Rate Design and Energy Affordability in Massachusetts

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1. Summary

The next one to two decades will bring fundamental changes to the level and shape of net electricity demand and the distribution of that demand across customers and utility service territories in Massachusetts. This in turn will influence the relative reliance for energy supply on electricity versus gasoline, natural gas, and other heating fuels, the need for investment in power grid infrastructure, and the ability of customers to manage electricity use and achieve energy affordability. In advance of these changes, it will be important to evaluate the alignment of electricity and natural gas rate structures with economic principles, production and consumption incentives, energy affordability, and public policy goals. Key features of the transition will likely include at least the following:

1) The level of electricity demand will increase faster than in recent history through a combination of transportation and building sector electrification, economic growth, and large load additions;
2) There will be continued expansion of behind the meter and grid-connected variable distributed energy resources on local distribution networks;
3) The shape of electricity demand will change in significant ways, will shift to a winter peaking system over time, and will become more uncertain and variable;
4) These changes will require accelerating and anticipatory investments in transmission and distribution system infrastructure, increasing the level of fixed capital investments needed to provide reliable electric service;
5) Natural gas local distribution companies will eventually experience flat to declining sales but will still need to invest in infrastructure to ensure safe and reliable delivery to customers remaining on the system;
6) Electricity costs for consumers may increase substantially absent proactive and sustained efforts to optimize the level of required infrastructure investments by reducing and managing the increases in net load on the system at the time of system peak demand.

The current design of utility rates in Massachusetts has served the State well for many decades. It has helped ensure revenue sufficiency for utilities discharging their public service obligations, it has achieved the goals of simplicity and fairness, and it has enabled the Commonwealth to implement important policy goals related to support for low-income customers, promotion of energy efficiency, and the establishment of commercially viable distributed energy resource industry.

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But current rate designs will not be sustainable from an affordability perspective as the energy transition results in increasing and shifting demand and increasing investments in system infrastructure. They will be far out of line with cost causation principles, more regressive and inequitable, increasingly unaffordable, and opaque to consumer actions that can help them manage their bills. These circumstances will be unacceptable from the perspectives of economic efficiency, equity and fairness, and will undoubtedly frustrate the Commonwealth's efforts to achieve important energy policy goals.

It is clear that fundamental changes in the design of utility rates are needed, and those changes need to start as soon as feasible. Why? Because altering the design of utility rates is not easy or fast. Practical (and important) boundaries on how quickly rate designs may change – considering principles of continuity, gradualism, simplicity, and fairness – restrict what the Department of Public Utilities (DPU) can do in any given year or rate case. The nature and magnitude of the rate design changes required to efficiently manage the energy system transition at the lowest possible cost go well beyond what can be achieved in one (or even two) rate case cycles.

Fortunately there is time, provided concerted efforts begin now – prior to major energy system changes. Changes in the level and shape of demand and increases in the required investments will not be immediate, and Governor Healey's Administration (through the DPU, the Department of Energy Resources (DOER), and the Office of Energy Transition (OET)) and the Office of Attorney General Campbell (OAG) have already proactively evaluated the features of electricity rate structures and mechanisms needed to prepare the state for the changes to come. These efforts have highlighted the key features of future rate designs that can address affordability, equity, cost causation, and efficiency challenges. They include the following:

1) A transition (for residential customers) from recovery of distribution system capital costs and policy costs primarily through volumetric charges to their recovery primarily through a mix of fixed charges and demand-based pricing, to align rates with the fixed nature of transmission and distribution service investments that are directly linked to peak electricity demand requirements;
2) The institution of increasingly targeted time-varying rates (both volumetric and demand based) to provide price signals for efficient consumption decisions, which will empower consumer actions to manage energy costs and minimize the extent of utility investment needed to reliably operationalize the transition;
3) Inclusion of requirements that the provision of supply services through basic service (and, where possible and to the extent within the Department's jurisdiction, through competitive suppliers and municipal aggregators), adheres to the goals of aligning prices with cost causation and enabling customer cost management through time-varying rates;
4) Programmatic changes fostering the development of technologies and programs to enable effective demand response along with a committed and sustained effort to educate consumers on ways to lower their energy costs in response to time-varying price signals;
5) Flexible interconnection practices for DERs to mitigate or delay the impact of DER saturation on local networks;
6) Tiered charges and other rate designs to address affordability for low and moderate income customers; and

7) A careful focus on ensuring that all customers that benefit from public policies and the system infrastructure utilities need to meet peak demand obligations pay their fair share of transmission, distribution, and programmatic/policy costs.

It is possible to address energy affordability and simultaneously maintain progress on state policy objectives. Doing so will require aligning rates over time with cost causation and efficient pricing principles, while committing to the full activation of price-responsive demand to enable customer energy use management. The Commonwealth can work with utilities and stakeholders to establish a vision for changes to occur incrementally over the next 10-15 years to achieve an ideal end point by the time electrification, large loads, and distributed resource interconnections would otherwise jeopardize energy affordability and frustrate the Commonwealth's energy policy goals. The vision should contain the following elements:

- A conceptual translation of economic growth, large load expectations, DER growth, and electrification policies to load and load profile expectations in five year increments through 2040;
- A 2040 endpoint goal whereby rate designs fully meet the features described above (including proper functionalization to fixed, demand, and energy components, and a system of effective time of use rate structures), and the demand side is fully activated through customer actions, third party load management providers, and flexible DER operational policies;
- A glide path describing the transition in five-year increments from where rates and programmatic spending are now, to the desired end point.

2. Ratemaking Principles and Practices

The setting of public utility rates is based on a century-long academic and judicial history that has established core ratemaking principles adopted in one form or another by virtually every public utility regulatory authority at the state and federal level. How they have been operationalized varies to an extent across states and across time, but they are no less relevant today than they were many decades ago when first being applied. These principles include:

1. *Revenue sufficiency:* revenue requirements must be set to recover a utility's reasonably and prudently-incurred costs along with a return commensurate with the risks faced by the utility.[2]
2. *Cost causation:* consumer prices should reflect the underlying costs associated with the provision of utility service in order to:
    a. promote the efficient use and production of energy, and[3]
    b. minimize arbitrary or excessive discrimination across utility customers.[4]
3. *Stability and predictability:* ratemaking should minimize unexpected changes seriously adverse to ratepayers or utility companies.[5]

In Massachusetts, the DPU has operationalized these principles by establishing precedent to guide their evaluation of the evidence presented in utility rate proceedings. Specifically, DPU administers investigations of utility cost recovery requests to ensure that the resulting rates are just and reasonable, and provide the utility an opportunity to recover costs prudently incurred to provide reliable services, including a fair and reasonable return on its investments (revenue sufficiency). In setting rates that meet this standard, the Department seeks to achieve an appropriate balance among several goals, including:[6]

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[2] This is the *capital attraction* objective of ratemaking as articulated by Bonbright (1961, 1988) - absent a fair return of and on invested capital, private utility companies will not undertake the level of investment required to provide the socially desirable quality of service. *See also Bluefield v. Pub. Serv. Comm'n of West Virginia. (1923)* ["[a] public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties"], and *Federal Power Commission v. Hope Natural Gas Co. (1944)* ["the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."].

[3] This is the *static efficiency* objective of ratemaking – rates should be designed to ensure consumer use is economically justified *i.e.,* the benefits of consumption/production exceed the private and social costs of consumption/production. Volumetric prices above the variable cost of supply will tend to result in inefficiently low levels of consumption (excessive conservation). *See* Bonbright (1988), pages 383-385.

[4] Rates should be designed to fairly apportion costs across customers to minimize cross-subsidization across customers and avoid arbitrary, capricious, or undue discrimination. *See* Bonbright (1988), pages 383-385.

[5] Stability and predictability of rates are administered in part through the *filed rate doctrine*, which states that filed rates are the only rates that may be lawfully charged and paid, and the *prohibition on retroactive ratemaking*, which requires changes to rates to be made on a prospective rather than retrospective basis. These regulatory principles reflect "a congressional determination that parties in the industry need to be able to rely on the finality of approved rates" (Constellation Energy Generation LLC v. FERC (3d Cir. 2024). Stable and predictable rates are needed to both set investors' legitimate expectations for the return of and on their invested capital, and to ensure captive customers do not experience rate shock. *See also* Federal Power Act § 206, 16 U.S. Code § 824e(a); *Narragansett Elec. Co. v. Burke*, 381 A.2d 1358, 1364 (R.I. 1977).

[6] "The Department has determined that the goals of designing utility rate structures are to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. G.L. c. 25, § 1A; D.P.U. 23-80/D.P.U. 23-81, at 367; D.P.U. 22-22, at 404; D.P.U. 20-120, at 412; D.P.U. 19-120, at 409. Efficiency means that the rate structure should allow a company to recover the cost of providing the service and should provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling consumers' needs should also be the lowest cost means for society as a whole. Thus, efficiency in rate structure means that it is cost-based and recovers the cost to society of the consumption of resources to produce the utility service. D.P.U. 23-80/D.P.U. 23-81, at 367-368; D.P.U. 22-22, at

- rate structures across rate classes that are a function of the cost of serving each rate class (cost causation, fairness, equity);
- rates that achieve efficient end-user consumption decisions and efficient utility investment and operational decisions (efficiency); and
- rates that are as simple as feasible and do not involve sudden change (simplicity, continuity, gradualism).

The process of determining the revenue requirement, the allocation and functionalization of the revenue requirement, and the design of rates by rate class is a complicated process that involves a balancing of many factors. These factors include the principles described above as well as considerations related to prevailing public policy goals and the unique circumstances faced by the utility under changing economic, financial, and operating conditions. For example, over the years the DPU has allowed various ratemaking provisions that are meant to achieve identified energy policy goals or that address specific and transitory conditions that are out of the utility's control. Net metering and the use of reconciling mechanisms represent two such examples.

With respect to net metering, the DPU has allowed full retail rate compensation for distributed energy resources (DERs), defining its net metering credit as the sum of basic service (generation), distribution, transmission, and transition charges.[7] Net metering historically was limited in application, but provided an important incentive for the development of a critical energy resource. Since its inception, it has contributed to the installation of a large amount of rooftop solar capacity, has supported the emergence of a commercially viable distributed energy resources sector, and has generated significant wholesale cost and environmental benefits.

There is, however, a growing tension between Massachusetts's current net metering policy and core ratemaking principles described above related to cost causation, fairness, and efficiency. The average cost of distribution assets (*e.g.,* substations, feeder circuits, and transformers), transmission assets (*e.g.,* high voltage transmission lines), and public policy charges are embedded in the net metering credit. Yet these costs are generally not avoided, or only partially or temporarily mitigated, through the operation of DERs. As a result, Massachusetts's net metering credit overcompensates customers relative to the private value

405; D.P.U. 20-120, at 412; D.P.U. 19-120, at 409. The Department has determined that a rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers to adjust their consumption patterns in response to a change in structure. In setting rates, the Department balances fairness and equity. Fairness means that no class of consumers should pay more than the costs of serving that class. Equity, in rate structure, means that the Department considers affordability among customers in establishing rate classes and when establishing discount rates for low-income customers. Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. G.L. c. 25, § 1A; D.P.U. 23-80/D.P.U. 23-81, at 368; D.P.U. 22-22, at 405; D.P.U. 20-120, at 413; D.P.U. 19-120, at 409-410." D.P.U. 23-150, at 476-477. *See also* "We conclude that the proposed PBR-O plan, as modified above, is likely […] to promote the Department's goals of safe, secure, reliable, equitable, and least-cost service and economic efficiency, cost control, lower rates, and reduced administrative burden in regulation." D.P.U. 23-150, at 97. These goals were originally described in D.P.U. 94-158. *See also* "In setting rates for utility service and otherwise providing for the recovery of costs by utilities, the Department applies the basic principle of cost causation; that is, the entity responsible for the cost to be incurred is responsible for payment of the costs (cost responsibility follows cost incurrence) ("Cost Causation Principle"). See, e.g., Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 167 (2009); Gas Unbundling, D.T.E. 98-32-B at 31 (1999); Boston Gas Company, D.P.U. 96-50 (Phase I), at 133-134 (1996); Electric Industry Restructuring, D.P.U. 96-100, at 51 (1996); Boston Gas Company, D.P.U. 93-60, at 331-337, 410, 432 (1993); Boston Edison Company, D. P. U. 1720, at 114 (1984); Generic Investigation of Rate Structures, D.P.U. 18810, at 14 (1977). In instances of public policy or where other discernable beneficiaries are identified, costs might be assigned and recovered from ratepayers other than just the entity responsible for the cost." D.P.U. 20-75-B, at 5;

[7] DPU 25-200, at 13.

of their excess distributed generation, resulting in inefficient outcomes and shifting costs to other (non-participating) customers. It is appropriate for the Commonwealth to reevaluate net metering with a focus on the marginal value of distributed energy generation, as has occurred in other states.[8,9]

With respect to reconciling mechanisms, for a couple decades Massachusetts has allowed collection and/or reconciliation of certain costs between traditional utility rate cases. Specifically, the Department has permitted reconciling cost mechanisms when the costs at issue are "(1) volatile in nature; (2) large in magnitude; (3) neutral to fluctuations in sales; and (4) beyond the company's control." The Department "has previously allowed reconciling tariffs […] in cases in which a distribution company has adequately demonstrated the need to recover between rate cases incremental costs associated with Department approved capital expenditure programs."[10] In instances where incremental capital expenditures are driven by a policy need, the Department has preauthorized capital expenditure programs (subject to a prudence review of project implementation) before permitting cost recovery through reconciliation mechanisms rather than base distribution rates.[11]

From a ratemaking perspective, the Department's use of reconciliation mechanisms is a sensible way to avoid large discrepancies between costs recovered based on a utility's historic test year and its realized costs, which may vary due to volatile factors outside of the control of the company, or due to specific safety, reliability, and/or public policy mandates. For example, when I was Chairman of the Commission in 2009, we approved the first Targeted Infrastructure Recovery Factor (TIRF), for Bay State Gas (D.P.U. 09-30). In that case, while we recognized that the proposed TIRF represented "…special ratemaking treatment," we approved it in light of compelling safety, reliability and environmental public policy needs (the replacement of aging steel pipeline infrastructure), the capital challenges and pressure on earnings the company might experience through the deferral of such large, non-revenue generating capital expenditures, and the safeguard of careful ongoing prudence review of the associated investments[12].

Yet it is timely to consider whether *certain* reconciling mechanisms remain necessary, and whether there are distribution-related costs that are either no longer needed or are sufficiently stable that they can be

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[8] California has adopted an avoided cost method. California's avoided cost methodology was recently upheld by the California Court of Appeal. Unlike retail rate compensation, California's "avoided cost calculator" "calculates seven types of avoided costs: generation capacity, energy, transmission and distribution capacity, ancillary services, Renewables Portfolio Standard, greenhouse gas emissions, and high global warming potential gases" to determine "the utilities' marginal costs of providing electric service to customers" that "can be avoided when the demand for energy decreases because of distributed energy resources, and are, thus, the benefits of using distributed energy resources." According to estimates by the California Public Utilities Commission, the use of avoided cost crediting results in lower bill credits to DER owners, but still provides sufficient revenues to pay back the upfront cost of a stand-alone solar system within nine years. *See* Center for Biological Diversity v. Public Utilities Commission (Cal. Ct. App. 2023)

[9] New York has adopted a "value stack" method. The value stack method compensates projects based on when and where they provide electricity to the grid and compensation is in the form of bill credits. This is determined by a DER's: Energy Value (LBMP), Capacity Value (ICAP), Environmental Value (E), Demand Reduction Value (DRV), and Locational System Relief Value (LSRV). *See* https://www.nyserda.ny.gov/All-Programs/ny-sun/contractors/value-of-distributed-energy-resources; https://www.osti.gov/servlets/purl/1871808

[10] D.P.U. 10-70, page 48.

[11] D.P.U. 24-11 (National Grid ESMP), Order (Aug. 28–29, 2024); D.P.U. 24-10 (Eversource ESMP), Order (Aug. 28–29, 2024); D.P.U. 24-12 (Unitil ESMP), Order (Aug. 28–29, 2024). *See also,* "Background and procedural requirements on electric sector modernization plans" available at: https://www.mass.gov/info-details/background-and-procedural-requirements-on-electric-sector-modernization-plans

[12] D.P.U. 09-30, pp. 132-135. See also, Craig Aubuchon and Paul Hibbard, "Summary of Quantifiable Benefits and Costs Related to Select Targeted Infrastructure Replacement Programs," January 2013, available at: https://www.analysisgroup.com/globalassets/content/insights/publishing/benefits_costs_tirf_jan2013.pdf

folded into base rates. This provides the DPU the opportunity to ensure their use does not cause rate designs to veer significantly from the principle of simplicity, and to ensure their impact on the balance of risks faced by utilities is well understood. Importantly, the Department has evaluated the impact of reconciling mechanisms on company financial risks when considering the cost of equity in distribution rate cases, resulting in a downward adjustment in the approved cost of equity.[13]

Net metering and reconciliation mechanisms are examples of circumstances where the design of utility rates deviates to some extent from core precedential ratemaking principles and practices in order to achieve specific policy objectives or to achieve an appropriate balance of risks and incentives. They reflect ways in which the process of designing company rates is both complicated and circumstantial, reflects a balance of a range of ratemaking and policy considerations, is responsive to the evolving conditions that affect utility investments and operations, and needs to ensure revenue sufficiency while considering the balance of risks and the costs to the Commonwealth's residents for essential services.

[13] "Further, we find that the revenue support that will be provided by the Company's PBR-O mechanism, ISRE mechanism, and ESMP cost recovery mechanism lowers its investment risk compared to the proxy groups and, therefore, National Grid's authorized ROE should be set in the lower half of the reasonable range." D.P.U. 23-150, page 474.

3. The Path to Long-Term Energy Affordability

a. Overview

The Commonwealth is entering a challenging part of its transition towards what will be a fundamentally different energy landscape.[14] Many elements of the transition are in place or will soon be underway: long-term contracts are in place and being sought with large, distant supply resources (wind, hydro, and potentially nuclear); grid-connected and distributed solar resources, and some storage, are expanding at a rapid rate; large load proposals are emerging across New England; policies are in place to accelerate consumers' transition to electric vehicles and efficient electric heating; natural gas utilities are on notice to plan for a future without significant growth while continuing to ensure safe and reliable service; electric utilities are administering grid modernization plans involving major system investments to connect distributed resources and manage shifting supply and demand conditions. All of this is happening against a background of continued seasonal vulnerability to natural gas supply constraints, inflationary cost pressures, fuel supply cost volatility, and the uncompromising obligation of safe and reliable energy service.

The Commonwealth's policy goals imply an energy transition that largely occurs over just one to two decades. This scope and pace of change has never been experienced in the electric or natural gas industries – not even close – and the majority of costs associated with most of the changes have not even begun to emerge. The magnitude of cost increases associated with electric service in particular can not yet be known with certainty, but major distribution and transmission system investments will be needed to reliably serve the expected increases in and changes in the shape of demand (from large loads and electrification), and to manage the magnitude and variability of new distributed resource interconnections.

While the costs of the transition remain largely unrealized, recent increases in electricity and natural gas costs associated primarily with inflationary pressures and episodic increases in fuel prices have put a bullseye on the rates of regulated utilities.[15] The Commonwealth has responded - the DPU, the DOER, the OET, and the OAG all have expended significant effort in evaluating the drivers of current affordability concerns and the prospects for minimizing electricity and natural gas costs going forward. These agencies – with the input of many industry stakeholders – have reviewed the features of electricity rate structures and mechanisms needed to address current affordability challenges and prepare the state for the changes to come.[16]

In these deliberations, three themes stand out: (1) rate designs must evolve to provide proper price signals that ensure fair distribution of costs and provide customers the incentive to manage consumption and

[14] This discussion focuses primarily on the challenges associated with the design of rates for electric distribution companies. However, many of the principles discussed are transferrable to considerations around how to adjust rates over time for the natural gas local distribution companies to ensure safe and reliable service and revenue sufficiency throughout a transition that is likely to result in lower sales of natural gas over time.

[15] Affordability discussions in MA have focused primarily on the affordability of electric service. In reality what matters most is the affordability of all energy services, including energy for electricity, heating, hot water, transportation, etc. To properly gauge the impact of the transition on consumers, one must net out increases in electricity costs with decreases in the costs of fuel use prior to electrification (i.e., gasoline, natural gas, oil, propane, wood, etc.). Going forward, assessment of the role of *electricity* cost increases must be viewed in this broader *energy* affordability framework.

[16] See the Interagency Rates Working Group (https://www.mass.gov/info-details/interagency-rates-working-group), DOER's Massachusetts Electric Rate Task Force (https://www.mass.gov/info-details/massachusetts-electric-rate-task-force), and OET's Financing the Transition Work Group (https://www.mass.gov/orgs/financing-the-transition-work-group).

costs; (2) the Commonwealth and its utilities should make a concerted effort through policies, programmatic spending, and education to transform the demand side of the equation – including load and distributed resources – into an effective load management tool; and (3) given the magnitude of costs associated with public policy programs and the way in which they shift the economics of resources involved, it makes sense to continuously evaluate the need for, value of, and most efficient funding mechanisms for the programs. It is through these changes that the state can mitigate the impact of changes in demand and distributed resource operations on system operations, reducing and delaying the system investments needed for reliable service. This is the clear path to managing energy affordability throughout the transition.

These types of changes are difficult, to say the least. Ratemaking is an aircraft carrier, not a battleship. The destination must be identified from a distance and well in advance; the path to get from point A to point B must be mapped out; and course alterations must be early and continuous. Similarly, creating the conditions for practical and effective load management can not happen overnight. For these and other reasons (discussed below), the state should embrace a vision and begin to initiate changes now that will allow for evolution of electricity rates simultaneous with and over the same time frame as the energy transition.

b. Key Challenges

While there is an identifiable set of foundational principles that underlies the setting of rates, setting rates in practice typically requires some degree of deviation from one or more of the core principles. This is because they are often at odds. For example, rates that fully comply with cost causation at the most granular level would be too complex and dynamic to meet the goals of simplicity and gradualism. Similarly, the smearing of costs across a single billing determinant – e.g. volumetric rates only – may meet the goal of simplicity, but does so in a way that violates cost causation and efficient pricing principles.

These challenges are exacerbated by the fact that successive rate decisions over a period of time can pile up the degree to which rate designs deviate from theoretical ideals. In most states, the history of ratemaking decisions over time in response to unique economic circumstances and different energy and environmental policy goals has resulted in rate designs that are out of whack relative to core rate design principles. The end result is rates that will not necessarily send the right price signals for achieving the most efficient level of consumption and production, and thereby may not achieve least societal cost outcomes.

This is not necessarily the wrong outcome. The framework for setting rates requires a balancing of objectives that span legal, economic, policy, and practical considerations. In reality, the basic structure of utility rates in Massachusetts has served the State well for decades, and has represented a reasonable balance of competing factors. It has helped ensure revenue sufficiency for utilities in discharging their public service obligations, it has achieved the goals of simplicity and fairness, and it has enabled the Commonwealth to implement important policy goals related to support for low-income customers, promotion of energy efficiency, and the establishment of commercially viable and profitable distributed energy resource industries.

However, as has become clear in the recent efforts of state agencies in concert with industry stakeholders, the status quo will rapidly become unacceptable in coming years as the state transitions to a vastly different framework for energy supply and demand. As energy costs increasingly shift to electricity costs, and as electricity costs increasingly shift towards capital investments (in supply, transmission and distribution) and away from variable costs,[17] volumetric-dominated rate designs will be increasingly out of line with cost causation principles. The continued proliferation of distributed resources whose owners can effectively avoid paying for their fair share of distribution system and policy costs means current rate designs will grow more regressive and inequitable. Failure to establish efficient pricing signals that are based on properly allocated customer contributions to fixed costs and system investments, and that reflect daily and seasonal variations in underlying costs, will increasingly frustrate the achievement of fairness and equity. And the lack of demand-based pricing and effective time of use rate designs will prevent the emergence of demand response as a tool to efficiently mitigate system peak demand and thereby minimize transition costs.

Perhaps the most significant challenge involves the incremental nature of changes typically allowable in the course of a given rate case. DPU rate decisions must adhere as much as possible to the principles of gradualism, continuity, and simplicity; principles that create practical limits on the nature, degree and pace of allowable adjustments to rate class configurations, cost functionalization and allocation, billing determinants, and overall rate designs. Avoiding customer anxiety and confusion requires balancing the pace of change towards efficient pricing design (including, e.g., time of use rates with both volumetric and demand components) against the need for rates to be simple, understandable, and not change dramatically from one month to the next. Unless viewed holistically and addressed proactively, these circumstances will increase affordability concerns over time and will undoubtedly frustrate the Commonwealth's efforts to achieve important energy policy goals.

c. Opportunities

On one hand, the historical and institutional challenges to change discussed above place practical boundaries on the scope and pace of changes that may be made to utility rate designs and programmatic goals. On the other hand, there is probably enough time to enact improvements at a pace that matches the changes underway in the industry. Changes in the level and shape of electricity demand should be governed by a reasonably gradual turnover of consumer transportation choices (from gasoline to electric) and building heating equipment (from oil/gas/propane to electric heat pumps). The impact of changing demand from large load additions can be managed to some extent through interconnection processes and the allocation of system costs to the commercial entities that cause them. System investments to accommodate interconnection of distributed resources will also expand at a measured pace, and local system challenges can be partially managed through flexible interconnection practices.

Thus the industry changes driving the need to alter rate designs will not occur overnight, providing an opportunity to administer the necessary changes over one to two decades, in an incremental fashion that will not compromise the goals of gradualism and continuity. But this is only true if the rate design

[17] This *trend* is most pronounced in the supply sector, as capacity and generation shift from low capital, high operating cost fossil fuel resources to high capital, low operating cost renewable generation resources. These circumstances already exist in transmission and distribution, which are dominated by the fixed costs of system infrastructure.

transition begins in earnest now, and progresses simultaneously with the pace of change in the industry. Fortunately, Massachusetts' state agencies have already proactively studied and identified the features of electricity rate structures and mechanisms needed to prepare the state for the changes to come.[18] These efforts have highlighted key features of future rate designs that can address affordability, equity, cost causation, and efficiency challenges. They include at least the following:

1. A transition (for residential customers) from recovery of distribution system capital costs and policy costs primarily through volumetric charges to their recovery primarily through a mix of fixed charges and demand-based pricing, to align rates with the fixed nature of transmission and distribution service investments that are directly linked to peak electricity demand requirements;
2. The institution of increasingly targeted time-varying rates (both volumetric and demand based) to provide price signals for efficient consumption decisions, which will empower consumer actions to manage energy costs and minimize the extent of utility investment needed to reliably operationalize the transition;
3. Inclusion of requirements that the provision of supply services through basic service (and, where possible and to the extent within the Department's jurisdiction, through competitive suppliers and municipal aggregators), adheres to the goals of aligning prices with cost causation and enabling customer cost management through time-varying rates;[19]
4. Programmatic changes fostering the development of technologies and programs to enable effective demand response along with a committed and sustained effort to educate consumers on ways to lower their energy costs in response to time-varying price signals;
5. Flexible interconnection practices for DERs to mitigate or delay the impact of DER saturation on local networks;
6. Tiered charges and other rate designs to address affordability for low and moderate income customers; and
7. A careful focus on ensuring that all customers that benefit from public policies and the system infrastructure utilities need to meet peak demand obligations pay their fair share of transmission, distribution, and programmatic/policy costs.

Items 2-5 are highlighted in this list because engaging the demand side to help moderate the pace and level of utility investment needs is by far the most effective tool the state has to address affordability concerns in an era of rapidly-increasing costs. It is too easy to look at the history of electricity supply and rate design and conclude that such an effort is not warranted as, historically, residential consumer demand is not price responsive and the technologies, demand aggregators, and programs to achieve meaningful demand response have not emerged. This is of course true. Consumers have not demonstrated the ability or interest in managing their consumption to lower demand under peak load conditions, or to lower consumption when supply costs are the highest. This is largely because flat volumetric pricing and the

[18] See the IRWG's Near-Term Rate Strategy Recommendations and Long-Term Ratemaking Recommendations, available at: https://www.mass.gov/info-details/interagency-rates-working-group

[19] The state's rate design authority is to an extent limited to regulated distribution company investments and costs. However, increasing transmission investment needs and continued volatility in the market designs for and cost of wholesale power supply will strongly influence the affordability of electricity for consumers. Consequently, the state must also pursue all opportunities available to it to align the pricing of transmission and wholesale power supply services with the principles described herein for the design of distribution system rates.

absence of time of use meters effectively eliminates the incentive to do so.[20] But there are at least three reasons to reconsider and double down on this opportunity at this point in time.

First, nearly all customers in the Commonwealth will soon have time of use meters in place, and access to data revealing the timing of electricity use alongside relevant pricing structures. In addition to providing customers a window into the nature of their consumption decisions, this opens the door to utilities establishing rate designs that vary with time and that are based upon the demand that individual customers impose on the system at key times (e.g., system peaks).

Second, the electrification of the economy will create real opportunities for individual customers and/or profitable opportunities for demand aggregators or other third parties to actively manage a significant portion of electricity demand associated with flexible loads, such as electric vehicle charging and possibly collective management of heating, ventilation and air conditioning equipment. The technology and/or software to accomplish this (whether collectively through an aggregator or individually through an app on one's phone) is not complicated, but it will take time and a concerted effort to educate customers and create the conditions for an engaged demand-side industry for such technologies and programs to take hold.

The third reason is necessity. The active planning for and management of the net electricity peak demand realized on the system is the only practical way to contain the costs associated with the transition within reasonable bounds, and is the most important way to address energy affordability and give customers the ability to manage their energy costs over time. It remains to be seen whether the load side of the equation can become a more significant source of demand reduction, but in this case history is of limited value. The Commonwealth can play a pivotal role in this respect by proactively creating the conditions to enable it.

Rather than focusing on what may be accomplished in a single rate case, the Commonwealth can work with utilities and stakeholders to establish a vision for changes to occur incrementally over the next 10-15 years to achieve an ideal end point by the time electrification, large loads, and distributed resource interconnections would otherwise jeopardize energy affordability and frustrate the Commonwealth's energy policy goals. The vision should contain the following elements:

- A conceptual translation of economic growth, large load expectations, DER growth, and electrification policies to load and load profile expectations in five year increments through 2040;
- A 2040 endpoint goal whereby rate designs fully meet the features described above (including proper functionalization to fixed, demand, and energy components, and a system of effective time of use rate structures), and the demand side is fully activated through customer actions, third party load management providers, and flexible DER operational policies;

[20] Customers do have some incentive to reduce total energy consumption (throughput), whether on their own (as a function of volumetric rates) or through participation in utility-funded energy efficiency (EE) programs. But throughput-focused conservation has only a marginal impact on peak demand, and thus on the capital intensive transmission and distribution system investments needed to provide reliable service at the time of system peak. This will be increasingly true going forward. The need to focus on reducing system peak demand rather than throughput to manage energy affordability highlights the potential benefits of reorienting programmatic spending towards programs and technologies that can support reductions in demand at the time of system peak.

- A glide path describing the transition in five-year increments from where rates and programmatic spending are now, to the desired end point.

It is possible to address energy affordability and simultaneously maintain progress on state policy objectives. Doing so will require aligning rates over time with cost causation and efficient pricing principles, while committing to the full activation of price-responsive demand to enable customer energy use management. To accomplish this, the Commonwealth should take actions now to pursue this outcome in time to manage a difficult transition.