



State Regulatory Update: Energy Efficiency

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Rising energy costs, thin reserve margins, higher load growth, and increasing environmental concerns and constraints have significantly increased regulatory and industry interest in cost-effective deployment of energy efficiency resources. These resources include demand reduction measures such as demand response and demand-side management (DSM).

Regulators and industry participants alike are placing high importance on developing and using such resources to lower consumption, defer additional capacity, and meet environmental and economic goals and commitments.

Many utilities are seeking regulatory reforms and approvals to increase their energy efficiency investment. At the same time, regulators in many states are exploring or revisiting energy efficiency regulatory policies and frameworks through informal and formal proceedings.

The **California** commission this year opened a rulemaking to develop a state energy efficiency strategic plan. The **New York** commission approved a program implementing what it called an “historic” energy efficiency portfolio standard that sets aggressive energy usage reduction goals. **Kansas** issued a regulatory framework for reviewing and evaluating energy efficiency programs as part of a multifaceted energy efficiency investigation.

Regulators in states such as **Arizona, California, Georgia, Indiana, Maryland, Michigan, Missouri, Nevada, New York, North Carolina, Ohio, Pennsylvania,** and **Virginia** instituted, resurrected, or expanded energy efficiency working groups and collaboratives to help figure out where programs need to be and how to get there. This trend reflects in part a desire by regulators to have the private sector play a leading role in whatever solution is developed.

Many state regulatory commissions have approved or are considering pilot and permanent utility energy efficiency programs. States like **Iowa** are considering updates and expansions of longstanding programs. Some pilots in states such as **Florida** and **Indiana** have become permanent after one or more extensions, while others, as in **Florida** and **New Jersey**, have been closed to new participants, significantly modified, or terminated due to failure to achieve expected savings.

Oklahoma and **Arkansas** regulators gave go-aheads in the past year to utilities to launch Quick Start programs, i.e., programs that can get off the ground quickly, provide measurable, near-term benefits, and eventually be expanded.

Underlying this regulatory activity in the states is a more comprehensive view of energy efficiency relative to energy costs, capacity needs, and environmental issues than in decades past.

Scale Investment

Nevertheless, while many states and utilities are taking proactive, forward-looking approaches to energy efficiency, the conversation, positive thinking, and activity across the country have not yet been parlayed into scale adoption of energy efficiency programs, especially on the scale of supply investment. Regulators generally have not attained a level of confidence in energy efficiency resources that would support decisions to make large investments in such resources.

Regulators are not suggesting a rejection of energy efficiency, nor are they suggesting that large investments in energy efficiency will obviate the need for new generation and transmission capacity in the future. Rather, they are increasingly recognizing that a better balance is needed between energy efficiency and generation and transmission capacity.

For example, regulators in **Arkansas, Iowa, Minnesota, North Carolina, and South Dakota** recently approved new baseload generation or transmission capacity. They generally found that existing energy efficiency measures could cost-effectively meet only a portion of the determined need and could not eliminate or delay the need for new capacity in the near term.

On the other hand, regulators in states such as **Oklahoma and Oregon** were not comfortable with utility proposals related to new generation construction in the absence of fuller evaluation of energy efficiency alternatives.

Fuller cost-effectiveness assessment of energy efficiency relative to building new capacity or purchasing supplemental power is a growing trend. On the legislative side, a 2007 **Florida** law requires regulators to consider whether renewable energy and conservation measures are being cost-effectively used by the utility applicant before they can approve new construction of certain types of power plants. The regulators must consider the extent to which such use of energy efficiency resources might mitigate the need for the plant.

A **Connecticut** law requires utilities to develop integrated resource plans using cost-effective energy efficiency resources and to evaluate cost impacts equitably with supply resources.

On the regulatory side, **Connecticut** regulators directly linked energy efficiency and supply resources when they approved four bid-winning contracts for incremental capacity procurement to reduce federally mandated congestion charges, including a 5 MW energy efficiency contract.

New Hampshire regulators recently required more robust assessment of energy efficiency resources in the context of approving a utility's integrated resource plan.

Some regulatory proceedings and negotiated settlements also are seeing concessions that link use of energy efficiency directly with rate or supply resource decisions.

For example, **Florida** regulators in 2006 approved construction of two peaking plants after the utility applicant agreed to, among other things, accelerate DSM and conservation programs. **Louisiana** regulators

conditioned approval of a baseload coal-fired plant partly on the future filing by the utility of a study on the potential for energy efficiency and load management program implementation.

Kansas regulators approved a settlement of advance ratemaking principles for a peaking plant conditioned on the utility's agreement to pursue new or expanded energy efficiency programs. Other states where such concessions have occurred include **New Mexico** and **Ohio**.

On the basis of these and other recent developments, the message from many state regulators and legislators is that utilities will increasingly be required to have a balance of both supply and demand side options to meet load.

Measuring Savings

Designing cost-effective energy efficiency programs may involve different assumptions in different states and among different utilities, which poses a challenge to gauging achievements of program savings and other ratepayer benefits. Some regulators have shown reluctance to approve ratepayer-funded investments in energy efficiency resources due to uncertainty over program outcomes.

For example, regulators in **Maryland** and **Missouri** required utilities that stepped up with proposals to develop more detailed program designs to help provide the needed assurance, e.g., through appropriate measurement and evaluation tools, that use of ratepayer funds would be justified by the ultimate savings.

Maryland followed up in a later decision with rejection of five out of six utility-proposed energy efficiency programs as too costly for ratepayers. The regulators said the fact that the proposals met some commonly used cost-effectiveness tests was not enough. They required a showing of a real rate of return that could be measured in meaningful ratepayer bill savings.

The Maryland action reflects an increasing recognition by regulators that measurement and evaluation tools are essential to developing metrics and calculating savings. In states such as **California**, where utilities are allowed to make a margin under a performance-based or other incentive plan, such tools provide the ability to measure and potentially share any benefits between ratepayers and shareholders.

In states such as **Florida**, underlying approval criteria or conditions for energy efficiency programs often apply to ensure monitorability and measurability of cost-effectiveness.

As knowledge and awareness of measurement and evaluation benefits evolve, states may become more involved in determining appropriate methodologies, e.g., for cost-effectiveness determinations. **New York** regulators, for example, made determinations on a number of potential factors for calculating the cost-effectiveness of specific initiatives using a total resource cost test, and on how to calculate demand management-related lost revenue that results from the initiatives.

Measurement and evaluation is a concern not only to regulators but also to industry participants, which increasingly are embracing the goal of developing energy efficiency as a viable, sustainable business. As the

debate over measurement and evaluation advances, so does the ability to develop business models based on consistent assumptions and methodologies.

Regulatory Frameworks

Developing viable, sustainable energy efficiency businesses also requires enabling regulatory frameworks that provide for appropriate cost recovery. Such frameworks may enable utilities to timely recover costs, remain whole for fixed costs, compensate for lost revenues, and/or make a margin.

A challenge in many states is determining how best to approach these enabling structures. Regulators in many states, including **Arkansas, California, Connecticut, Kansas, Maine, Massachusetts, Minnesota, Ohio, Rhode Island, Washington** and **Wisconsin**, have focused significant effort on reducing or removing financial disincentives and/or providing financial incentives to improve and increase delivery of energy efficiency measures.

States have adopted, authorized, or are exploring a variety of cost recovery approaches that may remove delivery disincentives. These approaches include incremental cost recovery through base rates (e.g., **Arizona**), special riders or surcharges (e.g., **Arkansas, Idaho, Kansas, Texas**), automatic adjustment mechanisms, or trackers (e.g., **Arizona, California, Colorado, Indiana, Kentucky, Montana, Ohio, Virginia**), and lost revenue recovery mechanisms (e.g., **Montana, New York, Ohio**).

Trackers

Cost trackers and special riders generally are seeing increasing use in the states. Trackers encourage investment by ensuring more timely recovery of energy efficiency program costs that are not capitalized.

New Mexico and **Illinois** commissions this year approved new adjustment mechanisms for specific utilities, while **Colorado, Idaho, and Montana** are among states that recently affirmed existing trackers and special riders.

Trackers include decoupling mechanisms, which remove the financial disincentive to sell less by allowing recovery of contributions to fixed costs that are lost due to implementation of energy efficiency programs and related sales reductions. Although wider use of trackers is a general trend, there is less regulatory activity on decoupling and lost revenue recovery. Decoupling is discussed in more detail below.

Still another incentive type of approach aimed at enabling/encouraging demand-related business development is rate-basing, where utilities, e.g., in **Missouri** and **Nevada**, are allowed (or will be allowed) to make a margin by capitalizing costs related to DSM programs or renewable generation.

Shareholder Incentives

Shareholder incentive mechanisms have been adopted or are under consideration in many states.

Colorado this year approved an incentive package for a specific utility that includes a bonus incentive for each year an approved energy efficiency plan is implemented, performance incentives for surpassing approved goals, and prospective program cost recovery via a revised, existing DSM cost tracker.

Ohio regulators recently approved more than a dozen residential and commercial DSM programs and related cost recovery for one utility via annually reconciled riders, including conditioned adjustments for shared savings with a 10% shareholder incentive.

The **California** commission adopted a sweeping energy efficiency risk/reward incentive program for the state's four shareholder-owned electric and gas utilities.

Arizona, Massachusetts, New Hampshire and Rhode Island have incentive mechanisms in place that are tied to achieving specified program goals. **Nevada** and **Minnesota** are exploring such mechanisms.

Other states have shown some resistance to incentive approaches. For example, **Hawaii** required the discontinuation of lost revenue and shareholder incentive recovery for all DSM programs, saying such recovery was unsuitable in light of a large expected reserve capacity shortfall and a law that requires renewable energy resource use. The statutory requirement obviates the need for an incentive, the regulators reasoned.

Decoupling

A priority in some states is determining how to remedy an apparent fundamental disconnect between how utilities receive revenues and how they achieve energy efficiency goals. In this context, some states have approved or are examining decoupling revenues from kWh sales through some type of adjustment mechanism as a way to remove an inherent disincentive of reduced sales resulting from demand reduction programs.

Massachusetts regulators took definitive action this year when they endorsed full decoupling as the best way to remove disincentives to demand resource deployment, and directed utilities to develop implementing rate mechanisms.

Maryland regulators approved a specific decoupling mechanism for two electric utilities, in part to remove the disincentive to deployment of energy efficiency programs.

Idaho regulators approved a decoupling pilot for one electric utility aimed at ensuring full recovery of allowed fixed costs through a fixed cost adjustment mechanism, regardless of power volumes. In the first yearly adjustment of this mechanism, the Idaho commission last spring approved an overall credit balance sought by the utility, but made changes in the proposed distribution method and required further fine-tuning.

Other states are reviewing, or have stated their intent to review, decoupling. **Montana** regulators said they plan to look at decoupling next year in a rate design proceeding, while affirming in the meantime continued recovery of lost revenue resulting from DSM acquisition. **Kansas** determined it has authority to consider and apply decoupling. **Delaware** and **New Hampshire** also have proceedings under way to explore the issue.

Laws recently enacted in **North Carolina** and **New Mexico** require regulators to consider decoupling as a means to promote in-state demand reduction and renewables.

As with other cost recovery approaches, some states have shown more hesitancy toward decoupling. **Oklahoma** regulators rejected a utility-proposed formula-based rate adjustment mechanism that would have delinked energy efficiency-related and other revenues from sales. The regulators said the mechanism as proposed was too broad to implement now in light of numerous concerns raised by parties, which generally said the normal rate process is adequate. The regulators expressed interest, however, in reviewing formula-based rate mechanisms in the future on a project-by-project basis.

Washington regulators also rejected a utility-proposed electric revenue decoupling mechanism, citing lack of operational details among the reasons.

Advanced Metering Infrastructure

Upgrading efficiency and related programs may require upgrading of delivery systems. Many utilities and regulators are looking toward the use of advanced metering infrastructure (AMI), which would use “smart grid” technology to provide consumers with the ability to use electricity more efficiently. The technology, which includes use of meters allowing two-way communication, also would provide utilities with the ability to detect problems on their systems and operate them more efficiently, thereby ultimately improving reliability and saving money for consumers.

Thus, regulators in several states, including **California, Kentucky, Maryland, Massachusetts, Oregon,** and **Texas**, have approved AMI pilots or permanent programs or phases, and related cost recovery, which may be subject to caps or other conditions.

New York has declined so far to authorize full-scale AMI implementation, but has directed utilities to implement pilots. The regulators cite uncertainty over the forecasted value of societal benefits and lack of proven technology.

Michigan initiated a smart grid collaborative that it later expanded to include plug-in hybrid electric vehicles.

States generally have declined to adopt the PURPA time-based metering standard, as revised by EPA Act 2005. They generally cite state actions already taken in this area and/or a failure to find the federal standard in the public interest. For example, **Arkansas** said the state already has issued guidelines providing for consideration of demand resource approaches in supply resource planning, and demand resource technologies and practices are best met by utility-specific initiatives.

Montana regulators said they favored a more incremental approach than provided by the federal standard. They plan to look at smart metering, along with decoupling and inverted block rates, next year in a rate design context.

In related activity, **California** set a timetable for a utility to propose dynamic pricing rates, which are a key component of a smart grid system. **Massachusetts** declined to open a targeted inquiry into dynamic pricing in favor of a broader investigation of commodity pricing options under a 2008 law.

Third-Party Administrators

An issue gaining greater visibility in state proceedings is the use of third-party administrators for energy efficiency programs. Some of the cases highlighted in this report touch on this issue.

New York regulators, in approving a program to implement the state's energy efficiency portfolio standard, designated both utilities and the New York State Research and Development Authority as program administrators, consistent with past practice.

In some state proceedings, intervenors or regulators pushed, or said they would explore, the use of third-party administrators in response to what they perceived as poor utility performance in energy efficiency. **Montana** regulators declined to act on such an intervenor proposal, saying it did not wish to divert valuable resources to consider this issue when other energy efficiency-related issues need attention.

On the other hand, **Connecticut** regulators said they planned to explore use of a third-party administrator in light of continued overspending by utilities of energy efficiency budgets.

Regulators in **Vermont**, where a third party runs the state's Efficiency Vermont program, approved a utility plan for investing monies from an existing efficiency fund in the utility's low-income energy efficiency program. The regulators said the utility plan supplements, rather than supplants, the third-party program.

Assistance Programs

The link between energy efficiency and assistance programs appears to be growing stronger in some states. Evidence is growing that consumers are finding it increasingly difficult to pay their utility bills in the current economy. This has regulators concerned, especially in states such as **Pennsylvania** and **Illinois**, where generation rate caps are set to expire or have already expired, triggering significant price increases. Low-income energy assistance is expected to garner more state regulatory attention in the coming months for this reason.

The **California** commission issued a decision late last year requiring utilities to take steps to better integrate low-income energy efficiency (LIEE) programs with other energy efficiency programs. The commission directed utilities to treat LIEE as an energy resource along with other energy efficiency programs.

Massachusetts this year opened an investigation into ways to better integrate LIEE and other energy efficiency programs.

Water Conservation

In what could be indicative of a future trend linking water savings and energy use reductions from a regulatory perspective, the **California** commission late last year approved pilot programs under which electric and gas utilities must enter into partnerships with water agencies to undertake water conservation programs. The commission also required study of the relationship between water savings and reduced energy consumption.

2005-08 Update

Examples of regulatory and legislative actions on energy efficiency during 2005-08 follow the list of EEI resources in chronological order, starting with the most recent action. Entries in **red** font indicate those added since the February 2008 update.

EEI Reference Resources

- *Quantifying the Benefits of Dynamic Pricing in the Mass Market*, The Brattle Group, January 2008, lays out methodology for quantifying the benefits to customers and utilities of dynamic pricing programs.
- *Making a Business of Energy Efficiency: Sustainable Business Models for Utilities*, August 2007, NERA Economic Consulting, identifies and discusses sustainable utility business models for energy efficiency as well as enabling regulatory and business circumstances.
- *Retail Electricity Pricing and Rate Design in Evolving Markets*, Christensen Associates, July 2007, explains the critical role that efficient rate design, including decoupling, can play in today's electricity markets, and suggests practical strategies for implementing such designs.
- *PURPA: Making the Sequel Better than the Original*, The Brattle Group, December 2006, addresses the issues and challenges of avoided cost, net metering and credits for customer demand reduction.
- *Deciding on "Smart" Meters: The Technology Implications of Section 1252 of the Energy Policy Act of 2005*—Plexus Research, September 2006, provides practical guidance on how to evaluate the cost-effectiveness of advanced metering infrastructures.
- *Distributed Resources: Incentives*, NERA Economic Consulting, May 2006, describes barriers to efficient distributed resources development and strategies for their removal; addresses the pros and cons of decoupling, and presents five conceptual designs for rate regulatory policies that would let utilities make a business out of distributed resources.
- *Responding to EAct 2005: Looking at Smart Meters for Electricity, Time-based Rate Structures, and Net Metering*—NERA Economic Consulting, May 2006, presents economic principles and policy issues for regulators to consider when evaluating rate options under EAct directives, and provides guidance on whether to adopt proposed standards relating to time-based rates, net metering, and other PURPA issues.
- *Reference Manual and Procedures for Implementation of the "PURPA Standards" in the Energy Policy Act of 2005*—NARUC, EEI, APPA, NRECA, March 2006, provides guidance on the procedures that states must follow to comply with the required PURPA considerations.
- *Economic Principles of Demand Response in Electricity*, NERA Economic Consulting, October 2002, identifies the economic principles that should underlie the expanded use of demand response in emerging markets.
- *Barriers to Price-Responsive Demand in Wholesale Electricity Markets*, Eric Hirst, PhD, June 2002, focuses on the need for increased integration of retail and wholesale markets and the barriers that prevent greater retail participation.

Regulatory and Legislative Examples

2008

Texas PUC – CenterPoint Energy Houston Electric

Decided 8/29/08 Filed 5/1/08 Case 35620

Following settlement, approves advanced meter information network (AMIN) under which 125,000 advanced meters/related infrastructure to be installed beginning Sep 2008. Under AMIN, participating retail electric providers (REPs) to finance meter buildout before CenterPoint implements advanced metering system (AMS), which is under review. REPs may not charge end-use customers unless/until PUC approves recovery of AMS costs via surcharge or base rates.

Texas PUC – Oncor Electric Delivery

Decided 8/29/08 Filed 5/28/08 Case 35718

Following settlement, approves advanced metering plan under which company to deploy advanced meters to all customers by end of 2012. Approves related cost recovery via annually trueed up surcharge, effective 1/1/09-12/31/19. Total revenue requirement over 11 years estimated approx. @\$1b.

New York PSC – Energy Efficiency Portfolio Standard Financial Incentives

Decided 8/22/08 Filed 6/23/08 Case 07-M-0548

Establishes policy governing application of incentives in electric utility efficiency programs per 6/23/08 order. Establishes potential statewide incentive levels relative to pre-determined estimate of overall program costs. Applies positive or negative monetary adjustments based on achieved MWh reductions for all electric utility-administered efficiency programs. Sets total reference figure of \$40m/yr. statewide; allocates max. potential incentive amount to levelized targets by service territory. Of \$40m, utilities to receive max. potential \$27m, w/remainder to NYSERDA. Allows for added incentive (\$5m) for EE programs undertaken in New York City to encourage peak MW reductions. (See 6/23/08 entry.)

Maryland PSC – Baltimore Gas & Electric

Decided 8/18/08 Filed 10/26/07 Case ML108061

Approves company-proposed residential low-income program but rejects five other EE programs as too costly for ratepayers, saying admin/overhead expenses too high relative to rebates/other items that directly reduce/incent reduced consumption. Also cites low market penetration, too much EE burden on residential ratepayers, and lack of info on ability of alternatives to offer comparable savings for less money. Says programs, which would cost \$174m thru 2015, would meet some commonly used cost-effectiveness tests, but real rate of return as measured in meaningful bill savings not shown for ratepayers, as required by recent law (EmPower Maryland Act). Requires filing by 9/29/08 (supplemental to statutory 9/1/08 filing) for meeting savings goals under act (15% by 2015). Approved program expands conservation home improvement to include full audits w/recommendations for EE improvements. Rejected were residential

Energy Star CFL/appliance, gas/electric HVAC, residential Energy Star new construction, residential retrofit, and small commercial incentive programs.

Massachusetts DPU – Dynamic Pricing

Decided 8/14/08 Filed 10/31/06 Case 06-101

Declines to open Dept. of Energy Resources-requested investigation into dynamic pricing at this time, citing plan to review commodity pricing options as part of broader mandate of 2008 law (Green Communities Act). Notes law requires review/approval of pilots that include TOU/hourly pricing for commodity service.

California PUC – Energy Efficiency Savings Goals

Decided 7/31/08 Filed 4/13/06 Case R.06-04-010

Adopts “total market gross” basis in setting interim EE goals for 2012-20, includes “free riders” in gross EE savings goals for 2009-11. Total market gross basis includes EE savings beyond utility programs: state building/ federal appliance standards and separate regulatory/legislative mandates. Free riders are ratepayers that take advantage of a utility EE service/incentive but would do so even in absence of program. Expects avoided capacity from goal attainment to be 4,500 MW from 2012-20, including avoided demand of 16,000 GWh of electricity/620m therms of gas.

California PUC – Pacific Gas and Electric

Decided 7/31/08 Filed 3/2/06 Case A.06-03-005

Adopts timetable for company to propose dynamic pricing (DP) rates for all C&I/ag customers by 2011, and to intro new DP options for residential in 2011. Specifically requires company to revise AMI plans to support default critical peak pricing (CPP) for large C&I customers (≥ 200 kW) in 2010 and optional real-time pricing (RTP) in 2011 vs. company-requested 2011 (CPP) and 2012 (RTP). Allows recording of plan modification costs in memorandum account for possible future recovery. Requires default CPP/TOU rate proposal for sm/med C&I (< 200 kW) for 2011 implementation. Requires optional RTP proposal for all customers for 2011. Requires default residential CPP rate proposal after any relevant statutory/regulatory directives. Requires related filings for cost recovery in general rate cases. Requires customer tool offerings to enable bill impact determinations. Adopts rate design guidance for DP, CPP, and RTP.

Massachusetts DPU – Decoupling

Decided 7/16/08 Filed 6/22/07 Case 07-50-A

Orders utilities to develop by end of 2012 base revenue adjustment mechanisms to fully decouple revenues from sale, for implementation via base rate proceedings. Requires annual companywide revenue reconciliations w/interim adjustments as needed, w/recovery thru distribution energy charges. Allows recovery of lost base revenue from incremental EE programs under 2008 law during three-year transition period. Allows existing rate plans/performance-based ratemaking to continue until end of terms. Says any changes in risk to be considered w/other factors affecting ROE as part of rate cases. Allows consideration of factors such as inflation, capital spending requirements in determining annual revenue recoverable via decoupling mechanism. Finds full decoupling removes disincentives to demand resource deployment better than partial decoupling or other shareholder incentives, e.g., rate-basing.

California PUC – Energy Efficiency Strategic Plan

Decided 7/14/08 Filed 6/2/08 Case R.08-07-011

Opens rulemaking to develop state EE strategic plan; consolidates w/joint application 6/2/08 by PG&E, SDG&E, SCE and SoCalGas proposing CA EE strategic plan (CEESP). States preference to develop PUC-approved plan vs. simply acting on utility application. Seeks comment on areas including incorporating CEESP aspects, market transformation strategies, coordinating EE w/demand response/solar programs, and coverage of low-income strategies. Decision expected Sep 2008.

Oklahoma CC – Oklahoma Gas and Electric

Decided 7/2/08 Filed 2/27/08 Case PUD 200800059

Following settlement, approves “Quick Start” DSM programs/partial recovery via company-proposed DSM rider of program costs, lost revenues and incentives: 25% of costs w/ measurable results and 15% of costs w/non-measurable results, such as EE education. OG&E estimates program costs of \$5.1m, incentives of \$1.9m and lost revenues of \$2m thru 12/31/09. Certain large customer classes may opt out.

Alabama PSC – Time-based Metering Standard

Decided 6/29/07 Filed 8/7/06 Case 30067

Deems PURPA time-based metering/communications standard, as revised by EPAct 2005, to be met. Cites approved rates/meter policies, including Alabama Power TOU rates/current advanced metering program for all customer classes.

Nevada PUC – Nevada Power

Decided 6/27/08 Filed 12/3/07 Case 07-12001

Approves recovery of previously authorized incentive return (500 basis points above authorized ROE) on DSM investments. Rejects staff proposal to deduct accumulated deferred income tax prior to calculating incentive; company had argued this would effectively reduce incentive from 5% to 3.25%. Approves rate base treatment of historical test year (ending 6/30/07) DSM costs w/staff/intervenor adjustments. Denies rate-basing of post-test year DSM costs, citing company failure to identify specific event/program affecting future DSM costs in measurable way; says cost estimates instead were based on integrated resource plan filings subject to change/on budgets. Allows three-year amortization of DSM program costs vs. existing two to align w/new general rate case cycle. Action comes w/approval of \$87.1m base rate increase.

New York PSC – Implementation of Energy Efficiency Portfolio Standard

Decided 6/23/08 Filed 5/16/07 Case 07-M-0548

Begins implementation of energy efficiency portfolio standard (EEPS) goal of reducing electricity usage by 15% statewide by 2015. Adopts specific interim three-year targets for MWh reduction and budgets. Approves specific “fast track” EE programs for immediate implementation by NY State Research and Development Authority (NYSERDA) and utilities. Directs investor-owned utilities to file EE plans/begin collection thru systems benefit charge (SBC) amounts to support EEPS thru 2011. Electric SBC is augmented to increase collections from \$175m-\$334m.

Adopts hybrid approach to meet goals set in EEPS designating both NYSEERDA/utilities as program administrators w/additional opportunities for independent administrators. Approves \$79.8m/yr. to NYSEERDA for expedited programs. Approves \$74.2m for expedited utility-administered electric programs and \$16.8m for utility-administered gas programs. Sets schedule for filing program plans beyond those approved in fast track. Initially allocates responsibility for EEPS targets to investor-owned utilities based on sales in service territories. Will consider whether certain territories have greater potential after time for assessment.

Gives NYSEERDA statewide goal w/direction to approach w/a balanced portfolio. Declines to establish long-term policy on utility incentives until parties have had more opportunity to comment. Declines to require on-bill financing but encourages parties to include on-bill financing as component of their plans. Agrees to resolve issues related to on-bill financing as part of next phase. Declines to acknowledge reduction in system losses and optimization of system operations as part of EEPS, but agrees to consider funding for system solutions thru individual rates cases.

Connecticut DPUC – Connecticut Light and Power, United Illuminating

Decided 6/19/08 Filed 10/1/07 Case 07-10-03

Approves, modifies company joint proposal for 2008 conservation/load mgt. (C&LM) programs/budgets, as follows: 1) For CL&P, total \$115.9m (\$88.7m for C&LM + \$27.2m for near-term peak demand reduction programs per 2005 Energy Independence Act (EIA)); 2) for UI, total \$20.8m (\$16.9m for C&LM + \$3.9m for EIA programs). CL&P had requested \$118m (revised); UI sought \$23.2m. Says companies did not deduct 2007 overspending from 2008 budgets as required. Says approved CL&P amount, which reflects restoration of \$11m from \$20m cut in May 2008 draft decision, was intended to avoid sudden program disruption.

Citing concern about continued overspending, directs companies to improve program management and stop borrowing from future collections. Directs CL&P to apply \$15m from 2009 C&LM revenues to 2007-08 under-recoveries, w/remainder of projected \$35m 2008 under-collection recovered via nonbypassable federally mandated congestion charges. Recommends elimination of certain marketing costs to help offset overspending. Directs companies to live w/in budgets (which are approved by Energy Conservation Management Board (ECMB) prior to DPUC review) in 2009 proposal; requires needs assessment for additional funding beyond existing C&LM charge (3 mill/kWh) in 2008.

Requires ECMB, which advises/assists utilities per statute, to report on need for demand response (DR), costs/benefits DR can provide, and role, if any, for utilities and ratepayer incentives; says it will reopen C&LM proceeding to examine these issues.

New Jersey BPU – Atlantic City Electric, Jersey Central Power & Light, Public Service Electric & Gas, Rockland Electric, et al.

Decided 6/13/08 Filed 4/8/08 Case EO08050326, et al.

Directs companies to propose demand response programs for all customer classes by 8/1/08 for three-year terms starting 6/1/09. Sets 300 MW statewide goal for first year, total 600 MW by end of 2011, allocated as follows: PSE&G, 165 MW (55%); JCP&L, 93 MW (31%); ACE, 36 MW (12%); RE, 6 MW (2%). Says cost-effectiveness to be primary criterion. Directs consideration of outside contractors for program services, e.g., installation services/operational support, based on competitive process. Also seeks proposals from other energy industry entities for parallel market-based approach.

Michigan PSC – Consumers Energy

Decided 6/10/08 Filed 3/30/07 Case U-15245

Defers action on company-proposed EE program until legislature acts on pending EE bills. Rejects intervenor-proposed amendment of general self-generation (GSG) tariff to remove capacity charge component from standby rates, saying GSG customers should not be insulated from marginal capacity costs when they elect to take such service. Approves 15 other staff changes to GSG tariff, about half of which not supported by company. Defers action on staff proposal for GSG communications options pending outcome of smart metering investigation (U-15183).

Colorado PUC – Xcel Energy

Decided 6/5/08 Filed 10/31/07 Case 07A-420E

Per 2007 law, approves/modifies company-proposed, \$738m-\$1.872b enhanced DSM program/related revisions to DSM cost adjustment (DSMCA) mechanism over 12 years. Specific cost recovery subject to approval of company biennial plans starting 2008. Approves incentive package as follows:

- Bonus, or upfront “disincentive offset,” of \$2m/year (after tax) for each year approved DSM plan implemented; if < 80% of yearly energy goal achieved, offset may be reduced.
- Performance incentives for surpassing “modest” goals; for ea. 1% of goal reached beyond 80%, company to earn additional 0.2% of net economic benefits, up to 10%@130% of goal attainment, after which company to earn additional 0.1% up to 12%@150% of goal attainment; adjusts incentives for 2009 to reflect least-cost planning commitments.
- Prospective program cost recovery; allows interest only on over-recoveries@customer deposit rate vs. company-proposed interest on over-/under-recovery@avg. weighted cost of capital. Says DSM costs treated as expenses, not cost of capital.

Incentives/cost recovery allowed via annually trued up DSMCA. Incentives + bonus capped at 20% of total annual DSM expenditures. Goals include DSM energy goal at company-proposed 150 GWh (0.53% of sales) for 2009, 220 GWh for 2010 (0.76% of sales), and 388 GWh for 2018 (1.15% of sales). Sets demand goals. Requires company commitment to low-income DSM in biennial plans. Declines to require third-party administration of DSM programs at this time, but affirms company practice of using third parties to deliver specific programs for operating efficiency/cost-effectiveness. Requires DSM market assessment update.

North Carolina UC – Duke Energy Carolinas

Decided 6/5/08 Filed 6/29/07 Case E-7, Sub 791, et al.

Approves construction certificates for two 620 MW, gas-fired, combined-cycle plants at Buck and Dan River generating facilities to provide intermediate capacity in 2010-12. Finds company cannot rely on DSM, EE, and renewables to eliminate or delay this capacity need.

Montana PSC – NorthWestern Energy

Decided 6/3/08 Filed 6/1/06 Case D2007.5.46, et al.

Finds DSM acquisition/other supply costs incurred 2005-06 and 2006-07 prudent/recoverable via existing electric supply cost tracker, w/certain exceptions including lost T&D revenue related to choice customer

loads. Approves company request to include \$27,388 additional lost revenue true-up in 2008-09 tracker due to results of independent evaluation of DSM programs, but recalculated to remove choice customer loads. Approves continued recovery of lost revenue resulting from DSM acquisition, citing lack of information on alternative decoupling, but requires continued talks w/advisors on decoupling. Prohibits continuation of lost revenue projections; allows future tracker inclusion of lost revenue based on actual program activity. Finds company budget process unreasonably withheld resources from DSM acquisition but does not disallow costs, citing lack of intervenor requests/uncertainty over effect on DSM performance.

Kansas CC – Energy Efficiency Framework

Decided 6/2/08 Filed 11/6/07 Case 08-GIMX-442-GIV

Establishes policy framework for review/evaluation of EE programs, including parameters for benefit/cost analysis and standards, dynamic pricing, program evaluation, measurement, and verification (EM&V) standards, program design guidelines, and education programs. Encourages Quick Start programs. Says EE programs must be available to all customer classes, including low-income/rental, and include EM&V plan. Will continue docket to provide for staff-led collaborative for development of EM&V protocol and details of benefit-cost analysis. Will open separate investigation to address fuel switching.

Idaho PUC – Idaho Power

Decided 5/30/08 Filed 3/14/08 Case IPC-E-08-03

Approves EE rider increase from 1.5% of base revenue to 2.5% for all customers to increase DSM funding from \$9m to \$16m/yr. Rejects company request to use rider funds for small renewable projects such as PV, saying more project/cost info needed. Approves elimination of rider caps for residential/irrigation customers.

Idaho PUC – Idaho Power

Decided 5/30/08 Filed 3/14/08 Case IPC-E-08-04

Approves overall, company-requested \$2.4m credit balance in first year of three-year fixed cost adjustment (FCA) pilot, to be distributed equally to residential/small commercial classes. Agrees w/staff that company assumptions/method of assigning fixed costs, which resulted in residential over-collection and small commercial under-collection, not valid because not yet set in general rate case per FCA formula and underlying cost of service study not approved. Company to work w/staff on allocation method. Requires customer counts/weather-normalized energy in mo. FCA reports to enable better tracking.

Oklahoma CC – Public Service Co. of Oklahoma

Decided 5/5/08 Filed 12/12/07 Case PUD 200700449

Following settlement, approves “Quick Start” DSM programs/partial recovery via company-proposed DSM rider of program costs, lost revenues and incentives: 25% of costs w/measurable results and 15% of costs w/non-measurable results. Approves separate one-year rider permitting a specified customer to participate in Southwest Power Pool surplus power market. PSO estimates first-year program costs of \$4.3m, shared savings of \$780k and lost revenues of \$478k. Certain large customer classes may opt out. Bases incentives to homebuilders on EPA Energy Star guidelines.

Oregon PUC – Portland General Electric

Decided 5/5/08 Filed Case UE 189

Following settlement, approves \$132.2m AMI deployment over 2.5 years, including installation of 850,000 smart meters. Approves 0.8 percent rate increase to recover, via company-proposed tariff, net \$12.9m/yr, reflecting capital costs (\$12.5m), accelerated depreciation of old meters (\$4.5m), and O&M savings (\$4.1m). Says cost recovery incorporates six-mo. lag, w/rate base adjusted mo., enabling revenue requirement levelization over deployment. Rate impact to be mitigated by previously announced income tax refund to customers. Approves inclusion of AMI in rate base thru 2010. Meters to immediately “close to plant” when received by PGE vs. charged to CWIP/closed to plant in service upon project completion. Finds premature early retirement of old meters is not imprudent. Approves stipulated conditions, some of which require separate approval, e.g., filing of critical peak pricing tariff. Notes customer/system benefits, e.g., demand response, will require further investment. Company estimates operational savings @\$18.2m in first year.

Idaho PUC – PacifiCorp

Decided 4/30/08 Filed 2/14/08 Case PAC-E-08-01

Approves increase in EE rider from 1.5% of retail revenue to 3.72% for all customer classes to fund projected 2008-09 activities, including addition of new commercial/industrial program, enhancements/changes to existing business/residential programs to improve performance, and continuation of other programs w/o change. Requires more detailed cost-effectiveness info for prudence review in next general rate case.

Louisiana PSC – Southwestern Electric Power

Decided 4/29/08 Filed 7/25/06 Case U-29702

Approves construction of 440 MW coal-fired Turk generating plant in Hempstead Co., AR, w/conditions, including requirement to file w/in six mos. a study on potential for implementing cost-effective EE/load management programs for La. customers.

Montana PSC – Montana-Dakota Utilities

Decided 4/22/08 Filed 7/12/07 Case D2007.7.79

Declines to adopt PURPA smart metering std., as revised by EAct 2005, saying it favors incremental vs. federal “flash cut” approach. Requires company to study time-differentiated rates prior to COS/RD filing and report on status of automated meter reading program. Requires filing of new cost of service/rate design (COS/RD) in one year, at which time it will consider use of inverted block rates, smart metering, and decoupling. Action comes w/approval of settlement providing for 11.5% (\$4.1m) base rate increase.

New Mexico PRC – Southwestern Public Service

Decided 4/17/08 Filed 9/24/07 Case 07-00376-UT

Approves company-proposed 2008 EE/load mgt. plan calling for eight “direct impact” programs totaling \$1.8m for residential, low-income, business and large customer classes. Approves related program cost recovery via proposed new mo. rider w/annual true-up, to be assessed as percent of bill, w/increases capped at lower of 1.5% or \$75,000/yr, per statute. Rejects company-proposed shared savings mechanism under

which 85/15 percent of net benefits shared by ratepayers/shareholders. Rejects hearing examiner-proposed rate-basing of investment to recover disincentives. Finds company has limited fixed cost disincentive but says amount not yet quantified. Disagrees w/staff that retail load growth offsets disincentive; says company entitled to benefit of sales growth but also bears risk of decline. Finds case not made for lost earnings disincentive recovery, citing EE investment benefits of lower capital needs thru freed-up capital or reduced borrowing needs.

Vermont PSB – Green Mountain Power

Decided 4/8/08 Filed Case 7213

Approves company request to allocate up to \$50,000/yr from previously approved pilot, which provides 10% rate discount to low-income customers, to separate company program, Power Partners, which helps low-income customers avoid disconnection. Says allocation benefits same customer class in different manner; cites support of staff/AARP. Says pilot funded by \$1m over three years from GMP efficiency fund, but company has spent only \$129,000 due to low participation.

Maryland PSC – Delmarva Power

Decided 3/19/08 Filed 3/4/08 Case ML109694

Approves one-time credit for amounts billed 10/3/07-1/16/08 for shipments of two CFL bulbs to 220,000 ratepayers. Company dropped 96 cents/mo. surcharge after customers complained they were not notified they would be charged. (See 9/26/07 entry.)

Vermont PSB – Green Mountain Power

Decided 3/14/08 Filed 11/15/07 Case 7412

Approves first year (2008) of five-year company plan for investing total \$7m from existing efficiency fund in new residential/business energy services programs. Cites concern w/using ratepayer funds for non-electric efficiency measures, e.g., proposed furnace replacement, but says company showed some electric savings still achieved and only one year at issue. Cites concern w/insufficient residential savings, but finds all ratepayers benefit despite incomplete class parity. Cites concern w/potential overlap w/previously approved EE third-party administrator (TPA), but says GMP programs supplement vs. supplant TPA programs.

California PUC – Southern California Edison

Decided 3/13/08 Filed 10/17/07 Case A.07-10-013

Approves four of eight third-party demand response (DR) resource purchase agreements, finding they meet benefit/cost ratio of 1.0 on portfolio basis. Two approved agreements are w/Ancillary Services Coalition (ASC), one w/North American Power Partners and one w/EnergyConnect. The four contracts total 190 MW; SCE may recover costs delineated confidentially plus related admin costs. Cites “unique structure” of ASC contracts that awards greater incentives to participants for performance vs. capacity reservation. Signals future move away from portfolio approach toward individual performance structures.

Michigan PSC – Smart Grid Initiative

Decided 3/11/08 Filed 4/24/07 Case U-15278

Expands ongoing smart grid collaborative to include pilot to integrate plug-in hybrid electric vehicles (PHEVs) into electric grid. Directs staff to ensure confidentiality of proprietary information and report annually. Cites opportunity via PHEVs for utilities to expand sales w/o contributing to system peak while reducing greenhouse gas emissions from utility/transportation sectors, and potential jobs/economic growth in state. Says PHEV success depends on smart grid technology deployment.

Massachusetts DPU – Fitchburg Gas & Electric

Decided 2/29/08 Filed 8/17/07 Case 07-71

Allows \$4.5m of AMI investment in rate base vs. requested \$5.2m, finding allowed portion was placed in service/used and useful in 2006 test year. Cites DPU accounting rule for incomplete projects allowing cost of part in operation/ready for service to be treated as plant in service. Requires halt to accruing AFUDC as of date plant went in service. Excludes \$700k reflecting post-test year expenditures, saying not significant increase to year-end rate base. Requires related depreciation/property tax adjustments. Requires report w/in six mos. on plans for demand response/conservation programs under AMI strategy; ancillary AMI features, e.g., disconnection; future cost/benefit savings for ea. system capability; and master timetable for future application development.

California PUC – Pacific Gas and Electric

Decided 2/28/08 Filed 7/13/07 Resolution E-4127

Approves company-proposed cafeteria style menu (CSM) demand response (DR) program providing customer options in several categories: 1) time of day events called, 2) event duration, 3) notification, 4) max. # of consecutive event days, 5) max. # of events/summer, and 6) amt. of load reduction/event. Requires option allowing customers to change committed load reduction on mo.-to-mo. basis; development of IT system for CSM, report monthly; process evaluation plan; and marketing/outreach evaluation. Company estimates 42 MW of additional DR by end of summer 2008; will transfer \$4m from approved funds for other DR programs for 2007-08.

New Mexico Legislature – Energy Efficiency Law

Enacted 2/27/08 Filed Law HB 305

Requires utilities to achieve EE gains = 5 percent of total sales in 2005, increasing to 10 percent by 2020, thru appliance rebates, home weatherization, CFL, or other programs. Requires regulators to identify/remove disincentives and barriers, consider decoupling, and allow utilities opportunity to earn profit on EE programs. Cost recovery is allowed via base rates or special surcharge.

Massachusetts DPU – Energy Efficiency/Assistance Programs

Decided 2/12/08 Filed 2/12/08 Case 08-4

Opens investigation into expanding low-income consumer protections/assistance, including better integration of assistance/EE programs. Seeks comments on ways to increase enrollment/participation in low-income EE

programs, using EE programs to help reduce arrearages/prevent service terminations, and opportunities to better integrate EE/weatherization programs w/other benefits.

Connecticut DPUC – Connecticut Light and Power

Decided 2/6/08 Filed 2/8/07 Case 05-10-03RE03

On rehearing of 12/21/06 decision, rescinds decoupling directive to increase fixed cost recovery via customer charges, saying it will address issue in appropriate rate case. Rescinds directives on “arbitrary” TOU price differentials, agreeing they should be cost-based/addressed in ongoing rate design proceeding (Case 03-07-02RE10). Affirms two-part TOU rates for large C&I.

Illinois CC – Ameren

Decided 2/6/08 Filed 11/5/07 Case 07-0539

Approves energy efficiency/demand response (EE/DR) programs and cost recovery via new, annually trued up adjustment mechanism. Directs three operating subs to impose separate such mechanisms for residential, small commercial/industrial (C&I) and large C&I customers vs. company-proposed single charge applied uniformly to all classes; cites consistency w/traditional ratemaking principles. Low-income program costs to be equally shared by all classes. Says programs implement new state law requiring annual energy savings of 0.2% in year ending 5/31/09 and 0.2% more/yr. to reach 2% cap by 2015. Notes total resource cost test in Illinois includes value of electricity savings but excludes natural gas savings. Approved EE portfolio includes residential lighting, home diagnostics, appliance recycling, incentives for C&I customers and street lighting. DR portfolio includes remote control for residential A/C/certain commercial equipment. Requires company to establish stakeholder process to review progress toward goals/strengthening portfolio.

Illinois CC – Commonwealth Edison

Decided 2/6/08 Filed 11/5/07 Case 07-0540

Approves energy efficiency/demand response (EE/DR) programs and cost recovery via new, annually trued up adjustment mechanism (Rider EDA). Directs company to impose separate such mechanisms for residential, small commercial/industrial (C&I), and large C&I customers vs. company-proposed single charge applied uniformly to all classes. Low-income program costs to be equally shared by all classes. Allows utility to monitor various EE/DR measures and reallocate incentives after applying total resource cost test to identify higher-return projects. Says programs implement new state law requiring annual energy savings of 0.2% in year ending 5/31/09 and 0.2% more/yr. to reach 2% cap by 2015. Approved EE portfolio includes residential lighting, home diagnostics, appliance recycling, incentives for C&I customers and street lighting. DR portfolio includes remote control of residential A/C and of certain commercial equipment. Requires company to establish stakeholder process to review progress toward goals/strengthening portfolio.

Connecticut DPUC – Connecticut Light and Power

Decided 1/31/08 Filed 8/14/07 Case 03-07-02RE10

Approves rate design/tariff changes per 2007 EE law, including: 1) finds existing two-period TOU rates in compliance; 2) approves company-proposed voluntary variable peak pricing for all customers; requires installation of least-cost meter to accommodate; 3) sets procedure to implement seasonal rates in Jun-Sep and directs company to embed 2 cents/kWh seasonal price differential in generation service charge (GSC) rates; 4) administratively determines cost-based GSC TOU differentials, which can be adjusted in rate cases or

when GSC rates are set; 5) requires company to develop energy-based TOU charges for transmission and nonbypassable federally mandated congestion charge rates; and 6) finalizes TOU tariffs for specified rates.

Connecticut DPUC – Connecticut Light and Power, United Illuminating

Decided 1/23/08 Filed 8/2 & 15/07 Case 07-08-01

Prohibits CL&P from forecasting lost energy revenues related to implementation of state Energy Independence Act, which offers incentives for businesses to produce/conserves energy. Disagrees w/CL&P method of forecasting lost revenues resulting from lower energy sales, then reversing them if earnings cap exceeded. Says lost revenue recovery allowed only if CL&P underearned for period, and lost revenues not incurred until actual earnings known. Notes this is first time CL&P requested lost distribution revenue recovery. Action comes w/approval of UI- and CL&P-proposed adjustments in semiannual reconciliations of generation/transmission-related charges for Jan-Jun 2007.

Wisconsin PSC – Northern States Power

Decided 1/8/08 Filed 6/1/07 Case 4220-UR-115

Approves transfer of certain DSM program costs from electric to natural gas operations. Requires company to work with ratepayer advocate/PSC staff to identify automatic meter reading options and develop implementation plan. Action comes w/approval of 8.1% (\$39.4m) rate increase.

Florida PSC – Florida Power & Light

Decided 1/7/08 Filed 9/17/07 Case 070602-EI

Following multiple settlements, approves company-proposed nuclear uprates of Turkey Point 3&4 and St. Lucie 1&2, after finding no renewable energy sources/technologies or conservation measures can mitigate capacity need. Cites need for system reliability/integrity, baseload generation to meet increasing demand/load growth, enhanced fuel diversity, and cost-effectiveness. Expansion to total 208 MW @\$750m for Turkey Point and 206 MW @\$651m for St. Lucie, w/completion set for 2012.

2007

California PUC – Pacific Gas and Electric

Decided 12/20/07 Filed 6/1/05 Case A.05-06-006, et al.

Approves definition of hard-to-reach customer targeted by previously approved business energy coalition (BEC) demand response (DR) program as one who: 1) has not participated in DR program and b) has rejected enrollment in DR program other than BEC. (See 5/3/07 entry.)

California PUC – Pacific Gas and Electric, San Diego Gas & Electric, Southern California Edison, et al.

Decided 12/20/07 Filed 1/16/07 Case A.07-01-024, et al.

Approves one-year pilots w/in each utility’s existing EE program, as of 7/1/08, thru which they must enter partnerships w/water agencies to undertake water conservation programs/measure results. Requires concurrent utility funding of studies of relationship between water savings/energy use reductions. Approves cumulative \$6m funding using unspent EE funds from prior years.

California PUC – Pacific Gas and Electric, San Diego Gas & Electric, Southern California Edison, et al.

Decided 12/20/07 Filed 1/25/07 Case R.07-01-042, et al.

Requires utilities to include low-income energy efficiency (LIEE) plan in previously required statewide long-term EE plan by 2/1/08. Requires applications for related budget authority by 5/15/08 for 2009-11 program budget cycle; says three-year budget must achieve approx. 25% of new programmatic initiative. Per new initiative, requires increased LIEE availability to eligible customers; utilities must offer participants all cost-effective measures in their residences by 2020. Also requires treatment of LIEE as energy resource as way to help low-income customers lower bills/improve quality of life. Says utilities must better integrate LIEE/EE programs to eventually become single program; notes LIEE programs funded by non-participating ratepayers thru public purpose program surcharge. Defers for future consideration SCE application for \$22m to distribute compact fluorescent lamps. (See 10/18/07 entry.)

California PUC – Pacific Gas and Electric, San Diego Gas & Electric, Southern California Edison

Decided 12/20/07 Filed 2/16/06 Case R.06-02-013

Modifies, approves long-term procurement plans (LTPPs) for 2007-16, but finds plans relied too much on conventional generation sources w/o sufficient analysis. Says plans should have filled net short positions w/low greenhouse gas (GHG)-emitting resources per statutory/regulatory directives. Requires future requests for offers (RFOs) to reflect statutory preferred resource “loading order” as follows: 1) energy efficiency, 2) demand response, 3) renewables, 4) distributed generation, and 5) clean fossil fuel. Requires RFOs to reflect efforts to reduce GHG levels and show how any fossil generation application fits into GHG reduction strategy. Says it will provide more explicit directions in next LTPP proceedings on steps for reducing carbon emissions, achieving state’s 33% renewables goal, and conforming to loading order.

Maine PUC – Bangor Hydro-Electric

Decided 12/20/07 Filed 1/16/07 Case 2006-661

Following settlement, approves 2% (\$1.1m) distribution rate increase as of 1/1/08 and 24.7% stranded cost rate decrease as of 3/1/08. Main driver of distribution increase was slow sales growth due in part to conservation programs. Company agrees to file w/in 60 days plan for purchasing/installing TOU meters by end of 2008 for med./lg. commercial classes, and rate design proposal that time differentiates distribution rate demand charge and, after any phase-in, recovers no more than 25% of those classes' distribution revenue requirements in off-peak charges.

Connecticut DPUC – Connecticut Light and Power

Decided 12/19/07 Filed 3/30/07 Case 05-10-03RE01

Per 2007 EE state law, sets metering guidelines for customers who choose complex real-time rates. Requires test of 10,000 advanced meters in 2008-09, including rate pilot to determine customer acceptance of/response to alternative real-time rates. Pending evaluation of results, delays previously required implementation of mandatory residential TOU rates from 2009 until at least 2010.

New York PSC – Consolidated Edison Co. of New York, Orange and Rockland Utilities

Decided 12/19/07 Filed 3/28/07 Case 94-E-0952, et al.

Declines to authorize full-scale AMI implementation at this time. Allows pre-deployment demonstration projects for which companies must file supplemental plans specifying timelines, milestones, cost estimates, decision-making criteria, and other factors. Says companies must eventually file full-scale AMI proposals. Says cost-effective, systemwide implementation relies on potential societal benefits, whose forecasted values are highly uncertain, and on rapidly developing technology, which has yet to be proven feasible.

Georgia PSC – Georgia Power

Decided 12/18/07 Filed 6/29/07 Case 25060-U

Following settlement, approves first-time, one-year, residential critical peak pricing pilot as of Apr 2008. Pilot limited to first 1,000 customers w/automated metering infrastructure; company may choose to increase participation level. Customers to receive credits in exchange for usage reduction in specified periods of extreme supply/demand conditions. Maximum hours/year = 50; energy credit rate = \$0.35/kWh. PSC notes industrial/large commercial customers have been offered real-time pricing since mid-80s.

Colorado PSC – Smart Metering Standard

Decided 12/6/07 Filed 3/29/06 Case 061-169E

Defers consideration of PURPA smart metering standard, as revised by EAct 2005, to allow for review of results of residential price response pilot.

Arkansas PSC – Southwestern Electric Power

Decided 11/21/07 Filed 12/8/06 Case 06-154-U

Conditionally approves 600 MW, coal-fired, Turk plant in Hempstead Co. as only realistic option to reliably/affordably meet previously demonstrated baseload capacity need in 2011 while diversifying generation portfolio. Says EE/conservation/demand response measures can only account for small portion of need.

Kansas CC – Kansas City Power & Light

Decided 11/20/07 Filed 3/1/07 Case 07-KCPE-905-RTS

Following settlement, approves EE rider to recover on current basis costs related to approved EE programs, including internal labor costs, incurred after 7/1/06. Company to file riders annually by 3/31 to recover costs incurred during prior year for recovery over following Jul-Jun period. Company initially sought rate-basing of EE costs and may file for new methodology to comply w/any future regulatory/legislative actions.

Kansas CC – Energy Efficiency Framework

Decided 11/6/07 Filed 10/10/07 Cases 08-GIMX-441-GIV, 08-GIMX-442-GIV

In two separate orders, opens investigations into: 1) cost recovery methods for EE programs, including decoupling; and 2) methods of evaluating EE programs and their costs/benefits. (See 10/10/07 entry.)

California PUC – Pacific Gas and Electric, San Diego Gas & Electric, Southern California Edison, et al.

Decided 10/18/07 Filed 4/13/06 Case R.06-04-010

In Phase 2 decision, institutes interim long-term EE strategy under which utilities directed to jointly prepare comprehensive, statewide plan in addition to individual applications for 2009-11 EE program portfolios, due 5/15/08. Reiterates goal of using ratepayer-funded EE programs to transform market/incorporate efficiency gains into codes/standards; affirms previously adopted savings goals for 2009-11. Adopts three “programmatically initiatives” (goals): 1) all new residential construction to be zero net energy by 2020, 2) all new commercial construction to be zero net energy by 2030, and 3) HVAC industry to be reshaped to ensure optimal equipment performance. Affirms utility key role as administrator of ratepayer-funded programs; establishes new collaborative processes w/govt. entities and stakeholders. Allows utilities to commit funds from next program cycle to fund longer-term programs w/no savings in current cycle to ensure funding of projects w/long lead times. Phase 1 addressed shareholder risk/reward incentive mechanism. (See 9/20/07 entry in this section.)

California PUC – San Diego Gas & Electric

Decided 10/18/07 Filed 5/11/07 Case E-4103

Denies company request to double max. deliveries, to 50 MW, by amending 2005 demand reduction/distributed resource agreement w/EnerNOC, which acquires rights to control/operate end-use customer load/generation to provide capacity/energy. Rejects utility’s notification of amendment using advice letter vs. procurement proceeding. Adopts staff finding that program no longer has characteristics of demand response (DR) resource as originally approved but now operates as supply-side resource program, because load reduction DR resources do not participate, only those w/backup generation.

Florida PSC – Tampa Electric

Decided 10/15/07 Filed 6/15/07 Case 070375-EG

Approves 11 new DSM programs (four residential, seven commercial) and nine program enhancements (four residential, five commercial) proposed by company following annual conservation review. Allows company to seek related cost recovery via annual energy conservation cost recovery clause. Approval based on monitorability, measurability, and finding of cost-effectiveness under rate impact measure, total resource cost, and participants tests. Approves 12th company-proposed new commercial demand response program but for limited four-year period. Allows continuation of residential load control program (Prime Time) only for current customers in absence of current cost-effectiveness analysis.

Oklahoma CC – Oklahoma Gas and Electric

Decided 10/11/07 Filed 1/17/07 Case PUD 200700012

Approves company-proposed DSM/EE programs, w/cost recovery subject to prudence review. Directs company to meet w/customers w/in 60 days to explore additional programs to defer need for additional capacity. Action comes w/denial of company-requested pre-approval of proposed 950 MW, coal-fired Red Rock generating plant and related cost recovery rider. Finds company needs 300 MW of additional baseload capacity by 2012 but failed to sufficiently consider reasonable alternatives. OGE/co-developer PS Oklahoma subsequently terminate construction agreement.

Kansas CC – Energy Efficiency Framework

Decided 10/10/07 Filed 9/11/06 Case 07-GIMX-247-GIV

Finds it has wide discretion to consider/apply methodologies for approving EE programs, including different cost-benefit tests and consideration of external environmental costs/benefits; broad authority to provide incentives to promote EE/conservation in addition to increases in rates of return; and to allow decoupling. Finds no need to create efficiency program administrator, but encourages munis/co-ops to voluntarily work together create such administrators. Says it will open two concurrent EE investigations to develop policy framework for: 1) cost/benefit analysis, to be completed in six mos., and 2) cost recovery methods, to be completed in nine mos. Finds it has broad authority to determine cost recovery/evaluation methods and to provide incentives.

Oklahoma CC – Public Service Co. of Oklahoma

Decided 10/9/07 Filed 9/29/06 Case PUD 200600285

Declines to adopt company-proposed formula-based rate (FBR) providing for: 1) monitoring earnings and adjusting rates annually (decoupling) based on changes in company investment, expenses and revenues, 2) earnings sharing, and 3) CWIP in rate base. Says proposed FBR too broad to implement now in light of numerous concerns raised by parties, which generally said normal rate process is adequately efficient and proposed FBR sharing mechanism is unfair. Finds, however, that FBR mechanisms have merit, esp. for large construction projects, and notes willingness to re-examine issue in future on project-by-project basis.

Orders company to seek approval w/in 60 days of comprehensive/cost-effective demand programs to begin in 2008. Requires inclusion of business plan and “robust” budget. Says programs must include: 1) education/information for various stakeholders, 2) low-income EE assistance, 3) incentives for

installation/use of high efficiency appliances/equipment, and 4) load interruption mechanisms or tariffs. Also approves company-proposed time-of-day (TOD) pilots, one for residential and two for commercial, each allowing 100 class members per program to be billed on “best rate” (i.e., lower of standard tariff or TOD rate). Approves two new company-proposed industrial interruptible tariffs and changes to existing energy price curtailable service rider that lower participation threshold and decrease duration of curtailment periods.

Maryland PSC – Allegheny Power, Baltimore Gas and Electric, Delmarva Power & Light, Pepco

Decided 9/28/07 Filed 6/8/07 Case 9111

Establishes parameters of AMI/DSM programs and directs utility participants in previously established collaborative to file comprehensive EE, conservation and demand reduction plans designed to achieve specified, “aggressive” usage reduction goals by 2015. Adopts cost recovery recommendations in collaborative’s 7/6/07 report as follows: 1) five-year expense amortization, 2) capital investments amortized over useful life, 3) program costs allocated to rate classes based on participation eligibility and derived program benefits, 4) annual carrying costs of unrecovered expenditures = approved company rate of return, 5) cost recovery via distribution rate surcharge, and 6) opportunity for plans to propose incentive mechanisms. Directs companies to use four cost-effectiveness tests: societal, all ratepayers, rate impact measure, and participant. Sets minimum standards for AMI programs. (See 6/8/07 entry.)

Arkansas PSC – Southwestern Electric Power

Decided 9/27/07 Filed 7/2/07 Case 07-082-TF

Approves four company-proposed initial EE programs developed as part of statewide Quick Start EE/conservation effort, and incremental cost recovery via staff-proposed/company-supported energy efficiency cost rate rider (EECR). Staff version makes terms/conditions/procedures consistent for all utilities in state. Company estimates costs @approx. \$1.8m for 10/1/07-12/31/09 for six programs, including two additional weatherization/education programs jointly proposed w/other utilities in separate dockets (Cases 07-079-TF, 07-083-TF). Company may propose lost revenue recovery mechanism in future proceeding.

Maryland PSC – Delmarva Power

Decided 9/26/07 Filed 9/14/07 Case ML107498

Approves two fast-track residential EE programs totaling \$2.5m for one year to achieve near-term benefits. Approves surcharge recovery as of 10/3/08 to fund CFL bulb distribution/energy awareness program. Requires mo. progress reports. (See 3/19/08 entry in this section.)

Connecticut DPUC – Connecticut Light and Power, United Illuminating

Decided 9/25/07 Filed 3/13/07 Case 05-07-17RE01

Terminates program for monetary grants for capital costs to emergency generator distributed generation (DG) units as of 7/25/07. Finds no benefits for energy/forward reserves from emergency generators participating only in ISO demand response (DR) program, and insufficient benefits or reduction of federally mandated congestion charges to justify minimum \$200/kW award. Continues baseload DG program approved 3/27/06 w/modifications as follows: 1) require 15-year security in third-party applications, 2) include application section on type of interconnection, 3) prohibit grants to projects > customer’s load, 4) require electric distribution companies (EDCs) to verify nameplate capacity/amount enrolled in ISO DR program, 5) make emergency generators 25 yrs old and baseload generators \geq 35 yrs eligible for grants, 6)

exclude EDCs from \$25/kW/yr awards for enrolling DG projects in ISO load response programs, and 7) make property owners/tenants eligible for grants. (See 3/27/06 entry.)

California PUC – Energy Efficiency Incentive Regulation

Decided 9/20/07 Filed 4/13/06 Case R.06-04-010

Adopts EE risk/reward incentive for state's four shareholder-owned electric/gas utilities designed around three metrics: 1) dollar valuation of PUC-established kWh, 2) kW, and 3) therm savings goals. Says achieving between 85%-100% of PUC goals during three-year program cycle to result in shareholder allocation of 9% of verified net savings. Achieving $\geq 100\%$ goals returns 12% to shareholders up to aggregate cap for four utilities of \$450m at 125% performance level. If performance $\leq 65\%$, penalties can be assessed @ 5¢/kWh, \$25/kW, and 45¢/therm. Performance level where net benefits are negative (estimated @ 40%-50%) requires utilities to "guarantee" \$-for-\$ payback to ratepayers of EE investment. Caps penalties at aggregate \$450m. Performance between 65%- 85% reflects deadband in which there is no reward/penalty.

Approves collection of authorized earnings under mechanism thru electric distribution/gas transportation rates and allocation to customer classes based on marginal cost allocation factors. Says while incentive payments may cause short-term increases in customer rates/bills, it expects program performance to translate quickly into lower revenue requirements/lower bills for customers. Says short-term avg. annual rate impacts for 2006-08 cycle could be 0.41% to 0.69% at 100% performance level; residential mo. bill increases could be \$0.09-\$0.58. Utilities can make two interim claims on earnings during each three-year cycle, reflecting "progress payments" toward total expected earnings, and final true-up claim. Says it will hold back 30% of each interim claim to provide "margin for error," pending final verification of program performance.

New York PSC – Consolidated Edison Co. of New York

Decided 9/20/07 Filed 5/1/07 Case 04-E-0572, et al.

Rejects request to recover incremental DSM program costs/lost revenue related to expanded program implementation before next rate plan expected Apr 2008. Says while it has emphasized EE, company's pending rate case and PSC's pending EE portfolio docket are better forums for request.

Arkansas PSC – Entergy Arkansas

Decided 9/19/07 Filed 7/2/07 Case 07-085-TF

Approves eight company-proposed EE programs developed as part of statewide Quick Start EE/conservation effort, and incremental cost recovery via staff-proposed/company-supported EE cost rate rider (EECR), as of 10/1/07. EECR terms/conditions to apply to seven electric/gas utilities in state on interim basis, pending comprehensive plan filings and further program/tariff review in 2009. Company estimates cost @ \$11.9m thru 2009 for 10 programs, including two additional weatherization/education programs jointly proposed w/other utilities in separate dockets (Cases 07-079-TF, 07-083-TF). PSC says it will allow individual utility cost allocation schemes due to immaterial effect of interim programs on overall utility rate levels. Rejects for now large customer requests for opt-out provisions and cost segregation by class.

Maryland PSC – Delmarva Power & Light, Pepco

Decided 9/19/07 Filed 3/21/07 Case 9111

Approves implementation of residential compact fluorescent light programs/related residential energy awareness campaign as cost-effective and enabling energy/money savings starting Oct 2007. Approves surcharge recovery of costs of CFL programs and portions of awareness campaign over five years, w/interest on unrecovered amounts set at each company's rate of return. Surcharge to be set annually based on budgeted and actual expenditures thru annual filings subject to PSC approval. Requires quarterly reports. (See 9/28/07, 6/8/07 entries.)

Florida PSC – Tampa Electric

Decided 9/17/07 Filed 1/17/07 Case 070056-EG

Approves permanent residential price-responsive load mgt. program w/multitiered rate structure and price signals to alert participants to reduce load/consumption in high cost periods. Company to install two-way communication equipment/smart thermostats by which participants control operation of selected appliances. Customers determine usage based on energy prices at various times of day. Program was piloted 2.5 years.

Minnesota PUC – Xcel Energy

Decided 9/14/07 Filed 12/4/06 Case E-002/CN-06-154

Grants certificates of need for three 115 kV transmission lines in southwestern MN based on findings that include: 1) need cannot be met more cost-effectively thru energy conservation/load mgt., and 2) lines will increase opportunities for installing distributed generation. Project to achieve up to 825 MW of generation outlet transmission capacity as interim step until previously approved, higher-voltage lines can be developed.

Florida PSC – Florida Power & Light

Decided 9/4/07 Filed 6/15/07 Case 070376-EG

Approves two-year residential thermostat load control pilot project and related cost recovery via energy conservation cost recovery clause. Up to 400 participants to use company-provided programmable thermostats to reduce at their option consumption via central AC/heating appliances. Says program removes barrier to those unwilling to yield control over such appliances to utility, as in existing load mgt. programs. Cites ability to monitor/produce measurable results; estimated total program cost is \$728,000.

Illinois Legislature – Electric Rate Relief Law

Decided 8/28/07 Law SB 1592

Establishes standards for energy procurement from renewable resource facilities and energy savings from EE/demand-response measures. Standards can be reduced any year to limit annual estimated avg. net increase due to costs of these resources. Generally limits cumulative rate increases for compliance w/RPS to 0.5%/yr. for first four years and 2.015% thereafter; similar limits apply to energy savings standard. Also requires IL CC to report to General Assembly by 6/30/11 on whether rate increase caps unduly constrain procurement of renewable resources or EE/demand-response measures.

Arkansas PSC – Time-based Metering Standard

Decided 8/22/07 Filed 1/12/06 Case 06-004-R

Declines to adopt PURPA time-based metering/communications standard, as revised by EPAAct 2005 as not in public interest. Says fostering demand response (DR) technologies/practices best met via utility-specific rate proceedings. Cites previous actions, e.g., issuance of guidelines on resource planning calling for comparable consideration of DR approaches w/supply resources (Case 06-028-R).

North Carolina Legislature – Energy Law

Enacted 8/20/07 Law SB 3

Provides that electric power suppliers can recover prudent/incremental costs incurred to comply w/new state renewables/energy efficiency portfolio standard (REPS) or any similar federal mandate and expenditures on related research up to \$1m/yr. Costs to comply w/federal mandate are fully recoverable, while costs to comply w/state REPS and funded research are capped at following per-account annual charges: 1) residential: \$10 in 2008-11, \$12 in 2012-14, and \$34 in 2015/thereafter; 2) commercial: \$50 in 2008-11 and \$150 in 2012/thereafter; and 3) industrial: \$500 in 2008-11 and \$1,000 in 2012/thereafter. Requires NCUC to adopt rules to establish procedure allowing for timely recovery of annual per-account charges. Also requires NCUC to adopt rules governing: REPS program compliance monitoring/enforcement, possible program modifications or delay, renewable facility interconnection standards, possible net metering for smaller renewable facilities, and procedures to track/account for RECs. NCUC also must analyze rate structures, policies, and measures—including decoupling—that would promote renewables/demand reduction for possible implementation in state.

Requires utilities to implement least-cost planning and seek approval for any cost-effective DSM/EE programs that require incentives, and authorizes NCUC to approve an annual rider to recover all reasonable/prudent implementation costs. NCUC must ensure program costs assigned only to customer classes that directly benefit. Industrial/large commercial customers can opt out of utility DSM/EE programs and costs upon showing they have taken/will take alternative measures to meet quantifiable goals.

Indiana URC – Vectren Energy Delivery

Decided 8/15/07 Filed 9/1/06 Case 43111

Following settlement, approves DSM adjustment mechanism to track changes from base rate amount of direct load control billing credits. Action comes w/approval of \$67.3m (16.3%) rate increase.

Hawaii PUC – Hawaiian Electric Light Co.

Decided 8/8/07 Filed 8/8/06 Case 05-0315

Declines to adopt at this time PURPA time-based metering/communications standard, as revised by EPAAct 2005. Says it agrees w/company/consumer advocate that current/proposed TOU rates generally consistent w/PURPA, and adoption of one-size-fits-all may have unintended consequences.

Indiana URC – Time-based Metering Standard

Decided 8/1/07 Filed 1/26/06 Case 43083

Declines to adopt at this time PURPA time-based metering/communications standard (Std 14), as revised by EPAAct 2005, citing lack of solid foundation of demand response (DR) programs from which mandate would be next step. Also cites testimony re relatively low rates in state, DR program implementation costs, and uncertain potential benefits. Urges utilities to takes steps to evaluate/develop programs.

California PUC – Southern California Edison

Decided 7/26/07 Filed 12/21/06 Case A.06-12-026

Approves \$45.22m vs. requested \$67m to fund AMI pre-deployment activities, including product mgt., information technology, business process/organizational readiness, field deployment, customer tariffs/programs, systems integration, and program mgt./organization. Allows as-incurred recording in modified AMI balancing account, for later recovery via distribution rates, of \$25.52m in pre-deployment expense, and \$19.7m in pre-deployment capital costs of which \$5.6m to be added to rate base in 2007 or 2008. Finds ratepayer funding warranted for activities resulting in product useful to SCE and providing ratepayer value regardless of ultimate decision on to-be-filed deployment application. Finds pre-deployment includes activities w/primary purposes as follows: 1) determine equipment, technology, and approach for full deployment, or 2) gather/refine data that improves estimates for cost/benefit analysis of full deployment proposal. Finds other activities in funding request are deployment—e.g., certain expenditures on system integration, info technology and organizational readiness—to be considered for funding later. Excludes all proposed contingency-related costs, citing lack of detailed justification.

Maryland PSC – Delmarva Power & Light

Decided 7/19/07 Filed 11/17/06 Case 9093

Approves company-proposed, staff/rate advocate-supported bill stabilization adjustment (BSA) mechanism that decouples revenues from abnormal levels in kWh sales and/or changes in customer numbers, but requires operation on monthly vs. proposed quarterly basis. Approves company-proposed cap on BSA credits/surcharges at 10% of test year avg. base rate, w/amounts > cap to be deferred to offset future over-/under-collections. Will open separate proceeding to consider adjustments relating to service quality, frequency, application to customer classes, and additional monitoring/studies. Says BSA reduces risk/cost of capital, removes major disincentive to full deployment of DSM/EE programs, and smoothes out bill variations induced by weather extremes, all to benefit of ratepayers.

Rejects company-proposed changes to standby service, referring issues to demand response distributed generation working group. Approves related reserved delivery capacity service rate but conditions based on concerns relating to potential redundancy, coverage of public purpose customers, and uncertainty over scope of coverage; requires company to identify customers w/redundant service and exempt them, but approves prospectively for customers seeking redundant service. Action comes w/approval of temporary \$14.9m (2.15%) distribution rate increase.

Maryland PSC – Pepco

Decided 7/19/07 Filed 11/17/06 Case 9092

Approves company-proposed, staff/rate advocate-supported bill stabilization adjustment (BSA) mechanism that decouples revenues from abnormal levels in kWh sales and/or changes in customer numbers, but requires operation on monthly vs. proposed quarterly basis. Says BSA reduces risk/cost of capital, removes major disincentive to full deployment of DSM/EE programs, and smoothes out bill variations induced by weather extremes, all to benefit of ratepayers. Rejects company-proposed changes to standby service, referring issues to demand response distributed generation working group. Action comes w/approval of temporary \$10.6m (0.56%) rate increase.

Georgia PSC – Georgia Power

Decided 7/12/07 Filed 1/31/07 Case 24505-U

Following settlement, approves integrated resource plan allowing five new DSM pilots and requiring expansion of existing DSM programs. Requires reconvening of previously created DSM working group to consider company use of RIM test, whether DSM activities should be reviewed on program or measure basis, and use of other evaluation tools. Allows company to earn additional 15% of net present value of net benefits resulting from one certified program (Power Credit Single Family); estimated benefits to be compared to actual verified impacts using actual metered data when available. Reward not available in any year company does not achieve 50% of projected participation. Costs subject to prudence review.

Idaho PUC – Avista Utilities

Decided 7/11/07 Filed 6/1/07 Case AVU-E-07-04

Approves two-year demand response pilot under which eligible residential/commercial customers in two localities volunteer to receive programmable thermostats or direct control switches for A/C units/other appliances, as of 7/15/07. Usage to be controlled in min. four critical peak events called per year of 4-6 hours each. Finds pilot cost-effective, w/estimated costs @\$123,000 and savings of min. \$150,000 in callable events. Approves measurement & evaluation of kW savings, technology, customer acceptance and interactions of peak demand on company distribution system. Finds program benefit all customers by lowering bills, deferring need for new supply resources and reducing company high-cost peak power needs.

Indiana URC – Indianapolis Power & Light

Decided 7/11/07 Filed 3/28/07 Case 43252

Following settlement, approves two-year extension of residential, multicomponent DSM program w/new authorized spending amounts in addition to remaining, previously authorized amounts. Approves continued incremental cost recovery, other than for lost revenue, via DSM quarterly adjustment mechanism (Rider 3), except incentives paid to AC load mgt. participants recovered via existing ACLM adjustment mechanism (Rider 13). Program includes income-qualified weatherization, renewable/EE education, HVAC, ACLM, and critical peak pricing pilot. Says extension provides continuity, more info to aid ongoing DSM investigation.

Ohio PUC – Duke Energy Ohio

Decided 7/11/07 Filed 1/24/06 Case 06-91-EL-UNC, et al.

Following settlement, approves company proposal for 10 new residential/three commercial DSM programs and related cost recovery via annually reconciled DSM riders, including adjustments for recovery of lost revenues and shared savings w/10% shareholder incentive, conditioned per settlement as follows: 1) for three residential programs, lost revenue/shared savings recovery subject to refund based on future impact studies; 2) independent program evaluation costs capped at 5% of ea. program's expenditures, 3) remaining monies of any program found not cost-effective go back to collaborative board for use in other new/expanded DSM programs, and 4) shared savings recovery allowed only after min. 65% of targeted savings achieved. Electric DSM programs run five years, but lost revenue recovery limited to three years from date of DSM install, per company proposal. Shareholder incentive is 10% of net resource savings (benefits – costs, w/benefits calculated on basis of present value of avoided costs over expected program life), to be stepped in per specified target achievement levels and capped at 10% for any program meeting 100% of goal.

New Mexico PRC – El Paso Electric

Decided 7/3/07 Filed 6/30/06 Case 06-00258-UT

Following settlement, approves 3.4% (\$5.5m) net rate increase, and related rate design applying gradualism, to enable company to redesign rates to promote EE/conservation and minimize impact of increases on certain rate classes.

Alabama PSC – Time-based Metering Standard

Decided 6/29/07 Filed 8/7/06 Case 30067

Deems PURPA time-based metering/communications standard, as revised by EPAct 2005, to be met. Cites approved rates/meter policies, including Alabama Power TOU rates/current advanced metering program for all customer classes.

Arizona CC – Arizona Public Service

Decided 6/28/07 Filed 11/4/05 Case E-01345A-05-0816, et al.

Rejects company-proposed \$4.9m net lost revenue adjustment for previously approved DSM programs, citing company ability to recover \$10m/yr. of DSM funding thru base rates, other DSM expenses thru DSM adjustor mechanism, and part of savings of successful DSM programs thru performance incentive allowed by approved 2005 settlement. Also says adjustment not sufficiently known/measurable to merit rate inclusion. Approves company-proposed performance incentive @10% of benefits achieved, capped at 10% of total DSM spending. Allows interest to accrue on unrecovered DSM adjustor balance. Disallows \$3m of additional DSM expenses. Approves three-year net metering pilot for ≤ kW renewable customers to encourage participation in solar credit purchase program, allowing company to require use of bidirectional meter; incremental cost to be funded thru existing environmental portfolio standard surcharge. Rejects company-proposed recovery of lost revenue related to net metering pilot, instead allowing deferral for possible recovery in next rate case. Requires study of demand response/load mgt. and program filing w/in one year. Action comes w/approval of \$321.7m (15.1%) rate increase.

Arkansas PSC – Entergy Arkansas

Decided 6/15/07 Filed 8/15/06 Case 06-101-U

Approves company-proposed \$300,000 addition to rate base and \$90,000 expense for broadband over power lines (BPL) pilot to study feasibility of using technology to enhance service delivery, outage detection/service restoration, and potential future deployment of demand response technology/advanced metering capabilities. Cites potential for more efficient utility operation that may directly benefit ratepayers. Reserves judgment on future cost assignment due to potential nonutility application/ratepayer subsidy.

Indiana URC – Indiana Michigan Power

Decided 6/13/07 Filed 2/27/07 Case 43231

Following settlement, approves company request to lower depreciation rates due to changes in plant since last depreciation study, citing company commitment to file rate case and provide direct ratepayer benefits, including conducting smart metering pilot under which company would: 1) not earn return on investment, 2) not defer related costs, and 3) conduct market potential study to assess EE/DSM viability.

Florida Legislature – IGCC Law

Enacted 6/12/07 Law HB 549

Requires PSC to consider whether renewable energy sources/technologies and energy conservation measures are being effectively utilized before approving construction of new power plant. Encourages utility investment in integrated gasification combined-cycle plants.

New York PSC – Consolidated Edison Co. of New York

Decided 6/12/07 Filed 3/29/07 Case 07-E-0392

Approves/modifies company-proposed enhancements to distribution load relief program (Rider U) to increase enrollment/demand response resources to draw on when reliability constrained, effective 7/1/07 temporarily. Rider U compensates volunteers for load reduction/delivery during relief periods. Changes allow aggregator participation/add summer reservation payment for those willing to participate on mandatory basis. Approves Tier 1 mandatory/voluntary reservation payments, Tier 2 reservation payments, and performance penalties. Requires program assessment by 1/31/08. Notes current program achieved only 1.1 MW of voluntary load reduction in summer 2006.

Kansas CC – Westar Energy

Decided 6/11/07 Filed 12/19/06 Case 07-WSEE-616-PRE

Following settlement, approves advance ratemaking principles for 618 MW, gas-fired Emporia Energy Center, conditioned on company agreement to expand DSM options, pursue conservation/efficiency programs, develop pilot real-time pricing tariff, and other items.

Maryland PSC – Allegheny Power, Baltimore Gas and Electric, Delmarva Power & Light, Pepco

Decided 6/8/07 Filed 3/21/07 Case 9111

Establishes generic collaborative process to consider four issues related to AMI/DSM: 1) technical standards for operational capabilities of advanced meters, 2) extent to which DSM programs are to be offered on competitively neutral basis, 3) DSM cost recovery, and 4) DSM cost-effectiveness measures. Applies to Allegheny, BGE, Delmarva, Pepco, and two cooperatives. Requires report by 7/6/07. Notes previously filed AMI/DSM applications by BGE (approved 2/21/07, 4/13/07 in Case ML104518), Delmarva and Pepco. Action comes w/issuance of separate order establishing company-specific collaborative to consider Delmarva-Pepco DSM initiatives (Case ML 105286, et al.) (See 9/28/07, 4/13/07, 2/21/07 entries.)

Maryland PSC – Delmarva Power & Light, Pepco

Decided 6/8/07 Filed 3/21/07 Case ML105286, et al.

Establishes Delmarva-Pepco collaborative to consider company-specific DSM initiatives and report back by 7/6/07. Action comes w/issuance of separate order (Case 9111) establishing generic collaborative process to consider issues related to AMI/DSM. (See 6/8/07, 9/19/07 entries.)

California PUC – San Diego Gas & Electric

Decided 6/7/07 Filed 5/18/07 Resolution E-4094

Approves confidential contracts w/two vendors for implementing Phase 1 of AMI, saying they meet six previously required functional requirements for utility AMI systems, e.g., implementation of price-responsive tariffs, collection of detailed usage data, and capability to interface w/load control communication technology. Phase 1 (construction/deployment of system, meters, communication network) set for completion 2Q 2011.

Connecticut Legislature – Comprehensive Energy Law

Enacted 6/4/07 Law HB 7432

Requires electric distribution companies (EDCs) to develop integrated resource plan/procurement schemes using cost-effective, reliable, feasible EE/demand reduction resources and evaluating cost impacts equitably w/supply-side resources. Other provisions: 1) require EDCs to offer conservation incentive program for summer 2007 that compares Jun-Aug 2007 usage w/same 2006 period adjusted for weather; 2) require DPUC to study feasibility of incentive program to encourage EDCs to stabilize/reduce peak demand; 3) require Energy Conservation Management Board, in consultation w/EDCs, to offer rebates for replacement of air conditioners not complying w/federal Energy Star efficiency standards; 4) require EDCs/competitive suppliers to waive demand charges for fuel cells under certain operating conditions, 5) affirm continued collection of systems benefit charges and authorize new uses (conservation/EE programs) for charge proceeds, 6) require TOU rates for customers \geq 350 kW as well as voluntary critical peak pricing or real-time pricing tariffs for all customer classes, and 7) require EDCs to submit plans for advanced metering systems that will support net metering/TOU pricing.

Florida PSC – Gulf Power

Decided 5/29/07 Filed 2/20/07 Case 070119-EG

Approves company-requested increase in customer cash incentives for system installation under voluntary residential/commercial geothermal heat pump programs to help increase participation. Finds changes pass cost-effectiveness tests (RIM/Participants). Requires disclosure of payback periods: 18 years for residential customers to receive net benefit, 13 years for commercial. Incentives to increase from \$150/ton to \$400/ton for residential/commercial full closed loop, and from \$75/ton to \$200/ton for commercial hybrid closed loop.

Texas PUC – AEP Texas North

Decided 5/29/07 Filed 11/9/06 Case 33310

Following settlement, approves application of any EE rider approved in pending rate case for affiliate AEP Texas Central to AEP TN, subject to approval. Rider would collect/refund EE costs beyond \$1.3m included in base rates. Action comes w/approval of \$13.7m delivery rate increase.

Nevada PUC – Nevada Power

Decided 5/24/07 Filed 11/15/06 Case 06-11022, et al.

Approves company-requested rate-basing of \$35.316m of DSM-related costs, of which \$26.921m eligible for equity adder (500 basis points above authorized ROE) per previously mandated DSM incentive. Requires rate base reduction of related \$9.7m of accumulated deferred income taxes, which is net of \$2.643m net operating carry-forward loss adjustment. Action comes w/approval of \$120.5m rate increase.

Connecticut DPUC – Connecticut Light and Power, United Illuminating

Decided 5/23/07 Filed 10/2/06 Case 06-10-02

Approves, modifies company joint proposal for 2007 conservation/load management (C&LM) programs/budgets, but declines to act on 2008 proposal due to budget uncertainties. Approves \$20.5m CL&P budget and \$4.8m UI budget to reduce near-term peak demand per 2005 Energy Independence Act (EIA), which calls for reduction of federally mandated congestion charges (FMCCs). Costs to be recovered via FMCCs. Approves joint RFP results offering direct load control (DLC) programs to two vendors for five years to achieve 64 MW reduction; directs companies to consider raising participation incentive while reducing enrollment incentive to increase/sustain participation. Allows bidding DLC capacity into forward capacity market (FCM) to reduce future program costs.

Approves additional \$13.3m total funding based on joint company scenario assuming full funding of Connecticut Energy Efficiency Fund (CEEF), estimated @\$21.3m for 2007. Specifically, approves company-proposed C&I programs and \$1m increase to low-income program, but rejects increases to less cost-effective residential new construction/home energy solutions programs and planning/program evaluation. Allocates remaining \$8m to pay for approved EIA programs, citing rate effect of near-term EIA program costs. Rejects longer-term company plan for achieving zero peak demand growth by 2010, citing major cost-effectiveness differences in programs that preclude endorsing program priorities at this time.

Also approves ratepayer recovery of any expenses, including DLC FCM-related costs, incurred due to insufficient resources submitted to FCM as result of legislative/regulatory reductions to CEEF. (See 12/28/05 entry in this section.)

Oregon Legislature – RPS Law

Decided 5/23/07 Senate Bill 838

Extends collection of public purpose charge from residential customers until 1/1/26 to fund conservation projects, market transformation efforts, above-market costs of renewables, and low-income weatherization. Authorizes PUC to allow rate inclusion of additional costs of new, cost-effective energy conservation measures, provided customers w/loads > 1 MW do not see rate increase of > 3% or receive direct benefits from programs funded by provision.

Michigan PSC – Upper Peninsula Power

Decided 5/22/07 Filed 2/26/07 Case U-15224

Approves first real-time pricing program for company, w/non-firm energy prices based on actual MISO locational marginal prices. Says customers > 1,000 kW who are interconnected w/ATC can provide day-ahead bids to obtain energy price certainty.

Missouri PSC – AmerenUE

Decided 5/22/07 Filed 7/7/06 Case ER-2007-0002

Rejects company-proposed industrial demand response pilot based on lack of evaluation plan; orders revised filing w/in 30 days.

Missouri PSC – Aquila

Decided 5/17/07 Filed 7/3/06 Case ER-2007-0004

Following partial settlement, approves deferral of prudent DSM-related program costs and annual calculation of AFUDC for such purposes. Allows transfer of deferred amounts to rate base in next rate case and 10-year amortization of balance. Company to implement only cost-effective programs as determined in separate proceeding, w/funding goal of 1% of annual revenue by 2010. Partial settlement was adopted 4/12/07 in rate case decided 5/17/07.

New Hampshire PUC – Energy Efficiency Rate Mechanisms

Issued 5/14/07 Case DE 07-064

Opens investigation of rate mechanisms, e.g., revenue decoupling, that could remove barriers to/encourage investment in energy efficiency.

Pennsylvania PUC – PPL

Decided 5/10/07 Filed 8/2/06 Case P-00062227

Approves company-revised bridge plan for transitioning from rate caps to market-based POLR supply pricing in 2010 that includes enhanced experimental DSM programs. Company to double participation limit

in 2008-09, and remove limit in 2010, for residential customer incentives to shift load from on-peak to off-peak periods, and expand from summer to year-round in 2010. Company to extend, from 2007 thru 2010, program under which large C&I may designate load portions to receive fixed-price service and actual hourly prices. Company also to end certain legacy DSM programs previously closed to new customers.

California PUC – Pacific Gas and Electric

Decided 5/3/07 Filed 2/8/07 Resolution E-4079

Approves company-proposed changes to previously approved business energy coalition demand response program, including: 1) expands eligibility from hard-to-reach customers in specific sectors (office, hospitality, high tech) to those in other public/private sectors including school/water districts; 2) expands availability from San Francisco/Bay area to entire service territory; 3) allows soft trigger for calling program as needed vs. use of inflexible criteria; and 4) provides incentive payment 1x/yr. vs. 2x. (See 12/20/07 entry.)

California PUC – Pacific Gas and Electric, Southern California Edison

Decided 5/3/07 Filed 2/28/07 Case A.07-02-032, et al.

Approves bid-winning demand response contracts entered into w/aggregators as innovative and likely to reduce system demand by expected MW range due to performance requirements/potential termination damages vs. existing voluntary approach. Approves PG&E cost recovery via energy resource recovery account, and SCE recovery via shifting existing DR funds. Notes flexible trigger mechanisms, long commitments—five consecutive summers for PG&E, year-round for two years for SCE—and range of energy strike prices/response times. Says it cannot evaluate cost-effectiveness yet, noting separate initiative to develop methodologies, but finds terms reasonable given DR market and competitive process that resulted in multiple bidders. Says company use of EE protocols to analyze cost-effectiveness misses potential benefits, e.g., avoiding T&D costs and option value. PG&E contracts are w/five aggregators to provide 35-46 MW of DR by Aug 2007, 107-129 MW by Aug 2008, and 132-149 MW in 2009-11; SCE contract is w/one aggregator for up to 40 MW of DR capacity by Jun 2008.

Connecticut DPUC – Connecticut Light and Power, United Illuminating

Decided 5/3/07 Filed 7/25/05 Case 05-07-14PH02

Approves four bid-winning contracts totaling 787 MW of incremental capacity to reduce federally mandated congestion charges per 2005 state law, including 5 MW EE program offered by Ameresco, and baseload/peaking generation. Requires UI to enter into EE and one peaking contract, and CL&P to enter other two contracts, to be reviewed in future proceeding. (See 9/13/06, 12/28/05 entries.)

Iowa UB – Interconnection Standard

Decided 4/25/07 Filed 7/3/06 Case NOI-06-4

Declines to adopt at this time parts of PURPA interconnection standard that, if voluntarily adopted by states per EAct 2005, require coverage of all customer-owned onsite/distributed generation and adoption of rules on agreements/procedures that reflect current best practices, e.g., based on NARUC model. Says it will continue to examine expansion/revisions but does not want to act hastily or encourage certain types of DG, e.g., fossil fuel-based. Notes only QFs/alternate energy providers now covered by state rules. Says NARUC model may be outdated; instead proposes preliminary model procedures/seeks comments. Finds it has

already met other part of standard, i.e., adoption of IEEE Standard 1547, as technical basis for interconnection.

Michigan PSC – Smart Grid Initiative

Decided 4/24/07 Filed 4/24/07 Case U-15278

Directs staff to: 1) convene collaborative to monitor national smart grid developments, 2) set evaluation criteria/standards to trigger pilots or broader deployment when options appear cost-effective and practical, and 3) report annually w/recommendations. Requires participation by regulated distribution utilities, munis, and co-ops.

Maryland PSC – Baltimore Gas and Electric

Decided 4/13/07 Filed 1/23/07 Case ML104518

Approves advanced metering infrastructure (AMI) component of company-proposed comprehensive DSM/AMI program, allowing creation of pilot program and regulatory asset to track related costs estimated @\$7m-\$10m. Reserves right to review prudence of expenditures. Requires more detailed program design, citing concern over initial lack of design to measure impact on critical peak pricing/peak demand reduction. Company to select 5,000 electric/gas customers whose existing meters to be replaced w/new high-tech devices. Pilot to begin spring 2008 w/full deployment planned in 2009. Action follows 2/21/07 approval of demand response component.

California PUC – San Diego Gas & Electric

Decided 4/12/07 Filed 3/15/05 Case A.05-03-015

Following settlement, approves AMI for electric/gas, rate recovery of \$572m for 2007-11 w/o prudence review, and risk contingency/symmetrical risk-reward sharing mechanism. Total project costs include additional functionality, e.g., home area network communications system, and extended warranty pricing for equipment, per settlement; total costs may decrease due to related RFP revisions. Finds \$40m-\$51m in net benefits. Deployment of approx. 1.4m new AMI-enabled, solid state electric meters to begin mid-2008 that can measure energy usage on time-differentiated basis and allow two-way communication.

Virginia Legislature – Re-regulation Law

Enacted 4/4/07 Filed 1/19/07 Law SB 1416

Allows timely recovery of EE program costs thru rate adjustment clause and increases allowable rate generating capacity of net metering customers from 0.1% to 1% of each electric distribution co.'s adjusted VA peak-load forecast.

Ohio PUC – EAct 2005 Standards

Decided 3/28/07 Filed 12/14/05 Case 05-1500-EL-COI

Adopts staff recommendations addressing EAct 2005 requirements, including: 1) institute voluntary stakeholder process to consider advanced energy portfolio standard, 2) expand allowed technologies for net metering and revise rules on customer credits for interconnection of distributed generation, 3) require distribution utilities to file reports on DG impacts on T&D systems, tariff information on daily time-sensitive rates, and list of AMI technologies/costs, 4) revise interconnection rules to ensure standardized process in

state/region and base review process for customer-owned distribution on level of generation, 5) direct staff to develop checklist/standard application for interconnection, and 6) conduct workshop on statewide pooling of standby power.

North Carolina UC – Duke Energy Carolinas

Decided 3/21/07 Filed 6/2/06 Case E-7, Sub 790

Approves construction of 800 MW supercritical pulverized coal generating facility at existing Cliffside Steam Stn. to meet load growth. Conditions approval on company commitment to invest 1% of annual sales revenues in EE/DSM programs, subject to results of collaborative workshops and regulatory treatment, and retirement of existing Cliffside 1-4 coal units. Requires retirement of additional coal units on MW-for-MW basis to account for EE/DSM-related load reductions. Finds EE/DSM/renewables cannot eliminate or delay need for baseload facilities by 2011.

California PUC – Southern California Edison

Decided 3/15/07 Filed 12/9/04 Case A.04-12-008

Approves company proposal w/mitigation conditions to construct Segments 2 & 3 of transmission line project to access Tehachapi-area wind development and prevent transmission system overloading. Says EE/demand response are insufficient to ensure continuing grid reliability/safety as renewable power/customer demands increase. (See 3/1/07 entry for same case.)

Idaho PUC – Idaho Power

Decided 3/12/07 Filed 8/10/04 Case IPC-E-04-15

Following non-unanimous settlement, approves company-proposed, three-year pilot fixed cost adjustment (FCA) decoupling mechanism, effective 1/1/07, for residential/small business customers. FCA allows annual true-up, concurrent w/existing power cost adjustment, of collected fixed costs and amount authorized in most recent rate case. Under-recovery to result in surcharge of up to 3%, w/carryover of unrecovered deferred costs to later years, and over-recovery to result in credit. Says estimated typical customer impact is \$1/mo. or less. Requires company to expand/improve EE/DSM programs and support more energy efficient building/energy codes. Approves other conditions, e.g., close monitoring by staff and ability of company or staff to seek pilot discontinuance during three-year period. Action comes w/contemporaneous approval of performance-based pilot for residential construction DSM program. (See 3/12/07 entry for IPC-E-06-32.)

Idaho PUC – Idaho Power

Decided 3/12/07 Filed 12/18/06 Case IPC-E-06-32

Approves company-proposed three-year DSM pilot, effective 1/1/07, providing for performance-based incentive/penalty payments related to residential construction program (ENERGY STAR[®]). Company to receive incentive payment = percentage of benefit exceeding specified targets for market share of homes built under program, and penalty for failing to achieve 4.9% market share. Incentive capped at 10% of program net benefits. Action comes w/contemporaneous approval of pilot decoupling mechanism. (See 3/12/07 entry for Case IPC-E-04-15.)

Maine PUC – Bangor Hydro-Electric

Decided 3/12/07 Filed 9/20/05 Case 2005-554

Following settlement, approves new revenue-neutral rate design for demand classes that shifts distribution charge from energy to demand over six years. Initiates Phase 2 to consider TOU meters/alternative rate designs for medium non-residential classes (D-1, D-2), which will experience 18-50% rate increases over six-year phase-in. Approved settlement also provides for optional standby rate for qualifying customers who self-generate.; 50% and 30% rate discounts offered depending on generator capacity, and 100% ratchet included whereby demand charge based on customers' highest recorded usage in prior 12 mos. Allows reconciliation of estimated distribution revenue lost/gained due to switching to standby rates w/revenue that otherwise would be realized, to be deferred until pending rate case decided but no later than 3/1/08.

Florida PSC – Time-based Metering Standard

Decided 3/7/07 Filed 3/7/06 Case 070022-EU

Declines to formally adopt PURPA time-based metering/communications standard as revised by EAct 2005, saying that since 1978 PURPA enactment, it has continued to explore/implement options for customers to monitor/control usage on time-differentiated basis and thru response to load control incentives. Notes many utilities w/o such rates/programs considered them but found not cost-effective or unneeded.

Iowa UB – Time-based Metering Standard

Decided 3/6/07 Filed 8/8/05 Case NOI-06-3

Declines to adopt at this time PURPA time-based metering/communications standard (Std 14) in its entirety, as revised by EAct 2005, saying it has considered/adopted portions of standard under prior state actions. For portion not previously adopted, cites lack of cost-benefit analysis supporting utility deployment of real-time metering/networked data collection. Directs staff to informally discuss w/utilities potential pilots/additional topics, e.g., MISO demand response program.

California PUC – Southern California Edison

Decided 3/1/07 Filed 12/9/04 Case A.04-12-007

Approves, modifies company proposal to construct 25.6-mile, 500 kV (initially energized at 220 kV) Segment 1 of transmission line project to access Tehachapi-area wind development. Says project is first effort in state since adoption of RPS to build transmission to concentrated renewable resource area, and EE/demand response are insufficient to ensure continuing grid reliability/safety as renewable power/customer demands increase. (See 3/15/07 entry for same case.)

Maryland PSC – Baltimore Gas and Electric

Decided 2/21/07 Filed 1/23/07 Case ML104518

Approves demand response component of company-proposed comprehensive DSM/AMI program, allowing creation of pilot and regulatory asset to track related costs estimated @\$1m. Reserves right to review prudence of expenditures. Pilot expected to run Jun-Sep 2007 involving install of smart thermostats/load control devices for 1,000 customers.

California PUC – Southern California Edison

Decided 2/15/07 Filed 11/8/06 Res. E-4059

Approves w/modifications company-proposed addition of “day of” option to previously approved capacity bidding program. Increases customer participation incentives to encourage more demand response in face of rising demand/potential future heat storms as follows: 1) Approves 15% higher day-of capacity prices over existing day-ahead option vs. company-proposed 7-9% differential, 2) allows customers w/multiple accounts to participate in both options, and 3) allows customers w/single account to nominate to both options. Says company proposal unclear on latter two points.

Ohio PUC – FirstEnergy

Decided 2/14/07 Filed 4/27/06 Case 04-1932-EL-ATA, et al.

Following settlement, approves company-proposed transmission cost rider update and parties’ condition of settlement providing for funding/implementation of previously approved three-year DSM programs (Case 05-1125-EL-ATA) over two years (2007-08), and affirmation of total \$25m DSM budget, including rollover from 2006; target implementation is now 3/1/07 vs. 2006.

Idaho PUC – PacifiCorp

Decided 2/13/07 Filed 12/5/06 Case IPC-E-06-12

Approves company-proposed second load control pilot for Schedule 10 irrigators in addition to existing program that allows interruptions at designated irrigation pump sites on scheduled basis. Pilot allows interruptions at company’s discretion from remote central network server; customers to receive yearly credit vs. existing monthly credits. Enrollment first come-first served up to 45 MW. Directs report on results after 2007 irrigation season.

Rhode Island PUC – National Grid

Decided 2/5/07 Filed 11/1/06 Case 3779

Following settlement, approves 2007 DSM programs w/projected total \$22.5m budget, funded thru conservation and load management adjustment and renewable factor of \$0.0023/kWh, as in 2006; \$0.002/kWh to be applied to DSM programs and \$0.0003/kWh to be submitted to state Energy Office Renewables Programs. Praises “new ideas” including high efficiency gas furnace incentive. Approves shareholder incentive allowing company to earn up to \$20,000 for each of five performance-based metrics vs. four metrics in 2006. Approves target incentive rate for kWh savings by sector of 4.4% of eligible spending budget, as in 2006. Target incentive amount is \$722,958 in 2007 vs. \$733,932 in 2006. The 2007 threshold performance level of energy savings is 60% of annual energy savings goal by sector, as in 2006. Company may earn additional incentive on savings of up to 125% of target savings, capped at \$778,698.

Wisconsin PSC – Wisconsin Power and Light

Decided 1/19/07 Filed 3/17/06 Case 6680-UR-115

Approves continued escrow accounting for conservation expenditures and \$29m recovery for 2007. Continues \$40m authorized annual capital investment in shared savings DSM program; directs company to work w/stakeholders on alternative financing to increase cost-effectiveness, and w/staff to develop 2007

goals. Approves return on shared savings investments of weighted cost of capital reflecting allowed ROE, but denies company request for \$2.5m return uplift, citing lower risk of such investments. Approves increase in existing experimental load factor energy credit for certain (Cp-2) customers, conditioned on customer accepting 50 more hours of interruptibility, and increase in interruptible credit/resulting interruptible demand charges, using annual avoided capacity cost of \$58-59/kW/yr.

Oregon PUC – PacifiCorp

Decided 1/16/07 Filed 8/30/06 Case UM 1208

Rejects draft RFP for bids for two new baseload plants to meet projected 808 MW in 2012 and 1,109 MW in 2013, saying not aligned w/2004 integrated resource plan (IRP). Finds case not made that baseload resources offer best cost-risk for customers compared to IRP alternatives, e.g., conservation/demand response/renewable resources beyond 1,400 MW in IRP. Says if company proceeds w/solicitation, it must address identified deficiencies.

District of Columbia PSC – Pepco

Decided 1/12/07 Filed 6/1/06 Case 1002-E-223

Approves two-year pilot smart meter program under which up to 2,250 randomly selected customers may volunteer for one of three revenue-neutral pricing options: 1) hourly pricing based on day-ahead prices posted on website; 2) critical peak pricing in effect four hours/day on 15 critical peak days/yr, and 3) critical peak rebate under which SOS generation charges apply w/opportunity to earn rebate (reduced consumption [kWh] times rebate amount [per kWh]) by reducing consumption. Up to half of participants to receive smart thermostats; other half to receive pricing/rebate-related messaging via email/paging/phone. Program to measure consumption reduction at peak times, overall consumption changes, customer satisfaction w/pricing options/technologies, usefulness of technologies, and value of additional pricing information to customers. Customers may exit anytime/revert to SOS rates.

Oregon PUC – Portland General Electric

Decided 1/12/07 Filed 3/15/06 Case UE 180, et al.

Following settlement, approves modified, company-proposed rate design based on cost causation. Settlement changes include modifying partial requirements service for large non-residential customers who self-generate, providing: 1) baseline demand based on historical loads prior to installation and including planned power sales; 2) option to reduce loads/avoid reserve charges for supplemental reserves if utility-approved load reduction provided; 3) tiered notice requirement for changes in baseline demand; and 4) application to customers ≥ 2 MW vs. current 1 MW. Action comes w/approval of \$20.5m net base rate increase.

Pennsylvania PUC – Metropolitan Edison, Pennsylvania Electric

Decided 1/11/07 Filed 4/10/06 Case R-00061366, et al.

For recovery over five years, approves deferred universal service and energy conservation costs incurred over six years ending 2004 w/o interest on unrecovered balance. Restructuring settlement allows deferral of costs incurred during T&D rate cap period that exceed amounts included in rates under earlier settlement. Recoverable costs: MetEd = \$182,000; Penelec = \$3.929m. Denies companies' proposed three-year recovery period, saying shorter time means higher charges. Rejects requested 6% carrying charge on ground settlement allowing deferral doesn't specify interest. Allows companies not to implement proposed riders

effective 1/1/08 to collect 0.01 ¢/kWh to fund sustainable energy funds (SEF) because companies earlier made large lump sum SEF contributions. Notes state's Alternative Energy Portfolio Standards law creates permanent funding source for such activities. PUC earlier ruled now is time to eliminate use of distribution revenues to support SEF. Rejects PennFuture-proposed voluntary real-time pricing initiatives, finding intervenor did not meet burden of proof, address implementation details, or prove real time rates to be just, reasonable or in public interest.

Wisconsin PSC – Wisconsin Public Service

Decided 1/11/07 Filed 3/31/06 Case 6690-UR-118

Approves company-proposed three-period, time-of-day residential rate that adds to existing two-period rate a weekday shoulder in which kWh rate = standard residential kWh rate. Approves company revision to Response Rewards rates for C&I customers that has energy charge based on cost of operating combustion turbine during 300 high-cost hours in return for lower on-/off-peak energy charges in remaining hours of year; revision includes 25% demand charge reduction and on-/off-peak energy charge reductions, and increase in critical peak energy price from \$0.30/kWh to \$0.35/kWh. Also approves residential Response Rewards option w/\$0.45/kWh critical peak price for 150 hours and on-/off-peak energy charges during remaining hours of year.

Maryland PSC – Delmarva Power

Decided 1/8/07 Filed 12/27/07 Case ML108874

Approves company-proposed monthly 6¢/1,000 kWh surcharge over five years to cover costs related to distribution of CFL bulbs, contingent on approval of bill insert to educate customers on program cost and CFL disposal.

Washington UTC – Puget Sound Energy

Decided 1/5/07 Filed 2/15/06 Case UE-060266, et al.

Approves three-year pilot energy conservation incentive mechanism, effective 1/1/07, based on energy savings performance of conservation programs. Company to earn incentive payment if conservation programs achieve/exceed savings above specified targets.

Indiana URC – Duke Energy Indiana

Decided 1/3/07 Filed 8/18/06 Case 43099

Following settlement, approves one-year, residential pilot DSM program, called personal energy report (PER), w/recovery of \$1m budgeted costs via existing Rider 66, which is used to recover other DSM program costs and reconciled like quarterly fuel clause. PER to disseminate survey-based individualized information to up to 200,000 households and suggested DSM applications, e.g., compact fluorescent light bulbs. Company to fund \$125,000 market potential study.

2006

Connecticut DPUC – Connecticut Light and Power

Decided 12/21/06 Filed 10/1/05 Case 05-10-03

Per 2005 state Energy Independence Act, and noting constraints of company's existing metering system/ongoing upgrade to billing system, requires: 1) redesign of TOU rates for large C&I customers and voluntary TOU residential rates/small C&I, as of 1/1/08; 2) implementation of voluntary real-time and variable peak pricing for large C&I as of 1/1/08; 3) mandatory seasonal rates for all customers as of 4/1/08; 4) phase in of mandatory TOU rates for residential and small C&I beginning 1/1/09; and 5) increased fixed recovery of residential distribution revenues over next five years as way to decouple earnings from sales/encourage company to promote customer conservation/EE.

Per company request, finds existing two-part TOU rates for customers > 350 kW/mo. comply w/law, but requires changes, including adjusting on-peak period to 12 pm-8pm on weekdays (from current 7 am-11 pm) as of 1/1/08. Approves 5 cents/kWh TOU peak/off-peak price differential. Does not require intervenor-requested three-part rates, saying stimulus to shift load away from peak less than two-period rates. Declines to adopt intervenor-requested mandatory critical peak pricing as too disruptive to most customers. Directs closure of residential space heating tariff (Rate 5) to new customers and gradual elimination over time as TOU rates phased in. Requires plan by 3/15/07 to implement residential/small C&I TOU metering.

Kentucky PSC – Duke Energy Kentucky

Decided 12/21/06 Filed 5/31/06 Case 2006-00172

Following settlement, approves \$49m (20.6%) rate increase, effective 1/1/07, that includes cost recovery for advanced metering infrastructure (AMI) program under which company to install 40,500 meters in 2007. Finds CPCN not needed because estimated \$14m capital investment not significant. Approves avoided cost pricing for PowerShare® program, to be incorporated in DSM program; company to file in separate ongoing DSM case (No. 2006-00426) to recover as part of non-residential DSM rates any resulting incremental costs. Approves one-year pilot for Rate DT customers (time of day for service at distribution voltage) w/load factors ≤ 45%; pilot has lower demand charge than on-peak kW rate and higher energy charges than regular DT rate. Company may continue pilot beyond 12/31/07 subject to PSC approval.

Kentucky PSC – Time-based Metering/Interconnection Standards

Decided 12/21/06 Filed 2/24/06 Case 2006-00045

Declines to adopt smart metering standard and IEEE Standard 1547 per EAct 2005 as unneeded due to low existing rates, significant costs and uncertain benefits. Cites value of underlying theories, directs Louisville G&E to finalize real-time pricing pilot per previously approved settlement, and LG&E, Kentucky Power, Kentucky Utilities and specified co-ops to develop voluntary such programs for large C&I customers. Directs jurisdictional utilities to include IEEE 1547 as core of technical interconnection requirements for generation resources ≤ 10 MVA or tariffs as appropriate.

Michigan PSC – Wisconsin Public Service

Decided 12/21/06 Filed 10/24/06 Case U-15114

Approves optional, revenue-neutral next day pricing tariff for large industrial customers to improve price signals/incentivize to reduce loads at high-cost times. Company to manage/communicate pricing day types—economy, mid-economy, peak, critical—based on day-ahead forecast of generation conditions. Customers must commit to one year.

Illinois CC – Ameren

Decided 12/20/06 Filed 9/29/06 Cases 06-0691, et al.

Approves revised residential real-time pricing (RTP) tariffs for subs CILCO, CIPS and IP. Finds rider pricing response program (PRP)—in conjunction w/existing RTP service—complies w/new law encouraging residential participation in demand response programs. Voluntary program allows customers to take market-based, hourly energy pricing service. Finds quantified PRP economic benefits from demand reduction are expected to exceed program costs, so all customers—including non-participants—benefit, and some program costs are eligible to be socialized. (Expects additional, non-quantified economic benefits from improved reliability/power quality, market power mitigation, and promotion of competition.) PRP participants must pay \$2.25/mo. charge. Approves recovery of remainder of program costs (for incremental metering, program admin/evaluation, data processing, and capacity/ancillary services) from all residential customers thru variable cost-based charge incorporated w/mo. customer charge. All residential delivery customers and those currently taking RTP service are eligible for Rider PRP service. Participants must have interval metering and agree to min. 12-mo. service obligation; exempts customers who change residences during initial period from latter. Approves processes to select/compensate independent program administrator.

Illinois CC – Commonwealth Edison

Decided 12/20/06 Filed 8/29/06 Case 06-0617

Approves revised residential real-time pricing (RRTP) tariffs, finds program—in conjunction w/company's revised basic electric service-hourly energy pricing rate (BES-H)—complies w/new law encouraging participation of residential customers in demand response programs. Voluntary program allows customers to take market-based, hourly energy pricing service. Finds quantified RRTP economic benefits from demand reduction are expected to exceed program costs by at least \$8.7m, so all customers—including non-participants—benefit, and some program costs are eligible to be socialized. (Expects additional, non-quantified economic benefits from improved reliability/power quality, market power mitigation, and promotion of competition.) First 110,000 customers choosing RRTP must pay \$2.25/mo. participation charge. Subsequent participants to pay “full cost of participation.” Approves recovery of remainder of initial program costs from all residential customers thru \$0.17 charge incorporated into monthly customer charge. Customers must have interval metering and agree to min. 12-mo. service obligation; exempts customers who change residences during initial period from latter. Approves processes to select/compensate independent program administrator. Also approves Rider RES-RRTP under which retail electric supplier can offer residential RTP program to its customers w/certain services provided by program administrator.

Illinois CC – Commonwealth Edison

Decided 12/20/06 Filed 5/23/06 Case 06-0411

Encourages contribution of \$30m in 2007-09 to low-income/senior programs and EE/renewable programs. Request made in conjunction w/CC approval of company's rate increase phase-in plan following expiration of frozen transition period rates. Considers any company expenditures under contribution to be voluntary and not eligible for recovery in future rates.

Idaho PUC – PacifiCorp

Decided 12/18/06 Filed 6/21/06 Case PAC-E-06-04, -08, -09

Following settlement, approves \$8.25m (5.1%) rate increase for irrigation/special contract customers. Approves deferral/refund of \$450,000, collected from irrigators 5/1/07-9/30/07, to encourage more participation in load control program in 2007 irrigation season; refund goes to irrigation participants by 12/31/07, resulting in lower (3.7%) total increase for this group. For Monsanto, approves increase in interruptible hours from 800 to 1,000/yr, to offset what would have been higher rate increase; says approved 16.5% increase (\$6.8m) moves Monsanto more than half-way to full cost of service.

Kentucky PSC – Kentucky Power

Decided 12/14/06 Filed 8/3/06 Case 2006-00373

Approves recovery of startup costs related to previously authorized home energy assistance program via DSM adjustment mechanism. Program to be funded by 10¢/mo. charge on residential meters and company contribution = surcharge revenue in first two years. Approves program details, e.g., coverage of customers who do not use electricity; subsidy is \$65 for electric participants/\$35 for non-electric.

Pennsylvania PUC – Duquesne Light

Decided 12/1/06 Filed 4/7/06 Case R-00061346, et al.

Following settlement, approves \$1.5m annual contribution thru 2010 to fund renewable and/or EE/education projects. At least 75% of funds to target projects in service territory w/remainder spent on projects directly benefiting customers in service territory. Action comes w/approval of \$117m (9.3%) distribution rate increase.

California PUC – Pacific Gas and Electric, San Diego Gas & Electric, Southern California Edison

Decided 11/30/06 Filed 6/1/05 Case A.05-06-006, et al.

Approves w/revisions company-proposed changes to demand response (DR) programs and several new DR programs to increase reliability in summer 2007 peak and beyond, following Jul 2006 heat wave that strained system. Approves funding thru reallocation of 2006-08 budgeted funds. Requires PG&E/SCE to solicit five-year proposals and bilateral agreements from customers/aggregators for permanent load shifting for summer 2007 and for additional DR resources. Says changes provide simpler incentive structures and enrollment processes, more flexible program rules, and increased role of third-party aggregators. New programs include PG&E AC cycling program, automated DR (Auto DR) for PG&E/SDG&E and expanded Auto DR pilot for SCE designed to link facility energy mgt. control w/external utility-generated price/emergency signals.

Approves increased incentives for three utilities for program where rebates offset costs of technology that customers install to participate in DR programs. (See 3/15/06 entry.)

Nevada PUC – Nevada Power, Sierra Pacific Power

Decided 11/13/06 Filed 6/30/06 Case 06-06051, et al.

Approves most of company-proposed DSM budgets of \$31.9m, \$37.4m and \$36.3m for 2007, 2008 and 2009 respectively. Opens investigation/rulemaking into DSM cost recovery mechanisms/incentives. Action comes w/approval of amendments to companies' integrated resource plans for which related costs are subject to rate case review.

New Hampshire PUC – Public Service Co. of New Hampshire

Decided 11/8/06 Filed 6/30/05 Case DE 04-072

Following partial settlement, approves revised 2004 least cost integrated resource plan (LCIRP) subject to changes. Requires fuller cost-effectiveness assessment of DSM relative to building new generation or purchasing supplemental power, including specific costs avoided w/DSM programs. Requires study of impact on DSM cost-effectiveness of potential CO₂ emissions regulation. Approves company use of total resource cost test to evaluate DSM cost effectiveness but requires study of effects of using rate impact test. Eliminates requirement for LCIRP inclusion of QF purchases as resource option in light of restructuring.

New Hampshire PUC – Unil Energy Systems

Decided 10/23/06 Filed 9/5/06 Case DE 06-123

Rejects company request to switch from six-month to annual default service rate for residential and small C&I customers to provide better rate continuity/smoothing, citing as one reason concern about sending wrong price signal that may result in less energy conservation during high-cost winter period.

Iowa UB – Interstate Power and Light

Decided 10/20/06 Filed 6/30/06 Case EEP-02-38, et al.

Following third settlement, approves major changes to interruptible program that: 1) equalize customer credits over time, 2) limit total hours of interruption to 64 except to maintain reliability, 3) include new customer charge applying to interruptible customers only, to which non-incentive program costs are transferred from EE cost recovery rider, and 4) establish three-tier classification system (normal, warning, interruption). Approves maintaining as EE program. (See 4/27/05, 5/15/06 entries.)

California PUC – Pacific Gas and Electric, San Diego Gas & Electric, Southern California Edison

Decided 10/19/06 Filed 6/1/06 Resolution E-4020

Approves new two-year capacity bidding program (CBP) to replace California Power Authority's demand reserves partnership when it expires May 2007. Says CBP projected to add 85 MW of demand response (DR) capability in 2007 and up to 100 MW in 2008; retail commercial/industrial/ag customers may nominate capacity directly or thru aggregators. PG&E to negotiate separate agreement w/wholesale customers. PUC modifies utilities' joint proposal to provide full capacity incentive payment (based on amount of nominated capacity/mo.) to aggregators and 80% to direct enrollees to facilitate third-party participation vs. no payment distinction. Also modifies to reward customers for partial demand reductions, include "day-of" component,

and fix capacity incentive payment rates for two years. Reduces requested budgets to reflect lower admin, measurement & eval costs; defers consideration of cost-effectiveness issues. Program funded per 2006-08 demand response budget approved 3/15/06 (Case A.05-06-006.) (See 3/15/06 entry.)

New Mexico PRC – Public Service Co. of New Mexico

Decided 10/5/06 Filed 7/6/05 Case 05-00275-UT

Following settlement, approves expansion of 141 MW Afton gas-fired CT to 235 MW combined cycle plant and related agreement to file by 1/31/07 to initiate comprehensive EE programs in acceleration of legislatively allowed schedule. Approves deferred recovery of related costs until after current rate freeze expires 12/31/07. Company to commission 3rd-party engineering study to evaluate renewable-sourced preheating of boiler feed water at or near plant.

Michigan PSC – Detroit Edison

Decided 9/26/06 Filed 9/30/05 Case U-14702

Rejects as inappropriate intervenor request to include resource planning and conservation/efficiency/DSM measures in power supply cost recovery process. Encourages rate design solutions that encourage such measures in more appropriate forum.

Connecticut DPUC – Connecticut Light and Power, United Illuminating

Decided 9/13/06 Filed 7/25/05 Case 05-07-14PH02

Approves RFP, subsequently issued 9/15/06, for procurement of incremental capacity to reduce federally mandated congestion charges (FMCCs) per 2005 Energy Independence Act. Includes generation, demand response and EE to meet projected 629 MW of demand in 2007, potentially increasing to 2,843MW in 2021, under contracts of up to 15 years. Capacity contracts allow bidders to bid one-way call option providing supplementary capacity payment to suppliers while hedging risk of high energy prices. Interim decision implements Phase 2 of FMCC reduction effort. (See 12/28/05 entry.)

Texas PUC – CenterPoint Energy Houston Electric

Decided 9/5/06 Filed 10/21/05 Case 32093

Following settlement, approves \$57.9m retail/wholesale rate cut consisting of \$52.9m distribution decrease and \$5m transmission decrease, to be frozen thru 6/30/10 w/certain exceptions. Approved decrease is net of \$10m company agrees to expend on EE programs annually, from 2007 thru filing of base rates by end of freeze period, plus pro rata share in 2006. Notes expenditures are in addition to \$13m of EE costs used in setting existing rates.

Florida PSC – Florida Power & Light

Decided 9/1/06 Filed 5/19/06 Case 060408-EI

Approves two new DSM programs (business water heating/business refrigeration) and seven revised DSM programs as requested by company per condition of 6/28/06 approval of need determination for West County Energy Center 1 & 2 generating plants. (See 6/28/06 entry.)

Minnesota PUC – Xcel Energy

Decided 9/1/06 Filed 11/2/05 Case E-002/GR-05-1428

Allows deferral of \$2.5m development costs for time-of-use pilot authorized but later terminated by PUC based on state of Washington experience showing residential customers paid more under TOU program; reaffirms prudence of such costs. Rejects company proposal to create rider mechanism, called “financial neutrality factor,” to compensate for loss of DSM/conservation improvement program (CIP) investment, including ROE portion of CIP investment. Opens probe into policies on conservation, EE, DSM, financial incentive mechanisms and related issues. Adopts company-supported changes to interruptible rates, including \$70/MWh threshold where load can be interrupted when estimated production/purchase costs exceed that amount, and 50¢ capacity credit increase for customers that are interruptible w/10 min. notice.

Michigan PSC – Detroit Edison

Decided 8/31/06 Filed 6/1/06 Case U-14838

Following settlement, approves optional power supply pricing under which customers may elect for min. two-year terms to have standby energy priced on basis of hourly market prices in response to unplanned generator outages, deviations from standby contract capacity, and maintenance. Standby energy to be priced based on real-time MISO locational marginal price plus 0.55¢/kWh added to apply to standby energy to recover MISO transmission/energy market costs. Admin/voltage level service adders also to apply. Pricing option is excluded from annual power supply cost recovery reconciliation. Action comes w/approval of two temporary \$78.75m rate reductions.

Connecticut DPUC – United Illuminating

Decided 8/30/06 Filed 7/18/05 Case 05-06-04

Finds decoupling sales from earnings is not disincentive to conserve, directs company to file proposal for sliding residential customer charge structure that reduces distribution revenue recovered thru energy charges, to be phased in over five years beginning 1/1/08. Requires company to move C&I customers \geq 350 kW to existing large power time of use (TOU) tariff, and to study/report on potential for phasing in mandatory residential TOU rates over next few years. Requires company to work w/ISO-NE on real-time or variable peak pricing proposal. Lengthens off-peak residential TOU period from 8 pm-9 am to 8 pm-noon, effective no later than 1/1/08. Directs company to submit plan to implement TOU pricing for transmission rates and federally mandated congestion charges. Rejects expansion of demand ratchets. Requires elimination of backup rate. Requires tracking/true-up of revenue impacts from rate design changes w/annual adjustment filing on 1/1; allows deferral of related costs for possible future recovery.

California PUC – Pacific Gas and Electric

Decided 8/24/06 Filed 4/14/06 Case A.06-04-014, et al.

Approves \$31.8m increase in low-income energy efficiency (LIEE) program budget vs. requested \$33.3m, all of which to be spent on additional LIEE installations. Amount includes previously authorized \$12m of LIEE carryover funds and brings total 2006 budget to slightly less than \$90m, funded by increase in public purpose program rates. Caps spending for 2006 admin and regulatory compliance at \$7.921m. Authorizes \$62,000 for pilot tankless water heater program. Notes other utilities in state did not request increases due to lower program targets.

Rhode Island PUC – National Grid

Decided 8/23/06 Filed 11/18/05 Case 3732

In advisory opinion to Energy Facility Siting Board, finds need/cost justification for company-proposed construction of new \$25.1m, 11.5 kV transmission line projects, citing company testimony that DSM/distributed generation alternatives were rejected as not providing enough capacity. Says project required for continued maintenance of firm/reliable electric supply.

Michigan PSC – Consumers Energy

Decided 8/22/06 Filed 9/30/05 Case U-14701

Denies intervenor request to include resource planning and conservation/efficiency/DSM measures in power supply cost recovery (PSCR) process, saying such concerns should be raised in more appropriate forum. Action comes w/approval of PSCR factor increase.

Nevada PUC – Nevada Power, Sierra Pacific Power

Decided 8/11/06 Filed 3/31/06 Case 06-03038, et al.

Reaffirms total resource cost test as primary DSM cost-effectiveness measure. Directs companies to: 1) consider new DSM programs to provide more cost-effective savings, 2) explore nonfinancial incentives for builders/developers, and 3) study costs/benefits and applicability of SoCal Ed residential Smart Metering programs. Approves budget increases for Sure Bet commercial customer incentives and Energy Star lighting and appliance programs. For latter, directs development of evidence of market share of such appliances, freeridership rates and need for continued direct financial incentives to participants. Rejects budget increase for second refrigerator collection/recycling project based on staff efficacy concerns. Directs creation of \$500,000, low income A/C replacement pilot w/conditions for 2006. Directs company efforts to expand participation in DSM collaborative. Actions come on proposed amendments to Nevada Power action plan for 2003-2022 integrated resource plan (IRP) and Sierra Pacific Power action plan for 2005-2024 IRP. Rejects staff proposal to limit action plan amendments in future.

New York PSC – Central Hudson Gas & Electric, Consolidated Edison Co. of New York, National Grid, New York State Electric and Gas, Orange and Rockland Utilities

Decided 8/1/06 Filed 3/28/07 Case 94-E-0952, et al.

Directs companies to file comprehensive plans for AMI development/deployment for all customers where feasible/cost-effective, including automated meter reading capability.

Illinois CC – Commonwealth Edison

Decided 7/26/06 Filed 8/31/05 Case 05-0597

Approves replacement of demand response (DR) Rider AC w/Rider AC7, which continues compensating residential customers for reducing load via installation of direct load control device. Approves consolidating core non-residential DR programs into Riders VLR7 & CLR7, which provide market-based incentives and pass thru value from PJM. Accepts company proposal to eliminate five other DR riders as outdated and inconsistent w/PJM incentives, and transitional interim supply rider as unneeded.

New York PSC – Consolidated Edison Co. of New York

Decided 7/24/06 Filed 7/21/05 Case 04-E-0572

Approves, modifies company proposed calculation of lost revenues related to systemwide/targeted demand management (DM) programs, per 3/24/05 order allowing DM-related lost revenue recovery via mo. adjustment clause. Company to multiply actual measured/verified kWh and kWh usage reductions using PSC-approved protocols (vs. company-proposed use of reported kWh/kWh usage reductions) by avg. seasonal rates, differentiated by each service class. Rejects company-proposed interest on lost revenues between DM install/actual recovery as unwarranted due to short interval. (See 3/16/06, 3/24/05 entries.)

South Dakota PUC – Montana-Dakota Utilities, Otter Tail Power, et al.

Decided 7/21/06 Filed 7/21/05 Case EL05-022

Conditionally approves construction by companies/five muni co-owners of 600 MW, coal-fired Big Stone II generating plant, saying DSM/renewables cannot meet this baseload demand; requires annual report as of 7/1/07 on DSM/renewable programs.

California PUC – Pacific Gas and Electric

Decided 7/20/06 Filed 6/16/05 Case A.05-06-028

Following stipulations, approves company-proposed advanced metering infrastructure (AMI) for all electric/gas customers and voluntary critical peak pricing (CPP) as of spring 2007 for residential and small C&I customers < 200 kW who install advanced meters. Authorizes recovery of estimated \$1.7b AMI costs over five years plus stipulated \$100m contingency providing for 10% shareholder penalty of overruns up to \$100m and post-fact prudence review for costs above \$1.8b. Adopts company-proposed electric/gas balancing accounts for recording AMI costs/operational benefits as incurred. Accepts company estimate of approx. 89% cost offset via anticipated operational savings/efficiencies, w/remaining 11% offset via demand response (DR) savings per CPP, and estimate of DR ranging from 206 to 448 MW by 2011 w/full AMI deployment and CPP rate. Adopted CPP provides higher rate for 15 critical peak periods/summer, lower rate in non-CPP summer hours, a participation credit (for residential, applies to higher statutory tiers), and first-year bill protection that guarantees customers pay no more under CPP tariff than under default rate.

Virginia SCC – Time-based Metering/Interconnection Standards

Decided 7/18/06 Filed 2/6/06 Case PUE-2006-00003

Declines to adopt EPAAct 2005 smart metering/interconnection standards, saying not convinced in public interest at this time. Cites utility availability of time-of-use rates, minimal customer demand, and uncertain customer capability/willingness to vary demand/usage in response to price changes in specific periods.

Florida PSC – Florida Power & Light

Decided 6/28/06 Filed 3/13/06 Case 060225-EI

Approves construction of proposed West County 1 and 2 gas-fired, combined-cycle peaking plants in Palm Beach Co. after company agrees to accelerate construction of coal-fired plants to diversify fuel sources, increase DSM/conservation programs, and expand pricing options for renewable producers.

Indiana URC – PSI Indiana

Decided 6/28/06 Filed 6/1/06 Case 42870

Following settlement, approves recovery of \$8.6m via summer reliability adjustment mechanism (Rider 70) for 10/1/04-9/30/05. This reconciliation amount includes purchased power demand costs, peak load management (PowerShare[®]) costs (\$628,004 credit) and off-system sales sharing (\$5.9m ratepayer charge), resulting in total 0.5% residential increase. Approves two-year pilot to expand PowerShare[®] from summer-only to year-round vs. initial request for permanent year-round recovery.

Florida PSC – Progress Energy Florida

Decided 6/26/06 Filed 1/20/06 Case 060048-EG

Approves modifications to three existing residential and two C&I DSM programs to meet new federal EE requirements, effective 8/1/06 when incorporated in state code, and to increase customer participation to help offset rising fuel costs. Approves recovery of reasonable/prudent costs thru energy conservation cost recovery clause.

Wisconsin PSC – Wisconsin Power and Light

Decided 6/6/06 Filed 2/6/06 Case 6680-GF-119

Approves increase in capital investment in Shared Savings DSM program from \$21m to \$40m for 2006, but defers ruling on request for expansion to \$40m in each of 2007 and 2008. Says as-yet unavailable results of company-commissioned study of third-party freeridership and impact on program of 2005 law that will result in DSM program funding/delivery changes must first be evaluated.

California PUC – Pacific Gas and Electric, San Diego Gas & Electric, Southern California Edison

Decided 5/25/06 Filed 1/20/05 Case A.05-01-016, et al.

Declines to adopt settlements opposed by consumer advocate TURN setting critical peak pricing (CPP) rates, directs inclusion of default CPP tariffs for customers w/loads ≥ 200 kW into next comprehensive rate design or other proceeding. Cites TURN concerns that agreements result in more limited demand response than default tariff. Says settling parties did not accept PUC preferred terms provided in ALJ proposed decision that supported 2006-07 as transition years from voluntary program to default rate, bill protection for 12 months, and bill analysis at end of 2006 critical peak period. PG&E/SCE joint settlement set voluntary CPP structure for bundled customers w/peak demand ≥ 200 kW; SDG&E settlement set default CPP tariff for C&I customers w/peak demand ≥ 200 kW. Indicates settlements' bill protection/analysis provisions less extensive than preferred terms. (See 4/21/05 entry.)

Minnesota PUC – Minnesota Power

Decided 5/19/06 Filed 9/15/04 Case E-015/RP-04-865

Following settlement, requires 60 MW of additions to renewable portfolio, transfer of Taconite Harbor coal-fired, unregulated wholesale generating plant into rate base, and addition of 50 MW of baseload capacity via PPA w/Manitoba Hydro. Finds DSM measures cannot eliminate need for additional baseload capacity. Action comes w/approval, modification of 2004 integrated resource plan.

Iowa UB – Interstate Power and Light

Decided 5/15/06 Filed 10/27/05 Case EEP-02-38, et al.

Following second settlement, approves new decision rules expanding criteria for C&I interruptions/residential AC cycling to increase energy/capacity savings. Approves new “buy through” tariff offering interruptible customers chance to avoid up to two of possible 10 interruptions/yr (or three of > 10 events) by paying cost of non-interruptible energy during interruption period, based on real-time locational marginal price at load zone plus any MISO market charges incurred by utility as result of buy-thru. Says new decision rules meet UB concerns that programs not being used optimally, e.g., no interruptions occurred in 2005. Sets reporting/notification requirements. (See 4/27/05 entry.)

Idaho PUC – Idaho Power

Decided 5/9/06 Filed 3/3/06 Case IPC-E-06-5

Approves second one-year extension of two previously approved residential TOU pricing pilots originally set to expire 4/1/06. Approves two changes: 1) limiting availability to customers w/usage \geq 300 kWh, and 2) increasing price differential between on-peak, off-peak, and mid-peak to provide stronger financial incentive for customers to shift usage. (See 3/22/05 entry.)

Iowa UB – Interstate Power and Light

Decided 4/28/06 Filed 6/30/05 Case RPU-05-3

Approves more uniform class rate structures/changes as part of revenue-neutral process to consolidate tariffs and equalize rate disparities across state resulting from mergers during past decade. For **residential**, rejects declining block summer energy rate in favor of flat design, saying former sends wrong message to increase usage, contrary to EE goals. Accepts three-step declining block rate for winter upon showing of significant load factor improvements w/increased kWh usage and fewer cost pressures for reducing peak demand. Adopts residential mo. \$10.50 customer charge, saying it mitigates billing impacts but does not reflect full customer cost, and avg. 2¢/kWh seasonal rate differential. For **commercial** class, adopts \$17.80 mo. customer charge, an avg. 2¢/kWh seasonal rate differential, and two-step declining block energy rate structure. Says it will explore declining block summer rate in future. Requires phase-in for four frozen rates. For **large commercial** class, accepts five-step declining block kW demand rate structure, saying EE messages are less important for large customers. Approves company method for calculating reactive demand charge/standby tariff, but requires filing of new standby tariff in next equalization filing. Adopts 50 kW min. billing demand. Accepts completion of process of moving some large customers to commercial class, w/mitigation provisions. Adopts other company-proposed changes, including realigned kW demand/kWh energy ratios and avg. seasonal rate differentials of \$6/kW and 0.7¢/kWh. Approves changes in day-ahead hourly pricing pilot to correct problems, e.g., encouraging certain customers to participate w/o changing usage patterns. Allows bulk power rate in all pricing ranges w/conditions/changes, and TOU rate revision w/annual true-up of estimated vs. lost TOU revenues.

New York PSC – National Grid

Decided 4/28/06 Filed 8/31/05 Case 01-E-1847

Approves company-proposed revisions to standby rate exemptions as follows: 1) extends exemption for small generators \leq 5 kVA from 12/31/05 to 12/31/11 (end of merger rate plan), 2) grants certain standard rate

customers one-time option to receive standby service prior to 12/31/11, and 3) maintains exemption for on-site generators using environmentally advantageous technologies. Also approves company-requested waiver of competition transition charge (CTC) related to standby contract demand charge for qualifying (i.e., energy efficient) combined heat/power projects, thereby encouraging purchase of standby service vs. installation of redundant/potentially uneconomic generation units. Lost revenue related to waiver to be included in standby service lost revenue deferral account and recovered thru adjustment at each CTC reset.

Nevada PUC – Sierra Pacific Power

Decided 4/27/06 Filed 10/3/05 Case 05-10003, et al.

Allows enhanced 5% ROE for \$905,000 of accumulated DSM costs based on previously approved stipulation. For these investments, the 5% is added to the existing allowed ROE of 10.6%. Disallows \$38,000 of requested \$3.1m of such costs in rate base and reduces DSM amortization expense by \$19,000, reflecting overbudget amount for Residential New Construction Builder Support program. Says company did not adequately justify program's consolidation w/Residential Energy Star for New Homes program.

New Jersey BPU – Public Service Electric and Gas

Decided 4/27/06 Filed 2/2/06 Case EO04060395

Approves company-requested transfer of customers enrolled in pilot load management day-ahead hourly pricing program (myPower Manager) to pilot time of use/critical peak pricing program (myPower Connection). Action follows company discovery that participants in former would see monthly bills increase, regardless of whether usage shifted to off-peak, due to high PJM hourly energy pricing compared to basic generation service auction price and also due to inclusion by company of G&T obligation costs thru flat 10¢/kWh adder to all summer weekday afternoon hourly energy rates. The two pilots and a full technology demand response program are set to begin 6/1/06 after initial approval 8/24/04, along w/deferred accounting treatment for actual incremental costs totaling approx. \$3.77m.

Hawaii PUC – Hawaiian Electric

Decided 4/26/06 Filed 12/5/05 Case 05-0069

Requires discontinuation of lost revenue/shareholder incentive recovery for all DSM programs, saying unsuitable in light of expected reserve capacity shortfall of 70 MW in 2006 and of law that requires renewable energy resource use. Action comes w/rejection of company request to continue lost margin recovery/shareholder incentives for existing DSM programs, citing company agreement per previously approved settlement not to seek to continue such measures in next rate case or thereafter. Approves company's interim proposals to modify several existing nonresidential efficiency/DSM programs and launch new residential program (Energy Solutions for the Home) to obtain approx. 3.87 MW of demand reduction to help address expected reserve capacity shortfall.

Washington UTC – PacifiCorp

Decided 4/17/06 Filed 5/5/05 Case UE-050684

Rejects three-year pilot decoupling mechanism proposed jointly by company and Natural Resources Defense Council that would allow recovery of revenue lost due to conservation efforts. Features included separating fixed cost from variable cost revenue requirements, annually truing up over-/under-recoveries from approved benchmark posted to balancing account, and removing weather risk by adjusting sales for weather-driven

fluctuations before true-up. Also rejects inter-jurisdictional cost allocation method (Revised Protocol) underlying request due to lack of showing of extent to which out-of-state facilities benefit Washington ratepayers. Says rejection of decoupling mechanism based on: 1) lack of approved underlying allocation methodology, 2) lack of necessary operational details, and 3) failure of company to identify/commit to incremental conservation measures to counterbalance potential risk reduction.

Arizona CC – Arizona Public Service

Decided 4/12/06 Filed 7/1/05 Case E-01345A-05-0477

Approves residential part of DSM portfolio plan filed per 4/7/05 order requiring \$48m of DSM expenditures over 2005-07 and creation of DSM working group. Approves staff estimated \$10.3m of net benefits and annual 17.7 MW peak demand reduction. Programs involve new construction, HVAC efficiency, and measurement/eval/research (MER). Company estimates \$9.8m of costs for first two programs and \$3.9m for MER over three-year period. (See 4/7/05, 2/23/06 entries.)

Arizona CC – Arizona Public Service

Decided 4/12/06 Filed 9/22/05 Case E-01345A-05-0674

Approves two experimental, voluntary residential time-of-use (TOU) rates similar to existing rates but w/two changes: 1) off-peak period is 7 pm-noon vs. existing 9 pm-9 am, and 2) ratio of summer on-peak to off-peak kWh charges is greater. Approves company-proposed higher rates to maintain revenue neutrality, saying customers will have greater chance to consume off-peak and intent is not to penalize/benefit company. Rejects company-proposed limit of 20,000 and staff limit of 50,000 participants, saying all customers should be able to use TOU rate to help lower consumption in light of recent rate increases. Rejects company request to recover \$1.2m of implementation costs thru basic service charge over three years, but allows opportunity to seek such recovery once enrollment reaches 50,000. Notes staff concern w/use of same on-/off-peak periods in winter/summer months but accepts company proposal in favor of simplicity, saying winter load shape has little impact on capacity needs; directs information to allow assessment when permanent TOU rates sought.

Delaware Legislature – Delmarva Power & Light

Decided 4/6/06 Filed 4/6/06 Law HB 6

In connection w/rate increase phase-in plan and integrated resource planning directives, HB 6 law authorizes PSC to require Delmarva P&L to implement DSM programs using techniques such as time-of-use rates, advanced metering, central A/C and water heating cycling, and interruptible rates, but prohibits use of “peak time billing.” Law requires recovery of costs of PSC-approved DSM programs thru distribution rates. Directs PSC in 60 days to start investigation of desirability and cost effectiveness of using advanced and time-of-use metering, but prohibits it from ordering 30-day peak demand billing unless legislature approves.

Connecticut DPUC – DG Incentive Rules

Decided 3/27/06 Filed 9/13/05 Case 05-07-16

Approves rules under which costs of customer-side distributed generation (DG) education, marketing, and promotion activities are assumed to be recoverable thru one-time monetary awards utilities are eligible for when DG units come online. Awards begin at \$200/kW for resources operational by 1/1/08, and decline by \$50/kW each year after that, remaining at \$50/kW after 1/1/10. Award amounts come from federally

mandated congestion charges (FMCCs) and are **not** counted as utility earnings for ratemaking purposes. Combined heat and power, demand reduction, and demand response systems are also eligible. Prudent utility costs of bringing customer-side DG online (technical, interconnection work, etc.) that DPUC finds prudent are recoverable from FMCCs to extent resulting reductions in FMCCs exceed costs. Customers installing and owning DG are eligible for monetary grants to defray capital costs, rebates of natural gas delivery charges, exemption from backup service charges, waiver of demand-ratchet features on firm gas service rates, and awards of renewable energy certificates for renewable DG output. Incentives range from \$200/kW to \$500/kW, depending on amount of FMCC reductions. Utility costs for gas delivery rebates, lost electric revenues, and customer incentive payments are recoverable thru FMCC reductions. (See 3/27/06 entry for Case 05-07-17.)

Connecticut DPUC – Connecticut Light and Power, United Illuminating

Decided 3/27/06 Filed 8/24/05 Case 05-07-17

Approves program for companies to award DPUC-approved monetary grants for capital costs to customers installing/owning new or incremental customer-side distributed resources (DR). Allows \$200/kW for emergency generators and \$450/kW for baseload customer-side projects, recoverable from federally mandated congestion charges (FMCCs). Non-generation demand response and conservation and load management to be awarded grants case-by-case. Requires CL&P and UI to purchase excess power from grant-approved DR projects thru existing rates based on ISO-NE spot market rate. Does not set performance metrics but requires initial security = 50% of grant and directs utilities to monitor/report annually on DR development/performance. (See 3/27/06 entry for Case 05-07-16.)

New Hampshire PUC – Granite State Electric, Public Service Co. of New Hampshire, et al.

Decided 3/17/06 Filed 10/4/05 Case DE 05-157

Following settlement, approves 2006 EE programs and continuation of performance incentive mechanism for achieving specific program goals. Per 2000 order, target incentive set at 8% of total program and evaluation budgets for each customer segment. Superior performance may be rewarded up to 12% of planned segment budgets. Incentive mechanism based on program performance measured in terms of actual cost-effectiveness and energy savings relative to projected cost-effectiveness and energy savings.

New York PSC – Consolidated Edison Co. of New York

Decided 3/16/06 Filed 8/16/05 Case 04-E-0572

Approves, modifies collaborative action plan to promote/improve demand management activities to cost-effectively reduce load growth in company's service territory, per 3/24/05 order. Plan provides for measurement of cost-effectiveness of specific initiatives on total resource cost (TRC) basis and allocation of program funding among EE, load mgt., and distributed generation. To resolve disputes/disagreements among collaborative members over definition of TRC cost test, addresses potential benefits as follows: 1) approves inclusion of agreed-upon elements of avoided electric energy usage, avoided capacity, avoided use of fuel, and quantifiable water/maintenance savings; 2) conditionally approves inclusion of avoided T&D costs, environmental externalities, and market power mitigation; and 3) rejects inclusion of market price effects, avoided ancillary service costs, and avoided variability and risk. (See 3/24/05 entry.)

Vermont PSB – Green Mountain Power, Vermont Electric Power

Decided 3/16/06 Filed 12/6/04 Case 7032

Approves \$20.3m transmission upgrade in Lamoille County to meet present/future demand that cannot otherwise be met via conservation/EE/load mgt. measures. Find DSM insufficient and distributed generation less reliable/available to defer/eliminate need for project.

California PUC – Pacific Gas and Electric, San Diego Gas & Electric, Southern California Edison

Decided 3/15/06 Filed 6/1/05 Case A.05-06-006, et al.

Following settlement, adopts demand response programs for 2006-08 w/following three-year budgets: PG&E-\$108.7m; SCE-\$101m; SDG&E-\$52.6m. SCE cost recovery is thru next rate case and subsequently in energy resource recovery account (ERRA) filing, w/tracking to occur in one-way balancing account. ERRA tracks fuel and purchased power revenues against recorded actual costs. PG&E cost recovery is thru rates using annual electric true-up or other proceeding, and using balancing accounts that cap expense and provide for over-/under-collections. In modification, prohibits elimination of scheduled load reduction program, citing statutory requirement.

Idaho PUC – PacifiCorp

Decided 3/3/06 Filed 9/6/05 Case PAC-E-05-10

Approves new rider to recover 1.5% of retail revenue (\$1.8m) to fund new, revised and expanded DSM programs for residential, commercial, industrial and agricultural customers, effective 5/1/06. Action finalizes conditional approval per previous order (Case 29952), which found residential class would benefit proportionately less than other classes. Accepts amended proposal to establish home EE incentive program for residential customers. Authorizes cost deferral for future recovery thru rider, w/reciprocal carrying charges set at customer deposit rate vs. company-proposed AFUDC rate.

Arizona CC – Arizona Public Service

Decided 2/23/06 Filed 7/1/05 Case E-01345A-05-0477

Approves non-residential part of company-proposed DSM portfolio plan on interim basis, directs re-filing of plan in 13 months for permanent decision. Plan was filed per 4/7/05 order requiring company to spend \$48m over 2005-07 and establish collaborative DSM working group. Allows recovery of \$1m of planning/admin expenses, w/opportunity to seek recovery of rest in 13 months. Allows schools K thru 12 to participate in any non-residential DSM program, seeks data in 13 months. Approves staff estimated \$41.4m of net savings. (See 4/7/05, 4/12/06 entries.)

Indiana URC – Vectren Energy Delivery

Decided 2/22/06 Filed 5/16/05 Case 42861

Following settlement, approves collaborative process for parties to consider DSM programs, to culminate in filing of proposed residential and commercial programs. Provides for company to file green power rider in 2006 and evaluate renewable energy projects for future resource alternatives. Action comes w/approval of clean coal technology projects and ratemaking treatments.

Rhode Island PUC – National Grid

Decided 1/26/06 Filed 10/14/05 Case 3701

Following settlement, approves DSM programs for 2006 w/projected total budget of \$21.7m, funded thru conservation and load management adjustment and renewable factor of \$0.0023/kWh, as in 2005, with \$0.002/kWh to be applied to DSM programs and \$0.0003/kWh to be submitted to state Energy Office Renewables Programs. Approves shareholder incentive allowing company to earn up to \$20,000 for each of four performance-based metrics vs. \$15,000 for each of five metrics in 2005, and target incentive rate for kWh savings by sector of 4.4% of eligible spending budget (as in 2005). Target incentive amount is \$733,932 in 2006 vs. \$673,475 in 2005. The 2006 threshold performance level of energy savings is 60% of annual energy savings goal by sector vs. 45% in 2005. Company may earn additional incentive on savings of up to 125% of target savings, capped at \$897,415.

Ohio PUC – FirstEnergy

Decided 1/4/06 Filed 9/9/05 Case 05-1125-EL-ATA, et al.

Following supplemental settlement, approves funding/implementation of DSM programs in 2006-08 and deferral/recovery of costs thru semiannual reconcilable rider as of 2009. Programs are Home Performance Energy Star @\$10m total, and Residential AC direct load control @\$15m total. Continuation of programs subject to meeting total resource cost (TRC) test. Costs are recoverable regardless of test result and include lost distribution revenues and carrying costs at each operating company's long-term cost of debt over three years starting in 2009. Any DSM funding not spent to roll over for one year. Companies to provide additional \$3m for DSM programs over 2007-08. (See 2/14/07 entry.)

2005

Connecticut DPUC – Connecticut Light and Power, United Illuminating

Decided 12/28/05 Filed 7/25/05 Case 05-07-14PH01

Approves \$12.3m expenditures to reduce near-term peak demand by estimated 43.3 MW in first of two-phase initiative to reduce federally mandated congestion charges (FMCCs) per 2005 Energy Independence Act. Approves CL&P \$7.94m 2006 budget for estimated 34.65 MW reduction vs. requested \$21.2m for 35 MW; to be funded by 2005 carryover funds from conservation and load management (C&LM) funds, resulting in no net rate increase. Approves UI \$4.36m 2006 budget for estimated 8.65 MW annual reduction vs. requested \$19.3m for 19 MW; to be funded by \$1.3m of carryover C&LM funds, resulting in \$3.1m net increase, recoverable via FMCC charges. Directs companies to apply for lost revenue recovery in semi-annual FMCC proceedings, saying it will allow recovery related to measures implemented while under-earning until next rate case decision. Approved programs include residential AC/lighting, gas efficiency, C&I load curtailment, and emergency generation. Estimates \$24.1m net benefits over first five years and \$57.8m over 10 years. Rejects company-proposed direct load control programs for residential and small C&I, requires more detailed filings. (See 9/13/06 entry.)

Ohio PUC – Cincinnati Gas & Electric

Decided 12/21/05 Filed 2/17/05 Case 05-59-EL-AIR

Following stipulation, requires implementation of non-residential DSM tracker, set initially at zero. Program content to be determined, but must include \$1.5m over three years for programs targeted at school facilities. Company must apply for approval of any DSM rider.

California PUC – Pacific Gas and Electric, San Diego Gas & Electric, Southern California Edison

Decided 11/18/05 Filed 6/1/05 Case A.05-06-004, et al.

Approves interim funding of \$163m (7.6% of total portfolio funding) for evaluation, measurement and verification (EMV) activities over 2006-08 EE program cycle. Allows cost recovery thru nonbypassable energy adjustment clause as it did for non-EMV portion approved on 9/22/05. (See 9/22/05 entry.)

Montana PSC – NorthWestern Energy

Decided 10/14/05 Filed 6/20/05 Case D2005.5.88

Approves net \$24.2m interim increase for 2005-06 electric default supply tracker period, excludes \$1m allowance for lost T&D revenues resulting from DSM programs for default supply customers. Says premature to allow tracking mechanism to remove financial disincentives to cost-effective DSM programs.

Hawaii PUC – Hawaiian Electric

Decided 9/27/05 Filed 11/12/04 Case 04-0113

Following partial settlement, approves interim \$53.3m (4.36%) base rate increase; disallows \$750,000 in conservation/EE advertising in customer service expenses.

New York PSC – Mandatory Real-time Pricing

Decided 9/23/05 Filed 4/30/03 Case 03-E-0641

Requires utilities to file w/in 60 days tariffs for mandatory, accelerated real-time pricing (RTP) programs for largest customer classifications that provide for mandatory time-of-use rates, saying measured pace of voluntary implementation is “no longer satisfactory” in face of rising fuel prices. Cites experiences of National Grid/CHG&E in requiring RTP for largest customers; directs National Grid to expand program to “significantly sized” customers, excuses CHG&E from additional tariff filings for now. Says RTP sends more accurate price signals, enabling more efficient demand response that benefits individual customers avoiding high-cost peak usage and ultimately all other customers by leading to more efficient investments in generation supply options. (See 4-18-05 entry.)

California PUC – Pacific Gas and Electric, San Diego Gas & Electric, Southern California Edison

Decided 9/22/05 Filed 6/1/05 Case A.05-06-004, et al.

Approves interim 2006-08 efficiency portfolio plans/funding and cost recovery thru nonbypassable energy adjustment clause charges. Requires at least 20% of funding (\$500m) to be allocated to competitively bid contracts for EE programs/measures. Concurs w/estimated \$5.4b in total resource savings over three years at \$2.7b cost. Allows 2006 funding to be spent in 2005 to reduce winter gas heating bills. Withholds final approval until companies finalize solicitations/compliance filings and develop final plans. Later proceedings to address evaluation, measurement & verification and risk/reward incentive mechanisms.

Texas PUC – Southwestern Electric Power

Decided 9/12/05 Filed 1/12/05 Case 31427

Following settlement, approves construction of 24.5-mile, 138 kV, DC transmission line/related facilities on company-preferred route along corridor of existing 69 kV line in Wood, Franklin and Hopkins counties, to connect existing Winnsboro and North Mineola substations to meet increased service/reliability needs arising from load growth. Says alternatives including distributed generation/renewable/EE measures are inadequate to relieve overload conditions.

Texas PUC – Entergy Gulf States

Decided 8/23/05 Filed 4/1/04 Case 29420

Following stipulation, approves construction of \$8.4m, five-mile, 230 kV transmission line in Montgomery Co. to meet significant load growth, saying eight alternatives included more costly distributed generation and DSM alternatives that would not address reliability concerns.

Kansas CC – Kansas City Power & Light

Decided 8/5/05 Filed 5/18/04 Case 04-KCPE-1025-GIE

Following settlement, approves company commitment to implement \$52.8m of demand response, EE and affordability programs, subject to approval/continuing review on program-by-program basis. Action comes w/approval of regulatory plan committing company to \$1.3b infrastructure investment program thru 6/1/10.

Missouri PSC – Empire District Electric

Decided 8/2/05 Filed 2/4/05 Case EO-2005-0263

Following settlement of long-term regulatory plan, approves formation of collaborative to make decisions on EE/demand response/affordability programs. Requires accumulation of related costs in regulatory asset accounts as incurred, to be amortized over 10 years as of earlier of effective date of next rate case or 3/27/08. Amounts not included in rate base to earn return of up to reduced AFUDC rate.

Wisconsin PSC – Wisconsin Power and Light

Decided 7/19/05 Filed 9/17/04 Case 6680-UR-114

Restores ROE on DSM investments (Shared Savings) to level of overall return (11.5%). Previously was lowered to 8% to reflect lower risk; says higher return provides incentive to aggressively pursue EE. Calls for success measures and savings goals, says “time is right to fully explore true-up mechanisms and performance-based incentives,” but not in this proceeding. (See 6/6/06 entry.)

Massachusetts DTE – NSTAR

Decided 6/30/05 Filed 2/21/03 Case 03-6

Approves company estimates of DSM savings for 1998-2000, authorizes recovery of \$12.7m of associated claimed shareholder incentives, representing 10.3% of \$123.7m spent on EE for period.

Maryland PSC – Delmarva Power & Light

Decided 6/22/05 Filed 8/20/03 Case 8975

Following settlement, approves standby service rider applying to new/existing customers who install/operate on-site generation after 5/1/04. Initial proposal revised to specify: exemption of self-generators < 60 kW; 20% reduction of energy/billing demand charges; grandfathering of certain existing generators; and exemption of 670 MW gas-fired Rock Springs plant during distribution rate freeze that ends 12/31/06.

Wisconsin PSC – Wisconsin Electric Power

Decided 5/17/05 Filed 5/10/04 Case 05-UR-101

In approving \$59.7m rate increase (3.1%), allocates costs of EE procurement plan (EEPP) using a system demand allocator for 50% of EEPP costs and 50% of EEPP costs on basis of dollars spent by customer class. The EEPP encourages customers to reduce demand at peak times. PSC to continue to review allocation of these costs in future rate cases.

Idaho PUC – Idaho Power

Decided 5/13/05 Filed 12/6/04 Case IPC-E-04-29

Approves increase in EE rider surcharge from 0.5% of base revenues to 1.5%, effective 6/1/05, and caps residential charges at \$1.75/mo. and irrigation customers at \$50/mo. to moderate increases. Denies additional increase on 6/1/07 to 2.4% in favor of periodic review. Approves application on percentage basis vs. existing flat fee for all customers except as conditioned by two caps. Approves new self-directed DSM option for

industrial and special contract customers. Says it expects faster deployment of DSM programs vs. further accumulation of funds.

Iowa UB – Interstate Power and Light

Decided 4/27/05 Filed 1/23/04 Case EEP-02-38

Following settlement, approves maintaining existing interruptible program until MISO Day 2 market has run one full year. Directs parties to jointly develop/file report by 6/30/06 on MISO Day 2 impacts and any proposed interruptible program changes, including those addressing status as EE program and achieving customer credit equalization. (See 5/15/06, 10/20/06 entries.)

California PUC – Pacific Gas and Electric, San Diego Gas & Electric, Southern California Edison

Decided 4/21/05 Filed 1/20/05 Case A.05-01-016, et al.

Rejects proposed default critical peak pricing tariffs for customers > 200 kW for summer 2005, saying customers have little ability to mitigate bill increases due to proposed rate designs even w/significant usage reduction, and limited applicability to non-ag customers between 200-500 kW per successful intervenor arguments significantly reduces potential demand reduction. Directs companies to file new proposals on 8/1/05, for consideration in separate rate design proceedings, that are more consistent w/each other and w/specified principles, e.g., rates for non-critical peak hours must be based on an adopted revenue requirement for all hours reflecting costs in a year w/no critical peak events and separate rate for critical peak period must reflect anticipated marginal cost to procure power during those periods. Also directs companies to explore narrowed peak of 2pm-6pm. (See 5/25/06 entry.)

Pennsylvania PUC – West Penn Power

Decided 4/21/05 Filed 11/25/03 Case R-00039022, et al.

Following settlement, allows customers generating surplus to choose two-meter or smart-meter option to receive payment for surplus. Company responsible for first \$1,000 of local distribution system upgrades for such purchases. Any future rate impacts to be addressed in future proceedings.

Hawaii PUC – Hawaiian Electric

Decided 4/20/05 Filed 5/15/03 Case 03-0142

Denies w/o prejudice proposed residential customer energy awareness pilot program and recovery of \$3.6m over two years via DSM adjustment component of integrated resource planning (IRP) cost recovery provision. Cites inability to determine cost-effectiveness per IRP framework requirements and to adequately measure results. Suggests program may be better suited as one component of DSM portfolio.

New York PSC – Central Hudson Gas & Electric

Decided 4/18/05 Filed 8/1/00 Case 00-E-1273

Approves elimination of market price charge (MPC) for large power companies, which now must choose hourly pricing provision (HPP) or energy service provider under retail access program. MPC reflects avg. monthly ¢/kWh cost of commodity purchases; HPP bills at NYISO hourly day-ahead, locational-based market price based on each customer's actual load shape. Says study showed HPP would result in bill increase due to hedge benefits reflected thru MPC and underlying rate design inaccuracies; approves

continued pro rata benefit of existing hedge for customers choosing HPP, but prohibits application of new hedges, saying previously approved policy bars new hedging for med-large C&I customers (Case 00-M-0504). Also approves replacing current HPP installed capacity charge w/unforced capacity obligations (UCAP) charge, saying UCAP to more accurately assign cost responsibility and energy balancing requirements among full service customers. (See 9/23/05 entry.)

Arizona CC – Arizona Public Service

Decided 4/7/05 Filed 1/27/03 Case E-01345A-03-0437

Following settlement, requires APS to continue funding DSM programs from base rates (\$10m annually) and an adjustor (averaging \$6m per year). Adjustor applies to both SOS and direct access customers. APS commits \$13m for DSM in 2005. Settlement creates DSM Working Group, which CC requires to target schools as a top priority. Requires APS to study whether large customers should be permitted to self-direct DSM investments and rate designs encouraging EE. DSM resources to be invited to participate in competitive solicitations and evaluated “in a consistent and comparable manner.”

Texas PUC – Southwestern Electric Power

Decided 4/5/05 Filed 10/20/03 Case 30659

Following settlement, approves construction of 22-mile, 138 kV, DC transmission line project in Camp, Wood and Franklin counties to meet load growth, saying alternatives including renewable/EE/distributed generation measures are inadequate to relieve overload conditions.

Colorado PUC – Xcel Energy

Decided 3/30/05 Filed 11/16/04 Case 04A-566E

Following settlement, approves \$4m residential price response pilot program w/cost recovery thru yearly DSM cost adjustment as incurred. Pilot available to residential customers in Boulder/Denver who use min. 1,800 kWh total during June, July and August and consists of three tariffs: residential time of use (TOU), critical peak pricing, and critical TOU. Makes program voluntary for company as well as customers, directs report on success and filing by 3/31/08 to expand or withdraw program depending on results.

Vermont PSB – Central Vermont Public Service

Decided 3/29/05 Revised 4/4/05 Filed 7/15/04 Case 6946, et al.

Requires removal of recurring distributed utility DSM expenditures from deferral account, thereby reducing balance to zero, and return to ratepayers of related over-collection in 2001-03. Says deferrals under previous accounting orders of DSM and other costs are high and could result in “intergenerational inequities; orders “reverse” amortization when a regulatory asset or liability expires so that associated rate revenue is booked as a regulatory liability and does not flow thru to income.

New York PSC – Consolidated Edison Co. of New York

Decided 3/24/05 Filed 4/30/04 Case 04-E-0572

Authorizes approx. \$224m to fund demand management activities in company service territory w/overall 300 MW target, split 50-50 between ConEd and New York State Energy R&D Authority. Allows recovery of lost revenues related to systemwide and targeted programs thru monthly adjustment clause. Institutes

collaborative process to address 16 specified topics. Initiatives to include EE, load management and distributed generation measures aimed at cost-effectively reducing load growth and deferring/avoiding T&D infrastructure investments. Action comes w/approval of three-year rate plan. (See 3/16/06 entry.)

Idaho PUC – Idaho Power

Decided 3/22/05 Filed 2/2/05 Case IPC-E-05-2

Approves two company-proposed, voluntary TOU pricing pilots for up to 300 total residential customers participating in advanced meter reading project, as follows: 1) Energy Watch program sets higher flat rate for consumption during designated watch periods, and 2) Time-of-Day program promotes shifting summer usage from peak to off-peak via three energy rates for on-peak (1 pm-9 pm M-F), mid-peak (7 am-1 pm M-F) and off-peak (9 pm-7 am all days + all hours Sat, Sun, and 4th of July). Pilots to run 6/1/05-4/1/06. (See 5/9/06 entry.)

North Carolina UC – Dominion North Carolina Power

Decided 3/18/05 Filed 1/29/04 Case E-22, Sub 412, et al.

Following stipulation, approves recording and amortizing regulatory liability and related deferred income tax costs associated w/ accumulated DSM cost over-recoveries. Former DSM deferral procedure no longer in effect. Action comes w/approval of \$12m reduction, five-year freeze.

Rhode Island PUC – Narragansett Electric

Decided 2/17/05 Filed 9/30/04 Case 3635

Following settlement, approves DSM programs for 2005 w/projected total budget of \$21.7m, funded thru conservation and load management adjustment and renewable factor of \$0.0023/kWh, w/\$0.002/kWh to be applied to DSM programs and \$0.0003/kWh to be submitted to state Energy Office. Approves shareholder incentive allowing company to earn up to \$15,000 for each of five performance-based metrics, and target incentive rate for kWh savings by sector of 4.4% of eligible spending budget. Target incentive amount is \$673,476. The 2005 threshold performance level of energy savings is 45% of annual energy savings goal by sector. Company may earn additional incentive on savings of up to 125% of target savings.

Florida PSC – Tampa Electric

Decided 2/16/05 Filed 1/13/04 Case 040033-EG

Approves all but one program in DSM plan, w/cost recovery via energy conservation cost recovery (ECCR) mechanism, effective 2/15/05. Finds approved programs cost-effective but will decide prudence of expenditures in annual ECCR cases. Plan includes new residential price response load mgt. pilot using multi-tiered rates/price signals to alert participants to reduce load/energy consumption during high-cost periods, and provides smart thermostats that can be manually adjusted in response to multi-tiered rates or critical price signals. Orders closing of existing voluntary residential load mgt. program (Prime Time) under which company interrupted service to water heaters, pool pumps and central heating/AC units to reduce peak demand, saying no longer cost-effective. Approves continuation of existing DSM programs w/few or no changes, including seven residential, eight C&I, one cogen, one R&D, and one renewable pilot.

Vermont PSB – Green Mountain Power, Vermont Electric Power

Decided 1/28/05 Filed 6/5/03 Case 6860

Approves w/modifications company-proposed, \$125m Northwest Reliability Project, consisting of 345 kV line, reconstruction of part of 34.5 kV/46 kV line, reconductoring of 115 kV line, and numerous substation upgrades to meet demand growth/improve reliability. Says non-transmission alternatives would require major demand reduction and min. three new 40 MW bulk generation plants in Chittenden Co.; says former is feasible, latter too uncertain re timely availability. Says flawed company planning process precluded early consideration of efficiency-related alternatives that may have become viable.