COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources.	))))	D.P.U. 07-50

COMMENTS OF THE CAPE LIGHT COMPACT ON THE INVESTIGATION INTO RATE STRUCTURES THAT WILL PROMOTE EFFICIENT DEPLOYMENT OF DEMAND RESOURCES

The Cape Light Compact ("Compact") hereby submits the following comments in response to the Investigation by the Department of Public Utilities ("DPU" or "the Department") on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources.

I. BACKGROUND

The Compact is a governmental aggregator under G.L. c. 164, § 134 and consists of the twenty-one towns in Barnstable and Dukes Counties, as well as the two counties themselves. It is organized through a formal Intergovernmental Agreement under G.L. c. 40, § 4A. The Compact's Aggregation Plan was approved by the Department in D.T.E. 00-47. The Compact maintains a business office within the Barnstable County offices located at the Superior Courthouse at 3195 Main Street in Barnstable, MA 02630.

The purposes of the Compact include, among other things, (1) to negotiate the best rates for the supply and distribution of electricity for consumers on Cape Cod and the Islands; (2) to advance consumer protection and interests for the residents of Cape Cod and the Islands; (3) to provide equal sharing of economic savings based on current electric rates and/or cost-of service ratemaking approved by the Department; and (4) to

utilize and encourage demand side management and other forms of energy efficiency through contract provisions and state mandated systems benefit charges for renewable energy and to use the funds from such charges to advance consumer awareness and adoption of a wide variety of energy efficiency measures through implementation of an energy efficiency plan. Compact Intergovernmental Agreement at Article I.

Toward that end, the Compact presently operates a municipal aggregation competitive supply program, which provides electric power supply on an opt-out basis to roughly 170,000 customers across all customers classes who are located within the Compact's service territory and would otherwise be served as default service customers. The Department approved the Compact's form of universal service competitive electric supply agreement in D.T.E. 04-32, pursuant to which the Compact has entered into supply agreements with Consolidated Edison *Solutions*, Inc. The Compact also operates an Energy Efficiency Plan ("EEP"): Phase I of the EEP was approved by the Department in D.T.E. 00-47C; Phase II of the EEP was approved in D.T.E. 03-39; and Phase III of the EEP was approved in D.T.E. 05-34. The Department is currently reviewing the Compact's EEP: 2007-2012 in D.P.U. 07-47.

II. EXECUTIVE SUMMARY

The Department filed its Vote and Order Opening Investigation on June 22, 2007 in this proceeding ("Order"). The Department's investigation is intended to review the current ratemaking practices by which electric and natural gas utilities in Massachusetts recover their costs. Order, at 1. The goal of the Department in this investigation is to create guidelines that help the Department in its review under G.L. c. 164, § 94 of electric and gas distribution rates, prices and charges collected within the Commonwealth. *Id.* In

its Order, the Department outlined the key elements of a straw proposal for a base revenue adjustment mechanism for which it seeks comments on. Order, at 19. Specifically, the Department set forth thirteen questions for commenters to address relating to the key elements of the straw proposal. *Id*. at 20-22.

The Department's investigation is focusing on two pressing issues: (1) the need to implement all economic system and end-use energy efficiency; and (2) the need to advance the response of demand to wholesale market prices. As with any potential change, the Department has the obligation to balance a number of ratemaking objectives including price, reliability, and economic and environmental or other social benefits. The Compact's comments are intended to provide assistance to the Department in balancing these various objectives. Specifically, the Compact is interested in: (1) competitive electric markets and rate structures; (2) consumer advocacy; (3) administration and delivery of energy efficiency services; and (4) public education.

III. COMMENTS

Allowed Revenues per Customer

1. *The Department's proposal that a company's allowed revenues per customer be determined through a subsequent base rate proceeding is intended to ensure that the allowed revenue levels, which serve as the basis for the base revenue adjustment mechanism, are closely aligned with the company's costs. Under what, if any, circumstances should the Department permit a company's allowed revenues per customer to be determined through some manner other than a base rate proceeding?*

The Compact strongly supports the Department's proposal that each utility's allowed revenues be determined through a base rate proceeding. A full rate case is essential in establishing, monitoring and revising allowed revenues.

It is important that the Department be clear whether the purpose of decoupling is to track costs, or to approximate revenues without demand side management ("DSM")

since those two objectives are different. In an economic boom, for example, a utility's revenues would tend to rise much faster than its costs for new equipment.[1] Tracking costs would result in much smaller revenue increases in a boom, and little if any reduction in revenue during an economic downturn. The Department should be leery of any decoupling approach that would raise rates in a recession.[2] The utilities should not be entirely insulated from the pain of a regional downturn.

Tracking costs may also be more speculative and contentious than tracking such growth factors as customer number, employment, or retail sales. Hence, the Compact urges the Department to consider options for tracking growth, rather than costs, and to require each utility to develop and measure rate impacts by customer class in a variety of Department-specified scenarios (covering inflation, customer number and economic trends, including a recession) with cost-of-service ratemaking and each proposed decoupling method.

In any case, the decoupling mechanism should be based on a full rate case, and the Department should order each electric utility, in order of decreasing customer count (NStar, NGrid, WMECo and Fitchburg), to file a rate proceeding. It is critical to start with up to date, verified costs in order to assess, among other things, the impact on revenues caused solely by DSM efforts.

---

[1] Major T&D upgrades require at least a couple of years of planning and implementation, and their costs are depreciated over decades. A three- or four-year cycle of rate cases should result in resetting of rates before much of the costs of new plant flow into the utility's earnings.

[2] The Maine Public Utilities Commission's experiment with revenue-per-customer decoupling in the early 1990s illustrates this problem. Falling sales and rising cost-tracking mechanisms resulted in Central Maine's proposing large rate increases for struggling businesses and unemployed residential customers. As a result, the Maine Public Utilities Commission terminated its decoupling experiment. While the DPU should be prepared to terminate decoupling early if major problems arise, the mechanism should be designed to avoid such foreseeable problems.

Once base rates are set, revenues per customer ("RPC") may not be the best approach for tracking costs.[3]

- For most classes, the incremental cost of adding a customer—a meter and perhaps a service drop—is much less than the average cost of serving customers in the class.[4] Some, but not all, new customers will require expansion of the area-spanning distribution system or increases in distribution capacity.

- For residential customers, the costs of serving a new single-family customer are likely to be greater than the cost of serving a new multi-family customer.

- The extent to which electricity and gas are used for space heating and water heating sources in new construction will differ from those in the existing customer base.

- For non-residential customers, costs per customer within a rate class may vary by orders of magnitude, from the smallest to the largest. The revenue target may be more reasonably based on such measures as employment or retail square footage added. The Department should examine the utilities' short-term forecasting models to determine whether the utilities are already using better predictors than customer number for predicting loads (and hence utility investments for customer and demand-related costs).

2. *The Department's proposal uses an approach in which a company's allowed revenues per customer for each rate class does not change between base rate proceedings. An alternate approach would be to adjust the allowed revenues per customer values periodically, based on changes in each rate class' average usage per customer. Please discuss the merits of each approach.*

Reducing allowed RPC values in proportion to changes in each rate class' average usage per customer would tend to undermine the objective of removing the incentives for utilities to encourage growth and discourage energy-efficiency and behind-the-meter generation. The costs of serving existing customers change very slowly over time with

[3] Revenue per customer may be a better estimate of revenues without DSM than it is of costs.

[4] Multi-family housing and many commercial properties require only one service drop to reach dozens of customers.

falling usage per customer, and increase in an uneven and difficult-to-characterize manner with rising usage per customer.

Conducting a base-rate proceeding every three to four years would allow for periodic resetting of the RPC allowance.

In the annual reconciliation filing, each utility should be required to file, and the DPU should review, data on the size and fuel-choice characteristics of new customers, to ensure that they are consistent with the characteristics of the existing customers from which costs per customer were estimated. Similarly, each utility should file data on re-metering of existing space, where a building that was a single large customer has become many smaller customers (e.g., individual apartments or offices) at the cost of only the additional meters.

Annual Reconciliation Calculation

3. *The Department's proposal that a company's actual versus allowed revenues be reconciled annually is intended to balance three objectives: rate stability, rate continuity, and administrative efficiency. Do annual reconciliations strike an appropriate balance among these three objectives or would alternate reconciliation periods (e.g., quarterly or semi-annually) better do so?*

Annual reconciliation is appropriate, so that over- and under-collections in one season (e.g., summer) are not recovered from a subsequent season (e.g., fall or winter) with a very different mix of loads. The reconciliation period need not be a calendar year.

The Department should retain flexibility in setting the recovery period for reconciliations to allow coordination with other rate components and avoidance of excessive instability in rates. For example, in a time of falling power-supply costs, the Department may choose to extend the recovery period for undercollections (so the

surcharge will coincide with the power-supply rate reductions) or accelerate recovery of an overcollection.

4. *The Department's proposal to determine a company's actual revenue based on billed revenues is consistent with the base rate treatment applied to distribution-related bad debt costs. An alternate approach would be to determine actual revenues based on payments received. Please discuss the merits of each approach.*

The Department should leave with the utility the risk and incentive related to management of bad debt, and should therefore base the decoupling on billed revenues. This approach also avoids illusory revenue shortfalls and surpluses due to the timing of cash flow at the beginning and end of a reconciliation year.

The Compact does not believe there are any benefits of using received payments in the decoupling computation. If the Department were to adopt decoupling based on payments received, an economic slowdown that delayed payments would result in the utility increasing decoupling charges to customers when they are already under financial stress.

5. *The Department's proposal for determining billed revenues is based on actual consumption. An alternate approach would be to determine billed revenues based on consumption normalized for weather and/or other factors.*

   (a) Please discuss the merits of determining billed revenues using actual versus weather-normalized consumption.

   (b) Should consumption be normalized for other factors (e.g., economic conditions)? If so, identify those factors and describe how the normalization for such factors could be done.

   (a) Using actual revenues, rather than weather-normalized revenues, has at least three major benefits. First, it avoids yet another estimation step in the comparison of achieved and allowed revenues, including the complication of determining what is "normal" weather in a time of changing climate. Second, using actual revenues mitigates

the wide swings in bills that customers will experience in extreme weather; a hot summer would produce large electric bills, part of which would be refunded through the decoupling mechanism. Third, the utility's earnings would not be subject to weather variability, so the cost of capital should be lower than with weather-normalized decoupling.[5]

(b) Normalizing consumption for economic conditions would better track revenues without DSM (but not necessarily costs), compared to a simple RPC computation. This point is discussed in the Compact's response to Question 1, above.

Annual Base Rate Adjustment

6. *The Department's proposal to recover the difference between a company's target and projected revenues through adjustments to its base energy charges is intended to send appropriate price signals to consumers. An alternate approach would be to adjust both base energy and demand charges (where applicable) to recover this difference. Please discuss the merits of each approach.*

An energy-price adjustment would be simpler to understand and administer.

In general, the Compact believes that the Department should move toward recovery of electric distribution costs through energy charges.[6] For customers with time-of-use meters, those charges should be primarily on-peak energy charges. Since most distribution costs (substations, feeders, most line transformers and secondary lines in network installations) are driven by the coincident peak loads of many customers, a non-diversified demand charge on the customer's maximum monthly or annual load is a poor

[5] The Vectren's Indiana gas subsidiaries use an interesting hybrid, in which sales are weather-normalized for each individual customer, based on the seasonality of the customer's use, and the weather-normalized sales are subject to a revenue-per-customer decoupling reconciliation.

[6] Specifically, *distribution* costs should be recovered through *distribution* energy charges, distinct from charges for generation, transmission, transition, or other costs. The Default Service Adjustment currently recovers generation costs through distribution rates, and the settlement in DTE 05-85 blurs the distinction between distribution and transition rates.

approximation of the customer's contribution to distribution costs. Historically, demand charges have been justified by revenue stability for the utility, precisely because they are difficult for customers to avoid. Rate design would be more effective in reducing energy use, peak loads, energy prices and greenhouse gases if more revenues were recovered through energy charges and less through demand charges.

Reconciliation Filings

7. *The Department's proposal to require a company to submit quarterly filings identifying actual and allowed revenues is intended to ensure that changes in rates are made in a predictable and gradual manner.*

(a) Under what circumstances should the Department allow an adjustment in base charges during a reconciliation period?

(b) Under what circumstances should the Department initiate a review of a company's base revenue adjustment mechanism?

(a) The Department should consider allowing an adjustment in base charges prior to the normal annual reconciliation if that adjustment would offset changes in other rate components, such as default-service charges. Thus, in periods of rising power costs (or other non-distribution costs), the Department should consider proposals to flow through a reduction in base charges; in periods of falling costs, the Department should consider proposals to flow through increases in base charges.

(b) Each base rate adjustment mechanism ("BRAM") should be reviewed on a regular schedule, along with the level of the utility's base rates. The Compact recommends a cycle of three to four years between rate cases, including BRAM review. That timing would:

- Permit fine-tuning of the BRAM based on real experience with the decoupling formulas and procedures, including updating estimates of incremental customer size;

- Allow utility shareholders to retain several years of savings from improvements in efficiency, encouraging innovation, while ensuring that cost reductions flow to ratepayers;

- Provide timely opportunity for review of utility service quality and other performance measures; and

- Limit the extent to which shareholders can retain the short-term savings from cost-cutting measures that degrade service.

8. *What standards should the Department use to measure the performance of a company's base revenue adjustment mechanism over time?*

The Department should examine whether the BRAM:

- Removes the utility's incentive to discourage or interfere with energy-efficiency and distributed generation;

- Creates appropriate incentives to procure all cost effective energy efficiency and demand response measures;

- Avoids increasing rates at times of economic downturn or distress; and

- Is unambiguous and efficient to apply.

Change in Risk

9. *How will the implementation of a base revenue adjustment mechanism affect a company's risk and how should such considerations be reflected in a company's capital structure and ROE?*

The base revenue adjustment mechanism should reduce the utility's risk, since its revenues and earnings will not be subject to variation in sales. Required return on equity would be expected to decrease accordingly. The magnitude of this effect should be determined in the initial rate cases that implement revenue decoupling. Those cases would also provide an opportunity to review cost-of-capital assumptions that have not been changed for over a decade.

Shared Earnings Provision

10. *The Department's proposal to include a shared earnings provision in the base revenue adjustment mechanism is intended to strike an appropriate balance between the risks borne by customers and shareholders associated with company earnings. Please comment on the merits of such a provision. Also, comment on the design of the proposed earnings sharing provision.*

There is no need for a shared-earning provision. If the utility is under-earning, it can file a rate case. If the utility is over-earning, the Department can open a proceeding (and the Attorney General can petition for such a proceeding) to reduce the utility's rates. Shared-earning mechanisms are a vestige of the regulatory lassitude of the Department of Telecommunications and Energy, and are neither needed nor desirable additions to a BRAM. The Compact cannot see how a shared earnings provision would facilitate the stated goals of this proceeding to advance energy efficiency and price responsive demand.

Performance Based Regulation

11. *Please comment on the merits of implementing a base rate adjustment mechanism with and without the individual elements of a PBR plan (e.g., fixed term, inflation, productivity, performance standards, exogenous factors).*

The BRAM should include a maximum term and performance standards. The maximum term between rate cases should be four years, as discussed in response to questions 2 and 7.

Performance standards remain important under a BRAM, to give the utilities incentives to maintain reliability, safety, and quality of service. In general, the existing incentives are inadequate, since the maximum penalty may be less than the annual cost of even a single service crew and truck. The Department should initiate a review of performance standards, with the intent of increasing the standards and potential penalties.

In addition, in computing the BRAM, the Department should mandate that utilities add back to actual revenues an estimate of revenues lost due to outages.

Implementation Schedule

12. *Please comment on how the Department should schedule the implementation of a base revenue adjustment mechanism for each gas and electric company in light of the need to move expeditiously, the resources required to implement such changes, and the specific circumstances of each company. How should the Department determine the order of individual base rate proceedings?*

The first filing should be that of NStar Electric, ninety days following the issuance of the final order in this proceeding, followed by NGrid Electric and then the other electric and gas utilities in declining order of distribution revenues. NStar Electric should file first, due to both its large size and importance in DSM implementation and the desirability of terminating the non-cost-based rate increases under the settlement in DTE 05-85 and their replacement with rational sales-decoupled ratemaking.

Other Questions

13. *How should the implementation of a base revenue adjustment mechanism affect the performance-based shareholder incentives that gas and electric companies currently are eligible to receive for promoting energy efficiency?*

As the Commission asserts, decoupling will remove a financial disincentive currently affecting distribution utilities in Massachusetts. Although such a ratemaking change may be *necessary* to increase the implementation rates of energy efficiency and demand response, it is not *sufficient* to cause this outcome. It is not clear that removing the current sales-based-revenue disincentive will spur the state's distribution utilities to make increased contributions to the expansion of their energy efficiency and demand response initiatives.

Decoupling should reduce the required magnitude of the incentives, since the major disincentive for energy-efficiency investment (loss of revenues and earnings) will have been eliminated. The Department should institute a generic proceeding on utility incentives, to determine:

- The percentage of annual sales reduction (by utility or be rate case) that constitutes adequate performance, below which the utility will be penalized;
- The percentage reduction that constitutes superior performance, above which the utility will be eligible for an incentive; and
- The formulae for the penalties and incentives, reflecting sharing of net benefits and other targeted incentives.

The standards should be set with reference to the most successful energy-efficiency portfolios, such as those in Vermont and California. Unless there is some very good reason to do something different for a specific utility, the performance incentives should be of the same form and proportional to load for all electric utilities. A separate but consistent performance-incentive formula should be applied to all gas utilities.

If a utility consistently fails to meet the Department's standard for adequate performance, the Department should remove the utility as administrator for the energy-efficiency portfolio, and turn responsibility for the portfolio over to another utility or a third-party administrator.

IV. REQUEST TO PARTICIPATE ON PANELS

The Compact would like to participate on the proposed panels to comment at the hearings. The Compact's representative will be Robert Mahoney, Chairman of the Compact. Mr. Mahoney's contact information is Robert Mahoney, PO Box 241, East Dennis, MA 02641, (ph) 508-385-7189, rpmahon@comcast.net.

Since the Compact has been administering ratepayer energy-efficiency funds and delivering programs on the Cape and Vineyard since July of 2001, Mr. Mahoney is well versed on the subject of energy efficiency and understands the complexity of delivering ratepayer-funded programs. Mr. Mahoney brings to the table the perspectives of both a consumer advocate and a program administrator. This viewpoint is not easily replicated by others, due to the unique nature of the Compact. Mr. Mahoney is specifically interested in participating on panels that will discuss: (1) competitive electric markets and rate structures; (2) consumer advocacy; (3) administration and delivery of energy efficiency services; and (4) public education. Mr. Mahoney may elect to have staff, legal counsel, or technical consultants assist and/or represent the Compact on the panels, as appropriate.

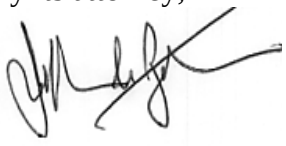
V. CONCLUSION

The Compact appreciates the opportunity to provide comment to the Department on these very important issues and to participate in the upcoming panels during the public hearings to be held in this Proceeding.

Respectfully submitted,

THE CAPE LIGHT COMPACT

By its attorney,



Jeffrey M. Bernstein, Esq. (BBO # 041190)
(jbernstein@bck.com)
BCK LAW, P.C.
One Gateway Center, Suite 851
Newton, MA 02458

617-244-9500 (voice)
617-244-9550 (fax)

On the Motion:

Audrey Eidelman*
(aeidelman@bck.com)
BCK LAW, P.C.
One Gateway Center, Suite 851
Newton, MA 02458
617-244-9500 (voice)
617-244-9550 (fax)
* Not yet admitted to the practice of law, pending results of July 2007 bar examination.

Dated: September 10, 2007

T:\Clients\BCY\DPU 07-50 (Efficient Deployment of Demand Resources)\Comments of the Cape Light Compact (FINAL).bcy.doc