers and therms sold, leading quickly to unaffordable rates and monthly bills for remaining gas customers.

To achieve the highly electrified, decarbonized future articulated by the Commonwealth at reasonable cost, the current gas planning process must be fundamentally reformed. It will need to become part of an Integrated Energy Planning process. To advance the decarbonization and electrification of the building sector at the pace necessary to achieve interim and 2050 GHG emission reduction mandates, a process far beyond the currently proposed NPA process will be needed. An Integrated Energy Planning process (IEP), focused on developing the electrified, decarbonized building energy system Massachusetts needs to achieve its climate goals, must be implemented.[1] Such a process may need to rethink the LDCs' obligation to serve, customer choice, and reliance on individual customer initiative that characterize the current planning process and the proposed NPA process. It will need to address a number of very real barriers that may prevent customers from electrifying – high initial cost, unfamiliarity with electrification technologies , lack of qualified contractors – and also the fact that simple customer inertia will challenge the pace of the transition. Of course, such a process will also need to interface with the transformations occurring in other sectors of the economy.

A key goal of the IEP process should be to avoid additional capital investments in the gas system wherever possible, in order to keep overall costs for Massachusetts ratepayers manageable. Indeed, our analysis estimates that the large majority of embedded infrastructure costs in 2040 or 2050 will be based on capital investments that have not yet been made, and thus may be, at least in principle, avoidable. This will likely require a managed transition, converting customers away from gas using a targeted geographic approach that will enable avoiding further gas investments (e.g., transitioning customers to

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[1] A successful Integrated Energy Planning ("IEP") process, as a tool for widescale decarbonization of existing building thermal energy needs, has two dimensions. First, it supports the shared, coordinated and integrated system planning of both gas distribution companies and electric distribution companies to achieve strategic electrification of building and transportation sectors in line with emission reduction mandates. Second, IEP must also focus on customer adoption and the customer's energy decisionmaking. Both gas and electric companies, as part of the IEP process, must do more to initiate new programs and approaches to aid the customer in choosing to decarbonize building energy needs, and facilitate implementation.

alternative energy sources *before* a pipe replacement becomes necessary, or to defer a gas investment temporarily with the aim of avoiding it later). Where action or investment appears necessary, strategies to defer, decommission, or repair equipment at lower cost, rather than replacing it, should be implemented. In addition, where a gas project can be deferred or avoided, the current capital planning process should avoid pulling other gas projects forward in time solely to fill the gas infrastructure construction/implementation gap; rather, it should apply similar strategies to avoid those other projects too in their time.

However, given that such a reformed planning process is not available now, and may take some time to develop and refine, an effective NPA process may offer some value in the near to medium term, if it is structured and implemented properly. Several factors will need to be considered in developing an effective NPA process; these include but are not limited to the following:

- Expanded planning horizon to ensure that there will always be sufficient time to give due consideration to potential NPA projects.
- Alternative project scoping to make potential NPAs feasible or improve their economics.
- The social cost of carbon (SCC) should be included in the NPA benefit cost analyses (BCAs).
- Barriers to customer adoption of NPAs must be considered and reduced, especially for low and moderate income customers. Barriers can be reduced by financing and/or subsidizing customer costs (particularly initial up-front customer costs to electrify), providing high quality, tailored information on NPA alternatives, supporting contractors, and facilitating customer implementation.

The LDCs have acknowledged some of these weaknesses in their current planning processes and are considering several of these factors as they continue to develop their NPA Framework. Since the LDCs have not specified how they will include these factors, it is impossible at this point to judge their proposed NPA framework. The application of an effective NPA process will also offer important lessons that will assist in developing and refining the broader IEP process that is necessary.

Key proposal strengths: ***The LDCs have acknowledged several limitations that impair finding and implementing NPAs (though they have not provided sufficient detail on their proposed NPA process to judge whether the application of their proposal will resolve these limitations).***

Key proposal challenges: ***The NPA process is structured around the LDCs' existing, pipe-centric BAU infrastructure planning process and planning assumptions; as such, NPAs will be unable to displace a material share of gas capital investments. A fundamentally reformed planning process is needed.***

Project Identification

[See related comments under Initial Viability Testing and Other headings]

Initial Viability Testing

The Initial Viability Testing step proposed by the LDCs will eliminate most projects from even being considered for an NPA, ensuring that NPAs will replace very few gas pipe projects.

To illustrate this limitation, we examined the application of the LDCs' Interim NPA Guidelines to the GSEP projects identified in the LDCs' DPU 2024-GSEP-01 to -06 filings. Table 1 below summarizes that analysis, showing that across all 6 LDCs, about 85% of projects (whether measured by numbers, costs, or miles) were screened out <u>before</u> the benefit-cost analysis step (National Grid screened out 60% of its GSEP projects from NPA consideration; the other 5 LDCs screened out 97-100%). Numerous reasons were given (though not using uniform or unique criteria): very often, projects were screened out of further NPA consideration due to insufficient time before a project was needed to undertake the NPA analysis. (In other instances, projects were eliminated for Paving, Reliability, Safety, System Integration, or combinations of these factors). Of course, even among the projects that made it past this initial screening step, it is not clear how many will or would proceed all the way to NPA implementation; some would likely be excluded at later steps of the process. But it is clear that this Initial Viability Testing step has the potential to screen out the majority of NPA opportunities, ensuring the planned projects will proceed as gas pipe replacement and thus additions to rate base, and so gas system planning must be revised from its current structure.

Figure 1: Summary of Exclusion Analysis

	EGMA	NSTAR	Liberty	Berkshire	Unitil	National Grid	All Utilities
Excluded projects/ Total	96/97 **97%**	189/190 **99%**	9/9 **100%**	55/56 **98%**	8/8 **100%**	109/186 **59%**	466/546 **85%**
Excluded costs / Total ($M)	$124/$125 **99.6%**	$103/$104 **99%**	$11/$11 **100%**	$21/ $21 **99%**	$13/$13 **100%**	$195/$290 **67%**	$467/$562 **83%**
Excluded miles / Total	53/53[1] **98%**	60/60[1] **99%**	8/8 **100%**	12/13 **95%**	6/6[1] **100%**	43/72[1] **59%**	182/212 **86%**
Excluded services/ Total	N/A	N/A	769/769[2] **100%**	792/793 **99%**	618/618 **100%**	N/A	2,179/2,180[3] **99.9%**

1) The values listed for Until, EGMA and NSTAR's main mileage, are from "Installation Footage" (adjusted to miles) given in Exh. Unitil-RKCL-5 Attachment B, DPU 24-GSEP-05 Exhibit EGMA-RJB-1 - Appendix A, and DPU 24-GSEP-06 Exhibit ES-RJB-1 Appendix A; The values listed for National Grid's main mileage, is the "GSEP mileage" given in Exhibit NG-GPP-4 and 5
2) The values listed for Liberty's services, are the number of "service replacements" and "service transfers" given in DPU 24-GSEP-04 Exh LU-NMW-2
3) Information on excluded services is not available for EGMA, NSTAR, and Boston Gas

Targeting for NPA analysis those projects with small numbers of affected customers (to increase likelihood of unanimity in customer acceptance to electrify) will exclude the large majority of gas projects from NPA consideration.

The LDCs are revising their Interim NPA processes and their overall planning process. If done well, their final NPA processes may be more effective, particularly in reducing the number of project exclusions due to insufficient time. However, another key exclusion criterion, one that will be more difficult to overcome, is the number of customers affected by each project. As the planning process is now structured, an NPA being evaluated to displace a pipe replacement project typically requires universal participation to electrify among affected gas customers. This precondition becomes highly unlikely for pipe replacement projects affecting more than a small handful of customers. In fact, the LDCs propose that the Initial Viability Testing step will screen projects based in part on the number of customers affected, excluding those that involve more than a few customers. Even acknowledging that the LDCs are considering redefining project scope (e.g., to break large projects into smaller pieces, some of which might be amenable to an NPA), this can only accomplish so much to avoid future stranded investment. The physical structure of the gas system (consisting mostly of long pipes that serve many downstream customers) ensures that the only instances where just a few customers would be affected occur at the very end of a line, or on a small branch serving, for example, a few customers on a cul de sac. If only such very small stubs of the gas system are even potentially amenable for an NPA, then the large majority of projects (and an even larger share of investment dollars) will be screened out, and most of the system will be rebuilt (and expanded) with gas pipes.

The gas planning process should ensure that there is sufficient time to fully evaluate NPA alternatives.

Unlike the Interim NPA process, which often found that there was insufficient time to evaluate an NPA, the proposed NPA framework should plan far enough forward in assessing future system needs that it does not encounter this obstacle. Proper advance planning should ensure that projects are defined and considered far enough in advance to accommodate full NPA consideration. The LDCs are aware of the composition of their systems, and therefore when and where pipes and components will require replacement. They have already identified and prioritized all the leak-prone pipe on their systems in the GSEP process, and similarly know what other infrastructure will need to be replaced, and when, so that the planning process to include robust NPAs can be organized and timed to ensure the opportunity for full NPA consideration for all projects. Thus, a clear principle for the NPA process is that insufficient time to evaluate an NPA should not be an acceptable exclusion criterion.

Of course, there must be an exception for unforeseen and unforeseeable emergency circumstances (e.g., significant leaks) that require immediate remediation. But even here, it may be possible to prioritize the repair of the small portion of the infrastructure that actually failed (e.g., a few pipe segments) for a much lower cost than planning and performing the entire infrastructure replacement project that contains that failure, and so the larger project need not be excluded for lack of time, and might still be a candidate for an NPA in a reasonable timeframe.

Gas System Feasibility Review and Electric System Feasibility Review

The gas feasibility review should be performed using reduced gas flow requirements, consistent with the announced building sector sublimits.

The gas feasibility review should account for the future decline in gas demand that is required to meet the Commonwealth's building sector emission sublimits. That is, the throughput projected in an NPA analysis using a BAU or system growth scenario should *not* be used to establish the feasibility of an NPA; instead the lower throughput consistent with the building sector sublimits should be utilized. Further, if a particular NPA appears at first to be infeasible due to gas flow effects, the LDCs should consider what further measures might reduce throughput to the point the NPA becomes feasible. If additional reductions can be achieved by expanding the NPA to reduce downstream demand further, bringing the gas system back into feasibility, that broader NPA scope should be evaluated.

The electric feasibility review should account for electric system expansions ultimately needed; any necessary expansion, however, may not be directly attributable to this NPA.

Similarly, the electric system feasibility review should account for the electric system expansions that will ultimately be needed to meet the Commonwealth's building sector emission sublimits. Rather than excluding a particular NPA because the electric system upgrades to accommodate it may make it appear uneconomic, the LDCs (and EDCs) should consider that those or similar upgrades may be necessary in the long run in any case as part of the EDCs' Electric Sector Modernization Planning, and thus may not be incremental to this particular NPA (though they may be accelerated by it). It is worth noting in connection with electric sector feasibility that electric system feasibility may at present seldom be a binding constraint. Most parts of the current electric system, built for a summer peak load, have considerable slack in winter (when electrified gas demand is material). Estimates suggest that in New England, electrifying gas demand quickly enough to achieve ambitious state climate goals may begin to encounter systematic electric system constraints around 2035, when the projected winter peak would begin to match the summer peak.

Benefit Cost Analysis

The Social Cost of Carbon (SCC) should be included in the total resource cost test (TRC).

The LDCs' proposed NPA framework, as presented to the NPA Working Group, includes the social cost of carbon in the Total Resource Cost test. That aspect should be maintained in the framework approved by the DPU.

Project Authorization and Prioritization

[No comment on this topic]

Project Execution

[No comment on this topic]

Customer Education, Engagement and Commitment

See Comments under Integrated Energy Planning, infra.

Impacts to Project Implementation

[No comment on this topic]

Framework Updating

Lessons learned from the NPA process may give important context for the development of an Integrated Energy Planning approach.

The NPA process itself is unlikely to make material progress toward the Commonwealth's climate goals. Nonetheless, lessons learned from early iterations of the NPA process may help to improve it in later iterations. Much more importantly, such lessons may be very useful in developing the Integrated Energy Planning approach.

Other: Integrated Energy Planning

The current gas planning process must be supplanted with a broader Integrated Energy Planning (IEP) process to achieve the Commonwealth's climate mandates, while keeping customer costs affordable.

The LDCs' existing gas planning processes are (understandably) pipe-centric, designed to re-build (and expand) the gas system gradually over time as gas system components need to be replaced. These capital construction programs are premised on the indefinite existence of and reliance on the gas system. But a planning process that, by design, is organized around the gas system components that need replacement will perform poorly at achieving the broad energy transformation needed to meet the Commonwealth's climate mandates, and will be unnecessarily costly. For example, the NPA process is organized around particular gas assets that need to be replaced; it defines the scope, geography and timing of potential NPAs to match the scope, geography and timing of a particular gas pipe replacement project. The NPA process as proposed is not designed to consider alternative configurations of electrified and decarbonized heating technologies, with a geographic scope or footprint different from the planned pipe addition, that may be much more effective at meeting goals for emissions reductions, ratepayer cost and customer equity.

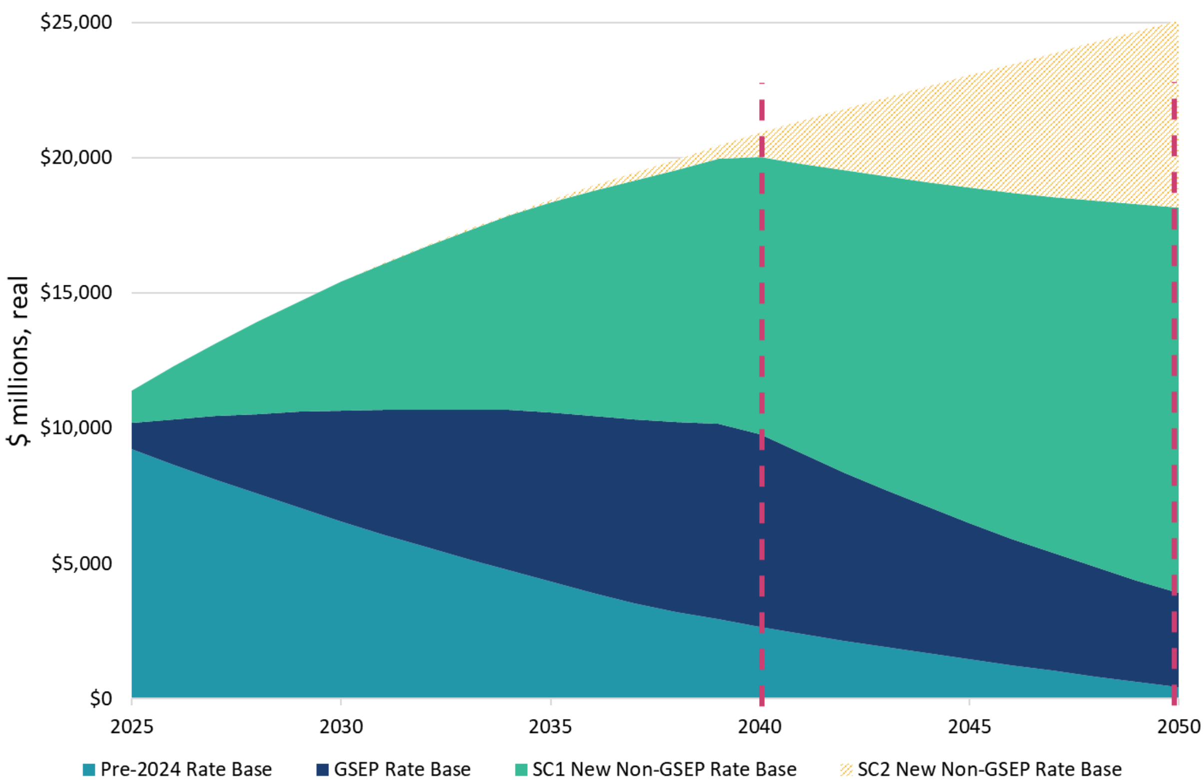
As noted above, the LDCs' proposed NPA process itself is unlikely to make material progress toward the highly electrified building sector that the Commonwealth is planning. This is for two primary reasons:

1) The NPA process will, at best, displace a minimal share of future gas pipe investments with NPAs. As seen above with the LDCs' Interim NPA process for GSEP projects, the Initial Viability Testing step has the potential to exclude from the outset most potential NPA projects from further consideration. Even if improvements are made to the process (planning with a longer time horizon, adjusting project scope), the LDCs will also likely screen out projects that affect more than a few customers, since the current planning process requires unanimous customer participation in an electrification solution for an NPA, and unanimity becomes highly unlikely with more than a few customers. The physical structure of the gas system (mostly long pipes serving many downstream customers) ensures that there are few instances where just a few customers would be affected – e.g., at the very end of a line, or on a small branch serving a few customers on a cul de sac. If only such very small stubs of the gas system are even potentially amenable to an NPA, then the large majority of projects (and an even larger share of investment dollars) will be screened out, leading over time to rebuilding (and expanding) the system with gas pipes.
2) The NPA process is structured around the LDCs' pipe-centric business-as-usual planning process and planning assumptions that was designed to rebuild the gas system over time, and operate it indefinitely. As such, the proposed NPA framework will be unable to displace a material share of gas capital investments.

In addition to the NPA process (which will have some value, but is ultimately unlikely to make a material contribution to achieving the Commonwealth's climate goals), a fundamentally reformed, more ambitious Integrated (Building) Energy Planning process is needed. That IEP process must promote electrifying and decarbonizing the building thermal sector at a pace that will achieve the Commonwealth's climate goals, and organizing it so as to avoid additional gas capital investments wherever possible, to substantially reduce overall costs.

Our analyses show that the large majority of system costs in the future will be a result of capital investments that have not yet been made, and thus may be, at least in principle, avoidable. With conservative assumptions, illustrated in Figure 2 below, we estimate that by 2050, about 98% of the gas rate base (and a correspondingly large share of customer costs) will consist of capital investments made <u>after</u> 2024. Only about 2% of the 2050 rate base will consist of pre-2024 investments; those earlier investments will have been largely depreciated by then. Even by 2040, over 85% of the rate base will consist of post-2024 investments, with just 15% remaining from pre-2024 investments. Thus new, post-2024 BAU investments (both GSEP and non-GSEP) make a very substantial contribution to future rate base and thus to customer costs. If a material share of those investments could be avoided, future customer costs could be reduced substantially.

Figure 2: Massachusetts Gas LDCs' Estimated Rate Base Over Time – BAU
Real (inflation-adjusted) 2024 $ Millions



Note: Scenario 1 assumes non-GSEP capital investment does not expand after GSEP ends, and overall investment drops substantially. Scenario 2 assumes non-GSEP investment does expand after GSEP ends, to keep the overall investment rate on the previous trajectory.

If customers were to be transitioned off gas in an uncoordinated fashion, it arguably may be necessary to continue with these BAU capital investments, resulting in a rebuilt gas system with its full complement of associated costs, but few customers and very limited throughput in the long run. Alternatively, however, if the Integrated Energy Planning process coordinates customer transitions at the same overall rate but successfully organizing them geographically to enable avoiding gas capital investments, it could avoid most future gas system costs, thus substantially reducing the overall costs of the transition.

Such an IEP process may need to rethink the LDCs' claimed obligation to serve, customer choice, and reliance on individual customer initiative that characterize the current planning process, including the proposed NPA process. This IEP process can supplant the gas planning concepts of NPAs, GSEP and other gas capital investments, new customer connections and line extensions, etc. It should be centered around a vision of electrification as the primary pathway for the building sector to achieve the Commonwealth's GHG mandates, and the energy system that will result in the long term, as articulated and refined in MA's planning documents such as the Decarbonization Roadmap and the Clean Energy and Climate Plan, and in DPU 20-80-B and C. It will also need to coordinate with the transformations occurring in other sectors, including electricity and transportation.

An IEP process (and a clear mechanism to implement the plan) is almost certainly necessary to achieve the scale and pace necessary to meet GHG mandates (including interim targets) for the building sector and gas sector, and can also reduce the burdens (both financial and logistic) on customers. It will need to address several very real barriers that may prevent customers from electrifying – high initial cost, unfamiliarity with electrification technologies, lack of qualified contractors – and also the fact that simple customer inertia will challenge the pace of the transition.

This IEP process would identify and implement electrified and decarbonized alternative building energy solutions, with gas pipe replacement needs guiding the geography and timing of these projects so as to eliminate the need for the pipe replacements. It would prioritize converting select, relevant gas customers to enable decommissioning gas assets before their replacement becomes necessary. Additional strategies can also be utilized to facilitate avoiding large gas capital investments – e.g., delay, repair rather than replace, enhanced monitoring, efficiency projects to limit demand. Such lower-cost strategies may provide additional time, where needed, until gas assets can be safely and reliably displaced by non-gas solutions. The IEP process would also incorporate non-gas delivered fuels (oil, propane) customers, to make additional progress toward the Commonwealth's GHG mandates and to make a project more effective and cost-efficient (e.g., a networked geothermal project that includes adjacent oil and propane customers in addition to gas customers may likely have better economics).

Of course, it will be necessary to coordinate the transition of fuel demands with electricity planning, to ensure the grid can accommodate the increased load (coordinating with the transportation sector as well, which will also add electric load). Broadly, the current electric system has considerable slack in winter when most of the heating-dominated gas demand occurs (the electric system is sized to accommodate the higher summer peak).

Estimates suggest that in New England, converting fossil fuel demand to electricity at a pace that is sufficient to achieve ambitious climate goals may begin to encounter winter electric system constraints around 2035. Localized constraints may be reached earlier, so careful coordination with electric system planning, at the generation, transmission and distribution levels, is essential.

Such an IEP process may be able to preempt a substantial share of future gas pipe projects and investments, both GSEP and non-GSEP. IEP may ultimately make much of the discrete gas planning process and capital investments (GSEP and other capital investments, line extensions, and NPAs for these) unnecessary. By addressing the need to replace gas infrastructure with alternative electrified and decarbonized heating solutions, before additional gas investments become necessary, the IEP process ideally can stay ahead of gas planning, avoiding very substantial gas infrastructure costs.

There would still likely be a role for NPA process at the (gas) project level, particularly in the near term, to help avoid some nearer-term gas investments as the IEP process is being developed, and also as a backstop or check on gas pipe projects that might not immediately be pre-empted by the IEP process.