15. Commitments and Contingencies

Energy Purchases, Energy Sales and Other Commitments

Energy Purchase Commitments

(PPL and PPL Energy Supply)

PPL Energy Supply enters into long-term purchase contracts to supply the fuel requirements and other costs of production for generation facilities. These contracts include commitments to purchase coal, emission allowances, limestone, natural gas, oil and nuclear fuel. These long-term contracts extend through 2023, with the exception of a limestone contract that extends through 2030. PPL Energy Supply also enters into long-term contracts for the storage and transportation of natural gas. The long-term natural gas storage contracts extend through 2015, and the long-term natural gas transportation contracts extend through 2032. PPL Energy Supply has entered into long-term contracts to purchase power that extend through 2017, with the exception of long-term power purchase agreements for the full output of two wind farms that extend through 2027. Additionally, PPL Energy Supply has entered into REC contracts that extend through 2038.

In 2008, PPL EnergyPlus acquired the rights to an existing long-term tolling agreement associated with the capacity and energy of Ironwood. Under the agreement, PPL EnergyPlus has control over the plant's dispatch into the electricity grid and supplies the natural gas necessary to operate the plant. The tolling agreement extends through 2021. See Note 11 for additional information.

(PPL, LKE, LG&E and KU)

LG&E and KU have a power purchase agreement with OVEC, extended in February 2011 to June 2040. FERC approval of the extension was received in May 2011, followed by KPSC and VSCC approvals in August 2011. Pursuant to the OVEC power purchase contract, LG&E and KU are responsible for their pro-rata share of certain obligations of OVEC under defined circumstances. These potential liabilities include unpaid OVEC indebtedness as well as shortfall amounts in certain excess decommissioning costs and other post-employment and post-retirement benefit costs other than pension. LKE's proportionate share of OVEC's outstanding debt was $117 million at December 31, 2011, consisting of LG&E's share of $81 million and KU's share of $36 million. Future obligations for power purchases from OVEC are unconditional demand payments, comprised of annual minimum debt service payments, as well as contractually required reimbursement of plant operating, maintenance and other expenses as follows:

	LG&E	KU	Total
2012	$ 20	$ 9	$ 29
2013	21	9	30
2014	21	9	30
2015	21	10	31
2016	22	10	32
Thereafter	595	264	859
	$ 700	$ 311	$ 1,011

In addition, LG&E and KU had total energy purchases under the OVEC power purchase agreement for the periods ended as follows:

	Successor		Predecessor	
	Year Ended December 31, 2011	Two Months Ended December 31, 2010	Ten Months Ended October 31, 2010	Year Ended December 31, 2009
LG&E	$ 22	$ 4	$ 17	$ 19
KU	10	2	7	8
Total	$ 32	$ 6	$ 24	$ 27

LG&E and KU enter into purchase contracts to supply the coal and natural gas requirements for generation facilities and LG&E's gas supply operations. The coal contracts extend through 2016 and the natural gas contracts extend through 2013. LG&E and KU also enter into contracts for other coal related consumables, coal transportation and fleeting services, which expire at different time periods through 2018. LG&E and KU also have transportation contracts for natural gas that extend through 2018.

(PPL and PPL Electric)

In 2009, the PUC approved PPL Electric's PLR energy procurement plan for the period January 2011 through May 2013. To date, PPL Electric has conducted ten of its 14 planned competitive solicitations. The solicitations include a mix of long-term and short-term purchases ranging from five months to ten years to fulfill PPL Electric's obligation to provide for customer supply as a PLR.

(PPL Energy Supply and PPL Electric)

See Note 16 for information on the power supply agreements between PPL EnergyPlus and PPL Electric.

Energy Sales Commitments

(PPL and PPL Energy Supply)

In connection with its marketing activities or hedging strategy for its power plants, PPL Energy Supply has entered into long-term power sales contracts that extend through 2024, excluding long-term retail sales agreements for the full output from solar generators that extend through 2036.

(PPL Energy Supply and PPL Electric)

See Note 16 for information on the power supply agreements between PPL EnergyPlus and PPL Electric.

PPL Montana Hydroelectric License Commitments *(PPL and PPL Energy Supply)*

PPL Montana owns and operates 11 hydroelectric facilities and one storage reservoir licensed by the FERC under long-term licenses pursuant to the Federal Power Act. Pursuant to Section 8(e) of the Federal Power Act, the FERC approved the transfer from Montana Power to PPL Montana of all pertinent licenses in connection with the Montana Asset Purchase Agreement.

The Kerr Dam Project license (50-year term) was jointly issued by the FERC to Montana Power and the Confederated Salish and Kootenai Tribes of the Flathead Nation in 1985, and requires PPL Montana (as successor licensee to Montana Power) to hold and operate the project for at least 30 years (to 2015). Between 2015 and 2025, the tribes have the option to purchase, hold and operate the project for the remainder of the license term, which expires in 2035. PPL Montana cannot predict if and when this option will be exercised. The license also requires PPL Montana to continue to implement a plan to mitigate the impact of the Kerr Dam on fish, wildlife and their habitats. Under this arrangement, PPL Montana has a remaining commitment to spend $8 million between 2012 and 2015, in addition to the annual rent it pays to the tribes.

PPL Montana entered into two Memoranda of Understanding (MOUs) with state, federal and private entities related to the issuance in 2000 of the FERC renewal license for the nine dams comprising the Missouri-Madison project. The MOUs are periodically updated and renewed and require PPL Montana to implement plans to mitigate the impact of its projects on fish, wildlife and their habitats, and to increase recreational opportunities. The MOUs were created to maximize collaboration between the parties and enhance the possibility to receive matching funds from relevant federal agencies. Under these arrangements, PPL Montana has a remaining commitment to spend $32 million between 2012 and 2040.

Legal Matters

(PPL, PPL Energy Supply, PPL Electric, LKE, LG&E and KU)

PPL and its subsidiaries are involved in legal proceedings, claims and litigation in the ordinary course of business. PPL and its subsidiaries cannot predict the outcome of such matters, or whether such matters may result in material liabilities, unless otherwise noted.

TC2 Construction *(PPL, LKE, LG&E and KU)*

In June 2006, LG&E and KU, as well as the Indiana Municipal Power Agency and Illinois Municipal Electric Agency (collectively, TC2 Owners), entered into a construction contract regarding the TC2 project. The contract is generally in the form of a turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price. During 2009 and 2010, the TC2 Owners received several contractual notices from the TC2 construction contractor asserting historical force majeure and excusable event claims for a number of adjustments to the contract price, construction schedule, commercial operations date, liquidated damages or other relevant provisions. In September 2010, the TC2 Owners and the construction contractor agreed to a settlement to resolve the force majeure and excusable event claims occurring through July 2010, under the TC2 construction contract, which settlement provided for a limited, negotiated extension of the contractual commercial operations date and/or relief from liquidated damage calculations. With limited exceptions, the TC2 Owners took care, custody and control of TC2 in January 2011. Pursuant to certain amendments to the construction agreement, the contractor will complete modifications to the combustion system prior to certain dates to allow operation of TC2 on all specified fuels categories. The provisions of the construction agreement relating to liquidated damages were also amended. In September 2011, the TC2 Owners and the construction contractor entered into a further amendment to the construction agreement settling, among other matters, certain historical change order, labor rate and prior liquidated damages amounts. The remaining issues are still under discussion with the contractor. PPL, LKE, LG&E and KU cannot currently predict the outcome of this matter or the potential impact on the capital costs of this project.

(PPL and PPL Energy Supply)

Spent Nuclear Fuel Litigation

Federal law requires the U.S. government to provide for the permanent disposal of commercial spent nuclear fuel, but there is no definitive date by which a repository will be operational. As a result, it was necessary to expand Susquehanna's on-site spent fuel storage capacity. To support this expansion, PPL Susquehanna contracted for the design and construction of a spent fuel storage facility employing dry cask fuel storage technology. The facility is modular, so that additional storage capacity can be added as needed. The facility began receiving spent nuclear fuel in 1999. PPL Susquehanna estimates that there is sufficient storage capacity in the spent nuclear fuel pools and the on-site dry cask storage facility at Susquehanna to accommodate spent fuel discharged through approximately 2017 under current operating conditions. If necessary, on-site dry cask storage capability can be expanded, assuming appropriate regulatory approvals are obtained, such that, together, the spent fuel pools and the expanded dry fuel storage facilities will accommodate all of the spent fuel expected to be discharged through the current licensed life of each unit, 2042 for Unit 1 and 2044 for Unit 2.

In 1996, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) ruled that the Nuclear Waste Policy Act imposed on the DOE an unconditional obligation to begin accepting spent nuclear fuel on or before January 31, 1998. In 1997, the D.C. Circuit Court ruled that the contracts between the utilities and the DOE provide a potentially adequate remedy if the DOE failed to begin accepting spent nuclear fuel by January 31, 1998. The DOE did not, in fact, begin to accept spent nuclear fuel by that date. The DOE continues to contest claims that its breach of contract resulted in recoverable damages. In January 2004, PPL Susquehanna filed suit in the U.S. Court of Federal Claims for unspecified damages suffered as a result of the DOE's breach of its contract to accept and dispose of spent nuclear fuel. In May 2011, the parties entered into a settlement agreement which resolved all claims of PPL Susquehanna through December 2013. Under the settlement agreement, PPL Susquehanna received $50 million for its share of claims to recover costs to store spent nuclear fuel at the Susquehanna plant through September 30, 2009, and recognized a credit to "Fuel" expense in the second quarter of 2011. PPL Susquehanna also will be eligible to receive payment of annual claims for allowed costs, as set forth in the settlement agreement, that are incurred thereafter through the December 31, 2013 termination date of the settlement agreement. In exchange, PPL Susquehanna has waived any claims against the United States government for costs paid or injuries sustained related to storing spent nuclear fuel at the Susquehanna plant through December 31, 2013.

Montana Hydroelectric Litigation

In November 2004, PPL Montana, Avista Corporation (Avista) and PacifiCorp commenced an action for declaratory judgment in Montana First Judicial District Court seeking a determination that no lease payments or other compensation for their hydroelectric facilities' use and occupancy of certain riverbeds in Montana can be collected by the State of Montana. This lawsuit followed dismissal on jurisdictional grounds of an earlier federal lawsuit seeking such compensation in the U.S. District Court of Montana. The federal lawsuit alleged that the beds of Montana's navigable rivers became state-owned trust property upon Montana's admission to statehood, and that the use of them should, under a 1931 regulatory scheme enacted after all but one of the hydroelectric facilities in question were constructed, trigger lease payments for use of land beneath. In July 2006, the Montana state court approved a stipulation by the State of Montana that it was not seeking compensation for the period prior to PPL Montana's December 1999 acquisition of the hydroelectric facilities.

Following a number of adverse trial court rulings, in 2007 Pacificorp and Avista each entered into settlement agreements with the State of Montana providing, in pertinent part, that each company would make prospective lease payments for use of the State's navigable riverbeds (subject to certain future adjustments), resolving the State's claims for past and future compensation.

Following an October 2007 trial of this matter on damages, in June 2008, the Montana District Court awarded the State retroactive compensation of approximately $35 million for the 2000-2006 period and approximately $6 million for 2007 compensation. Those unpaid amounts continued to accrue interest at 10% per year. The Montana District Court also deferred determination of compensation for 2008 and future years to the Montana State Land Board. In October 2008, PPL Montana appealed the decision to the Montana Supreme Court, requesting a stay of judgment and a stay of the Land Board's authority to assess compensation for 2008 and future periods.

In 2009, PPL Montana adjusted its previously recorded accrual by $8 million, $5 million after tax. Of this total, $5 million, $3 million after tax, related to prior periods. In March 2010, the Montana Supreme Court substantially affirmed the June 2008 Montana District Court decision. As a result, in the first quarter of 2010, PPL Montana recorded a charge of $56 million ($34 million after tax or $0.08 per share, basic and diluted, for PPL), representing estimated rental compensation for the first quarter of 2010 and prior years, including interest. Rental compensation was estimated for periods subsequent to 2007. The portion of the pre-tax charge that related to prior years totaled $54 million ($32 million after tax). The charge recorded on the Statement of Income was $49 million in "Other operation and maintenance" and $7 million in "Interest Expense." PPL Montana continued to accrue interest expense for the prior years and rent expense for the subsequent years.

In August 2010, PPL Montana filed a petition for a writ of certiorari with the U.S. Supreme Court requesting review of this matter. In June 2011, the U.S. Supreme Court granted PPL Montana's petition. Oral argument was held in December 2011 and on February 22, 2012, the U.S. Supreme Court issued a decision overturning the Montana Supreme Court decision and remanded the case to the Montana Supreme Court for further proceedings consistent with the U.S. Supreme Court's opinion. As a result, PPL Montana reversed its total loss accrual of $89 million ($53 million after-tax or $0.09 per share, basic and diluted for PPL), which had been recorded prior to the U.S. Supreme Court decision. The amount reversed was recorded on the Statements of Income as a $75 million credit to "Other operation and maintenance" and a $14 million credit to "Interest Expense." PPL Montana believes the U.S. Supreme Court decision resolves certain questions of liability in this case in favor of PPL Montana and leaves open for reconsideration by Montana courts, consistent with the findings of the U.S. Supreme Court, certain other questions. The State of Montana has 30 days from February 22, 2012 to petition the U.S. Supreme Court for a rehearing. PPL Montana has concluded it is no longer probable, but it remains reasonably possible, that a loss has been incurred. While unable to estimate a range of loss, PPL Montana believes that any such amount would not be material.

Bankruptcy of Southern Montana Electric Generation and Transmission Cooperative, Inc.

On October 21, 2011, SMGT, a Montana cooperative and purchaser of electricity under a long-term supply contract with PPL EnergyPlus expiring in June 2019 (SMGT Contract), filed for protection under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court in Montana. At the time of the bankruptcy filing, SMGT was PPL EnergyPlus' largest customer.

The SMGT Contract provides for fixed volume purchases on a monthly basis at established prices. A trustee has been appointed for SMGT's estate in the bankruptcy proceeding, and PPL EnergyPlus has been involved in preliminary discussions with the trustee concerning possible modifications to the SMGT Contract as part of the bankruptcy reorganization. Pursuant to a court order and subsequent stipulations entered into by SMGT and PPL EnergyPlus, since the date of its Chapter 11 filing through January 2012, SMGT continued to purchase electricity from PPL EnergyPlus at the price specified in the SMGT Contract, and has made timely payments for such purchases, but at lower volumes than as prescribed in the SMGT Contract. During January 2012, the trustee notified PPL EnergyPlus that SMGT would not purchase electricity under the SMGT Contract for the month of February. In addition, the trustee requested PPL EnergyPlus to leave the SMGT Contract in place to permit SMGT to purchase electricity in the event its requirements were not met by third-party providers from whom the trustee intends to purchase power on behalf of SMGT, at prices more favorable than under the SMGT Contract, for future periods. PPL EnergyPlus is evaluating the trustee's request.

PPL EnergyPlus' damage claim under the SMGT Contract totaled approximately $11 million at December 31, 2011, all of which has been fully reserved. No assurance can be given as to the collectability of these damages.

At the present time, PPL cannot predict whether SMGT will be successful in its attempts to reorganize its business under Chapter 11 of the U.S. Bankruptcy Code or the extent to which the SMGT Contract may be modified as part of a successful Chapter 11 reorganization and, in either case, PPL cannot presently predict the extent to which it will be able to market to third parties any amount of power that SMGT ultimately does not continue to purchase from PPL EnergyPlus.

Regulatory Issues

(PPL, PPL Electric, LKE, LG&E and KU)

See Note 6 for information on regulatory matters related to utility rate regulation.

Enactment of Financial Reform Legislation *(PPL, PPL Energy Supply, PPL Electric, LKE, LG&E and KU)*

In July 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act includes provisions that impose derivative transaction reporting requirements and require most over-the-counter derivative transactions to be executed through an exchange and to be centrally cleared. The Dodd-Frank Act also provides that the CFTC may impose collateral and margin requirements for over-the-counter derivative transactions, as well as capital requirements for certain entity classifications. Final rules on major provisions in the Dodd-Frank Act are being established through rulemakings, and the CFTC generally has postponed implementation until the later of July 16, 2012 or when required key final rules are issued (e.g. definitional rules for "swap" and "swap dealer"). In order to comply with implementing regulations of the Dodd-Frank Act, the Registrants likely will be faced with significant new recordkeeping and reporting requirements. Also, the Registrants could face significantly higher operating costs or may be required to post additional collateral if they are subject to margin requirements as ultimately adopted in the implementing regulations of the Dodd-Frank Act. The Registrants will continue to evaluate the provisions of the Dodd-Frank Act. At this time, the Registrants cannot predict the impact that the law or its implementing regulations will have on their businesses or operations, or the markets in which they transact business, but could incur material costs related to compliance with the Dodd-Frank Act.

New Jersey Capacity Legislation *(PPL, PPL Energy Supply and PPL Electric)*

In January 2011, New Jersey enacted a law that intervenes in the wholesale capacity market exclusively regulated by the FERC: S. No. 2381, 214th Leg. (N.J. 2011) (the Act). To create incentives for the development of new, in-state electric generation facilities, the Act implements a "long-term capacity agreement pilot program (LCAPP)." The Act requires New Jersey utilities to pay a guaranteed fixed price for wholesale capacity, imposed by the New Jersey Board of Public Utilities (BPU), to certain new generators participating in PJM, with the ultimate costs of that guarantee to be borne by New Jersey ratepayers. PPL believes the intent and effect of the LCAPP is to encourage the construction of new generation in New Jersey even when, under the FERC-approved PJM economic model, such new generation would not be economic. The Act could depress capacity prices in PJM in the short term, impacting PPL Energy Supply's revenues, and harm the long-term ability of the PJM capacity market to incent necessary generation investment throughout PJM. In February 2011, the PJM Power Providers Group (P3), an organization in which PPL is a member, filed a complaint before the FERC seeking changes in PJM's capacity market rules designed to ensure that subsidized generation, such as may result from the implementation of the LCAPP, will not be able to set capacity prices artificially low as a result of their exercise of buyer market power. In April 2011, the FERC issued an order granting in part and denying in part P3's complaint and ordering changes in PJM's capacity rules consistent with a significant portion of P3's requested changes. PPL, PPL Energy Supply and PPL Electric cannot predict the outcome of this proceeding or the economic impact on their businesses or operations, or the markets in which they transact business.

In addition, in February 2011, PPL, and several other generating companies and utilities filed a complaint in U.S. District Court in New Jersey challenging the Act on the grounds that it violates well-established principles under the Supremacy Clause and the Commerce Clause of the U.S. Constitution. In this action, the plaintiffs request declaratory and injunctive relief barring implementation of the Act by the Commissioners of the BPU. In October 2011, the court denied the BPU's motion to dismiss the proceeding and the litigation is moving forward. PPL, PPL Energy Supply and PPL Electric cannot predict the outcome of this proceeding or the economic impact on their businesses or operations, or the markets in which they transact business.

Pacific Northwest Markets *(PPL and PPL Energy Supply)*

Through its subsidiaries, PPL Energy Supply made spot market bilateral sales of power in the Pacific Northwest during the period from December 2000 through June 2001. Several parties subsequently claimed refunds at FERC as a result of these sales. In June 2003, the FERC terminated proceedings to consider whether to order refunds for spot market bilateral sales made in the Pacific Northwest, including sales made by PPL Montana, during the period December 2000 through June 2001. In August 2007, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC's decision and ordered the FERC to consider additional evidence. In October 2011, FERC initiated proceedings to consider additional evidence.

Although PPL and its subsidiaries believe that they have not engaged in any improper trading or marketing practices affecting the Pacific Northwest markets, PPL and PPL Energy Supply cannot predict the outcome of the above-described proceedings or whether any subsidiaries will be the subject of any additional governmental investigations or named in other lawsuits or refund proceedings. Consequently, PPL and PPL Energy Supply cannot estimate a range of reasonably possible losses, if any, related to this matter.

(PPL, PPL Energy Supply, PPL Electric, LKE, LG&E and KU)

FERC Market-Based Rate Authority

In November 1998, the FERC authorized LG&E and KU and, in December 1998, authorized PPL EnergyPlus to make wholesale sales of electric power and related products at market-based rates. In those orders, the FERC directed LG&E and KU and PPL EnergyPlus, respectively, to file an updated market analysis within three years after the order, and every three years thereafter. Since then, periodic market-based rate filings with the FERC have been made by LG&E, KU, PPL EnergyPlus, PPL Electric, PPL Montana and most of PPL Generation's subsidiaries. These filings consisted of a Northwest market-based rate filing for PPL Montana and a Northeast market-based rate filing for most of the other PPL subsidiaries in PJM's region. In June 2011, FERC approved PPL's market-based rate update for the Eastern region and PPL's market-based rate update for the Western region. Also, in June 2011, PPL filed its market-based rate update for the Southeast region, including LG&E and KU in addition to PPL EnergyPlus. In June 2011, the FERC issued an order approving LG&E's and KU's request for a determination that they no longer be deemed to have market power in the Big Rivers Electric Corporation balancing area and removing restrictions on their market-based rate authority in such region.

Currently, a seller granted FERC market-based rate authority may enter into power contracts during an authorized time period. If the FERC determines that the market is not workably competitive or that the seller possesses market power or is not charging "just and reasonable" rates, it may institute prospective action, but any contracts entered into pursuant to the FERC's market-based rate authority remain in effect and are generally subject to a high standard of review before the FERC can order changes. Recent court decisions by the U.S. Court of Appeals for the Ninth Circuit have raised issues that may make it more difficult for the FERC to continue its program of promoting wholesale electricity competition through market-based rate authority. These court decisions permit retroactive refunds and a lower standard of review by the FERC for changing power contracts, and could have the effect of requiring the FERC in advance to review most, if not all, power contracts. In June 2008, the U.S. Supreme Court reversed one of the decisions of the U.S. Court of Appeals for the Ninth Circuit, thereby upholding the higher standard of review for modifying contracts. At this time, PPL, PPL Energy Supply, LKE, LG&E and KU cannot predict the impact of these court decisions on the FERC's future market-based rate authority program or on their businesses.

Energy Policy Act of 2005 - Reliability Standards

The NERC is responsible for establishing and enforcing mandatory reliability standards (Reliability Standards) regarding the bulk power system. The FERC oversees this process and independently enforces the Reliability Standards.

The Reliability Standards have the force and effect of law and apply to certain users of the bulk power electricity system, including electric utility companies, generators and marketers. The FERC has indicated it intends to vigorously enforce the Reliability Standards using, among other means, civil penalty authority. Under the Federal Power Act, the FERC may assess civil penalties of up to $1 million per day, per violation, for certain violations. The first group of Reliability Standards approved by the FERC became effective in June 2007.

LG&E, KU , PPL Electric and certain subsidiaries of PPL Energy Supply monitor their compliance with the Reliability Standards and continue to self-report potential violations of certain applicable reliability requirements and submit accompanying mitigation plans, as required. The resolution of a number of potential violations is pending. Any regional reliability entity determination concerning the resolution of violations of the Reliability Standards remains subject to the approval of the NERC and the FERC. The Registrants cannot predict the outcome of these matters, and cannot estimate a range of reasonably possible losses, if any, other than the amounts currently recorded.

In the course of implementing its program to ensure compliance with the Reliability Standards by those PPL affiliates subject to the standards, certain other instances of potential non-compliance may be identified from time to time.

Environmental Matters - Domestic

(PPL, PPL Energy Supply, PPL Electric, LKE, LG&E and KU)

Due to the environmental issues discussed below or other environmental matters, PPL subsidiaries may be required to modify, curtail, replace or cease operating certain facilities or operations to comply with statutes, regulations and other requirements of regulatory bodies or courts.

(PPL, PPL Energy Supply, LKE, LG&E and KU)

Air

The Clean Air Act addresses, among other things, emissions causing acid deposition, installation of best available control technologies for new or substantially modified sources, attainment of national ambient air quality standards, toxic air emissions and visibility standards in the U.S. Amendments to the Clean Air Act requiring additional emission reductions have been proposed but are unlikely to be introduced or passed in this Congress. The Clean Air Act allows states to develop more stringent regulations and in some instances, as discussed below, Kentucky, Pennsylvania and Montana have done so.

To comply with air-related requirements and other environmental requirements as described below, PPL's forecast for capital expenditures reflects a best estimate projection of expenditures that may be required within the next five years. Such projections are a combined $3.1 billion for LG&E and KU. These projections include $100 million for LG&E and $400 million for KU associated with currently approved ECR plans through 2013 to achieve emissions reductions and manage coal combustion residuals. The projections also include $1.4 billion for LG&E and $900 million for KU associated with the recently approved 2011 ECR Plans for additional expenditures to comply with new clean air rules and manage coal combustion residuals and an additional $300 million for other environmental expenditures. Such projections for PPL Energy Supply are $130 million. Actual costs (including capital, allowance purchases and operational modifications) may be significantly lower or higher depending on the final requirements and market conditions. Certain environmental compliance costs incurred by LG&E and KU in serving KPSC jurisdictional customers are subject to recovery through the ECR. See Note 6 for additional information on LG&E and KU's ECR plan.

CSAPR (formerly Clean Air Transport Rule)

In July 2011, the EPA signed the CSAPR, which finalizes and renames the Clean Air Transport Rule (Transport Rule) proposed in August 2010, and made revisions to the rule on February 7, 2012. The CSAPR replaces the EPA's previous Clean Air Interstate Rule (CAIR) which was struck down by the U.S. Court of Appeals for the District of Columbia Circuit (the Court) in July 2008. CAIR subsequently was effectively reinstated by the Court in December 2008, pending finalization of the Transport Rule. Like CAIR and the proposed Transport Rule, the CSAPR only applies to PPL's coal generation facilities located in Kentucky and Pennsylvania.

The CSAPR is meant to facilitate attainment of ambient air quality standards for ozone and fine particulates by requiring reductions in sulfur dioxide and nitrogen oxides. The CSAPR established new sulfur dioxide emission allowance cap and trade programs that are completely independent of, and more stringent than, the current Acid Rain Program. The CSAPR also established new nitrogen oxides emission allowance cap and trade programs to replace the current programs. All trading is more restrictive than previously under CAIR. The CSAPR provides for two-phased programs of sulfur dioxide and nitrogen oxide emissions reductions, with initial reductions in 2012 and more stringent reductions in 2014.

In December 2011, the Court stayed implementation of the CSAPR and left CAIR in effect pending a final resolution on the merits of the validity of the rule. Oral argument on the various challenges to the CSAPR is scheduled for April 2012, and a final decision on the validity of the rule could be released as early as May 2012.

With respect to the Kentucky coal-fired generating plants, the stay of the CSAPR will initially only impact the unit dispatch order. With the return of the CAIR and the Kentucky companies' significant number of sulfur dioxide allowances, those units will be dispatched with lower operating cost, but slightly higher sulfur dioxide and nitrogen oxide emissions. However, a key component of the Court's final decision, even if the CSAPR is upheld, will be whether the ruling delays the implementation of the CSAPR by one year for both Phases I and II, or instead still requires the significant sulfur dioxide and nitrogen oxide reductions associated with Phase II to begin in 2014. LG&E's and KU's CSAPR compliance strategy is based on over-compliance during Phase I to generate allowances sufficient to cover the expected shortage during the first two years of Phase II (2014 and 2015) when additional pollution control equipment will be installed. Should Phase I of the CSAPR be shortened to one year, it will be more difficult and costly to provide enough excess allowances in one year to meet the shortage projected for 2014 and 2015.

PPL Energy Supply's coal fired power plants can meet both the CAIR and the proposed CSAPR sulfur dioxide emission requirements with the existing scrubbers that went in-service in 2008 and 2009. For nitrogen oxide, under both the CAIR and the proposed CSAPR, PPL Energy Supply would need to buy allowances or make operational changes, the cost of which is not anticipated to be significant.

National Ambient Air Quality Standards

In addition to the reductions in sulfur dioxide and nitrogen oxide emissions required under the CSAPR for the Pennsylvania and Kentucky plants, PPL's coal plants, including those in Montana, may face further reductions in sulfur dioxide and nitrogen oxide emissions as a result of more stringent national ambient air quality standards for ozone, nitrogen oxide, sulfur dioxide and/or fine particulates. The EPA has recently finalized a new one-hour standard for sulfur dioxide, and states are required to identify areas that meet those standards and areas that are in non-attainment. For non-attainment areas, states are required to develop plans by 2014 to achieve attainment by 2017. For areas in attainment or that are unclassifiable, states are required to develop maintenance plans by mid-2013 that demonstrate continued attainment. PPL, PPL Energy Supply, LKE, LG&E and KU anticipate that some of the measures required for compliance with the CSAPR such as upgraded or new sulfur dioxide scrubbers at some of their plants or, in the case of LG&E and KU, upgraded or new sulfur dioxide scrubbers at the Mill Creek plant and retirement of the Cane Run, Green River, and Tyrone plants, will also be necessary to achieve compliance with the new one-hour sulfur dioxide standard. If additional reductions were to be required, the economic impact could be significant.

Mercury and Other Hazardous Air Pollutants

In May 2011, the EPA published a proposed regulation providing for stringent reductions of mercury and other hazardous air pollutants. On February 16, 2012, the EPA published the final rule, known as the Mercury and Air Toxics Standards (MATS), with an effective date of April 16, 2012. The rule provides for a three-year compliance deadline with the potential for a one-year extension as provided under the statute. Based on their assessment of the need to install pollution control equipment to meet the provisions of the proposed rule, LG&E and KU filed requests with the KPSC for environmental cost recovery to facilitate moving forward with plans to install environmental controls including sorbent injection and fabric-filter baghouses to remove certain hazardous air pollutants. Recovery of the cost of certain controls was granted by KPSC order issued in December 2011. The cost for these controls is reflected in the combined costs of $3.1 billion for LG&E and KU noted under "Air" above. LG&E and KU have also announced the anticipated retirement of coal-fired generating units at the Cane Run, Green River, and Tyrone plants and have filed requests with the KPSC for replacement of those units with natural gas-fired generating units to be constructed or purchased. With the publication of the final MATS rule, LG&E and KU are currently assessing whether changes in the final rule warrant revision of their approved compliance plans. With respect to PPL Energy Supply's Pennsylvania plants, PPL believes that these plants are reasonably well controlled and require installation of chemical additive systems, the cost of which is not expected to be material. With respect to PPL Montana plants, modifications to the current air pollution controls installed on Colstrip may be required, the cost of which also is not expected to be material. For the Corette plant, additional controls are being evaluated, the cost of which could be significant. PPL Energy Supply, LG&E and KU are continuing to conduct in-depth reviews of the MATS.

Regional Haze and Visibility

In January 2012, the EPA proposed limited approval of the Pennsylvania Regional Haze State Implementation Plan. That proposed action would essentially approve PPL's analysis that further particulate controls at PPL Energy Supply's Pennsylvania plants are not warranted. The limited approval does not address deficiencies of the state plan arising from the remand of the CAIR rule. Previously, the EPA had determined that implementation of the CAIR requirements would meet regional haze BART (Best Available Retrofit Technology) requirements for sulfur dioxide and nitrogen oxides. In December 2011, the EPA proposed that implementation of the CSAPR would also meet the BART. This is expected to address that deficiency.

In Montana, the EPA Region 8 is developing the regional haze plan as the Montana Department of Environmental Quality declined to develop a BART state implementation plan at this time. PPL submitted to the EPA its analyses of the visibility impacts of sulfur dioxide, nitrogen oxides and particulate matter emissions for Colstrip Units 1 and 2 and Corette. PPL's analyses concluded that further reductions are not warranted. The EPA responded to PPL's reports for Colstrip and Corette and requested further information and analysis. PPL completed further analysis and submitted addendums to its initial reports for Colstrip and Corette. In February 2009, PPL received an information request for data related to the non-BART-affected emission sources of Colstrip Units 3 and 4. PPL responded to this request in March 2009.

In November 2010, PPL Montana received a request from the EPA Region 8, under the EPA's Reasonable Further Progress goals of the Regional Haze Rules, to provide further analysis with respect to Colstrip Units 3 and 4. PPL completed a high-level analysis of various control options to reduce emissions of sulfur dioxide and particulate matter for these units, and submitted that analysis to the EPA in January 2011. The analysis shows that any incremental reductions would not be cost effective and that further analysis is not warranted. PPL also concluded that further analysis for nitrogen oxides was not justifiable as these units installed controls under a Consent Decree in which the EPA had previously agreed that, when implemented, would satisfy the requirements for installing the BART for nitrogen oxides. The EPA is expected to issue a proposed Federal Implementation Plan for Montana in March 2012. Discussions with the EPA are ongoing with respect to this issue.

PPL and PPL Energy Supply cannot predict whether any additional reductions in emissions will be required in Pennsylvania or Montana. If additional reductions are required, the economic impact could be significant depending on what is required.

LG&E and KU also submitted analyses of the visibility impacts of their Kentucky BART-eligible sources to the Kentucky Division for Air Quality (KDAQ). Only LG&E's Mill Creek plant was determined to have a significant regional haze impact. The KDAQ has submitted a regional haze state implementation plan (SIP) to the EPA which requires the Mill Creek plant to reduce its sulfuric acid mist emissions from Units 3 and 4. After approval of the Kentucky SIP by the EPA and revision of the Mill Creek plant's Title V air permit, LG&E intends to install sorbent injection controls at the plant to reduce sulfuric acid mist emissions. In the event that the EPA determines that compliance with the CSAPR would be insufficient to meet the BART requirements, it would be necessary for LG&E and KU to reassess their planned compliance measures.

New Source Review (NSR)

The NSR regulations require major new or modified sources of regulated pollutants to receive pre-construction and operating permits with limits that prevent the significant deterioration of air quality in areas that are in attainment of the ambient air quality standards for certain pollutants.

The EPA has continued its NSR enforcement efforts targeting coal-fired generating plants. The EPA has asserted that modification of these plants has increased their emissions and, consequently, that they are subject to stringent NSR requirements under the Clean Air Act. In April 2009, PPL received EPA information requests for its Montour and Brunner Island plants. The requests are similar to those that PPL received several years ago for its Colstrip, Corette and Martins Creek plants. PPL and the EPA have exchanged certain information regarding this matter. In January 2009, PPL and other companies that own or operate the Keystone plant in Pennsylvania received a notice of violation from the EPA alleging that certain projects were undertaken without proper NSR compliance. PPL and PPL Energy Supply cannot predict the outcome of these matters, and cannot estimate a range of reasonably possible losses, if any.

In addition, in August 2007, LG&E and KU received information requests for their Mill Creek, Trimble County, and Ghent plants, but have received no further communications from the EPA since providing their responses. PPL, LKE, LG&E and KU cannot predict the outcome of these matters, and cannot estimate a range of reasonably possible losses, if any.

In March 2009, KU received a notice alleging that KU violated certain provisions of the Clean Air Act's rules governing NSR and prevention of significant deterioration by installing sulfur dioxide scrubbers and SCR controls at its Ghent generating plant without assessing potential increased sulfuric acid mist emissions. KU contends that the work in question, as pollution control projects, was exempt from the requirements cited by the EPA. In December 2009, the EPA issued an information request on this matter. KU has exchanged settlement proposals and other information with the EPA regarding imposition of additional permit limits and emission controls and anticipates continued settlement negotiations. In addition, any settlement or future litigation could potentially encompass a September 2007 notice of violation alleging opacity violations at the plant. Depending on the provisions of a final settlement or the results of litigation, if any, resolution of this matter could involve significant increased operating and capital expenditures. PPL, LKE and KU cannot predict the final outcome of this matter, but currently do not expect such outcome to result in material losses above the respective amounts accrued by KU.

If PPL subsidiaries are found to have violated NSR regulations, PPL would, among other things, be required to meet permit limits reflecting Best Available Control Technology (BACT) for the emissions of any pollutant found to have significantly increased due to a major plant modification. The costs to meet such limits, including installation of technology at certain units, could be significant.

States and environmental groups also have initiated enforcement actions and litigation alleging violations of the NSR regulations by coal-fired plants, and PPL is unable to predict whether such actions will be brought against any of PPL's plants.

TC2 Air Permit (PPL, LKE, LG&E and KU)

The Sierra Club and other environmental groups petitioned the Kentucky Environmental and Public Protection Cabinet to overturn the air permit issued for the TC2 baseload generating unit, but the agency upheld the permit in an Order issued in September 2007. In response to subsequent petitions by environmental groups, the EPA ordered certain non-material changes to the permit which were incorporated into a final revised permit issued by the KDAQ in January 2010. In March 2010, the environmental groups petitioned the EPA to object to the revised state permit. Until the EPA issues a final ruling on the pending petition and all available appeals are exhausted, PPL, LKE, LG&E and KU cannot currently predict the outcome of this matter or the potential impact on the capital costs of this project, if any.

(PPL, PPL Energy Supply, LKE, LG&E and KU)

Global Climate Change

There is concern nationally and internationally about global climate change and the possible contribution of GHG emissions including, most significantly, carbon dioxide, from the combustion of fossil fuels. This has resulted in increased demands for carbon dioxide emission reductions from investors, environmental organizations, government agencies and the international community. These demands and concerns have led to federal legislative proposals, actions at regional, state and local levels, litigation relating to GHG emissions and the EPA regulations on GHGs.

Greenhouse Gas Legislation

While climate change legislation was considered during the 111th Congress, the outcome of the 2010 elections has halted the debate on such legislation in the current 112th Congress. The timing and elements of any future legislation addressing GHG emission reductions are uncertain at this time. In the current Congress, legislation barring the EPA from regulating GHG emissions under the existing authority of the Clean Air Act has been passed by the U.S. House of Representatives. Various bills providing for barring or delaying the EPA from regulating GHG emissions have been introduced in the U.S. Senate, but the prospects for passage of such legislation remain uncertain. At the state level, the 2010 elections in Pennsylvania have also reduced the likelihood of GHG legislation in the near term, and there are currently no prospects for such legislation in Kentucky or Montana.

Greenhouse Gas Regulations and Tort Litigation

As a result of the April 2007 U.S. Supreme Court decision that the EPA has the authority to regulate GHG emissions from new motor vehicles under the Clean Air Act, in April 2010, the EPA and the U.S. Department of Transportation issued new light-duty vehicle emissions standards that apply to 2012 model year vehicles. The EPA has also clarified that this standard triggers regulation of GHG emissions from stationary sources under the NSR and Title V operating permit provisions of the Clean Air Act starting in 2011. This means that any new sources or major modifications to existing sources causing a net significant emissions increase requires the BACT permit limits for GHGs. The EPA recently proposed guidance for conducting a BACT analysis for projects that trigger such a review. In addition, New Source Performance Standards for new and existing power plants were expected to be proposed in September 2011 and finalized in May 2012, but this has been delayed. The EPA is expected to announce a new schedule for this rulemaking in the future.

At the regional level, ten northeastern states signed a Memorandum of Understanding (MOU) agreeing to establish a GHG emission cap-and-trade program, called the Regional Greenhouse Gas Initiative (RGGI). The program commenced in January 2009 and calls for stabilizing carbon dioxide emissions, at base levels established in 2005, from electric power plants with capacity greater than 3 MW. The MOU also provides for a 10% reduction in carbon dioxide emissions from base levels by 2019.

Pennsylvania has not stated an intention to join the RGGI, but has enacted the Pennsylvania Climate Change Act of 2008 (PCCA). The PCCA established a Climate Change Advisory Committee to advise the PADEP on the development of a Climate Change Action Plan. In December 2009, the Advisory Committee finalized its Climate Change Action Report which identifies specific actions that could result in reducing GHG emissions by 30% by 2020. Some of the proposed actions, such as a mandatory 5% efficiency improvement at power plants, could be technically unachievable. To date, there have been no regulatory or legislative actions taken to implement the recommendations of the report. In addition, legislation has been introduced that would, if enacted, accelerate the solar supply requirements and restrict eligible solar projects to those located in Pennsylvania. PPL cannot predict at this time whether this legislation will be enacted.

Eleven Western states, including Montana and certain Canadian provinces, are members of the Western Climate Initiative (WCI). The WCI has established a goal of reducing carbon dioxide emissions 15% below 2005 levels by 2020 and is currently developing GHG emission allocations, offsets, and reporting recommendations.

In November 2008, the Governor of Kentucky issued a comprehensive energy plan including non-binding targets aimed at promoting improved energy efficiency, development of alternative energy, development of carbon capture and sequestration projects, and other actions to reduce GHG emissions. In December 2009, the Kentucky Climate Action Plan Council was established to develop an action plan addressing potential GHG reductions and related measures. To date the state has yet to issue a final plan. The impact of any such plan is not now determinable, but the costs to comply with the plan could be significant.

A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities, and the law remains unsettled on these claims. In September 2009, the U.S.

Court of Appeals for the Second Circuit in the case of AEP v. Connecticut reversed a federal district court's decision and ruled that several states and public interest groups, as well as the City of New York, could sue five electric utility companies under federal common law for allegedly causing a public nuisance as a result of their emissions of GHGs. In June 2011, the U.S. Supreme Court overturned the lower court and held that such federal common law claims were displaced by the Clean Air Act and regulatory actions of the EPA. In Comer v. Murphy Oil, the U.S. Court of Appeals for the Fifth Circuit declined to overturn a district court ruling that plaintiffs did not have standing to pursue state common law claims against companies that emit GHGs. The complaint in the Comer case named the previous indirect parent of LKE as a defendant based upon emissions from the Kentucky plants. In January 2011, the Supreme Court denied a petition to reverse the Court of Appeals' ruling. In May 2011, the plaintiffs in the Comer case filed a substantially similar complaint in federal district court in Mississippi against 87 companies, including KU and three other indirect subsidiaries of LKE, under a Mississippi statute that allows the re-filing of an action in certain circumstances. Additional litigation in federal and state courts over these issues is continuing. PPL, LKE and KU cannot predict the outcome of this litigation or estimate a range of reasonably possible losses, if any.

In 2011, PPL's power plants emitted approximately 74 million tons of carbon dioxide compared with 68 million tons in 2010. The totals reflect 36 million tons from PPL Generation and 38 million tons from LG&E's and KU's generating fleet. All tons are U.S. short tons (2,000 lbs/ton).

Renewable Energy Legislation (PPL and PPL Energy Supply)

There has been interest in renewable energy legislation at both the state and federal levels. At the federal level, House and Senate bills proposed in the 111th Congress would have imposed mandatory renewable energy supply and energy efficiency requirements in the 15% to 20% range by approximately 2020. Earlier in 2011, there were discussions regarding a Clean Energy Standard (CES) that addressed not only renewables but also encouraged clean energy requirements (as yet to be defined). At this time, neither the renewable energy debate nor the CES discussion is expected to gain momentum at the federal or state levels (beyond what is otherwise already required in Pennsylvania and Montana) in the near term.

PPL believes there are financial, regulatory and logistical uncertainties related to GHG reductions and the implementation of renewable energy mandates. These will need to be resolved before the impact of such requirements on PPL can be meaningfully estimated. Such uncertainties, among others, include the need to provide back-up supply to augment intermittent renewable generation, potential generation oversupply that could result from such renewable generation and back-up, impacts to PJM's capacity market and the need for substantial changes to transmission and distribution systems to accommodate renewable energy. These uncertainties are not directly addressed by proposed legislation. PPL and PPL Energy Supply cannot predict at this time the effect on their future competitive position, results of operation, cash flows and financial position of any GHG emissions, renewable energy mandate or other global climate change requirements that may be adopted, although the costs to implement and comply with any such requirements could be significant.

<u>Water/Waste</u>

Coal Combustion Residuals (CCRs) (PPL, PPL Energy Supply, LKE, LG&E and KU)

In June 2010, the EPA proposed two approaches to regulating the disposal and management of CCRs under the Resource Conservation and Recovery Act (RCRA). CCRs include fly ash, bottom ash and sulfur dioxide scrubber wastes. The first approach would regulate CCRs as a hazardous waste under Subtitle C of the RCRA. This approach would have very significant impacts on any coal-fired plant, and would require plants to retrofit their operations to comply with full hazardous waste requirements for the generation of CCRs and associated waste waters through transportation and disposal. This would also have a negative impact on the beneficial use of CCRs and could eliminate existing markets for CCRs. The second approach would regulate CCRs as a solid waste under Subtitle D of the RCRA. This approach would mainly affect disposal and most significantly affect any wet disposal operations. Under this approach, many of the current markets for beneficial uses would not be affected. Currently, PPL expects that several of its plants in Kentucky and Montana could be significantly impacted by the requirements of Subtitle D of the RCRA, as these plants are using surface impoundments for management and disposal of CCRs.

The EPA has issued information requests on CCR management practices at numerous plants throughout the power industry as it considers whether or not to regulate CCRs as hazardous waste. PPL has provided information on CCR management practices at most of its plants in response to the EPA's requests. In addition, the EPA has conducted follow-up inspections to evaluate the structural stability of CCR management facilities at several PPL plants and PPL has implemented certain actions in response to recommendations from these inspections.

The EPA is continuing to evaluate the unprecedented number of comments it received on its June 2010 proposed regulations. In October 2011, the EPA issued a Notice of Data Availability (NODA) that requests comments on selected documents that the EPA received during the comment period for the proposed regulations. Comments were submitted on the NODA in November 2011. In addition, the U.S. House of Representatives in October 2011 approved a bill to modify Subtitle D of the RCRA to provide for the proper management and disposal of CCRs and that would preclude the EPA from regulating CCRs under Subtitle C of the RCRA. The bill has been introduced in the Senate and the prospect for passage of this legislation is uncertain. In January 2012, a coalition of environmental groups filed a 60-day notice of intent to sue the EPA for failure to perform nondiscretionary duties under RCRA, which could require a hard deadline for EPA to issue strict CCR regulations. In February 2012, a CCR recycling company also issued a 60-day notice of intent to sue the EPA over its timeliness in issuing CCR regulations, but that company requests that the EPA take a Subtitle D approach that would allow for continued recycling of CCRs.

PPL, PPL Energy Supply, LKE, LG&E and KU cannot predict at this time the final requirements of the EPA's CCR regulations or potential changes to the RCRA and what impact they would have on their facilities, but the economic impact could be significant.

Martins Creek Fly Ash Release (PPL and PPL Energy Supply)

In 2005, there was a release of approximately 100 million gallons of water containing fly ash from a disposal basin at the Martins Creek plant used in connection with the operation of the plant's two 150 MW coal-fired generating units. This resulted in ash being deposited onto adjacent roadways and fields, and into a nearby creek and the Delaware River. PPL determined that the release was caused by a failure in the disposal basin's discharge structure. PPL conducted extensive clean-up and completed studies, in conjunction with a group of natural resource trustees and the Delaware River Basin Commission, evaluating the effects of the release on the river's sediment, water quality and ecosystem.

The PADEP filed a complaint in Pennsylvania Commonwealth Court against PPL Martins Creek and PPL Generation, alleging violations of various state laws and regulations and seeking penalties and injunctive relief. PPL and the PADEP have settled this matter. The settlement also required PPL to submit a report on the completed studies of possible natural resource damages. PPL subsequently submitted the assessment report to the Pennsylvania and New Jersey regulatory agencies and has continued discussing potential natural resource damages and mitigation options with the agencies. Subsequently, in August 2011 the DEP submitted its National Resource Damage Assessment report to the court and to the intervenors. The intervenors have commented on the report and the PADEP and PPL recently filed separate responses with the court. The settlement agreement for the Natural Resources Damage Claim has not yet been submitted to the court or for public comments.

Through December 31, 2011, PPL Energy Supply has spent $28 million for remediation and related costs and an insignificant remediation liability remains on the balance sheet. PPL and PPL Energy Supply cannot be certain of the outcome of the natural resource damage assessment or the associated costs, the outcome of any lawsuit that may be brought by citizens or businesses or the exact nature of any other regulatory or other legal actions that may be initiated against PPL, PPL Energy Supply or their subsidiaries as a result of the disposal basin release. However, PPL and PPL Energy Supply currently do not expect such outcomes to result in material losses above the amounts currently recorded.

Seepages and Groundwater Infiltration - Pennsylvania, Montana and Kentucky

(PPL, PPL Energy Supply, LKE, LG&E and KU)

Seepages or groundwater infiltration have been detected at active and retired wastewater basins and landfills at various PPL plants. PPL has completed or is completing assessments of seepages or groundwater infiltration at various facilities and is working with agencies to implement abatement measures, where required. A range of reasonably possible losses cannot currently be estimated.

(PPL and PPL Energy Supply)

In 2007, six plaintiffs filed a lawsuit in the Montana Sixteenth Judicial District Court against the Colstrip plant owners asserting property damage claims from seepage from wastewater ponds at Colstrip. A settlement agreement was reached in July 2010 which would have resulted in a payment by PPL Montana, but certain of the plaintiffs later argued that the settlement was not final. The Colstrip plant owners filed a motion to enforce the settlement and in October 2011 the court granted the motion and ordered the settlement to be completed in 60 days. The plaintiffs have appealed the October order to the Montana Supreme Court, which is presently being briefed. The parties are in the process of submitting their briefs to the Montana Supreme Court. That court's decision is expected in the second half of 2012. The settlement ordered by the district court is, therefore, not final and PPL and PPL Energy Supply cannot predict the outcome of the appeal, although PPL Montana's share of any final settlement in excess of amounts recorded is not expected to be significant.

Conemaugh River Discharges (PPL and PPL Energy Supply)

In April 2007, PennEnvironment and the Sierra Club brought a Clean Water Act citizen suit in the U.S. District Court for the Western District of Pennsylvania (the Western District Court) against GenOn Northeast Management Company (then known as Reliant Energy Northeast Management Company) (GenOn), as operator of Conemaugh Generating Station (CGS), seeking civil penalties and injunctive relief for alleged violations of CGS's NPDES water discharge permit. A PPL Energy Supply subsidiary holds a 16.25% undivided, tenant-in-common ownership interest in CGS.

Throughout the relevant time period, the operators of CGS have worked closely with the PADEP to ensure that the facility is operated in a manner that does not cause any adverse environmental impacts to the Conemaugh River, a waterway already significantly impacted by discharges from abandoned coal mines and other historical industrial activity with respect to which neither PPL nor CGS had any involvement. Pursuant to a Consent Order and Agreement between the PADEP and GenOn (the CGS COA), a variety of studies have been conducted, a water treatment facility for cooling tower blowdown has been designed and built, and a second treatment facility for sulfur dioxide scrubber waste water has been designed (and is awaiting final PADEP approval for construction), all in order to comply with the stringent limits set out in CGS's NPDES permit.

In March 2011, the Western District Court entered a partial summary judgment in the plaintiffs' favor, declaring that discharges from CGS violated the NPDES permit. Subsequently, the parties agreed to settle the dispute and in August 2011 the court entered a Consent Decree and Order resolving the mater. PPL Energy Supply's share of the settlement is not significant.

In a separate matter, the PADEP plans to file a complaint in the Commonwealth Court of Pennsylvania alleging several violations of Clean Streams Law at the Conemaugh generating facility. The PADEP and GenOn Northeast Management Company, the operator, signed and lodged with the court a consent decree that when entered by the court will resolve the issues. It is expected that the court will enter the consent decree in March 2012 after a 30-day public comment period has lapsed. Under the terms of the consent decree, GenOn will be obligated to pay a civil penalty of $500,000. PPL Energy Supply is responsible for 16.25% of this amount.

Other Issues (PPL, PPL Energy Supply, LKE, LG&E and KU)

In 2006, the EPA significantly decreased to 10 parts per billion (ppb) the drinking water standards related to arsenic. In Pennsylvania, Montana and Kentucky, this arsenic standard has been incorporated into the states' water quality standards and could result in more stringent limits in NPDES permits for PPL's Pennsylvania, Montana and Kentucky plants. Subsequently, the EPA developed a draft risk assessment for arsenic that increases the cancer risk exposure by more than 20 times, which would lower the current standard from 10 ppb to 0.1 ppb. If the lower standard becomes effective, costly treatment would be required to attempt to meet the standard and, at this time, there is no assurance that it could be achieved. PPL, PPL Energy Supply, LKE, LG&E and KU cannot predict the outcome of the draft risk assessment and what impact, if any, it would have on their facilities, but the costs could be significant.

The EPA is reassessing its polychlorinated biphenyls (PCB) regulations under the Toxics Substance Control Act, which currently allow certain PCB articles to remain in use. In April 2010, the EPA issued an Advanced Notice of Proposed Rulemaking for changes to these regulations. This rulemaking could lead to a phase-out of all PCB-containing equipment. PPL, PPL Energy Supply, LKE, LG&E and KU cannot predict at this time the outcome of these proposed EPA regulations and what impact, if any, they would have on their facilities, but the costs could be significant.

The EPA finalized requirements in 2004 for new or modified cooling water intake structures. These requirements affect where generating facilities are built, establish intake design standards and could lead to requirements for cooling towers at new and modified power plants. Another rule, finalized in 2004, that addressed existing structures was withdrawn following a 2007 decision by the U.S. Court of Appeals for the Second Circuit. In 2009, however, the U.S. Supreme Court ruled that the EPA has discretion to use cost-benefit analysis in determining the best technology available for minimizing adverse environmental impact to aquatic organisms. The EPA published the proposed rule in April 2011. The industry and PPL reviewed the proposed rule and submitted comments. The EPA is evaluating comments and meeting with industry groups to discuss options. The final rule is to be issued by July 2012. The proposed rule contains two requirements to reduce impact to aquatic organisms. The first requires all existing facilities to meet standards for the reduction of mortality of aquatic organisms that become trapped against water intake screens regardless of the levels of mortality actually occurring or the cost of achieving the requirements. The second requirement is to determine and install best technology available to reduce mortality of aquatic organisms that are pulled through the plant's cooling water system. A form of cost-benefit analysis is allowed for this second requirement. This process involves a site-specific evaluation based on nine factors including impacts to energy delivery reliability and remaining useful life of the plant. PPL, PPL Energy Supply, LKE, LG&E and KU will be unable to determine the exact impact until a final rule is issued, the required studies have been completed, and each state in which they operate has decided how to implement the rule.

In October 2009, the EPA released its Final Detailed Study of the Steam Electric Power Generating effluent limitations guidelines and standards. Final regulations are expected to be effective in January 2014. PPL expects the revised guidelines and standards to be more stringent than the current standards especially for sulfur dioxide scrubber wastewater and ash basin discharges, which could result in more stringent discharge permit limits. In the interim, PPL is unable to predict whether the EPA and the states may impose more stringent limits on a case-by-case best professional judgment basis under existing authority as permits are renewed.

PPL has signed a Consent Order and Agreement (the Brunner COA) with the PADEP under which it agreed, under certain conditions, to take further actions to minimize the possibility of fish kills at its Brunner Island plant. Fish are attracted to warm water in the power plant discharge channel, especially during cold weather. Debris at intake pumps can result in a unit trip or reduction in load, causing a sudden change in water temperature. PPL is in the process of constructing a barrier to prevent debris from entering the river water intake area at a cost which is not expected to be material.

PPL has also investigated alternatives to exclude fish from the discharge channel and submitted three alternatives to the PADEP. According to the Brunner COA, once the cooling towers at Brunner Island became operational, PPL must implement one of these fish exclusion alternatives if a fish kill occurs in the discharge channel due to thermal impacts from the plant . Following start-up of the cooling towers in April 2010, several hundred dead fish were found in the cooling tower intake basket although there were no sudden changes in water temperature. In the third quarter of 2010, PPL discussed this matter with the PADEP and both parties agreed that this condition was not one anticipated by the Brunner COA, thereby concluding it did not trigger a need to implement a fish exclusion project. At this time, no fish exclusion project is planned.

In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County plant. In November 2010, the Cabinet issued a final order upholding the permit. In December 2010, the environmental groups appealed the order to state court. PPL, LKE, LG&E, and KU are unable to predict the outcome of this matter or estimate a range of reasonably possible losses, if any.

The EPA and the Army Corps of Engineers are working on a guidance document that will expand the federal government's interpretation of what constitutes "waters of the United States" (WOUS) subject to regulation under the Clean Water Act. This change has the potential to affect generation and delivery operations, with the most significant effect being the potential elimination of the existing regulatory exemption for plant waste water treatment systems. The costs that may be imposed as a result of any eventual expansion of this interpretation cannot reliably be estimated at this time.

(PPL, PPL Energy Supply, PPL Electric, LKE, LG&E and KU)

Superfund and Other Remediation

PPL Electric is a potentially responsible party at several sites listed by the EPA under the federal Superfund program, including the Columbia Gas Plant site, the Metal Bank site and the Ward Transformer site. Clean-up actions have been or are being undertaken at all of these sites, the costs of which have not been significant to PPL Electric. However, should the EPA require different or additional measures in the future, or should PPL Electric's share of costs at multi-party sites increase significantly more than currently expected, the costs could be significant.

PPL Electric, LG&E and KU are remediating or have completed the remediation of several sites that were not addressed under a regulatory program such as Superfund, but for which PPL Electric, LG&E and KU may be liable for remediation. These include a number of former coal gas manufacturing facilities in Pennsylvania and Kentucky previously owned or operated or currently owned by predecessors or affiliates of PPL Electric, LG&E and KU. There are additional sites, formerly owned or operated by PPL Electric, LG&E and KU predecessors or affiliates, for which PPL Electric, LG&E and KU lack information on current site conditions and are therefore unable to predict what, if any, potential liability they may have.

In June 2011, Lepore-Moyers Partnership (LMP) filed a complaint in federal district court against PPL Electric, UGI Corporation and a neighboring property owner relating to contamination allegedly emanating from the former Mount Joy Manufactured Gas Plant (MGP) site located in Lancaster County, Pennsylvania. LMP owns property adjacent to the Mount Joy MGP site and claims that environmental testing done on its property indicates the presence of volatile organic compounds in the soil and/or groundwater. LMP claims that defendants are responsible for, among other things, the reimbursement of costs, future response costs, investigation and remediation of the contamination, and damages caused by the contamination. PPL Electric expects the costs related to this matter to be insignificant.

Depending on the outcome of investigations at sites where investigations have not begun or been completed or developments at sites for which PPL currently lacks information, the costs of remediation and other liabilities could be substantial. PPL and its subsidiaries also could incur other non-remediation costs at sites included in current consent orders or other contaminated sites which could be significant. PPL is unable to estimate a range of reasonably possible losses, if any, related to these matters.

The EPA is evaluating the risks associated with polycyclic aromatic hydrocarbons and naphthalene, chemical by-products of coal gas manufacturing. As a result of the EPA's evaluation, individual states may establish stricter standards for water quality and soil cleanup. This could require several PPL subsidiaries to take more extensive assessment and remedial actions at former coal gas manufacturing facilities. PPL cannot estimate a range of reasonably possible losses, if any, related to these matters.

Under the Pennsylvania Clean Streams Law, subsidiaries of PPL Generation are obligated to remediate acid mine drainage at former mine sites and may be required to take additional steps to prevent potential acid mine drainage at previously capped refuse piles. One PPL Generation subsidiary is pumping mine water at two mine sites and treating water at one of these sites. Another PPL Generation subsidiary has installed a passive wetlands treatment system at a third site. At December 31, 2011, PPL Energy Supply had accrued a discounted liability of $24 million to cover the costs of pumping and treating groundwater at the two mine sites for 50 years and for operating and maintaining passive wetlands treatment at the third site. PPL Energy Supply discounted this liability based on risk-free rates at the time of the mine closures. The weighted-average rate used was 8.15%. Expected undiscounted payments are estimated at $2 million for 2012, $1 million for each of the years from 2013 through 2016, and $133 million for work after 2016.

From time to time, PPL undertakes remedial action in response to spills or other releases at various on-site and off-site locations, negotiates with the EPA and state and local agencies regarding actions necessary for compliance with applicable requirements, negotiates with property owners and other third parties alleging impacts from PPL's operations, and undertakes similar actions necessary to resolve environmental matters which arise in the course of normal operations. Based on analyses to date, resolution of these general environmental matters is not expected to have a material adverse impact on PPL's operations.

Future cleanup or remediation work at sites currently under review, or at sites not currently identified, may result in material additional costs for the Registrants.

Electric and Magnetic Fields

Concerns have been expressed by some members of the public regarding potential health effects of power frequency EMFs, which are emitted by all devices carrying electricity, including electric transmission and distribution lines and substation equipment. Government officials in the U.S. and the U.K. have reviewed this issue. The U.S. National Institute of Environmental Health Sciences concluded in 2002 that, for most health outcomes, there is no evidence that EMFs cause adverse effects. The agency further noted that there is some epidemiological evidence of an association with childhood leukemia, but that the evidence is difficult to interpret without supporting laboratory evidence. The U.K. National Radiological Protection Board (part of the U.K. Health Protection Agency) concluded in 2004 that, while the research on EMFs does not provide a basis to find that EMFs cause any illness, there is a basis to consider precautionary measures beyond existing exposure guidelines. The Stakeholder Group on Extremely Low Frequency EMF, set up by the U.K. Government, has issued two reports, one in April 2007 and one in June 2010, describing options for reducing public exposure to EMF. The U.K. Government responded to the first report in 2009, agreeing to some of the proposals, including a proposed voluntary code to optimally phase 132 kilovolt overhead lines to reduce public exposure to EMF where it is cost effective to do so. In February 2011, the U.K. Government and the Energy Networks Association agreed to voluntary codes of practice under which new high voltage lines will be designed and operated using optimal phasing to reduce EMF unless doing so would be unreasonable, and defining the circumstances under which utilities will need to provide evidence of compliance with EMF exposure limits adopted by the U.K. Government. The U.K. Government is currently considering the second report which concentrates on EMF exposure from distribution systems. PPL and its subsidiaries believe research on EMF and health issues should continue and are taking steps to reduce EMFs, where practical, in the design of new transmission and distribution facilities. PPL and its subsidiaries are unable to predict what effect, if any, the EMF issue might have on their operations and facilities either in the U.S. or the U.K., and the associated cost, or what, if any, liabilities they might incur related to the EMF issue.

Environmental Matters - WPD ***(PPL)***

WPD's distribution businesses are subject to environmental regulatory and statutory requirements. PPL believes that WPD has taken and continues to take measures to comply with the applicable laws and governmental regulations for the protection of the environment.

The U.K. Government has requested that utilities undertake projects to alleviate the impact of flooding on the U.K. utility infrastructure, including major electricity substations. WPD has agreed with the Ofgem to spend $44 million on flood prevention, which will be recovered through rates during the ten-year period commencing April 2010. WPD is currently liaising on site-specific proposals with local offices of a U.K. Government agency.

The U.K.'s 2008 Climate Change Act imposes a duty on certain companies, including WPD, to report on climate change adaptation. The first information request was received by WPD in March 2010 and submissions for all four distribution network operators were made in June 2011. In October 2011, the U.K. Government confirmed that the reports submitted by WPD fulfill the obligations imposed by Climate Change Act. WPD has worked with other U.K. electricity network operators to undertake research with the internationally recognized U.K. Met Office (the national weather service) and to report using common agreed methodology.

There are no other material legal or administrative proceedings pending against or related to WPD with respect to environmental matters. See "Electric and Magnetic Fields" above for a discussion of EMFs.

Other

Nuclear Insurance *(PPL and PPL Energy Supply)*

PPL Susquehanna is a member of certain insurance programs that provide coverage for property damage to members' nuclear generating plants. Facilities at the Susquehanna plant are insured against property damage losses up to $2.75 billion under these programs. PPL Susquehanna is also a member of an insurance program that provides insurance coverage for the cost of replacement power during prolonged outages of nuclear units caused by certain specified conditions.

Under the property and replacement power insurance programs, PPL Susquehanna could be assessed retroactive premiums in the event of the insurers' adverse loss experience. At December 31, 2011, this maximum assessment was $44 million.

In the event of a nuclear incident at the Susquehanna plant, PPL Susquehanna's public liability for claims resulting from such incident would be limited to $12.6 billion under provisions of The Price-Anderson Act Amendments under the Energy Policy Act of 2005. PPL Susquehanna is protected against this liability by a combination of commercial insurance and an industry assessment program.

In the event of a nuclear incident at any of the reactors covered by The Price-Anderson Act Amendments under the Energy Policy Act of 2005, PPL Susquehanna could be assessed up to $235 million per incident, payable at $35 million per year.

At December 31, 2011, the property, replacement power and nuclear incident insurers maintained an A.M. Best financial strength rating of A ("Excellent").

Guarantees and Other Assurances

(PPL, PPL Energy Supply, PPL Electric, LKE, LG&E and KU)

In the normal course of business, the Registrants enter into agreements that provide financial performance assurance to third parties on behalf of certain subsidiaries. Such agreements include, for example, guarantees, stand-by letters of credit issued by financial institutions and surety bonds issued by insurance companies. These agreements are entered into primarily to support or enhance the creditworthiness attributed to a subsidiary on a stand-alone basis or to facilitate the commercial activities in which these subsidiaries enter.

(PPL)

PPL fully and unconditionally guarantees all of the debt securities of PPL Capital Funding.

(PPL, PPL Energy Supply, PPL Electric, LKE, LG&E and KU)

The table below details guarantees provided as of December 31, 2011. The total recorded liability at December 31, 2011 and 2010 was $14 million for PPL and $11 million for LKE. Other than as noted in the descriptions for "WPD guarantee of pension and other obligations of unconsolidated entities," the probability of expected payment/performance under each of these guarantees is remote.

	Exposure at December 31, 2011 (a)	Expiration Date
PPL		
Indemnifications for sale of PPL Gas Utilities	$ 300 (b)	
Indemnifications related to the WPD Midlands acquisition	(c)	
WPD indemnifications for entities in liquidation and sales of assets	287 (d)	2014 - 2018
WPD guarantee of pension and other obligations of unconsolidated entities	88 (e)	2015
Tax indemnification related to unconsolidated WPD affiliates	8 (f)	2012
PPL Energy Supply (g)		
Letters of credit issued on behalf of affiliates	21 (h)	2012 - 2014
Retrospective premiums under nuclear insurance programs	44 (i)	
Nuclear claims assessment under The Price-Anderson Act Amendments under The Energy Policy Act of 2005	235 (j)	
Indemnifications for sales of assets	338 (k)	2012 - 2025
Indemnification to operators of jointly owned facilities	6 (l)	
Guarantee of a portion of a divested unconsolidated entity's debt	22 (m)	2018
PPL Electric (n)		
Guarantee of inventory value	14 (o)	2016
LKE (n)		
Indemnification of lease termination and other divestitures	301 (p)	2021 - 2023
LG&E and KU (q)		
LG&E and KU guarantee of shortfall related to OVEC	(r)	2040

(a) Represents the estimated maximum potential amount of future payments that could be required to be made under the guarantee.

(b) PPL has provided indemnification to the purchaser of PPL Gas Utilities and Penn Fuel Propane, LLC for damages arising out of any breach of the representations, warranties and covenants under the related transaction agreement and for damages arising out of certain other matters, including certain pre-closing unknown environmental liabilities relating to former manufactured gas plant properties or off-site disposal sites, if any, outside of Pennsylvania. The indemnification provisions for most representations and warranties, including tax and environmental matters, are capped at $45 million, in the aggregate, and are triggered (i) only if the individual claim exceeds $50,000, and (ii) only if, and only to the extent that, in the aggregate, total claims exceed $4.5 million. The indemnification provisions for most representations and warranties expired on September 30, 2009 without any claims having been made. Certain representations and warranties, including those having to do with transaction authorization and title, survive indefinitely, are capped at the purchase price and are not subject to the above threshold or deductible. The indemnification provision for the tax matters representations survives for the duration of the applicable statute of limitation. The indemnification provision for the environmental matters representations expired on September 30, 2011 without any claims having been made. The indemnification for covenants survives until the applicable covenant is performed and is not subject to any cap.

(c) WPD Midlands Holdings Limited (formerly Central Networks Limited) had agreed prior to the acquisition to indemnify certain former directors of a Turkish entity in which WPD Midlands Holdings Limited previously owned an interest for any liabilities that may arise as a result of an investigation by Turkish tax authorities, and PPL WEM has received a cross-indemnity from E.ON AG with respect to these indemnification obligations. Additionally, PPL subsidiaries agreed to provide indemnifications to subsidiaries of E.ON AG for certain liabilities relating to properties and assets owned by affiliates of E.ON AG that were transferred to WPD Midlands in connection with the acquisition. The maximum exposure and expiration of these indemnifications cannot be estimated because the maximum potential liability is not capped and there is no expiration date in the transaction documents.

(d) In connection with the liquidation of wholly owned subsidiaries that have been deconsolidated upon turning the entities over to the liquidators, certain affiliates of PPL Global have agreed to indemnify the liquidators, directors and/or the entities themselves for any liabilities or expenses arising during the liquidation process, including liabilities and expenses of the entities placed into liquidation. In some cases, the indemnifications are limited to a maximum amount that is based on distributions made from the subsidiary to its parent either prior or subsequent to being placed into liquidation. In other cases, the maximum amount of the indemnifications is not explicitly stated in the agreements. The indemnifications generally expire two to seven years subsequent to the date of dissolution of the entities. The exposure noted only includes those cases in which the agreements provide for a specific limit on the amount of the indemnification, and the expiration date was based on an estimate of the dissolution date of the entities.

In connection with their sales of various businesses, WPD and its affiliates have provided the purchasers with indemnifications that are standard for such transactions, including indemnifications for certain pre-existing liabilities and environmental and tax matters. In addition, in connection with certain of these sales, WPD and its affiliates have agreed to continue their obligations under existing third-party guarantees, either for a set period of time following the transactions or upon the condition that the purchasers make reasonable efforts to terminate the guarantees. Finally, WPD and its affiliates remain secondarily responsible for lease payments under certain leases that they have assigned to third parties.

(e) As a result of the privatization of the utility industry in the U.K., certain electric associations' roles and responsibilities were discontinued or modified. As a result, certain obligations, primarily pension-related, associated with these organizations have been guaranteed by the participating members. Costs are allocated to the members based on predetermined percentages as outlined in specific agreements. However, if a member becomes insolvent, costs can be reallocated to and are guaranteed by the remaining members. At December 31, 2011, WPD has recorded an estimated discounted liability based on its current allocated percentage of the total expected costs for which the expected payment/performance is probable. Neither the expiration date nor the maximum amount of potential payments for certain obligations is explicitly stated in the related agreements. Therefore, they have been estimated based on the types of obligations.

(f) Two WPD unconsolidated affiliates were refinanced during 2005. Under the terms of the refinancing, WPD has indemnified the lender against certain tax and other liabilities.

(g) Other than the letters of credit, all guarantees of PPL Energy Supply, on a consolidated basis, also apply to PPL on a consolidated basis for financial reporting purposes.

(h) Standby letter of credit arrangements under PPL Energy Supply's credit facilities for the purposes of protecting various third parties against nonperformance by PPL. This is not a guarantee by PPL on a consolidated basis.

(i) PPL Susquehanna is contingently obligated to pay this amount related to potential retrospective premiums that could be assessed under its nuclear insurance programs. See "Nuclear Insurance" above for additional information.

(j) This is the maximum amount PPL Susquehanna could be assessed for each incident at any of the nuclear reactors covered by this Act. See "Nuclear Insurance" above for additional information.

(k) PPL Energy Supply's maximum exposure with respect to certain indemnifications and the expiration of the indemnifications cannot be estimated because, in the case of certain indemnification provisions, the maximum potential liability is not capped by the transaction documents and the expiration date is based on the applicable statute of limitation. The exposure and expiration dates noted are only for those cases in which the agreements provide for specific limits.

A subsidiary of PPL Energy Supply has agreed to provide indemnification to the purchaser of the Long Island generation business for damages arising out of any breach of the representations, warranties and covenants under the related transaction agreement and for damages arising out of certain other matters, including liabilities relating to certain renewable energy facilities which were previously owned by one of the PPL subsidiaries sold in the transaction but which were unrelated to the Long Island generation business. The indemnification provisions are subject to certain customary limitations, including thresholds for allowable claims, caps on aggregate liability, and time limitations for claims arising out of breaches of most representations and warranties. The indemnification provisions for most representations and warranties expired in the third quarter of 2011.

A subsidiary of PPL Energy Supply has agreed to provide indemnification to the purchasers of the Maine hydroelectric facilities for damages arising out of any breach of the representations, warranties and covenants under the respective transaction agreements and for damages arising out of certain other matters, including liabilities of the PPL Energy Supply subsidiary relating to the pre-closing ownership or operation of those hydroelectric facilities. The indemnification obligations are subject to certain customary limitations, including thresholds for allowable claims, caps on aggregate liability, and time limitations for claims arising out of breaches of representations and warranties. The indemnification provisions for certain representations and warranties expired in the second quarter of 2011.

Subsidiaries of PPL Energy Supply have agreed to provide indemnification to the purchasers of certain non-core generation facilities sold in March 2011 (see Note 9 for additional information) for damages arising out of any breach of the representations, warranties and covenants under the related transaction agreements and for damages arising out of certain other matters relating to the facilities that were the subject of the transaction, including certain reduced capacity payments (if any) at one of the facilities in the event specified PJM rule changes are proposed and become effective. The indemnification provisions are subject to certain customary limitations, including thresholds for allowable claims, caps on aggregate liability, and time limitations for claims arising out of breaches of most representations and warranties.

(l) In December 2007, a subsidiary of PPL Energy Supply executed revised owners agreements for two jointly owned facilities, the Keystone and Conemaugh generating plants. The agreements require that in the event of any default by an owner, the other owners fund contributions for the operation of the generating plants, based upon their ownership percentages. The maximum obligation among all owners, for each plant, is currently $20 million. The non-defaulting owners, who make up the defaulting owner's obligations, are entitled to the generation entitlement of the defaulting owner, based upon their ownership percentage. The agreements do not have an expiration date.

(m) A PPL Energy Supply subsidiary owned a one-third equity interest in Safe Harbor Water Power Corporation (Safe Harbor) that was sold in March 2011. Beginning in 2008, PPL Energy Supply guaranteed one-third of any amounts payable with respect to certain senior notes issued by Safe Harbor. Under the terms of the sale agreement, PPL Energy Supply continues to guarantee the portion of Safe Harbor's debt, but received a cross-indemnity from the purchaser in the event PPL Energy Supply is required to make a payment under the guarantee. Exposure noted reflects principal only. See Note 9 for additional information on the sale of this interest.

(n) All guarantees of PPL Electric and LKE, on a consolidated basis, also apply to PPL on a consolidated basis for financial reporting purposes.

(o) PPL Electric entered into a contract with a third party logistics firm that provides inventory procurement and fulfillment services. Under the contract, the logistics firm has title to the inventory purchased for PPL Electric's use. Upon termination of the contract, PPL Electric has guaranteed to purchase any remaining inventory that has not been used or sold by the logistics firm at the weighted-average cost at which the logistics firm purchased the inventory, thus protecting the logistics firm from reductions in the fair value of the inventory.

(p) LKE provides certain indemnifications, the most significant of which relate to the termination of the WKE lease in July 2009. These guarantees cover the due and punctual payment, performance and discharge by each party of its respective present and future obligations. The most comprehensive of these guarantees is the LKE guarantee covering operational, regulatory and environmental commitments and indemnifications made by WKE under the WKE Transaction Termination Agreement. This guarantee has a term of 12 years ending July 2021, and a cumulative maximum exposure of $200 million. Certain items such as non-excluded government fines and penalties fall outside the cumulative cap. Another guarantee with a maximum exposure of $100 million covering other indemnifications expires in 2023. Certain matters are currently under discussion among the parties, including one matter currently in arbitration and a further matter for which LKE is contesting the applicability of the indemnification requirement. The matter in arbitration may be ruled upon during early 2012, which ruling may result in increases or decreases to the liability estimate LKE has currently recorded. The ultimate outcome of both matters cannot be predicted at this time. Additionally, LKE has indemnified various third parties related to historical obligations for other divested subsidiaries and affiliates. The indemnifications vary by entity and the maximum amount limits range from being capped at the sale price to no specified maximum; however, LKE is not aware of formal claims under such indemnities made by any party at this time. LKE could be required to perform on these indemnifications in the event of covered losses or liabilities being claimed by an indemnified party. No additional material loss is anticipated by reason of such indemnification.

(q) All guarantees of LG&E and KU also apply to LKE on a consolidated basis for financial reporting purposes.

(r) As described in the "Energy Purchase Commitments" section of this footnote, pursuant to a power purchase agreement with OVEC, LG&E and KU are obligated to pay a demand charge which includes, among other charges, decommissioning costs, postretirement and post employment benefits. The demand charge is expected to cover LG&E's and KU's shares of the cost of these items over the term of the contract. However, in the event there is a shortfall in covering these costs, LG&E and KU are obligated to pay their share of the excess.

The Registrants provide other miscellaneous guarantees through contracts entered into in the normal course of business. These guarantees are primarily in the form of indemnification or warranties related to services or equipment and vary in duration. The amounts of these guarantees often are not explicitly stated, and the overall maximum amount of the obligation under such guarantees cannot be reasonably estimated. Historically, no significant payments have been made with respect to these types of guarantees and the probability of payment/performance under these guarantees is remote.

PPL, on behalf of itself and certain of its subsidiaries, maintains insurance that covers liability assumed under contract for bodily injury and property damage. The coverage requires a maximum $4 million deductible per occurrence and provides maximum aggregate coverage of $200 million. This insurance may be applicable to obligations under certain of these contractual arrangements.

16. Related Party Transactions

(PPL Energy Supply and PPL Electric)

PLR Contracts/Purchase of Accounts Receivable

In 2009, PPL EnergyPlus supplied PPL Electric's entire PLR load under power purchase contracts that expired on December 31, 2009. Under these contracts, PPL EnergyPlus provided electricity at the predetermined capped prices that PPL Electric was authorized to charge its PLR customers. These purchases totaled $1.8 billion in 2009 and included nuclear decommissioning recovery and amortization of an up-front contract payment. Additionally, beyond 2009, PPL EnergyPlus has been awarded a portion of the PLR generation supply through competitive solicitations. See Note 15 for additional information on PPL Electric's energy procurement plan for the period January 2011 through May 2013 and related competitive solicitations. PPL Electric's purchases from PPL EnergyPlus for 2011 and 2010 totaled $26 million and $320 million. The purchases are included in the Statements of Income as "Wholesale energy marketing to affiliate" by PPL Energy Supply and as "Energy purchases from affiliate" by PPL Electric.

Under the standard Supply Master Agreement for the solicitation process, PPL Electric requires all suppliers to post collateral once credit exposures exceed defined credit limits. PPL EnergyPlus is required to post collateral with PPL Electric: (a) when the market price of electricity to be delivered by PPL EnergyPlus exceeds the contract price for the forecasted quantity of electricity to be delivered and (b) this market price exposure exceeds a contractual credit limit. Based on the current credit rating of PPL Energy Supply, as guarantor, PPL EnergyPlus' credit limit was $35 million at December 31, 2011. In no instance is PPL Electric required to post collateral to suppliers under these supply contracts.

PPL Electric's customers may choose an alternative supplier for their generation supply. See Note 1 for additional information regarding PPL Electric's purchases of accounts receivable from alternative suppliers, including PPL EnergyPlus.

At December 31, 2011, PPL Energy Supply had a net credit exposure of $36 million to PPL Electric from its commitment as a PLR supplier and from the sale of its accounts receivable to PPL Electric.

NUG Purchases

PPL Electric has a reciprocal contract with PPL EnergyPlus to sell electricity purchased under contracts with NUGs. PPL Electric purchases electricity from the NUGs at contractual rates and then sells the electricity at the same price to PPL EnergyPlus. These purchases were insignificant in 2011 and 2010 and were $70 million in 2009. These amounts are included in the Statements of Income as "Electric revenue to affiliate" by PPL Electric, and as "Energy purchases from affiliate" by PPL Energy Supply. Most of the NUG contracts have expired, with the final NUG contract expiring in 2014.

Wholesale Sales and Purchases *(LG&E and KU)*

LG&E and KU jointly dispatch their generation units with the lowest cost generation used to serve their retail native load. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail native load and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are reflected in the Statements of Income as "Electric revenue from affiliate" and "Energy purchases from affiliate" and are recorded at a price equal to the seller's fuel cost. Savings realized from such intercompany transactions are shared equally between the two companies. The volume of energy each company has to sell to the other is dependent on its native load needs and its available generation.

Allocations of PPL Services Costs *(PPL Energy Supply, PPL Electric and LKE)*

PPL Services provides corporate functions such as financial, legal, human resources and information technology services. PPL Services charges the respective PPL subsidiaries for the cost of certain services when they can be specifically identified. The cost of services that is not directly charged to PPL subsidiaries is allocated to applicable subsidiaries based on an average of the subsidiaries' relative invested capital, operation and maintenance expenses and number of employees. PPL Services allocated the following amounts, which PPL management believes are reasonable, including amounts applied to accounts that are further distributed between capital and expense.

	2011	2010	2009 (a)
PPL Energy Supply	$ 189	$ 232	$ 214
PPL Electric	145	134	121
LKE	16	3 (b)	

(a) Excludes allocated costs associated with the February 2009 workforce reduction. See Note 13 for additional information.
(b) Represents costs allocated during the two months ending December 31, 2010 as LKE was acquired November 1, 2010.

Intercompany Billings by LKS *(LG&E and KU)*

LKS provides LG&E and KU with a variety of centralized administrative, management and support services. The cost of these services is directly charged to the company or, for general costs that cannot be directly attributed, charged based on predetermined allocation factors, including the following measures: number of customers, total assets, revenues, number of employees and/or other statistical information. LKS charged the amounts in the table below, which LKE management believes are reasonable, including amounts that are further distributed between capital and expense.

	Successor		Predecessor	
	Year Ended December 31, 2011	Two Months Ended December 31, 2010	Ten Months Ended October 31, 2010	Year Ended December 31, 2009
LG&E	$ 190	$ 32	$ 200	$ 180
KU	204	34	222	155

In addition, LG&E and KU provide services to each other and to LKS. Billings between LG&E and KU relate to labor and overheads associated with union and hourly employees performing work for the other company, charges related to jointly-owned generating units and other miscellaneous charges. Tax settlements between LKE and LG&E and KU are reimbursed through LKS.

Intercompany Borrowings

(PPL Energy Supply)

A PPL Energy Supply subsidiary holds revolving lines of credit and demand notes from certain affiliates. A note with PPL Energy Funding had an outstanding balance at December 31, 2011 of $198 million, which is reflected in "Notes receivable from affiliates" on the Balance Sheet. The interest rate on this borrowing was equal to one-month LIBOR plus 3.50%. There were no balances outstanding at December 31, 2010. Interest earned on these revolving facilities is included in "Interest Income from Affiliates" on the Statements of Income. For 2011, interest earned on borrowings was $8 million, which was substantially attributable to borrowings by PPL Energy Funding as discussed above. For 2010, interest earned on borrowings, excluding the term notes discussed below, was $5 million. Interest rates were equal to one-month LIBOR plus 1% and one-month LIBOR plus 3.50%. For 2009, interest earned on borrowings was insignificant.

(PPL Energy Supply, LKE, LG&E and KU)

In November 2010, a PPL Energy Supply subsidiary held term notes with LG&E and KU. These notes were subsequently repaid and therefore no balances were outstanding at December 31, 2010. Interest on these notes was due monthly at interest rates between 4.24% and 7.04%. Interest on these notes is included in "Interest Income from Affiliates" for PPL Energy Supply and "Interest Expense with Affiliates" for LKE, LG&E and KU. When balances were outstanding, interest on these notes was $4 million for 2010.

(LKE)

LKE maintains a $300 million revolving line of credit with a PPL Energy Supply subsidiary whereby LKE can borrow funds on a short-term basis at market-based rates. The interest rates on borrowings are equal to one-month LIBOR plus a spread. There was no balance outstanding at December 31, 2011 or 2010. Interest on the revolving line of credit with the PPL Energy Supply subsidiary was not significant for 2011 or 2010.

After PPL's acquisition of LKE in November 2010, LKE held a note receivable from a PPL affiliate. At December 31, 2011, $15 million was outstanding compared with $61 million at December 31, 2010. The interest rate on the outstanding borrowing was 2.27% and 2.26% for 2011 and 2010. Interest income on this note was not significant in 2011 or 2010.

Prior to PPL's acquisition of LKE in November 2010, LKE had revolving credit facilities and several short-term and long-term loans with its former E.ON AG affiliates. During 2010 and 2009, LKE incurred interest expense on these debt arrangements of $131 million and $155 million, which is included in the Statements of Income as "Interest Expense with Affiliate." The consolidated debt had a weighted-average interest rate of 3.76% at December 31, 2009. Any such borrowings were repaid in 2010 prior to or at the time of the acquisition by PPL.

(LG&E)

LG&E participates in an intercompany money pool agreement whereby LKE and/or KU make available to LG&E funds up to $500 million at an interest rate based on a market index of commercial paper issues. At December 31, 2011 there was no balance outstanding. At December 31, 2010, $12 million was outstanding. The interest rate for the period ended December 31, 2010 was 0.25%. Interest expense incurred on the money pool agreement with LKE and/or KU was not significant for 2011, 2010 or 2009.

Prior to PPL's acquisition of LKE in November 2010, LG&E had long-term loans from its former E.ON AG affiliates. During 2010 and 2009, LG&E incurred interest expense related to these debt arrangements of $22 million and $27 million, which is included in the Statements of Income as "Interest Expense with Affiliate." The long-term intercompany debt had a weighted-average interest rate of 5.49% at December 31, 2009. Any such borrowings were repaid in 2010 prior to or at the time of the acquisition by PPL.

(KU)

KU participates in an intercompany money pool agreement whereby LKE and/or LG&E make available to KU funds up to $500 million at an interest rate based on a market index of commercial paper issues. At December 31, 2011, there was no balance outstanding. At December 31, 2010, $10 million was outstanding. The interest rate for the period ended December 31, 2010 was 0.25%. Interest expense incurred on the money pool agreement with LKE and/or LG&E was not significant for 2011, 2010 or 2009.

Prior to PPL's acquisition of LKE in November 2010, KU had long-term loans from its former E.ON AG affiliates. During 2010 and 2009, KU incurred interest expense on these debt arrangements of $62 million and $69 million, which are included in the Statements of Income as "Interest Expense with Affiliate." The long-term intercompany debt had a weighted-average interest rate of 5.50% at December 31, 2009. Any such borrowings were repaid in 2010 prior to or at the time of the acquisition by PPL.

(PPL Energy Supply)

Intercompany Derivatives

In 2010 and 2009, PPL Global, which was a subsidiary of PPL Energy Supply, entered into a combination of average rate forwards and average rate options with PPL to sell British pounds sterling. These hedging instruments had terms identical to average rate forwards and average rate options entered into by PPL with third parties to protect the translation of expected income denominated in British pounds sterling to U.S. dollars. As a result of PPL Energy Supply's January 2011 distribution of its membership interest in PPL Global to its parent, gains and losses, both realized and unrealized, on these types of hedging instruments are reflected in "Income (Loss) from Discontinued Operations (net of income taxes)" on the Statements of Income. PPL Energy Supply recorded an insignificant net gain in 2010 and a net loss of $9 million during 2009 related to average rate forwards and average rate options. Contracts outstanding at December 31, 2010 hedged a total exposure of £89 million related to the translation of expected income in 2011. The fair value of these positions was insignificant at December 31, 2010.

PPL Global was also a party to forward contracts with PPL to sell British pounds sterling to protect the value of a portion of its net investment in WPD. These hedging instruments had terms identical to forward sales contracts entered into by PPL with third parties. The total amount of the contracts outstanding at December 31, 2010 was £35 million ($62 million based on contracted rates). The fair value of these positions at December 31, 2010 was an asset of $7 million, which is included in "Current Assets - Price risk management assets" with an offsetting after-tax amount included in the foreign currency translation adjustment component of AOCI on the Balance Sheet.

As a result of PPL Energy Supply's distribution of its membership interest in PPL Global to its parent, these intercompany derivatives were removed from PPL Energy Supply's balance sheet in 2011. See Note 9 for additional information.

Trademark Royalties

A PPL subsidiary owns PPL trademarks and billed certain affiliates for their use. PPL Energy Supply was billed $40 million of license fees in 2011, 2010 and 2009. These fees are primarily included in "Other operation and maintenance" on the Statements of Income.

On December 31, 2011, this agreement was terminated.

Distribution of Interest in PPL Global to Parent

In January 2011, PPL Energy Supply distributed its membership interest in PPL Global to its parent, PPL Energy Funding. See Note 9 for additional information.

Intercompany Insurance *(PPL Electric)*

PPL Power Insurance Ltd. (PPL Power Insurance) is a subsidiary of PPL that provides insurance coverage to PPL and its subsidiaries for property damage, general/public liability and workers' compensation.

Due to damages resulting from several PUC-reportable storms that occurred in 2011, PPL Electric has exceeded its deductible for the 2011 policy year. Probable recoveries on insurance claims with PPL Power Insurance of $26.5 million were recorded during 2011, of which $16 million was included in "Other operation and maintenance" on the Statement of Income and the remainder was recorded in PP&E on the Balance Sheet.

Other *(PPL Energy Supply, PPL Electric, LKE, LG&E and KU)*

See Note 1 for discussions regarding the intercompany tax sharing agreement and Note 7 for a discussion regarding capital transactions by PPL Energy Supply, PPL Electric, LKE, LG&E and KU. For PPL Energy Supply, PPL Electric and LKE, refer to Note 1 for discussions regarding intercompany allocations of stock-based compensation expense. For PPL Energy Supply, PPL Electric, LG&E and KU, see Note 13 for discussions regarding intercompany allocations associated with defined benefits.

17. Other Income (Expense) - net

(PPL, PPL Energy Supply, PPL Electric, LKE, LG&E and KU)

The breakdown of "Other Income (Expense) - net" was:

	PPL			PPL Energy Supply			PPL Electric		
	2011	2010	2009	2011	2010	2009	2011	2010	2009
Other Income									
Gains related to the extinguishment of notes (a)			$ 29			$ 25			
Earnings on securities in NDT funds	$ 24	$ 20	20	$ 24	$ 20	20			
Interest income	7	8	14	1	4	5	$ 1	$ 2	$ 8
AFUDC	7	5	1				7	5	1
Net hedge gains associated with the 2011 Bridge Facility (b)	55								
Gain on redemption of debt (c)	22								
Miscellaneous - Domestic	11	5	9	6	4	3		1	
Miscellaneous - International	1	1	1						
Total Other Income	127	39	74	31	28	53	8	8	9
Other Expense									
Economic foreign currency exchange contracts	(10)	(3)	9						
Charitable contributions	9	4	6	3	1		2	1	2
Cash flow hedges (d)		29							
LKE other acquisition-related costs (Note 10)		31							
WPD Midlands other acquisition-related costs (Note 10)	34								
Foreign currency loss on 2011 Bridge Facility (e)	57								
U.K. stamp duty tax	21								
Miscellaneous - Domestic	9	7	8	5	5	9	1	2	1
Miscellaneous - International	3	2	4						
Total Other Expense	123	70	27	8	6	9	3	3	3
Other Income (Expense) - net	$ 4	$ (31)	$ 47	$ 23	$ 22	$ 44	$ 5	$ 5	$ 6

	Successor		Predecessor	
	Year Ended December 31, 2011	Two Months Ended December 31, 2010	Ten Months Ended October 31, 2010	Year Ended December 31, 2009
LKE				
Other Income				
Net derivative gains (losses)			$ 19	$ 18
Interest income	$ 1			1
Equity in earnings of unconsolidated affiliate	1		3	
AFUDC				4
Life insurance			2	3
Gains on disposals of property				3
Miscellaneous	2		1	2
Total Other Income	4		25	31
Other Expense				
Charitable contributions	4	$ 1	5	5
Joint-use-asset depreciation			3	
Miscellaneous	1	1	3	3
Total Other Expense	5	2	11	8
Other Income (Expense) - net	$ (1)	$ (2)	$ 14	$ 23
LG&E				
Other Income				
Net derivative gains (losses)			$ 19	$ 18
Gains on disposals of property				3
Miscellaneous			1	1
Total Other Income			20	22
Other Expense				
Charitable contributions	$ 1		2	2
Miscellaneous	1	$ 3	1	1
Total Other Expense	2	3	3	3
Other Income (Expense) - net	$ (2)	$ (3)	$ 17	$ 19
KU				
Other Income				
Interest income				$ 1
Equity in earnings of unconsolidated affiliate	$ 1		$ 3	1
AFUDC				4
Life insurance			2	3
Miscellaneous			1	
Total Other Income	1		6	9
Other Expense				
Charitable contributions	1		1	1
Joint-use-asset depreciation			3	
Miscellaneous	1		1	2
Total Other Expense	2		5	3
Other Income (Expense) - net	$ (1)		$ 1	$ 6

(a) Represents PPL Energy Supply's $25 million gain on its tender offers to purchase up to $250 million aggregate principal amount of certain of its outstanding senior notes and PPL's additional net gain of $4 million as a result of reclassifying net gains on related cash flow hedges from AOCI into earnings.
(b) Represents a gain on foreign currency contracts that hedged the repayment of the 2011 Bridge Facility borrowing.
(c) As a result of PPL Electrics redemption of 7.125% Senior Secured Bonds due 2013, PPL recorded a gain on the accelerated amortization of the fair value adjustment to the debt recorded in connection with previously settled fair value hedges.
(d) Represents losses reclassified from AOCI into earnings associated with discontinued hedges at PPL for debt that had been planned to be issued by PPL Energy Supply. As a result of the expected net proceeds from the sale of certain non-core generation facilities, coupled with the monetization of full-requirement sales contracts, the debt issuance was no longer needed.
(e) Represents a foreign currency loss related to the repayment of the 2011 Bridge Facility borrowing.

18. Fair Value Measurements and Credit Concentration

(PPL, PPL Energy Supply, PPL Electric, LKE, LG&E and KU)

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). PPL and its subsidiaries use, as appropriate, a market approach (generally, data from market transactions), an income approach (generally, present value techniques and option-pricing models), and/or a cost approach (generally, replacement cost) to measure the fair value of an asset or liability. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk.

Recurring Fair Value Measurements

The assets and liabilities measured at fair value were:

	December 31, 2011				December 31, 2010			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
PPL								
Assets								
Cash and cash equivalents	$ 1,202	$ 1,202			$ 925	$ 925		
Short-term investments - municipal debt securities					163	163		
Restricted cash and cash equivalents (a)	209	209			66	66		
Price risk management assets:								
Energy commodities	3,423	3	$ 3,390	$ 30	2,503		$ 2,452	$ 51
Interest rate swaps	3		3		15		15	
Foreign currency exchange contracts	18		18		11		11	
Cross-currency swaps	24		20	4	44		44	
Total price risk management assets	3,468	3	3,431	34	2,573		2,522	51
NDT funds:								
Cash and cash equivalents	12	12			10	10		
Equity securities								
U.S. large-cap	292	202	90		303	207	96	
U.S. mid/small-cap	117	87	30		119	89	30	
Debt securities								
U.S. Treasury	86	86			75	75		
U.S. government sponsored agency	10		10		7		7	
Municipality	83		83		69		69	
Investment-grade corporate	38		38		33		33	
Other	2		2		1		1	
Receivables (payables), net		(3)	3		1	(1)	2	
Total NDT funds	640	384	256		618	380	238	
Auction rate securities (b)	24			24	25			25
Total assets	$ 5,543	$ 1,798	$ 3,687	$ 58	$ 4,370	$ 1,534	$ 2,760	$ 76
Liabilities								
Price risk management liabilities:								
Energy commodities	$ 2,345	$ 1	$ 2,327	$ 17	$ 1,552		$ 1,498	$ 54
Interest rate swaps	63		63		53		53	
Cross-currency swaps	2		2		9		9	
Total price risk management liabilities	$ 2,410	$ 1	$ 2,392	$ 17	$ 1,614		$ 1,560	$ 54
PPL Energy Supply								
Assets								
Cash and cash equivalents	$ 379	$ 379			$ 661	$ 661		
Restricted cash and cash equivalents (a)	145	145			26	26		
Price risk management assets:								
Energy commodities	3,423	3	$ 3,390	$ 30	2,503		$ 2,452	$ 51
Foreign currency exchange contracts					11		11	
Cross-currency swaps					44		44	
Total price risk management assets	3,423	3	3,390	30	2,558		2,507	51
NDT funds:								
Cash and cash equivalents	12	12			10	10		
Equity securities								
U.S. large-cap	292	202	90		303	207	96	
U.S. mid/small-cap	117	87	30		119	89	30	
Debt securities								
U.S. Treasury	86	86			75	75		
U.S. government sponsored agency	10		10		7		7	
Municipality	83		83		69		69	
Investment-grade corporate	38		38		33		33	
Other	2		2		1		1	
Receivables (payables), net		(3)	3		1	(1)	2	
Total NDT funds	640	384	256		618	380	238	
Auction rate securities (b)	19			19	20			20
Total assets	$ 4,606	$ 911	$ 3,646	$ 49	$ 3,883	$ 1,067	$ 2,745	$ 71
Liabilities								
Price risk management liabilities:								
Energy commodities	$ 2,345	$ 1	$ 2,327	$ 17	$ 1,541		$ 1,487	$ 54
Cross-currency swaps					9		9	
Total price risk management liabilities	$ 2,345	$ 1	$ 2,327	$ 17	$ 1,550		$ 1,496	$ 54

	December 31, 2011				December 31, 2010			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
PPL Electric								
Assets								
Cash and cash equivalents	$ 320	$ 320			$ 204	$ 204		
Restricted cash and cash equivalents (c)	13	13			14	14		
Total assets	$ 333	$ 333			$ 218	$ 218		
LKE								
Assets								
Cash and cash equivalents	$ 59	$ 59			$ 11	$ 11		
Short-term investments - municipal debt securities					163	163		
Restricted cash and cash equivalents (c)	29	29			23	23		
Total assets	$ 88	$ 88			$ 197	$ 197		
Liabilities								
Price risk management liabilities:								
Energy commodities (d)					$ 2		$ 2	
Interest rate swaps (e)	$ 60		$ 60		34		34	
Total liabilities	$ 60		$ 60		$ 36		$ 36	
LG&E								
Assets								
Cash and cash equivalents	$ 25	$ 25			$ 2	$ 2		
Short-term investments - municipal debt securities					163	163		
Restricted cash and cash equivalents (c)	29	29			22	22		
Total assets	$ 54	$ 54			$ 187	$ 187		
Liabilities								
Price risk management liabilities:								
Energy commodities (d)					$ 2		$ 2	
Interest rate swaps (e)	$ 60		$ 60		34		34	
Total liabilities	$ 60		$ 60		$ 36		$ 36	
KU								
Assets								
Cash and cash equivalents	$ 31	$ 31			$ 3	$ 3		
Restricted cash and cash equivalents (c)					1	1		
Total assets	$ 31	$ 31			$ 4	$ 4		

(a) Current portion is included in "Restricted cash and cash equivalents" and long-term portion is included in "Other noncurrent assets" on the Balance Sheets.
(b) Included in "Other investments" on the Balance Sheets.
(c) Current portion is included in "Other current assets" on the Balance Sheets. Such amounts were insignificant at December 31, 2011 and December 31, 2010. The long-term portion is included in "Other noncurrent assets" on the Balance Sheets.
(d) Included in "Other current liabilities" on the Balance Sheets.
(e) Current portion is included in "Other current liabilities" on the Balance Sheets. The long-term portion is included in "Price risk management liabilities" on the Balance Sheets.

At December 31, 2011 and 2010, KU's price risk management assets and liabilities arising from energy commodities and interest rate swaps accounted for at fair value on a recurring basis were not significant.

A reconciliation of net assets and liabilities classified as Level 3 for the years ended is as follows:

	PPL Fair Value Measurements Using Significant Unobservable Inputs (Level 3)			
	Energy Commodities, net	Auction Rate Securities	Cross-Currency Swaps	Total
December 31, 2011				
Balance at beginning of period	$ (3)	$ 25		$ 22
Total realized/unrealized gains (losses)				
Included in earnings	(65)			(65)
Included in OCI (a)	(1)	(1)	$ (10)	(12)
Purchases	1			1
Sales	(3)			(3)
Settlements	20			20
Transfers into Level 3	(10)		14	4
Transfers out of Level 3	74			74
Balance at end of period	$ 13	$ 24	$ 4	$ 41
December 31, 2010				
Balance at beginning of period	$ 107	$ 25		$ 132
Total realized/unrealized gains (losses)				
Included in earnings	(137)			(137)
Included in OCI (a)	11			11
Net purchases, sales, issuances and settlements (b)	(16)			(16)
Transfers into Level 3	(15)			(15)
Transfers out of Level 3	47			47
Balance at end of period	$ (3)	$ 25		$ 22

(a) "Energy Commodities" and "Cross-Currency Swaps" are included in "Qualifying derivatives" and "Auction Rate Securities" are included in "Available-for-sale securities" on the Statements of Comprehensive Income.

(b) Accounting guidance effective January 1, 2011 requires purchase, sale, issuance and settlement transactions within Level 3 to be presented on a gross basis. The transactions in 2010 are reported on a net basis.

A reconciliation of net assets and liabilities classified as Level 3 for the years ended is as follows:

	PPL Energy Supply Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Energy Commodities, net	Auction Rate Securities	Total
December 31, 2011			
Balance at beginning of period	$ (3)	$ 20	$ 17
Total realized/unrealized gains (losses)			
Included in earnings	(65)		(65)
Included in OCI (a)	(1)	(1)	(2)
Purchases	1		1
Sales	(3)		(3)
Settlements	20		20
Transfers into Level 3	(10)		(10)
Transfers out of Level 3	74		74
Balance at end of period	$ 13	$ 19	$ 32
December 31, 2010			
Balance at beginning of period	$ 107	$ 20	$ 127
Total realized/unrealized gains (losses)			
Included in earnings	(137)		(137)
Included in OCI (a)	11		11
Net purchases, sales, issuances and settlements (b)	(16)		(16)
Transfers into Level 3	(15)		(15)
Transfers out of Level 3	47		47
Balance at end of period	$ (3)	$ 20	$ 17

(a) "Energy Commodities" are included in "Qualifying derivatives" and "Auction Rate Securities" are included in "Available-for-sale securities" on the Statements of Comprehensive Income.

(b) Accounting guidance effective January 1, 2011 requires purchase, sale, issuance and settlement transactions within Level 3 to be presented on a gross basis. The transactions in 2010 are reported on a net basis.

A reconciliation of net assets and liabilities classified as Level 3 for the periods ended December 31 is as follows:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Energy Commodities, net		
	Successor		Predecessor
	Year Ended December 31, 2011	Two Months Ended December 31, 2010	Ten Months Ended October 31, 2010
LKE			
Balance at beginning of period		$ 24	$ 75
Included in discontinued operations		(3)	3
Settlements		(21)	(54)
Balance at end of period		$	$ 24

Net gains and losses on assets and liabilities classified as Level 3 and included in earnings for the years ended were reported in the Statements of Income as follows:

	PPL and PPL Energy Supply			
	Energy Commodities, net			
	Unregulated Retail Electric and Gas	Wholesale Energy Marketing	Net Energy Trading Margins	Energy Purchases
December 31, 2011				
Total gains (losses) included in earnings	$ 32		$ (1)	$ (96)
Change in unrealized gains (losses) relating to positions still held at the reporting date	23	$ 5	1	(2)
December 31, 2010				
Total gains (losses) included in earnings	11	14		(162)
Change in unrealized gains (losses) relating to positions still held at the reporting date	4	6		(119)

PPL and its subsidiaries recognize transfers between levels at end-of-reporting-period values.

Price Risk Management Assets/Liabilities - Energy Commodities

Energy commodity contracts are generally valued using the income approach, except for exchange-traded derivative gas, oil and emission allowance contracts, which are valued using the market approach and are classified as Level 1. When observable inputs are used to measure all or most of the value of a contract, the contract is classified as Level 2. Over-the-counter (OTC) contracts are valued using quotes obtained from an exchange, binding and non-binding broker quotes, prices posted by ISOs or published tariff rates. Furthermore, PPL and its subsidiaries obtain independent quotes from the market to validate the forward price curves. OTC contracts include forwards, swaps, options and structured deals for electricity, gas, oil and/or emission allowances and may be offset with similar positions in exchange-traded markets. To the extent possible, fair value measurements utilize various inputs that include quoted prices for similar contracts or market-corroborated inputs. In certain instances, these instruments may be valued using models, including standard option valuation models and standard industry models. For example, the fair value of a structured deal that delivers power to an illiquid delivery point may be measured by valuing the nearest liquid trading point plus the value of the basis between the two points. The basis input may be from market quotes, FTR prices or historical prices.

When unobservable inputs are significant to the fair value measurement, a contract is classified as Level 3. Additionally, Level 2 and Level 3 fair value measurements include adjustments for credit risk based on PPL's own creditworthiness (for net liabilities) and its counterparties' creditworthiness (for net assets). PPL's credit department assesses all reasonably available market information and probabilities of default used to calculate the credit adjustment. PPL assumes that observable market prices include sufficient adjustments for liquidity and modeling risks, but for Level 3 fair value measurements, PPL also assesses the need for additional adjustments for liquidity or modeling risks. The contracts classified as Level 3 represent contracts for which delivery is at a location where pricing is unobservable or the delivery dates are beyond the dates for which independent prices are available. To measure the fair value of these contracts, PPL uses internally developed models that project forward prices. The models use proxy locations, historical settlement prices and extrapolation of observable forward curves.

In certain instances, energy commodity contracts are transferred between Level 2 and Level 3. The primary reasons for the transfers during 2011 and 2010 were changes in the availability of market information and changes in the significance of the unobservable portion of the contract. As the delivery period of a contract becomes closer, market information may become available. When this occurs, the model's unobservable inputs are replaced with observable market information.

Price Risk Management Assets/Liabilities - Interest Rate Swaps/Foreign Currency Exchange Contracts/Cross-Currency Swaps

To manage their interest rate risk, PPL and its subsidiaries generally use interest rate contracts such as forward-starting swaps, floating-to-fixed swaps and fixed-to-floating swaps. To manage their foreign currency exchange risk, PPL and its subsidiaries generally use foreign currency exchange contracts such as forwards and options, as well as cross-currency swaps that contain characteristics of both interest rate and foreign currency exchange contracts. PPL and its subsidiaries use an income approach to measure the fair value of these contracts, utilizing readily observable inputs, such as forward interest rates (e.g., LIBOR and government security rates) and forward foreign currency exchange rates (e.g., GBP and Euro), as well as inputs that may not be observable, such as credit valuation adjustments. In certain cases, PPL and its subsidiaries cannot practicably obtain market information to value credit risk and therefore rely on their own models. These models use projected probabilities of default based on historical observances. When the credit valuation adjustment is significant to the overall valuation, the contracts are classified as Level 3. Certain cross-currency contracts were executed in 2011 and upon remeasurement of their fair value were transferred to Level 3 due to the significance of the credit adjustment driven by the long dated nature of the contracts.

(PPL and PPL Energy Supply)

NDT Funds

PPL and PPL Energy Supply generally use the market approach to measure the fair value of equity securities held in the NDT funds.

- The fair value measurements of equity securities classified as Level 1 are based on quoted prices in active markets and are comprised of securities that are representative of the Wilshire 5000 index, which is invested in approximately 70% large-cap stocks and 30% mid/small-cap stocks.

- Investments in commingled equity funds are classified as Level 2 and represent securities that track the S&P 500 index and the Wilshire 4500 index. These fair value measurements are based on firm quotes of net asset values per share, which are not obtained from a quoted price in an active market.

Debt securities are generally measured using a market approach, including the use of matrix pricing. Common inputs include reported trades, broker/dealer bid/ask prices, benchmark securities and credit valuation adjustments. When necessary, the fair value of debt securities is measured using the income approach, which incorporates similar observable inputs, as well as benchmark yields, credit valuation adjustments, reference data from market research publications, monthly payment data, collateral performance and new issue data.

The debt securities held by the NDT funds at December 31, 2011 have a weighted-average coupon of 4.40% and a weighted-average maturity of 8.46 years.

Auction Rate Securities

PPL's and PPL Energy Supply's auction rate securities include Federal Family Education Loan Program guaranteed student loan revenue bonds, as well as various municipal bond issues. At December 31, 2011, contractual maturities for these auction rate securities were a weighted average of approximately 24 years. PPL and PPL Energy Supply do not have significant exposure to realize losses on these securities; however, auction rate securities are classified as Level 3 because failed auctions limit the amount of observable market data that is available for measuring the fair value of these securities.

The fair value of auction rate securities is estimated using an income approach with inputs for the underlying structure and credit quality of each security; the present value of future interest payments, estimated based on forward rates of the SIFMA Index, and principal payments discounted using interest rates for bonds with a credit rating and remaining term to maturity similar to the stated maturity of the auction rate securities; and the impact of auction failures or redemption at par.

Nonrecurring Fair Value Measurements

The following nonrecurring fair value measurements occurred during the reporting periods, resulting in asset impairments.

	Carrying Amount (a)	Fair Value Measurements Using Level 2	Level 3	Loss (b)
Sulfur dioxide emission allowances (c):				
September 30, 2011	$ 1			$ 1
March 31, 2011	1			1
December 31, 2010	2		$ 1	1
September 30, 2010	6		2	4
June 30, 2010	11		3	8
March 31, 2010	13		10	3
December 31, 2009	20		13	7
March 31, 2009	45		15	30
RECs (c):				
September 30, 2011	1			1
June 30, 2011	2	$ 1		1
March 31, 2011	3			3
Certain non-core generation facilities:				
September 30, 2010	473	381		96
Long Island generation business:				
December 31, 2009	132	128		5
September 30, 2009	137	133		5
June 30, 2009	189	138		52

(a) Represents carrying value before fair value measurement.
(b) Losses on sulfur dioxide emission allowances and RECs were recorded in the Supply segment and included in "Other operation and maintenance" on the Statements of Income. Losses on certain non-core generation facilities and the Long Island generation business were recorded in the Supply segment and included in "Income (Loss) from Discontinued Operations (net of income taxes)" on the Statements of Income.
(c) Current and long-term sulfur dioxide emission allowances and RECs are included in "Other intangibles" in their respective areas on the Balance Sheets.

Sulfur Dioxide Emission Allowances

Due to declines in market prices, PPL Energy Supply assessed the recoverability of sulfur dioxide emission allowances not expected to be consumed. When available, observable market prices were used to value the sulfur dioxide emission allowances. When observable market prices were not available, fair value was modeled using prices from observable transactions and appropriate discount rates. The modeled values were significant to the overall fair value measurement, resulting in the Level 3 classification.

RECs

Due to declines in forecasted full-requirement obligations in certain markets as well as declines in market prices, PPL Energy Supply assessed the recoverability of certain RECs not expected to be used. Observable market prices (Level 2) were used to value the RECs.

Certain Non-Core Generation Facilities

Certain non-core generation facilities met the held for sale criteria at September 30, 2010. As a result, net assets held for sale were written down to their estimated fair value less cost to sell. The fair value in the table above excludes $4 million of estimated costs to sell and was based on the negotiated sales price (achieved through an active auction process). See Note 9 for additional information on the completed sale.

Long Island Generation Business

The Long Island generation business met the held for sale criteria at June 30, 2009. As a result, net assets held for sale were written down to their estimated fair value less cost to sell. The fair value in the table above excludes $1 million of estimated costs to sell and was based on the negotiated sales price (achieved through an active auction process). See Note 9 for additional information on the completed sale.

Financial Instruments Not Recorded at Fair Value *(PPL, PPL Energy Supply, PPL Electric, LKE, LG&E and KU)*

The carrying amounts of contract adjustment payments related to the 2010 Purchase Contract component of the 2010 Equity Units, the 2011 Purchase Contract component of the 2011 Equity Units, and long-term debt on the Balance Sheets and their estimated fair values are set forth below. The fair values of these instruments were estimated using an income approach by discounting future cash flows at estimated current cost of funding rates. The effect of third-party credit enhancements is not included in the fair value measurement.

	December 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
PPL				
Contract adjustment payments (a)	$ 198	$ 198	$ 146	$ 148
Long-term debt	17,993	19,392	12,663	12,868
PPL Energy Supply				
Long-term debt	3,024	3,397	5,589	5,919
PPL Electric				
Long-term debt	1,718	2,012	1,472	1,578
LKE				
Long-term debt	4,073	4,306	3,825	3,607
LG&E				
Long-term debt	1,112	1,164	1,112	1,069
KU				
Long-term debt	1,842	2,000	1,841	1,728

(a) Included in "Other current liabilities" and "Other deferred credits and noncurrent liabilities" on the Balance Sheets.

The carrying value of short-term debt (including notes between affiliates), when outstanding, represents or approximates fair value due to the variable interest rates associated with the financial instruments. The carrying value of held-to-maturity, short-term investments approximates fair value due to the liquid nature and short-term duration of these instruments.

Credit Concentration Associated with Financial Instruments

(PPL, PPL Energy Supply, PPL Electric, LKE, LG&E and KU)

PPL and its subsidiaries enter into contracts with many entities for the purchase and sale of energy. Many of these contracts qualify for NPNS and as such, the fair value of these contracts is not reflected in the financial statements. However, the fair value of these contracts is considered when committing to new business from a credit perspective. See Note 19 for information on credit policies used by PPL and its subsidiaries to manage credit risk, including master netting arrangements and collateral requirements.

(PPL)

At December 31, 2011, PPL had credit exposure of $3.0 billion from energy trading partners, excluding the effects of netting arrangements and collateral. As a result of netting arrangements and collateral, PPL's credit exposure was reduced to $866 million. One of the counterparties accounted for 11% of the exposure, and the next highest counterparty accounted for 6% of the exposure. Ten counterparties accounted for $457 million, or 53%, of the net exposure. These counterparties had an investment grade credit rating from S&P or Moody's. The foregoing excludes a long-term supply contract with SMGT due to SMGT's filing for bankruptcy protection during the fourth quarter of 2011. The outstanding accounts receivable associated with SMGT at December 31, 2011 was $14 million, of which $11 million has been reserved. See Note 15 for more information.

(PPL Energy Supply)

At December 31, 2011, PPL Energy Supply had credit exposure of $3.0 billion from energy trading partners, excluding exposure from related parties and the effects of netting arrangements and collateral. As a result of netting arrangements and collateral, this credit exposure was reduced to $863 million. One of the counterparties accounted for 11% of the exposure, and the next highest counterparty accounted for 6% of the exposure. Ten counterparties accounted for $457 million, or 53%, of the net exposure. These counterparties had an investment grade credit rating from S&P or Moody's. The foregoing excludes a long-term supply contract with SMGT due to SMGT's filing for bankruptcy protection during the fourth quarter of 2011. The outstanding accounts receivable associated with SMGT at December 31, 2011 was $14 million, of which $11 million has been reserved. See Note 15 for more information.

(PPL Electric)

At December 31, 2011, PPL Electric had no credit exposure under energy supply contracts (including its supply contracts with PPL EnergyPlus).

(LKE, LG&E and KU)

At December 31, 2011, LKE's, LG&E's and KU's credit exposure was not significant.

19. Derivative Instruments and Hedging Activities

Risk Management Objectives

(PPL, PPL Energy Supply, PPL Electric, LKE, LG&E and KU)

PPL has a risk management policy approved by the Board of Directors to manage market risk and counterparty credit risk. The RMC, comprised of senior management and chaired by the Chief Risk Officer, oversees the risk management function. Key risk control activities designed to ensure compliance with the risk policy and detailed programs include, but are not limited to, credit review and approval, validation of transactions and market prices, verification of risk and transaction limits, VaR analyses, portfolio stress tests, gross margin at risk analyses, sensitivity analyses and daily portfolio reporting, including open positions, determinations of fair value and other risk management metrics. During the second quarter of 2011, the RMC formally approved the inclusion of the risk programs for LKE (acquired in November 2010) under the risk management policy. WPD Midlands (acquired in April 2011) adhered to the applicable risk management programs, including interest rate and foreign currency exchange programs, from the date of acquisition.

Market Risk

Market risk is the potential loss PPL and its subsidiaries may incur as a result of price changes associated with a particular financial or commodity instrument. PPL and its subsidiaries utilize forward contracts, futures contracts, options, swaps and structured deals, such as tolling agreements, as part of risk management strategies, to minimize unanticipated fluctuations in earnings caused by changes in commodity prices, volumes of full-requirement sales contracts, basis exposure, interest rates and/or foreign currency exchange rates. All derivatives are recognized on the Balance Sheets at their fair value, unless they qualify for NPNS.

PPL is exposed to market risk from foreign currency exchange risk primarily associated with its investments in U.K. affiliates, as well as additional market risk from certain subsidiaries, as discussed below. As described in Note 9, in January 2011, PPL Energy Supply distributed its membership interest in PPL Global to PPL Energy Supply's parent, PPL Energy Funding. Therefore, effective January 2011, PPL Energy Supply is no longer subject to interest rate and foreign currency exchange risk associated with investments in U.K. affiliates.

PPL Energy Supply is exposed to market risk from:

- commodity price, basis and volumetric risks for energy and energy-related products associated with the sale of electricity from its generating assets and other electricity marketing activities (including full-requirement sales contracts) and the purchase of fuel and fuel-related commodities for generating assets, as well as for proprietary trading activities;
- interest rate and price risk associated with debt used to finance operations, as well as debt and equity securities in NDT funds and defined benefit plans; and
- foreign currency exchange rate risk associated with firm commitments in currencies other than the applicable functional currency.

PPL Electric is exposed to market and volumetric risks from PPL Electric's obligation as PLR. The PUC has approved a cost recovery mechanism that allows PPL Electric to pass through to customers the cost associated with fulfilling its PLR obligation. This cost recovery mechanism substantially eliminates PPL Electric's exposure to market risk. PPL Electric also mitigates its exposure to volumetric risk by entering into full-requirement supply agreements for its customers. These supply agreements transfer the volumetric risk associated with the PLR obligation to the energy suppliers.

By definition, the regulatory environments for PPL's other regulated entities, LKE (through its subsidiaries LG&E and KU) and WPD, significantly mitigate market risk. LG&E's and KU's rates are set to permit the recovery of prudently incurred costs, including certain mechanisms for fuel, gas supply and environmental expenses. These mechanisms generally provide for timely recovery of market price and volumetric fluctuations associated with these expenses. LG&E and KU primarily utilized forward financial transactions to manage price risk associated with expected economic generation capacity in excess of expected load requirements. WPD does not have supply risks as it is only in the distribution business.

LG&E also utilizes over-the-counter interest rate swaps to limit exposure to market fluctuations on interest expense. WPD utilizes over-the-counter cross currency swaps to limit exposure to market fluctuations on interest and principal payments from foreign currency exchange rates.

Credit Risk

Credit risk is the potential loss PPL and its subsidiaries may incur due to a counterparty's non-performance, including defaults on payments and energy commodity deliveries.

PPL is exposed to credit risk from interest rate and foreign currency derivatives with financial institutions, as well as additional credit risk through certain of its subsidiaries, as discussed below.

PPL Energy Supply is exposed to credit risk from commodity derivatives with their energy trading partners, which include other energy companies, fuel suppliers and financial institutions.

PPL Electric is exposed to credit risk from PPL Electric's supply agreements for its PLR obligation.

LG&E is exposed to credit risk from interest rate derivatives with financial institutions.

The majority of PPL's and its subsidiaries' credit risk stems from PPL subsidiaries' commodity derivatives for multi-year contracts for energy sales and purchases. If PPL Energy Supply's counterparties fail to perform their obligations under such contracts and PPL Energy Supply could not replace the sales or purchases at the same prices as those under the defaulted contracts, PPL Energy Supply would incur financial losses. Those losses would be recognized immediately or through lower revenues or higher costs in future years, depending on the accounting treatment for the defaulted contracts. In the event a supplier of LKE (through its subsidiaries LG&E and KU) or PPL Electric defaults on its obligation, those entities would be required to seek replacement power or replacement fuel in the market. In general, incremental costs incurred by these entities would be recoverable from customers in future rates.

PPL and its subsidiaries have credit policies to manage their credit risk, including the use of an established credit approval process, daily monitoring of counterparty positions and the use of master netting agreements. These agreements generally include credit mitigation provisions, such as margin, prepayment or collateral requirements. PPL and its subsidiaries may request the additional credit assurance, in certain circumstances, in the event that the counterparties' credit ratings fall below investment grade or their exposures exceed an established credit limit. See Note 18 for credit concentration associated with financial instruments.

Master Netting Arrangements

PPL and its subsidiaries have elected not to offset net derivative positions against the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements.

PPL's and PPL Energy Supply's obligation to return counterparty cash collateral under master netting arrangements was $147 million and $338 million at December 31, 2011 and December 31, 2010.

PPL Electric, LKE, LG&E and KU had no obligation to return cash collateral under master netting arrangements at December 31, 2011 and December 31, 2010.

PPL Energy Supply, PPL Electric and KU had not posted any cash collateral under master netting arrangements at December 31, 2011 and December 31, 2010.

PPL, LKE and LG&E had posted cash collateral under master netting arrangements of $29 million at December 31, 2011 and $19 million at December 31, 2010.

Commodity Price Risk (Non-trading)

(PPL and PPL Energy Supply)

Commodity price and basis risks are among PPL's and PPL Energy Supply's most significant risks due to the level of investment that PPL and PPL Energy Supply maintain in their competitive generation assets, as well as the extent of their marketing and proprietary trading activities. Several factors influence price levels and volatilities. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation/transmission availability and reliability within and between regions, market liquidity, and the nature and extent of current and potential federal and state regulations.

PPL and PPL Energy Supply enter into financial and physical derivative contracts, including forwards, futures, swaps and options, to hedge the price risk associated with electricity, gas, oil and other commodities. Certain contracts qualify for

NPNS or are non-derivatives and are therefore not reflected in the financial statements until delivery. PPL and PPL Energy Supply segregate their remaining non-trading activities into two categories: cash flow hedge activity and economic activity. In addition, the monetization of certain full-requirement sales contracts in 2010 impacted both the cash flow hedge and economic activity, as discussed below.

Monetization of Certain Full-Requirement Sales Contracts

In July 2010, in order to raise additional cash for the LKE acquisition, PPL Energy Supply monetized certain full-requirement sales contracts that resulted in cash proceeds of $249 million and triggered certain accounting:

- A portion of these sales contracts had previously been accounted for as NPNS and received accrual accounting treatment. PPL Energy Supply could no longer assert that it was probable that any contracts with these counterparties would result in physical delivery. Therefore, the fair value of the NPNS contracts of $160 million was recorded on the Balance Sheet in "Price risk management assets," with a corresponding gain of $144 million recorded to "Wholesale energy marketing - Realized" on the Statement of Income, and $16 million recorded to "Wholesale energy marketing - Unrealized economic activity," related to full-requirement sales contracts that had not been monetized.

- The related purchases to supply these sales contracts were accounted for as cash flow hedges, with the effective portion of the change in fair value being recorded in AOCI and the ineffective portion recorded in "Energy purchases - Unrealized economic activity." The corresponding cash flow hedges were dedesignated and all amounts previously recorded in AOCI were reclassified to earnings. This resulted in a pre-tax reclassification of $(173) million of losses from AOCI into "Energy purchases - Unrealized economic activity" on the Statement of Income. An additional charge of $(39) million was also recorded in "Wholesale energy marketing - Unrealized economic activity" on the Statement of Income to reflect the fair value of the sales contracts previously accounted for as economic activity.

- The net result of these transactions, excluding the full-requirement sales contracts that have not been monetized, was a loss of $(68) million, or $(40) million, after tax.

The proceeds of $249 million from these monetizations are reflected in the Statement of Cash Flows as a component of "Net cash provided by operating activities."

Cash Flow Hedges

Many derivative contracts have qualified for hedge accounting so that the effective portion of a derivative's gain or loss is deferred in AOCI and reclassified into earnings when the forecasted transaction occurs. The cash flow hedges that existed at December 31, 2011 range in maturity through 2016. At December 31, 2011, the accumulated net unrecognized after-tax gains (losses) that are expected to be reclassified into earnings during the next 12 months were $394 million for PPL and PPL Energy Supply. Cash flow hedges are discontinued if it is no longer probable that the original forecasted transaction will occur by the end of the originally specified time periods and any amounts previously recorded in AOCI are reclassified into earnings once it is determined that the hedge transaction is probable of not occurring. For 2011, such reclassifications were insignificant. For 2010 and 2009, such reclassifications were after-tax gains (losses) of $(89) million and $9 million. The amounts recorded in 2010 were primarily due to the monetization of certain full-requirement sales contracts, for which the associated hedges are no longer required, as discussed above.

For 2011, 2010 and 2009, hedge ineffectiveness associated with energy derivatives was, after-tax, a loss of $(22) million, a loss of $(30) million and a gain of $41 million.

In addition, when cash flow hedge positions fail hedge effectiveness testing, hedge accounting is not permitted in the quarter in which this occurs and, accordingly, the entire change in fair value for the periods that failed is recorded to the Statement of Income. Certain power and gas cash flow hedge positions failed effectiveness testing during 2008 and the first quarter of 2009. However, these positions were not dedesignated as hedges, as prospective regression analysis demonstrated that these hedges were expected to be highly effective over their term. During 2009, fewer power and gas cash flow hedges failed hedge effectiveness testing; therefore, a portion of the previously recognized unrealized gains recorded in 2008 associated with these hedges were reversed. For 2009, after-tax gains (losses) of $(215) million were recognized in earnings as a result of these reversals. During the first quarter of 2010, after-tax gains (losses) of $(82) million were recognized in earnings as a result of these reversals continuing. Effective April 1, 2010, clarifying accounting guidance was issued that precludes the reversal of previously recognized gains/losses resulting from hedge failures. By the end of the first quarter of 2010, all previously recorded hedge ineffectiveness gains resulting from hedge failures were reversed; thus, the new accounting guidance did not have a significant impact at adoption on April 1, 2010.

Economic Activity

Certain derivative contracts economically hedge the price and volumetric risk associated with electricity, gas, oil and other commodities but do not receive hedge accounting treatment. These derivatives hedge a portion of the economic value of PPL and PPL Energy Supply's competitive generation assets and unregulated full-requirement and retail contracts, which are subject to changes in fair value due to market price volatility and volume expectations. Additionally, economic activity includes the ineffective portion of qualifying cash flow hedges (see "Cash Flow Hedges" above). The derivative contracts in this category that existed at December 31, 2011 range in maturity through 2019.

Examples of economic activity include certain purchase contracts used to supply full-requirement sales contracts; FTRs or basis swaps used to hedge basis risk associated with the sale of competitive generation or supplying unregulated full-requirement sales contracts; spark spreads (sale of electricity with the simultaneous purchase of fuel); retail electric and gas activities; and fuel oil swaps used to hedge price escalation clauses in coal transportation and other fuel-related contracts. PPL Energy Supply also uses options, which include the sale of call options and the purchase of put options tied to a particular generating unit. Since the physical generating capacity is owned, the price exposure is limited to the cost of the particular generating unit and does not expose PPL Energy Supply to uncovered market price risk.

Unrealized activity associated with monetizing certain full-requirement sales contracts was also included in economic activity during 2011.

The net fair value of economic positions at December 31, 2011 and December 31, 2010 was a net (asset) liability of $63 million and $389 million for PPL Energy Supply. The unrealized gains (losses) for economic activity are as follows.

	2011	2010	2009
Operating Revenues			
Unregulated retail electric and gas	$ 31	$ 1	$ 6
Wholesale energy marketing	1,407	(805)	(229)
Operating Expenses			
Fuel	6	29	49
Energy purchases	(1,123)	286	(155)

The net gains (losses) recorded in "Wholesale energy marketing" resulted primarily from certain full-requirement sales contracts for which PPL Energy Supply did not elect NPNS, from hedge ineffectiveness, including hedges that failed effectiveness testing, as discussed in "Cash Flow Hedges" above, and from the July 2010 monetization of certain full-requirement sales contracts. The net gains (losses) recorded in "Energy purchases" resulted primarily from certain purchase contracts to supply the full-requirement sales contracts noted above for which PPL Energy Supply did not elect hedge treatment, from hedge ineffectiveness, including hedges that failed effectiveness testing, and from purchase contracts that no longer hedge the full-requirement sales contracts that were monetized as discussed above in "Monetization of Certain Full-Requirement Sales Contracts."

(PPL, LKE, LG&E and KU)

LG&E and KU primarily utilized forward financial transactions to manage price risk associated with expected economic generation capacity in excess of expected load requirements. Hedge accounting treatment was not elected for these transactions; therefore, realized and unrealized gains and losses are recorded in the Statements of Income.

The net fair value of economic positions for LKE, LG&E and KU at December 31, 2010 were not significant. There are no economic positions at December 31, 2011. Unrealized gains (losses) for economic activity for LKE, LG&E and KU in 2011, 2010 and 2009 were not significant.

(PPL and PPL Energy Supply)

Commodity Price Risk (Trading)

PPL Energy Supply also executes energy contracts to take advantage of market opportunities. As a result, PPL Energy Supply may at times create a net open position in its portfolio that could result in significant losses if prices do not move in the manner or direction anticipated. PPL Energy Supply's trading activity is shown in "Net energy trading margins" on the Statements of Income.

Commodity Volumetric Activity

PPL Energy Supply currently employs four primary strategies to maximize the value of its wholesale energy portfolio. As further discussed below, these strategies include the sales of baseload generation, optimization of intermediate and peaking generation, marketing activities, and proprietary trading activities. The tables within this section present the volumes of PPL Energy Supply's derivative activity, excluding those that qualify for NPNS, unless otherwise noted.

Sales of Baseload Generation

PPL Energy Supply has a formal hedging program for its competitive baseload generation fleet, which includes 7,252 MW of nuclear, coal and hydroelectric generating capacity. The objective of this program is to provide a reasonable level of near-term cash flow and earnings certainty while preserving upside potential of power price increases over the medium term. PPL Energy Supply sells its expected generation output on a forward basis using both derivative and non-derivative instruments. Both are included in the following tables.

The following table presents the expected sales, in GWh, from competitive baseload generation and tolling arrangements that are included in the baseload portfolio based on current forecasted assumptions for 2012-2014. These expected sales could be impacted by several factors, including plant availability.

2012	2013	2014
53,737	53,136	53,502

The following table presents the percentage of expected baseload generation sales shown above that has been sold forward under fixed price contracts and the related percentage of fuel that has been purchased or committed at December 31, 2011.

			Fuel Purchases (c)	
Year	Derivative Sales (a)	Total Power Sales (b)	Coal	Nuclear
2012	85%	93%	98%	100%
2013	63%	71%	89%	100%
2014 (d)	4%	10%	62%	100%

(a) Excludes non-derivative contracts and contracts that qualify for NPNS. Volumes for option contracts factor in the probability of an option being exercised and may be less than the notional amount of the option.
(b) Amount represents derivative (including contracts that qualify for NPNS) and non-derivative contracts. Volumes for option contracts factor in the probability of an option being exercised and may be less than the notional amount of the option. Percentages are based on fixed-price contracts only.
(c) Coal and nuclear contracts receive accrual accounting treatment, as they are not derivative contracts. Percentages are based on both fixed- and variable-priced contracts.
(d) Volumes for derivative sales contracts that deliver in future periods total 1,541 GWh and 7.2 Bcf.

In addition to the fuel purchases above, PPL Energy Supply attempts to economically hedge the fuel price risk that is within its fuel-related and coal transportation contracts, which are tied to changes in crude oil or diesel prices. PPL Energy Supply has also entered into contracts to financially hedge the physical sale of oil. The following table presents the net volumes (in thousands of barrels) of derivative (sales)/purchase contracts used in support of these strategies at December 31, 2011.

	2012	2013	2014
Oil Swaps	591	540	240

Optimization of Intermediate and Peaking Generation

In addition to its competitive baseload generation activities, PPL Energy Supply attempts to optimize the overall value of its competitive intermediate and peaking fleet, which includes 3,256 MW of gas and oil-fired generation. The following table presents the net volumes of derivative (sales)/purchase contracts used in support of this strategy at December 31, 2011.

	Units	2012	2013	2014 (a)
Power Sales	GWh	(2,860)	(1,224)	(408)
Fuel Purchases (b)	Bcf	27.1	8.1	2.5

(a) Volumes for derivative contracts used in support of these strategies that deliver in future periods are insignificant.
(b) Included in these volumes are non-options and exercised option contracts that converted to non-option derivative contracts. Volumes associated with option contracts are not significant.

Marketing Activities

PPL Energy Supply's marketing portfolio is comprised of full-requirement sales contracts and their related supply contracts, retail gas and electricity sales contracts and other marketing activities. The full-requirement sales contracts and their related supply contracts make up a significant component of the marketing portfolio. The obligations under the full-requirement sales contracts include supplying a bundled product of energy, capacity, RECs, and other ancillary products. The full-requirement sales contracts PPL Energy Supply is awarded do not provide for specific levels of load, and actual load could vary significantly from forecasted amounts. PPL Energy Supply uses a variety of strategies to hedge its full-requirement sales contracts, including purchasing energy at a liquid trading hub or directly at the load delivery zone, purchasing capacity and RECs in the market and supplying the energy, capacity and RECs with its generation. The following table presents the volume of (sales)/purchase contracts, excluding FTRs, RECs, basis and capacity contracts, used in support of these activities at December 31, 2011.

	Units	2012	2013	2014
Energy sales contracts (a)	GWh	(16,235)	(6,524)	(3,681)
Related energy supply contracts (a)				
Energy purchases	GWh	10,658	1,359	136
Volumetric hedges (b)	GWh	254	128	93
Generation supply	GWh	5,389	4,462	3,259
Retail gas sales contracts	Bcf	(13.5)	(2.6)	(0.7)
Retail gas purchase contracts	Bcf	13.2	2.5	0.7

(a) Includes NPNS and contracts that are not derivatives, which receive accrual accounting.
(b) PPL Energy Supply uses power and gas options, swaps and futures to hedge the volumetric risk associated with full-requirement sales contracts since the demand for power varies hourly. Volumes for option contracts factor in the probability of an option being exercised and may be less than the notional amount of the option.

Proprietary Trading Activity

At December 31, 2011, PPL Energy Supply's proprietary trading positions, excluding FTR, basis and capacity contract activity that is included in the tables below, were not significant.

Other Energy-Related Positions

FTRs and Other Basis Positions

PPL Energy Supply buys and sells FTRs and other basis positions to mitigate the basis risk between delivery points related to the sales of its generation, the supply of its full-requirement sales contracts and retail contracts, as well as for proprietary trading purposes. The following table presents the net volumes of derivative FTR and basis (sales)/purchase contracts at December 31, 2011.

	Units	2012	2013	2014
FTRs	GWh	16,562		
Power Basis Positions (a)	GWh	(18,035)	(8,343)	(2,628)
Gas Basis Positions (a)	Bcf	11.0	(5.2)	(0.9)

(a) Net volumes that deliver in future periods are (677) GWh and (5.1) Bcf.

Capacity Positions

PPL Energy Supply buys and sells capacity related to the sales of its generation and the supply of its full-requirement sales contracts. These contracts qualify for NPNS and receive accrual accounting. PPL Energy Supply also sells and purchases capacity for proprietary trading purposes. These contracts are marked to fair value through earnings. The following table presents the net volumes of derivative capacity (sales)/purchase contracts at December 31, 2011.

	Units	2012	2013	2014 (a)
Capacity	MW-months	(7,797)	(3,108)	(2,578)

(a) Volumes that deliver in future periods are 989 MW-months.

Interest Rate Risk

(PPL, PPL Energy Supply, LKE and LG&E)

PPL and its subsidiaries have issued debt to finance their operations, which exposes them to interest rate risk. PPL and its subsidiaries utilize various financial derivative instruments to adjust the mix of fixed and floating interest rates in their debt portfolio, adjust the duration of their debt portfolio and lock in benchmark interest rates in anticipation of future financing, when appropriate. Risk limits under the risk management program are designed to balance risk exposure to volatility in interest expense and changes in the fair value of PPL's and its subsidiaries' debt portfolio due to changes in benchmark interest rates.

Cash Flow Hedges *(PPL and PPL Energy Supply)*

Interest rate risks include exposure to adverse interest rate movements for outstanding variable rate debt and for future anticipated financings. PPL and PPL Energy Supply enter into financial interest rate swap contracts that qualify as cash flow hedges to hedge floating interest rate risk associated with both existing and anticipated debt issuances. For PPL, outstanding interest rate swap contracts ranged in maturity through 2022 and had a notional value of $150 million at December 31, 2011. No contracts were outstanding for PPL Energy Supply at December 31, 2011.

Through PPL, PPL WEM holds a notional position in cross-currency interest rate swaps totaling $960 million that mature through 2021 to hedge the interest payments and principal of the U.S. dollar-denominated senior notes issued by PPL WEM in April 2011. Additionally, PPL WW holds a notional position in cross-currency interest rate swaps totaling $302 million that mature through December 2028 to hedge the interest payments and principal of its U.S. dollar-denominated senior notes. In 2010, these PPL WW swaps were part of PPL Energy Supply's business. As a result of the distribution of PPL Energy Supply's membership interest in PPL Global to PPL Energy Funding effective January 2011, these swaps are no longer part of PPL Energy Supply's business.

For 2011, hedge ineffectiveness associated with interest rate derivatives resulted in a net after-tax gain (loss) of $(9) million for PPL, which included a gain (loss) of $(4) million attributable to certain interest rate swaps that failed hedge effectiveness testing during the second quarter of 2011. For 2010, hedge ineffectiveness associated with these derivatives resulted in a net after-tax gain (loss) of $(9) million for PPL and was insignificant for PPL Energy Supply. For 2009, hedge ineffectiveness associated with these derivatives was insignificant for PPL and PPL Energy Supply.

Cash flow hedges are discontinued if it is no longer probable that the original forecasted transaction will occur by the end of the originally specified time periods and any amounts previously recorded in AOCI are reclassified into earnings once it is determined that the hedged transaction is probable of not occurring. PPL had no such reclassifications for 2011. As a result of the expected net proceeds from the anticipated sale of certain non-core generation facilities, coupled with the monetization of certain full-requirement sales contracts, debt that had been planned to be issued by PPL Energy Supply in 2010 was no longer needed. As a result, hedge accounting associated with interest rate swaps entered into by PPL in anticipation of a debt issuance by PPL Energy Supply was discontinued. PPL reclassified into earnings a net after-tax gain (loss) of $(19) million in 2010 and an insignificant amount in 2009. PPL Energy Supply had no such reclassifications in 2011, 2010 and 2009.

At December 31, 2011, the accumulated net unrecognized after-tax gains (losses) on qualifying derivatives that are expected to be reclassified into earnings during the next 12 months were $(12) million for PPL and insignificant for PPL Energy Supply. Amounts are reclassified as the hedged interest payments are made.

Fair Value Hedges

(PPL and PPL Energy Supply)

PPL and PPL Energy Supply are exposed to changes in the fair value of their debt portfolios. To manage this risk, PPL and PPL Energy Supply may enter into financial contracts to hedge fluctuations in the fair value of existing debt issuances due to changes in benchmark interest rates. At December 31, 2011, PPL held contracts that range in maturity through 2047 and had a notional value of $99 million. PPL Energy Supply did not hold any such contracts at December 31, 2011. PPL and PPL Energy Supply did not recognize gains or losses resulting from the ineffective portion of fair value hedges or from a portion of the hedging instrument being excluded from the assessment of hedge effectiveness for 2011, 2010 and 2009.

(PPL)

In 2011, PPL Electric redeemed $400 million of 7.125% Senior Secured Bonds due 2013. As a result of this redemption, PPL recorded a gain (loss) of $22 million, or $14 million after tax, for 2011 in "Other Income (Expense) - net" on the

Statement of Income as a result of accelerated amortization of the fair value adjustments to the debt in connection with previously settled fair value hedges. Additionally, PPL recognized insignificant amounts from hedges of debt that no longer qualified as fair value hedges for 2010 and 2009.

(PPL Energy Supply)

PPL Energy Supply did not recognize any gains or losses resulting from hedges of debt issuances that no longer qualified as fair value hedges for 2011, 2010 and 2009.

Economic Activity *(PPL, LKE and LG&E)*

LG&E enters into interest rate swap contracts that economically hedge interest payments on variable rate debt. Because realized gains and losses from the swaps, including a terminated swap contract, are recoverable through regulated rates, any subsequent changes in fair value of these derivatives are included in regulatory assets or liabilities until they are realized as interest expense. Realized gains and losses are recognized in "Interest Expense" on the Statements of Income when the hedged transaction occurs. At December 31, 2011, LG&E held contracts with aggregate notional amounts of $179 million that range in maturity through 2033. The fair value of these contracts were recorded as liabilities of $60 million and $34 million at December 31, 2011 and 2010, with equal offsetting amounts recorded as regulatory assets.

Prior to the third quarter of 2010, LG&E Predecessor accounted for these contracts as cash flow hedges and reclassified amounts previously recorded in AOCI to earnings in the same period during which the forecasted transaction affected earnings.

Foreign Currency Risk

(PPL and PPL Energy Supply)

PPL is exposed to foreign currency risk, primarily through investments in U.K. affiliates. In addition, PPL and its subsidiaries are exposed to foreign currency risk associated with firm commitments in currencies other than the applicable functional currency.

PPL has adopted a foreign currency risk management program designed to hedge certain foreign currency exposures, including firm commitments, recognized assets or liabilities, anticipated transactions and net investments. In addition, PPL enters into financial instruments to protect against foreign currency translation risk of expected earnings.

Cash Flow Hedges

PPL may enter into foreign currency derivatives associated with foreign currency-denominated debt and the exchange rate associated with firm commitments (including those for the purchase of equipment) denominated in foreign currencies; however, at December 31, 2011, there were no existing contracts of this nature. Amounts previously settled and recorded in AOCI are reclassified as the hedged interest payments are made and as the related equipment is depreciated. Insignificant amounts are expected to be reclassified into earnings during the next 12 months.

During 2011, 2010 and 2009, no cash flow hedges were discontinued because it was probable that the original forecasted transaction would not occur by the end of the originally specified time periods.

Fair Value Hedges

PPL enters into foreign currency forward contracts to hedge the exchange rate risk associated with firm commitments denominated in foreign currencies; however, at December 31, 2011, there were no existing contracts of this nature and no gains or losses recorded for 2011, 2010 and 2009 related to hedge ineffectiveness, or from a portion of the hedging instrument being excluded from the assessment of hedge effectiveness, or from hedges of firm commitments that no longer qualified as fair value hedges.

Net Investment Hedges

PPL enters into foreign currency contracts on behalf of a subsidiary to protect the value of a portion of its net investment in WPD. In 2010 and 2009, these contracts were included in PPL Energy Supply's business. As a result of the distribution of PPL Energy Supply's membership interest in PPL Global to PPL Energy Funding, effective January 2011, these contracts are no longer included in PPL Energy Supply's business.

The contracts outstanding at December 31, 2011 had an aggregate notional amount of £92 million (approximately $150 million based on contracted rates). The settlement dates of these contracts range from January 2012 through September 2012. At December 31, 2011 and 2010, the fair value of these positions was a net asset of $7 million. For 2011, PPL recognized an insignificant amount of activity in the foreign currency translation adjustment component of AOCI. For 2010 and 2009, PPL and PPL Energy Supply recognized insignificant amounts in the foreign currency translation adjustment component of AOCI. At December 31, 2011, PPL had $19 million of accumulated net investment hedge after-tax gains (losses) that were included in the foreign currency translation adjustment component of AOCI. At December 31, 2010, PPL and PPL Energy Supply had $15 million of accumulated net investment hedge after-tax gains (losses) that were included in the foreign currency translation adjustment component of AOCI.

Economic Activity

(PPL)

In anticipation of the repayment of a portion of the GBP-denominated borrowings under the 2011 Bridge Facility with U.S. dollar proceeds received from PPL's issuance of common stock and 2011 Equity Units and PPL WEM's issuance of U.S. dollar-denominated senior notes, as discussed in Note 7, PPL entered into forward contracts to purchase GBP in order to economically hedge the foreign currency exchange rate risk related to the repayment. When these trades were settled in April 2011, PPL recorded $55 million of pre-tax, net gains (losses) in "Other Income (Expense) - net" on the Statements of Income.

(PPL and PPL Energy Supply)

PPL and PPL Energy Supply may enter into foreign currency contracts as an economic hedge of anticipated earnings denominated in British pounds sterling. In 2010 and 2009, these contracts were included in PPL Energy Supply's business. As a result of the distribution of PPL Energy Supply's membership interest in PPL Global to PPL Energy Funding, effective January 2011, these contracts are no longer included in PPL Energy Supply's business. At December 31, 2011, the total exposure hedged by PPL was £288 million and the fair value of these positions was a net asset of $11 million. These contracts had termination dates ranging from January 2012 to November 2012. For PPL and PPL Energy Supply, the net fair value of similar hedging instruments outstanding at December 31, 2010 was insignificant. PPL records gains (losses) on these contracts, both realized and unrealized, in "Other Income (Expense) - net" on the Statements of Income. PPL Energy Supply records gains (losses) on these contracts, both realized and unrealized, in "Income (Loss) from Discontinued Operations (net of income taxes)" on the Statements of Income. For 2011, PPL recorded gains (losses) of $10 million. For 2010, the amounts for PPL and PPL Energy Supply were insignificant. For 2009, PPL and PPL Energy Supply recorded gains (losses) of $(9) million.

Accounting and Reporting

(PPL, PPL Energy Supply, PPL Electric, LKE, LG&E and KU)

All derivative instruments are recorded at fair value on the Balance Sheet as an asset or liability unless they qualify for NPNS. NPNS contracts for PPL and PPL Energy Supply include full-requirement sales contracts, other physical sales contracts and certain retail energy and physical capacity contracts, and for PPL Electric include full-requirement purchase contracts and other physical purchase contracts. Changes in the derivatives' fair value are recognized currently in earnings unless specific hedge accounting criteria are met, except for the changes in fair value of LG&E's interest rate swaps, which beginning in the third quarter of 2010, have been recognized as regulatory assets. See Note 6 for amounts recorded in regulatory assets at December 31, 2011 and December 31, 2010.

See Note 1 for additional information on accounting policies related to derivative instruments.

(PPL)

The following tables present the fair value and location of derivative instruments recorded on the Balance Sheets.

	December 31, 2011				December 31, 2010			
	Derivatives designated as hedging instruments		Derivatives not designated as hedging instruments (a)		Derivatives designated as hedging instruments		Derivatives not designated as hedging instruments (a)	
	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities
Current:								
Price Risk Management Assets/Liabilities (b):								
Interest rate swaps	$ 3	$ 3		$ 5	$ 11	$ 19		$ 2
Cross-currency swaps		2			7	9		
Foreign currency exchange contracts	7		$ 11		7		$ 4	
Commodity contracts	872	3	1,655	1,557	878	19	1,011	1,095
Total current	882	8	1,666	1,562	903	47	1,015	1,097
Noncurrent:								
Price Risk Management Assets/Liabilities (b):								
Interest rate swaps				55	4			32
Cross-currency swaps	24				37			
Commodity contracts	42	2	854	783	169	7	445	431
Total noncurrent	66	2	854	838	210	7	445	463
Total derivatives	$ 948	$ 10	$ 2,520	$ 2,400	$ 1,113	$ 54	$ 1,460	$ 1,560

(a) $237 million and $326 million of net gains associated with derivatives that were no longer designated as hedging instruments are recorded in AOCI at December 31, 2011 and 2010.
(b) Represents the location on the Balance Sheet.

The after-tax balances of accumulated net gains (losses) (excluding net investment hedges) in AOCI were $527 million, $695 million and $602 million at December 31, 2011, 2010 and 2009.

The following tables present the pre-tax effect of derivative instruments recognized in income, OCI or regulatory assets.

Derivatives in Fair Value Hedging Relationships	Hedged Items in Fair Value Hedging Relationships	Location of Gain (Loss) Recognized in Income	Gain (Loss) Recognized in Income on Derivative	Gain (Loss) Recognized in Income on Related Item
2011				
Interest rate swaps	Fixed rate debt	Interest expense	$ 2	$ 25
		Other Income - net		22
2010				
Interest rate swaps	Fixed rate debt	Interest expense	$ 48	$ (6)
2009				
Interest rate swaps	Fixed rate debt	Interest expense	$ 12	$ 29
		Other Income - net		7

Derivative Relationships	Derivative Gain (Loss) Recognized in OCI (Effective Portion)	Location of Gain (Loss) Recognized in Income	Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
2011				
Cash Flow Hedges:				
Interest rate swaps	$ (55)	Interest expense	$ (13)	$ (13)
Cross-currency swaps	(35)	Interest expense	5	
		Other income (expense) - net	29	
Commodity contracts	431	Wholesale energy marketing	835	(39)
		Fuel	1	
		Depreciation	2	
		Energy purchases	(243)	1
Total	$ 341		$ 616	$ (51)
Net Investment Hedges:				
Foreign exchange contracts	$ 6			

Derivative Relationships	Derivative Gain (Loss) Recognized in OCI (Effective Portion)	Location of Gain (Loss) Recognized in Income	Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
2010				
Cash Flow Hedges:				
Interest rate swaps	$ (145)	Interest expense	$ (4)	$ (17)
		Other income (expense) - net	(30)	
Cross-currency swaps	25	Interest expense	2	
		Other income (expense) - net	16	
Commodity contracts	487	Wholesale energy marketing	680	(201)
		Fuel	2	
		Depreciation	2	
		Energy purchases	(458)	3
Total	$ 367		$ 210	$ (215)
Net Investment Hedges:				
Foreign exchange contracts	$ 5			
2009				
Cash Flow Hedges:				
Interest rate swaps	$ 64	Interest expense	$ (2)	
		Other income (expense) - net	1	
Cross-currency swaps	(45)	Interest expense	2	
		Other income (expense) - net	(20)	
Commodity contracts	829	Wholesale energy marketing	358	$ (296)
		Fuel	(20)	2
		Depreciation	1	
		Energy purchases	(544)	(7)
		Other O&M	1	
Total	$ 848		$ (223)	$ (301)
Net Investment Hedges:				
Foreign exchange contracts	$ (9)			

Derivatives Not Designated as Hedging Instruments:	Location of Gain (Loss) Recognized in Income on Derivatives	2011	2010	2009
Foreign exchange contracts	Other income (expense) - net	$ 65	$ 3	$ (9)
Interest rate swaps	Interest expense	(8)		
Commodity contracts	Utility	(1)	(2)	
	Unregulated retail electric and gas	39	11	13
	Wholesale energy marketing	1,606	(70)	588
	Net energy trading margins (a)	(6)	1	
	Fuel	(1)	12	12
	Energy purchases	(1,493)	(405)	(808)
	Total	$ 201	$ (450)	$ (204)

Derivatives Not Designated as Hedging Instruments:	Location of Gain (Loss) Recognized as Regulatory Liabilities/Assets	2011	2010	2009
Interest rate swaps	Regulatory assets - noncurrent	$ (26)	$ (11)	

(a) Differs from the Statement of Income due to intra-month transactions that PPL defines as spot activity, which is not accounted for as a derivative.

(PPL Energy Supply)

The following tables present the fair value and location of derivative instruments recorded on the Balance Sheets.

	December 31, 2011				December 31, 2010			
	Derivatives designated as hedging instruments		Derivatives not designated as hedging instruments (a)		Derivatives designated as hedging instruments		Derivatives not designated hedging instruments (a)	
	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities
Current:								
Price Risk Management Assets/Liabilities (b):								
Cross-currency swaps					$ 7	$ 9		
Foreign currency exchange contracts					7		$ 4	
Commodity contracts	$ 872	$ 3	$ 1,655	$ 1,557	878	19	1,011	$ 1,084
Total current	872	3	1,655	1,557	892	28	1,015	1,084

	December 31, 2011				December 31, 2010			
	Derivatives designated as hedging instruments		Derivatives not designated as hedging instruments (a)		Derivatives designated as hedging instruments		Derivatives not designated hedging instruments (a)	
	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities
Noncurrent:								
Price Risk Management Assets/Liabilities (b):								
Cross-currency swaps					37			
Commodity contracts	42	2	854	783	169	7	445	431
Total noncurrent	42	2	854	783	206	7	445	431
Total derivatives	$ 914	$ 5	$ 2,509	$ 2,340	$ 1,098	$ 35	$ 1,460	$ 1,515

(a) $237 million and $326 million of net gains associated with derivatives that were no longer designated as hedging instruments are recorded in AOCI at December 31, 2011 and 2010.
(b) Represents the location on the Balance Sheet.

The after-tax balances of accumulated net gains (losses) (excluding net investment hedges) in AOCI were $605 million, $733 million and $573 million at December 31, 2011, 2010 and 2009. The December 31, 2011 AOCI balance reflects the effect of PPL Energy Supply's distribution of its membership interest in PPL Global to its parent, PPL Energy Funding. See Note 9 for additional information.

The following tables present the pre-tax effect of derivative instruments recognized in income or OCI.

Derivatives in Fair Value Hedging Relationships	Hedged Items in Fair Value Hedging Relationships	Location of Gain (Loss) Recognized in Income	Gain (Loss) Recognized in Income on Derivative	Gain (Loss) Recognized in Income on Related Item
2011				
Interest rate swaps	Fixed rate debt	Interest expense		$ 2
2010				
Interest rate swaps	Fixed rate debt	Interest expense		2
2009				
Interest rate swaps	Fixed rate debt	Interest expense	$ 1	

Derivative Relationships	Derivative Gain (Loss) Recognized in OCI (Effective Portion)	Location of Gain (Loss) Recognized in Income	Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
2011				
Cash Flow Hedges:				
Commodity contracts	$ 431	Wholesale energy marketing	$ 835	$ (39)
		Fuel	1	
		Depreciation	2	
		Energy purchases	(243)	1
Total	$ 431		$ 595	$ (38)
2010				
Cash Flow Hedges:				
Interest rate swaps		Discontinued operations (net of income taxes)		$ (3)
Cross-currency swaps	$ 25	Discontinued operations (net of income taxes)	$ 18	
Commodity contracts	487	Wholesale energy marketing	680	(201)
		Fuel	2	
		Depreciation	2	
		Energy purchases	(458)	3
Total	$ 512		$ 244	$ (201)
Net Investment Hedges:				
Foreign exchange contracts	$ 5			

Derivative Relationships	Derivative Gain (Loss) Recognized in OCI (Effective Portion)	Location of Gain (Loss) Recognized in Income	Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
2009				
Cash Flow Hedges:				
Cross-currency swaps	$ (45)	Discontinued operations (net of income taxes)	$ (18)	
Commodity contracts	829	Wholesale energy marketing	358	$ (296)
		Fuel	(20)	2
		Depreciation	1	
		Energy purchases	(544)	(7)
		Other O&M	1	
Total	$ 784		$ (222)	$ (301)
Net Investment Hedges:				
Foreign exchange contracts	$ (9)			

Derivatives Not Designated as Hedging Instruments:	Location of Gain (Loss) Recognized in Income on Derivatives	2011	2010	2009
Foreign exchange contracts	Discontinued Operations (net of income taxes)		$ 3	$ (9)
Commodity contracts	Unregulated retail electric and gas	$ 39	11	13
	Wholesale energy marketing	1,606	(70)	588
	Net energy trading margins (a)	(6)	1	
	Fuel	(1)	12	12
	Energy purchases	(1,493)	(405)	(808)
	Total	$ 145	$ (448)	$ (204)

(a) Differs from the Statement of Income due to intra-month transactions that PPL Energy Supply defines as spot activity, which is not accounted for as a derivative.

(LKE and LG&E)

There were no derivatives designated as hedging instruments as of December 31, 2011 and December 31, 2010. The following table presents the fair value and location of derivative instruments not designated as hedging instruments recorded on the Balance Sheets:

	December 31, 2011		December 31, 2010	
	Derivatives not designated as hedging instruments		Derivatives not designated as hedging instruments	
	Assets	Liabilities	Assets	Liabilities
Current:				
Other Current Liabilities				
Assets/Liabilities (a):				
Interest rate swaps		$ 5		$ 2
Commodity contracts				2
Total current		5		4
Noncurrent:				
Price Risk Management				
Assets/Liabilities (a):				
Interest rate swaps		55		32
Total noncurrent		55		32
Total derivatives		$ 60		$ 36

(a) Represents the location on the Balance Sheet.

The following tables present the pre-tax effect of derivative instruments recognized in income or regulatory assets for the periods ended December 31, 2011, 2010 and 2009, for the Successor and Predecessor.

Derivatives Not Designated as Hedging Instruments:	Location of Gain (Loss) Recognized in Income on Derivatives	Successor		Predecessor	
		Year Ended December 31, 2011	Two Months Ended December 31, 2010	Ten Months Ended October 31, 2010	Year Ended December 31, 2009
Interest rate swaps	Interest expense	$ (8)	$ (1)	$ (7)	$ 1
Commodity contracts	Operating revenues - retail and wholesale	(1)	(2)	3	9
	Total	$ (9)	$ (3)	$ (4)	$ 10

Derivatives Not Designated as Hedging Instruments:	Location of Gain (Loss) Recognized as Regulatory Liabilities/Assets	December 31, 2011	December 31, 2010
Interest rate swaps	Regulatory assets	$ (26)	$ (43)

(KU)

There were no derivatives designated as hedging instruments as of December 31, 2011 and December 31, 2010. There were no after-tax balances of accumulated net gains (losses) in AOCI at December 31, 2011 and 2010. The gains and losses recognized in income on derivatives associated with commodity contracts were not significant for the periods ended December 31, 2011, 2010, and 2009.

Credit Risk-Related Contingent Features *(PPL, PPL Energy Supply, LKE and LG&E)*

Certain of PPL's, PPL Energy Supply's, LKE's and LG&E's derivative contracts contain credit risk-related contingent provisions which, when in a net liability position, would permit the counterparties to require the transfer of additional collateral upon a decrease in the credit ratings of PPL, PPL Energy Supply, LKE, LG&E, or certain of their subsidiaries. Most of these provisions would require PPL, PPL Energy Supply, LKE or LG&E to transfer additional collateral or permit the counterparty to terminate the contract if the applicable credit rating were to fall below investment grade. Some of these provisions also would allow the counterparty to require additional collateral upon each decrease in the credit rating at levels that remain above investment grade. In either case, if the applicable credit rating were to fall below investment grade (i.e., below BBB- for S&P or Fitch, or Baa3 for Moody's), and assuming no assignment to an investment grade affiliate were allowed, most of these credit contingent provisions require either immediate payment of the net liability as a termination payment or immediate and ongoing full collateralization by PPL, PPL Energy Supply, LKE or LG&E on derivative instruments in net liability positions.

Additionally, certain of PPL's, PPL Energy Supply's, LKE's and LG&E's derivative contracts contain credit risk-related contingent provisions that require PPL, PPL Energy Supply, LKE or LG&E to provide "adequate assurance" of performance if the other party has reasonable grounds for insecurity regarding PPL's, PPL Energy Supply's, LKE's or LG&E's performance of its obligation under the contract. A counterparty demanding adequate assurance could require a transfer of additional collateral or other security, including letters of credit, cash and guarantees from a creditworthy entity. This would typically involve negotiations among the parties. However, amounts disclosed below represent assumed immediate payment or immediate and ongoing full collateralization for derivative instruments in net liability positions with "adequate assurance" provisions.

At December 31, 2011, the effect of a decrease in credit ratings below investment grade on derivative contracts that contain credit contingent features and were in a net liability position is summarized as follows:

	PPL	PPL Energy Supply	LKE	LG&E
Aggregate fair value of derivative instruments in a net liability position with credit risk-related contingent provisions	$ 156	$ 118	$ 39	$ 39
Aggregate fair value of collateral posted on these derivative instruments	38	9	29	29
Aggregate fair value of additional collateral requirements in the event of a credit downgrade below investment grade (a)	183	173	10	10

(a) Includes the effect of net receivables and payables already recorded on the Balance Sheet.

20. Goodwill and Other Intangible Assets

Goodwill

(PPL and PPL Energy Supply)

The changes in the carrying amount of goodwill by segment were:

	Kentucky Regulated		International Regulated		Supply		Total	
	2011	2010	2011	2010	2011	2010	2011	2010
PPL								
Balance at beginning of period (a)	$ 662		$ 679	$ 715	$ 420	$ 91	$ 1,761	$ 806
Goodwill recognized during the period (b)		$ 662	2,391			334	2,391	996
Allocation to discontinued operations (c)						(5)		(5)
Effect of foreign currency exchange rates			(38)	(36)			(38)	(36)
Balance at end of period (a)	$ 662	$ 662	$ 3,032	$ 679	$ 420	$ 420	$ 4,114	$ 1,761

	International Regulated		Supply		Total	
	2011	2010	2011	2010	2011	2010
PPL Energy Supply						
Balance at beginning of period (a)	$ 679	$ 715	$ 86	$ 91	$ 765	$ 806
Derecognition (d)	(679)				(679)	
Allocation to discontinued operations (c)				(5)		(5)
Effect of foreign currency exchange rates		(36)				(36)
Balance at end of period (a)	$	$ 679	$ 86	$ 86	$ 86	$ 765

(a) There were no accumulated impairment losses related to goodwill.
(b) Activity in 2011 recognized as a result of the acquisition of WPD Midlands. Activity in 2010 recognized as a result of the acquisition of LKE. A portion of the goodwill related to the acquisition of LKE was allocated to the Supply segment. See Note 10 for additional information.
(c) Represents goodwill allocated to certain non-core generation facilities that were held for sale in 2010 and sold in 2011.
(d) Represents the amount of goodwill derecognized as a result of PPL Energy Supply's distribution of its membership interest in PPL Global to PPL Energy Supply's parent, PPL Energy Funding. See Note 9 for additional information on the distribution. Subsequent to the distribution, PPL Energy Supply operates in a single reportable segment and reporting unit.

(LKE, LG&E and KU)

The changes in the carrying amounts of goodwill were as follows.

	LKE	LG&E	KU
Balance at December 31, 2009 and October 31, 2010, Predecessor (a)	$ 837		
Dispositions (b)	(837)		
Purchase accounting adjustments (c)	996	$ 389	$ 607
Balance at December 31, 2010 and 2011, Successor (a)	$ 996	$ 389	$ 607

(a) The opening balances included $1.5 billion of impairment losses related to goodwill recorded in 2009. There were no accumulated impairment losses related to goodwill at December 31, 2010 or 2011.
(b) Predecessor goodwill was eliminated in purchase accounting at November 1, 2010.
(c) Recognized as a result of the November 1, 2010 acquisition by PPL. For LG&E and KU, the allocation of goodwill was based on the net asset values of the respective companies. See Note 10 for additional information.

(LKE)

For the 2009 annual impairment test, the estimated fair values of LG&E and KU were based on a combination of the income approach, which estimates the fair value of the reporting unit based on discounted future cash flows and the market approach, which estimates the fair value of the reporting unit based on market comparables. The discounted cash flows for LG&E and KU were based on discrete financial forecasts developed by management for planning purposes and consistent with those given to E.ON AG, LKE's former parent company. Cash flows beyond the discrete forecasts were estimated using a terminal-value calculation, which incorporated historical and forecasted financial trends for each of LG&E and KU and considered long-term earnings growth rates for publicly-traded peer companies. The level 3 income-approach valuations included a cash flow discount rate of 6.3% and a terminal-value growth rate of 1.1%. In addition, subsequent to 2009 but prior to the issuance of the 2009 financial statements, discussions were held with interested parties for the possible sale of LKE, including the regulated utilities. Data from this process was used for evaluating the carrying value of goodwill at December 31, 2009.

Based on information represented by bids received from interested parties, including PPL, LKE completed a goodwill impairment analysis at December 31, 2009. As a result of the impairment analysis described above, LKE recorded a goodwill impairment charge of $1.5 billion in 2009. The primary factors contributing to the goodwill impairment charge in 2009 were the significant economic downturn, which caused a decline in the volume of projected sales of electricity to commercial customers and an increase in the implied discount rate due to higher risk premiums. In addition, a lower control premium was assumed, based on observable market data.

Other Intangibles

(PPL)

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2011		December 31, 2010	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Contracts (a) (b)	$ 611	$ 155	$ 597	$ 49
Land and transmission rights (c)	263	110	256	110
Emission allowances/RECs (d) (e) (f)	20		37	
Licenses and other (g)	265	35	242	30
Total subject to amortization	1,159	300	1,132	189
Not subject to amortization due to indefinite life:				
Land and transmission rights	16		16	
Easements (h)	199		77	
Total not subject to amortization due to indefinite life	215		93	
Total	$ 1,374	$ 300	$ 1,225	$ 189

(a) Gross carrying amount for 2010 includes $394 million, which represents the fair value of contracts with terms favorable to market recognized as a result of the 2010 acquisition of LKE. The weighted average amortization period of these contracts was five years at the acquisition date. An offsetting regulatory liability was recorded related to these contracts, which is being amortized over the same weighted-average period as the intangible assets, eliminating any income statement impact. See Note 6 for additional information.

(b) Gross carrying amount for 2011 includes $10 million, which represents the fair value of customer contracts with terms favorable to market recognized as a result of the 2011 acquisition of WPD Midlands. The weighted-average amortization period of these contracts was ten years at the acquisition date. See Note 10 for additional information.

(c) Gross carrying amount for 2010 includes $14 million, which represents the fair value of land and transmission rights recognized as a result of the 2010 acquisition of LKE. The weighted-average amortization period of these rights was 14 years at the acquisition date. An offsetting regulatory liability was recorded related to these rights, which is being amortized over the same weighted-average period as the intangible assets, eliminating any income statement impact. See Note 6 for additional information.

(d) These emission allowances/RECs are expensed when consumed or sold. Consumption expense was $16 million, $45 million, and $32 million in 2011, 2010 and 2009. Consumption expense is expected to be insignificant in future periods.

(e) Gross carrying amount for 2010 includes the fair value of emission allowances recognized as a result of the 2010 acquisition of LKE. An offsetting regulatory liability was recorded related to these emission allowances, which is being amortized as the emission allowances are consumed, eliminating any income statement impact. See Note 6 for additional information. The carrying amounts of these emission allowances were $5 million and $16 million as of December 31, 2011 and 2010. Consumption related to these emission allowances was $11 million and $2 million for 2011 and 2010.

(f) During 2011 and 2010, PPL recorded $7 million and $17 million of impairment charges. See Note 18 for additional information.

(g) "Other" includes costs for the development of licenses, the most significant of which is the COLA. Amortization of these costs begins when the related asset is placed in service. See Note 8 for additional information on the COLA.

(h) Gross carrying amount for 2011 includes $88 million, which represents the fair value of easements recognized as a result of the 2011 acquisition of WPD Midlands. See Note 10 for additional information.

Current intangible assets are included in "Other current assets" and long-term intangible assets are included in "Other intangibles" in their respective areas on the Balance Sheets.

Amortization expense, excluding consumption of emission allowances/RECs, was as follows:

	2011	2010	2009
Intangible assets with no regulatory offset	$ 25	$ 24	$ 22
Intangible assets with regulatory offset	87	11	
Total	$ 112	$ 35	$ 22

Amortization expense for each of the next five years, excluding consumption of emission allowances/RECs, is estimated to be:

	2012	2013	2014	2015	2016
Intangible assets with no regulatory offset	$ 24	$ 24	$ 24	$ 24	$ 22
Intangible assets with a regulatory offset	46	52	46	51	27
Total	$ 70	$ 76	$ 70	$ 75	$ 49

(PPL Energy Supply)

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2011		December 31, 2010	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Contracts	$ 203	$ 53	$ 203	$ 38
Land and transmission rights	17	13	19	16
Emission allowances/RECs (a) (b)	15		20	
Licenses and other (c)	255	30	239	29
Total subject to amortization	490	96	481	83
Not subject to amortization due to indefinite life:				
Easements (d)			77	
Total	$ 490	$ 96	$ 558	$ 83

(a) Removed from the Balance Sheets and expensed when consumed or sold. Consumption expense was $16 million, $46 million, and $32 million in 2011, 2010, and 2009. Consumption expense is expected to be insignificant in future periods.
(b) During 2011 and 2010, PPL Energy Supply recorded $7 million and $16 million of impairment charges. See Note 18 for additional information.
(c) "Other" includes costs for the development of licenses, the most significant of which is the COLA. Amortization of these costs begins when the related asset is placed in service. See Note 8 for additional information on the COLA.
(d) Easements for 2010 pertain to WPD. As a result of PPL Energy Supply's January 2011 distribution of its membership interest in PPL Global to its parent, PPL Energy Funding, the assets and liabilities of PPL Global, including WPD's easements at December 31, 2010 were removed from PPL Energy Supply's balance sheet in 2011. See Note 9 for additional information.

Current intangible assets are included in "Other current assets" and long-term intangible assets are presented as "Other intangibles" in their respective areas on the Balance Sheets.

Amortization expense, excluding consumption of emission allowances/RECs, was as follows:

	2011	2010	2009
Amortization expense	$ 20	$ 20	$ 19

Amortization expense for each of the next five years, excluding consumption of emission allowances/RECs, is estimated to be:

	2012	2013	2014	2015	2016
Estimated amortization expense	$ 20	$ 20	$ 20	$ 20	$ 18

(PPL Electric)

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2011		December 31, 2010	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Land and transmission rights	$ 232	$ 96	$ 222	$ 93
Licenses and other	4	1	3	1
Total subject to amortization	236	97	225	94
Not subject to amortization due to indefinite life:				
Land and transmission rights	16		16	
Total	$ 252	$ 97	$ 241	$ 94

Intangible assets are shown as "Intangibles" on the Balance Sheets.

Amortization expense was insignificant in 2011, 2010 and 2009, and is expected to be insignificant in future years.

(LKE)

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2011		December 31, 2010	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Coal contracts (a)	$ 269	$ 89	$ 269	$ 9
Land and transmission rights (b)	14	1	14	
Emission allowances (c)	5		16	
OVEC power purchase agreement (d)	126	9	126	2
Total subject to amortization	$ 414	$ 99	$ 425	$ 11

(a) Gross carrying amount represents the fair value of contracts with terms favorable to market recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability was recorded related to these contracts, which is being amortized over the same period as the intangible assets, eliminating any income statement impact. See Note 6 for additional information.
(b) Gross carrying amount represents the fair value of land and transmission rights recognized as an intangible asset as a result of adopting PPL's accounting policies in the Successor period. Amortization expense is recovered through base rates and is expected to be insignificant for future periods.
(c) Represents the fair value of emission allowances recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability was recorded related to these emission allowances, which is being amortized as the emission allowances are consumed, eliminating any income statement impact. Consumption related to these emission allowances was $11 million and $2 million for 2011 and 2010.
(d) Gross carrying amount represents the fair value of the OVEC power purchase contract recognized as a result of the 2010 acquisition by PPL. See Note 6 for additional information.

Current intangible assets and long-term intangible assets are presented as "Other intangibles" in their respective areas on the Balance Sheets.

Amortization expense for the Successor, excluding consumption of emission allowances, was as follows:

	2011	2010
Intangible assets with no regulatory offset	$ 1	
Intangible assets with regulatory offset	87	$ 11
Total	$ 88	$ 11

Amortization expense for each of the next five years, excluding consumption of emission allowances, is estimated to be:

	2012	2013	2014	2015	2016
Intangibles with regulatory offset	$ 46	$ 52	$ 46	$ 51	$ 27

(LG&E)

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2011		December 31, 2010	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Coal contracts (a)	$ 124	$ 46	$ 124	$ 6
Land and transmission rights (b)	6	1	6	
Emission allowances (c)	2		7	
OVEC power purchase agreement (d)	87	6	87	1
Total subject to amortization	$ 219	$ 53	$ 224	$ 7

(a) Gross carrying amount represents the fair value of contracts with terms favorable to market recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability was recorded related to these contracts, which is being amortized over the same period as the intangible assets, eliminating any income statement impact. See Note 6 for additional information.
(b) Gross carrying amount represents the fair value of land and transmission rights recognized as an intangible asset as a result of adopting PPL's accounting policies in the Successor period. Amortization expense is recovered through base rates and is expected to be insignificant for future periods.
(c) Represents the fair value of emission allowances recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability was recorded related to these emission allowances, which is being amortized as the emission allowances are consumed, eliminating any income statement impact. Consumption related to these emission allowances was $5 million and $1 million for 2011 and 2010.
(d) Gross carrying amount represents the fair value of the OVEC power purchase contract recognized as a result of the 2010 acquisition by PPL. See Note 6 for additional information.

Current intangible assets and long-term intangible assets are presented as "Other intangibles" in their respective areas on the Balance Sheets.

Amortization expense for the Successor, excluding consumption of emission allowances, was as follows:

	2011	2010
Intangible assets with no regulatory offset	$ 1	
Intangible assets with regulatory offset	45	$ 7
Total	$ 46	$ 7

Amortization expense for each of the next five years, excluding consumption of emission allowances, is estimated to be:

	2012	2013	2014	2015	2016
Intangibles with regulatory offset	$ 22	$ 25	$ 23	$ 24	$ 14

(KU)

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2011		December 31, 2010	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Contracts (a)	$ 145	$ 43	$ 145	$ 3
Land and transmission rights (b)	8		8	
Emission allowances (c)	3		9	
OVEC power purchase agreement (d)	39	3	39	1
Total subject to amortization	$ 195	$ 46	$ 201	$ 4

(a) Gross carrying amount represents the fair value of contracts with terms favorable to market recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability was recorded related to these contracts, which is being amortized over the same period as the intangible assets, eliminating any income statement impact. See Note 6 for additional information.
(b) Gross carrying amount represents the fair value of land and transmission rights recognized as an intangible asset as a result of adopting PPL's accounting policies in the Successor period. Amortization expense is recovered through base rates and is expected to be insignificant for future periods.
(c) Represents the fair value of emission allowances recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability was recorded related to these emission allowances, which is being amortized as the emission allowances are consumed, eliminating any income statement impact. Consumption related to these emission allowances was $6 million and $1 million for 2011 and 2010.
(d) Gross carrying amount represents the fair value of the OVEC power purchase contract recognized as a result of the 2010 acquisition by PPL. See Note 6 for additional information.

Current intangible assets and long-term intangible assets are presented as "Other intangibles" in their respective areas on the Balance Sheets.

Amortization expense for the Successor, excluding consumption of emission allowances, was as follows:

	2011	2010
Intangible assets with regulatory offset	$ 42	$ 4

Amortization expense for each of the next five years, excluding consumption of emission allowances, is estimated to be:

	2012	2013	2014	2015	2016
Intangibles with regulatory offset	$ 24	$ 27	$ 23	$ 27	$ 13

21. Asset Retirement Obligations

(PPL)

WPD has recorded conditional AROs required by U.K. law related to treated wood poles, gas-filled switchgear and fluid-filled cables.

(PPL and PPL Energy Supply)

PPL Energy Supply has recorded liabilities in the financial statements to reflect various legal obligations associated with the retirement of long-lived assets, the most significant of which relates to the decommissioning of the Susquehanna plant. The accrued nuclear decommissioning obligation was $292 million and $270 million at December 31, 2011 and 2010, and is included in "Asset retirement obligations" on the Balance Sheets. The fair value of investments that are legally restricted for the decommissioning of the Susquehanna nuclear plant was $640 million and $618 million at December 31, 2011 and 2010, and is included in "Nuclear plant decommissioning trust funds" on the Balance Sheets. See Notes 18 and 23 for additional information on the nuclear decommissioning trust funds. Other AROs recorded relate to various environmental requirements for coal piles, ash basins and other waste basin retirements.

PPL Energy Supply has recorded several conditional AROs, the most significant of which related to the removal and disposal of asbestos-containing material. In addition to the AROs that were recorded for asbestos-containing material, PPL Energy Supply identified other asbestos-related obligations, but were unable to reasonably estimate their fair values. PPL Energy Supply management was unable to reasonably estimate a settlement date or range of settlement dates for the remediation of all of the asbestos-containing material at certain of the generation plants. If economic events or other circumstances change that enable PPL Energy Supply to reasonably estimate the fair value of these retirement obligations, they will be recorded at that time.

PPL Energy Supply also identified legal retirement obligations associated with the retirement of a reservoir that could not be reasonably estimated due to an indeterminable settlement date.

(PPL and PPL Electric)

PPL Electric has identified legal retirement obligations for the retirement of certain transmission assets that could not be reasonably estimated due to indeterminable settlement dates. These assets are located on rights-of-way that allow the grantor to require PPL Electric to relocate or remove the assets. Since this option is at the discretion of the grantor of the right-of-way, PPL Electric is unable to determine when these events may occur.

(PPL, LKE, LG&E and KU)

LG&E's and KU's AROs are primarily related to the final retirement of assets associated with generating units. LG&E also has AROs related to natural gas mains and wells. LG&E's and KU's transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, no material AROs are recorded for transmission and distribution assets. As described in Notes 1 and 6, the accretion and depreciation expense recorded by LG&E and KU is offset with a regulatory credit on the income statement, such that there is no earnings impact.

(PPL, PPL Energy Supply, LKE, LG&E and KU)

The changes in the carrying amounts of AROs were:

	PPL		PPL Energy Supply	
	2011	2010	2011	2010
ARO at beginning of period	$ 448	$ 426	$ 345	$ 426
Accretion expense	33	32	26	31
Obligations assumed in acquisition of LKE		103		
Obligations assumed in acquisition of WPD Midlands (a)	15			
Derecognition (b)			(5)	
Obligations incurred	14	4	11	4
Changes in estimated cash flow or settlement date	5	(100)	(1)	(100)
Obligations settled	(18)	(17)	(17)	(16)
ARO at end of period	$ 497	$ 448	$ 359	$ 345

	LKE	LG&E	KU
ARO at December 31, 2009, Predecessor	$ 65	$ 31	$ 34
Accretion expense	4	2	2
Changes in estimated cash flow or settlement date	54	30	24
Obligations settled	(1)	(1)	
ARO at October 31, 2010, Predecessor	122	62	60
Purchase accounting	(19)	(13)	(6)
ARO at December 31, 2010, Successor	103	49	54
Accretion expense	6	3	3
Obligations incurred	3	2	1
Changes in estimated cash flow or settlement date	7	4	3
Obligations settled	(1)	(1)	
ARO at December 31, 2011, Successor	$ 118	$ 57	$ 61

(a) Obligations required under U.K. law related to treated wood poles, gas-filled switchgear and fluid-filled cables. See Note 10 for additional information on the acquisition.
(b) Represents AROs derecognized as a result of PPL Energy Supply's distribution of its membership interest in PPL Global to PPL Energy Supply's parent, PPL Energy Funding. See Note 9 for additional information on the distribution.

In the third quarter of 2010, PPL Susquehanna completed a site-specific study to update the estimated cost to dismantle and decommission each Susquehanna nuclear unit immediately following final shutdown. This estimate included decommissioning the radiological portions of the station and the cost of removal of non-radiological structures and materials. Based on this study, which used a methodology consistent with the prior site-specific study done in 2002, the decommissioning ARO liability and the associated long-lived asset were reduced by $103 million. The primary factor for this decline was the lower estimated inflation rate assumption used in the 2010 ARO calculation.

The classification of AROs on the Balance Sheets was as follows.

	December 31, 2011				
	PPL	PPL Energy Supply	LKE	LG&E	KU
Current portion (a)	$ 13	$ 10	$ 2	$ 2	
Long-term portion (b)	484	349	116	55	$ 61
Total	$ 497	$ 359	$ 118	$ 57	$ 61

	December 31, 2010				
	PPL	PPL Energy Supply	LKE	LG&E	KU
Current portion (a)	$ 13	$ 13			
Long-term portion (b)	435	332	$ 103	$ 49	$ 54
Total	$ 448	$ 345	$ 103	$ 49	$ 54

(a) Included in "Other current liabilities."
(b) Included in "Asset retirement obligations."

22. Variable Interest Entities

(PPL and PPL Energy Supply)

In December 2001, a subsidiary of PPL Energy Supply entered into a $455 million operating lease arrangement, as lessee, for the development, construction and operation of a gas-fired combined-cycle generation facility located in Lower Mt. Bethel Township, Northampton County, Pennsylvania. The owner/lessor of this generation facility, LMB Funding, LP, was created to own/lease the facility and incur the related financing costs. The initial lease term commenced on the date of commercial operation, which occurred in May 2004, and ends in December 2013. Under a residual value guarantee, if the generation facility is sold at the end of the lease term and the cash proceeds from the sale are less than the original acquisition cost, the subsidiary of PPL Energy Supply is obligated to pay up to 70.52% of the original acquisition cost. This residual value guarantee protects the other variable interest holders from losses related to their investments. LMB Funding, LP cannot extend or cancel the lease or sell the facility without the prior consent of the PPL Energy Supply subsidiary. As a result, LMB Funding, LP was determined to be a VIE and the subsidiary of PPL Energy Supply was considered the primary beneficiary that consolidates this VIE.

The lease financing, which includes $437 million of "Long-term Debt" and $18 million of "Noncontrolling interests" at December 31, 2011 and December 31, 2010, is secured by, among other things, the generation facility, the carrying amount of which is disclosed on the Balance Sheets. The debt matures at the end of the initial lease term. As a result of the consolidation, PPL Energy Supply has recorded interest expense in lieu of rent expense. For 2011, 2010 and 2009, additional depreciation on the generation facility of $16 million, $16 million and $11 million was recorded.

23. Available-for-Sale Securities

(PPL, PPL Energy Supply, LKE and LG&E)

PPL and its subsidiaries classify certain short-term investments, securities held by the NDT funds and auction rate securities as available-for-sale. Available-for-sale securities are carried on the Balance Sheet at fair value. Unrealized gains and losses on these securities are reported, net of tax, in OCI or are recognized currently in earnings when a decline in fair value is determined to be other-than-temporary. The specific identification method is used to calculate realized gains and losses.

The following table shows the amortized cost, the gross unrealized gains and losses recorded in AOCI and the fair value of available-for-sale securities.

	December 31, 2011				December 31, 2010			
	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
PPL								
Short-term investments								
- municipal debt securities (a)					$ 163			$ 163
NDT funds:								
Cash and cash equivalents	$ 12			$ 12	10			10
Equity securities:								
U.S. large-cap	173	$ 119		292	180	$ 123		303
U.S. mid/small-cap	67	50		117	67	52		119
Debt securities:								
U.S. Treasury	76	10		86	71	4		75
U.S. government sponsored agency	9	1		10	6	1		7
Municipality	80	4	$ 1	83	69			69
Investment-grade corporate	35	3		38	31	2		33
Other	2			2	1			1
Receivables/payables, net					1			1
Total NDT funds	454	187	1	640	436	182		618
Auction rate securities	25		1	24	25			25
Total	$ 479	$ 187	$ 2	$ 664	$ 624	$ 182		$ 806
PPL Energy Supply								
NDT funds:								
Cash and cash equivalents	$ 12			$ 12	$ 10			$ 10
Equity securities:								
U.S. large-cap	173	$ 119		292	180	$ 123		303
U.S. mid/small-cap	67	50		117	67	52		119
Debt securities:								
U.S. Treasury	76	10		86	71	4		75
U.S. government sponsored agency	9	1		10	6	1		7
Municipality	80	4	$ 1	83	69			69
Investment-grade corporate	35	3		38	31	2		33
Other	2			2	1			1
Receivables/payables, net					1			1
Total NDT funds	454	187	1	640	436	182		618
Auction rate securities	20		1	19	20			20
Total	$ 474	$ 187	$ 2	$ 659	$ 456	$ 182		$ 638
LKE and LG&E								
Short-term investments								
- municipal debt securities (a)					$ 163			$ 163

(a) Represents tax-exempt bonds issued by Louisville/Jefferson County, Kentucky, on behalf of LG&E that were subsequently purchased by LG&E. Such bonds were remarketed to unaffiliated investors in January 2011.

There were no securities with credit losses at December 31, 2011 and 2010.

The following table shows the scheduled maturity dates of debt securities held at December 31, 2011.

	Maturity Less Than 1 Year	Maturity 1-5 Years	Maturity 5-10 Years	Maturity in Excess of 10 Years	Total
PPL					
Amortized cost	$ 14	$ 69	$ 62	$ 82	$ 227
Fair value	14	72	67	90	243
PPL Energy Supply					
Amortized cost	$ 14	$ 69	$ 62	$ 77	$ 222
Fair value	14	72	67	85	238

The following table shows proceeds from and realized gains and losses on sales of available-for-sale securities.

	2011	2010	2009
PPL			
Proceeds from sales of NDT securities (a)	$ 156	$ 114	$ 201
Other proceeds from sales	163		154
Gross realized gains (b)	28	13	27
Gross realized losses (b)	16	5	20
PPL Energy Supply			
Proceeds from sales of NDT securities (a)	$ 156	$ 114	$ 201
Other proceeds from sales			154
Gross realized gains (b)	28	13	27
Gross realized losses (b)	16	5	20

(a) These proceeds are used to pay income taxes and fees related to managing the trust. Remaining proceeds are reinvested in the trust.
(b) Excludes the impact of other-than-temporary impairment charges recognized in the Statements of Income.

Short-term Investments

(PPL, LKE and LG&E)

At December 31, 2010, LG&E held $163 million aggregate principal amount of tax-exempt revenue bonds issued by Louisville/Jefferson County, Kentucky on behalf of LG&E that were purchased from the remarketing agent in 2008. At December 31, 2010, these investments were reflected in "Short-term investments" on the Balance Sheet. In 2011, LG&E received $163 million for its investments in these bonds when they were remarketed to unaffiliated investors. No realized or unrealized gains (losses) were recorded on these securities, as the difference between carrying value and fair value was not significant.

(PPL and PPL Energy Supply)

In December 2008, the PEDFA issued $150 million aggregate principal amount of Exempt Facilities Revenue Bonds, Series 2008A and 2008B due 2038 (Series 2008 Bonds) on behalf of PPL Energy Supply. PPL Investment Corp. acted as the initial purchaser of the Series 2008 Bonds upon issuance. In April 2009, PPL Investment Corp. received $150 million for its investment in the Series 2008 Bonds when they were refunded by the PEDFA. No realized or unrealized gains (losses) were recorded on these securities, as the difference between carrying value and fair value was insignificant.

NDT Funds

Beginning in January 1999 and ending in December 2009, in accordance with the PUC Final Order, decommissioning costs were recovered from PPL Electric's customers through the CTC over the 11-year life of the CTC rather than the remaining life of the Susquehanna nuclear plant. The recovery included a return on unamortized decommissioning costs. Under the power supply agreements between PPL Electric and PPL EnergyPlus, these revenues were passed on to PPL EnergyPlus. Similarly, these revenues were passed on to PPL Susquehanna under a power supply agreement between PPL EnergyPlus and PPL Susquehanna.

Amounts collected from PPL Electric's customers for decommissioning, less applicable taxes, were deposited in external trust funds for investment and can only be used for future decommissioning costs. To the extent that the actual costs for decommissioning exceed the amounts in the nuclear decommissioning trust funds, PPL Susquehanna would be obligated to fund 90% of the shortfall.

When the fair value of a security is less than amortized cost, PPL and PPL Energy Supply must make certain assertions to avoid recording an other-than-temporary impairment that requires a current period charge to earnings. The NRC requires that nuclear decommissioning trusts be managed by independent investment managers, with discretion to buy and sell securities in the trusts. As a result, PPL and PPL Energy Supply have been unable to demonstrate the ability to hold an impaired security until it recovers its value; therefore, unrealized losses on debt securities through March 31, 2009 and unrealized losses on equity securities for all periods presented, represented other-than-temporary impairments that required a current period charge to earnings. PPL and PPL Energy Supply recorded impairments for certain securities invested in the NDT funds of $6 million, $3 million and $18 million for 2011, 2010 and 2009. These impairments are reflected on the Statements of Income in "Other-Than-Temporary Impairments."

Effective April 1, 2009, when PPL and PPL Energy Supply intend to sell a debt security or more likely than not will be required to sell a debt security before recovery, then the other-than-temporary impairment recognized in earnings will equal the entire difference between the security's amortized cost basis and its fair value. However, if there is no intent to sell a debt security and it is not more likely than not that they will be required to sell the security before recovery, but the security has suffered a credit loss, the other-than-temporary impairment will be separated into the credit loss component, which is recognized in earnings, and the remainder of the other-than-temporary impairment, which is recorded in OCI. Temporary impairments of debt securities and unrealized gains on both debt and equity securities are recorded to OCI.

24. New Accounting Guidance Pending Adoption

(PPL, PPL Energy Supply, PPL Electric, LKE, LG&E and KU)

Fair Value Measurements

Effective January 1, 2012, the Registrants will prospectively adopt accounting guidance that was issued to clarify existing fair value measurement guidance as well as enhance fair value disclosures. The additional disclosures required by this guidance include quantitative information about significant unobservable inputs used for Level 3 measurements, qualitative information about the sensitivity of recurring Level 3 measurements, information about any transfers between Level 1 and 2 of the fair value hierarchy, information about when the current use of a non-financial asset is different from the highest and best use, and the hierarchy classification for assets and liabilities whose fair value is disclosed only in the notes to the financial statements.

Any fair value measurement differences resulting from the adoption of this guidance will be recognized in income in the period of adoption. The adoption of this guidance is not expected to have a significant impact on the Registrants.

Testing Goodwill for Impairment

Effective January 1, 2012, the Registrants will prospectively adopt accounting guidance which will allow an entity to elect the option to first make a qualitative evaluation about the likelihood of an impairment of goodwill. If, based on this assessment, the entity determines it is not more likely than not the fair value of a reporting unit is less than the carrying amount, the two-step goodwill impairment test is not necessary. However, the first step of the impairment test is required if an entity concludes it is more likely than not the fair value of a reporting unit is less than the carrying amount based on the qualitative assessment.

The adoption of this standard is not expected to have a significant impact on the Registrants.

Improving Disclosures about Offsetting Balance Sheet Items

Effective January 1, 2013, the Registrants will retrospectively adopt accounting guidance issued to enhance disclosures about financial instruments and derivative instruments that either (1) offset on the balance sheet or (2) are subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet.

Upon adoption, the enhanced disclosure requirements are not expected to have a significant impact on the Registrants.

25 . Subsequent Events

(PPL and PPL Energy Supply)

In February 2012 PPL announced that its indirect wholly owned subsidiary, PPL Generation, had entered into a definitive agreement (Acquisition Agreement) to acquire from AES Ironwood, Inc. , a subsidiary of The AES Corporation, all of the equity interests of AES Ironwood, L.L.C. and AES Prescott, L.L.C., which together own and operate the 705 MW (winter rating) AES Ironwood combined-cycle natural-gas-fired power plant (Ironwood Facility) located in Lebanon, Pennsylvania. The Ironwood Facility began operation in 2001 and, since July 1, 2008, PPL EnergyPlus has supplied natural gas for the operation of the Ironwood Facility in return for receiving its full electricity output pursuant to a tolling agreement that expires in 2021.

The Acquisition Agreement provides for the sale of 100% of the issued and outstanding membership interests (collectively, the "Interests") of each of AES Ironwood, L.L.C. and AES Prescott, L.L.C. (collectively, the "Acquired Companies") to PPL Generation. The consideration payable by PPL Generation in respect of the acquisition is $87 million in cash, which includes approximately $4.8 million of net working capital of the Acquired Companies expected to be received at closing, plus the assumption at closing, through consolidation as a result of acquiring the Interests, of approximately $217 million of net outstanding project indebtedness of AES Ironwood, L.L.C. The outstanding project indebtedness is represented by $308.5 million aggregate principal amount of AES Ironwood, L.L.C. 8.857% senior secured bonds due 2025, the net amount of which expected to be outstanding at closing is approximately $226 million, plus $8 million of debt service reserve loans, less approximately $17 million of restricted cash reserves. The cash purchase price is subject to adjustment based on the amounts by which the actual closing date net working capital and net project indebtedness vary from expected balances.

AES Ironwood, Inc. and PPL Generation have each made customary representations, warranties and covenants in the Acquisition Agreement. The transaction is subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, receipt of required regulatory approvals, including approval by the Federal Energy Regulatory Commission under section 203 of the Federal Power Act, and either a reaffirmation of the current ratings of Standard & Poor's Rating Group and Moody's Investors Services, Inc. on the outstanding project indebtedness or consent of the holders of two-thirds of the outstanding project indebtedness.

PPL Energy Supply has agreed to guarantee PPL Generation's obligations under the Acquisition Agreement until the cash purchase price has been paid in full, including any post-closing adjustments for net working capital and project indebtedness.

SCHEDULE I - PPL CORPORATION
CONDENSED UNCONSOLIDATED STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31,
(Millions of Dollars, except share data)

	2011	2010	2009
Operating Revenues	$	$	$
Operating Expenses			
Other operation and maintenance		4	
Total Operating Expenses		4	
Operating Loss		(4)	
Other Income - net			
Equity in earnings of subsidiaries	1,562	1,038	378
Other income (expense)	(25)	(60)	3
Total	1,537	978	381
Interest Expense - net	76	80	(39)
Income Before Income Taxes	1,461	894	420
Income Tax Expense (Benefit)	(34)	(44)	13
Net Income Attributable to PPL Corporation	$ 1,495	$ 938	$ 407
Earnings Per Share of Common Stock:			
Net Income Available to PPL Corporation Common Shareowners:			
Basic	$ 2.71	$ 2.17	$ 1.08
Diluted	$ 2.70	$ 2.17	$ 1.08
Weighted-Average Shares of Common Stock Outstanding (in thousands)			
Basic	550,395	431,345	376,082
Diluted	550,952	431,569	376,406

The accompanying Notes to Condensed Unconsolidated Financial Statements are an integral part of the financial statements.

SCHEDULE I - PPL CORPORATION
CONDENSED UNCONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31,
(Millions of Dollars)

	2011	2010	2009
Cash Flows from Operating Activities			
Net cash provided by (used in) operating activities	$ 880	$ 713	$ 995
Cash Flows from Investing Activities			
Capital contributions to affiliated subsidiaries	(827)	(2,709)	(642)
Acquisition of LKE		(6,842)	
Return of capital from affiliated subsidiaries	549	150	100
Net cash provided by (used in) investing activities	(278)	(9,401)	(542)
Cash Flows from Financing Activities			
Issuance of equity, net of issuance costs	2,297	2,441	60
Net increase (decrease) in short-term debt with affiliates	(2,071)	6,826	5
Payment of common stock dividends	(746)	(566)	(517)
Contract adjustment payment	(72)	(13)	
Other	(10)		(1)
Net cash provided by (used in) financing activities	(602)	8,688	(453)
Net Increase (Decrease) in Cash and Cash Equivalents			
Cash and Cash Equivalents at Beginning of Period			
Cash and Cash Equivalents at End of Period	$	$	$
Supplemental Disclosures of Cash Flow Information:			
Cash Dividends Received from Affiliated Subsidiaries	$ 812	$ 507	$ 717
Non-cash transactions:			
Reduction in "Short-term debt with affiliates" and "Affiliated companies at equity"		$ 2,784	
Present value of contract adjustment payments	$ 123	157	

The accompanying Notes to Condensed Unconsolidated Financial Statements are an integral part of the financial statements.

SCHEDULE I - PPL CORPORATION
CONDENSED UNCONSOLIDATED BALANCE SHEETS AT DECEMBER 31,
(Millions of Dollars)

	2011	2010
Assets		
Current Assets		
Accounts Receivable		
Other	$ 5	$ 6
Affiliates	25	29
Prepayments	36	121
Deferred income taxes	8	11
Price risk management assets	23	15
Total Current Assets	97	182
Investments		
Affiliated companies at equity	14,181	13,406
Other Noncurrent Assets	80	32
Total Assets	$ 14,358	$ 13,620
Liabilities and Equity		
Current Liabilities		
Short-term debt with affiliates	$ 1,991	$ 4,062
Accounts payable with affiliates	1,095	958
Dividends	203	170
Price risk management liabilities	23	22
Other current liabilities	98	55
Total Current Liabilities	3,410	5,267
Deferred Credits and Other Noncurrent Liabilities	120	143
Equity		
PPL Corporation Shareowners' Common Equity		
Common stock - $0.01 par value (a)	6	5
Additional paid-in capital	6,813	4,602
Earnings reinvested	4,797	4,082
Accumulated other comprehensive loss	(788)	(479)
Total PPL Corporation Shareowners' Common Equity	10,828	8,210
Total Liabilities and Equity	$ 14,358	$ 13,620

(a) 780,000 shares authorized; 578,405 and 483,391 shares issued and outstanding at December 31, 2011 and December 31, 2010.

The accompanying Notes to Condensed Unconsolidated Financial Statements are an integral part of the financial statements.

SCHEDULE I - PPL CORPORATION
NOTES TO CONDENSED UNCONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation

PPL Corporation is a holding company and conducts substantially all of its business operations through its subsidiaries. Substantially all of its consolidated assets are held by such subsidiaries. Accordingly, its cash flow and its ability to meet its obligations are largely dependent upon the earnings of these subsidiaries and the distribution or other payment of such earnings to it in the form of dividends, loans or advances or repayment of loans and advances from it. These condensed financial statements and related footnotes have been prepared in accordance with Reg. §210.12-04 of Regulation S-X. These statements should be read in conjunction with the consolidated financial statements and notes thereto of PPL Corporation.

PPL Corporation indirectly or directly owns all of the ownership interests of its significant subsidiaries. PPL Corporation does not own the preferred securities of PPL Electric Utilities Corporation. PPL Corporation relies on dividends or loans from its subsidiaries to fund PPL Corporation's dividends to its common shareholders and to meet its other cash requirements.

2. Commitments and Contingencies

See Note 15 to PPL Corporation's consolidated financial statements for commitments and contingencies of its subsidiaries.

Guarantees and Other Assurances

PPL Corporation's subsidiaries are separate and distinct legal entities and have no obligation to pay any amounts that may become due under PPL Corporation's guarantees or other assurances or to make any funds available for such payment.

PPL Corporation fully and unconditionally guarantees the payment of principal, premium and interest on all of the debt securities of PPL Capital Funding. The estimated maximum potential amount of future payments that could be required under the guarantees at December 31, 2011 was $5.2 billion. These guarantees will expire in 2067.

PPL Corporation has provided indemnification to the purchaser of PPL Gas Utilities and Penn Fuel Propane, LLC for damages arising out of any breach of the representations, warranties and covenants under the related transaction agreement and for damages arising out of certain other matters, including certain pre-closing unknown environmental liabilities relating to former manufactured gas plant properties or off-site disposal sites, if any, outside of Pennsylvania. The estimated maximum potential amount of future payments that could be required under the indemnifications at December 31, 2011 was $300 million. The indemnification provisions for most representations and warranties, including tax and environmental matters, are capped at $45 million, in the aggregate, and are triggered (i) only if the individual claim exceeds $50,000, and (ii) only if, and only to the extent that, in the aggregate, total claims exceed $4.5 million. The indemnification provisions for most representations and warranties expired on September 30, 2009 without any claims having been made. Certain representations and warranties, including those having to do with transaction authorization and title, survive indefinitely, are capped at the purchase price and are not subject to the above threshold or deductible. The indemnification provision for the tax matters representations survives for the duration of the applicable statute of limitation. The indemnification provision for the environmental matters representations expired on September 30, 2011 without any claims having been made. The indemnification for covenants survives until the applicable covenant is performed and is not subject to any cap.

The probability of expected payment under each of the guarantees is remote.

SCHEDULE I - LG&E and KU Energy LLC
CONDENSED UNCONSOLIDATED STATEMENTS OF INCOME
(Millions of Dollars)

	Successor		Predecessor	
	Year Ended December 31, 2011	Two Months Ended December 31, 2010	Ten Months Ended October 31, 2010	Year Ended December 31, 2009
Operating Revenues				
Operating Expenses				
Other operation and maintenance			$ (3)	$ (1)
Total Operating Expenses			(3)	(1)
Loss on Impairment of Goodwill				1,493
Operating Income (Loss)			3	(1,492)
Equity in Earnings of Subsidiaries	$ 267	$ 48	204	(61)
Other Income (Expense) - net			(1)	
Interest Income with Affiliate	29	5	29	31
Interest Expense	31	4		
Interest Expense with Affiliate	2	1	47	60
Income (Loss) from Continuing Operations Before Income Taxes	263	48	188	(1,582)
Income Tax Expense (Benefit)	(2)	1	(2)	(6)
Income (Loss) from Continuing Operations After Income Taxes	265	47	190	(1,576)
Income (Loss) from Discontinued Operations (net of income taxes)				39
Net Income (Loss)	265	47	190	(1,537)
Noncontrolling Interest - Loss from Discontinued Operations				5
Net Income (Loss) Attributable to Member	$ 265	$ 47	$ 190	$ (1,542)

The accompanying Notes to Condensed Unconsolidated Financial Statements are an integral part of the financial statements.

SCHEDULE I - LG&E and KU Energy LLC
CONDENSED UNCONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions of Dollars)

	Successor		Predecessor	
	Year Ended December 31, 2011	Two Months Ended December 31, 2010	Ten Months Ended October 31, 2010	Year Ended December 31, 2009
Cash Flows from Operating Activities				
Net cash provided by (used in) operating activities	$ 346	$ 53	$ 156	$ 63
Cash Flows from Investing Activities				
Capital contributions to affiliated subsidiaries		(3)	(525)	(75)
Net decrease (increase) in notes receivable from affiliates	(63)	313	234	(742)
Net cash provided by (used in) investing activities	(63)	310	(291)	(817)
Cash Flows from Financing Activities				
Net increase (decrease) in debt with affiliates		(208)	243	803
Repayment of short-term borrowings		(2,103)		
Retirement of long-term debt		(400)		
Issuance of long-term debt	250	870		
Debt-issuance costs		(6)		
Contribution from member		1,565		
Distribution to member	(533)	(100)		
Payment of common stock dividends			(87)	(49)
Net cash provided by (used in) financing activities	(283)	(382)	156	754
Net Increase (Decrease) in Cash and Cash Equivalents		(19)	21	
Cash and Cash Equivalents at Beginning of Period	2	21		
Cash and Cash Equivalents at End of Period	$ 2	$ 2	$ 21	$
Supplemental disclosures of cash flow information:				
Cash Dividends Received from Affiliated Subsidiaries	$ 207	$	$ 105	$ 80

The accompanying Notes to Condensed Unconsolidated Financial Statements are an integral part of the financial statements.

SCHEDULE I - LG&E and KU Energy LLC
CONDENSED UNCONSOLIDATED BALANCE SHEETS AT DECEMBER 31,
(Millions of Dollars)

	2011	2010
Assets		
Current Assets		
Cash and cash equivalents	$ 2	$ 2
Accounts receivable from affiliates	11	61
Notes receivable from affiliates	1,520	787
Other current assets	4	
Total Current Assets	1,537	850
Investments		
Affiliated companies at equity	4,056	3,998
Other Noncurrent Assets		
Notes receivable from affiliates		670
Deferred income taxes	163	166
Other noncurrent assets	8	6
Total Other Noncurrent Assets	171	842
Total Assets	$ 5,764	$ 5,690
Liabilities and Equity		
Current Liabilities		
Accounts payable to affiliates	$ 701	$ 606
Other current liabilities	6	7
Total Current Liabilities	707	613
Long-term Debt		
Long-term debt	1,120	870
Notes payable to affiliates	196	196
Total Long-term Debt	1,316	1,066
Equity	3,741	4,011
Total Liabilities and Equity	$ 5,764	$ 5,690

The accompanying Notes to Condensed Unconsolidated Financial Statements are an integral part of the financial statements.

Schedule I - LG&E and KU Energy LLC
Notes to Condensed Unconsolidated Financial Statements

1. Basis of Presentation

LG&E and KU Energy LLC (LKE) is a holding company and conducts substantially all of its business operations through its subsidiaries. Substantially all of its consolidated assets are held by such subsidiaries. Accordingly, its cash flow and its ability to meet its obligations are largely dependent upon the earnings of these subsidiaries and the distribution or other payment of such earnings to it in the form of dividends or repayment of loans and advances from the subsidiaries. These condensed financial statements and related footnotes have been prepared in accordance with Reg. §210.12-04 of Regulation S-X. These statements should be read in conjunction with the consolidated financial statements and notes thereto of LKE.

LKE indirectly or directly owns all of the ownership interests of its significant subsidiaries. LKE relies primarily on dividends from its subsidiaries to fund LKE's dividends to its member and to meet its other cash requirements.

2. Commitments and Contingencies

See Note 15 to LKE's consolidated financial statements for commitments and contingencies of its subsidiaries.

Guarantees

In connection with various divestitures, LKE has indemnified/guaranteed respective parties against certain liabilities that may arise in connection with these transactions and business activities. The terms of these indemnifications/guarantees vary, as do the expiration terms. LKE has issued direct financial guarantees to parties involved in the WKE lease termination, which occurred in July 2009. These guarantees cover the due and punctual payment, performance and discharge by each party of its respective present and future obligations. The most comprehensive of these guarantees is a guarantee covering operational, regulatory and environmental commitments and indemnifications made by WKE under the WKE Transaction Termination Agreement. This guarantee has a term of 12 years beginning on July 16, 2009 and a cumulative maximum exposure of $200 million. Certain items, such as non-excluded government fines and penalties, fall outside the cumulative cap. Another guarantee with a maximum exposure of $100 million covering other indemnifications expires in 2023. Certain matters are currently under discussion among the parties, including one matter currently in arbitration and a further matter for which LKE is contesting the applicability of the indemnification requirement. The matter in arbitration may be ruled upon during early 2012, which ruling may result in increases or decreases to the liability estimate LKE has currently recorded. The ultimate outcome of both matters cannot be predicted at this time. See Note 9, Discontinued Operations, for further information. Additionally, LKE has indemnified various third parties related to historical obligations for divested subsidiaries and affiliates. The indemnifications vary by entity and the maximum amounts range from being capped at the sale price to no specified maximum; however, LKE is not aware of claims made by any party at this time. LKE could be required to perform on these indemnifications in the event of covered losses or liabilities being claimed by an indemnified party. No additional material loss is anticipated by reason of such indemnifications. A subsidiary of LKE has recorded liabilities for all guarantees totaling $11 million with respect to which LKE has certain guarantee obligations.

QUARTERLY FINANCIAL, COMMON STOCK PRICE AND DIVIDEND DATA (Unaudited)
PPL Corporation and Subsidiaries
(Millions of Dollars, except per share data)

	For the Quarters Ended (a)			
	March 31	June 30	Sept. 30	Dec. 31
2011				
Operating revenues	**$ 2,910**	**$ 2,489**	**$ 3,120**	**$ 4,218**
Operating income	**805**	**595**	**767**	**934**
Income from continuing operations after income taxes	**402**	**201**	**449**	**458**
Income (loss) from discontinued operations	**3**	**(1)**		
Net income	**405**	**200**	**449**	**458**
Net income attributable to PPL Corporation	**401**	**196**	**444**	**454**
Income from continuing operations after income taxes available to PPL Corporation common shareowners: (b)				
Basic EPS	**0.82**	**0.35**	**0.76**	**0.78**
Diluted EPS	**0.82**	**0.35**	**0.76**	**0.78**
Net income available to PPL Corporation common shareowners: (b)				
Basic EPS	**0.82**	**0.35**	**0.76**	**0.78**
Diluted EPS	**0.82**	**0.35**	**0.76**	**0.78**
Dividends declared per share of common stock (c)	**0.350**	**0.350**	**0.350**	**0.350**
Price per common share:				
High	**$ 26.98**	**$ 28.38**	**$ 29.61**	**$ 30.27**
Low	**24.10**	**25.23**	**25.00**	**27.00**
2010				
Operating revenues	$ 3,006	$ 1,473	$ 2,179	$ 1,863
Operating income	476	226	522	642
Income from continuing operations after income taxes	247	85	306	338
Income (loss) from discontinued operations	8	7	(53)	21
Net income	255	92	253	359
Net income attributable to PPL Corporation	250	85	248	355
Income from continuing operations after income taxes available to PPL Corporation common shareowners: (b)				
Basic EPS	0.64	0.20	0.62	0.69
Diluted EPS	0.64	0.20	0.62	0.69
Net income available to PPL Corporation common shareowners: (b)				
Basic EPS	0.66	0.22	0.51	0.73
Diluted EPS	0.66	0.22	0.51	0.73
Dividends declared per share of common stock (c)	0.350	0.350	0.350	0.350
Price per common share:				
High	$ 32.77	$ 28.80	$ 28.00	$ 28.14
Low	27.47	23.75	24.83	25.13

(a) Quarterly results can vary depending on, among other things, weather and the forward pricing of power. In addition, earnings in 2011 and 2010 were affected by special items. Accordingly, comparisons among quarters of a year may not be indicative of overall trends and changes in operations.
(b) The sum of the quarterly amounts may not equal annual earnings per share due to changes in the number of common shares outstanding during the year or rounding.
(c) PPL has paid quarterly cash dividends on its common stock in every year since 1946. Future dividends, declared at the discretion of the Board of Directors, will be dependent upon future earnings, cash flows, financial requirements and other factors.

QUARTERLY FINANCIAL DATA (Unaudited)
PPL Electric Utilities Corporation and Subsidiaries
(Millions of Dollars)

	For the Quarters Ended (a)			
	March 31	June 30	Sept. 30	Dec. 31
2011				
Operating revenues	**$ 558**	**$ 440**	**$ 455**	**$ 439**
Operating income	**103**	**82**	**69**	**94**
Net income	**56**	**40**	**32**	**61**
Net income available to PPL Corporation	**52**	**36**	**28**	**57**
2010				
Operating revenues	$ 813	$ 522	$ 571	$ 549
Operating income	87	56	79	62
Net income	42	23	40	30
Net income available to PPL Corporation	37	16	36	26

(a) PPL Electric's business is seasonal in nature, with peak sales periods generally occurring in the winter and summer months. Accordingly, comparisons among quarters of a year may not be indicative of overall trends and changes in operations.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

PPL Corporation, PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of disclosure controls and procedures.

PPL Corporation, PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company

The registrants' principal executive officers and principal financial officers, based on their evaluation of the registrants' disclosure controls and procedures (as defined in Rules 13a-15(e) or 15d-15(e) of the Securities Exchange Act of 1934) have concluded that, as of December 31, 2011, the registrants' disclosure controls and procedures are effective to ensure that material information relating to the registrants and their consolidated subsidiaries is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, particularly during the period for which this annual report has been prepared. The aforementioned principal officers have concluded that the disclosure controls and procedures are also effective to ensure that information required to be disclosed in reports filed under the Exchange Act is accumulated and communicated to management, including the principal executive and principal financial officers, to allow for timely decisions regarding required disclosure.

PPL Corporation

PPL acquired WPD Midlands on April 1, 2011. These companies are included in PPL's 2011 financial statements as of the date of the acquisition, on a one-month lag. WPD Midlands accounted for approximately 9% of PPL's net income for the twelve months ended December 31, 2011. WPD Midlands represented 19% and 27% of PPL's total assets and net assets at December 31, 2011. The internal control over financial reporting of WPD Midlands was excluded from a formal evaluation of effectiveness of PPL's disclosure controls and procedures. This decision was based upon the significance of these companies to PPL, and the timing of integration efforts underway to transition WPD Midlands' processes, information technology systems and other components of internal control over financial reporting to the internal control structure of PPL. PPL has expanded its consolidation and disclosure controls and procedures to include the acquired companies, and PPL continues to assess the current internal control over financial reporting at WPD Midlands. Risks related to the increased account balances were partially mitigated by PPL's expanded controls and PPL's existing policy of consolidating foreign subsidiaries on a one-month lag, which provided management additional time for review and analysis of WPD Midlands' results and their incorporation into PPL's consolidated financial statements.

(b) Changes in internal control over financial reporting.

PPL Corporation

PPL's principal executive officer and principal financial officer have concluded that a recent systems migration related to the WPD Midlands acquisition created a material change to its internal control over financial reporting. Specifically, on December 1, 2011 the use of legacy information technology systems at WPD Midlands was discontinued and the related data, processes and internal controls were migrated to the systems, processes and controls currently in place at PPL WW. Due to PPL's existing policy of consolidating foreign subsidiaries on a one-month lag, the system migration will primarily impact 2012 financial reporting for PPL and will likely have limited impact on PPL's 2011 financial reporting.

Risks related to the system migration were partially mitigated by PPL's expanded internal control over financial reporting that were implemented subsequent to the acquisition and PPL's existing policy of consolidating foreign subsidiaries on a one-month lag, which provided management additional time for review and analysis of WPD Midlands' results and their incorporation into PPL's consolidated financial statements. PPL continues to assess the internal control over financial reporting at WPD subsequent to the December 1, 2011 system migration.

The aforementioned principal executive officer and principal financial officer have concluded that there were no other changes in the registrant's internal control over financial reporting during the registrant's fourth fiscal quarter that have materially affected, or are reasonably likely to materially affect, the registrant's internal control over financial reporting.

PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company

The registrants' principal executive officers and principal financial officers have concluded that there were no changes in the registrants' internal control over financial reporting during the registrants' fourth fiscal quarter that have materially affected, or are reasonably likely to materially affect, the registrants' internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

PPL Corporation

PPL's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f) or 15d-15(f). PPL's internal control over financial reporting is a process designed to provide reasonable assurance to PPL's management and Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in "Internal Control - Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in "Internal Control - Integrated Framework," our management concluded that our internal control over financial reporting was effective as of December 31, 2011. The effectiveness of our internal control over financial reporting has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report contained on page 195.

In accordance with SEC rules, management excluded WPD Midlands from its evaluation of internal control over financial reporting due to the significance of these companies to PPL's financial results and the migration of WPD Midlands' legacy information technology systems, processes and controls to those at PPL WW. WPD Midlands accounted for 9% of PPL's net income for the year ended December 31, 2011. WPD Midlands represented 19% and 27% of PPL's consolidated total assets and net assets, respectively, at December 31, 2011. As discussed above, PPL Corporation is continuing to enhance and evaluate processes, information technology systems and other components of internal control over financial reporting as part of its ongoing integration activities.

PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company

Management of PPL's non-accelerated filer companies, PPL Energy Supply, PPL Electric, LKE, LG&E and KU, are responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f) or 15d-15(f). PPL's internal control over financial reporting is a process designed to provide reasonable assurance to PPL's management and Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Under the supervision and with the participation of our management, including our principal executive officers and principal financial officers, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in "Internal Control - Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in "Internal Control - Integrated Framework," our management concluded that our internal control over financial reporting was effective as of December 31, 2011. This annual report does not include an attestation report of Ernst & Young LLP, the companies' independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the companies' registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit the companies to provide only management's report in this annual report.

ITEM 9B. OTHER INFORMATION

PPL Corporation, PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

PPL Corporation

Additional information for this item will be set forth in the sections entitled "Nominees for Directors," "Board Committees - Audit Committee" and "Section 16(a) Beneficial Ownership Reporting Compliance" in PPL's 2012 Notice of Annual Meeting and Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2011, and which information is incorporated herein by reference. There have been no changes to the procedures by which shareowners may recommend nominees to PPL's board of directors since the filing with the SEC of PPL's 2011 Notice of Annual Meeting and Proxy Statement. Information required by this item concerning the executive officers of PPL is set forth at the end of Part I of this report.

PPL has adopted a code of ethics entitled "Standards of Integrity" that applies to all directors, managers, trustees, officers (including the principal executive officers, principal financial officers and principal accounting officers (each, a "principal officer")), employees and agents of PPL and PPL's subsidiaries for which it has operating control (including PPL Energy Supply, PPL Electric, LKE, LG&E and KU). The "Standards of Integrity" are posted on PPL's Internet website: www.pplweb.com/about/corporate+governance . A description of any amendment to the "Standards of Integrity" (other than a technical, administrative or other non-substantive amendment) will be posted on PPL's Internet website within four business days following the date of the amendment. In addition, if a waiver constituting a material departure from a provision of the "Standards of Integrity" is granted to one of the principal officers, a description of the nature of the waiver, the name of the person to whom the waiver was granted and the date of the waiver will be posted on PPL's Internet website within four business days following the date of the waiver.

PPL also has adopted its "Guidelines for Corporate Governance," which address, among other things, director qualification standards and director and board committee responsibilities. These guidelines, and the charters of each of the committees of PPL's board of directors, are posted on PPL's Internet website: www.pplweb.com/about/corporate+governance .

PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company

Item 10 is omitted as PPL Energy Supply, PPL Electric, LKE, LG&E and KU meet the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K.

EXECUTIVE OFFICERS OF THE REGISTRANTS

Officers of the Registrants are elected annually by their Boards of Directors (or Board of Managers for PPL Energy Supply) to serve at the pleasure of the respective Boards. There are no family relationships among any of the executive officers, nor is there any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

There have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

Listed below are the executive officers at December 31, 2011.

PPL Corporation

Name	Age	Positions Held During the Past Five Years	Dates
James H. Miller (a)	63	Chairman	October 2006 - present
		Chief Executive Officer	October 2006 - November 2011
		President	August 2005 - July 2011
William H. Spence (b)	54	President and Chief Executive Officer	November 2011 - present
		President-PPL Generation	June 2008 - present
		President and Chief Operating Officer	July 2011 - November 2011
		Executive Vice President and Chief Operating Officer	June 2006 - July 2011
Paul A. Farr	44	Executive Vice President and Chief Financial Officer	April 2007 - present
		Senior Vice President-Financial	January 2006 - March 2007
Robert J. Grey	61	Senior Vice President, General Counsel and Secretary	March 1996 - present
David G. DeCampli (c)	54	President-PPL Electric	April 2007 - present
		Senior Vice President-Transmission and Distribution Engineering and Operations-PPL Electric	December 2006 - April 2007
Robert D. Gabbard (c)	52	President-PPL EnergyPlus	June 2008 - present
		Senior Vice President-Trading-PPL EnergyPlus	June 2008 - June 2008
		Senior Vice President Merchant Trading Operations-Conectiv Energy	June 2005 - May 2008
Rick L. Klingensmith (c)	51	President-PPL Global	August 2004 - present
Victor A. Staffieri (c)	56	Chairman of the Board, President and Chief Executive Officer-LKE	May 2001 - present
James E. Abel	59	Senior Vice President-Finance and Treasurer	August 2010 - present
		Vice President-Finance and Treasurer	June 1999 - August 2010
J. Matt Simmons, Jr. (c)	46	Vice President-Risk Management and Chief Risk Officer	September 2009 - present
		Vice President and Controller	January 2006 - March 2010
Vincent Sorgi	40	Vice President and Controller	March 2010 - present
		Controller-Supply Accounting	June 2008 - March 2010
		Controller-PPL EnergyPlus	April 2007 - June 2008
		Financial Director-Supply-PPL Generation	April 2006 - April 2007

(a) On July 22, 2011, James H. Miller resigned as President. On November 17, 2011, he also resigned as Chief Executive Officer. Mr. Miller has announced he will be retiring, effective April 1, 2012.

(b) On July 22, 2011, William H. Spence resigned as Executive Vice President and was elected President and Chief Operating Officer. On November 17, 2011, he also resigned as Chief Operating Officer and was elected President and Chief Executive Officer.

(c) Designated an executive officer of PPL by virtue of their respective positions at a PPL subsidiary.

ITEM 11. EXECUTIVE COMPENSATION

PPL Corporation

Information for this item will be set forth in the sections entitled "Compensation of Directors," "Compensation Committee Interlocks and Insider Participation" and "Executive Compensation" in PPL's 2012 Notice of Annual Meeting and Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2011, and which information is incorporated herein by reference.

PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company

Item 11 is omitted as PPL Energy Supply, PPL Electric, LKE, LG&E and KU meet the conditions set forth in General Instructions (I)(1)(a) and (b) of Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

PPL Corporation

Information for this item will be set forth in the section entitled "Stock Ownership" in PPL's 2012 Notice of Annual Meeting and Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2011, and which information is incorporated herein by reference. In addition, provided below in tabular format is information as of December 31, 2011, with respect to compensation plans (including individual compensation arrangements) under which equity securities of PPL are authorized for issuance.

Equity Compensation Plan Information

	Number of securities to be issued upon exercise of outstanding options, warrants and rights (3)	Weighted-average exercise price of outstanding options, warrants and rights (3)	Number of securities remaining available for future issuance under equity compensation plans (4)
Equity compensation plans approved by security holders (1)	4,559,845 - ICP 2,970,353 - ICPKE 7,530,198 - Total	$ 30.90- ICP $ 30.28- ICPKE $ 30.65- Combined	1,107,321 - ICP 7,608,727 - ICPKE 14,452,166 - DDCP 23,168,214 - Total
Equity compensation plans not approved by security holders (2)			

(1) Includes (a) the Amended and Restated Incentive Compensation Plan (ICP), under which stock options, restricted stock, restricted stock units, performance units, dividend equivalents and other stock-based awards may be awarded to executive officers of PPL; (b) the Amended and Restated Incentive Compensation Plan for Key Employees (ICPKE), under which stock options, restricted stock, restricted stock units, performance units, dividend equivalents and other stock-based awards may be awarded to non-executive key employees of PPL and its subsidiaries; and (c) the Directors Deferred Compensation Plan (DDCP), under which stock units may be awarded to directors of PPL. See Note 12 to the Financial Statements for additional information.

(2) All of PPL's current compensation plans under which equity securities of PPL are authorized for issuance have been approved by PPL's shareowners.

(3) Relates to common stock issuable upon the exercise of stock options awarded under the ICP and ICPKE as of December 31, 2011. In addition, as of December 31, 2011, the following other securities had been awarded and are outstanding under the ICP, ICPKE and DDCP: 45,400 shares of restricted stock, 549,805 restricted stock units and 236,714 performance units under the ICP; 24,600 shares of restricted stock, 1,420,230 restricted stock units and 161,894 performance units under the ICPKE; and 425,306 stock units under the DDCP.

(4) Based upon the following aggregate award limitations under the ICP, ICPKE and DDCP: (a) under the ICP, 15,769,431 awards (i.e., 5% of the total PPL common stock outstanding as of April 23, 1999) granted after April 23, 1999; (b) under the ICPKE, 16,573,608 awards (i.e., 5% of the total PPL common stock outstanding as of January 1, 2003) granted after April 25, 2003, reduced by outstanding awards for which common stock was not yet issued as of such date of 2,373,812 resulting in a limit of 14,199,796; and (c) under the DDCP, 15,052,856 securities. In addition, each of the ICP and ICPKE includes an annual award limitation of 2% of total PPL common stock outstanding as of January 1 of each year.

PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company

Item 12 is omitted as PPL Energy Supply, PPL Electric, LKE, LG&E and KU meet the conditions set forth in General Instructions (I)(1)(a) and (b) of Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

PPL Corporation

Information for this item will be set forth in the sections entitled "Transactions with Related Persons" and "Independence of Directors" in PPL's 2012 Notice of Annual Meeting and Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2011, and is incorporated herein by reference.

PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company

Item 13 is omitted as PPL Energy Supply, PPL Electric, LKE, LG&E and KU meet the conditions set forth in General Instructions (I)(1)(a) and (b) of Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

PPL Corporation

Information for this item will be set forth in the section entitled "Fees to Independent Auditor for 2011 and 2010" in PPL's 2012 Notice of Annual Meeting and Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2011, and which information is incorporated herein by reference.

PPL Energy Supply, LLC

The following table presents an allocation of fees billed, including expenses, by Ernst & Young LLP (EY) to PPL for the fiscal years ended December 31, 2011 and 2010, for professional services rendered for the audit of PPL Energy Supply's annual financial statements and for fees billed for other services rendered by EY.

	2011	2010
	(in thousands)	
Audit fees (a)	$ 1,701	$ 2,581
Audit-related fees (b)	9	16
Tax fees (c)	518	375
All other fees (d)		118

(a) Includes estimated fees for audit of annual financial statements and review of financial statements included in PPL Energy Supply's Quarterly Reports on Form 10-Q and for services in connection with statutory and regulatory filings or engagements, including comfort letters and consents for financings and filings made with the SEC.

(b) Fees for performance of specific agreed-upon procedures.

(c) Includes fees for tax advice in connection with a tax basis and earnings and profit study, a private letter ruling related to the sale of Safe Harbor, the funding of the Western Power Utilities Pension Scheme, review and consultation related to PPL's recognition of tax benefits resulting from U.S. Court decisions, consultation and analysis related to non-income tax process improvements initiated by PPL and review, consultation and analysis related to investment tax credits and related capital expenditures on certain hydro-electric plant upgrades.

(d) Fees related to access to an EY online accounting research tool and an International Financial Reporting Standards diagnostic readiness assessment.

PPL Electric Utilities Corporation

The following table presents an allocation of fees billed, including expenses, by EY to PPL for the fiscal years ended December 31, 2011 and 2010, for professional services rendered for the audit of PPL Electric's annual financial statements and for fees billed for other services rendered by EY.

	2011	2010
	(in thousands)	
Audit fees (a)	$ 1,193	$ 810
Audit-related fees (b)	45	21
Tax fees (c)	19	58
All other fees (d)		42

(a) Includes estimated fees for audit of annual financial statements and review of financial statements included in PPL Electric's Quarterly Reports on Form 10-Q and for services in connection with statutory and regulatory filings or engagements, including comfort letters and consents for financings and filings made with the SEC.

(b) Fees for consultation on a transmission and distribution study and performance of specific agreed-upon procedures.

(c) Fees for consultation and analysis related to non-income tax process improvements initiated by PPL and review and consultation related to tax impacts resulting from U.S. Court decisions.

(d) Fees related to access to an EY online accounting research tool and an International Financial Reporting Standards diagnostic readiness assessment.

LG&E and KU Energy LLC

For the fiscal year ended 2011, EY served as LKE's independent auditor. For the fiscal year ended 2010, PricewaterhouseCoopers LLP (PwC) served as LKE's independent auditor. The following table presents an allocation of fees billed, including expenses, by EY and PwC to LKE for the fiscal years ended December 31, 2011 and 2010, for professional services rendered for the audits of LKE's annual financial statements and for fees billed for other services rendered by EY and PwC.

	Successor	Predecessor
	2011	2010
	(in thousands)	
Audit fees (a)	$ 1,528	$ 1,964
Tax fees		6
All other fees		2

(a) Includes estimated fees for audit of annual financial statements and review of financial statements included in LKE's Quarterly Reports on Form 10-Q and for services in connection with statutory and regulatory filings or engagements, including comfort letters and consents for financings and filings made with the SEC.

Louisville Gas and Electric Company

For the fiscal year ended 2011, EY served as LG&E's independent auditor. For the fiscal year ended 2010, PwC served as LG&E's independent auditor. The following table presents an allocation of fees billed, including expenses, by EY and PwC to LG&E for the fiscal years ended December 31, 2011 and 2010, for professional services rendered for the audits of LG&E's annual financial statements and for fees billed for other services rendered by EY and PwC.

	Successor	Predecessor
	2011	2010
	(in thousands)	
Audit fees (a)	$ 552	$ 871
All other fees		1

(a) Includes estimated fees for audit of annual financial statements and review of financial statements included in LG&E's Quarterly Reports on Form 10-Q and for services in connection with statutory and regulatory filings or engagements, including comfort letters and consents for financings and filings made with the SEC.

Kentucky Utilities Company

For the fiscal year ended 2011, EY served as KU's independent auditor. For the fiscal year ended 2010, PwC served as KU's independent auditor. The following table presents an allocation of fees billed, including expenses, by EY and PwC to KU for the fiscal years ended December 31, 2011 and 2010, for professional services rendered for the audits of KU's annual financial statements and for fees billed for other services rendered by EY and PwC.

	Successor	Predecessor
	2011	2010
	(in thousands)	
Audit fees (a)	$ 552	$ 811
Tax fees		6
All other fees		1

(a) Includes estimated fees for audit of annual financial statements and review of financial statements included in KU's Quarterly Reports on Form 10-Q and for services in connection with statutory and regulatory filings or engagements, including comfort letters and consents for financings and filings made with the SEC.

PPL Corporation, PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company

Approval of Fees The Audit Committee of PPL has procedures for pre-approving audit and non-audit services to be provided by the independent auditor. These procedures are designed to ensure the continued independence of the independent auditor. More specifically, the use of the independent auditor to perform either audit or non-audit services is prohibited unless specifically approved in advance by the Audit Committee of PPL. As a result of this approval process, the Audit Committee of PPL has pre-approved specific categories of services and authorization levels. All services outside of the specified categories and all amounts exceeding the authorization levels are approved by the Chair of the Audit Committee of PPL, who serves as the Committee designee to review and approve audit and non-audit related services during the year. A listing of the approved audit and non-audit services is reviewed with the full Audit Committee of PPL no later than its next meeting.

The Audit Committee of PPL approved 100% of the 2011 and 2010 services provided by EY.

The Audit Committee of PPL approved 100% of the 2010 services provided by PwC to LKE, LG&E and KU following their acquisition by PPL. Prior to the November 2010 acquisition of LKE by PPL, the Audit Committee of LKE, LG&E and KU maintained procedures for pre-approval of independent auditor services and fees substantially similar to those described above. The LKE, LG&E and KU Audit Committee approved 100% of the 2010 services provided by PwC prior to the PPL acquisition.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

PPL Corporation, PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company

(a) The following documents are filed as part of this report:

1. Financial Statements - Refer to the "Table of Contents" for an index of the financial statements included in this report.

2. Supplementary Data and Supplemental Financial Statement Schedule - included in response to Item 8.

   Schedule I - PPL Corporation Condensed Unconsolidated Financial Statements.

   Schedule I - LG&E and KU Energy LLC Condensed Unconsolidated Financial Statements.

   All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements or notes thereto.

3. Exhibits

   See Exhibit Index immediately following the signature pages.

SHAREOWNER AND INVESTOR INFORMATION

Annual Meetings : The 2012 annual meeting of shareowners of PPL will be held on Wednesday, May 16, 2012, at the Zoellner Arts Center, on the campus of Lehigh University in Bethlehem, Pennsylvania, in Northampton County.

Proxy and Information Statement Material : A proxy statement and notice of PPL's annual meeting is mailed to all shareowners of record as of February 29, 2012.

PPL Annual Report : The report is published and mailed in the beginning of April to all shareowners of record. The latest annual report can be accessed at www.pplweb.com. If you have more than one account, or if there is more than one investor in your household, you may call the PPL Shareowner Information Line to request that only one annual report be delivered to your address. Please provide account numbers for all duplicate mailings.

Dividends : Subject to the declaration of dividends on PPL common stock by the PPL Board of Directors or its Executive Committee and PPL Electric preference stock by the PPL Electric Board of Directors, dividends are paid on the first business day of April, July, October and January. The 2012 record dates for dividends are expected to be March 9, June 8, September 10 and December 10.

Direct Deposit of Dividends: Shareowners may choose to have their dividend checks deposited directly into their checking or savings account.

PPL Shareowner Information Line (1-800-345-3085): Shareowners can get detailed corporate and financial information 24 hours a day using the PPL Shareowner Information Line. They can hear timely recorded messages about earnings, dividends and other company news releases; request information by fax; and request printed materials in the mail. Other PPL publications, such as the annual and quarterly reports to the Securities and Exchange Commission (Forms 10-K and 10-Q), will be mailed upon request, or write to:

Manager - PPL Investor Services
Two North Ninth Street (GENTW13)
Allentown, PA 18101

FAX: 610-774-5106
Via email: invserv@pplweb.com

PPL's Website (www.pplweb.com): Shareowners can access PPL Securities and Exchange Commission filings, corporate governance materials, news releases, stock quotes and historical performance. Visitors to our website can provide their email address and indicate their desire to receive future earnings or news releases automatically.

Shareowner Inquiries :

PPL Shareowner Services
Wells Fargo Bank, N.A.
161 North Concord Exchange
South St. Paul, MN 55075-1139

Toll Free: 1-800-345-3085
Outside U.S.: 651-453-2129
FAX: 651-450-4085
www.wellsfargo.com/shareownerservices

Online Account Access : Registered shareowners can access account information by visiting www.shareowneronline.com.

Dividend Reinvestment and Direct Stock Purchase Plan (Plan): PPL offers its existing shareowners, employees and new investors the opportunity to acquire shares of PPL common stock through its Plan. Shareowners may choose to have dividends on their PPL common stock fully or partially reinvested in PPL common stock or can receive full payment of cash dividends by check or EFT. Participants in the Plan may choose to have their common stock certificates deposited into their Plan account.

Direct Registration System: PPL participates in the Direct Registration System (DRS). Shareowners may choose to have their common stock certificates deposited into the DRS.

Listed Securities:

New York Stock Exchange

PPL Corporation:
Common Stock (Code: PPL)

Corporate Units issued 2010 (Code: PPLPRU)

Corporate Units issued 2011 (Code: PPLPRW)

PPL Capital Funding, Inc.:
2007 Series A Junior Subordinated Notes due 2067 (Code: PPL/67)

6.85% Senior Notes due 2047 (Code: PLV)

Fiscal Agents:

Stock Transfer Agent and Registrar; Dividend Reinvestment Plan Agent
Wells Fargo Bank, N.A.
Shareowner Services
161 North Concord Exchange
South St. Paul, MN 55075-1139

Toll Free: 1-800-345-3085
Outside U.S.: 651-453-2129

Dividend Disbursing Office
PPL Investor Services
Two North Ninth Street (GENTW13)
Allentown, PA 18101

FAX: 610-774-5106
Via email: invserv@pplweb.com

Or call the PPL Shareowner Information Line
Toll Free: 1-800-345-3085

1945 Mortgage Bond Trustee, Transfer and Bond Interest Paying Agent
Deutsche Bank Trust Company Americas
5022 Gate Parkway (Suite 200)
Jacksonville, FL 32256

Toll Free: 1-800-735-7777
FAX: 615-866-3887

Indenture Trustee
The Bank of New York Mellon
101 Barclay Street
New York, NY 10286

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PPL Corporation
(Registrant)

By /s/ William H. Spence
William H. Spence -
President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

By /s/ William H. Spence
William H. Spence -
President and
Chief Executive Officer
(Principal Executive Officer)

By /s/ Paul A. Farr
Paul A. Farr -
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

By /s/ Vincent Sorgi
Vincent Sorgi -
Vice President and Controller
(Principal Accounting Officer)

Directors:

Frederick M. Bernthal
John W. Conway
Steven G. Elliott
Louise K. Goeser
Stuart E. Graham
Stuart Heydt

Venkata Rajamannar Madabhushi
James H. Miller
Craig A. Rogerson
William H. Spence
Natica von Althann
Keith H. Williamson

By /s/ William H. Spence
William H. Spence, Attorney-in-fact

Date: February 28, 2012

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PPL Energy Supply, LLC
(Registrant)

By /s/ James H. Miller
James H. Miller -
President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

By /s/ James H. Miller
James H. Miller -
President
(Principal Executive Officer)

By /s/ Paul A. Farr
Paul A. Farr -
Executive Vice President
(Principal Financial Officer)

By /s/ Vincent Sorgi
Vincent Sorgi -
Vice President and Controller
(Principal Accounting Officer)

Managers:

/s/ James H. Miller
James H. Miller

/s/ Paul A. Farr
Paul A. Farr

/s/ Robert J. Grey
Robert J. Grey

/s/ William H. Spence
William H. Spence

Date: February 28, 2012

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PPL Electric Utilities Corporation
(Registrant)

By /s/ David G. DeCampli
David G. DeCampli -
President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

By /s/ David G. DeCampli
David G. DeCampli -
President
(Principal Executive Officer)

By /s/ Vincent Sorgi
Vincent Sorgi -
Vice President and Chief Accounting Officer
(Principal Financial and Accounting Officer)

Directors:

/s/ James H. Miller James H. Miller	/s/ William H. Spence William H. Spence
/s/ Paul A. Farr Paul A. Farr	/s/ David G. DeCampli David G. DeCampli
/s/ Robert J. Grey Robert J. Grey	/s/ Dean A. Christiansen Dean a. Christiansen

Date: February 28, 2012

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

LG&E and KU Energy LLC
(Registrant)

By /s/ Victor A. Staffieri
Victor A. Staffieri -
Chairman, Chief Executive Officer and
President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

By /s/ Victor A. Staffieri
Victor A. Staffieri -
Chairman, Chief Executive Officer and
President
(Principal Executive Officer)

By /s/ Kent W. Blake
Kent W. Blake -
Chief Financial Officer
(Principal Financial Officer and
Principal Accounting Officer)

Directors:

/s/ Paul A. Farr Paul A. Farr	/s/ William H. Spence William H. Spence
/s/ Chris Hermann Chris Hermann	/s/ Victor A. Staffieri Victor A. Staffieri
/s/ John R. McCall John R. McCall	/s/ Paul W. Thompson Paul W. Thompson
/s/ S. Bradford Rives S. Bradford Rives	

Date: February 28, 2012

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Louisville Gas and Electric Company
(Registrant)

By /s/ Victor A. Staffieri
Victor A. Staffieri -
Chairman, Chief Executive Officer and
President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

By /s/ Victor A. Staffieri
Victor A. Staffieri -
Chairman, Chief Executive Officer and
President
(Principal Executive Officer)

By /s/ Kent W. Blake
Kent W. Blake -
Chief Financial Officer
(Principal Financial Officer and
Principal Accounting Officer)

Directors:

/s/ Paul A. Farr Paul A. Farr	/s/ William H. Spence William H. Spence
/s/ Chris Hermann Chris Hermann	/s/ Victor A. Staffieri Victor A. Staffieri
/s/ John R. McCall John R. McCall	/s/ Paul W. Thompson Paul W. Thompson
/s/ S. Bradford Rives S. Bradford Rives	

Date: February 28, 2012

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Kentucky Utilities Company
(Registrant)

By /s/ Victor A. Staffieri
Victor A. Staffieri -
Chairman, Chief Executive Officer and
President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

By /s/ Victor A. Staffieri
Victor A. Staffieri -
Chairman, Chief Executive Officer and
President
(Principal Executive Officer)

By /s/ Kent W. Blake
Kent W. Blake -
Chief Financial Officer
(Principal Financial Officer and
Principal Accounting Officer)

Directors:

/s/ Paul A. Farr Paul A. Farr	/s/ William H. Spence William H. Spence
/s/ Chris Hermann Chris Hermann	/s/ Victor A. Staffieri Victor A. Staffieri
/s/ John R. McCall John R. McCall	/s/ Paul W. Thompson Paul W. Thompson
/s/ S. Bradford Rives S. Bradford Rives	

Date: February 28, 2012

EXHIBIT INDEX

The following Exhibits indicated by an asterisk preceding the Exhibit number are filed herewith. The balance of the Exhibits have heretofore been filed with the Commission and pursuant to Rule 12(b)-32 are incorporated herein by reference. Exhibits indicated by a [_] are filed or listed pursuant to Item 601(b)(10)(iii) of Regulation S-K.

3(a)	-	Amended and Restated Articles of Incorporation of PPL Corporation, effective as of May 21, 2008 (Exhibit 3(i) to PPL Corporation Form 8-K Report (File No. 1-11459) dated May 21, 2008)
3(b)	-	Amended and Restated Articles of Incorporation of PPL Electric Utilities Corporation, effective as of May 2, 2006 (Exhibit 3(a) to PPL Electric Utilities Corporation Form 10-Q Report (File No. 1-905) for the quarter ended March 31, 2006)
3(c)-1	-	Certificate of Formation of PPL Energy Supply, LLC, effective as of November 14, 2000 (Exhibit 3.1 to PPL Energy Supply, LLC Form S-4 (Registration Statement No. 333-74794))
*3(c)-2	-	Certificate of Amendment of PPL Energy Supply, LLC, effective as of November 12, 2002
3(d)	-	Amended and Restated Bylaws of PPL Corporation, effective as of May 19, 2010 (Exhibit 99.1 to PPL Corporation Form 8-K Report (File No. 1-11459) dated May 24, 2010)
3(e)	-	Amended and Restated Bylaws of PPL Electric Utilities Corporation, effective as of March 30, 2006 (Exhibit 3.2 to PPL Electric Utilities Corporation Form 8-K Report (File No. 1-905) dated March 30, 2006)
3(f)	-	Limited Liability Company Agreement of PPL Energy Supply, LLC, effective as of March 20, 2001 (Exhibit 3.2 to PPL Energy Supply, LLC Form S-4 (Registration Statement No. 333-74794))
3(g)	-	Articles of Organization of LG&E and KU Energy LLC, effective as of December 29, 2003 (Exhibit 3(a) to Registration Statement filed on Form S-4 (File No. 333-173665))
3(h)	-	Amended and Restated Operating Agreement of LG&E and KU Energy LLC, effective as of November 1, 2010 (Exhibit 3(b) to Registration Statement filed on Form S-4 (File No. 333-173665))
3(i)-1	-	Amended and Restated Articles of Incorporation of Louisville Gas and Electric Company, effective as of November 6, 1996 (Exhibit 3(a) to Registration Statement filed on Form S-4 (File No. 333-173676))
3(i)-2	-	Articles of Amendment to Articles of Incorporation of Louisville Gas and Electric Company, effective as of April 6, 2004 (Exhibit 3(b) to Registration Statement filed on Form S-4 (File No. 333-173676))
3(j)	-	Bylaws of Louisville Gas and Electric Company, effective as of December 16, 2003 (Exhibit 3(c) to Registration Statement filed on Form S-4 (File No. 333-173676))
3(k)-1	-	Amended and Restated Articles of Incorporation of Kentucky Utilities Company, effective as of December 14, 1993 (Exhibit 3(a) to Registration Statement filed on Form S-4 (File No. 333-173675))
3(k)-2	-	Articles of Amendment to Articles of Incorporation of Kentucky Utilities Company, effective as of April 8, 2004 (Exhibit 3(b) to Registration Statement filed on Form S-4 (File No. 333-173675))
3(l)	-	Bylaws of Kentucky Utilities Company, effective as of December 16, 2003 (Exhibit 3(c) to Registration Statement filed on Form S-4 (File No. 333-173675))
4(a)	-	Pollution Control Facilities Loan Agreement, dated as of May 1, 1973, between PPL Electric Utilities Corporation and the Lehigh County Industrial Development Authority (Exhibit 5(z) to Registration Statement No. 2-60834)
4(b)-1	-	Amended and Restated Employee Stock Ownership Plan, dated January 12, 2007 (Exhibit 4(a) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2006)

4(b)-2	-	Amendment No. 1 to said Employee Stock Ownership Plan, dated July 2, 2007 (Exhibit 4(a) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended September 30, 2007)
4(b)-3	-	Amendment No. 2 to said Employee Stock Ownership Plan, dated December 13, 2007 (Exhibit 4(a)-3 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2007)
4(b)-4	-	Amendment No. 3 to said Employee Stock Ownership Plan, dated August 19, 2009 (Exhibit 4(a) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended September 30, 2009)
4(b)-5	-	Amendment No. 4 to said Employee Stock Ownership Plan, dated December 2, 2009 (Exhibit 4(a)-5 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2009)
4(b)-6	-	Amendment No. 5 to said Employee Stock Ownership Plan, dated November 17, 2010 (Exhibit 4(b)-6 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(c)	-	Trust Deed constituting £150 million 9 ¼ percent Bonds due 2020, dated November 9, 1995, between South Wales Electric plc and Bankers Trustee Company Limited (Exhibit 4(k) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2004)
4(d)-1	-	Indenture, dated as of November 1, 1997, among PPL Corporation, PPL Capital Funding, Inc. and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee (Exhibit 4.1 to PPL Corporation Form 8-K Report (File No. 1-11459) dated November 12, 1997)
4(d)-2	-	Supplemental Indenture No. 7, dated as of July 1, 2007, to said Indenture (Exhibit 4(b) to PPL Corporation Form 8-K Report (File No. 1-11459) dated July 16, 2007)
4(e)	-	Indenture, dated as of March 16, 2001, among WPD Holdings UK, Bankers Trust Company, as Trustee, Principal Paying Agent, and Transfer Agent and Deutsche Bank Luxembourg, S.A., as Paying and Transfer Agent (Exhibit 4(g) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2009)
4(f)-1	-	Indenture, dated as of August 1, 2001, by PPL Electric Utilities Corporation and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee (Exhibit 4.1 to PPL Electric Utilities Corporation Form 8-K Report (File No. 1-905) dated August 21, 2001)
4(f)-2	-	Supplemental Indenture No. 4, dated as of February 1, 2005, to said Indenture (Exhibit 4(g)-5 to PPL Electric Utilities Corporation Form 10-K Report (File No. 1-905) for the year ended December 31, 2004)
4(f)-3	-	Supplemental Indenture No. 5, dated as of May 1, 2005, to said Indenture (Exhibit 4(b) to PPL Electric Utilities Corporation Form 10-Q Report (File No. 1-905) for the quarter ended June 30, 2005)
4(f)-4	-	Supplemental Indenture No. 6, dated as of December 1, 2005, to said Indenture (Exhibit 4(a) to PPL Electric Utilities Corporation Form 8-K Report (File No. 1-905) dated December 22, 2005)
4(f)-5	-	Supplemental Indenture No. 7, dated as of August 1, 2007, to said Indenture (Exhibit 4(b) to PPL Electric Utilities Corporation Form 8-K Report (File No. 1-905) dated August 14, 2007)
4(f)-6	-	Supplemental Indenture No. 9, dated as of October 1, 2008, to said Indenture (Exhibit 4(c) to PPL Electric Utilities Corporation Form 8-K Report (File No. 1-905) dated October 31, 2008)
4(f)-7	-	Supplemental Indenture No. 10, dated as of May 1, 2009, to said Indenture (Exhibit 4(b) to PPL Electric Utilities Corporation Form 8-K Report (File No. 1-905) dated May 22, 2009)

4(f)-8	-	Supplemental Indenture No. 11, dated as of July 1, 2011, to said Indenture (Exhibit 4.1 to PPL Electric Utilities Corporation Form 8-K Report (File No. 1-905) dated July 13, 2011)
4(f)-9	-	Supplemental Indenture No. 12, dated as of July 1, 2011, to said Indenture (Exhibit 4(a) to PPL Electric Utilities Corporation Form 8-K Report (File No. 1-905) dated July 18, 2011)
4(f)-10	-	Supplemental Indenture No. 13, dated as of August 1, 2011, to said Indenture (Exhibit 4(a) to PPL Electric Utilities Corporation Form 8-K Report (File No. 1-905) dated August 23, 2011)
4(g)-1	-	Indenture, dated as of October 1, 2001, by PPL Energy Supply, LLC and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee (Exhibit 4.1 to PPL Energy Supply, LLC Form S-4 (Registration Statement No. 333-74794))
4(g)- 2	-	Supplemental Indenture No. 2, dated as of August 15, 2004, to said Indenture (Exhibit 4(h)-4 to PPL Energy Supply, LLC Form 10-K Report (File No. 333-74794) for the year ended December 31, 2004)
4(g)-3	-	Supplemental Indenture No. 3, dated as of October 15, 2005, to said Indenture (Exhibit 4(a) to PPL Energy Supply, LLC Form 8-K Report (File No. 333-74794) dated October 28, 2005)
4(g)-4	-	Form of Note for PPL Energy Supply, LLC's $300 million aggregate principal amount of 5.70% REset Put Securities due 2035 (REPS SM) (Exhibit 4(b) to PPL Energy Supply, LLC Form 8-K Report (File No. 333-74794) dated October 28, 2005)
4(g)-5	-	Supplemental Indenture No. 4, dated as of May 1, 2006, to said Indenture (Exhibit 4(a) to PPL Energy Supply, LLC Form 10-Q Report (File No. 333-74794) for the quarter ended June 30, 2006)
4(g)-6	-	Supplemental Indenture No. 6, dated as of July 1, 2006, to said Indenture (Exhibit 4(c) to PPL Energy Supply, LLC Form 10-Q Report (File No. 333-74794) for the quarter ended June 30, 2006)
4(g)-7	-	Supplemental Indenture No. 7, dated as of December 1, 2006, to said Indenture (Exhibit 4(f)-10 to PPL Energy Supply, LLC Form 10-K Report (File No. 333-74794) for the year ended December 31, 2006)
4(g)-8	-	Supplemental Indenture No. 8, dated as of December 1, 2007, to said Indenture (Exhibit 4(b) to PPL Energy Supply, LLC Form 8-K Report (File No. 333-74794) dated December 20, 2007)
4(g)-9	-	Supplemental Indenture No. 9, dated as of March 1, 2008, to said Indenture (Exhibit 4(b) to PPL Energy Supply, LLC Form 8-K Report (File No. 333-74794) dated March 14, 2008)
4(g)-10	-	Supplemental Indenture No. 10, dated as of July 1, 2008, to said Indenture (Exhibit 4(b) to PPL Energy Supply, LLC Form 8-K Report (File No. 1-32944) dated July 21, 2008)
4(g)-11	-	Supplemental Indenture No. 11, dated as of December 1, 2011, to said Indenture (Exhibit 4(a) to PPL Corporation Form 8-K Report (File No. 1-1149) dated December 16, 2011)
4(h)-1	-	Trust Deed constituting £200 million 5.875 percent Bonds due 2027, dated March 25, 2003, between Western Power Distribution (South West) plc and J.P. Morgan Corporate Trustee Services Limited (Exhibit 4(o)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2004)
4(h)-2	-	Supplement, dated May 27, 2003, to said Trust Deed, constituting £50 million 5.875 percent Bonds due 2027 (Exhibit 4 (o)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2004)
4(i)-1	-	Pollution Control Facilities Loan Agreement, dated as of February 1, 2005, between PPL Electric Utilities Corporation and the Lehigh County Industrial Development Authority (Exhibit 10(ff) to PPL Electric Utilities Corporation Form 10-K Report (File No. 1-905) for the year ended December 31, 2004)

4(i)-2	-	Pollution Control Facilities Loan Agreement, dated as of May 1, 2005, between PPL Electric Utilities Corporation and the Lehigh County Industrial Development Authority (Exhibit 10(a) to PPL Electric Utilities Corporation Form 10-Q Report (File No. 1-905) for the quarter ended June 30, 2005)
4(i)-3	-	Pollution Control Facilities Loan Agreement, dated as of October 1, 2008, between Pennsylvania Economic Development Financing Authority and PPL Electric Utilities Corporation (Exhibit 4(a) to PPL Electric Utilities Corporation Form 8-K Report (File No. 1-905) dated October 31, 2008)
4(j)	-	Trust Deed constituting £105 million 1.541 percent Index-Linked Notes due 2053, dated December 1, 2006, between Western Power Distribution (South West) plc and HSBC Trustee (CI) Limited (Exhibit 4(i) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2006)
4(k)	-	Trust Deed constituting £120 million 1.541 percent Index-Linked Notes due 2056, dated December 1, 2006, between Western Power Distribution (South West) plc and HSBC Trustee (CI) Limited (Exhibit 4(j) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2006)
4(l)	-	Trust Deed constituting £225 million 4.80436 percent Notes due 2037, dated December 21, 2006, between Western Power Distribution (South Wales) plc and HSBC Trustee (CI) Limited (Exhibit 4(k) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2006)
4(m)-1	-	Subordinated Indenture, dated as of March 1, 2007, between PPL Capital Funding, Inc., PPL Corporation and The Bank of New York, as Trustee (Exhibit 4(a) to PPL Corporation Form 8-K Report (File No. 1-11459) dated March 20, 2007)
4(m)-2	-	Supplemental Indenture No. 1, dated as of March 1, 2007, to said Subordinated Indenture (Exhibit 4(b) to PPL Corporation Form 8-K Report (File No. 1-11459) dated March 20, 2007)
4(m)-3	-	Supplemental Indenture No. 2, dated as of June 28, 2010, to said Subordinated Indenture (Exhibit 4.3 to PPL Corporation Form 8-K Report (File No. 1-11459) dated June 30, 2010)
4(m)-4	-	Supplemental Indenture No. 3, dated as of April 15, 2011, to said Subordinated Indenture (Exhibit 4.3 to PPL Corporation Form 8-K Report (File No. 1-11459) dated April 19, 2011).
4(n)-1	-	Series 2009A Exempt Facilities Loan Agreement, dated as of April 1, 2009, between PPL Energy Supply, LLC and Pennsylvania Economic Development Financing Authority (Exhibit 4(a) to PPL Energy Supply, LLC Form 8-K Report (File No. 1-32944) dated April 9, 2009)
4(n)-2	-	Series 2009B Exempt Facilities Loan Agreement, dated as of April 1, 2009, between PPL Energy Supply, LLC and Pennsylvania Economic Development Financing Authority (Exhibit 4(b) to PPL Energy Supply, LLC Form 8-K Report (File No. 1-32944) dated April 9, 2009)
4(n)-3	-	Series 2009C Exempt Facilities Loan Agreement, dated as of April 1, 2009, between PPL Energy Supply, LLC and Pennsylvania Economic Development Financing Authority (Exhibit 4(c) to PPL Energy Supply, LLC Form 8-K Report (File No. 1-32944) dated April 9, 2009)
4(o)	-	Trust Deed constituting £200 million 5.75 percent Notes due 2040, dated March 23, 2010, between Western Power Distribution (South Wales) plc and HSBC Corporate Trustee Company (UK) Limited (Exhibit 4(a) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended March 31, 2010)
4(p)	-	Trust Deed constituting £200 million 5.75 percent Notes due 2040, dated March 23, 2010, between Western Power Distribution (South West) plc and HSBC Corporate Trustee Company (UK) Limited (Exhibit 4(b) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended March 31, 2010)
4(q)-1	-	Indenture, dated as of October 1, 2010, between Kentucky Utilities Company and The Bank of New York Mellon, as Trustee (Exhibit 4(q)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)

4(q)-2	-	Supplemental Indenture No. 1, dated as of October 15, 2010, to said Indenture (Exhibit 4(q)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(q)-3	-	Supplemental Indenture No. 2, dated as of November 1, 2010, to said Indenture (Exhibit 4(q)-3 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(r)-1	-	Indenture, dated as of October 1, 2010, between Louisville Gas and Electric Company and The Bank of New York Mellon, as Trustee (Exhibit 4(r)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(r)-2	-	Supplemental Indenture No. 1, dated as of October 15, 2010, to said Indenture (Exhibit 4(r)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(r)-3	-	Supplemental Indenture No. 2, dated as of November 1, 2010, to said Indenture (Exhibit 4(r)-3 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(s)-1	-	Indenture, dated as of November 1, 2010, between LG&E and KU Energy LLC and The Bank of New York Mellon, as Trustee (Exhibit 4(s)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(s)-2	-	Supplemental Indenture No. 1, dated as of November 1, 2010, to said Indenture (Exhibit 4(s)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(s)-3	-	Supplemental Indenture No. 2, dated as of September 1, 2011, to said Indenture (Exhibit 4(a) to PPL Corporation Form 8-K Report (File No. 1-11459) dated September 30, 2011)
4(t)-1	-	2002 Series A Carroll County Loan Agreement, dated February 1, 2002, by and between Kentucky Utilities Company, and County of Carroll, Kentucky (Exhibit 4(w)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(t)-2	-	Amendment No. 1 dated as of September 1, 2010 to said Loan Agreement by and between Kentucky Utilities Company, and County of Carroll, Kentucky (Exhibit 4(w)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(u)-1	-	2002 Series B Carroll County Loan Agreement, dated February 1, 2002, by and between Kentucky Utilities Company, and County of Carroll, Kentucky (Exhibit 4(x)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(u)-2	-	Amendment No. 1 dated as of September 1, 2010, to said Loan Agreement by and between Kentucky Utilities Company, and County of Carroll, Kentucky (Exhibit 4(x)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(v)-1	-	2002 Series C Carroll County Loan Agreement, dated July 1, 2002, by and between Kentucky Utilities Company, and County of Carroll, Kentucky (Exhibit 4(y)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(v)-2	-	Amendment No. 1 dated as of September 1, 2010, to said Loan Agreement by and between Kentucky Utilities Company, and County of Carroll, Kentucky (Exhibit 4(y)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(w)-1	-	2004 Series A Carroll County Loan Agreement, dated October 1, 2004 and amended and restated as of September 1, 2008, by and between Kentucky Utilities Company, and County of Carroll, Kentucky (Exhibit 4(z)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(w)-2	-	Amendment No. 1 dated as of September 1, 2010, to said Loan Agreement by and between Kentucky Utilities Company, and County of Carroll, Kentucky (Exhibit 4(z)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)

4(x)-1	-	2006 Series B Carroll County Loan Agreement, dated October 1, 2006 and amended and restated September 1, 2008, by and between Kentucky Utilities Company, and County of Carroll, Kentucky (Exhibit 4(aa)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(x)-2	-	Amendment No. 1 dated as of September 1, 2010, to said Loan Agreement by and between Kentucky Utilities Company, and County of Carroll, Kentucky (Exhibit 4(aa)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(y)-1	-	2007 Series A Carroll County Loan Agreement, dated March 1, 2007, by and between Kentucky Utilities Company and County of Carroll, Kentucky (Exhibit 4(bb)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(y)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Kentucky Utilities Company, and County of Carroll, Kentucky (Exhibit 4(bb)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(z)-1	-	2008 Series A Carroll County Loan Agreement, dated August 1, 2008 by and between Kentucky Utilities Company, and County of Carroll, Kentucky (Exhibit 4(cc)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(z)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Kentucky Utilities Company, and County of Carroll, Kentucky (Exhibit 4(cc)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(aa)-1	-	2000 Series A Mercer County Loan Agreement, dated May 1, 2000 and amended and restated as of September 1, 2008, by and between Kentucky Utilities Company, and County of Mercer, Kentucky (Exhibit 4(dd)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(aa)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Kentucky Utilities Company, and County of Mercer, Kentucky (Exhibit 4(dd)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(bb)-1	-	2002 Series A Mercer County Loan Agreement, dated February 1, 2002, by and between Kentucky Utilities Company, and County of Mercer, Kentucky (Exhibit 4(ee)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(bb)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Kentucky Utilities Company, and County of Mercer, Kentucky (Exhibit 4(ee)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(cc)-1	-	2002 Series A Muhlenberg County Loan Agreement, dated February 1, 2002, by and between Kentucky Utilities Company, and County of Muhlenberg, Kentucky (Exhibit 4(ff)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(cc)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Kentucky Utilities Company, and County of Muhlenberg, Kentucky (Exhibit 4(ff)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(dd)-1	-	2007 Series A Trimble County Loan Agreement, dated March 1, 2007, by and between Kentucky Utilities Company, and County of Trimble, Kentucky (Exhibit 4(gg)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(dd)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Kentucky Utilities Company, and County of Trimble, Kentucky (Exhibit 4(gg)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)

4(ee)-1	-	2000 Series A Louisville/Jefferson County Metro Government Loan Agreement, dated May 1, 2000 and amended and restated as of September 1, 2008, by and between Louisville Gas and Electric Company, and Louisville/Jefferson County Metro Government, Kentucky (Exhibit 4(hh)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(ee)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Louisville Gas and Electric Company, and Louisville/Jefferson County Metro Government, Kentucky (Exhibit 4(hh)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
*4(ee)-3	-	Amendment No. 2 dated as of October 1, 2011, to said Loan Agreement by and between Louisville Gas and Electric Company, and Louisville/Jefferson County Metro Government, Kentucky
4(ff)-1	-	2001 Series A Jefferson County Loan Agreement, dated July 1, 2001, by and between Louisville Gas and Electric Company, and Jefferson County, Kentucky (Exhibit 4(ii)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(ff)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Louisville Gas and Electric Company, and Jefferson County, Kentucky (Exhibit 4(ii)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(gg)-1	-	2001 Series A Jefferson County Loan Agreement, dated November 1, 2001, by and between Louisville Gas and Electric Company, and Jefferson County, Kentucky (Exhibit 4(jj)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(gg)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Louisville Gas and Electric Company, and Jefferson County, Kentucky (Exhibit 4(jj)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(hh)-1	-	2001 Series B Jefferson County Loan Agreement, dated November 1, 2001, by and between Louisville Gas and Electric Company, and Jefferson County, Kentucky (Exhibit 4(kk)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(hh)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Louisville Gas and Electric Company, and Jefferson County, Kentucky (Exhibit 4(kk)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(ii)-1	-	2003 Series A Louisville/Jefferson County Metro Government Loan Agreement, dated October 1, 2003, by and between Louisville Gas and Electric Company and Louisville/Jefferson County Metro Government, Kentucky (Exhibit 4(ll)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(ii)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Louisville Gas and Electric Company, and Louisville/Jefferson County Metro Government, Kentucky (Exhibit 4(ll)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(jj)-1	-	2005 Series A Louisville/Jefferson County Metro Government Loan Agreement, dated February 1, 2005 and amended and restated as of September 1, 2008, by and between Louisville Gas and Electric Company, and Louisville/Jefferson County Metro Government, Kentucky (Exhibit 4(mm)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(jj)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Louisville Gas and Electric Company, and Louisville/Jefferson County Metro Government, Kentucky (Exhibit 4(mm)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(kk)-1	-	2007 Series A Louisville/Jefferson County Metro Government Loan Agreement, dated as of March 1, 2007 and amended and restated as of September 1, 2008, by and between Louisville Gas and Electric Company, and Louisville/Jefferson County Metro Government, Kentucky (Exhibit 4(nn)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)

4(kk)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Louisville Gas and Electric Company, and Louisville/Jefferson County Metro Government, Kentucky (Exhibit 4(nn)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(ll)	-	2007 Series B Louisville/Jefferson County Metro Government Amended and Restated Loan Agreement, dated November 1, 2010, by and between Louisville Gas and Electric Company and Louisville/Jefferson County Metro Government, Kentucky (Exhibit 4(oo) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(mm)-1	-	2000 Series A Trimble County Loan Agreement, dated August 1, 2000, by and between Louisville Gas and Electric Company, and County of Trimble, Kentucky (Exhibit 4(pp)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(mm)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Louisville Gas and Electric Company, and County of Trimble, Kentucky (Exhibit 4(pp)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(nn)-1	-	2001 Series A Trimble County Loan Agreement, dated November 1, 2001, by and between Louisville Gas and Electric Company, and County of Trimble, Kentucky (Exhibit 4(qq)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(nn)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Louisville Gas and Electric Company, and the County of Trimble, Kentucky (Exhibit 4(qq)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(oo)-1	-	2001 Series B Trimble County Loan Agreement, dated November 1, 2001, by and between Louisville Gas and Electric Company, and County of Trimble, Kentucky (Exhibit 4(rr)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(oo)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Louisville Gas and Electric Company, and County of Trimble, Kentucky (Exhibit 4(rr)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(pp)-1	-	2002 Series A Trimble County Loan Agreement, dated July 1, 2002, by and between Louisville Gas and Electric Company, and County of Trimble, Kentucky (Exhibit 4(ss)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(pp)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Louisville Gas and Electric Company, and County of Trimble, Kentucky (Exhibit 4(ss)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(qq)-1	-	2007 Series A Trimble County Loan Agreement, dated March 1, 2007, by and between Louisville Gas and Electric Company, and County of Trimble, Kentucky (Exhibit 4(tt)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(qq)-2	-	Amendment No. 1 dated September 1, 2010, to said Loan Agreement by and between Louisville Gas and Electric Company, and County of Trimble, Kentucky (Exhibit 4(tt)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
4(rr)-1	-	Indenture, dated April 21, 2011, between PPL WEM Holdings PLC, as Issuer, and The Bank of New York Mellon, as Trustee (Exhibit 10.2 to PPL Corporation Form 8-K Report (File No. 1-11459) dated April 21, 2011)
4(rr)-2	-	Supplemental Indenture No. 1, dated April 21, 2011, to said Indenture (Exhibit 10.3 to PPL Corporation Form 8-K Report (File No. 1-11459) dated April 21, 2011)

4(ss)-1	-	Trust Deed, dated April 27, 2011, by and among Western Power Distribution (East Midlands) plc and Western Power Distribution (West Midlands) plc, as Issuers, and HSBC Corporate Trustee Company (UK) Limited as Note Trustee (Exhibit 4.1 to PPL Corporation Form 8-K Report (File No.1-11459) dated May 17, 2011)
4(ss)-2	-	Final Terms of WPD West Midlands £800,000,000 5.75 per cent Notes due 2032 (Exhibit 1.1 to PPL Corporation Form 8-K Report (File No. 1-11459) dated May 17, 2011)
4(ss)-3	-	Final Terms of WPD East Midlands £600,000,000 5.25 per cent Notes due 2023 (Exhibit 1.2 to PPL Corporation Form 8-K Report (File No. 1-11459) dated May 17, 2011)
4(ss)-4	-	Final Terms of WPD East Midlands £100,000,000 Index Linked Notes due 2043 (Exhibit 1.1 to PPL Corporation Form 8-K Report (File No. 1-11459) dated June 2, 2011)
4(tt)	-	Agency Agreement, dated April 27, 2011, by and among Western Power Distribution (East Midlands) plc and Western Power Distribution (West Midlands) plc, as Issuers, and HSBC Corporate Trustee Company (UK) Limited and HSBC Bank plc (Exhibit 4.2 to PPL Corporation Form 8-K Report (File No. 1-11459) dated May 17, 2011)
4(uu)	-	Registration Rights Agreement, dated September 29, 2011, between LG&E and KU Energy LLC and the Initial Purchasers (Exhibit 4(b) to PPL Corporation Form 8-K Report (File No. 1-11459) dated September 30, 2011)
10(a)	-	Generation Supply Agreement, dated as of June 20, 2001, between PPL Electric Utilities Corporation and PPL EnergyPlus, LLC (Exhibit 10.5 to PPL Energy Supply, LLC Form S-4 (Registration Statement No. 333-74794))
10(b)-1	-	Master Power Purchase and Sale Agreement, dated as of October 15, 2001, between NorthWestern Energy Division (successor in interest to The Montana Power Company) and PPL Montana, LLC (Exhibit 10(g) to PPL Montana, LLC Form 10-K Report (File No. 333-50350) for the year ended December 31, 2001)
10(b)-2	-	Confirmation Letter, dated July 5, 2006, between PPL Montana, LLC and NorthWestern Corporation (PPL Corporation and PPL Energy Supply, LLC Form 8-K Reports (File Nos. 1-11459 and 333-74794) dated July 6, 2006)
10(c)	-	Guaranty, dated as of December 21, 2001, from PPL Energy Supply, LLC in favor of LMB Funding, Limited Partnership (Exhibit 10(j) to PPL Energy Supply, LLC Form 10-K Report (File No. 333-74794) for the year ended December 31, 2001)
10(d)-1	-	Agreement for Lease, dated as of December 21, 2001, between LMB Funding, Limited Partnership and Lower Mt. Bethel Energy, LLC (Exhibit 10(m) to PPL Energy Supply, LLC Form 10-K Report (File No. 333-74794) for the year ended December 31, 2003)
10(d)-2	-	Amendment No. 1 to said Agreement for Lease, dated as of September 16, 2002, between LMB Funding, Limited Partnership and Lower Mt. Bethel Energy, LLC (Exhibit 10(m)-1 to PPL Energy Supply, LLC Form 10-K Report (File No. 333-74794) for the year ended December 31, 2003)
10(e)-1	-	Lease Agreement, dated as of December 21, 2001, between LMB Funding, Limited Partnership and Lower Mt. Bethel Energy, LLC (Exhibit 10(n) to PPL Energy Supply, LLC Form 10-K Report (File No. 333-74794) for the year ended December 31, 2003)
10(e)-2	-	Amendment No. 1 to said Lease Agreement, dated as of September 16, 2002, between LMB Funding, Limited Partnership and Lower Mt. Bethel Energy, LLC (Exhibit 10(n)-1 to PPL Energy Supply, LLC Form 10-K Report (File No. 333-74794) for the year ended December 31, 2003)
10(f)	-	Facility Lease Agreement (BA 1/2) between PPL Montana, LLC and Montana OL3, LLC (Exhibit 4.7a to PPL Montana, LLC Form S-4 (Registration Statement No. 333-50350))

10(g)	-	Facility Lease Agreement (BA 3) between PPL Montana, LLC and Montana OL4, LLC (Exhibit 4.8a to PPL Montana, LLC Form S-4 (Registration Statement No. 333-50350))
10(h)	-	Services Agreement, dated as of July 1, 2000, among PPL Corporation, PPL Energy Funding Corporation and its direct and indirect subsidiaries in various tiers, PPL Capital Funding, Inc., PPL Gas Utilities Corporation, PPL Services Corporation and CEP Commerce, LLC (Exhibit 10.20 to PPL Energy Supply, LLC Form S-4 (Registration Statement No. 333-74794))
10(i)-1	-	Asset Purchase Agreement, dated as of June 1, 2004, by and between PPL Sundance Energy, LLC, as Seller, and Arizona Public Service Company, as Purchaser (Exhibit 10(a) to PPL Corporation and PPL Energy Supply, LLC Form 10-Q Reports (File Nos. 1-11459 and 333-74794) for the quarter ended June 30, 2004)
10(i)-2	-	Amendment No. 1, dated December 14, 2004, to said Asset Purchase Agreement (Exhibit 99.1 to PPL Corporation and PPL Energy Supply, LLC Form 8-K Reports (File Nos. 1-11459 and 333-74794) dated December 15, 2004)
10(j)-1	-	Receivables Sale Agreement, dated as of August 1, 2004, between PPL Electric Utilities Corporation, as Originator, and PPL Receivables Corporation, as Buyer (Exhibit 10(d) to PPL Electric Utilities Corporation Form 10-Q Report (File No. 1-905) for the quarter ended June 30, 2004)
10(j)-2	-	Amendment No. 1, dated as of August 5, 2008, to said Receivables Sale Agreement, between PPL Electric Utilities Corporation, as Originator, and PPL Receivables Corporation, as Buyer (Exhibit 10(b) to PPL Electric Utilities Corporation Form 8-K Report (File No. 1-905) dated August 6, 2008)
10(j)-3	-	Credit and Security Agreement, dated as of August 5, 2008, among PPL Receivables Corporation, PPL Electric Utilities Corporation, Victory Receivables Corporation, the Liquidity Banks from time to time party thereto and The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch (Exhibit 10(a) to PPL Electric Utilities Corporation Form 8-K Report (File No. 1-905) dated August 6, 2008)
10(j)-4	-	Amendment No. 1, dated as of July 28, 2009, to said Credit and Security Agreement (Exhibit 10(a) to PPL Electric Utilities Corporation Form 10-Q Report (File No. 1-905) for the quarter ended September 30, 2009)
10(j)-5	-	Amendment No. 2, dated as of July 27, 2010, to said Credit and Security Agreement (Exhibit 10(g) to PPL Electric Utilities Corporation Form 10-Q Report (File No. 1-905) for the quarter ended June 30, 2010)
10(j)-6	-	Amendment No. 3, dated as of December 23, 2010, to said Credit and Security Agreement (Exhibit 10(j)-6 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
10(j)-7	-	Amendment No. 4, dated as of March 31, 2011, to said Credit and Security Agreement (Exhibit 10(c) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended March 31, 2011)
10(j)-8	-	Amendment No. 5, dated as of July 26, 2011, to said Credit and Security Agreement (Exhibit 10(c) to PPL Corporation Form 10-Q/A Report (File No. 1-11459) for the quarter ended June 30, 2011)
10(k)-1	-	Reimbursement Agreement, dated as of March 31, 2005, among PPL Energy Supply, LLC, The Bank of Nova Scotia, as Issuer and Administrative Agent, and the Lenders party thereto from time to time (Exhibit 10(a) to PPL Energy Supply, LLC Form 10-Q Report (File No. 333-74794) for the quarter ended March 31, 2005)
10(k)-2	-	First Amendment, dated as of June 16, 2005, to said Reimbursement Agreement (Exhibit 10(b) to PPL Energy Supply, LLC Form 10-Q Report (File No. 333-74794) for the quarter ended June 30, 2005)

10(k)-3	-	Second Amendment, dated as of September 1, 2005, to said Reimbursement Agreement (Exhibit 10(a) to PPL Energy Supply, LLC Form 10-Q Report (File No. 333-74794) for the quarter ended September 30, 2005)
10(k)-4	-	Third Amendment, dated as of March 30, 2006, to said Reimbursement Agreement (Exhibit 10(a) to PPL Energy Supply, LLC Form 8-K Report (File No. 333-74794) dated April 5, 2006)
10(k)-5	-	Fourth Amendment, dated as of April 12, 2006, to said Reimbursement Agreement (Exhibit 10(b) to PPL Energy Supply, LLC Form 10-Q Report (File No. 333-74794) for the quarter ended September 30, 2006)
10(k)-6	-	Fifth Amendment, dated as of November 1, 2006, to said Reimbursement Agreement (Exhibit 10(q)-6 to PPL Energy Supply, LLC Form 10-K Report (File No. 333-74794) for the year ended December 31, 2006)
10(k)-7	-	Sixth Amendment, dated as of March 29, 2007, to said Reimbursement Agreement (Exhibit 10(q)-7 to PPL Energy Supply, LLC Form 10-K Report (File No. 333-74794) for the year ended December 31, 2007)
10(k)-8	-	Seventh Amendment, dated as of March 1, 2008, to said Reimbursement Agreement (Exhibit 10(a) to PPL Energy Supply, LLC Form 10-Q Report (File No. 333-74794) for the quarter ended March 31, 2008)
10(k)-9	-	Eighth Amendment, dated as of March 30, 2009, to said Reimbursement Agreement (Exhibit 10(a) to PPL Energy Supply, LLC Form 10-Q Report (File No. 1-32944) for the quarter ended March 31, 2009)
10(k)-10	-	Ninth Amendment, dated as of March 31, 2010, to said Reimbursement Agreement (Exhibit 99.1 to PPL Energy Supply, LLC Form 8-K Report (File No. 1-32944) dated April 6, 2010)
*10(k)-11	-	Tenth Amendment, dates as of February 22, 2012, to said Reimbursement Agreement
10(l)-1	-	$200,000,000 Revolving Credit Agreement, dated as of December 31, 2010, among PPL Electric Utilities Corporation, the Lenders party thereto and Wells Fargo Bank, National Association, as Administrative Agent, Swingline Lender and Issuing Lender (Exhibit 10.1 to PPL Electric Utilities Corporation Form 8-K Report (File No. 1-905) dated January 6, 2011)
10(l)-2	-	Amendment No. 1, dated as of October 19, 2011, to said Revolving Credit Agreement (Exhibit 10.2 to PPL Corporation Form 8-K Report (File No. 1-11459) dated October 25, 2011)
10(m)-1	-	$4,000,000,000 Revolving Credit Agreement, dated as of October 19, 2010, among PPL Energy Supply, LLC, the Lenders party thereto and Wells Fargo Bank, National Association, as Administrative Agent, Swingline Lender and Issuing Lender (Exhibit 10.1 to PPL Energy Supply, LLC Form 8-K Report (File No. 1-32944) dated October 21, 2010)
10(m)-2	-	Notice of Reduction to said Revolving Credit Agreement, dated November 17, 2010, effective as of December 1, 2010 (Exhibit 10(p)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
10(m)-3	-	Amendment No. 1, dated as of October 19, 2011, to said Revolving Credit Agreement (Exhibit 10.1 to PPL Corporation Form 8-K Report (File No. 1-11459) dated October 25, 2011)
10(n)	-	£150 million Credit Agreement, dated as of January 24, 2007, among Western Power Distribution Holdings Limited and the banks named therein (Exhibit 10(y) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2006)
10(o)	-	£210 million Multicurrency Revolving Facility Agreement, dated July 7, 2009, between Western Power Distribution (South West) plc and HSBC Bank plc, Lloyds TSB Bank plc and Clydesdale Bank plc (Exhibit 10(c) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended June 30, 2009)

10(p)	-	Purchase and Sale Agreement, dated as of April 28, 2010, by and between E.ON US Investments Corp., PPL Corporation and E.ON AG (Exhibit No. 99.1 to PPL Corporation Form 8-K Report (File No. 1-11459) dated April 30, 2010)
10(q)	-	$500 million Facility Agreement, dated as of May 14, 2010, among PPL Energy Supply, LLC, as Borrower, and Morgan Stanley Bank, as Issuer (Exhibit 10(b) to PPL Energy Supply, LLC Form 10-Q Report (File No. 1-32944) for the quarter ended June 30, 2010)
10(r)	-	Purchase and Sale Agreement, dated as of September 9, 2010, by and between PPL Holtwood, LLC and LSP Safe Harbor Holdings, LLC (Exhibit 10.1 to PPL Corporation Form 8-K Report (File No. 1-11459) dated September 13, 2010)
10(s)	-	Purchase and Sale Agreement, dated as of September 9, 2010, by and between PPL Generation, LLC and Harbor Gen Holdings, LLC (Exhibit 10.2 to PPL Corporation Form 8-K Report (File No. 1-11459) dated September 13, 2010)
10(t)	-	Open-End Mortgage, Security Agreement and Fixture Filing from PPL Montour, LLC to Wilmington Trust FSB, as Collateral Agent, dated as of October 26, 2010 (Exhibit 10(w) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
10(u)	-	Open-End Mortgage, Security Agreement and Fixture Filing from PPL Brunner Island, LLC to Wilmington Trust FSB, as Collateral Agent, dated as of October 26, 2010 (Exhibit 10(x) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
10(v)	-	Guaranty of PPL Montour, LLC and PPL Brunner Island, LLC, dated as of November 3, 2010, in favor of Wilmington Trust FSB, as Collateral Agent, for itself as Beneficiary and for the Secured Counterparties described therein (Exhibit 10 (y) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2010)
10(w)-1	-	$400,000,000 Revolving Credit Agreement, dated as of November 1, 2010, among Kentucky Utilities Company, the Lenders party thereto and Wells Fargo Bank, National Association, as Administrative Agent, Swingline Lender and Issuing Lender (Exhibit 10.1 to PPL Corporation Form 8-K Report (File No. 1-11459) dated November 1, 2010)
10(w)-2	-	Amendment No.1, dated as of June 13, 2011, to said Revolving Credit Agreement (Exhibit 10(a) to PPL Corporation Form 10-Q/A Report (File No. 1-11459) for the quarter ended June 30, 2011)
10(w)-3	-	Amendment No. 2, dated as of October 19, 2011, to said Revolving Credit Agreement (Exhibit 10.4 to PPL Corporation Form 8-K Report (File No. 1-11459) dated October 25, 2011)
10(x)-1	-	$400,000,000 Revolving Credit Agreement, dated as of November 1, 2010, among Louisville Gas and Electric Company, the Lenders party thereto and Wells Fargo Bank, National Association, as Administrative Agent, Swingline Lender and Issuing Lender (Exhibit 10.2 to PPL Corporation Form 8-K Report (File No. 1-11459) dated November 1, 2010)
10(x)-2	-	Amendment No. 1, dated as of June 13, 2011, to said Revolving Credit Agreement (Exhibit 10(b) to PPL Corporation Form 10-Q/A Report (File No. 1-11459) for the quarter ended June 30, 2011)
10(x)-3	-	Amendment No. 2, dated as of October 19, 2011, to said Revolving Credit Agreement (Exhibit 10.3 to PPL Corporation Form 8-K Report (File No. 1-11459) dated October 25, 2011)
10(y)-1	-	£3,600,000,000 Senior Bridge Term Loan Credit Agreement, dated as of March 25, 2011, among PPL Capital Funding, Inc. and PPL WEM Holdings PLC (f/k/a WPD Investment Holdings Limited), as Borrowers, PPL, as Guarantor, the lenders from time to time party thereto and Bank of America, N.A., as Administrative Agent, Credit Suisse, AG, as Syndication Agent, and Merrill Lynch, Pierce, Fenner & Smith Incorporation and Credit Suisse Securities (USA) LLC as Joint Lead Arrangers and Joint Bookrunners (Exhibit 10.1 to PPL Corporation Form 8-K Report (File No. 1-11459) dated March 29, 2011)

10(y)-2	-	Amendment No. 1, dated April 15, 2011, to said Senior Bridge Term Loan Credit Agreement (Exhibit 10.1 to PPL Corporation Form 8-K Report (File No. 1-11459) dated April 19, 2011)
10(z)	-	£300,0000,000 Multicurrency Revolving Credit Facility Agreement, dated April 4, 2011, among Western Power Distribution (West Midlands) plc and Royal Bank of Canada as Lead Arranger, Bank of America Securities Limited as Bookrunner and Facility Agent, Bank of America, N.A. as Issuing Bank and the other banks party thereto as Mandated Lead Arrangers (Exhibit 10.1 to PPL Corporation Form 8-K Report (File No. 1-11459) dated April 8, 2011)
10(aa)	-	£300,000,000 Multicurrency Revolving Credit Facility Agreement, dated April 4, 2011, among Western Power Distribution (East Midlands) plc and Royal Bank of Canada as Lead Arranger, Bank of America Securities Limited as Bookrunner and Facility Agent, Bank of America, N.A. as Issuing Bank and the other banks party thereto as Mandated Lead Arrangers (Exhibit 10.2 to PPL Corporation Form 8-K Report (File No. 1-11459) dated April 8, 2011)
10(bb)-1	-	$198,309,583.05 Letter of Credit Agreement, dated as of April 29, 2011, among Kentucky Utilities Company, as Borrowers, and Banco Bilbao Vizcaya Argentaria, S.A., New York Branch, as Administrative Agent and the lenders and letter of credit issuing banks party thereto from time to time (Exhibit 10.1 to PPL Corporation Form 8-K Report (File No. 1-11459) dated May 2, 2011)
10(bb)-2	-	Amendment No. 1, dated as of August 2, 2011, to said Letter of Credit Agreement (Exhibit 10(d) to PPL Corporation Form 10-Q/A Report (File No. 1-11459) for the quarter ended June 30, 2011)
10(cc)	-	£245,000,000 Revolving Credit Facility Agreement, dated January 12, 2012, among Western Power Distribution (South West) plc, the lenders party thereto and Lloyds TSB Bank Plc and Mizuho Corporate Bank, Ltd. as Joint Coordinators (Exhibit 10.1 to PPL Corporation Form 8-K Report (File No. 1-11459) dated January 18, 2012)
[_]10(dd)-1	-	Amended and Restated Directors Deferred Compensation Plan, dated June 12, 2000 (Exhibit 10(h) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2000)
[_]10(dd)-2	-	Amendment No. 1 to said Directors Deferred Compensation Plan, dated December 18, 2002 (Exhibit 10(m)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2002)
[_]10(dd)-3	-	Amendment No. 2 to said Directors Deferred Compensation Plan, dated December 4, 2003 (Exhibit 10(q)-2 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2003)
[_]10(dd)-4	-	Amendment No. 3 to said Directors Deferred Compensation Plan, dated as of January 1, 2005 (Exhibit 10(cc)-4 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2005)
[_]10(dd)-5	-	Amendment No. 4 to said Directors Deferred Compensation Plan, dated as of May 1, 2008 (Exhibit 10(x)-5 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2008)
[_]10(dd)-6	-	Amendment No. 5 to said Directors Deferred Compensation Plan, dated May 28, 2010 (Exhibit 10(a) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended June 30, 2010)
[_]10(ee)-1	-	Trust Agreement, dated as of April 1, 2001, between PPL Corporation and Wachovia Bank, N.A. (as successor to First Union National Bank), as Trustee
[_]10(ee)-2	-	Trust Agreement, dated as of March 20, 2007, between PPL Corporation and Wachovia Bank, N.A., as Trustee (Exhibit 10(c) to PPL Corporation Form 10-Q Report (File No. 1-1149) for the quarter ended March 31, 2007)

[_]10(ee)-3	-	Trust Agreement, dated as of March 20, 2007, between PPL Corporation and Wachovia Bank, N.A., as Trustee (Exhibit 10(d) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended March 31, 2007)
[_]10(ee)-4	-	Trust Agreement, dated as of March 20, 2007, between PPL Corporation and Wachovia Bank, N.A., as Trustee (Exhibit 10(e) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended March 31, 2007)
[_]10(ff)-1	-	Amended and Restated Officers Deferred Compensation Plan, dated December 8, 2003 (Exhibit 10(r) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2003)
[_]10(ff)-2	-	Amendment No. 1 to said Officers Deferred Compensation Plan, dated as of January 1, 2005 (Exhibit 10(ee)-1 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2005)
[_]10(ff)-3	-	Amendment No. 2 to said Officers Deferred Compensation Plan, dated as of January 22, 2007 (Exhibit 10(bb)-3 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2006)
[_]10(ff)-4	-	Amendment No. 3 to said Officers Deferred Compensation Plan, dated as of June 1, 2008 (Exhibit 10(z)-4 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2008)
*[_]10(ff)-5	-	Amendment No. 4 to said Officers Deferred Compensation Plan, dated as of February 15, 2012
[_]10(gg)-1	-	Amended and Restated Supplemental Executive Retirement Plan, dated December 8, 2003 (Exhibit 10(s) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2003)
[_]10(gg)-2	-	Amendment No. 1 to said Supplemental Executive Retirement Plan, dated December 16, 2004 (Exhibit 99.1 to PPL Corporation Form 8-K Report (File No. 1-11459) dated December 17, 2004)
[_]10(gg)-3	-	Amendment No. 2 to said Supplemental Executive Retirement Plan, dated as of January 1, 2005 (Exhibit 10(ff)-3 to PPL Corporation Form 10-K Report (File 1-11459) for the year ended December 31, 2005)
[_]10(gg)-4	-	Amendment No. 3 to said Supplemental Executive Retirement Plan, dated as of January 22, 2007 (Exhibit 10(cc)-4 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2006)
[_]10(gg)-5	-	Amendment No. 4 to said Supplemental Executive Retirement Plan, dated as of December 9, 2008 (Exhibit 10(aa)-5 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2008)
*[_]10(gg)-6	-	Amendment No. 5 to said Supplemental Executive Retirement Plan, dated as of February 15, 2012
[_]10(hh)-1	-	Amended and Restated Incentive Compensation Plan, effective January 1, 2003 (Exhibit 10(p) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2002)
[_]10(hh)-2	-	Amendment No. 1 to said Incentive Compensation Plan, dated as of January 1, 2005 (Exhibit 10(gg)-2 to PPL Corporation Form 10-K Report (File 1-11459) for the year ended December 31, 2005)
[_]10(hh)-3	-	Amendment No. 2 to said Incentive Compensation Plan, dated as of January 26, 2007 (Exhibit 10(dd)-3 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2006)
[_]10(hh)-4	-	Amendment No. 3 to said Incentive Compensation Plan, dated as of March 21, 2007 (Exhibit 10(f) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended March 31, 2007)

[_]10(hh)-5	-	Amendment No. 4 to said Incentive Compensation Plan, effective December 1, 2007 (Exhibit 10(a) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended September, 30, 2008)
[_]10(hh)-6	-	Amendment No. 5 to said Incentive Compensation Plan, dated as of December 16, 2008 (Exhibit 10(bb)-6 to PPL Corporation Form 10-K Report (File 1-11459) for the year ended December 31, 2008)
[_]10(hh)-7	-	Form of Stock Option Agreement for stock option awards under the Incentive Compensation Plan (Exhibit 10(a) to PPL Corporation Form 8-K Report (File No. 1-11459) dated February 1, 2006)
[_]10(hh)-8	-	Form of Restricted Stock Unit Agreement for restricted stock unit awards under the Incentive Compensation Plan (Exhibit 10(b) to PPL Corporation Form 8-K Report (File No. 1-11459) dated February 1, 2006)
[_]10(hh)-9	-	Form of Restricted Stock Unit Agreement for restricted stock unit awards under the Incentive Compensation Plan pursuant to PPL Corporation Cash Incentive Premium Exchange Program (Exhibit 10(c) to PPL Corporation Form 8-K Report (File No. 1-11459) dated February 1, 2006)
[_]10(ii)-1	-	Amended and Restated Incentive Compensation Plan for Key Employees, effective January 1, 2003 (Schedule B to Proxy Statement of PPL Corporation, dated March 17, 2003)
[_]10(ii)-2	-	Amendment No. 1 to said Incentive Compensation Plan for Key Employees, dated as of January 1, 2005 (Exhibit (hh)-1 to PPL Corporation Form 10-K Report (File 1-11459) for the year ended December 31, 2005
[_]10(ii)-3	-	Amendment No. 2 to said Incentive Compensation Plan for Key Employees, dated as of January 26, 2007 (Exhibit 10 (ee)-3 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2006)
[_]10(ii)-4	-	Amendment No. 3 to said Incentive Compensation Plan for Key Employees, dated as of March 21, 2007 (Exhibit 10(q) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended March 31, 2007)
[_]10(ii)-5	-	Amendment No. 4 to said Incentive Compensation Plan for Key Employees, dated as of December 15, 2008 (Exhibit 10 (cc)-5 to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2008)
[_]10(ii)-6	-	Amendment No. 5 to said Incentive Compensation Plan for Key Employees, dated as of March 24, 2011 (Exhibit 10(a) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended March 31, 2011)
[_]10(jj)	-	Short-term Incentive Plan (Schedule A to Proxy Statement of PPL Corporation, dated April 6, 2011)
[_]10(kk)	-	Agreement, dated January 15, 2003, between PPL Corporation and Mr. Miller regarding Supplemental Pension Benefits (Exhibit 10(u) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2002)
[_]10(ll)	-	Employment letter, dated May 31, 2006, between PPL Services Corporation and William H. Spence (Exhibit 10(pp) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2006)
[_]10(mm)	-	Amendments to certain compensation programs and arrangements for Named Executive Officers of PPL Corporation and PPL Electric Utilities Corporation and compensation arrangement changes for non-employee Directors of PPL Corporation (PPL Corporation and PPL Electric Utilities Corporation Form 8-K Reports (File Nos. 1-11459 and 1-905) dated November 1, 2006)
[_]10(nn)	-	Form of Retention Agreement entered into between PPL Corporation and Messrs. Farr and Miller (Exhibit 10(h) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended March 31, 2007)

[_]10(oo)-1	-	Form of Severance Agreement entered into between PPL Corporation and the Named Executive Officers (Exhibit 10(i) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended March 31, 2007)
[_]10(oo)-2	-	Amendment to said Severance Agreement (Exhibit 10(a) to PPL Corporation Form 10-Q Report (File No. 1-11459) for the quarter ended June 30, 2009)
[_]10(pp)	-	Form of Performance Unit Agreement entered into between PPL Corporation and the Named Executive Officers (Exhibit 10(ss) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2007)
[_]10(qq)	-	Retention Agreement, effective as of December 1, 2010, entered into between PPL Corporation and Victor A. Staffieri (Exhibit 10(rr) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2011)
[_]10(rr)	-	Amended and Restated Employment and Severance Agreement, dated as of October 29, 2010, between E.ON U.S. LLC and Victor A. Staffieri (Exhibit 10(ss) to PPL Corporation Form 10-K Report (File No. 1-11459) for the year ended December 31, 2011)
*12(a)	-	PPL Corporation and Subsidiaries Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends
*12(b)	-	PPL Energy Supply, LLC and Subsidiaries Computation of Ratio of Earnings to Fixed Charges
*12(c)	-	PPL Electric Utilities Corporation and Subsidiaries Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends
*12(d)	-	LG&E and KU Energy LLC and Subsidiaries Computation of Ratio of Earnings to Fixed Charges
*12(e)	-	Louisville Gas and Electric Company Computation of Ratio of Earnings to Fixed Charges
*12(f)	-	Kentucky Utilities Company Computation of Ratio of Earnings to Fixed Charges
*21	-	Subsidiaries of PPL Corporation
*23(a)	-	Consent of Ernst & Young LLP - PPL Corporation
*23(b)	-	Consent of Ernst & Young LLP - PPL Energy Supply, LLC
*23(c)	-	Consent of Ernst & Young LLP - PPL Electric Utilities Corporation
*23(d)	-	Consent of PricewaterhouseCoopers LLP - PPL Corporation
*24	-	Power of Attorney
*31(a)	-	Certificate of PPL's principal executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31(b)	-	Certificate of PPL's principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31(c)	-	Certificate of PPL Energy Supply's principal executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

*31(d)	-	Certificate of PPL Energy Supply's principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31(e)	-	Certificate of PPL Electric's principal executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31(f)	-	Certificate of PPL Electric's principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31(g)	-	Certificate of LKE's principal executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31(h)	-	Certificate of LKE's principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31(i)	-	Certificate of LG&E's principal executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31(j)	-	Certificate of LG&E's principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31(k)	-	Certificate of KU's principal executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31(l)	-	Certificate of KU's principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32(a)	-	Certificate of PPL's principal executive officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32(b)	-	Certificate of PPL's principal financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32(c)	-	Certificate of PPL Energy Supply's principal executive officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32(d)	-	Certificate of PPL Energy Supply's principal financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32(e)	-	Certificate of PPL Electric's principal executive officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32(f)	-	Certificate of PPL Electric's principal financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32(g)	-	Certificate of LKE's principal executive officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32(h)	-	Certificate of LKE's principal financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32(i)	-	Certificate of LG&E's principal executive officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

*32(j)	-	Certificate of LG&E's principal financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32(k)	-	Certificate of KU's principal executive officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32(l)	-	Certificate of KU's principal financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	-	XBRL Instance Document for PPL Corporation, PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company
101.SCH	-	XBRL Taxonomy Extension Schema for PPL Corporation, PPL Corporation, PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company
101.CAL	-	XBRL Taxonomy Extension Calculation Linkbase for PPL Corporation, PPL Corporation, PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company
101.DEF	-	XBRL Taxonomy Extension Definition Linkbase for PPL Corporation, PPL Corporation, PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company
101.LAB	-	XBRL Taxonomy Extension Label Linkbase for PPL Corporation, PPL Corporation, PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company
101.PRE	-	XBRL Taxonomy Extension Presentation Linkbase for PPL Corporation, PPL Corporation, PPL Energy Supply, LLC, PPL Electric Utilities Corporation, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company

CERTIFICATE OF AMENDMENT

OF

PPL ENERGY SUPPLY, LLC

1. The name of the limited liability company is PPL Energy Supply, LLC.

2. The Certificate of Formation of the limited liability company is hereby amended as follows:

SECOND: The address of its registered office in the State of Delaware is to be Corporation Trust Company, 1209 Orange Street, Wilmington, County of New Castle, Delaware 19801, and its registered agent at such address is Corporation Trust Company.

IN WITNESS WHEREOF, the undersigned has executed this Certificate of Amendment of PPL Energy Supply, LLC this ______ day of November, 2002.

By: ____________________________
Michael A. McGrail
Secretary

Exhibit 4(ee)-3

EXECUTION COPY

LOUISVILLE/JEFFERSON COUNTY METRO GOVERNMENT, KENTUCKY

AND

LOUISVILLE GAS AND ELECTRIC COMPANY

A Kentucky Corporation

* * * * *

AMENDMENT NO. 2 TO AMENDED AND RESTATED LOAN AGREEMENT IN CONNECTION WITH POLLUTION CONTROL FACILITIES

* * * * *

Dated as of October 1, 2011

* * * * *

NOTICE: The interest of the Louisville/Jefferson County Metro Government, Kentucky in and to this Amendment No. 2 to Amended and Restated Loan Agreement has been assigned to The Bank of New York Mellon, as Trustee, under the Second Amended and Restated Indenture of Trust dated as of October 1, 2011.

TABLE OF CONTENTS

ARTICLE I AMENDMENTS TO THE LOAN AGREEMENT		3
Section 1.1.	Amendment of Section 1.02. Incorporation of Certain Terms by Reference	
Section 1.2.	Amendment of Section 1.03 Additional Definitions	3
Section 1.3.	Amendment of Section 10.3. Obligations to Prepay Loan	3
ARTICLE II REPRESENTATIONS, WARRANTIES AND COVENANTS		3
Section 2.1.	Representations, Warranties and Covenants by the Issuer	6
Section 2.2.	Representations, Warranties and Covenants by the Company	6
ARTICLE III MISCELLANEOUS		6
Section 3.1.	Term of Amendment No. 2 to Loan Agreement	7
Section 3.2.	Ratification	7
Section 3.3.	Effective Date	7
Section 3.4.	Binding Effect	7
Section 3.5.	Severability	7
Section 3.6.	Execution in Counterparts	7
Section 3.7.	Applicable Law	7
Section 3.8.	Captions	8
Section 3.9.	No Pecuniary Liability of Issuer	8

THIS AMENDMENT NO. 2 TO AMENDED AND RESTATED LOAN AGREEMENT, dated as of October 1, 2011 (this "Amendment No. 2 to Loan Agreement"), by and between the LOUISVILLE/JEFFERSON COUNTY METRO GOVERNMENT, KENTUCKY, the governmental successor in interest by operation of law to the County of Jefferson, Kentucky, being a public body corporate and politic duly created and existing as a de jure political subdivision under the Constitution and laws of the Commonwealth of Kentucky, and LOUISVILLE GAS AND ELECTRIC COMPANY, a corporation organized and existing under the laws of the Commonwealth of Kentucky.

WITNESSETH:

WHEREAS, the Louisville/Jefferson County Metro Government, Kentucky (the "Metro Government" or "Issuer") is the governmental successor in interest by operation of law to the County of Jefferson, Kentucky and constitutes a public body corporate and politic duly created and existing as a de jure political subdivision under the Constitution and laws of the Commonwealth of Kentucky, and pursuant to the provisions of Chapter 67C and Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "Act"), the Issuer has the power to enter into the transactions contemplated by this Amendment No. 2 to Loan Agreement and to carry out its obligations hereunder; and

WHEREAS, Issuer came into legal existence on January 6, 2003, by operation of law and voter approval in accordance with laws now codified as Chapter 67C of the Kentucky Revised Statutes and replaced and superseded the prior governments of both the City of Louisville, Kentucky and the County of Jefferson, Kentucky (the "Predecessor County") and pursuant to law has mandatorily assumed all existing contracts and obligations of the former City and County and has been endowed with all powers of each of such former City and County; and

WHEREAS, the Metro Government, as successor to the Predecessor County, is authorized pursuant to the Act to issue negotiable bonds and lend the proceeds from the sale of such bonds to a utility company to finance and refinance the acquisition of "pollution control facilities," as defined by the Act ("Pollution Control Facilities"), for the abatement and control of air pollution and to refund bonds of the Predecessor County which were previously issued for any of such purposes; and

WHEREAS, on May 19, 2000, the Issuer, at the request of Louisville Gas and Electric Company (the "Company"), issued its Pollution Control Revenue Bonds, 2000 Series A (Louisville Gas and Electric Company Project) in the original principal amount of $25,000,000 (the "Bonds" or "2000 Series A Bonds"), pursuant to the Indenture of Trust dated as of May 1, 2000, with The Bank of New York Mellon, as Trustee, Paying Agent and Bond Registrar (the "Trustee"), which Indenture of Trust was amended and restated pursuant to the Amended and Restated Indenture of Trust dated as of September 1, 2008, between the Issuer and the Trustee, and has been further amended and supplemented pursuant to the Supplemental Indenture No. 1 to Amended and Restated Indenture of Trust dated as of September 1, 2010, between the Issuer and the Trustee (collectively, "Original Indenture of Trust"), and the Issuer loaned the proceeds of the 2000 Series A Bonds to the Company pursuant to the Loan Agreement dated as of May 1, 2000, between the Issuer and the Company, which Loan Agreement was amended and restated pursuant to the Amended and Restated Loan Agreement dated as of September 1, 2008, between the Issuer and the Company, and has been further amended and supplemented pursuant to the Amendment No. 1 to Loan Agreement dated as of September 1, 2010, between the Issuer and the Company (collectively, the "Loan Agreement"); and

WHEREAS, pursuant to Section 13.01 of the Original Indenture of Trust, the consent of the holders of the 2000 Series A Bonds is not required for the Issuer and the Company to enter into an amendment to the Loan Agreement in order to conform the Loan Agreement with changes and modifications to the Original Indenture of Trust made pursuant to Section 12.01 of the Original Indenture of Trust; and

WHEREAS, it is now appropriate and necessary that the Loan Agreement be amended pursuant to Section 13.01 of the Original Indenture of Trust in order to permit the Bonds to be converted to a mode that will allow for the 2000 Series A Bonds to be purchased by the Purchaser (as hereinafter defined) and to bear interest at the rates applicable during a "LIBOR Index Rate Period", as more particularly described and provided for in the Second Amended and Restated Indenture of Trust dated as of October 1, 2011, between the Issuer and Trustee (the "Indenture" or "Indenture of Trust"); and

WHEREAS, pursuant to and in accordance with the provisions of the Act and an Ordinance duly adopted by the Issuer on [October 27,] 2011, and in furtherance of the purposes of the Act and at the request of the Company, the Issuer has determined to enter into this Amendment No. 2 to Loan Agreement; and

WHEREAS, the Issuer and the Trustee have entered into the Second Amended and Restated Indenture of Trust between the Issuer and the Trustee of even date (the "Indenture of Trust") herewith pursuant to ARTICLE XII of the Original Indenture of Trust; and

WHEREAS, the Company shall cause to be delivered to the Issuer and the Trustee the opinion of Bond Counsel required under ARTICLE XIII of the Indenture of Trust concurrently with the execution and delivery of this Amendment No. 2 to Loan Agreement; and

WHEREAS, all acts, conditions and things required by the Constitution and laws of the Commonwealth of Kentucky and by the requirements of the Issuer to happen, exist and be performed precedent to and in the execution and delivery of this Amendment No. 2 to Loan Agreement have happened, have existed and have been performed as so required in order to make this Amendment No. 2 to Loan Agreement a valid and binding loan agreement for the security of the holders of the 2000 Series A Bonds and for the payment of all amounts due under the Loan Agreement and this Amendment No. 2 to Loan Agreement in accordance with their respective terms.

NOW, THEREFORE, FOR AND IN CONSIDERATION OF THE PREMISES AND THE MUTUAL COVENANTS AND AGREEMENTS HEREINAFTER CONTAINED, THE PARTIES HERETO AGREE EACH WITH THE OTHER AS FOLLOWS:

ARTICLE I

AMENDMENTS TO THE LOAN AGREEMENT

Section 1.1. Amendment of Section 1.02. Incorporation of Certain Terms by Reference. The following defined terms are hereby added to Section 1.02 of the Loan Agreement and shall have the meanings set forth in ARTICLE I of the Indenture of Trust:

"Bank"
"Base Rate"
"Bond Purchase and Bank Covenants Agreement"
"Default Rate"
"Federal Funds Open Rate"
"Governmental Authority"
"Initial Libor Index Rate Period"
"LIBOR"
"LIBOR Applicable Rating Level"
"LIBOR Index Rate"
"LIBOR Index Rate Period"
"LIBOR Margin"
"Margin Rate Factor"
"Maximum Federal Corporate Tax Rate"
"Prime Rate"
"Purchaser"

Section 1.2. Amendment of Section 1.03 Additional Definitions. In addition to the terms whose definitions are incorporated by reference herein pursuant to ARTICLE I of the Indenture of Trust, the following terms shall have the meanings set forth in this Section unless the use or context clearly indicates otherwise:

"Taxable Period" means, with respect to the 2000 Series A Bonds, the period which elapses from the date on which the interest on the 2000 Series A Bonds is includable in the gross income of the holders thereof as a result of a Determination of Taxability to and including the mandatory purchase date for the 2000 Series A Bonds as a result of such Determination of Taxability.

"Taxable Rate" means LIBOR plus the LIBOR Margin.

Section 1.3. Amendment of Section 10.3. Obligations to Prepay Loan. Section 10.3 of the Loan Agreement is hereby amended and restated to read as follows:

Section 10.3 Obligations to Prepay Loan.

(a) Mandatory Redemption Upon Determination of Taxability. Company shall be obligated to prepay the entire Loan or any part thereof, as provided below, prior to the required full payment of the 2000 Series A Bonds (or prior to making provision for payment thereof in accordance with the Indenture) on the 180th day (or such earlier date as may be designated by Company), which, in every case, must be a Business Day, upon the occurrence of a Determination of Taxability. The Issuer and Company shall take all actions required to mandatorily redeem the 2000 Series A Bonds at the cost of the Company upon the terms specified in this Agreement and in Article IV of the Indenture following the occurrence of a Determination of Taxability, including, but not limited to, prepaying appropriate amounts due on the 2000 Series A Bonds in order to effect such redemption. The 2000 Series A Bonds shall be redeemed by the Issuer, in whole, or in such part as described below, at a redemption price equal to 100% of the principal amount thereof, without redemption premium, plus accrued interest, if any, to the redemption date, within 180 days following a Determination of Taxability. For purposes of this section, a "Determination of Taxability" shall mean the receipt by the Trustee of written notice from a current or former registered owner of a 2000 Series A Bond or from the Company or the Issuer of (i) the issuance of a published or private ruling or a technical advice memorandum by the Internal Revenue Service in which the Company participated or has been given the opportunity to participate, and which ruling or memorandum the Company, in its discretion, does not contest or from which no further right of administrative or judicial review or appeal exists, or (ii) a final determination from which no further right of appeal exists of any court of competent jurisdiction in the United States in a proceeding in which the Company has participated or has been a party, or has been given the opportunity to participate or be a party, in each case, to the effect that as a result of a failure by the Company to perform or observe any covenant or agreement or the inaccuracy of any representation contained in this Agreement or any other agreement or certificate delivered in connection with the 2000 Series A Bonds, the interest on the 2000 Series A Bonds is included in the gross income of the owners thereof for federal income tax purposes, other than with respect to a person who is a "substantial user" or a "related person" of a substantial user within the meaning of the Section 147 of Internal Revenue Code of 1986, as amended (the "Code"); provided, however, that no such Determination of Taxability shall be considered to exist as a result of the Trustee receiving notice from a current or former registered owner of a 2000 Series A Bond or from the Issuer unless (i) the Issuer or the registered owner or former registered owner of the 2000 Series A Bond involved in such proceeding or action (A) gives the Company and the Trustee prompt notice of the commencement thereof, and (B) (if the Company agrees to pay all expenses in connection therewith) offers the Company the opportunity to control unconditionally the defense thereof, and (ii) either (A) the Company does not agree within 30 days of receipt of such offer to pay such expenses and liabilities and to control such defense, or (B) the Company shall exhaust or choose not to exhaust all available proceedings for the contest, review, appeal or rehearing of such decree, judgment or action which the Company determines to be appropriate. No Determination of Taxability described above will result from the inclusion of interest on any 2000 Series A Bond in the computation of minimum or indirect taxes. All of the 2000 Series A Bonds shall be redeemed upon a Determination of Taxability as described above unless, in the opinion of Bond Counsel, redemption of a portion of the 2000 Series A Bonds of one or more series or one or more maturities would have the result that interest payable on the remaining 2000 Series A Bonds outstanding after the redemption would not be so included in any such gross income.

In the event any of the Issuer, the Company or the Trustee has been put on notice or becomes aware of the existence or pendency of any inquiry, audit or other proceedings relating to the 2000 Series A Bonds being conducted by the Internal Revenue Service, the party so put on notice shall give immediate written notice to the other parties of such matters.

Promptly upon learning of the occurrence of a Determination of Taxability (whether or not the same is being contested), or any of the events described in this Section 10.3(a), the Company shall give notice thereof to the Trustee and the Issuer.

(b) In the case of the mandatory obligation of Company to prepay the Loan or any part thereof after the occurrence of a Determination of Taxability, pursuant to Section 10.3(a) hereof, Company shall be obligated to prepay such Loan or such part thereof not later than 180 days after any such final determination as specified in Section 10.3(a) hereof and to provide to Trustee for deposit in the Bond Fund an amount sufficient, together with other funds deposited with the Trustee and available for such purpose, to redeem such 2000 Series A Bonds at the price of 100% of the principal amount thereof in accordance with Section 5.1 hereof plus interest accrued and to accrue to the date of redemption of the 2000 Series A Bonds and to pay all reasonable and necessary fees and expenses of Trustee and any paying agents and all other liabilities of Company accrued and to accrue hereunder to the date of redemption of the 2000 Series A Bonds.

(c) If a Determination of Taxability occurs when all or any portion of the 2000 Series A Bonds are owned by the Purchaser, the Company hereby agrees to pay to the Purchaser, in addition to the redemption price of the 2000 Series A Bonds owned by the Purchaser, the following additional amounts:

(i) an additional amount equal to the difference between (1) the amount of interest paid on the 2000 Series A Bonds during the Taxable Period and (2) the amount of interest that would have been paid on the 2000 Series A Bonds during the Taxable Period had the 2000 Series A Bonds borne interest at the Taxable Rate; and

(ii) an amount equal to any interest, penalties on overdue interest and additions to tax (as referred to in Subchapter A of Chapter 68 of the Code) owed by the Purchaser as a result of occurrence of a Determination of Taxability.

ARTICLE II

REPRESENTATIONS, WARRANTIES AND COVENANTS

Section 2.1. Representations, Warranties and Covenants by the Issuer. The Issuer represents, warrants and covenants that:

(a) The Issuer is a public body corporate and politic duly created and existing as a de jure political subdivision under the Constitution and laws of the Commonwealth of Kentucky and, pursuant to the Act, the Issuer has the power to enter into this Amendment No. 2 to Loan Agreement and the Indenture of Trust and the transactions contemplated hereby and thereby and to carry out its obligations hereunder and thereunder.

(b) To its knowledge, the Issuer is not in default under or in violation of the Constitution or any of the laws of the Commonwealth of Kentucky relevant to the consummation of the transactions contemplated hereby, and the Issuer has been duly authorized to execute and deliver this Amendment No. 2 to Loan Agreement and the Indenture of Trust. The Issuer agrees that it will do or cause to be done in a timely manner all things necessary to preserve and keep in full force and effect its existence, and to carry out Issuer's respective representations, warranties, covenants, agreements and obligations set forth in this Amendment No. 2 to Loan Agreement.

Section 2.2. Representations, Warranties and Covenants by the Company. The Company represents, warrants and covenants that:

(a) The Company (i) is a corporation duly incorporated, validly existing and in good standing under the laws of the Commonwealth of Kentucky, (ii) is duly qualified, authorized and licensed to transact business in each jurisdiction wherein failure to qualify would have a material adverse effect on the conduct of its business, and (iii) is not in violation of any provision of its Articles of Incorporation, its By-Laws or any laws of the Commonwealth of Kentucky relevant to the transactions contemplated hereby.

(b) The Company has full and complete legal power and authority to execute and deliver this Amendment No. 2 to Loan Agreement, and has by proper corporate action duly authorized the execution and delivery of this Amendment No. 2 to Loan Agreement.

(c) No event of default, and no event of the type described in clauses (a) through (f) of Section 9.1 of the Loan Agreement has occurred and is continuing, and no condition exists which, with the giving of notice or the lapse of time, or both, would constitute an event of default or a default under any agreement or instrument to which the Company is a party or by which the Company is or may be bound or to which any of the property or assets of the Company is or may be subject which would impair in any material respect its ability to carry out its obligations under the Loan Agreement, this Amendment No. 2 to Loan Agreement or the transactions contemplated hereby or thereby. Neither the execution and delivery of the Loan Agreement, this Amendment No. 2 to Loan Agreement, nor the consummation of the transactions contemplated hereby or by the Indenture of Trust, nor the fulfillment of or compliance with the terms and conditions hereof or thereof, conflicts with or results in a breach of the terms, conditions or provisions of any corporate restriction or any agreement or instrument to which the Company is now a party or by which it is bound, or constitutes a default under any of the foregoing, or results in the creation or imposition of any prohibited lien, charge or encumbrance whatsoever upon any of the property or assets of the Company under the terms of any instrument or agreement.

ARTICLE III

MISCELLANEOUS

Section 3.1. Term of Amendment No. 2 to Loan Agreement. This Amendment No. 2 to Loan Agreement shall remain in full force and effect from the date hereof to and including the later of May 1, 2027, or until such time as all of the 2000 Series A Bonds shall have been fully paid (or provision made for such payment pursuant to the Indenture of Trust and any amendments thereto), whichever shall be later; provided, however, that the Loan Agreement, as amended pursuant to this Amendment No. 2 to Loan Agreement, may be cancelled and terminated prior to said date in accordance with the provisions of Section 11.1 of the Loan Agreement.

Section 3.2. Ratification. Except as amended and supplemented by Articles I and II hereof, the Issuer and the Company hereby ratify and reaffirm the terms and provisions of the Loan Agreement and their respective representations, warranties, covenants, agreements and obligations set forth therein.

Section 3.3. Effective Date. This Amendment No. 2 to Loan Agreement has been made and entered into as of the date first written above.

Section 3.4. Binding Effect. This Amendment No. 2 to Loan Agreement shall inure to the benefit of and shall be binding upon the Issuer, the Company and their respective successors and assigns, subject, however, to the limitations contained in Sections 7.2, 8.1 and 8.3 of the Loan Agreement.

Section 3.5. Severability. In the event any provision of this Amendment No. 2 to Loan Agreement shall be held invalid or unenforceable by any court of competent jurisdiction, such holding shall not invalidate or render unenforceable any other provision hereof.

Section 3.6. Execution in Counterparts. This Amendment No. 2 to Loan Agreement may be simultaneously executed in several counterparts, each of which shall be an original and all of which shall constitute but one and the same instrument.

Section 3.7. Applicable Law. This Amendment No. 2 to Loan Agreement shall be governed by and construed in accordance with the laws of the Commonwealth of Kentucky.

Section 3.8. Captions. The captions or headings in this Amendment No. 2 to Loan Agreement are for convenience only and in no way define, limit or describe the scope or intent of any provisions, Articles or Sections of this Amendment No. 2 to Loan Agreement.

Section 3.9. No Pecuniary Liability of Issuer. No provision, covenant or agreement contained in this Amendment No. 2 to Loan Agreement or breach thereof shall constitute or give rise to a pecuniary liability of the Issuer or a charge upon its general credit or taxing powers.

(signature page immediately follows)

IN WITNESS WHEREOF , the Issuer and the Company have caused this Amendment No. 2 to Loan Agreement to be executed in their respective corporate names and their respective corporate seals to be hereunto affixed and attested by their duly authorized officers, all of the date first written.

LOUISVILLE/JEFFERSON COUNTY
METRO GOVERNMENT, KENTUCKY

(SEAL)

By______________________________

GREG FISCHER
Mayor

ATTEST:

____

KATHLEEN J. HERRON
Metro Council Clerk

APPROVED AS TO FORM AND LEGALITY :

Michael J. O'Connell
Jefferson County Attorney

By______________________________

TERRI A. GERAGHTY
Assistant County Attorney

LOUISVILLE GAS AND ELECTRIC
COMPANY

(SEAL)

By______________________________

DANIEL K. ARBOUGH
Treasurer

ATTEST:

____

JOHN R. McCALL
Secretary

Exhibit 10(k)-11

Execution Version

TENTH AMENDMENT TO REIMBURSEMENT AGREEMENT

THIS TENTH AMENDMENT TO REIMBURSEMENT AGREEMENT, dated as of February 22, 2012 (this " Amendment "), to the Existing Reimbursement Agreement (as defined below) is made by PPL ENERGY SUPPLY, LLC, a Delaware limited liability company (the " Account Party "), and certain of the Lenders (such capitalized term and other capitalized terms used in this preamble and the recitals below to have the meanings set forth in, or are defined by reference in, Article I below).

W I T N E S S E T H :

WHEREAS, the Account Party, the Lenders and The Bank of Nova Scotia, as the Issuer and as Administrative Agent, are all parties to the Reimbursement Agreement, dated as of March 31, 2005 (as amended or otherwise modified prior to the date hereof, the " Existing Reimbursement Agreement ", and as amended by this Amendment and as the same may be further amended, supplemented, amended and restated or otherwise modified from time to time, the " Reimbursement Agreement "); and

WHEREAS, the Account Party has requested that the Lenders amend certain provisions of the Existing Reimbursement Agreement and the Lenders are willing to modify the Existing Reimbursement Agreement on the terms and subject to the conditions hereinafter set forth;

NOW, THEREFORE, the parties hereto hereby covenant and agree as follows:

ARTICLE I
DEFINITIONS

SECTION 1.1. Certain Definitions . The following terms when used in this Amendment shall have the following meanings (such meanings to be equally applicable to the singular and plural forms thereof):

" Account Party " is defined in the preamble .

" Amendment " is defined in the preamble .

" Existing Reimbursement Agreement " is defined in the first recital .

" Reimbursement Agreement " is defined in the first recital .

SECTION 1.2. Other Definitions . Terms for which meanings are provided in the Existing Reimbursement Agreement are, unless otherwise defined herein or the context otherwise requires, used in this Amendment with such meanings.

ARTICLE II
AMENDMENTS TO THE EXISTING REIMBURSEMENT AGREEMENT

Effective as of the date hereof, but subject to the occurrence of the satisfaction of the conditions in Article III , the provisions of the Existing Reimbursement Agreement referred to below are hereby amended in accordance with this Article II

SECTION 2.1. Amendment to Section 1.1 . Section 1.1 of the Existing Reimbursement Agreement is hereby amended (a) by deleting the definition of "Applicable Margin", (b) by deleting the reference to "Applicable Margin" in the definition of "Debt Rating" and (c) by amending and restating the definitions of "Applicable Commitment Fee Margin", "Applicable Letter of Credit Margin", "Applicable Margin" and "Incorporated Agreement" in their entireties as follows:

" Applicable Commitment Fee Margin " from time to time, the following percentages per annum, based upon the Debt Rating as set forth below:

Pricing Level	Debt Rating	Applicable Commitment Fee Margin
1	≥ A- from S&P/ A3 from Moody's	0.125%
2	BBB+ from S&P/ Baa1 from Moody's	0.175%
3	BBB from S&P/ Baa2 from Moody's	0.20%
4	BBB- from S&P/Baa3 from Moody's	0.25%
5	<BBB- from S&P/ Baa3 from Moody's	0.35%

" Applicable Letter of Credit Margin " from time to time, the following percentages per annum, based upon the Debt Rating as set forth below:

Pricing Level	Debt Rating	Applicable Letter of Credit Margin
1	≥ A- from S&P/ A3 from Moody's	1.10%
2	BBB+ from S&P/ Baa1 from Moody's	1.35%
3	BBB from S&P/ Baa2 from Moody's	1.60%
4	BBB- from S&P/Baa3 from Moody's	1.725%
5	<BBB- from S&P/ Baa3 from Moody's	1.975%

"" Incorporated Agreement " means the $4,000,000,000 Revolving Credit Agreement, dated as of October 19, 2010, as amended by Amendment No. 1 to the Revolving Credit Agreement, dated as of October 19, 2011, among the Account Party, the lenders from time to time party thereto, Wells Fargo Bank, National Association, as administrative agent, issuing lender and swingline lender, certain financial institutions, as syndication agents, certain financial institutions, as lead arrangers, and certain financial institutions, as documentation agents, as in effect on the date hereof and without giving effect to any subsequent modification, supplement, amendment or waiver by the lenders under, or by other parties to, the Incorporated Agreement, unless the Required Lenders agree in writing that such modification, supplement, amendment or waiver shall apply to such provisions or schedules incorporated herein.

SECTION 2.2. Amendment to Section 3.1 . Section 3.1 of the Existing Reimbursement Agreement is hereby amended by replacing the reference therein to "the Applicable Margin" with a reference to "2%".

ARTICLE III
CONDITIONS TO EFFECTIVENESS

This Amendment and the amendments contained herein shall become effective as of the date hereof when each of the conditions set forth in this Article III shall have been fulfilled to the satisfaction of the Administrative Agent.

SECTION 3.1. Counterparts . The Administrative Agent shall have received counterparts hereof executed on behalf of the Account Party and the each of the Lenders.

SECTION 3.2. Costs and Expenses, etc . The Administrative Agent shall have received for the account of each Lender, all fees, costs and expenses due and payable pursuant to Section 10.3 of the Reimbursement Agreement, if then invoiced.

SECTION 3.3. Satisfactory Legal Form . The Administrative Agent and its counsel shall have received all information, and such counterpart originals or such certified or other copies of such materials, as the Administrative Agent or its counsel may reasonably request, and all legal matters incident to the effectiveness of this Amendment shall be satisfactory to the Administrative Agent and its counsel. All documents executed or submitted pursuant hereto or in connection herewith shall be reasonably satisfactory in form and substance to the Administrative Agent and its counsel.

ARTICLE IV
MISCELLANEOUS

SECTION 4.1. Cross-References . References in this Amendment to any Article or Section are, unless otherwise specified, to such Article or Section of this Amendment.

SECTION 4.2. Loan Document Pursuant to Existing Reimbursement Agreement . This Amendment is a Loan Document executed pursuant to the Existing Reimbursement Agreement and shall (unless otherwise expressly indicated therein) be construed, administered and applied in accordance with all of the terms and provisions of the Existing Reimbursement Agreement, as amended hereby, including Article X thereof.

SECTION 4.3. Successors and Assigns . This Amendment shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns.

SECTION 4.4. Counterparts. This Amendment may be executed by the parties hereto in several counterparts, each of which when executed and delivered shall be an original and all of which shall constitute together but one and the same agreement. Delivery of an executed counterpart of a signature page to this Amendment by facsimile shall be effective as delivery of a manually executed counterpart of this Amendment.

SECTION 4.5. Governing Law. THIS AMENDMENT WILL BE DEEMED TO BE A CONTRACT MADE UNDER AND GOVERNED BY THE INTERNAL LAWS OF THE STATE OF NEW YORK (INCLUDING FOR SUCH PURPOSE SECTIONS 5-1401 AND 5-1402 OF THE GENERAL OBLIGATIONS LAW OF THE STATE OF NEW YORK).

SECTION 4.6. Full Force and Effect; Limited Amendment. Except as expressly amended hereby, all of the representations, warranties, terms, covenants, conditions and other provisions of the Existing Reimbursement Agreement and the Loan Documents shall remain unchanged and shall continue to be, and shall remain, in full force and effect in accordance with their respective terms. The amendments set forth herein shall be limited precisely as provided for herein to the provisions expressly amended herein and shall not be deemed to be an amendment to, waiver of, consent to or modification of any other term or provision of the Existing Reimbursement Agreement or any other Loan Document or of any transaction or further or future action on the part of any Obligor which would require the consent of the Lenders under the Existing Reimbursement Agreement or any of the Loan Documents.

SECTION 4.7. Representations and Warranties. In order to induce the Lenders to execute and deliver this Amendment, the Account Party hereby represents and warrants to the Lenders, on the date this Amendment becomes effective pursuant to Article III, that both before and after giving effect to this Amendment, all statements set forth in clauses (a) and (b) of Section 5.2.1 of the Reimbursement Agreement are true and correct as of such date, except to the extent that any such statement expressly relates to an earlier date (in which case such statement was true and correct on and as of such earlier date).

IN WITNESS WHEREOF, the parties hereto have executed and delivered this Amendment as of the date first above written.

PPL ENERGY SUPPLY, LLC,
as the Account Party

By:_________________________
Title:

THE BANK OF NOVA SCOTIA,
as the Administrative Agent, as the Issuer and as a Lender

By:_________________________
Name: James R. Trimble
Title: Managing Director

AMENDMENT NO. 4

TO

PPL OFFICERS DEFERRED COMPENSATION PLAN

WHEREAS, PPL Services Corporation ("PPL") has adopted the PPL Officers Deferred Compensation Plan ("Plan") effective July 1, 2000; and

WHEREAS, the Plan was amended and restated effective November 1, 2003, and subsequently amended by Amendment No. 1, 2 and 3; and

WHEREAS, PPL desires to further amend the Plan;

NOW, THEREFORE, the Plan is hereby amended as follows:

I. Effective January 1, 2012, the following sections of Articles 1, 2, 3, and 4 are amended to read:

Article I
Purpose

1.1 The purpose of this Executive Deferred Compensation Plan is to provide certain executive officers and senior management employees of PPL and other Participating Companies a financially advantageous method to defer earned income. This Plan received account balances from the terminated PPL Montana Officers Deferred Compensation Plan and the terminated PPL Global Officers Deferred Compensation Plan, effective November 1, 2003, by reason of the merger of those two terminated Plans into this Plan as of that date.

Article II
Definitions

2.12 **"Plan"** means this Executive Deferred Compensation Plan as set forth herein and as hereafter amended from time to time.

2.16 **" Savings Plan"** means the PPL Deferred Savings Plan, PPL Subsidiary Savings Plan, or PPL Retirement Savings Plan.

Article III
Eligibility

3.1 Any elected officer or other key employee of PPL or of a Participating Company who is designated as eligible in a resolution adopted by the Board of Directors of such Participating Company and is approved for participation in this Plan by the CLC.

As of January 1, 2012, all newly hired salaried employees in Base Pay Salary Groups 1-10 shall be eligible, and as of June 1, 2012, all salaried employees hired prior to January 1, 2012, who are not eligible for participation shall be eligible if they are in or attain Base Pay Salary Groups 1-10. Any salaried employee of PPL or a Participating Company hired after January 1, 2012, who is not in Base Pay Salary Groups 1-10 and whose Cash Compensation and Cash Awards for the calendar year exceed the annual income ceiling of Code Section 401(a)(17) shall be eligible for the make-up contribution of Section 4.12 only.

Article IV
Deferred Cash Compensation and Deferred Cash Awards

4.1 Participant shall have the right to elect to defer all, or a portion, of his Cash Compensation in excess of the estimated minimum annual payroll tax amount that the Participant must legally pay without regard to any deferral election.

4.10 The Account of any Participant hired prior to January 1, 2012, with Deferred Cash Compensation and Deferred Cash Awards for the calendar year shall be increased by a matching contribution amount, equal to 100% of the aggregate Deferred Cash Compensation and Deferred Cash Awards that do not exceed 3% of Cash Compensation, minus the maximum amount of Matching Contributions that could have been made to Participant's Accounts in the PPL Deferred Savings Plan and/or PPL Subsidiary Savings Plan for that calendar year if the Participant had made the maximum employee contributions permitted.

4.11 The Account of any Participant hired on or after January 1, 2012, with Deferred Cash Compensation and Deferred Cash Awards for the calendar year shall be increased by a Matching Contribution and a Fixed Contribution. The Matching Contribution shall be an amount equal to 100% of the aggregate Deferred Cash Compensation and Deferred Cash Awards that do not exceed 6% Cash Compensation, minus the maximum amount of Matching Contributions that could have been made to the Participant's Accounts in the PPL Retirement Savings Plan for that calendar year if the Participant made the maximum employee contributions permitted. The Fixed Contribution shall be an amount equal to 3% of Cash Compensation minus the amount of the Fixed Contribution made to the Participant's Accounts in the PPL Retirement Savings Plan for that calendar year.

4.12 For each year a salaried employee is eligible for the make-up contribution described herein, in accordance with Section 3.1, there shall be an Account for that employee to which shall be credited an amount equal to 9% of the excess of the Cash Compensation and Cash Awards for the year over the Code Section 401(a)(17) annual income ceiling. Except for the absence of any deferral by the employee, this Account shall constitute an "Account" under this Plan and subject to all provisions herein.

II. Except as provided for in this Amendment No. 4, all other provisions of the Plan shall remain in full force and effect.

IN WITNESS WHEREOF, this Amendment No. 4 is executed this _____ day of ____________________, 2012.

PPL SERVICES CORPORATION

By:______________________________

James E. Abel
Senior Vice President - Finance
and Treasurer

AMENDMENT NO. 5

TO

PPL SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN

WHEREAS, PPL Services Corporation ("PPL") adopted the PPL Supplemental Executive Retirement Plan (the "Plan"), effective July 1, 2000, for certain of its employees; and

WHEREAS, the Plan was amended and restated effective July 1, 2003, and subsequently amended by Amendment No. 1, 2, 3 and 4; and

WHEREAS, PPL desires to further amend the Plan;

NOW, THEREFORE, the Plan is hereby amended as follows:

I. Effective January 1, 2012, the following sections of Articles 2 and 3 are amended to read as follows:

ARTICLE II **DEFINITIONS**

2. **Definitions** .

The following terms shall have the same definitions as they are given in the PPL Retirement Plan:

(a) Actuarial Equivalent.

(b) Affiliated Company or Affiliated Companies.

(c) Board of Directors (herein referred to as "Board").

(d) PPL.

The following terms shall have the following definitions under this PPL Supplemental Executive Retirement Plan:

(e) **"Benefit"** means the Benefit payable under this Plan calculated under Article 4.

(f) **"Cause"** for Participant's Termination of Employment by PPL or an Affiliated Company means

(1) If a "Change in Control," as defined below, has occurred,

(A) the willful and continued failure by Participant to substantially perform Participant's duties with PPL or an Affiliated Company (other than any such failure resulting from Participant's incapacity due to physical or mental illness or, if applicable, any such actual or anticipated failure after the issuance of any "Notice of Termination for Good Reason" by the Participant pursuant to any severance agreement between Participant and PPL or an Affiliated Company) after a written demand for substantial performance is delivered to Participant by the Board, which demand specifically identifies the manner in which the Board believes that Participant has not substantially performed Participant's duties, or

(B) the willful engaging by Participant in conduct which is demonstrably and materially injurious to PPL or an Affiliated Company, monetarily or otherwise.

(C) For purposes of Subsections (A) and (B) of this definition, (A) no act, or failure to act, on Participant's part shall be deemed "willful" unless done, or omitted to be done, by Participant not in good faith and without reasonable belief that Participant's act, or failure to act, was in the best interest of PPL or the Affiliated Company, and (B) in the event of a dispute concerning the application of this provision, no claim by PPL or an Affiliated Company that Cause exists shall be given effect unless PPL or the Affiliated Company establishes to the Board by clear and convincing evidence that Cause exists.

(2) If a "Change in Control," as defined below, has not occurred, "Cause" means:

(i) Participant's engagement is misconduct which is materially injurious to PPL or an Affiliated Company,

(ii) Participant's insubordination after clear and lawful direction,

(iii) Participant's commission of a felony in the performance of duties to PPL or an Affiliated Company,

(iv) Participant's commission of an act or acts constituting any fraud against or embezzlement from PPL or an Affiliated Company,

(v) Participant's material breach of any confidentiality or non-competition covenant entered into between the Participant and PPL or an Affiliated Company, or

(vi) Participant's employment with a competitor while employed by PPL or an Affiliated Company. The determination of the existence of Cause shall be made by the Board in good faith, which determination shall be conclusive for the purpose of this Plan.

(g) " Change in Control " shall mean the occurrence of any of the following events:

(i) any Person or Group is or becomes the "beneficial owner" (as defined in rules 13d-3 and 13d-5 under the Securities Exchange Act of 1934, as amended) directly or indirectly of more than 30% of the total voting power of the voting stock of PPL Corporation (or any entity which controls PPL Corporation) within a 12-month period, including by way of merger, consolidation, tender or exchange offer, or otherwise;

(ii) a reorganization, recapitalization, merger or consolidation (a " Corporate Transaction ") involving PPL Corporation, unless securities representing 70% or more of the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors of PPL Corporation or the corporation resulting from such Corporate Transaction (or the parent of such corporation) are held subsequent to such transaction by the Person or

Persons who were the "beneficial owners" of the outstanding voting securities entitled to vote generally in the election of directors of PPL Corporation immediately prior to such Corporate Transaction, in substantially the same proportions as their ownership immediately prior to such Corporate Transaction;

(iii) the sale or disposition, in one or a series of related transactions, of all or substantially all, of the assets of PPL Corporation to any Person or Group; or

(iv) during any period of 12 months, individuals who at the beginning of such period constituted the Board (together with any new directors whose election by such Board or whose nomination for election by the stockholders of PPL Corporation was approved by a vote of a majority of the directors of PPL Corporation, then still in office, who were either directors at the beginning of such period or whose election or nomination for election was previously so approved) cease for any reason to constitute a majority of the Board, then in office.

(h) **"CLC"** shall mean the Corporate Leadership Council of PPL Corporation.

(i) **"Early Retirement Reduction Factor"** means the percentage that appears adjacent to the Participant's age below determined under the appropriate column.

(1) Column (1) shall apply to any Retiree.

(2) Column (2) shall apply to any Terminated Vested Participant.

Percentage of Benefit Received

	(1) **Age When**	(2)
Benefits Start	Retiree	Terminated Vested
60	100	100
59	95	90
58	90	80
57	85	70
56	80	60
55	75	50
54	70	N/A
53	65	N/A
52	60	N/A
51	55	N/A
50	50	N/A
49 or younger	N/A	N/A

(j) **"Good Reason"** shall mean "Good Reason" or such similar concept as defined in any employment, severance, or similar agreement then in effect between the Participant and any of PPL or an Affiliated Company, or, if no such agreement containing a definition of "Good Reason" is then in effect or if such term is not defined therein, "Good Reason" shall mean without the Participant's consent, (i) a change caused by PPL or an Affiliated Company in the Participant's duties and responsibilities

(j) which is materially inconsistent with the Participant's position at the applicable entity that is a member of the Affiliated Companies, (ii) a material reduction in the Participant's annual base salary, annual incentive compensation opportunity or other employee benefits (excluding any such reduction that is part of a plan to reduce annual base salaries, annual incentive compensation opportunities or other employee benefits of comparably situated employees of any entity that is a member of the Affiliated Companies generally), or (iii) a relocation of the Participant's current principle place of employment; provided that, notwithstanding anything to the contrary in the foregoing, the Participant shall only have "Good Reason" to terminate employment following the applicable entity's failure to remedy the act which is alleged to constitute "Good Reason" within thirty (30) days following such entity's receipt of written notice from the Participant specifying such act, so long as such notice is provided within sixty (60) days after such event has first occurred.

(k) **"Participant"** means

(1) any elected officer or other key employee of PPL or of a Participating Company who is hired prior to January 1, 2012, is designated as eligible in a resolution adopted by the board of directors of such Participating Company, and is approved for participation in this Plan by the CLC.

(2) any individual formerly described in Paragraph (1) who has not yet had a Termination of Employment, or any individual formerly described in Paragraph (1) who has had a Termination of Employment and is entitled to receive benefits under Article 3 of this Plan. All Participants of this Plan are listed in Appendix A.

(l) **"Participating Company"** means PPL Services Corporation, PPL Electric Utilities Corporation (prior to February 14, 2000, PP&L, Inc.), PPL EnergyPlus, LLC (prior to February 14, 2000, PP&L EnergyPlus Co., LLC), PPL Global, LLC, PPL Montana, LLC and each other Affiliated Company that is designated by the CLC to adopt this Plan by action of its board of directors or managers.

(m) **"Plan"** means this Supplemental Executive Retirement Plan, as amended from time to time.

(n) **"PPL Corporation"** means PPL Corporation (prior to February 14, 2000, PP&L Resources, Inc.).

(o) **"Retiree"** means a Participant who has a Termination of Employment after:

(1) attaining age 55 and completing at least 10 Years of Service, or

(2) attaining age 60.

(p) **"Retirement Plan"** means the PPL Retirement Plan, as amended from time to time.

(q) **"Section 409A"** means Section 409A of the Internal Revenue Code of 1986, as amended, and the final Treasury Regulations issued thereunder.

(r) **"Supplemental Final Average Earnings"** means the following:

(1) Supplemental Final Average Earnings means twelve times the average of a Participant's "compensation" as defined in Paragraphs (A) through (B) below, from PPL and/or an Affiliated Company, for the 60 highest full months in the final 120 (or fewer) full consecutive months during which he is employed by PPL and/or an Affiliated Company. For this purpose, non-consecutive months interrupted by periods in which the Participant receives no "compensation" shall be treated as consecutive. For purposes of this Section, "compensation" shall include the following:

(A) the Participant's base salary from PPL and/or any Affiliated Company prior to any deferrals to the Officers Deferred Compensation Plan or any other nonqualified deferred compensation plan of an Affiliated Company or any Internal Revenue Code section 401(k) plan by which Participant is covered, plus

(B) the value of any cash grants attributable to any month used in the average, awarded to Participant pursuant to the executive incentive awards program initially approved by the Board on October 25, 1989 or any similar program maintained by an Affiliated Company. For the final calendar year of employment, "Compensation" shall include an amount equal to the value of any cash grant that would have been paid for service in the final calendar year of employment, as if 100% of target goals were achieved, but prorated by multiplying by a fraction equal to the number of full calendar months of service completed divided by 12.

(2) For the purposes of determining the Participant's "compensation" under Subsection (1) of this definition, the CLC will determine the amount of any cash grant awarded to the Participant under any incentive awards program, and prorate such amount over the year for which the award was granted.

Notwithstanding the foregoing, if a Participant transfers from a Participating Company to an Affiliated Company that is not a Participating Company after becoming a Participant, earnings with the Affiliated Company after the date of such transfer (or for the duration of each such transfer if the Participant transfers more than once) shall not count in the Participant's Supplemental Final Average Earnings.

(s) **"Terminated Vested Participant"** means a Participant:

(1) who has a Termination of Employment after attaining age 50 but not age 55, and completing at least 10 Years of Service.

(t) **"Termination of Employment"** means the Participant's separation from service (as such term is defined in Section 409A) from PPL and all Affiliated Companies.

(u) **"Years of Service"** means the number of full and partial years used to calculate Participant's accrued benefit under the

Retirement Plan, or which would be used to calculate an accrued benefit if the Participant were eligible to participate in the Retirement Plan but (1) excluding years prior to Participant's attainment of age 30, and (2) including service with any Affiliated Company prior to the Participant's most recently becoming a Participant eligible under this Plan, provided such service would otherwise be counted under the Retirement Plan, but excluding any such service with an Affiliated Company performed before the Affiliated Company became an Affiliated Company, and (3) including Supplemental Years of Service granted to the Participant as set forth in Appendix A. In the event of a "Change in Control," and a Termination of Employment by PPL or an Affiliated Company not for Cause, or a Termination of Employment for Good Reason, all Supplemental Years of Service granted to the Participant as set forth in Appendix A shall become Years of Service and Years of Vesting Service under the Plan, on a pro rata basis, as follows:

(1) For Supplemental Years of Service requiring a specified number of Years of Service, by multiplying the maximum number of Supplemental Years of Service by actual Years of Service divided by the specified number of Years of Service otherwise required.

(2) For Supplemental Years of Service requiring attainment of a specified age, by multiplying the maximum number of Supplemental Years of Service by actual Years of Service divided by the number of Years of Service that would have been attained if the Participant worked to the specified age.

(v) **"Year(s) of Vesting Service"** means (1) the number of full years used to calculate Participant's vested interest in his accrued benefit under the Retirement Plan, or which would be used if eligible under the Retirement Plan, but excluding any such service with an Affiliated Company performed before the Affiliated Company became an Affiliated Company, and (2) the number of Supplemental Years of Service, if any, that may have been granted to the Participant, as set forth in Appendix A. In the event of a "Change in Control," and a Termination of Employment by PPL or an Affiliated Company not for Cause, or a Termination of Employment for Good Reason, all Supplemental Years of Service granted to the Participant as set forth in Appendix A shall become Years of Service and Years of Vesting Service under the Plan, on a pro rata basis, as follows:

(1) For Supplemental Years of Service requiring a specified number of Years of Service, by multiplying the maximum number of Supplemental Years of Service by actual Years of Vesting Service divided by the specified number of Years of Service otherwise required.

(2) For Supplemental Years of Service requiring attainment of a specified age, by multiplying the maximum number of Supplemental Years of Service by actual Years of Vesting Service divided by the number of Years of Vesting Service that would have been attained if the Participant worked to the specified age.

ARTICLE III

BENEFIT ELIGIBILITY

3. **Benefit Eligibility** .

(c) Notwithstanding Section 3(a), in the event of a "Change in Control," all Participants who have a Termination of Employment by PPL or an Affiliated Company not for Cause, or who have a Termination of Employment for Good Reason, shall be eligible for a Benefit.

II. Except as provided for in this Amendment No. 5, all other provisions of the Plan shall remain in full force and effect.

IN WITNESS WHEREOF, this Amendment No. 5 is executed this ____ day of __________________, 2012.

PPL SERVICES CORPORATION

By:______________________________

James E. Abel
Senior Vice President - Finance
and Treasurer

Exhibit 12(a)

PPL CORPORATION AND SUBSIDIARIES

COMPUTATION OF RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

(Millions of Dollars)

	2011	2010	2009	2008	2007
Earnings, as defined:					
Income from Continuing Operations Before Income Taxes	$ **2,201**	$ 1,239	$ 538	$ 1,273	$ 1,230
Adjustment to reflect earnings from equity method investments on a cash basis	**1**	7	1		2
	2,202	1,246	539	1,273	1,232
Total fixed charges as below	**1,022**	698	513	568	609
Less:					
Capitalized interest	**51**	30	43	57	55
Preferred security distributions of subsidiaries on a pre-tax basis	**23**	21	24	27	23
Interest expense and fixed charges related to discontinued operations	**3**	12	15	16	39
Total fixed charges included in Income from Continuing Operations Before Income Taxes	**945**	635	431	468	492
Total earnings	$ **3,147**	$ 1,881	$ 970	$ 1,741	$ 1,724
Fixed charges, as defined:					
Interest charges (a)	$ **955**	$ 637	$ 446	$ 518	$ 565
Estimated interest component of operating rentals	**44**	39	42	22	21
Preferred securities distributions of subsidiaries on a pre-tax basis	**23**	21	24	27	23
Fixed charges of majority-owned share of 50% or less-owned persons		1	1	1	
Total fixed charges (b)	$ **1,022**	$ 698	$ 513	$ 568	$ 609
Ratio of earnings to fixed charges	**3.1**	2.7	1.9	3.1	2.8
Ratio of earnings to combined fixed charges and preferred stock dividends (c)	**3.1**	2.7	1.9	3.1	2.8

(a) Includes interest on long-term and short-term debt, as well as amortization of debt discount, expense and premium - net.

(b) Interest on unrecognized tax benefits is not included in fixed charges.

(c) PPL, the parent holding company, does not have any preferred stock outstanding; therefore, the ratio of earnings to combined fixed charges and preferred stock dividends is the same as the ratio of earnings to fixed charges.

Exhibit 12(b)

PPL ENERGY SUPPLY, LLC AND SUBSIDIARIES

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(Millions of Dollars)

	2011	2010	2009	2008	2007
Earnings, as defined:					
Income (Loss) from Continuing Operations Before Income Taxes	**$ 1,212**	$ 881	$ (13)	$ 671	$ 785
Adjustments to reflect earnings from equity method investments on a cash basis	**1**	7	1		2
	1,213	888	(12)	671	787
Total fixed charges as below	**259**	426	364	390	388
Less:					
Capitalized interest	**47**	33	44	57	54
Interest expense and fixed charges related to discontinued operations	**3**	147	102	157	217
Total fixed charges included in Income from Continuing Operations Before Income Taxes	**209**	246	218	176	117
Total earnings	**$ 1,422**	$ 1,134	$ 206	$ 847	$ 904
Fixed charges, as defined:					
Interest charges (a)	**$ 223**	$ 387	$ 321	$ 374	$ 374
Estimated interest component of operating rentals	**36**	38	42	15	14
Fixed charges of majority-owned share of 50% or less-owned persons		1	1	1	
Total fixed charges (b)	**$ 259**	$ 426	$ 364	$ 390	$ 388
Ratio of earnings to fixed charges	**5.5**	2.7	0.6	2.2	2.3

(a) Includes interest on long-term and short-term debt, as well as amortization of debt discount, expense and premium - net.
(b) Interest on unrecognized tax benefits is not included in fixed charges.

Exhibit 12(c)

PPL ELECTRIC UTILITIES CORPORATION AND SUBSIDIARIES

COMPUTATION OF RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

(Millions of Dollars)

	2011	2010	2009	2008	2007
Earnings, as defined:					
Income Before Income Taxes	$ 257	$ 192	$ 221	$ 278	$ 246
Total fixed charges as below	105	102	121	114	143
Total earnings	$ 362	$ 294	$ 342	$ 392	$ 389
Fixed charges, as defined:					
Interest charges (a)	$ 102	$ 101	$ 120	$ 113	$ 139
Estimated interest component of operating rentals	3	1	1	1	4
Total fixed charges (b)	$ 105	$ 102	$ 121	$ 114	$ 143
Ratio of earnings to fixed charges	3.4	2.9	2.8	3.4	2.7
Preferred stock dividend requirements on a pre-tax basis	$ 21	$ 23	$ 28	$ 28	$ 27
Fixed charges, as above	105	102	121	114	143
Total fixed charges and preferred stock dividends	$ 126	$ 125	$ 149	$ 142	$ 170
Ratio of earnings to combined fixed charges and preferred stock dividends	2.9	2.4	2.3	2.8	2.3

(a) Includes interest on long-term and short-term debt, as well as amortization of debt discount, expense and premium - net.
(b) Interest on unrecognized tax benefits is not included in fixed charges.

Exhibit 12(d)

LG&E AND KU ENERGY LLC AND SUBSIDIARIES

COMPUTATION OF RATIO OF EARNINGS TO COMBINED FIXED CHARGES

(Millions of Dollars)

	Successor		Predecessor				
	Year Ended Dec. 31, 2011	2 Months Ended Dec. 31, 2010	10 Months Ended Oct. 31, 2010	Year Ended December 31, 2009	2008	2007	2006
Earnings, as defined:							
Income from Continuing Operations Before Income Taxes	$ 419	$ 70	$ 300	$ (1,235)	$ (1,536)	$ 332	$ 310
Adjustment to reflect earnings from equity method investments on a cash basis	(1)		(4)	11		(5)	(2)
Loss on impairment of goodwill				1,493	1,806		
Mark to market impact of derivative instruments		2	(20)	(19)	34		
	418	72	276	250	304	327	308
Total fixed charges as below	153	25	158	186	199	170	161
Total earnings	$ 571	$ 97	$ 434	$ 436	$ 503	$ 497	$ 469
Fixed charges, as defined:							
Interest charges (a)	$ 147	$ 24	$ 153	$ 176	$ 184	$ 155	$ 143
Estimated interest component of operating rentals	6	1	5	5	5	4	4
Estimated discontinued operations interest component of rental expense				5	10	10	10
Preferred stock dividends						1	4
Total fixed charges	$ 153	$ 25	$ 158	$ 186	$ 199	$ 170	$ 161
Ratio of earnings to fixed charges	3.7	3.9	2.7	2.3	2.5	2.9	2.9

(a) Includes interest on long-term and short-term debt, as well as amortization of debt discount, expense and premium - net.

Exhibit 12(e)

LOUISVILLE GAS AND ELECTRIC COMPANY

COMPUTATION OF RATIO OF EARNINGS TO COMBINED FIXED CHARGES

(Millions of Dollars)

	Successor		Predecessor				
	Year Ended Dec. 31, 2011	2 Months Ended Dec. 31, 2010	10 Months Ended Oct. 31, 2010	Year Ended December 31, 2009	2008	2007	2006
Earnings, as defined:							
Income Before Income Taxes	**$ 195**	$ 29	$ 167	$ 142	$ 131	$ 179	$ 179
Mark to market impact of derivative instruments		1	(20)	(20)	35		
	195	30	147	122	166	179	179
Total fixed charges as below	**46**	8	40	46	60	53	47
Total earnings	**$ 241**	$ 38	$ 187	$ 168	$ 226	$ 232	$ 226
Fixed charges, as defined:							
Interest charges (a)	**$ 44**	$ 8	$ 38	$ 44	$ 58	$ 50	$ 41
Estimated interest component of operating rentals	**2**		2	2	2	2	2
Preferred stock dividends						1	4
Total fixed charges	**$ 46**	$ 8	$ 40	$ 46	$ 60	$ 53	$ 47
Ratio of earnings to fixed charges	**5.2**	4.8	4.7	3.7	3.8	4.4	4.8

(a) Includes interest on long-term and short-term debt, as well as amortization of debt discount, expense and premium - net.

Exhibit 12(f)

KENTUCKY UTILITIES COMPANY

COMPUTATION OF RATIO OF EARNINGS TO COMBINED FIXED CHARGES

(Millions of Dollars)

	Successor		Predecessor				
	Year Ended Dec. 31, 2011	2 Months Ended Dec. 31, 2010	10 Months Ended Oct. 31, 2010	Year Ended December 31, 2009	2008	2007	2006
Earnings, as defined:							
Income Before Income Taxes	$ 282	$ 55	$ 218	$ 200	$ 226	$ 244	$ 226
Adjustment to reflect earnings from equity method investments on a cash basis	(1)		(4)	11		(5)	(2)
Mark to market impact of derivative instruments				1	(1)		
	281	55	214	212	225	239	224
Total fixed charges as below	73	11	71	79	77	59	41
Total earnings	$ 354	$ 66	$ 285	$ 291	$ 302	$ 298	$ 265
Fixed charges, as defined:							
Interest charges (a)	$ 70	$ 10	$ 69	$ 76	$ 74	$ 57	$ 39
Estimated interest component of operating rentals	3	1	2	3	3	2	2
Total fixed charges	$ 73	$ 11	$ 71	$ 79	$ 77	$ 59	$ 41
Ratio of earnings to fixed charges	4.8	6.0	4.0	3.7	3.9	5.1	6.5

(a) Includes interest on long-term and short-term debt, as well as amortization of debt discount, expense and premium - net.

PPL Corporation
Subsidiaries of the Registrant
At December 31, 2011

Exhibit 21

Company Name Business Conducted under Same Name	State or Jurisdiction of Incorporation/Formation
LG&E and KU Energy LLC	Kentucky
Louisville Gas and Electric Company	Kentucky
Kentucky Utilities Company	Kentucky and Virginia
PPL Electric Utilities Corporation	Pennsylvania
PPL Energy Funding Corporation	Pennsylvania
PPL Energy Supply, LLC	Delaware
PPL Investment Corporation	Delaware
PPL EnergyPlus, LLC	Pennsylvania
PPL Generation, LLC	Delaware
PPL Montour, LLC	Delaware
PPL Susquehanna, LLC	Delaware
PPL Holtwood, LLC	Delaware
PPL Montana Holdings, LLC	Delaware
PPL Montana, LLC	Delaware
PPL Global, LLC	Delaware
PMDC International Holdings, Inc.	Delaware
PPL UK Holdings, LLC	Delaware
PPL UK Resources Limited	United Kingdom
PPL WW Holdings Limited	United Kingdom
Western Power Distribution LLP	United Kingdom
Western Power Distribution (South West) plc	United Kingdom
Western Power Distribution (South Wales) plc	United Kingdom
PPL UK Investments Limited	United Kingdom
PPL WEM Holdings plc	United Kingdom

Exhibit 23(a)

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in PPL Corporation's Registration Statement on Form S-3 No. 333-158200, the Registration Statement on Form S-3D No 333-161826, and the Registration Statements on Form S-8 (Nos. 333-02003, 333-112453, 333-110372, 333-95967, 333-144047, and 333-175680) of our reports dated February 28, 2012, with respect to the consolidated financial statements and schedule of PPL Corporation and the effectiveness of internal control over financial reporting of PPL Corporation, included in this Annual Report (Form 10-K) for the year ended December 31, 2011.

/s/ Ernst & Young LLP

Philadelphia, Pennsylvania
February 28, 2012

Exhibit 23(b)

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in PPL Energy Supply, LLC's Registration Statement on Form S-3 No. 333-158200-02 of our report dated February 28, 2012, with respect to the consolidated financial statements of PPL Energy Supply, LLC, included in this Annual Report (Form 10-K) for the year ended December 31, 2011.

/s/ Ernst & Young LLP

Philadelphia, Pennsylvania
February 28, 2012

Exhibit 23(c)

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in PPL Electric Utilities Corporation's Registration Statement on Form S-3 No. 333-158200-01 of our report dated February 28, 2012, with respect to the consolidated financial statements of PPL Electric Utilities Corporation, included in this Annual Report (Form 10-K) for the year ended December 31, 2011.

/s/ Ernst & Young LLP

Philadelphia, Pennsylvania
February 28, 2012

Exhibit 23(d)

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in PPL Corporation's Registration Statement on Form S-3 No. 333-158200, the Registration Statement on Form S-3D No 333-161826, and the Registration Statements on Form S-8 (Nos. 333-02003, 333-112453, 333-110372, 333-95967, 333-144047, and 333-175680) of our reports dated February 25, 2011, relating to the consolidated financial statements and financial statement schedule of LG&E and KU Energy LLC, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Louisville, Kentucky
February 28, 2012

PPL CORPORATION

2011 ANNUAL REPORT
TO THE SECURITIES AND EXCHANGE COMMISSION
ON FORM 10-K

POWER OF ATTORNEY

The undersigned directors of PPL Corporation, a Pennsylvania corporation, that is to file with the Securities and Exchange Commission, Washington, D.C., under the provisions of the Securities Exchange Act of 1934, as amended, its Annual Report on Form 10-K for the year ended December 31, 2011 ("Form 10-K Report"), do hereby appoint each of William H. Spence, Paul A. Farr, Robert J. Grey and Michael A. McGrail, and each of them, their true and lawful attorney, with power to act without the other and with full power of substitution and resubstitution, to execute for them and in their names the Form 10-K Report and any and all amendments thereto, whether said amendments add to, delete from or otherwise alter the Form 10-K Report, or add or withdraw any exhibits or schedules to be filed therewith and any and all instruments in connection therewith. The undersigned hereby grant to each said attorney full power and authority to do and perform in the name of and on behalf of the undersigned, and in any and all capacities, any act and thing whatsoever required or necessary to be done in and about the premises, as fully and to all intents and purposes as the undersigned might do, hereby ratifying and approving the acts of each of the said attorneys.

IN WITNESS WHEREOF, the undersigned have hereunto set their hands this day of February, 2012.

/s/ Frederick M. Bernthal Frederick M. Bernthal	/s/ Venkata Rajamannar Madabhushi Venkata Rajamannar Madabhushi
/s/ John W. Conway John W. Conway	/s/ James H. Miller James H. Miller
/s/ Steven G. Elliott Steven G. Elliott	/s/ Craig A. Rogerson Craig A. Rogerson
/s/ Louise K. Goeser Louise K. Goeser	/s/ William H. Spence William H. Spence
/s/ Stuart E. Graham Stuart E. Graham	/s/ Natica von Althann Natica von Althann
/s/ Stuart Heydt Stuart Heydt	/s/ Keith H. Williamson Keith H. Williamson

Exhibit 31(a)

CERTIFICATION

I, WILLIAM H. SPENCE, certify that:

1. I have reviewed this annual report on Form 10-K of PPL Corporation (the "registrant") for the year ended December 31, 2011;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

/s/ William H. Spence
William H. Spence
President and Chief Executive Officer
PPL Corporation

Exhibit 31(b)

CERTIFICATION

I, PAUL A. FARR, certify that:

1. I have reviewed this annual report on Form 10-K of PPL Corporation (the "registrant") for the year ended December 31, 2011;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

/s/ Paul A. Farr
Paul A. Farr
Executive Vice President and Chief Financial Officer
PPL Corporation

Exhibit 31(c)

CERTIFICATION

I, JAMES H. MILLER, certify that:

1. I have reviewed this annual report on Form 10-K of PPL Energy Supply, LLC (the "registrant") for the year ended December 31, 2011;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

/s/ James H. Miller
James H. Miller
President
PPL Energy Supply, LLC

CERTIFICATION

I, PAUL A. FARR, certify that:

1. I have reviewed this annual report on Form 10-K of PPL Energy Supply, LLC (the "registrant") for the year ended December 31, 2011;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

/s/ Paul A. Farr
Paul A. Farr
Executive Vice President
PPL Energy Supply, LLC

CERTIFICATION

I, DAVID G. DECAMPLI, certify that:

1. I have reviewed this annual report on Form 10-K of PPL Electric Utilities Corporation (the "registrant") for the year ended December 31, 2011;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

/s/ David G. DeCampli
David G. DeCampli
President
PPL Electric Utilities Corporation

CERTIFICATION

I, VINCENT SORGI, certify that:

1. I have reviewed this annual report on Form 10-K of PPL Electric Utilities Corporation (the "registrant") for the year ended December 31, 2011;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

/s/ Vincent Sorgi
Vincent Sorgi
Vice President and Chief Accounting Officer
PPL Electric Utilities Corporation

Exhibit 31(g)

CERTIFICATION

I, VICTOR A. STAFFIERI, certify that:

1. I have reviewed this annual report on Form 10-K of LG&E and KU Energy LLC (the "registrant") for the year ended December 31, 2011;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

/s/ Victor A. Staffieri
Victor A. Staffieri
Chairman, President and Chief Executive Officer
LG&E and KU Energy LLC

Exhibit 31(h)

CERTIFICATION

I, KENT W. BLAKE, certify that:

1. I have reviewed this annual report on Form 10-K of LG&E and KU Energy LLC (the "registrant") for the year ended December 31, 2011;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

/s/ Kent W. Blake
Kent W. Blake
Chief Financial Officer
LG&E and KU Energy LLC

CERTIFICATION

I, VICTOR A. STAFFIERI, certify that:

1. I have reviewed this annual report on Form 10-K of Louisville Gas and Electric Company (the "registrant") for the year ended December 31, 2011;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

/s/ Victor A. Staffieri
Victor A. Staffieri
Chairman, President and Chief Executive Officer
Louisville Gas and Electric Company

Exhibit 31(j)

CERTIFICATION

I, KENT W. BLAKE, certify that:

1. I have reviewed this annual report on Form 10-K of Louisville Gas and Electric Company (the "registrant") for the year ended December 31, 2011;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

/s/ Kent W. Blake
Kent W. Blake
Chief Financial Officer
Louisville Gas and Electric Company

CERTIFICATION

I, VICTOR A. STAFFIERI, certify that:

1. I have reviewed this annual report on Form 10-K of Kentucky Utilities Company (the "registrant") for the year ended December 31, 2011;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

/s/ Victor A. Staffieri
Victor A. Staffieri
Chairman, President and Chief Executive Officer
Kentucky Utilities Company

Exhibit 31(l)

CERTIFICATION

I, KENT W. BLAKE, certify that:

1. I have reviewed this annual report on Form 10-K of Kentucky Utilities Company (the "registrant") for the year ended December 31, 2011;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2012

/s/ Kent W. Blake
Kent W. Blake
Chief Financial Officer
Kentucky Utilities Company

Exhibit 32(a)

CERTIFICATE PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
FOR PPL CORPORATION'S FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2011

In connection with the annual report on Form 10-K of PPL Corporation (the "Company") for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Covered Report"), I, the principal executive officer of the Company, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify that:

- The Covered Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- The information contained in the Covered Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2012

/s/ William H. Spence
William H. Spence
President and Chief Executive Officer
PPL Corporation

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

CERTIFICATE PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
FOR PPL CORPORATION'S FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2011

In connection with the annual report on Form 10-K of PPL Corporation (the "Company") for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Covered Report"), I, the principal financial officer of the Company, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify that:

- The Covered Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- The information contained in the Covered Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2012

/s/ Paul A. Farr
Paul A. Farr
Executive Vice President and Chief Financial Officer
PPL Corporation

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(c)

CERTIFICATE PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
FOR PPL ENERGY SUPPLY, LLC'S FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2011

In connection with the annual report on Form 10-K of PPL Energy Supply, LLC (the "Company") for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Covered Report"), I, the principal executive officer of the Company, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify that:

- The Covered Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- The information contained in the Covered Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2012

/s/ James H. Miller
James H. Miller
President
PPL Energy Supply, LLC

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(d)

CERTIFICATE PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
FOR PPL ENERGY SUPPLY, LLC'S FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2011

In connection with the annual report on Form 10-K of PPL Energy Supply, LLC (the "Company") for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Covered Report"), I, the principal financial officer of the Company, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify that:

- The Covered Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- The information contained in the Covered Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2012

/s/ Paul A. Farr
Paul A. Farr
Executive Vice President
PPL Energy Supply, LLC

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(e)

CERTIFICATE PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
FOR PPL ELECTRIC UTILITIES CORPORATION'S FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2011

In connection with the annual report on Form 10-K of PPL Electric Utilities Corporation (the "Company") for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Covered Report"), I, the principal executive officer of the Company, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify that:

- The Covered Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- The information contained in the Covered Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2012

/s/ David G. DeCampli
David G. DeCampli
President
PPL Electric Utilities Corporation

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(f)

CERTIFICATE PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
FOR PPL ELECTRIC UTILITIES CORPORATION'S FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2011

In connection with the annual report on Form 10-K of PPL Electric Utilities Corporation (the "Company") for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Covered Report"), I, the principal financial officer of the Company, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify that:

- The Covered Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- The information contained in the Covered Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2012

/s/ Vincent Sorgi
Vincent Sorgi
Vice President and Chief Accounting Officer
PPL Electric Utilities Corporation

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

CERTIFICATE PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
FOR LG&E AND KU ENERGY LLC'S FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2011

In connection with the annual report on Form 10-K of LG&E and KU Energy LLC (the "Company") for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Covered Report"), I, the principal executive officer of the Company, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify that:

- The Covered Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- The information contained in the Covered Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2012

/s/ Victor A. Staffieri
Victor A. Staffieri
Chairman, President and Chief Executive Officer
LG&E and KU Energy LLC

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(h)

CERTIFICATE PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
FOR LG&E AND KU ENERGY LLC'S FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2011

In connection with the annual report on Form 10-K of LG&E and KU Energy LLC (the "Company") for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Covered Report"), I, the principal financial officer of the Company, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify that:

- The Covered Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- The information contained in the Covered Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2012

/s/ Kent W. Blake
Kent W. Blake
Chief Financial Officer
LG&E and KU Energy LLC

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(i)

CERTIFICATE PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
FOR LOUISVILLE GAS AND ELECTRIC COMPANY'S FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2011

In connection with the annual report on Form 10-K of Louisville Gas and Electric Company (the "Company") for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Covered Report"), I, the principal executive officer of the Company, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify that:

- The Covered Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- The information contained in the Covered Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2012

/s/ Victor A. Staffieri
Victor A. Staffieri
Chairman, President and Chief Executive Officer
Louisville Gas and Electric Company

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

CERTIFICATE PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
FOR LOUISVILLE GAS AND ELECTRIC COMPANY'S FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2011

In connection with the annual report on Form 10-K of Louisville Gas and Electric Company (the "Company") for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Covered Report"), I, the principal financial officer of the Company, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify that:

- The Covered Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- The information contained in the Covered Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2012

/s/ Kent W. Blake
Kent W. Blake
Chief Financial Officer
Louisville Gas and Electric Company

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(k)

CERTIFICATE PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
FOR KENTUCKY UTILITIES COMPANY'S FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2011

In connection with the annual report on Form 10-K of Kentucky Utilities Company (the "Company") for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Covered Report"), I, the principal executive officer of the Company, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify that:

- The Covered Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- The information contained in the Covered Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2012

/s/ Victor A. Staffieri
Victor A. Staffieri
Chairman, President and Chief Executive Officer
Kentucky Utilities Company

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(l)

CERTIFICATE PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
FOR KENTUCKY UTILITIES COMPANY'S FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2011

In connection with the annual report on Form 10-K of Kentucky Utilities Company (the "Company") for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Covered Report"), I, the principal financial officer of the Company, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify that:

- The Covered Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- The information contained in the Covered Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2012

/s/ Kent W. Blake
Kent W. Blake
Chief Financial Officer
Kentucky Utilities Company

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

KWalton

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What if my heating and air conditioning service technician recommends I have my switch disconnected?

While we have attempted to educate heating and air conditioning contractors about the Demand Conservation program, on occasion, they may recommend your switch be removed or disconnected. Please have your service technicians call us at **1-800-356-5467** before allowing them to proceed with disconnection or removal. We have worked with the equipment manufacturers during the design of this device and program, so you can be assured your switch will not damage your air conditioner or heat pump in any way and will not affect your equipment's warranty.

Exactly how does my switch cut power off to my air conditioner compressor?

The switch is connected to the low voltage wire that goes from your thermostat to your air conditioner's compressor. The switch turns off the compressor just as if you had manually adjusted your thermostat to turn the air conditioner off for a few minutes. It's that simple. Your switch is also a radio that receives the control signal from us.

My switch has a label that says there will be a 3- to 7-minute delay after a power interruption. What does this mean?

This is one of the safety features. After a power interruption (outage) to the air conditioning unit or heat pump, the compressor is not allowed to operate for three to seven minutes to prevent short cycling, which could damage the compressor.

I'm having a new air conditioner or heat pump installed in my house. What should I do?

Call **1-800-356-5467** to let us know. We will arrange to have your switch installed on your new air conditioner or heat pump.

What if I have more than one central air conditioning unit at my home or business?

You will receive a $5 per summer month credit for each central air conditioner or heat pump you have at your home or business.

Does the Demand Conservation switch work on other appliances?

Yes, it does. If you have an electric water heater or pool pump, we will install a Demand Conservation device and pay you $2 per summer month (June–September) per device. If you are interested in adding your water heater or pool pump to the program, you can sign up online at **www.lge-ku.com/dc** or by calling **1-800-356-5467**.

I'm moving to a new house. What should I do?

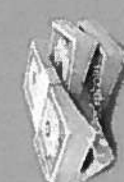
Call us at **1-800-356-5467.** We can arrange for a switch to be installed on the unit at your new house.

How do I sign up a neighbor or friend for the Demand Conservation program?

Have your friend, relative or neighbor call **1-800-356-5467** to sign up or visit **www.lge-ku.com/dc** to sign up online. For any other questions or comments, call us at **1-800-356-5467**.

LG&E and KU Energy LLC
P.O. Box 32010
Louisville, KY 40232

LG&E KU
PPL companies



Demand Conservation

Frequently Asked Questions.

LG&E KU
PPL companies

What is a Demand Conservation switch?

The Demand Conservation switch is a small radio receiver mounted near your outdoor air conditioning unit. Once installed, it is used briefly to interrupt your air conditioner's cycles on "peak" summer days to save electricity.

We don't control the switch very often or for very long. In fact, we have a maximum number of days we are allowed to use the switches. Plus, customers participating in the program report that they feel little or no difference in their home's temperature on the days we control.

In short, Demand Conservation helps preserve the environment and keep down the costs of generating electricity on peak demand days. Plus, you receive a credit on your electric bills during the summer months (June, July, August and September).

Who will install my Demand Conservation switch?

Our business partner, GoodCents, installs our switches at no cost to you. GoodCents specializes in the installation of these demand-saving devices and maintains all of the necessary licenses, permits and insurance. They have a proven track record of providing high-quality installations and superior customer service.

How do I sign up to get my Demand Conservation switch?

You can sign up online at **www.lge-ku.com/dc** or by calling us toll-free at **1-800-356-5467**.

When will I receive my first credit on my bill if I select the switch option?

The first June, July, August or September bill you receive after the switch is installed on your home should include the $5 credit. Please allow several days after the installation for us to process your paperwork.

How will my Demand Conservation switch work?

During periods of peak energy use in the summer months, a radio signal is sent to your switch to activate it. This signal will interrupt the flow of electricity to the compressor on your air conditioner or heat pump for a few minutes each half-hour. This reduces the peak demand for energy, helping to keep down the cost of electricity. Your fan will continue to run if your thermostat calls for cooling, circulating the cool air already inside your home and keeping you comfortable.

Does that mean my home will get hot?

You should notice little, if any, difference in your home's indoor air temperature. Our experience has been that customers see little difference in overall comfort level. Programs similar to this have been implemented by other large electric utilities since the early 1980s, and customers rarely, if ever, notice any difference in their indoor air temperature.

What should I do if I get hot?

Call us at **1-800-356-5467**. Typically, we can troubleshoot the problem over the telephone and either solve the problem or send one of our technicians. Of the few calls we have received, more than 90% of the problems that have been identified are related to something other than the switch.

How often will my switch be activated?

We will call for activation only on summer days when demand for electricity reaches a peak. Typically, this will occur for a few hours no more than 20 days all summer during the late afternoon and early evening. We will not activate your switch on weekends or holidays unless there is an extreme system emergency.

How long will it take after I sign up to install my switch?

Generally, your switch will be installed within three to four weeks. This can vary depending on the time of year and the number of customers who have signed up for the program.

Do I need to be home when my switch is installed?

You do not need to be home when it's installed. Just be sure any gates that provide access to your outside air conditioning unit are unlocked, and that there is not a lock on the electrical disconnect box located beside your air conditioning unit. We will leave a packet of information for you when we install the device.

How do I know if my switch is activated or is working properly?

A red or yellow light will show in the window on front of your switch when it has been activated. This light will stay on during the few minutes that electricity is being interrupted to the compressor. When the light goes out, electricity has been restored to the compressor, and cooling will continue. This process will repeat every thirty minutes during the period the switch is activated. If you see a green light on, off or momentarily flashing, it means the switch is testing itself.

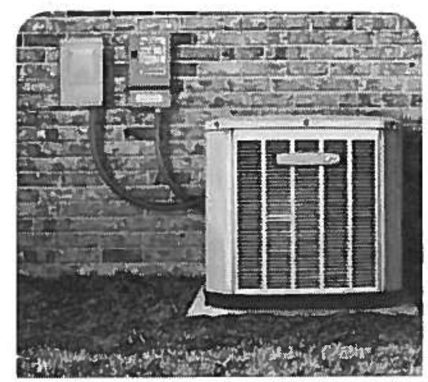
Please don't hesitate to contact us at **1-800-356-5467** anytime you have a question about your switch.

If my switch fails or is damaged, will it prevent my air conditioner or my heat from working?

Your switch is an extremely reliable piece of equipment with a failure rate of well below 1%. However, it is designed to allow your cooling or heating to continue working in the unlikely event of a failure.

I'm having a problem with my air conditioner or heating system not operating properly. What should I do? Is there someone I can call to make sure that it's not related to my switch?

First, we ask that you check your circuit breaker or fuses to make sure there is not a problem with them. If all of that checks out okay, call us at **1-800-356-5467** anytime, day or night. We can often help you determine the problem over the phone. If there is a problem with the switch, we will send a technician to your home right away to make any necessary corrections.



KWalton

LG&E and KU - Energy Efficiency - Demand Co
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Demand Conservation Program Facts

Demand Conservation is a program that allows us to put technology to work to save energy during peak times. We connect a small device to your central air conditioner, water heater or pool pump. When cycling is necessary (on summer weekdays between late afternoon and early evening), we send a signal to your air conditioner or heat pump to cycle off for a few minutes each half hour. Water heater and pool pump cycling occurs on a different schedule.

- Typically, air conditioner and heat pump cycling occurs no more than 20 days a year — but never on weekends or holidays — between the hours of 2 p.m. and 6 p.m.

- Most people are not even aware when their air conditioner is being cycled.

2012 Cycling Events:

Date	Day	Start Time	End Time
September 5, 2012	Wednesday	2:00 PM EDT	4:15 PM EDT
August 27, 2012	Monday	2:30 PM EDT	6:00 PM EDT
August 7, 2012	Tuesday	2:00 PM EDT	6:00 PM EDT
August 2, 2012	Thursday	2:00 PM EDT	6:00 PM EDT
August 1, 2012	Wednesday	2:00 PM EDT	6:00 PM EDT
July 31, 2012	Tuesday	2:00 PM EDT	6:00 PM EDT
July 26, 2012	Thursday	2:00 PM EDT	6:00 PM EDT
July 25, 2012	Wednesday	2:00 PM EDT	6:00 PM EDT
July 17, 2012	Tuesday	2:00 PM EDT	6:00 PM EDT
June 29, 2012	Friday	2:00 PM EDT	6:00 PM EDT

2011 Cycling Events

More than 160,000 customers currently participate in the program and are helping manage peak energy demand for everyone.

If you are already participating in the program, thank you for making a difference in our communities.

If you are considering participation, please read more about the program. Please contact us if you have questions or need more information.

If you're not already enrolled, please sign up today.

KWalton

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139 FERC ¶ 61,094
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Bluegrass Generation Company, L.L.C.
Louisville Gas and Electric Company
Kentucky Utilities Company

Docket No. EC12-29-000

ORDER CONDITIONALLY AUTHORIZING DISPOSITION AND ACQUISITION OF JURISDICTIONAL FACILITIES AND ACQUISITION OF GENERATING FACILITIES

(Issued May 4, 2012)

1. On November 14, 2011, Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU, and collectively with LG&E, LG&E/KU)[1] and Bluegrass Generation Company, L.L.C. (Bluegrass Generation, and collectively with LG&E/KU, Applicants) filed an application requesting Commission authorization under section 203(a)(1) of the Federal Power Act (FPA)[2] and Part 33 of the Commission's regulations,[3] for LG&E/KU to purchase from Bluegrass Generation an approximately 495 megawatt (MW) gas-fired generating facility (Bluegrass Facility) and certain

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[1] LG&E/KU state that they have filed this section 203 application on behalf of themselves and, to the extent necessary, their public utility affiliates in the PPL Corporation family of companies, which include: Electric Energy, Inc., LG&E Energy Marketing, Inc., Midwest Electric Power, Inc., PPL Electric Utilities Corporation, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Great Works, LLC, PPL Holtwood, LLC, PPL Maine, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL Susquehanna, LLC, PPL EnergyPlus, LLC, PPL New Jersey Solar, LLC, PPL New Jersey Biogas, LLC, PPL Renewable Energy, LLC, PPL Montana, LLC, PPL Colstrip I, LLC, and PPL Colstrip II, LLC.

[2] 16 U.S.C. § 824b(a)(1) (2006).

[3] 18 C.F.R. pt. 33 (2011).

jurisdictional facilities (Proposed Transaction).[4] The Commission has reviewed the Application under the Commission's Merger Policy Statement.[5] The Commission finds that the Proposed Transaction results in significant screen failures in the horizontal market power analysis. Therefore, the Commission is unable, at this time, to find that the Proposed Transaction will not have an adverse effect on competition. The Proposed Transaction is thus conditionally authorized, subject to LG&E/KU proposing adequate mitigation to remedy the identified screen failures, as discussed below.

I. Background

A. Description of the Parties

2. LG&E/KU are vertically-integrated electric utilities that are part of the PPL Corporation family. They are indirect, wholly-owned subsidiaries of PPL Corporation, a holding company under the Public Utility Holding Company Act of 2005.[6] Applicants state that, through various subsidiaries, PPL Corporation delivers electricity to more than 1.4 million customers in Pennsylvania, delivers electricity and natural gas to 1.3 million customers in Kentucky, Virginia and Tennessee, and sells energy in key U.S. markets.

3. LG&E is a public utility that owns and operates electric generation, transmission and distribution facilities, and also natural gas distribution, transmission and storage

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[4] *Application for Approval Pursuant to Section 203 of the Federal Power Act and Request for Expedited Consideration*, Docket No. EC12-29-000 (Nov. 14, 2011) (Application). The jurisdictional facilities associated with the Proposed Transaction include limited generation interconnection facilities and step-up transformers. Bluegrass Generation also states that authorization for termination of the lease for the Bluegrass Facility that it currently has with Oldham County, Kentucky may be required under section 203(a)(1). Application at n.5.

[5] *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997) (Merger Policy Statement). *See also FPA Section 203 Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 (2007) (Supplemental Policy Statement). *See also Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs. ¶ 31,111 (2000), *order on reh'g*, Order No. 642-A, 94 FERC ¶ 61,289 (2001). *See also Transactions Subject to FPA Section 203*, Order No. 669, FERC Stats. & Regs. ¶ 31,200 (2005), *order on reh'g*, Order No. 669-A, FERC Stats. & Regs. ¶ 31,214, *order on reh'g*, Order No. 669-B, FERC Stats. & Regs. ¶ 31,225 (2006).

[6] 42 U.S.C. §§ 16,451-16,463 (2006).

facilities in Kentucky, with limited electric transmission and natural gas storage facilities in Indiana. KU is a public utility that owns and operates electric generation, transmission and distribution facilities in Kentucky, Virginia, and Tennessee. Combined, LG&E and KU directly own approximately 8,001 MW of generation capacity and hold minority interests in certain entities that own generation.[7] Together they serve approximately 941,000 electric customers, and LG&E serves approximately 322,000 natural gas customers. LG&E and KU are authorized to engage in wholesale sales of capacity and energy at market-based rates,[8] but their market-based rate tariffs are currently limited to sales outside of the joint LG&E/KU balancing authority area (LG&E/KU BAA). KU also supplies power to several wholesale customers within the LG&E/KU BAA under cost-based formula rates.[9]

4. Additionally, Applicants state that LG&E owns and operates approximately 379 miles of natural gas transmission mains and approximately 4,249 miles of natural gas distribution mains, the majority of which are located in Kentucky. LG&E also owns five natural gas storage fields located in Kentucky and Indiana. LG&E/KU jointly own and operate an approximately six-mile natural gas transmission pipeline in Kentucky. KU owns and operates an approximately eleven-mile natural gas transmission pipeline in Kentucky.

5. Applicants state that Bluegrass Generation is a Delaware limited liability company, and a wholly-owned subsidiary of Port River, LLC (Port River). Port River is a Delaware limited liability company owned by LS Power Equity Partners II, L.P. and indirectly owned by LS Power Equity Partners II PIE, L.P. and LS Power Partners II, L.P. Bluegrass Generation is an exempt wholesale generator and has received market-based rate authority from the Commission.

6. The Bluegrass Facility is a three-unit, simple-cycle, gas-fired combustion turbine peaking generating facility with a combined summer rating of 495 MW located in

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[7] Applicants list the energy subsidiaries and energy affiliates of LG&E/KU in Exhibit B to the Application.

[8] *Louisville Gas & Elec. Co.*, 85 FERC ¶ 61,215 (1998) (accepting for filing joint market-based rate tariff of LG&E/KU, FERC Electric Tariff, Original Vol. No. 2); *Louisville Gas & Elec. Co.*, Docket No. ER02-1077-000 (Apr. 16, 2002) (delegated letter order accepting "short form" market-based rate tariff of LG&E/KU, FERC Electric Tariff, Original Vol. No. 3).

[9] *Kentucky Utilities Co.*, 125 FERC ¶ 61,242 (2008).

LaGrange, Kentucky.[10] The Bluegrass Facility is interconnected with LG&E's transmission system and the natural gas lines supplying fuel to the Bluegrass Facility are owned by Texas Gas Transmission. Applicants state that the energy output of the Bluegrass Facility is sold to a variety of parties, including LG&E and KU, on a spot basis.

B. Description of Proposed Transaction

7. Applicants state that, in order to comply with existing and planned Environmental Protection Agency (EPA) regulations for power plant emissions, LG&E/KU intend to retire six coal-fired generating units at three locations. As a result, LG&E/KU's generating capacity will be reduced by approximately 800 MW. Applicants state that these retirements will result in a capacity shortfall in 2016 of 877 MW, creating a significant need for new and additional resources to meet LG&E/KU's current load and projected load growth. After considering various resource alternatives, Applicants state that LG&E/KU have requested approval from the Kentucky Public Service Commission (Kentucky Commission) to build a natural gas combined-cycle generating unit at the existing Cane Run site and purchase the Bluegrass Facility. Applicants also state that they expect to file an application seeking Virginia State Corporation Commission (Virginia Commission) approval for the Proposed Transaction.[11]

8. Under the terms of the asset purchase agreement between Bluegrass Generation and LG&E/KU, LG&E/KU will pay approximately $110 million in cash for the Bluegrass Facility, subject to certain adjustments. The facilities to be conveyed include the generating facility itself, generator leads, and step-up transformers. LG&E/KU will acquire the Bluegrass Facility as tenants in common, with LG&E owning a 69 percent interest and KU a 31 percent interest.[12] Applicants state that Bluegrass Generation will retain its market-based rate tariff, as well as contracts and books and records thereunder.

---

[10] Applicants explain that the Bluegrass Facility is currently subject to a lease with Oldham County, Kentucky, and that immediately prior to the consummation of the Proposed Transaction, the lease will be terminated so that ownership of the Bluegrass Facility will revert to Bluegrass Generation before the sale of the facility to LG&E/KU. Application at 7.

[11] Application at 8-10, 29.

[12] *Id.* at 10, 21.

II. Notice of Filing

9. Notice of Applicants' filing was published in the *Federal Register*, 76 Fed. Reg. 72,195 (2011), with interventions and protests due on or before December 5, 2011. The comment date was subsequently extended to January 13, 2012.[13] No interventions or protests were filed.

III. Discussion

A. Standard of Review Under Section 203

10. Section 203(a)(4) requires the Commission to approve a transaction if it determines that the transaction will be consistent with the public interest.[14] The Commission's analysis of whether a transaction will be consistent with the public interest generally involves consideration of three factors: (1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation.[15] Section 203(a)(4) also requires the Commission to find that the transaction will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless the Commission determines that the cross-subsidization, pledge, or encumbrance will be consistent with the public interest. The Commission's regulations establish verification and information requirements for applicants that seek a determination that a transaction will not result in inappropriate cross-subsidization or pledge or encumbrance of utility assets.[16]

B. Analysis Under Section 203

1. Effect on Competition – Horizontal Market Power

a. Applicants' Analysis

11. Applicants submit that the Proposed Transaction will have no adverse effect on horizontal competition in generation. They identify the following relevant products across relevant geographic markets as: non-firm energy, short-term capacity (firm energy), long-term capacity, and certain ancillary services. In their analysis of non-firm

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[13] Errata Notice Extending Comment Date (Issued November 17, 2011), Docket No. EC12-29-000.

[14] 16 U.S.C. § 824b(a)(4) (2006).

[15] *See* Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,111.

[16] 18 C.F.R. § 33.2(j) (2011).

energy markets, Applicants argue that the relevant geographic market for analysis of the impact of the Proposed Transaction on horizontal competition in generation is the LG&E/KU BAA, as this is the only market in which the sales of LG&E/KU (and their affiliates) overlap with that of Bluegrass Generation.[17] Applicants explain that the Bluegrass Facility is located in the LG&E/KU BAA, interconnected with the transmission lines owned by LG&E, and the vast majority of sales from the Bluegrass Facility are made to LG&E/KU to serve their customers in the LG&E/KU BAA.[18]

12. In their analysis of non-firm energy markets, Applicants use economic capacity (EC) and available economic capacity (AEC) as proxies for a supplier's ability to participate in the market.[19] Applicants performed an Appendix A analysis, which includes a Delivered Price Test, to evaluate the effect on competition in the relevant markets over 10 separate time periods: super peak, peak and off-peak periods for summer, winter and shoulder seasons, along with an extreme summer super peak. Although Applicants' analysis considers all 10 periods, they state that the Bluegrass Facility is economic in only the two summer peak periods (summer super peak 1 and summer super peak 2), the winter super peak period and the shoulder super peak period.[20]

13. Applicants incorporate prices in their Delivered Price Test analysis ranging from $26/MWh in the shoulder off-peak period to $72/MWh in the summer super peak 1 period.[21] Applicants also examine price sensitivities of base case prices plus 10 percent, with prices ranging from $28/MWh in the shoulder off-peak period to $79/MWh in the summer super peak 1 period.[22] They also examine a sensitivity with prices 10 percent

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[17] Application at 12; and Appendix 2 (Solomon Affidavit) at 9-10.

[18] *Id.* at 12-13. Applicants state that the both LG&E/KU (along with their affiliates) and Bluegrass Generation make sales in the PJM Interconnection, L.L.C. (PJM) BAA, but that such sales are *de minimis*. *See* Application at nn.28-29.

[19] Each supplier's "economic capacity" is the amount of capacity that could compete in the relevant market given market prices, running costs, and transmission availability. "Available economic capacity" is based on the same factors but subtracts the supplier's native load obligation from its capacity and adjusts transmission availability accordingly. Applicants state that under both measures, capacity that is attributed to a market participant is that capacity controlled by it that can reach the destination market, taking transmission constraints and costs into account, at a price no higher than 105 percent of the destination market price. Appendix 2 (Solomon Affidavit) at 9-10.

[20] Application at 13.

[21] Appendix 2 (Solomon Affidavit) at 21.

[22] *Id.* at 24.

less than those in the base case, and an additional sensitivity based on Ventyx forecast prices, with prices ranging from $29/MWh in the shoulder off-peak period to $90/MWh in the summer super peak 1 period.[23]

14. In explaining the choice of prices used in their Delivered Price Test analysis, Applicants state that data for markets that are not in regional transmission organizations (RTO), such as the LG&E/KU BAA, are derived from data found in Electric Quarterly Reports (EQRs), or based on third-party forecasts. Applicants argue that reliance on EQR data is not without problems in the context of the Proposed Transaction. Among other things, Applicants state that short-term transactions in the LG&E/KU BAA are reported for a very small number of hours (approximately 1,000 hours in 2010). Applicants state that this is far fewer hours, covering far less volume, than the Commission deemed to be statistically reliable in its recent order conditionally approving the merger of Duke Energy Corporation and Progress Energy, Inc.[24] Applicants state that observations in the LG&E/KU BAA totaled 11.5 percent per year (i.e., 11.5 percent of 8,760 hours), as compared to 47 percent and 56 percent for the Duke Energy Carolinas and Progress Energy Carolinas East BAAs, respectively, as detailed in the Duke/Progress Merger Order.[25]

15. Second, Applicants state that the Proposed Transaction involves the acquisition of a single generating asset, which, as a combustion turbine (CT), is expected to operate infrequently. In this regard, Applicants state that the Bluegrass Facility operated only 315 hours in 2010 (3.6 percent), and had an average capacity factor of about 2.5 percent.[26] Applicants add that some LG&E/KU CTs have tended to have somewhat higher capacity factors (about 8 percent in 2010), but argue that any price series that infers operation of CTs at significantly higher levels raises serious doubts about the validity of the assumption about destination market prices.[27]

16. Third, Applicants state that a review of the potential destination market prices drawn from the three available data sources (system lambdas, EQRs, and Ventyx forecast

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[23] *Id.* at 25.

[24] *Id.* at 14 (quoting *Duke Energy Corp.*, 136 FERC ¶ 61,245, at P 126 (2011) (Duke/Progress Merger Order)).

[25] *Id.* at 13-15.

[26] *Id.* at 15.

[27] *Id.*

prices)[28] provided further insight into choosing reasonable market prices for the Delivered Price Test. Applicants state that using system lambdas generates an implied capacity factor of 0.01 percent for the Bluegrass Facility, both Ventyx forecast prices and EQR/system lambdas generate implied capacity factors of 4.7 percent, while EQR average prices generate an implied capacity factor of 28.7 percent. On the basis of implied capacity factors, Applicants argue that the appropriate base case prices to use for this analysis is the combination of system lambdas and EQRs, and therefore used this price series as the base case for their analysis.[29]

17. Applicants report failures of the Competitive Analysis Screen for AEC in all four seasons/load conditions in which the Bluegrass Facility is economic: super summer peak 1 and 2, winter super peak and shoulder super peak. The screen failures range from 402 to 1,081 points, with post-merger market concentrations ranging from 1,250 to 2,780 on the Herfindahl-Hirschman Index (HHI), with two screen failures occurring in a moderately concentrated market, denoted by an HHI value between 1,000 and 1,800, and two more in highly concentrated markets, denoted by an HHI value above 1,800.[30]

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[28] *Id.* at 16. Applicants state that their "system lambdas" price series is based on 2010 LG&E/KU hourly data reported in its FERC Form No. 714, adjusted to reflect 2012 system conditions by adjusting the prices to reflect changes in fuel costs between 2010 and 2012. Likewise, the Ventyx price series is based on Ventyx near-term (18 month) price forecast for 2012, for the LG&E/KU and East Kentucky Power Company BAAs, the EQR Average price series is based on a simple average of EQR short-term energy sales for the LG&E/KU BAA in 2010, also adjusted to reflect changes in fuel costs between 2010 and 2012, and the EQR/system lambda price series is based on a combination of EQR data and system lambdas, by "filling in" missing EQR price observations with system lambda data, with the implication that if there are no short-term sales, system lambdas become a reasonable approximation of the market price.

[29] Appendix 2 (Solomon Affidavit) at 16-17.

[30] Appendix 2 (Solomon Affidavit) at 8, n.5. The HHI is a widely accepted measure of market concentration, calculated by squaring the market share of each firm competing in the market and summing the results. The HHI increases both as the number of firms in the market decreases and as the disparity in size between those firms increases. Markets in which the HHI is less than 1,000 points are considered to be unconcentrated; markets in which the HHI is greater than or equal to 1,000 but less than 1,800 points are considered to be moderately concentrated; and markets in which the HHI is greater than or equal to 1,800 points are considered to be highly concentrated. In a horizontal merger, an increase of more than 50 HHI points in a highly concentrated market or an increase of 100 HHI points in a moderately concentrated market fails its screen and warrants further review. Merger Policy Statement, FERC Stats. & Regs.

(continued...)

Applicants argue that AEC is the appropriate measure by which to evaluate the impact of the Proposed Transaction on competition because there is no retail competition in Kentucky and the Commission has tended to rely on Delivered Price Test results for AEC where there is no retail competition.[31]

18. Applicants note that the Commission has indicated that it considers whether a proposed transaction will remove a competitor from the marketplace.[32] Applicants state that in the present case, although the Proposed Transaction will result in Bluegrass Generation and its affiliates no longer controlling generating capacity in the LG&E/KU BAA, that change will not for all intents and purposes remove a competitor from the marketplace.[33]

19. Specifically, Applicants note that, in recent years, LG&E/KU have purchased most of the output of the Bluegrass Facility. Applicants state that in 2010 LG&E/KU purchased 88,494 MWh of the 90,180 MWh of energy (including imbalance energy) reportedly sold by Bluegrass Generation, or 98 percent. Additionally, according to Applicants, in the first three quarters of 2011, LG&E/KU purchased all of the 34,172 MWh of energy (including imbalance energy) reportedly sold by Bluegrass Generation. Further, because the facility's capacity factor is low - approximately 2 percent in recent years – the acquisition of the facility by LG&E/KU to serve native load obligations will not, according to Applicants, create a market power problem in energy markets. Applicants state that, in recent years, the few sales not made directly or indirectly to LG&E/KU were made not in the LG&E/KU BAA, but rather in the PJM footprint. Applicants add that KU's wholesale customers are under requirements contracts with five-year termination provisions.[34]

¶ 31,044 at ¶ 30,129; *see Order Reaffirming Commission Policy and Terminating Proceeding,* 138 FERC ¶ 61,109 (2012) (affirming the Commission's use of the thresholds adopted in the Merger Policy Statement).

[31] Appendix 2 (Solomon Affidavit) at 3 n.1 (citing Duke/Progress Merger Order, among others).

[32] Application at 13, n.30. Applicants cite to Order No. 642, in which the Commission stated, at P 38: "Recognizing that energy companies are entering new product markets and that the effect of a merger could be to eliminate one of the merged companies as a perceived potential competitor in such new product markets, we will…require applicants to identify product markets in which they may be reasonably perceived as potential competitors."

[33] Application at 13.

[34] *Id.* at 13-14; Appendix 2 (Solomon Affidavit) at 3.

20. Applicants state that, in addition to LG&E/KU, there are only two other entities in the LG&E/KU BAA with a possible need to purchase wholesale energy in the marketplace – Owensboro Municipal Utilities (Owensboro), which generally satisfies its needs from its own generation, and the Kentucky Municipal Power Agency (KMPA), which in the past has been a wholesale customer of the Tennessee Valley Authority (TVA). Applicants further state that, currently, KMPA primarily purchases power from the Midwest Independent System Transmission Operator, Inc. market pending completion of the Prairie State Energy generating facility, of which KMPA owns a 7.82 percent share. Applicants state that, after the Prairie State Energy generating facility begins commercial operation, that facility will be sufficient to serve KMPA's load. Applicants conclude that, because they already purchase 98 percent of the output of the Bluegrass Facility and for the other reasons outlined above, a change in ownership of the Bluegrass Facility from Bluegrass Generation to LG&E/KU will not "materially remove a competitor from the marketplace."[35]

21. Applicants state that because of the time required to retrofit existing units with additional pollution controls and the time required to construct new generating capacity, LG&E/KU had to conduct studies and issue a request for proposals in 2010 so they would have time to implement the least cost alternative determined through the process. Applicants state that the acquisition of the Bluegrass Facility proved to be an element of the least cost solution even though it involves an acquisition in 2012 of capacity that is not expected to be required until 2016 with the retirement of certain coal units. Applicants argue that any increase in market concentration is thus transitory in nature and does not indicate the type of structural market power problem that generally concerns the Commission in the section 203 context.[36] Specifically, Applicants state that these retirements will result in a capacity shortfall of 877 MW in 2016.[37]

22. Applicants further argue that the Commission has approved transactions under FPA section 203 which, like the instant one, involved relatively small quantities of generating capacity where there were Competitive Analysis Screen failures for some periods,[38] citing, for example, the Commission's 2005 approval of the acquisition by Nevada Power Company of a 75 percent interest in a 560 MW generating facility located in the Nevada Power BAA. Applicants note that the application in that case showed

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[35] *Id.* at 14-15.

[36] *Id.* at 15-16.

[37] *Id.* at 13-14.

[38] *Id.* at 16.

Competitive Analysis Screen failures for one period under the AEC measure and for 11 of 14 periods under the EC measure.[39]

23. Applicants assert that several facts that the Commission found important in *Nevada Power* are also relevant to the Proposed Transaction. First, Nevada Power Company lacked market-based rate authority in its home BAA. Second, the Nevada Power BAA remained only moderately concentrated following the transaction in the spring peak period, the one period under the AEC measure showing a screen failure. Applicants note that the Commission nevertheless determined in that case that the transaction did not adversely affect competition and urge the Commission to come to the same conclusion with respect to the Proposed Transaction.[40]

b. <u>Commission Determination</u>

24. We find that, based on the record in this proceeding, Applicants have not shown that the Proposed Transaction will not have an adverse effect on horizontal competition in the LG&E/KU BAA. We will, however, afford Applicants the opportunity to propose mitigation measures to address the screen failures identified below. This approach is consistent with the Merger Policy Statement, in which the Commission noted that the merger guidelines "contemplate using remedies to mitigate any harm to competition."[41] The Commission explained that "[t]here could be mergers where, at the end of an analysis, market power concerns persist but that could be made acceptable with measures to mitigate potential market power problems."[42] We stated that proposing mitigation measures could "avoid the need for a formal hearing on competition issues and thus result in a quicker decision."[43]

25. Accordingly, as discussed more fully below, we conditionally authorize the Proposed Transaction, subject to LG&E/KU proposing adequate mitigation to address the existing screen failures in all four seasons/load conditions. Such mitigation measures are necessary to address the screen failures reported by Applicants attributed to the additional capacity that LG&E/KU will have from the date that the Proposed Transaction closes until capacity is removed from the LG&E/KU BAA as a result of all of the coal-fired units ceasing commercial operations. If commercial operation has ceased at all of the

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[39] *Id.* (citing *Nevada Power Co.*, 113 FERC ¶ 61,265 (2005) (*Nevada Power*)).

[40] *Id.* at 16-17.

[41] Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,118.

[42] *Id.*

[43] *Id.*

coal-fired units referenced in the Application, but screen failures still exist, LG&E/KU must propose additional mitigation measures to address the screen failures and such measures must be accepted by the Commission. In this way, the Commission will be able to ensure that there is no adverse effect on horizontal competition resulting from the Proposed Transaction either during the interim period or after. In any event, a new Delivered Price Test must be filed no later than December 31, 2016 so the Commission can determine if the mitigation should continue to be necessary.

26. We agree with Applicants that market prices, *supplemented* by system lambdas, provide a more accurate picture of the competitive situation in the LG&E/KU BAA than EQR data alone.[44] We make this determination based on Applicants' construction of implied capacity factors[45] and the limited amount of EQR data available for transactions in the LG&E/KU BAA. However, we note that in their plus 10 percent price sensitivity run, Applicants did not include a price range sufficient to cover a full range of possible price conditions, since the maximum price they examined was only $79/MWh.

27. Applicants' Delivered Price Test results using EQR prices supplemented by system lambda data show that there are screen failures in four of the 10 seasons/load periods in the AEC base case. These failures occur in the summer super peak 1 and summer super peak 2, winter super peak, and shoulder super peak seasons/load periods where LG&E/KU have high market shares involving large HHI increases.[46] The

[44] However, as we stated in the Duke/Progress Merger Order, the Commission prefers the use of actual market prices rather than price proxies such as system lambda. *See* Duke/Progress Merger Order, 136 FERC ¶ 61,245 at P 121.

[45] Applicants construct the price series, "EQR Average," based on a simple average of EQR short-term energy sales for the LG&E/KU BAA in 2010, adjusted to reflect changes in fuel costs between 2010 and 2012. Applicants' analysis using these prices results in a predicted (or "implied") capacity factor of 28.7 percent for the Bluegrass Facility. It is not reasonable to expect a peaking unit, such as the Bluegrass Facility, to operate in this many hours of the year. In contrast, Applicants' price series based on a combination of EQR data and system lambdas (EQR/lambdas), constructed by filling in missing EQR data with system lambdas, results in an implied capacity factor of 4.7 percent. Since this price series generates a much more reasonable capacity factor for the Bluegrass Facility, the Commission accepts it for use in its analysis of the impact of the Proposed Transaction on horizontal competition.

[46] The post-merger HHI for summer super peak 1 is 1,458 with an increase of 402 points; for summer super peak 2 the post-merger HHI is 2,780 with an increase of 1,081 points; and for winter super peak, the post-merger HHI is 1,954 with an increase of 595 points. LG&E/KU's largest market share in these three periods is 51.5 percent.

sensitivity analysis performed using EQR prices supplemented by system lambda data with a 10 percent price increase results in one additional screen failure, for a total of five screen failures.[47] The sensitivity analysis performed using EQR prices with a 10 percent decrease results in only three screen failures.[48] Based on these results, Applicants fail the summer super peak 1, summer super peak 2, and winter super peak seasons/load periods, under both the base case and 10 percent price increase sensitivity analyses.[49]

28. The Commission is normally concerned with cases where there are systematic screen failures, that is, where screen failures "present a consistent pattern across time periods and/or markets."[50] The Commission has indicated that systematic screen failures in markets that are highly concentrated and where an entity seeking authorization has a significant share of the market are a cause for concern.[51] We find that the screen failures in the LG&E/KU BAA (as shown in the table below) demonstrate a consistent pattern across various time periods and therefore indicate potential harm to competition. The failures are present in both summer and winter in all three price series (i.e., the base case, and the 10 percent price increase and 10 percent price decrease) as well as in multiple periods in the summer.

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[47] The additional failure is in the summer peak period (post-merger HHI of 3,857, an increase of 1,205 points). LG&E/KU's market share in this period is 61.5 percent.

[48] The post-merger HHI for summer super peak 1 is 1,460 with an increase of 400 points; for summer super peak 2 the post-merger HHI is 2,768 with an increase of 1,077 points; for winter super peak, the post-merger HHI is 1,940 with an increase of 592 points. LG&E/KU's largest market share in these three seasons/load periods is 51.5 percent.

[49] The post-merger HHI for summer super peak 1 is 1,524 with an increase of 458 points; for summer super peak 2 the post-merger HHI is 2,763 with an increase of 1,074 points; for winter super peak, the post-merger HHI is 1,938 with an increase of 590 points. LG&E/KU's largest market share in these three seasons/load periods is 51.5 percent.

[50] *CP&L Holdings, Inc.*, 92 FERC ¶ 61,023, at 61,054 (2000).

[51] *Nevada Power Co.*, 113 FERC ¶ 61,265, at P 15 (2005) (explaining that systematic screen failures would be cause for concern if a market was highly concentrated and post-merger the applicant had a more significant market share).

Table: Applicants' HHI Analysis

	Base Case Post Merger			Price Increase 10% Post Merger			Price Decrease 10% Post Merger			Ventyx Prices		
Period	Mkt Share	HHI	HHI Chg	Mkt Share	HHI	HHI Chg	Mkt Share	HHI	HHI Chg	Mkt Share	HHI	HHI Chg
S_SP1	35.90%	**1,458**	**402**	36.9%	**1,524**	**458**	35.9%	**1,460**	**400**	36.9%	**1,524**	**458**
S_SP2	51.50%	**2,780**	**1,081**	52.1%	**2,835**	**1,095**	51.5%	**2,768**	**1,077**	51.5%	**2,763**	**1,074**
S_P	23.90%	842	-	61.5%	**3,857**	**1,205**	21.1%	743	-	21.1%	741	-
S_OP	33.30%	1,349	-	45.0%	2,197	-	27.8%	1,059	-	33.3%	1,357	-
W_SP	42.70%	**1,954**	**595**	42.8%	**2,001**	**595**	42.8%	**1,940**	**592**	42.7%	**1,938**	**590**
W_P	15.30%	499	-	15.3%	482	-	0.8%	373	-	15.3%	500	-
W_OP	10.50%	422	-	21.0%	684	-	5.3%	517	-	10.6%	433	-
SH_SP	33.10%	**1,250**	**418**	34.9%	**1,371**	**461**	16.2%	526	-	26.0%	881	256
SH_P	3.30%	409	-	15.4%	550	-	0.5%	493	-	21.1%	671	-
SH_OP	20.70%	824	-	20.9%	745	-	19.5%	821	-	21.1%	709	-

Source: Solomon Affidavit at 21, 24, and 25.

29. We reject Applicants' argument that Bluegrass Generation is not a competitor in the wholesale markets in LG&E/KU BAA and, thus, that LG&E/KU's acquisition of the Bluegrass Facility will not materially remove a competitor from the market place. As noted above, Applicants base their argument on two claims: first, that Bluegrass Generation has not made any material sales to any entities other than LG&E/KU in the past few years; and second, that the only other potential wholesale market customers in the LG&E/KU BAA (Owensboro and KMPA) will not need to purchase any generation from the Bluegrass Facility. However, with respect to the first of these claims, Applicants ignore the fact that Bluegrass Generation made a competitive offer in LG&E/KU's request for proposals, indeed, one that LG&E/KU accepted as a least cost resource option. Therefore, the Proposed Transaction does remove a competitor from the marketplace. The latter claim is based on Applicants' unsubstantiated assertion that Owensboro and KMPA have not historically made purchases from Bluegrass Generation and that neither of them will do so in the future because, according to Applicants, Owensboro generally satisfies its needs from its own generation and KMPA will soon do so with the completion of the Prairie State Energy generation facility.

30. We also reject Applicants' argument that the facts presented in this case are similar to those in *Nevada Power*. In *Nevada Power*, there was only one screen failure in

a moderately concentrated market in which Nevada Power's market share was approximately 21 percent. Under these circumstances, the Commission did not find that Nevada Power had an ability to exercise market power.[52] In contrast, in this proceeding, Applicants have reported a consistent pattern of screen failures across various time periods.

31. In light of the consistent pattern of screen failures discussed above, we find that Applicants have not shown that the Proposed Transaction will not have an adverse effect on horizontal competition in the LG&E/KU BAA. Therefore, the Commission is unable, at this time, to find that the Proposed Transaction will not have an adverse effect on competition. We are not persuaded that the Proposed Transaction will not harm competition, either during the interim period or after commercial operation has ceased at all of the coal-fired units have been. Specifically, the analysis Applicants provide does not demonstrate that the retirement of the coal-fired units will mitigate or address the screen failures that will result from the Proposed Transaction. Accordingly, the Commission is conditionally authorizing the Proposed Transaction subject to LG&E/KU making two compliance filings.

32. Specifically, in the first compliance filing, due within 60 days of the date of this order, LG&E/KU must propose adequate mitigation to address the existing screen failures in all four seasons/load conditions, as well as to demonstrate that they will pass our screens in future years when the coal-fired generating units have been retired. To remedy this concern, LG&E/KU could explore mitigation such as relinquishing operational control (or selling the output under a long-term firm contract) of a sufficient amount of the output of the Bluegrass Facility (or comparable other capacity) as to remedy the screen failures. We note that LG&E/KU are not limited to this mitigation, which is intended to serve as guidance only. LG&E/KU may propose a different mitigation measure to remedy the anticompetitive effects of the Proposed Transaction. LG&E/KU should include in their compliance filing an HHI analysis of the proposed mitigation reflecting a base case scenario of the pre-transaction market. After providing an opportunity for comments from interested parties, the Commission will issue a subsequent order indicating whether the proposed mitigation is sufficient.

33. LG&E/KU are directed to make a second compliance filing after a mitigation plan for LG&E/KU is approved by the Commission and the Proposed Transaction closes, within 60 days of the date on which the last of the six coal-fired units is no longer

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[52] *Nevada Power Co.*, 113 FERC ¶ 61,265 at P 15.

available for commercial operation,[53] but in any event, no later than December 31, 2016. In this compliance filing, LG&E/KU are directed to use the pre-transaction market as the base case to analyze the effect on competition. If, prior to December 31, 2016, LG&E/KU determine on the basis of a new Delivered Price Test that the conditions in the LG&E/KU BAA market have changed such that there are no longer any screen failures in the LG&E/KU BAA (i.e., LG&E/KU are able to demonstrate that they have ceased commercial operation of a sufficient amount of MW of capacity such that no horizontal screen failures remain), LG&E/KU may make their second compliance filing at that time.

2. Effect on Competition – Vertical Market Power

a. Applicants' Analysis

34. Applicants contend that the Proposed Transaction does not raise any vertical market power issues. Applicants argue that the consolidation of LG&E/KU's electric transmission assets with the Bluegrass Facility will not enhance vertical market power because it will not enhance any ability of LG&E/KU to restrict potential downstream competitors' access to upstream supply. Applicants further note that LG&E/KU's transmission lines are subject to an open access transmission tariff (OATT) and the oversight of Southwest Power Pool (SPP)[54] and TVA, and contend that the facilities to be acquired from Bluegrass Generation will provide LG&E/KU no enhanced ability to restrict potential downstream competitors' access to upstream supply. Applicants argue that in previous transactions, the Commission has found that open access to transmission

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[53] We note that Applicants use the terms "retire" and "retirement" to refer to an event or action that will cause the six coal-fired units listed in the Application to reduce LG&E/KU's generating capacity by approximately 800 MW. We interpret these terms to refer to the point in time when the six plants are no longer available for commercial operation.

[54] We note that in *Louisville Gas & Elec. Co.,* 137 FERC ¶ 61,195 (2011), the Commission conditionally approved the appointment of TranServ International, Inc. as the Independent Transmission Organization for the LG&E/KU BAA when the contract with SPP expires on August 31, 2012.

facilities provided sufficient assurance that the applicants could not use their control of transmission facilities in a manner that could harm competition.[55]

35. Applicants argue that LG&E's ownership of natural gas distribution systems and storage facilities also does not raise any vertical market power concerns. Applicants state that LG&E's natural gas distribution system and storage facilities are not connected with nor are they used to serve any non-affiliated gas-fired generating facilities. Applicants add that LG&E is authorized to offer firm and interruptible natural gas storage services in interstate commerce at market-based rates.[56] Applicants also state that Kentucky state law and regulation require LG&E to offer retail gas service on a non-discriminatory basis. Applicants assert that, while LG&E does reserve interstate pipeline capacity primarily to serve its retail customers, LG&E's share of the interstate pipeline capacity in Kentucky was recently estimated at no more than 2.2 percent.[57]

36. Applicants argue that the Proposed Transaction will not provide LG&E/KU any ability to erect barriers to market entry. Applicants state that LG&E/KU's natural gas assets are limited in nature and cannot be used to restrict market entry. Applicants contend that while LG&E/KU own and control an extensive electric transmission system, access to this system – including generator interconnections – is subject to open access pursuant to the LG&E/KU OATT, which is administered by an independent transmission operator. Applicants add that neither LG&E/KU, Bluegrass Generation, nor any of their affiliates, own or control sites for new potential generation in such quantities that the siting and construction of new generation is foreclosed or harmed in any meaningful way.[58]

b. Commission Determination

37. As the Commission has previously found, transactions that combine electric generation assets with inputs to generating power (such as natural gas, transmission, or fuel) can harm competition if the transaction increases a firm's ability or incentive to exercise vertical market power in wholesale electricity markets. For example, by denying

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[55] Application at 18 (citing *TECO Wholesale Generation, Inc.*, 107 FERC ¶ 62,208 (2004)).

[56] *Louisville Gas & Elec. Co.*, 99 FERC ¶ 62,040 (2002); *Louisville Gas & Elec. Co.*, 120 FERC ¶ 62,031 (2007).

[57] Application at 18-19 (citing *PPL Corp. and E.ON U.S. LLC*, Docket No. EC10-77, section 203 Application, Affidavit of Dr. Joseph P. Kalt and Joseph Cavicchi at P 76).

[58] Application at 19-20.

rival firms access to inputs or by raising their input costs, a firm created by the transaction could impede entry of new competitors or inhibit existing competitors' ability to undercut an attempted price increase in the downstream wholesale electricity market.

38. The Commission finds that the Proposed Transaction does not raise any vertical market power concerns. As Applicants note, LG&E/KU's transmission lines are subject to an open access transmission tariff and the oversight of SPP and TVA, and the only transmission facilities involved in the Proposed Transaction are limited interconnection facilities associated with the Bluegrass Facility. Likewise, Applicants have stated that LG&E's ownership of a natural gas distribution system and storage facilities also does not raise any vertical market power concerns, and that the Proposed Transaction will not increase Applicants' ability to erect barriers to entry.

3. <u>Effect on Rates</u>

a. <u>Applicants' Analysis</u>

39. Applicants argue that the Proposed Transaction will have no adverse effect on transmission rates or on rates for wholesale requirements customers. Applicants state that KU sells wholesale power to 12 municipal utilities under long-term agreements containing cost-based formula rates on file with the Commission. Applicants add that while the inputs to the formula will likely change as a result of the Proposed Transaction – by reflecting the net book value of the Bluegrass Facility – the formula itself will not change. Applicants state that any change to the formula inputs would likely result in only a small change in the amounts charged by KU to these wholesale customers and any increase may be offset by potential savings in energy rates. Applicants state that because KU will own 31 percent of the facility, that same percentage of the net book value of the facility will be included in the inputs to KU's formula rates, which LG&E/KU estimates will increase capacity charges by 1.16 percent. As to energy rates, Applicants state that KU's cost-based wholesale customers pay an average system charge that in many hours may be unaffected or reduced by the purchase of the Bluegrass Facility. Applicants also argue that if the formula rate produces a slightly higher charge for wholesale requirements customers in a given year compared to existing rate levels following the Proposed Transaction, the Commission has held in the section 203 context that rate increases do not amount to "adverse effects" on rates when there are countervailing benefits that derive from the transaction, including environmental benefits. Applicants explain that although LG&E/KU sell short-term wholesale power to certain entities under agreements entered into under the terms of their cost-based rate tariff for short-term energy sales, the prices for these sales are negotiated, subject to a cap of 110 percent of the LG&E/KU system incremental cost, and therefore customers under these agreements are shielded from any adverse rate effect of the Proposed Transaction. Applicants also add that LG&E/KU's spot energy sales outside of the LG&E/KU BAA are made via

contracts entered into under their market-based rate tariffs, and that these contracts cannot impose any costs related to the Proposed Transaction on their customers.[59]

40. Applicants also argue that the Proposed Transaction will have no adverse effect on LG&E/KU's transmission service rates. Applicants state that all of the assets being acquired by LG&E/KU pursuant to the Proposed Transaction are generation assets and/or limited transmission assets such as generation leads or step-up transformers associated with the Bluegrass Facility. Applicants therefore argue that these assets are not classified as transmission assets for cost-of-service ratemaking purposes.[60]

b. Commission Determination

41. Under the circumstances presented, the Commission finds that the Proposed Transaction will not have an effect on rates that is inconsistent with the public interest. Although Applicants indicate that there may be a small increase in capacity charges under their formula rates for wholesale requirements customers, they represent that such increase may be offset by savings in energy rates. Moreover, under state regulation in Kentucky and Virginia, Applicants will retire coal-fired generation based on existing and planned EPA regulations and they have explained that the Proposed Transaction is part of a least-cost resource procurement process that is intended to satisfy those legal requirements. Likewise, we note that transmission customers will not be affected by the Proposed Transaction since the assets being transferred are not classified as transmission assets for cost-of-service ratemaking purposes. We note that no parties have argued that the Proposed Transaction will adversely affect rates.

4. Effect on Regulation

a. Applicants' Analysis

42. Applicants assert that the Proposed Transaction will not diminish federal regulatory authority over LG&E/KU insofar as, following the Proposed Transaction, LG&E/KU and the Bluegrass Facility will remain subject to the Commission's jurisdiction under the FPA. Applicants submit that the Proposed Transaction will have no adverse impact on state regulation insofar as consummation is conditioned on approval by the Kentucky Commission and the Virginia Commission.[61]

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[59] Application at 21-22.

[60] *Id.* at 23.

[61] *Id.* at 23-24.

b. Commission Determination

43. We find no evidence that either state or federal regulation will be impaired by the Proposed Transaction. The Commission's review of a transaction's effect on regulation focuses on ensuring that it does not result in a regulatory gap at the federal or state level.[62] We find that the Proposed Transaction will not create a regulatory gap at the federal level because the Commission will retain its regulatory authority over the companies after the Proposed Transaction is consummated. The Commission stated in the Merger Policy Statement that it ordinarily will not set the issue of the effect of a transaction on state regulatory authority for a trial-type hearing where a state has authority to act on the transaction. However, if the state lacks this authority and raises concerns about the effect on regulation, the Commission stated that it may set the issue for hearing, and that it will address such circumstances on a case-by-case basis.[63] We note that no state commission has requested that the Commission address the issue of the effect of the Proposed Transaction on state regulation.

5. Cross-subsidization

a. Applicants' Analysis

44. Applicants assert that the Proposed Transaction qualifies for the state review "safe harbor" from cross-subsidization review. Specifically, they state that the Proposed Transaction is subject to review by the Kentucky Commission, and that the Kentucky Commission, by reviewing the Proposed Transaction, will be able to protect against any inappropriate cross-subsidization that could result from the Proposed Transaction. In light of this review, Applicants submit that there is no need for a further examination of cross-subsidization and encumbrance concerns as to the Proposed Transaction.[64]

45. Notwithstanding the application of the state review safe harbor, Applicants state that the Proposed Transaction also satisfies the Commission's four-part test for cross-subsidization.[65] Applicants contend that based on facts and circumstances known to them or that are reasonably foreseeable, the Proposed Transaction will not result in, at the time of the Proposed Transaction or in the future, cross-subsidization of a non-utility associate company or pledge or encumbrance of utility assets for the benefit of an associate company. Applicants further state that the Proposed Transaction will not result

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[62] Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,124.

[63] *Id.* at 30,125.

[64] Application, Exhibit M at M-1.

[65] 18 C.F.R. § 33.2(j)(1) (2011).

in, now or in the future: (1) any transfer of facilities between a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, and an associate company; (2) any new issuance of securities by a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company; or (3) any new affiliate contract between a non-utility associate company and a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, other than non-power goods and services agreements subject to review under sections 205 and 206 of the FPA.[66]

46. With respect to any pledge or encumbrance of assets of a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company, Applicants note that the assets to be acquired in the Proposed Transaction will automatically become subject to the liens under LG&E/KU's existing first mortgage indentures, which secure existing or future long-term debt issued by LG&E/KU, particularly first mortgage bonds series, including certain series which serve as collateral for pollution control bonds issued by either company. Thus, Applicants explain that the assets to be acquired will be pledged or encumbered in a manner similar to other like property of LG&E/KU, and only in such similar manner. Finally, Applicants disclose LG&E/KU's existing pledges and encumbrances of utility assets, as required under Order No. 669-A and section 33.2(j)(1) of the Commission's regulations.[67]

b. Commission Determination

47. Based on the representations as presented in the Application, we find that the Proposed Transaction will not result in cross-subsidization or the pledge or encumbrance of utility assets for the benefit of an associate company or, where there is a new encumbrance, it is consistent with the public interest.

C. Accounting Matters

48. LG&E/KU propose to account for the purchase of the generating facility in accordance with Electric Plant Instruction (EPI) No. 5 and Account 102, Electric Plant Purchased or Sold. They anticipate a negative acquisition adjustment resulting from the purchase and propose to record the amount as a credit to Account 108, Accumulated

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[66] Application, Exhibit M at M-1 to M-2.

[67] *See* Application at Exhibit M at M-2.

Provision for Depreciation of Electric Utility Plant. LG&E/KU must submit their final accounting entries in accordance with EPI No. 5 and Account 102 within six months of the date that the Proposed Transaction is consummated, and the accounting submissions must provide all the accounting entries and amounts related to the purchase along with narrative explanations describing the basis for the entries.

D. Reliability and Cyber Security Standards

49. Information and/or systems connected to the bulk power system involved in this transaction may be subject to reliability and cyber security standards approved by the Commission pursuant to FPA section 215. Compliance with these standards is mandatory and enforceable regardless of the physical location of the affiliates or investors, information databases, and operating systems. If affiliates, personnel or investors are not authorized for access to such information and/or systems connected to the bulk power system, a public utility is obligated to take the appropriate measures to deny access to this information and/or the equipment/software connected to the bulk power system. The mechanisms that deny access to information, procedures, software, equipment, and the like, must comply with all applicable reliability and cyber security standards. The Commission, North American Electric Reliability Corporation, or the relevant regional entity may audit compliance with reliability and cyber security standards.

The Commission orders:

(A) The Proposed Transaction is hereby conditionally authorized subject to the Commission finding that any mitigation measures proposed by LG&E/KU, in a first compliance filing filed within 60 days of the issuance of this order, address the identified screen failures such that the Proposed Transaction does not have an adverse effect on competition, as discussed in the body of this order.

(B) LG&E/KU are also directed to make a second compliance filing within 60 days of the date that the last of the six coal-fired units ceases commercial operation, but in any event no later than December 31, 2016, to analyze the effect on competition, as discussed in the body of this order.

(C) Applicants must inform the Commission within 30 days of any material change in circumstances that departs from the facts the Commission relied upon in conditionally authorizing the Proposed Transaction.

(D) The foregoing conditional authorization is without prejudice to the authority of the Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determination of costs, or any other matter whatsoever now pending or which may come before the Commission.

(E) Nothing in this order shall be construed to imply acquiescence in any estimate or determination of costs or any valuation of property claimed or asserted.

(F) The Commission retains authority under section 203(b) and 309 of the FPA to issue supplemental orders as appropriate.

(G) Applicants must make any appropriate filings under section 205 of the FPA, as necessary, to implement the Proposed Transaction.

(H) Applicants must notify the Commission within 10 days of the date on which the Proposed Transaction is consummated.

(I) LG&E/KU must account for the Proposed Transaction in accordance with EPI No. 5 and Account 102, of the Uniform System of Accounts. LG&E/KU must submit their final accounting entries within six months of the date that the purchase is consummated, and the accounting submissions must provide all the accounting entries and amounts related to the purchase along with narrative explanations describing the basis for such entries.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

KWalton

LG&E and KU - Energy Efficiency - Demand Co
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Demand Conservation - 2011 Cycling Events

Here is a list of the 2011 cycling events:

Date	Day	Start Time	End Time
June 8, 2011	Wednesday	2:00 PM	6:00 PM
July 11, 2011	Monday	2:00 PM	6:00 PM
July 12, 2011	Tuesday	2:00 PM	3:11 PM
July 20, 2011	Wednesday	2:00 PM	6:00 PM
July 21, 2011	Thursday	2:00 PM	6:00 PM
July 22, 2011	Friday	2:00 PM	6:00 PM
July 27, 2011	Wednesday	2:00 PM	6:00 PM
July 28, 2011	Thursday	2:00 PM	6:00 PM
September 1, 2011	Thursday	2:00 PM	6:00 PM
September 2, 2011	Friday	2:00 PM	6:00 PM

KWalton

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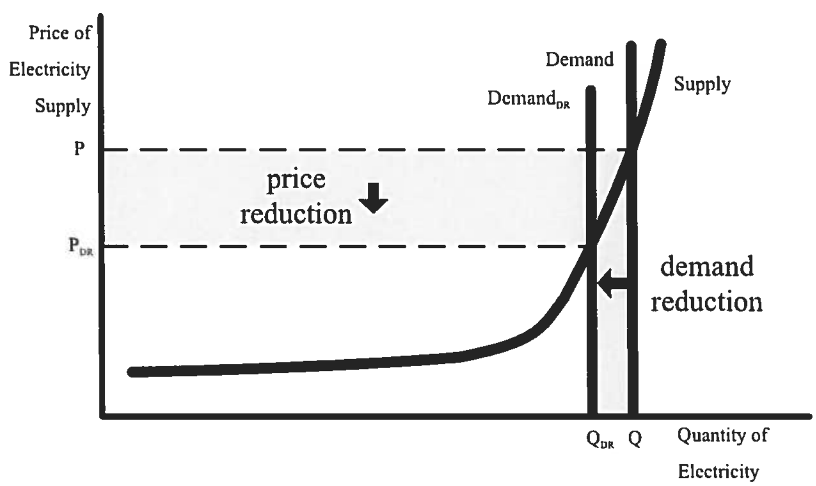
BENEFITS OF DEMAND RESPONSE IN ELECTRICITY MARKETS AND RECOMMENDATIONS FOR ACHIEVING THEM

A REPORT TO THE UNITED STATES CONGRESS PURSUANT TO SECTION 1252 OF THE ENERGY POLICY ACT OF 2005



February 2006

U.S. Department of Energy

The Secretary [of Energy] shall be responsible for... not later than 180 days after the date of enactment of the Energy Policy Act of 2005, providing Congress with a report that identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007.

--Sec. 1252(d), the Energy Policy Act of 2005, August 8, 2005

EXECUTIVE SUMMARY

Sections 1252(e) and (f) of the U.S. Energy Policy Act of 2005 (EPACT)[1] state that it is the policy of the United States to encourage "time-based pricing and other forms of demand response" and encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public. The law also requires the U.S. Department of Energy (DOE) to provide a report to Congress, not later than 180 days after its enactment, which "identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007" (EPACT, Sec. 1252(d)).

Background

Most electricity customers see electricity rates that are based on average electricity costs and bear little relation to the true production costs of electricity as they vary over time. Demand response is a tariff or program established to motivate changes in electric use by end-use customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized.

- *Price-based demand response* such as real-time pricing (RTP), critical-peak pricing (CPP) and time-of-use (TOU) tariffs, give customers time-varying rates that reflect the value and cost of electricity in different time periods. Armed with this information, customers tend to use less electricity at times when electricity prices are high.
- *Incentive-based demand response programs* pay participating customers to reduce their loads at times requested by the program sponsor, triggered either by a grid reliability problem or high electricity prices.

Limited demand response capability exists in the U.S. today.[2] Total demand response and load management capability has fallen by about one-third since 1996 due to diminished utility support and investment.

States should consider aggressive implementation of price-based demand response for retail customers as a high priority, as suggested by EPACT. Flat, average-cost retail rates that do not reflect the actual costs to supply power lead to inefficient capital investment in new generation, transmission and distribution infrastructure and higher electric bills for customers. Price-based demand response cannot be achieved immediately for all customers. Conventional metering and billing systems for most customers are not adequate for charging time-varying rates and most customers are not used to making electricity decisions on a daily or hourly basis. The transformation to time-varying retail rates will not happen quickly. Consequently, fostering demand response through

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[1] Public Law 109-58, August 8, 2005.

[2] In 2004 potential demand response capability equaled about 20,500 megawatts (MW), 3% of total U.S. peak demand, while actual delivered peak demand reduction was about 9,000 MW (1.3% of peak).

incentive-based programs will help improve efficiency and reliability while price-based demand response grows.

The Benefits of Demand Response

The most important benefit of demand response is improved resource-efficiency of electricity production due to closer alignment between customers' electricity prices and the value they place on electricity. This increased efficiency creates a variety of benefits, which fall into four groups:

- *Participant financial benefits* are the bill savings and incentive payments earned by customers that adjust their electricity demand in response to time-varying electricity rates or incentive-based programs.
- *Market-wide financial benefits* are the lower wholesale market prices that result because demand response averts the need to use the most costly-to-run power plants during periods of otherwise high demand, driving production costs and prices down for all wholesale electricity purchasers. Over the longer term, sustained demand response lowers aggregate system capacity requirements, allowing load-serving entities (utilities and other retail suppliers) to purchase or build less new capacity. Eventually these savings may be passed onto most retail customers as bill savings.
- *Reliability benefits* are the operational security and adequacy savings that result because demand response lowers the likelihood and consequences of forced outages that impose financial costs and inconvenience on customers.
- *Market performance benefits* refer to demand response's value in mitigating suppliers' ability to exercise market power by raising power prices significantly above production costs.

Quantifying the National Benefits of Demand Response

DOE reviewed recent studies that have quantified demand response benefits and assessed the analytical methods used and analyzed ten studies that estimated the benefits of actual or proposed demand response initiatives for specific regions. The results point out important inconsistencies in how demand response is currently measured.

To date there is little consistency in demand response quantification. Three types of studies have looked at demand response benefits; the time horizons and categories of benefits examined vary widely.

- *Illustrative analyses* quantify the economic impacts of demand response; the four studies examined here look within organized wholesale markets. These studies report relatively high levels of benefits in part because they assume high levels of demand response penetration over a large customer base and long-term sustained benefits.
- *Integrated resource planning studies* look at whether and how much to use demand response resources as part of a long-term resource plan. These studies

assume regional impacts over a long time period and report high levels of demand response benefits.

- *Program performance studies* measure the actual delivered value of demand response programs implemented by several independent grid operators (e.g., the PJM Interconnection [PJM], the New York Independent System Operator [NYISO], and ISO-New England [ISO-NE]). These studies report the lowest level of demand response benefits, in part because they reflect market conditions over a short time period and do not necessarily capture the full range of market circumstances or value long-term impacts.

Based on this review, DOE concludes that, to date, the estimated benefits of demand response are driven primarily by the quantification method, assumptions regarding customer participation and responsiveness, and market characteristics. Without accepted analytical methods, DOE finds that it is not possible to quantify the national benefits of demand response. Moreover, regional differences in market design, operation, and resource balance are important and must be taken into account. Estimates of demand response benefits are best done for service territories, states, and regions, because the magnitude of potential benefits is tied directly to local electric system conditions (e.g., the supply mix, the presence or absence of supply constraints, the rate of demand growth, and resource plans for meeting demand growth).

Recommendations

EPACT directs DOE to recommend how more demand response can be put in place by January 1, 2007. DOE concludes that eleven months is too short a time for meaningful recommendations to be implemented and have any practical impact. Instead, DOE offers recommendations to encourage demand response nation-wide, which are organized as follows:

- **Fostering Price-Based Demand Response**—by making available time-varying pricing plans that let customers take control of their electricity costs. More efficient pricing of retail electricity service is of the utmost importance.
- **Improving Incentive-Based Demand Response**—to broaden the ways in which load management contributes to the reliable, efficient operation of electric systems. Incentive-based demand response programs can help improve grid operation, enhance reliability, and achieve cost savings.
- **Strengthening Demand Response Analysis and Valuation**—so that program designers, policymakers and customers can anticipate demand response impacts and benefits. Demand response program managers and overseers need to be able to reliably measure the net benefits of demand response options to ensure that they are both effective at providing needed demand reductions and cost-effective.
- **Integrating Demand Response into Resource Planning**—so that the full impacts of demand response, and the maximum level of benefits, are realized. Such efforts help establish expectations for the short- and long-run value and contributions of

demand response, and enable utilities and other stakeholders to compare demand response options with other alternatives.

- **Adopting Enabling Technologies**—to realize the full potential for managing usage on an ongoing basis given innovations in communications, control, and computing. Innovations in monitoring and controlling loads are underway offering an array of new technologies that will enable substantially higher level of demand response in all customer segments.
- **Enhancing Federal Demand Response Actions**—to take advantage of existing channels for disseminating information, providing technical assistance, and expanding opportunities for public-private collaboratives. Enhancing cooperation among those that provide new products and services and those that will use them is paramount.

OVERVIEW: KEY FINDINGS AND RECOMMENDATIONS

Introduction

Sections 1252(e) and (f) of EPACT state that it is the policy of the United States to encourage "time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them." It further states that "deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary services markets shall be eliminated". To help implement this new policy on demand response, the Act creates new requirements for electric utilities and states with respect to demand response. States are charged with conducting investigations to determine how those new provisions could be applied and whether to adopt widespread time-based pricing and advanced metering for utility retail customers.

EPACT directs DOE to encourage demand response by:

- educating consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects, and
- working with States, utilities, other energy providers, and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs (EPACT, Sec. 1252(d)).

The law also requires DOE to provide a report to Congress, not later than 180 days after its enactment, which "identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007" (EPACT, Sec. 1252(d)). This report fulfills that requirement.

Defining and Characterizing Demand Response

Demand response, defined broadly, refers to active participation by retail customers in electricity markets, seeing and responding to prices as they change over time. Currently, most customers see only flat, average-cost based electric rates that give them no indication that electricity values change over time, nor any incentive to vary their electric use in response to prices.

Demand response can be defined more specifically as:

> *Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*

Lower electricity use in peak periods creates benefits by reducing the amount of generation and transmission assets required to provide electric service. Lower demand in response to high prices (particularly market clearing prices in an organized regional spot market) reduces the costs of electricity production and holds down prices in electricity spot markets. Reduced demand in response to system reliability problems enhances operators' ability to manage the electric grid—the network that transmits electricity from generators to consumers—and reduces the potential for forced outages or full-scale blackouts.

Why is Demand Response Important?

Demand response offers a variety of financial and operational benefits for electricity customers, load-serving entities (whether integrated utilities or competitive retail providers) and grid operators. Electric power systems have three important characteristics. First, because electricity cannot be stored economically, the supply of and demand for electricity must be maintained in balance in real time. Second, grid conditions can change significantly from day-to-day, hour-to-hour, and even within moments. Demand levels also can change quite rapidly and unexpectedly, and resulting mismatches in supply and demand can threaten the integrity of the grid over very large areas within seconds. Third, the electric system is highly capital-intensive, and generation and transmission system investments have long lead times and multi-decade economic lifetimes.

These features of electric power systems require that power grids be planned and managed for years in advance to ensure that the system can operate reliably in real time despite the many uncertainties surrounding future demands, fuel sources, asset availability and grid conditions. Working in a competitive bulk power market, load serving entities (integrated utilities or retail electric providers) buy or build from 60 to 95% of their electricity in advance, with the expectation that they will be able to generate or purchase enough spot market electricity in real time to meet changing system demands.

These challenges and uncertainties are what make demand response so valuable—it offers flexibility at relatively low cost. Grid operators—Independent System Operators (ISOs), Regional Transmission Organizations (RTOs) or utilities—and other entities can use demand response to curtail or shift loads instead of, traditionally, building more generation. And although it takes time to establish and recruit customers for a demand response program, well-structured pricing and incentive-based demand response can produce significant savings in close to real time, often at lower costs than supply-side resources.

Types of Demand Response

Demand response can be classified according to how load changes are brought about.

- *Price-based demand response* refers to changes in usage by customers in response to changes in the prices they pay and include real-time pricing, critical-peak pricing, and time-of-use rates. If the price differentials between hours or time periods are significant, customers can respond to the price structure with significant changes in energy use, reducing their electricity bills if they adjust the timing of their electricity usage to take advantage of lower-priced periods and/or avoid consuming when prices are higher. Customers' load use modifications are entirely voluntary.
- *Incentive-based demand response* programs are established by utilities, load-serving entities, or a regional grid operator. These programs give customers load-reduction incentives that are separate from, or additional to, their retail electricity rate, which may be fixed (based on average costs) or time-varying. The load reductions are needed and requested either when the grid operator thinks reliability conditions are compromised or when prices are too high. Most demand response programs specify a method for establishing customers' baseline energy consumption level, so observers can measure and verify the magnitude of their load response. Some demand response programs penalize customers that enroll but fail to respond or fulfill their contractual commitments when events are declared.[3]

The textbox below summarizes the major price-based and incentive-based demand response programs now in use.

EPACT encourages demand response that that allows customers to face the time-varying value of electricity and respond as they choose to those changes. Incentive-based demand response programs offer additional options to policymakers to help solve an area's or market's problems. For example, they can help address reliability problems or can be tailored to achieve specific operational goals, such as localized load reductions to relieve transmission congestion.

Over the long term, the maximum benefits of demand response will come about as the entire range of demand response programs are made available to customers—diversity has value on the demand side as well as the supply-side. Because power system and market circumstances change quickly, a variety of price-based and incentive-based demand response programs can help resolve longstanding industry challenges, such as matching the extended time required to site, approve and build generation and transmission assets to serve uncertain demand growth. In the meantime, it is necessary to understand how to identify and quantify the impacts and benefits of demand response, to facilitate effective and cost-effective implementation of demand response programs and enabling technologies.

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[3] These performance-based requirements are intended to increase system operators' confidence that demand reductions will materialize when needed.

Demand Response Options	
Price-Based Options	**Incentive-Based Programs**
• *Time-of-use (TOU):* a rate with different unit prices for usage during different blocks of time, usually defined for a 24 hour day. TOU rates reflect the average cost of generating and delivering power during those time periods. • *Real-time pricing (RTP):* a rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. Customers are typically notified of RTP prices on a day-ahead or hour-ahead basis. • *Critical Peak Pricing (CPP):* CPP rates are a hybrid of the TOU and RTP design. The basic rate structure is TOU. However, provision is made for replacing the normal peak price with a much higher CPP event price under specified trigger conditions (e.g., when system reliability is compromised or supply prices are very high).	• *Direct load control:* a program by which the program operator remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers. • *Interruptible/curtailable (I/C) service:* curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. Penalties maybe assessed for failure to curtail. Interruptible programs have traditionally been offered only to the largest industrial (or commercial) customers. • *Demand Bidding/Buyback Programs:* customers offer bids to curtail based on wholesale electricity market prices or an equivalent. Mainly offered to large customers (e.g., one megawatt [MW] and over). • *Emergency Demand Response Programs:* programs that provide incentive payments to customers for load reductions during periods when reserve shortfalls arise. • *Capacity Market Programs:* customers offer load curtailments as system capacity to replace conventional generation or delivery resources. Customers typically receive day-of notice of events. Incentives usually consist of up-front reservation payments, and face penalties for failure to curtail when called upon to do so. • *Ancillary Services Market Programs:* customers bid load curtailments in ISO/RTO markets as operating reserves. If their bids are accepted, they are paid the market price for committing to be on standby. If their load curtailments are needed, they are called by the ISO/RTO, and may be paid the spot market energy price.

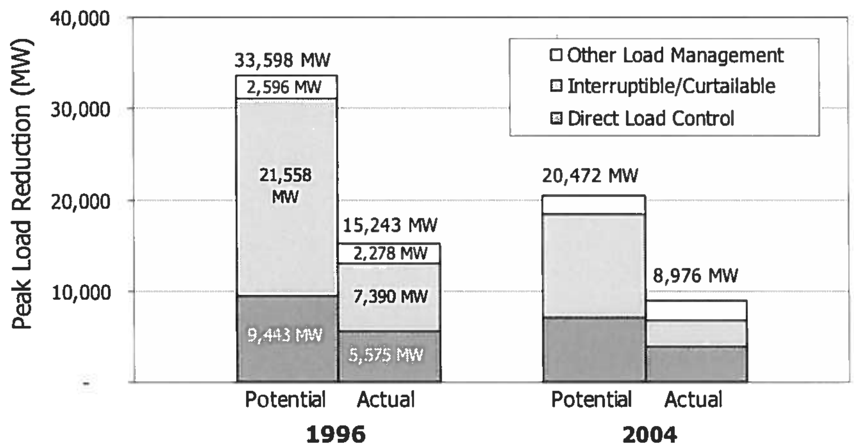
Current Demand Response Capability and Recent Initiatives

Limited demand response capability exists in the United States at present, as Figure O-1 illustrates. Several important trends are worth noting:

- Demand response potential in 2004 was about 20,500 megawatts (MW)—3% of total U.S. peak demand. Actual delivered peak demand reductions were about 9,000 MW, or 1.3% of total peak demand (EIA 2004).
- Total potential load management capability has fallen by 32% since 1996. Factors affecting this trend include fewer utilities offering load management services, declining enrollment in existing programs, the changing role and responsibility of utilities, and changing supply/demand balance. However, the demand-side

management (DSM) information reported by industry participants do not fully reflect current demand response activity levels.[4]

- Actual peak reductions are affected by the available installed load reduction capability (i.e., the demand response potential), whether utilities or grid operators need to call program events, and the extent to which enrolled participants respond during program events.
- In 2004, utilities reported spending about $515M on load management programs; this represents about a 10% decrease from the early to mid-1990s.



1996		2004
407	Number of Utilities	273
572	Program Costs (million nominal $)	515

Figure O-1. Existing U.S. Demand Response Potential

A number of recent initiatives highlight renewed interest by federal and state policymakers, regional grid operators and utilities in strengthening demand response capability. Examples include:

- The Federal Energy Regulatory Commission (FERC) has recognized the value that demand response offers for grid reliability and resource adequacy, and has repeatedly encouraged its incorporation and expansion within regions with organized spot markets to enhance competition and more resource-efficient markets.
- Several regional grid operators (e.g., NYISO, PJM, ISO-NE, and the Electric Reliability Council of Texas [ERCOT]) have encouraged customer load participation and taken steps to integrate demand response resources into their wholesale markets.

[4] For example, information on time-varying tariffs (e.g. RTP, CPP, and TOU) is not systematically reported by utilities and competitive retailers do not systematically report the types and mix of contracts/products provided to retail customers.

- Regional initiatives and planning processes in New England and the Mid-Atlantic and the Pacific Northwest regions have involved many stakeholders and developed strategies to promote demand response and overcome barriers.
- Several states (Maryland, New Jersey, New York, and Pennsylvania) have adopted real-time pricing as the default service for large customers or implemented large-scale CPP pilot programs (e.g., California, Florida). Several utilities have aggressively implemented real-time pricing as an optional service for large customers and have attracted significant customer participation (e.g. Georgia Power, Duke Power, Tennessee Valley Authority).
- A number of utilities have deployed or are considering deploying advanced metering systems on a system-wide basis that enables "price-based" demand response for all customer classes.

DOE encourages more of these initiatives, shares Congress' views about the importance and value of demand response, and welcomes the opportunity to help make demand response a more effective, integral part of the nation's electricity markets and system.

Identifying the Benefits of Demand Response

Demand response produces benefits primarily as resource savings that improve the efficiency of electricity provision. It is instructive to trace the flow of these benefits through the market to ascertain who gains and by how much. Accordingly, the benefits of demand response can be classified in terms of whether they accrue directly to participants or to some or all groups of electricity consumers.

- *Participant bill savings*—electricity bill savings and incentive payments earned by customers that adjust load in response to current supply costs or other incentives.
- *Bills savings for other customers*—lower wholesale market prices that result from demand response translate into reduced supply costs to retailers and eventually make their way to almost all retail customers as bill savings.
- *Reliability benefits*—reductions in the likelihood and consequences of forced outages that impose financial costs and inconvenience on customers.

Demand response also provides other benefits that are not easily quantifiable or traceable, but can have a significant impact on electricity market operation. Examples include:

- *Market performance*—demand response acts as a deterrent to the exercise of market power by generators;
- *Improved choice*—customers have more options for managing their electricity costs; and
- *System security*—system operators are provided with *more flexible resources* to meet contingencies.

Quantifying the Benefits of Demand Response

Quantifying the potential nation-wide benefits of demand response is a difficult undertaking requiring the following key information and assumptions:

- *Demand Response Options*—the types of time-varying rates and demand response programs currently offered (or potentially available);
- *Customer Participation*—the likelihood that customers will choose to take part in the offered programs;
- *Customer Response*—documenting and quantifying participants' current energy usage patterns, and determining how participants adjust that usage in response to changes in prices or incentive payments;
- *Financial Benefits*—developing methods to quantify the short- and long-term resource savings of load response under varying market structures;
- *Other Benefits*—identifying and quantifying any additional benefits provided by demand response resources (e.g., improved reliability); and
- *Costs*—establishing the costs associated with achieving demand response.

Estimates of the Benefits and Costs of Demand Response

DOE conducted a literature review to understand how previous studies have estimated the benefits of demand response and selected ten recent studies to analyze the methods used to quantify demand response benefits and their impact on the results.

Three types of studies have estimated the benefits of demand response:

- *Illustrative analyses* quantify the economic impacts of demand response within an electricity market. The four examples selected by DOE examined regions with organized wholesale markets. The benefits of demand response are hypothetical and speculative in these studies, often with few details of where the demand response comes from. The ability of these studies to accurately estimate demand response benefits depends on how closely actual circumstances match the assumptions used in the analysis.
- *Integrated Resource Planning (IRP) studies* assess whether and how much demand response resources should be acquired in a long-term resource plan, based on avoided supply costs and anticipated loads and resource needs. The three selected IRP studies were performed by organizations responsible for long-term, regional resource plans or as an illustration of how that planning process could be conducted to include and value demand response.
- *Program performance analyses* measure actual outcomes of demand response programs implemented by regional grid operators (ISO-NE, NYISO, PJM) and provide an after-the-fact estimate of delivered value. The three selected studies estimated the impacts of load curtailments on market prices, quantified the level and distribution of benefits and explicitly accounted for reliability benefits.

DOE found that the estimates of demand response benefits depend on key assumptions, even for studies that seemingly adopted the same market framework. For example, two studies commissioned to measure the nation-wide benefits of demand response from its integration into wholesale market operations produced wildly disparate estimates of $362 million and $2.6 billion per year.

Consequently, in this report, DOE normalized the estimated gross benefits to allow more informative comparisons.[5] This normalization adjusts for differences in the time horizon, market size and the level of customer participation across studies and expresses annual benefits in terms of dollars per system peak load. This provides a better understanding of the impact of study methodologies and assumptions that produced such disparate benefit estimates. Figure O-2 illustrates the results, comparing the range of normalized gross benefit values over all studies and by the three study categories.

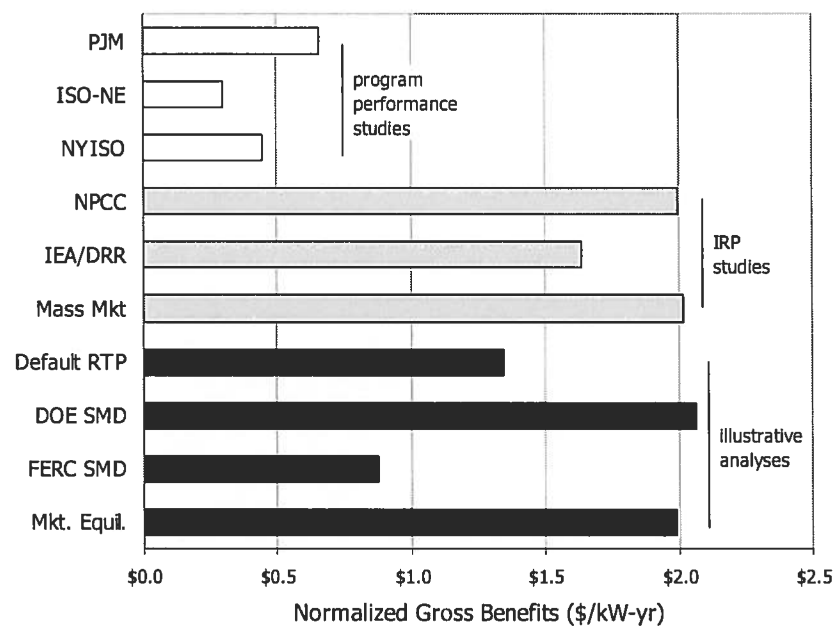


Figure O-2. Normalized Gross Demand Response Benefits: Estimates of Ten Selected Studies

Key findings from this cross-study comparison include:

- Even after normalizing results, the estimated gross benefits of demand response vary widely and are driven by the analytical methods used and the assumptions made.
- The illustrative analysis studies report relatively high gross benefits, in part because they assume high levels of demand response penetration over a large customer base and because they estimate demand response impacts under varying electricity market conditions over a multi-year time horizon.

[5] Net benefits were not reported because program cost data were not included in all ten studies.

- The IRP studies also report high levels of benefits because they consider and simulate the potential impacts of demand response over the full range of electricity market conditions over a multi-decade period. Their explicit treatment of key uncertainties allows demand response to be deployed during low probability but high consequence events over a long planning horizon. These studies assume that demand response programs and benefits will persist for as long as the physical assets they would complement or replace.
- The program performance studies conducted by regional grid operators report the lowest demand response benefits, in part because they reflect market conditions over a short time period and do not necessarily capture the full range of market circumstances. Program impacts and benefits also do not explicitly account for the forward value of demand response.

This analysis reveals that demand response is viewed and evaluated differently in regions with ISO- or RTO-managed organized spot markets than in regions with vertically integrated utilities with a monopoly franchise. Vertically integrated utilities internalize and pass through all of their energy production, transmission and distribution costs, so they (and their regulators) take a long-term view and evaluate demand response against the alternative of building (or buying) new generation. Thus, utilities with retail monopolies evaluate and measure demand response benefits primarily in terms of avoided capacity costs over the long run. In contrast, regions with organized wholesale markets have active energy trading opportunities with transparent market clearing prices (and in four of the seven ISO/RTO regions, no comparable capacity market), so they tend to evaluate demand response benefits primarily in terms of time-varying energy and capacity values in competitive markets. This view frames demand response benefits in the short run, and tends to understate long-term benefits.

Based on this review, DOE concludes that, to date, the estimated benefits of demand response are driven primarily by analysis methods, assumptions regarding customer participation and responsiveness, and market characteristics. Without standardized and accepted analytical methods to quantify the benefits of demand response, DOE finds that it is not possible to produce a meaningful estimate of the national benefits of demand response. Moreover, DOE recognizes that regional differences in market design, operation, and resource balance are important and must be taken into account. Estimates of demand response benefits are best done for service territories, states, and regions, because the magnitude of potential benefits is tied directly to local electric system conditions (e.g., supply mix, the presence or absence of supply constraints, the rate of demand growth, and resource plans for meeting demand growth).

DOE Recommendations

EPACT directed DOE to offer recommendations for achieving specific levels of demand response benefits by January 1, 2007. DOE concludes that it is not possible to offer recommendations in 2006 that can produce meaningful new demand response by January 2007.

The recommendations outlined below, and covered in more detail in Section 5 of this report, aim to expand the availability and effectiveness of demand response programs, expand the reach and effectiveness of enabling technologies, and suggest tasks for the electric industry to better analyze and use demand response in system planning and operations. These recommendations are summarized below and detailed in Table O-1.

- **Fostering Price-Based Demand Response**—by making available time-varying pricing plans that let customers take control of their electricity costs;
- **Improving Incentive-Based Demand Response**—to broaden the ways in which reliability-driven programs contribute to the reliable operation of electric systems;
- **Strengthening Demand Response Analysis and Valuation**—so that program designers, policymakers and customers can anticipate demand response impacts and benefits;
- **Adopting Enabling Technologies**—to realize the full potential for managing usage on an ongoing basis;
- **Integrating Demand Response into Resource Planning**—so that the full impacts of demand response are recognized and the maximum level of resource benefits are realized; and
- **Enhancing Federal Demand Response Actions**—to take advantage of existing channels for disseminating information and forming public-private collaboratives.

Table O-1: List of Recommendations	
Fostering Price-Based Demand Response	In accordance with EPACT, State regulatory authorities must decide whether their utilities must offer customers time-based rate schedules (i.e., RTP, CPP and TOU rates) and advanced metering and communications technology. <u>Large Customers</u> • In states that allow retail competition, state regulatory authorities and electric utilities should consider adopting RTP as their default service option for large customers. • In states that do not allow retail competition, state regulatory authorities and electric utilities should consider offering RTP to large customers as an optional service. • Regional entities and collaborative processes, state regulatory authorities, and electric utilities should provide education, outreach, and technical assistance to customers to maximize the effectiveness of RTP tariffs. <u>Medium and Small Business Customers</u> • State regulatory authorities and electric utilities should investigate new strategies for segmenting medium and small business customers to identify relatively homogeneous sub-sectors that might make them better candidates for price-based demand response approaches. • State regulatory authorities and electric utilities should consider conducting business case analysis of CPP for medium and small business customers. Results from existing pilot programs should be carefully evaluated and included in the analysis. • State regulatory authorities and electric utilities should consider conducting policy or business case analysis of RTP for medium business customers. Results from existing pilot programs should be carefully evaluated and included in the analysis. <u>Residential Customers</u> • State regulatory authorities and electric utilities should consider conducting business case analysis of CPP for residential customers. Results from existing pilot programs should be carefully evaluated and included in the analysis. • State regulatory authorities and electric utilities should investigate the cost-effectiveness of offering technical and/or financial assistance to small business and residential customers to enable their participation in CPP or TOU tariffs and enhance their abilities to reduce demand in response to higher prices.

Improving Incentive-Based Demand Response	• Traditional load management (LM) programs such as direct load control of residential and small commercial equipment and appliances (e.g., air conditioners, water heaters, and pool pumps) with an established track record of providing cost-effective demand response should be maintained or expanded.
	• State regulatory authorities and electric utilities should consider offering existing and new participants in these LM programs "pay-for-performance" incentive designs, similar to those implemented by ISOs/RTOs and some utilities, which include a certain level of payment to customers who successfully reduce demand when called upon to do so during events.
	• Regional entities, state regulatory authorities, and electric utilities should consider including the following emergency demand response program features:
	  o Payments that are linked to the higher of real-time market prices or an administratively-determined floor payment that exceeds customers' transaction costs;
	  o "Pay-for-performance" approaches that include methods to measure and verify demand reductions;
	  o Low entry barriers for demand response providers, and in vertically integrated systems, procedures to ensure that customers have access to these programs; and
	  o Multi-year commitments from regional entities for emergency demand response programs so that customers and aggregators can make decisions about committing time and resources.
	• State regulatory authorities should investigate whether it would be cost-effective for default service providers to implement demand response. They should also provide cost recovery for demand response investments undertaken by distribution utilities.

Table O-1: List of Recommendations	
Strengthening Demand Response Analysis and Valuation	• A voluntary and coordinated effort should be undertaken to strengthen demand response analysis capabilities. This effort should include participation from regional entities, state regulatory authorities, electric utilities, trade associations, demand response equipment manufacturers and providers, customers, environmental and public interest groups, and technical experts. The goal should be to establish universally applicable methods and practices for quantifying the benefits of demand response.
Integrating Demand Response into Resource Planning	• FERC and state regulatory agencies should work with interested ISOs/RTOs, utilities, other market participants and customer groups to examine how much demand response is needed to improve the efficiency and reliability of their wholesale and retail markets. • Resource planning initiatives should review existing demand response characterization methods and improve existing planning models to better incorporate different types of demand response as resource options. • ISOs and RTOs, in conjunction with other stakeholders, should conduct studies to understand demand response benefits under foreseeable future circumstances as part of regional transmission planning and under current market conditions in their demand response performance studies.
Adopting Enabling Technologies	• State regulatory authorities and electric utilities should assure that utility consideration of advanced metering systems includes evaluation of their ability to support price-based and reliability-driven demand response, and that the business case analysis includes the potential impacts and benefits of expanded demand response along with the operational benefits to utilities. • State regulatory authorities and electric utilities should evaluate enabling technologies that can enhance the attractiveness and effectiveness of demand response to customers and/or electric utilities, particularly when they can be deployed to leverage advanced metering, communications, and control technologies for maximum value and impact. • State legislatures should consider adopting new codes and standards that do not discourage deployment of cost-effective demand response and enabling technologies in new residential and commercial buildings and multi-building complexes.
Enhancing Federal Actions	• DOE, to the extent annual appropriations allow, should continue to provide technical assistance on demand response to states, regions, electric utilities, and the public including activities with stakeholders to enhance information exchange so that lessons learned, best practices, new technologies, barriers, and ways to mitigate the barriers can be identified and discussed. • DOE and FERC should continue to coordinate their respective demand response and related activities. • FERC should continue to encourage demand response in the wholesale markets it oversees. • DOE, through its Federal Energy Management Program, should explore the possibility of conducting demand response audits at Federal facilities. • DOE and the Environmental Protection Agency should explore efforts to include appropriate demand response programs and pricing approaches, where appropriate, in the ENERGY STAR® and other voluntary programs.

TABLE OF CONTENTS

EXECUTIVE SUMMARY v
- Background v
- The Benefits of Demand Response vi
- Quantifying the National Benefits of Demand Response vi
- Recommendations vii

OVERVIEW: KEY FINDINGS AND RECOMMENDATIONS ix
- Introduction ix
- Defining and Characterizing Demand Response ix
  - Why is Demand Response Important? x
  - Types of Demand Response x
  - Current Demand Response Capability and Recent Initiatives xii
- Identifying the Benefits of Demand Response xiv
- Quantifying the Benefits of Demand Response xv
- DOE Recommendations xvii

TABLE OF CONTENTS xxi

LIST OF TABLES AND FIGURES xxiii

ACRONYMS AND ABBREVIATIONS xxv

SECTION 1. INTRODUCTION 2

SECTION 2. DEFINING AND CHARACTERIZING DEMAND RESPONSE 6
- What is Demand Response? 6
- Why is Demand Response Important? 7
- Classifying Demand Response Options 8
- Current U.S. Demand Response Capability 10
- The Role of Demand Response in Electric Power Systems 13
- How Do Customers Accomplish Demand Response? 17

SECTION 3. BENEFITS OF DEMAND RESPONSE 22
- Demand Response Costs 22
- Benefits of Demand Response 26
  - Participant Benefits 26
  - Collateral Benefits 26
  - Other Benefits 29

SECTION 4. QUANTIFYING DEMAND RESPONSE BENEFITS 30
- Intensity of Customer Demand Response 31
  - Customer Response to Time-Varying Prices 31
  - Customer Response to Load Control Programs 33
  - Impact of Enabling Technologies on Price Response 34
  - Summary 35
- Quantifying the Value of Demand Response 36
  - Benefits of Demand Response: Review of Existing Studies 38
  - Demand Response Benefit Case Studies: Comparison of Key Features 39
  - Demand Response Benefit Case Studies: Discussion of Results 44
- Establishing Protocols and Practices for Estimating Demand Response Benefits 49

SECTION 5. RECOMMENDATIONS FOR ACHIEVING THE BENEFITS OF DEMAND RESPONSE 51
- Fostering Price-Based Demand Response 52

Large Customers ... 52
Medium and Small Business Customers ... 53
Residential Customers ... 54
Improving Incentive-Based Demand Response ... 55
Strengthening Demand Response Analysis and Valuation ... 56
Integrating Demand Response into Resource Planning ... 57
Adopting Enabling Technologies ... 58
Enhancing Federal Actions ... 59
REFERENCES ... 61
APPENDIX A. ORGANIZATIONS THAT PROVIDED INPUT ON RECOMMENDATIONS ... 67
APPENDIX B. ECONOMIC AND RELIABILITY BENEFITS OF DEMAND RESPONSE ... 69
Short-Term Market Impacts: Supply Costs and Market Prices ... 69
Societal Benefits ... 69
Supply Cost and Market Price Impacts in Regions with Differing Market Structures ... 72
Long-term Market Impacts: Capacity Benefits ... 74
Timing and Distribution of Market Impacts of Demand Response ... 76
Market Impacts of Demand Response for Vertically Integrated Utilities ... 76
Market Impacts of Demand Response in Regions with Organized Wholesale Markets ... 78
Reliability Benefits ... 80
APPENDIX C. INTENSITY OF CUSTOMER DEMAND RESPONSE ... 85
Indicators of Demand Response Intensity ... 85
Price Elasticity Estimates ... 86
Impact of Enabling Technologies on Price Response ... 89
Load Impacts from Direct Load Control ... 91
APPENDIX D. STANDARDS, PROTOCOLS AND PRACTICES FOR ESTIMATING THE BENEFITS OF DEMAND RESPONSE ... 93

LIST OF TABLES AND FIGURES

Overview: Key Findings and Recommendations

Table O-1: List of Recommendations xix

Figure O-1. Existing U.S. Demand Response Potential xiii
Figure O-2. Normalized Gross Demand Response Benefits: Estimates of Ten Selected Studies xvi

Main Report

Table 1-1. Response to EPACT Requirements 3
Table 3-1. Costs of Demand Response 23
Table 3-2. Benefits of Demand Response 27
Table 4-1. Benefits of Demand Response: Review of Selected Studies 40

Figure 2-1. Existing U.S. Demand Response Potential 11
Figure 2-2. Electric System Planning and Scheduling: Timescales and Decision Mechanisms 13
Figure 2-3. Role of Demand Response in Electric System Planning and Operations 15
Figure 2-4. Customer Decisions for Demand-Side Management 17
Figure 2-5. Factors Affecting Customer Decisions About Demand Response 18
Figure 4-1. Customer Response to Time-Varying Prices: Price Elasticity Estimates 32
Figure 4-2. Estimated Load Impacts from Direct Load Control Programs 34
Figure 4-3. Load Response from Critical Peak Pricing and Demand Response Enabling Technologies 35
Figure 4-4. Normalized Gross Demand Response Benefits: Estimates of Ten Selected Studies 46
Figure 4-5. Normalized Gross Demand Response Benefits by Type of Study 46

Appendices

Table C-1. Demand Response Program and Pricing Studies: Estimated Price Elasticity of Demand 88
Table C-2. Load Response from Enabling Technologies in Combination with CPP 90
Table C-3. Direct Load Control Programs: Estimated Load Impacts 92

Figure B-1. Inefficiencies of Average-Cost Pricing 70
Figure B-2. Impact of Demand Response on Vertically Integrated Utility Supply Costs 72
Figure B-3. Impact of Demand Response in Regions with Organized Wholesale Markets 73
Figure B-4. Market Impacts of Demand Response for Vertically Integrated Utilities 77
Figure B-5. Market Impacts of Demand Response in Regions with Organized Wholesale Markets 79
Figure B-6. Valuing the Reliability Benefits of Demand Response 82

ACRONYMS AND ABBREVIATIONS

A/C	air conditioning
AMI	advanced metering infrastructure
AMR	automated meter reading
AMS	advanced metering systems
CAISO	California Independent System Operator
CPP	critical peak pricing
DLC	direct load control (program)
DOE	United States Department of Energy
DSM	demand-side management
EIA	United States Energy Information Administration
EPACT	United States Energy Policy Act (of 2005)
ERCOT	Electric Reliability Council of Texas
EUE	expected un-served energy
FERC	Federal Energy Regulatory Commission
I/C	interruptible/curtailable (rate)
IRP	integrated resource plan (planning)
ISO	Independent System Operator
ISO-NE	ISO—New England (RTO)
kW	kilowatt
kWh	kilowatt-hour
LM	load management
LSE	Load Serving Entity
MISO	Midwest Independent System Operator
MW	Megawatt
NYISO	New York Independent System Operator
PJM	Pennsylvania/New Jersey/Maryland Interconnection (RTO)
PURPA	Public Utilities Regulatory Policy Act
RTO	Regional Transmission Organization
RTP	real-time pricing (rate)
SMD	Standard Market Design
SPM	Standard Practice Manual
SPP	(California) Statewide Pricing Pilot
TOU	time-of-use (rate)
VOLL	value of lost load

SECTION 1. INTRODUCTION

Sections 1252(e) and (f) of EPACT state that it is the policy of the United States to encourage "time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them." It further states that "deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary services markets shall be eliminated." To help implement this new policy on demand response, the Act creates new requirements for electric utilities and states with respect to demand response. States are charged with conducting investigations to determine how those new requirements should be applied and whether to adopt widespread time-based pricing and advanced metering for utility retail customers.[6]

EPACT provides specific guidance to DOE in encouraging demand response. Specifically, the Secretary of Energy is authorized to:

- educate consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects; and
- work with States, utilities, other energy providers, and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs (EPACT, Sec. 1252(d)).

The law also requires DOE to provide a report to Congress, not later than 180 days after its enactment, that "identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007" (EPACT, Sec. 1252(d)).

This document is the report to Congress. DOE views the report requirements as consisting of two parts: the first, "identifies and quantifies the national benefits of demand response" is addressed by Sections 2, 3, and 4 of this report; the second, "makes a recommendation on achieving specific levels of such benefits by January 1, 2007", is addressed by Section 5 of this report. Table 1-1 summarizes how this report is organized to respond to the EPACT requirements.

The report is further organized as follows:

- Section 2 characterizes and defines demand response options, summarizes the role of demand response in our nation's provision of electricity, and introduces a framework for customer decisions about demand response.
- Section 3 includes a conceptual and qualitative discussion of the benefits of demand response.

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[6] Public Law 109-58, August 8, 2005.

- Section 4 provides a comparative review and analysis of ten studies that estimate demand response benefits for specific regions or purposes. DOE also suggests methods and considerations for future state or regional efforts to quantify benefits of demand response.
- Section 5 presents specific recommendations for state, regional and federal agencies, electric utilities and consumers to enhance demand response in varying wholesale and retail market structures.
- There are several technical appendices. Appendix A lists interested parties that provided suggestions to DOE on actions or policies to encourage demand response. Appendix B provides a more in-depth conceptual and qualitative discussion of the benefits of demand response. Appendix C summarizes studies on customer response to time-varying prices and demand response programs (e.g. load impacts). Appendix D provides suggestions and technical discussion on protocols and methods for future state or regional efforts to quantify benefits of demand response.

Table 1-1. Response to EPACT Requirements

EPACT Requirement	Approach	Section of Report
Identify national benefits of demand response	• Synthesize literature and stakeholder input	Section 3
Quantify national benefits of demand response	• Review empirical studies of demand response benefits, normalize results and report range of estimates • Synthesize literature and stakeholder input to develop recommended methods	Section 4
Make recommendation on achieving specific levels of benefits by January 1, 2007	• Solicit stakeholder input and review literature to develop recommendations for encouraging and eliminating barriers to demand response	Section 5

Some discussion is warranted on how the report organization and content aligns with DOE's responsibilities for the report to Congress, as set forth in Section 1252(d) of EPACT.

With respect to the first major requirement ("identifies and quantifies the national benefits of demand response"), no existing study provides a comprehensive estimate of the net benefits of demand response *on a national scale*, nor was it possible for DOE to undertake such a detailed and complex analysis given the timeframe and resources available for completion of this report.[7] Instead, DOE selected ten studies that have estimated demand response benefits for specific regions or purposes that provide a range of estimates and illustrate important methodological issues (see Section 4). DOE believes that estimates of demand response benefits are most usefully done at a utility, state, or regional level, as part of policymakers' decisions on what is the appropriate level of demand response for that geographic footprint under consideration.

[7] While a number of studies have attempted to estimate local, regional, or national demand response benefits, empirically or conceptually, they lack a common methodological framework and scope.

With respect to the second requirement ("make a recommendation on achieving specific levels of such benefits by January 1, 2007"), DOE concludes that it is not possible to offer recommendations in 2006 that can produce significantly greater levels of demand response at a national level by January 2007. Instead, DOE offers a set of recommendations for consideration by state, regional and federal agencies, electric utilities and consumers to enhance demand response in a manner that is consistent with the existing market structures of various states and regions. DOE developed these recommendations after consideration of suggestions gained from a public input process in which interested parties provided suggestions, through a web survey, for actions to encourage demand response in different wholesale and retail market structures.[8]

Finally, this report makes the following new contributions to the continuing policy and technical discussions on demand response:

- It is the first study to systematically compare the results of existing quantitative assessments of demand response benefits that use different methods, types of demand response programs, and time horizons.
- It explicitly addresses differences in valuing demand response benefits in vertically integrated utility systems compared to organized electricity markets in which an ISO/RTO administers organized spot markets, and offers recommendations on valuation methods and policy approaches for policymakers.

[8] Appendix A identifies the contributing organizations.

SECTION 2. DEFINING AND CHARACTERIZING DEMAND RESPONSE

What is Demand Response?

Demand response, defined broadly, refers to participation by retail customers in electricity markets, seeing and responding to prices as they change over time. Any commodity market—oil, gold, wheat or tomatoes—consists of both sellers, or suppliers of the commodity, and buyers, or consumers of the goods. For a variety of reasons, very few consumers of electricity are currently exposed to retail prices that reflect varying wholesale market costs, and thus have no incentive to respond to conditions in electricity markets, with results that are detrimental to all.

Demand response may be defined more definitively as:

> *Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*

From the perspective of the electric system as a whole, the emphasis of demand response is on *reductions* in usage at critical times.[9] Critical times are typically only a few hours per year, when wholesale electricity market prices are at their highest or when reserve margins are low due to contingencies such as generator outages, downed transmission lines, or severe weather conditions.

Demand response may be elicited from customers either through a retail electricity rate that reflects the time-varying nature of electricity costs, or a program—an attempt to induce customers to change their consumption behavior—that provides an incentive to reduce load at critical times. The incentive is unrelated to the normal price paid for electricity (e.g., supplemental) and may involve payments for load reductions, penalties for not reducing load, or both.

Demand response represents the outcome of an action undertaken by an electricity consumer in response to a stimulus and typically involves customer behavioral changes. However, its value to society is derived from its cumulative impacts on the entire electric system. Understanding and reconciling these two perspectives is key to characterizing and valuing demand response as well as recognizing its limitations.

The discussion in this section begins by establishing why demand response is important and classifying options for obtaining it. Information on current U.S. demand response capability is then presented. Next, demand response is characterized from the system perspective, illustrating how it fits into electricity system planning and scheduling.

[9] Demand response may also result in *increases* in electricity usage during the majority of hours when electricity prices are lower than average. This too results in more efficient use of the electric system and may also promote economic growth.

Finally, demand response is discussed from the customer perspective, focusing on how and why customers make decisions to participate and respond (or not).

Why is Demand Response Important?

There is a growing consensus that insufficient levels of demand response exist in the U.S. electric power system.

In recent years, there has been growing consensus among federal and state policymakers that insufficient levels of demand response exist in the U.S. electric power system (EPACT 2005, FERC 2003, NARUC 2000, GAO 2004 and 2005). Due to its physical properties, electricity is not economically storable at the scale of large power systems. This means that the amount of power plant capacity available at any given moment of time must equal or exceed consumers' demand for it in real time. Electricity also has few substitutes for certain end uses (e.g. refrigeration, lighting). The marginal cost of supplying electricity is extremely variable because demand fluctuates cyclically with time of day and season and can surge due to unpredictable events (e.g., extreme temperatures) and because generation or transmission capacity availability fluctuates (e.g., due to a generation plant outage or transmission line failure).[10] While the cost of electric power varies on very short time scales (e.g., every 15 minutes, hourly), most consumers face retail electricity rates that are fixed for months or years at a time, representing *average* electricity production (and transmission and distribution) costs.

The disconnect between short-term electricity production costs and time-averaged, fixed retail rates paid by most consumers leads to an inefficient use of resources.

This disconnect between short-term marginal electricity production costs and retail rates paid by consumers leads to an inefficient use of resources. Because customers don't see the underlying short-term cost of supplying electricity, they have little or no incentive to adjust their demand to supply-side conditions.[11] Thus, flat electricity prices encourage customers to over-consume—relative to an optimally efficient system in hours when electricity prices are higher than the average rates, and under-consume in hours when the cost of producing electricity is lower than average rates. As a result, electricity costs may be higher than they would otherwise be because high-cost generators must sometimes run to meet the non-price-responsive demands of consumers. The lack of price-responsive demand also gives

[10] LSEs must secure access to capacity for generation, transmission, and distribution in place before demand occurs, given that electricity can not be stored and must be supplied in real-time to meet geographically dispersed demand. Typically, the most costly generators to operate are only used when demand is at its highest or when other units are temporarily unavailable.

[11] This disconnect between short-term power costs and what retail electricity customers pay may also lead consumers to acquire appliances and pursue applications of electricity that build in long-term inefficiencies and barriers to change.

generators the opportunity to raise prices above competitive levels and exercise "market power" in certain situations.[12]

> *An important benefit of demand response is avoided need to build power plants to serve heightened demand that occurs in just a few hours per year.*

In the long term, the impact of insufficient demand response may be even greater as non-price-responsive peak demand can result in long-term investments in expensive generation capacity. An important benefit of demand response is therefore avoidance of capacity investments in peaking generation units to serve heightened demand that occurs in just a few hours per year.

Demand response also provides short-term reliability benefits as it can offer load relief to resolve system and/or local capacity constraints. During a system emergency or when reserve margins are low, it may be necessary for a utility to ration end user loads to preserve system integrity and/or prevent cascading blackouts. Selectively curtailing service to customers that place lower values on loss of service and voluntarily elect to participate in an emergency demand response program is less expensive, less disruptive and more efficient than random rationing (e.g. curtailing loads via rotating outages).[13] It is also possible for time-varying rates (e.g., RTP) to provide load relief that can help resolve system capacity constraints as customers respond to high on-peak prices.

Many regions are facing significant energy price pressure, demands for substantial grid infrastructure modernization, and concerns regarding excessive reliance on natural gas to fuel electric generation. Improved demand response is critical to improving all of these situations.

Classifying Demand Response Options

There are two basic categories of demand response options: retail pricing tariffs and demand response programs. The specific options for demand response are defined and described in the textbox below.

Time-varying retail tariffs, which include TOU, RTP and CPP rates can be characterized as *"price-based" demand response.* In these tariff options, the price of electricity fluctuates (to varying degrees) in accordance with variations in the underlying costs of electricity production. Time-varying tariffs may be offered as an optional alternative to a

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[12] Excessive market power has been measured in several electricity markets in the U.S. and attributed, among other reasons, to insufficient price-responsive load (Borenstein et al. 2000, ISO-NE 2005a, PJM Interconnection 2005a).

[13] Utilities (and now ISOs/RTOs) have developed several program designs that induce customers to reveal their private values/information on outage costs. One approach, based on demand subscription, allows customers to specify a firm service level (FSL) below which they cannot be curtailed and are priced at a higher rate than applies to any residual load, which is curtailable (Woo 1990, Spulber 1992). The customer agrees to curtail this interruptible load during a system emergency.

Demand Response Options

Policymakers have several tariff and program options for eliciting demand response. The most commonly implemented options are described below.

Tariff Options
("price-based" demand response)

- *Time-of-use (TOU):* a rate with different unit prices for usage during different blocks of time, usually defined for a 24-hour day. TOU rates reflect the average cost of generating and delivering power during those time periods. TOU rates often vary by time of day (e.g., peak vs. off-peak period), and by season and are typically pre-determined for a period of several months or years. Time-of-use rates are in widespread use for large commercial and industrial (C/I) customers and require meters that register cumulative usage during the different time blocks.
- *Real-time pricing (RTP):* a rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. RTP prices are typically known to customers on a day-ahead or hour-ahead basis.
- *Critical Peak Pricing (CPP):* CPP rates include a pre-specified high rate for usage designated by the utility to be a critical peak period. CPP events may be triggered by system contingencies or high prices faced by the utility in procuring power in the wholesale market, depending on the program design. CPP rates may be super-imposed on either a TOU or time-invariant rate and are called on relatively short notice for a limited number of days and/or hours per year. CPP customers typically receive a price discount during non-CPP periods. CPP rates are not yet common, but have been tested in pilots for large and small customers in several states (e.g., Florida, California, and North and South Carolina).

Program Options
("incentive-based" demand response)

- *Direct load control:* a program in which the utility or system operator remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice to address system or local reliability contingencies. Customers often receive a participation payment, usually in the form of an electricity bill credit. A few programs provide customers with the option to override or opt-out of the control action. However, these actions almost always reduce customer incentive payments. Direct load control programs are primarily offered to residential and small commercial customers.
- *Interruptible/curtailable (I/C) service:* programs integrated with the customer tariff that provide a rate discount or bill credit for agreeing to reduce load, typically to a pre-specified firm service level (FSL), during system contingencies. Customers that do not reduce load typically pay penalties in the form of very high electricity prices that come into effect during contingency events or may be removed from the program. Interruptible programs have traditionally been offered only to the largest industrial (or commercial) customers.
- *Demand Bidding/Buyback Programs:* programs that (1) encourage large customers to bid into a wholesale electricity market and offer to provide load reductions at a price at which they are willing to be curtailed, or (2) encourage customers to identify how much load they would be willing to curtail at a utility-posted price. Customers whose load reduction offers are accepted must either reduce load as contracted (or face a penalty).
- *Emergency Demand Response Programs:* programs that provide incentive payments to customers for measured load reductions during reliability-triggered events; emergency demand response programs may or may not levy penalties when enrolled customers do not respond.
- *Capacity Market Programs:* these programs are typically offered to customers that can commit to providing pre-specified load reductions when system contingencies arise. Customers typically receive day-of notice of events. Incentives usually consist of up-front reservation payments, determined by capacity market prices, and additional energy payments for reductions during events (in some programs). Capacity programs typically entail significant penalties for customers that do not respond when called.
- *Ancillary Services Market Programs:* these programs allow customers to bid load curtailments in ISO/RTO markets as operating reserves. If their bids are accepted, they are paid the market price for committing to be on standby. If their load curtailments are needed, they are called by the ISO/RTO, and may be paid the spot market energy price.

regular fixed electricity rate or as the regular, default rate itself.[14] Customers on these rates can reduce their electricity bills if they respond by adjusting the timing of their electricity usage to take advantage of lower-priced periods and/or avoid consuming when prices are higher. Customer response is typically driven by an internal economic decision-making process and any load modifications are entirely voluntary.

Incentive-based demand response programs represent contractual arrangements designed by policymakers, grid operators, load-serving entities (utilities and retail electricity suppliers) to elicit demand reductions from customers at critical times called program "events".[15] These programs give participating customers incentives to reduce load that are separate from, or additional to, those customers' retail electricity rate, which may be fixed (based on average costs) or time-varying. The incentives may be in the form of explicit bill credits or payments for pre-contracted or measured load reductions. Customer enrollment and response are voluntary, although some demand response programs levy penalties on customers that enroll but fail to respond or fulfill contractual commitments when events are declared.[16] In order to determine the magnitude of the demand reductions for which consumers will be paid, demand response programs typically specify a method for establishing customers' baseline energy consumption (or firm service) level against which their demand reductions are measured.

Current U.S. Demand Response Capability

Limited demand response capability exists in the U.S. at present.

Limited demand response capability exists in the United States at present. The Energy Information Administration (EIA) has collected annual information on demand-side management (i.e., energy efficiency and load management) from industry participants since the early 1990s. Industry participants (mostly utilities) provide the following information on company-administered load management programs: potential peak reduction, actual peak reductions, and program costs. Potential peak reductions reflect the installed load reduction capability, in megawatts (MW), of program participants during the time of system peak, while actual peak reduction reflects the changes in the demand for electricity resulting from a load management program that is in effect at the same time that the utility experiences its annual peak load. Program costs include direct and indirect utility expenses (e.g., program administration, payments to participants, marketing).[17] Prior to 1997, utilities reported information on a more disaggregated basis based on type

[14] TOU rates are in common use as the default service for large commercial and industrial customers throughout the U.S. RTP has been offered as an optional rate for large customers at 40-50 utilities in the U.S., and has been adopted or is under consideration as the default electricity service for large customers in several states where customers can choose their retail supplier (e.g., New Jersey, Maryland, Pennsylvania, New York).

[15] Events may be in response to high wholesale electricity market prices or contingencies that threaten electric system reliability, which can occur at any time of the year.

[16] These performance-based requirements are intended to increase system operators' confidence that demand reductions will materialize when needed.

[17] Costs reported to EIA do not include those incurred directly by participating customers.

of demand response program, which included categories for direct load control (DLC) and interruptible/curtailable (I/C) rate programs.

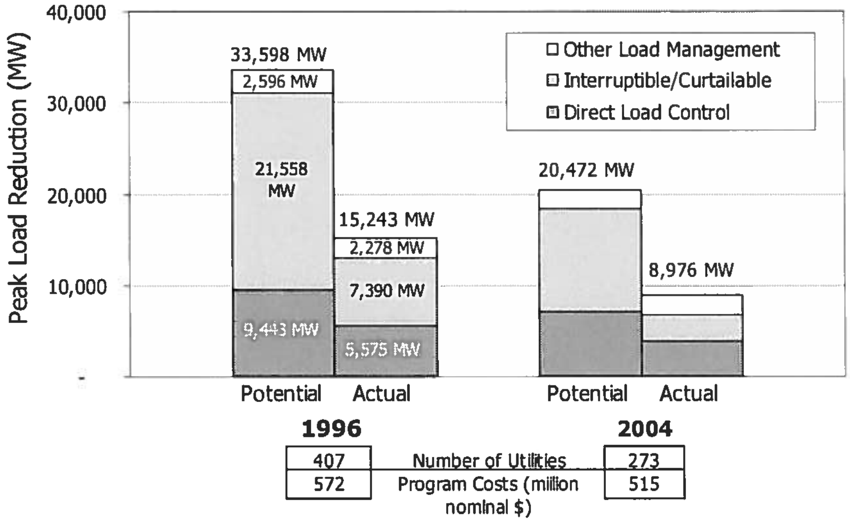

Figure 2-1. Existing U.S. Demand Response Potential

Figure 2-1 summarizes information on potential and actual peak reductions and program costs for 1996 and 2004.[18] Several trends are worth noting:

- Demand response potential in 2004 was about 20,500 MW, 3% of total U.S. peak demand. Actual delivered peak demand reduction was about 9,000 MW, about 1.3% of total peak (NERC 2005).
- Total potential load management capability has fallen by 32% since 1996. Factors affecting this trend include fewer utilities offering load management services (407 utilities in 1996 to 273 in 2004), declining enrollment in existing programs, the changing role and responsibility of utilities, and the increase in installed capacity The DSM information reported by industry participants to EIA does not fully reflect current demand response activity levels.[19]
- Actual peak reductions are affected by the available installed load reduction capability (i.e., the demand response potential), whether utilities or ISOs/RTOs called program events, and the extent to which enrolled participants respond during events.

[18] 1996 is both the year with the highest potential load reduction capability and the last year for which disaggregated information on demand response program type is available; 2004 is the most recent year of reported data.

[19] For example, utilities do not systematically report information on customer participation in optional "price-based" demand response programs (e.g. RTP, CPP, and TOU) and competitive retailers do not report the types and mix of contracts/products provided to retail customers. It is unlikely that all industry participants enrolled in ISO demand response programs are reporting their demand response activities.

- In 2004, utilities reported spending about $515M on load management programs; this represents about a 10% decrease from the early to mid-1990s.
- Although not shown explicitly in Figure 2-1, residential and industrial customers account for the bulk of actual peak load reductions (32% and 50% respectively) in 2004.

Market Structures for Electricity Production in the U.S.

Historically, the U.S. electric power industry has relied heavily on a market structure based on vertically integrated utilities that planned and operated electric generation, transmission and distribution systems on an integrated basis. Investor-owned utilities have an obligation to provide reliable service to customers in established, franchise service territories and are subject to regulation as a monopoly by state public utility commissions that set retail rates and review major capital investments and utility operations.

During the last decade, federal legislation (e.g., Energy Policy Act of 1992) and various Federal Regulatory Energy Commission (FERC) orders have helped create more competitive wholesale power markets with mandated open transmission access. Today almost every load-serving entity in the nation purchases some portion of its supply from these wholesale power markets, whether through bilateral contracts or in an organized spot market. Organized spot markets for wholesale electricity, operated by RTOs or ISOs) exist in the Northeast, Mid-Atlantic, much of the Midwest, and in Texas and California. ISOs/RTOs are typically responsible for maintaining grid reliability by overseeing and operating the high-voltage bulk power system and coordinating electricity generation, operating bid-based markets for spot energy (e.g. real-time, day-ahead, or ancillary services), and conducting long-term regional planning to identify system upgrade and expansion needs and overseeing capacity markets (in some cases).

In those states and regions without an ISO or RTO, electricity is delivered and transacted primarily by vertically integrated utilities through self-generation and bilateral contracts with significant state regulatory oversight of resource planning and rates.

Retail competition has been established in 18 states, which give customers additional choices in the supply and pricing of electricity. In these states, there have also been significant changes in the roles and responsibility of utilities (e.g. divesting of some generation assets, separation of competitive retail service function from transmission and distribution services which remain regulated).

A significant number of customers (20-25% of U.S. electric load) are also served by rural electric cooperatives or public power (municipal or public utility district) utilities. These entities have structural characteristics that are similar to vertically integrated utilities in that they typically have an obligation to serve customers in an established franchise service territory and many own generation, transmission and distribution assets, but their governance structure differs in that they are overseen by local authorities and boards. In a few states they are also regulated at the state level. Some public power utilities and rural cooperatives purchase some or all of their power requirements from vertically integrated utilities, generation and transmission cooperatives, power marketing authorities, or through wholesale markets and in some cases have developed load management resources to a greater extent than investor-owned utilities (Kexel 2004).[20]

[20] For some rural cooperatives, the primary reason for implementing load management programs was to reduce billed demand charges to the member cooperatives themselves and to reduce the capacity requirements of their Generation and Transmission cooperatives (Kexel 2004).

The Role of Demand Response in Electric Power Systems

In assessing the benefits of demand response, it is important for policymakers to be cognizant of the physical infrastructure and operational requirements necessary to construct and reliably operate an electric power system as well as regional differences in market structure and industry organization (see the previous textbox).

In all market structures, the management of electric power systems is largely shaped by two important physical properties of electricity production. First, electricity is not economically storable, and this in turn requires maintaining the supply/demand balance at the system level in real time. Mismatches in supply and demand can threaten the integrity of the electrical grid over extremely large areas within seconds. Second, the electric power industry is very capital intensive. Generation and transmission system investments are large, complex projects with expected economic lifetimes of several decades that often take many years to develop, site and construct.

These features of electric power systems necessitate management of electricity on a range of timescales, from years (or even decades) for generation and transmission planning and construction, to seconds for balancing power delivery against fluctuations in demand (see Figure 2-2). Decisions are made at several junctures along this timeframe. Generally speaking, the amount of load committed at each juncture declines as the time horizon approaches power delivery. For example, 70-80% of supplied load is often committed through forward energy contracts, months or even years before it is delivered. The amount of power arranged on a day-ahead basis varies, but is typically 10-25% of total requirements. In most cases, less than 5% of supply is committed in the last two hours before its delivery.

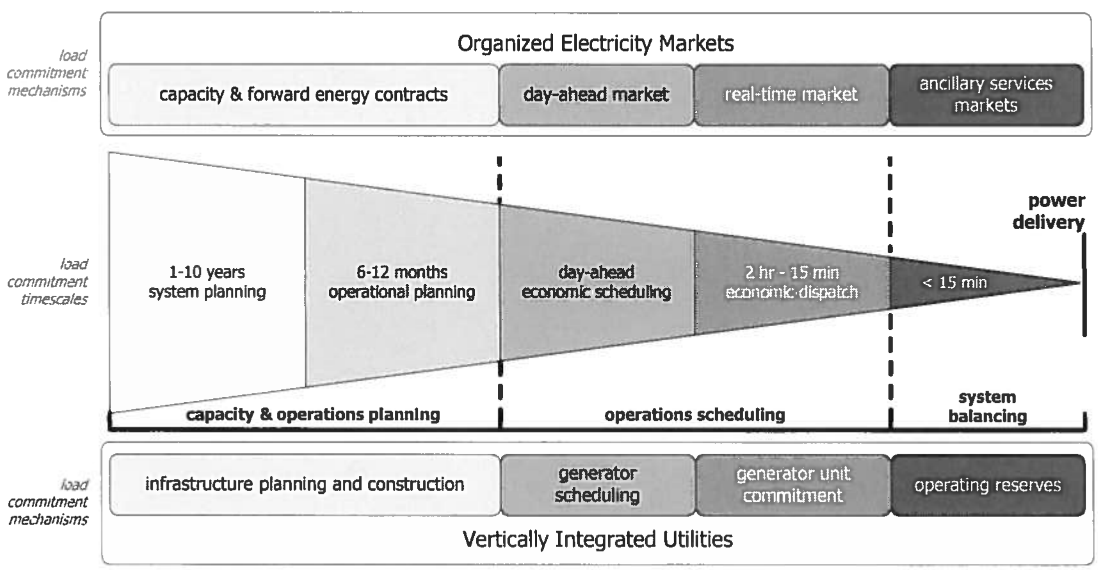

Figure 2-2. Electric System Planning and Scheduling: Timescales and Decision Mechanisms

The major infrastructure planning and operational power delivery decision timeframes are similar in regions with organized wholesale markets and in vertically integrated systems, although the mechanisms for committing energy supply responsibilities differ (see Figure 2-2). In states with retail competition, default service providers and competitive retailers often have a much shorter horizon for acquiring resources than a vertically integrated utility in a state without retail competition.

- *Capacity and operations planning* includes long-term investment and planning decisions. Capacity, or system, planning involves assessing the need for and investing in new generation, transmission and distribution system infrastructure over a multi-year time horizon. Operations planning involves scheduling available resources to meet expected seasonal demand and spans a period of months. In vertically integrated utility systems, these investments are typically evaluated in a utility resource planning process, subject to state regulatory review. In regions with organized wholesale markets, responsibility for these activities is more diffuse. An ISO or RTO engages in a long-term transmission planning process, while distribution utilities retain responsibility for distribution system planning and operations. ISO-administered energy and capacity markets (in some areas) determine the scheduling and operation of available resources to meet daily and seasonal needs and also provide price signals for investments in new generation plants. Utilities and competitive retail suppliers, collectively referred to as load-serving entities (LSEs), contract with generators to meet forward energy requirements.
- *Operations scheduling* refers to the process of determining which generators operate to meet expected near-term demand. This typically involves making day-ahead commitments based on the next day's forecasted demand, with adjustments made in a period of hours down to 15 minutes to account for discrepancies in day-ahead and day-of demand forecasts as well as to account for any unexpected generation plant outages or transmission line problems. Day-ahead and real-time markets administered by ISOs or RTOs fulfill these responsibilities in regions with organized wholesale markets, using generator (or demand resource) offers as the mechanism for scheduling resources for dispatch. Vertically integrated utilities evaluate and schedule generation plants on a merit order basis ranked according to their variable operating costs.
- *System balancing* refers to adjusting resources to meet last-minute fluctuations in power requirements. In regions with organized wholesale markets, resources offer to provide various ancillary services, such as reactive supply and voltage control, frequency-responsive spinning reserves, regulation, and system black-start capability that are necessary to support electrical grid operation.[21] Vertically integrated utilities typically provide ancillary services as part of their integrated operation of the power system.

Ultimately, supply resources are valued according to the timescale of their *commitment* or *dispatch*. Yet because electricity is not storable, its *delivery* to consumers—the goal

[21] Reserves are a type of ancillary service for which ISO/RTO markets have been established in regions with organized wholesale markets. Generators (and loads) bid their availability to supply backup power with varying degrees of notice (usually from 30 minutes down to 10 minutes). Other types of ancillary services are typically contracted for directly by ISOs or RTOs.

around which power systems are constructed and managed—occurs in real-time, regardless of when it was committed and priced.

> *Demand response options can be deployed at all time scales of electricity system management.*

Demand response options can be deployed at all timescales of electricity system management (see Figure 2-3) and can be coordinated with the pricing and commitment mechanisms appropriate for the timescale of their commitment or dispatch.[22] For example, demand response programs designed to alert customers of load response opportunities on a day-ahead basis should be coordinated with either a day-ahead market or, in a vertically integrated market structure, with the utility's generator scheduling process. Like generation resources, the actual *delivery* of customer load reductions occurs in real time.

Energy efficiency is a demand-side resource that can be integrated and valued as part of the system planning process and time horizon (Figure 2-3). Though not dispatchable, energy-efficiency measures often create permanent demand-reduction impacts as well as electricity savings.

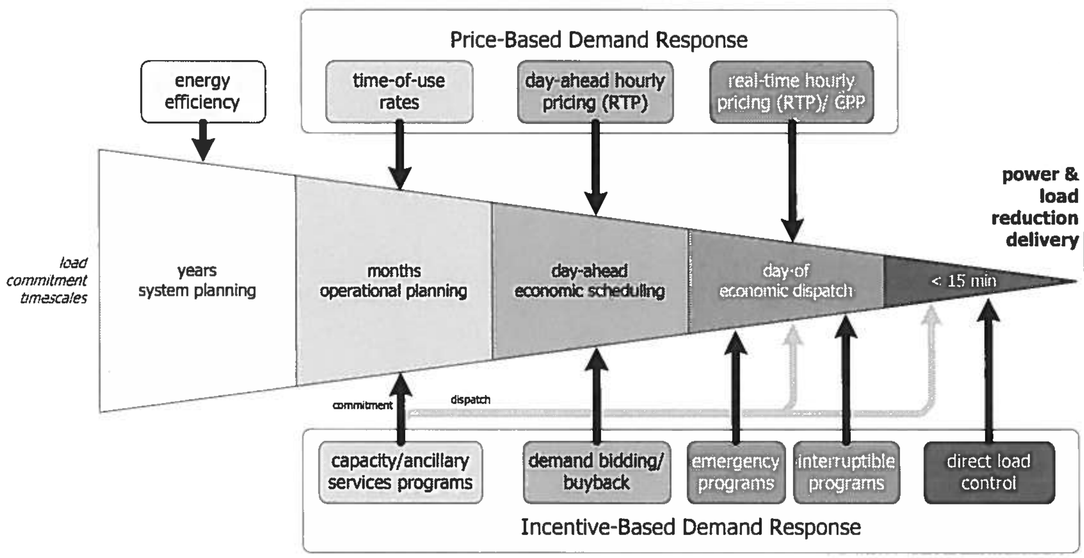

Figure 2-3. Role of Demand Response in Electric System Planning and Operations

If utility resource planners and system operators have a good sense of how their customers respond to changes in the price of electricity, price-based demand response options may be incorporated into system planning at different time scales (Figure 2-3):

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[22] In some cases, demand response resources have been included in a Request for Proposals (RFP) process designed to alleviate short-term (e.g., 3-4 years), localized transmission capacity constraints. For example, ISO-NE issued an RFP for demand relief over four years in Southwest Connecticut, where construction of transmission capacity was delayed (Platts 2004), and Bonneville Power Administration issued an RFP for demand reduction, energy efficiency and distributed generation options to defer new transmission investments on a five-year timescale in 1994.

- *TOU rates*, which reflect diurnal and seasonal variations in electricity costs but are fixed months in advance, may be valued and integrated as part of operations planning.
- *RTP* provides hourly prices to customers with day-ahead or near-real-time notice, depending on the tariff design.[23] In wholesale markets with ISOs/RTOs, RTP prices are typically indexed to transparent, location-based, day-ahead or real-time hourly energy market prices; absent an organized spot market, utilities establish RTP "prices" based on the utility's marginal procurement costs.
- *CPP rates* are essentially TOU rates with the addition of a critical peak price that is called on a day-of basis.

Incentive-based demand response programs may be introduced at virtually all timescales of electric system management (Figure 2-3):

- *Capacity programs* involve load reduction commitments made ahead of time (e.g., months), which the system operator has the option to call when needed. The call option is usually exercised with two or less hours of notice, depending on the specific program design. Participants receive up-front capacity payments, linked to capacity market prices, from entities that otherwise would need to purchase comparable levels of generation to satisfy capacity reserve obligations.
- *Ancillary services programs* also involve establishing customer load commitments ahead of time. Customers whose reserve market bids are accepted must then be "on call" to provide load reductions, often with less than an hour's notice.[24]
- Load reductions from *demand buyback* or *bidding programs* are typically scheduled day-ahead, and incentive payments are valued and coordinated with day-ahead energy markets.
- *Emergency programs* are reliability-based, and payments for load reductions are often linked to real-time energy market prices (in regions with organized wholesale markets) or values that reflect customer's outage cost or the value of lost load. Program events are usually declared within 30 minutes to 2 hours of power delivery.
- *DLC programs* are typically reliability-based and can be deployed within minutes because the utility or system operator triggers the reduction directly, without waiting for a customer-induced response.[25]

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[23] In some states (e.g., New Jersey, Maryland, Pennsylvania), RTP tariffs have been implemented that are indexed to real-time markets that do not communicate prices until after the fact. No studies assessing observed price response from this tariff design have been conducted. It is conceivable that customers look to near real time prices or day-ahead market prices posted by the PJM Interconnection, as a proxy and adjust their usage accordingly (Barbose et al. 2005).
[24] See Kirby (2003) and Kueck et al. (2001) for more information on customer load participation in ancillary services markets.
[25] DLC can also be used by LSEs to mitigate the impact of high wholesale market prices or manage system-demand related charges.

How Do Customers Accomplish Demand Response?

There are significant challenges in matching customers' preferences for demand response program features to system characteristics that drive value. From the customer perspective, investments in demand response and energy efficiency are both DSM strategies that can be used to manage energy costs. Participation in DSM programs (or making DSM investments) involves a series of decisions (see Figure 2-4).

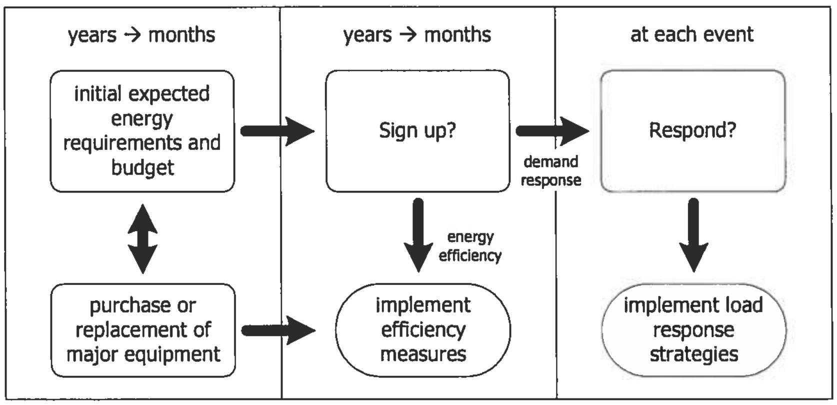

Figure 2-4. Customer Decisions for Demand-Side Management

First, customers implicitly or explicitly determine an initial energy budget based on their expectations of current and future average electricity prices and their household or facility energy needs (see Figure 2-5). The timeframe for this decision (or expectation) is typically monthly or annual, and decisions about purchasing or replacing major energy-using equipment may be made at the same time (see Figure 2-4). The decision-making process may be somewhat different for residential and small commercial customers, who may have a less formalized notion of their usage needs and budget than for large commercial or industrial facilities that may include energy costs as part of a specific operating budget.[26] Larger demand-metered customers are also more likely to be concerned with managing their peak demand in response to demand charges, which are typically included in their electricity tariffs.

Customer participation in demand response options involves *two* important decisions: whether or not to sign up for a voluntary program or tariff (or remain on the option in the case of a default tariff) and, subsequently, whether or not to respond to program events or adjust usage in response to prices as they occur (see Figure 2-4). This is in contrast to traditional energy-efficiency programs, in which customers invest in high-efficiency equipment in response to an existing program offered by a utility, state agency, or public benefits administrator that provides information, technical assistance and/or financial incentives.[27] In most cases energy-efficiency measures, once installed, continue to reduce

[26] This characterization of the customer decision process is more applicable to large, sophisticated, customers. There is a portion of the customer base, particularly many residential and small business customers that have limited understanding of their energy usage patterns and existing tariffs.
[27] Many customers also decide to invest in high efficiency equipment or measures based solely on their own internal economic decision criteria, apart from publicly funded programs.

energy usage over a multi-year economic lifetime, usually without much ongoing customer attention.[28] Compared to the initial usage and budget decision, which is relatively simple and familiar to customers, customers' decisions to enroll in demand response programs and to respond during events can be quite complex.

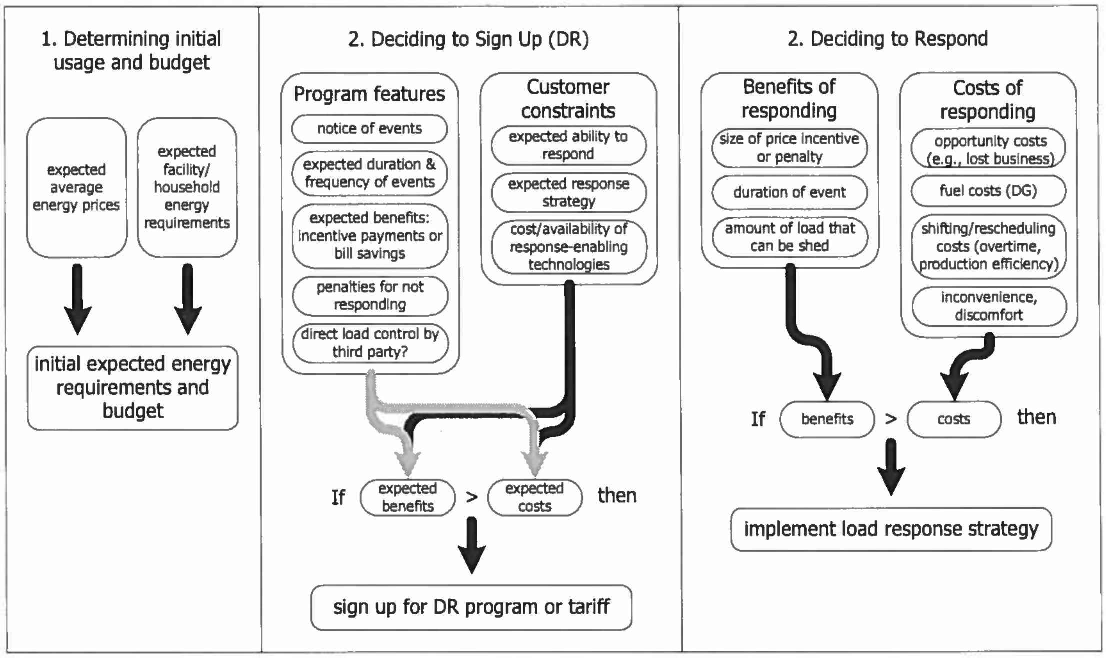

Figure 2-5. Factors Affecting Customer Decisions About Demand Response

The decision to sign up for demand response options involves evaluating offered program or tariff features and weighing the *expected* costs and benefits (see Figure 2-5). A demand response program may specify key parameters of interest to customers (e.g., maximum number of emergency events, payment if event is called), although there is significant uncertainty about the probability and timing of emergency events for the customer.

Ultimately, uncertainties in the costs and benefits of program participation represent risks to customers that may pose significant barriers to their signing up. For example, under RTP, future hourly prices are uncertain, making the benefits of participation difficult to predict.[29]

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[28] Some energy-efficient equipment does require ongoing commissioning or maintenance to ensure energy savings continue to be realized over time, or savings may be affected by changes in customer usage of the equipment. Nonetheless, most energy-efficiency investments produce at least some level of savings over a period of years without further customer attention.

[29] However, the most popular form of RTP, two-part RTP, provides some financial protection against unexpectedly high prices, and the primary driver of participation is likely the expectation of *lower* average prices than under a standard tariff. Experience at successful programs (e.g., Georgia Power and Duke Power Company) has shown that some customers reduce load substantially during hours of high prices. Thus, RTP customers have the possibility of achieving bill savings from both lower prices overall, and from responding to high prices when they occur.

> *The relative certainty of a benefit stream may be as important to customers as the benefits themselves.*

Potential participants in emergency demand response programs also face uncertainty about the number of demand response events in which they will be able to achieve benefits, and the payments they will receive when the events occur. Only in capacity-related demand response programs are up-front payments typically provided, in return for which customers agree to curtail on short notice when notified. The relative *certainty* of a benefit stream may be as important as the incentive payments themselves. While certain up-front investments, such as programmable thermostats, energy management systems or onsite generation equipment, may make responding easier, uncertainties about the benefits of responding can make these investment decisions difficult to justify.

Once enrolled, customers must decide whether or not to respond as events arise (see Figure 2-5). The benefits of responding are dependent on the actual financial incentive payment that applies to the given event (including the penalty for not responding), the number of hours that the event extends for, the amount of load the customer can shed, and may also include such considerations as the desire to help others by keeping the electric system secure.[30]

Customers may adopt one or more of three basic load response strategies (see the textbox below) and will assess the actual costs of responding in a specific situation. Their costs of responding depend in part on the type of response strategy undertaken. For example, customers who forego usage without making it up later incur costs due to lost productivity or foregone amenity. Customers that shift or reschedule their energy usage may incur costs from labor rescheduling, overtime pay or productivity losses from adjustments to their production process. If onsite generation is used to respond, fuel and maintenance costs are incurred. For any response strategy, inconvenience or discomfort to building occupants or tenants are likely to be important considerations and may be an important part of the cost-benefit decision, even if they are not directly monetized.

[30] Note that customers in DLC programs often do not have the choice about whether or not to respond during emergency events. Rather, their choices are focused on the decision to enroll or continue to participate in the program.

Types of Customer Load Response

Customers participating in demand response options may respond to high prices or program events in three possible ways:

- *Foregoing:* involves reducing usage at times of high prices or demand response program events without making it up later. For example, a residential customer might turn off lights or turn up the thermostat on an air conditioner during an event, or a commercial facility might turn off office equipment. In both cases, a temporary loss of amenity or comfort results.
- *Shifting:* involves rescheduling usage away from times of high prices or demand response program events to other times. For example, a residential customer might put off running a dishwasher until later in the day, or an industrial facility might reschedule a batch production process to the prior evening hours or the next day. The lost amenity or service is made up either prior to or at a subsequent time.
- *Onsite generation:* some customers may respond by turning on an onsite or backup emergency generator to supply some or all of their electricity needs. Although the customer may have little or no interruption to their electrical usage, their net load and requirements on the power system is reduced.

Load response strategies may be enhanced with technologies and techniques that allow for fully automated demand response. Pilot projects have demonstrated this potential (Piette et al. 2005), although few customers have yet adopted fully automated demand response.

SECTION 3. BENEFITS OF DEMAND RESPONSE

EPACT requires DOE to identify the benefits of demand response in this report. This section addresses this requirement with a conceptual discussion of the various benefits of demand response, how they are derived, to whom they accrue and how to correctly ascribe value to them. The latter is important to policymakers and utilities in determining how much and what types of time-varying rates and demand response programs to include in their resource portfolios.

The following considerations underlie this discussion of demand response benefits:

- *Customers adjust their electricity usage from typical levels in expectation of receiving benefits.* These benefits must be tangible and sufficient to compensate them for the costs they incur to provide demand response, or else they will not respond.
- *Customers and program administrators incur costs in achieving demand response.* Thus, any discussion of benefits must also define and recognize costs, and quantitative assessments should identify net benefits.
- Policymakers should consider the distributional impacts—*who bears the costs and who receives the benefits*—in designing and evaluating demand response strategies.
- *The durability of benefits must be taken into account*; short-term impacts should be distinguished from long-term impacts that provide benefits over a multi-year period.
- There are important *differences in the timing and distribution of demand response benefits* for vertically integrated utilities in states without retail competition compared to regions with organized wholesale markets and retail competition.

This section begins by identifying and discussing the costs of enabling and implementing demand response. Demand response benefits are then discussed, looking at benefits to participants, collateral benefits (which include economic and reliability benefits enjoyed by some or all market participants), and other benefits that are not easily quantifiable. Appendix B provides a more detailed discussion of collateral benefits, including a discussion of differences in the timing and flow of benefits in different market structures.

Demand Response Costs

The costs of realizing demand response can be distinguished as *participant* and *system* costs (see Table 3-1). Individual customers that curtail usage incur participant costs. Demand response program administrators incur system costs to create the infrastructure required to launch and support demand response, including providing incentive payments to customers. System costs may be recovered from ratepayers (either all ratepayers or designated classes of customers) or, in some cases, through "public benefits" charges on their electric bills. Cost recovery decisions are typically made with oversight from state regulatory agencies.

Table 3-1. Costs of Demand Response

Type of Cost		Cost	Responsibility/ Recovery Mechanism
Participant costs	Initial costs	Enabling technology investments	Customer pays; incentives may be available from public benefit or utility demand response programs to offset portion of costs
		Establishing response plan or strategy	Customer pays; technical assistance may be available from public benefits or utility demand response programs
	Event-specific costs	Comfort/inconvenience costs	Customer bears "opportunity costs" of foregone electricity use
		Reduced amenity/lost business	
		Rescheduling costs (e.g., overtime pay)	
		Onsite generator fuel and maintenance costs	
System costs	Initial costs	Metering/communications system upgrades	Level of costs and cost responsibility vary according to the scope of the upgrade (e.g., large customers vs. mass market), the utility business case for advanced metering system or upgrades, and state legislation/policies
		Utility equipment or software costs, billing system upgrades	Utility typically passes cost through to customers in rates
		Customer education	Ratepayers, public benefits funds
	Ongoing program costs[1]	Program administration/management	Costs are incurred by the administering utility, LSE or ISO/RTO and are recovered from ratepayers
		Marketing/recruitment	
		Payments to participating customers	
		Program evaluation	
		Metering/communication[2]	

[1] Ongoing program costs apply for incentive-based demand response programs and optional price-based programs only. For default-service time-varying pricing, ongoing costs are equivalent to any other default-service tariff offering.
[2] Metering/communications costs can include dedicated wire or wireless lines leased from a third-party telecommunications provider and costs to communicate pricing or curtailment information to customers or their energy services suppliers.

Customers undertaking load reductions may incur *initial* as well as *ongoing* costs to respond (see Table 3-1):

- *Initial costs* are incurred before a particular demand response behavior or action can be undertaken. They include devising a load response strategy that takes costs and benefits into account, and investing in enabling technologies to assist with load response. Enabling technologies include devices, such as "smart" thermostats, peak load controls, energy management control or information systems fully integrated into a business customer's operations, and onsite generators deployed as backup to network service. Policymakers may find it appropriate to invest in customer education and/or technology rebate programs, using ratepayer or public benefits funds, to defray some of participating customers' initial costs, especially if they are barriers to the achievement of demand response potential.

- *Ongoing costs* are incurred by customers when they respond to high prices or demand response program events. These costs may be measurable financial costs (e.g., lost business activity, rescheduling costs such as employee overtime pay, fuel and maintenance costs from operating onsite generation) or more abstract measures of the value of electricity (e.g., the inconvenience or discomfort associated with load reductions).

Various system-wide costs are incurred in implementing demand response, which should be considered in assessing cost-effectiveness.

A variety of *system-wide costs*, which may be passed through to ratepayers or borne by utility or LSE shareholders, are associated with implementing demand response and require consideration in evaluating benefits. These include *initial costs* as well as *ongoing costs* for certain demand response options (see Table 3-1).

Initial costs can be organized into several functional categories, as follows:

Metering and communication system upgrade costs can present a significant barrier to widespread implementation of price-based DR.

- *Metering/communication system upgrade costs.* Customer retail rates typically charge only for the monthly volume of energy consumed, and for larger customers for maximum monthly demand. Time-varying tariffs (e.g., RTP, CPP) requires chronological measurement of energy usage or demand. This is typically accomplished by installing advanced metering systems (AMS) that measure and store energy usage at intervals of one hour or less and include communication links that allow the utility to remotely retrieve current usage information whenever need.[31] Metering and communications system upgrade costs depend on the existing technology as well as the applicable customer classes. Because the aggregate costs may be substantial, they can present a significant barrier to widespread implementation of time-varying tariffs especially for small and medium-sized customers and often raise cost responsibility and recovery issues. Advanced metering issues are discussed in the textbox below.

- *Utility billing system* upgrades may be necessary for some demand response options (e.g., RTP, CPP) because most legacy systems are not equipped to handle time-varying costs or usage. Pricing hourly (RTP), or having provision to price some hours differently (CPP), requires changing the way metered data are collected, processed, and stored.[32]

[31] Note that for some pricing applications (e.g., TOU rates) only usage by daily pricing period (peak and off-peak) needs to be recorded.

[32] RTP (and/or CPP) rates significantly increase the amount of usage data that must be collected (i.e., from two to four observations of customer demand and energy usage per month to at least 720 observations).

Advanced Metering to Support Price-Based Demand Response

Advanced metering is a key technology that enables many utility and customer functions. This textbox addresses four key questions regarding the role and cost of advanced metering.[33]

What is the relationship between price-based demand response and advanced metering? Price-based demand response (e.g., RTP or CPP) requires a tariff that links what the customer pays to the hourly wholesale costs of power. Advanced metering provides utilities with the capability to collect hourly interval or more frequent usage data, which is necessary to support RTP or CPP tariffs.

What is advanced metering? There are three basic types or classes of meters.

- *Conventional "kilowatt-hour" (kWh) meters* account for more than 90% of the current meter population. They record cumulative energy usage and are usually read once each month during an on-site visit by a utility employee.
- *Automated meter reading systems (AMR)* add a low power transceiver, a communication link, to a conventional kWh meter. The transceiver allows the meter to be read from a utility vehicle that drives by the customer site. These meter systems are usually limited by communication capability to collecting a single cumulative kWh reading. AMR speeds up the metering reading function and reduces utility personnel costs.
- *Advanced metering systems (AMS)*, also referred to as *advanced metering infrastructure (AMI)*, provide two features that distinguish them from conventional and AMR systems: (1) the capability to measure and store energy usage at intervals of one hour or less and, (2) a communication link that allows the utility to remotely retrieve current usage information to support customer billing and other utility operational functions.

Aren't advanced meters expensive? Advancements in communications and solid-state technology have reduced the cost of AMI to about $100 per meter if deployed system-wide. Costs to enhance and/or upgrade utility customer information and billing systems are extra. Several recent studies suggest that per-meter hardware and installation costs for advanced metering systems may be comparable to the cost of a new AMR system (King 2004).

What factors should be considered when evaluating the costs and benefits of advanced meters? Advanced metering (AMI) evaluations should consider three major categories of cost and benefit impacts:

- *Utility Operational Impacts:* AMI is first and foremost a technology for automating and improving basic utility operations. Interval metered customer usage data is essential to support billing, outage management, complaint resolution, forecasting, real-time dispatch, rate design and other utility functions. Benefits such as reductions in theft that do not impact utility revenue requirements also need to be addressed. Operational savings alone economically justified all 13 major AMI installations undertaken in North America through 2005. Utility business case analyses should account for the net impact of forecasted operational savings in estimating changes in the utility's revenue requirement from AMI deployment.
- *Demand Response Impacts:* AMI enables RTP, CPP and other forms of performance-based demand response.
- *Societal Impacts:* Societal impacts include improved customer service, environmental, equity and other benefits from more efficient utility operation.

Billing invoices must also be expanded to provide detailed, hour-by-hour accounting. Some utilities and load serving entities can accommodate these new pricing schemes at moderate cost if their existing billing systems are compatible with detailed usage accounting, while others may need to completely revamp or replace their entire billing systems (depending on the number of customers eligible for RTP or CPP).

[33] For more information on Advanced Metering Infrastructure, see http://www.energetics.com/madri/toolbox/.

- *Customer education* about the time-varying nature of electricity costs, potential load response strategies, and available retail market choices is often included in the rollout of demand response options.

Ongoing costs, including program administration and operation, marketing, evaluation, and customer recruitment costs, apply to incentive-based demand response programs and optional pricing tariff options that are offered in addition to customers' standard electricity tariff. For incentive-based demand response programs, additional costs also include payments to participating customers. For most default-service price-based options, there are no incremental ongoing costs relative to any other default-service tariff. However, depending on the type of metering/communication infrastructure used, ongoing equipment operation or leasing costs may apply.

Benefits of Demand Response

The benefits of demand response can be classified into three functional categories: *direct*, *collateral* and *other* benefits (see Table 3-2). Direct benefits accrue to consumers that undertake demand response actions, and collateral and other benefits are enjoyed by some or all groups of electricity consumers. Direct and collateral benefits can be quantified in monetary terms. Other benefits are more difficult to quantify and monetize.

<u>Participant Benefits</u>

Customers who adjust their electricity usage in response to prices or demand response program incentives do so primarily to realize *financial* benefits. In addition, they may be motivated by implicit *reliability* benefits (see Table 3-2).

- *Financial benefits* include cost savings on customers' electric bills from using less energy when prices are high, or from shifting usage to lower-priced hours, as well as any explicit financial payments the customer receives for agreeing to or actually curtailing usage in a demand response program.
- *Reliability benefits* refer to the reduced risk of losing service in a blackout. This benefit may be associated with an internalized benefit, in cases where the customer perceives (and monetized) benefits from the reduced likelihood of being involuntarily curtailed and incurring even higher costs, or societal, in which the customer derives satisfaction from helping to avoid widespread contingencies. Both are difficult to quantify but may nonetheless be important motivations for some customers.

The level of direct benefits received by participating customers depends on their ability to shift or curtail load and the incentives afforded by time-varying electricity prices and any additional program incentives that are offered.

<u>Collateral Benefits</u>

Demand response, through its impacts on supply costs and system reliability, produces *collateral benefits* that are realized by most or all consumers (see Table 3-2). It is these collateral benefits, which have system-wide impacts, that provide the primary motivation for policymakers' interest in demand response.

Table 3-2. Benefits of Demand Response

Type of Benefit	Recipient(s)	Benefit		Description/ Source
Direct benefits	Customers undertaking demand response actions	Financial benefits		• Bill savings • Incentive payments (incentive-based demand response)
		Reliability benefits		• Reduced exposure to forced outages • Opportunity to assist in reducing risk of system outages
Collateral benefits	Some or all consumers	Market impacts	Short-term	• Cost-effectively reduced marginal costs/prices during events • Cascading impacts on short-term capacity requirements and LSE contract prices
			Long-term	• Avoided (or deferred) capacity costs • Avoided (or deferred) T&D infrastructure upgrades • Reduced need for market interventions (e.g., price caps) through restrained market power
		Reliability benefits		• Reduced likelihood and consequences of forced outages • Diversified resources available to maintain system reliability
Other benefits	• Some or all consumers • ISO/RTO • LSE	More robust retail markets		• Market-based options provide opportunities for innovation in competitive retail markets
		Improved choice		• Customers and LSE can choose desired degree of hedging • Options for customers to manage their electricity costs, even where retail competition is prohibited
		Market performance benefits		• Elastic demand reduces capacity for market power • Prospective demand response deters market power
		Possible environmental benefits		• Reduced emissions in systems with high-polluting peaking plants
		Energy independence/ security		• Local resources within states or regions reduce dependence on outside supply

Collateral benefits can be categorized functionally as *short-term* and *long-term market impacts* as well as *reliability* benefits:

- *Short-term market impacts* are the most immediate and easily measured source of financial benefits from demand response. Broadly speaking, they are savings in variable supply costs brought about by more efficient use of the electricity system, given available infrastructure. More efficient resource use, enabled by building better linkages between retail rates and marginal supply costs, translates to short-term bill savings to consumers from avoided energy and, in some cases, capacity costs. Where customers are served by vertically integrated utilities, short-term benefits are limited to avoided variable supply costs. In areas with organized spot markets, demand response also reduces wholesale market prices for all energy traded in the applicable market. Reductions in usage during high-priced peak periods result in a lower wholesale spot market clearing price. The amount of savings from lowered wholesale market prices depends on the amount of energy traded in spot markets, rather than being committed in forward contracts.[34]

- *Long-term market impacts* hinge on the ability of demand response to reduce system or local peak demand, thereby displacing the need to build additional generation, transmission or distribution capacity infrastructure. Because the electricity sector is extremely capital-intensive, avoided capacity investments can be a significant source of savings. However, for demand response resources to reduce capacity costs, it must be available and perform reliably at high-demand periods throughout the year because it is displacing other capacity resources.

Demand response also provides reliability benefits, reducing the probability and severity of forced outages.

- *Reliability benefits* refer to reducing the probability and severity of forced outages when system reserves fall below desired levels.[35] By reducing electricity demand at critical times (e.g., when a generator or a transmission line unexpectedly fails), demand response that is dispatched by the system operator on short notice can help return electric system (or localized) reserves to pre-contingency levels.[36] These reliability benefits can be valued according to the amount of load that demand response load reductions removed from the risk of being disconnected and the value that consumers place on reliable service (the "value of lost load").

Appendix B provides a more detailed discussion of the collateral benefits of demand response to assist policymakers' understanding of economic efficiency gains, avoided capacity benefits and capacity program design and valuation issues, the impact of different market structures on the timing and distribution of short-term and long-term demand response benefits, and the identification and valuation of reliability benefits.

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[34] Many load-serving entities currently purchase a substantial portion of their electricity in ISO-administered spot energy markets. In New York, a state with organized wholesale markets and retail competition, over 50% of electricity is traded in day-ahead and real-time spot markets, with the rest settled in forward contracts. In New England, about 40% of the electricity volume is traded in ISO-NE's spot markets, with about 60% committed in forward contracts.

[35] At times, system dispatchers are faced with either shutting off load to parts of the system, or risk an outage that affects many more customers and load. The loads that are shut off depend on exigent circumstances. Demand response reduces load and thereby lowers the likelihood of the need to impose forced outages. It also reduces the amenity impact of a given level of load shedding because it is distributed among customers according to their willingness and ability to curtail (given appropriate incentives) rather than, for example, cutting off all customers and all load served by a given substation.

[36] Dispatchable demand response resources include direct load control programs, interruptible/curtailable rates and emergency demand response programs. Reliability benefits derive from curtailments undertaken when all available generation has been exhausted and only load reductions can serve to restore system reliability to acceptable levels.

Other Benefits

Demand response can provide several *other benefits* that accrue to some or all market participants but are not easily quantified or monetized:

- *More robust retail markets.* In competitive retail markets, default-service RTP can stimulate innovation by retail suppliers (Barbose et al. 2005), and ISO/RTO-administered demand response programs can provide value-added opportunities for marketers (Neenan et al. 2003).
- *Improved choice.* Demand response can provide expanded choices for customers in varying retail market structures (e.g. states with or without retail competition) through additional options to manage their electricity costs.

Demand response can reduce the potential for generators to exert market power by with-holding supply.

- *Market performance benefits.* Demand response can also play an important role in mitigating the potential for generators to exert market power in wholesale electricity markets by withholding supply in order to cause prices to increase. Price-responsive demand mitigates this potential because demand reductions in response to high prices increase suppliers' risk of being priced out of the market. Demand response can provide this "market performance" benefit even if it is rarely exercised because the *prospect* of demand response may be a sufficient deterrent to prevent generators from attempting market manipulation.
- *Possible environmental benefits.* Demand response may provide environmental benefits by reducing the emissions of generation plants during peak periods. It may also provide overall conservation effects, both directly from demand response load reductions (that are not made up at another time) and indirectly from increased customer awareness of their energy usage and costs (King and Delurey 2005). However, policymakers should exercise caution in attributing environmental gains to demand response, because they are dependent on the emissions profiles and marginal operating costs of the generation plants in specific regions.[37] Emission reductions during peak periods need to be balanced against possible increases in emissions during off-peak hours as well as from increased use of onsite generation.

[37] See Holland and Mansur (2004) for an analysis of regional differences in the impacts of load response on net power plant emissions, and Keith et al. (2003) for an analysis of impacts of demand response resources on net power sector emissions in New England.

SECTION 4. QUANTIFYING DEMAND RESPONSE BENEFITS

Quantifying the potential nation-wide benefits of demand response, as EPACT charges DOE to accomplish, is a large and complex undertaking and involves several functional aspects:

- *Demand Response Options*—the types of time-varying rates and demand response programs that are currently offered (or potentially available);
- *Customer Participation*—the likelihood that a customer will choose to take part in the program;
- *Response*—documenting and quantifying participants' current energy usage patterns, and determining how participants adjust that usage in response to changes in prices or incentive payments;
- *Financial Benefits*—developing methods to quantify the level and distribution of short-and long-term resource savings of load response under varying market structures;
- *Other Benefits*—identifying and quantifying any additional benefits provided by demand response resources (e.g., improved reliability); and
- *Costs*—establishing the costs associated with achieving demand response.

Given differences in market structure among states, the lack of a uniform method to measure demand response benefits and significant data limitations and gaps, which could not be overcome in the time allotted for completion of this report, DOE has chosen to take a different approach to meet its mandate.[38]

> *DOE's approach in meeting its EPACT mandate is to summarize and compare the results of recent studies that quantified demand response benefits.*

DOE's approach is to summarize and compare the results of a number of recent studies that have attempted to quantify demand response benefits under a variety of contexts and scopes and for different regions or markets. Results are used as a basis for recommendations that can guide future efforts to quantify demand response benefits at the regional market level.

This section begins by summarizing the results of recent studies of the intensity of customer response to time-varying pricing and other demand response programs to establish the extent to which participants adjust their usage in response to price changes or incentive payments. Then, ten selected studies of demand response benefits are reviewed to assess and compare the impact of varying demand response mechanisms, study methodologies, and wholesale and retail market structure. The estimates of demand response benefits are normalized to provide insight into the importance of some factors in

[38] A comprehensive study quantifying the national benefits of demand response would have to account for different types of demand response (e.g., time-varying tariffs, incentive-based demand response programs).

determining the level of benefits attributed to demand response. Finally, recommendations on practices, protocols, and standards for improving estimates of the benefits of demand response are summarized.

Intensity of Customer Demand Response

To quantify demand response benefits in aggregate, two key inputs are: (1) measures of customer acceptance and participation rates in dynamic pricing and demand response programs, and (2) measures of the extent to which individual customers curtail load in response to either time-varying prices or demand response program incentive payments i.e. intensity).

With respect to the first input, a number of studies have characterized drivers to customer participation as part of evaluations of demand response programs or pilot tariffs. Important factors in the customer's decision to enroll and participate include the level and type of incentives offered, program requirements and conditions (e.g., notice, duration, and frequency of curtailments), customer assessment of risks and value proposition (e.g., financial consequences for failure to curtail loads), and effectiveness of program design and implementation (e.g., marketing, customer education and information, technical assistance).

With respect to the second input, a relatively large number of studies characterize the extent to which customers respond to dynamic prices and demand response programs. Results are typically reported in terms of two measures (or indicators): 1) price elasticity or 2) absolute or relative load impact (e.g., kilowatt [kW] or percent load reduction).

Customer Response to Time-Varying Prices

Price elasticity is a normalized measure of the intensity of customers' load response to prices.

A price elasticity provides a normalized measure of the intensity of customers' load changes in response to price circumstances especially for time-varying rates or demand response programs that induce load modifications directly in response to price changes. It is defined as the percentage change in usage for a one-percent change in price, and takes on values of zero and above, in absolute terms.[39] For example, if a customer's price elasticity is 0.15, then a doubling (100% change) of price results in a 15% reduction in electricity usage, other things equal. Higher elasticity values

[39] This definition is for own-price elasticity, which is always *negative*; usage goes down as price goes up. There are several variations on the concept of price elasticity that relate to different aspects of the full consequences of the change in usage. For example, a cross-price elasticity measures the consequences of reduced electricity usage on other goods. If a customer buys less electricity, then it has more money to spend on other goods and services. A substitution elasticity characterizes how a customer shifts the use of electricity in one period of the day to another (e.g. peak versus off-peak) in response to price differences between the two periods. A substitution elasticity can have a *positive* value (or zero). The discussion in this section reports elasticity values on an absolute basis, with the sign always positive, to emphasize the differences in results among studies. Appendix C provides a more complete and technically accurate characterization of the study results.

translate into increased price response by customers. Price elasticity is a useful measure because it allows for comparison of the load response of customers facing different prices.

Figure 4-1 summarizes the results of studies that estimated the price response exhibited by customers that participated in voluntary programs that involved time-varying prices (see Appendix C for more detailed information):

- several existing RTP programs available to larger industrial and commercial customers that have been operating for many years;
- an ongoing residential real-time-pricing (RTP) pilot;
- the California CPP pilot conducted in 2003-4; and
- pooled results of five residential TOU pilots conducted in the late 1970s.[40]

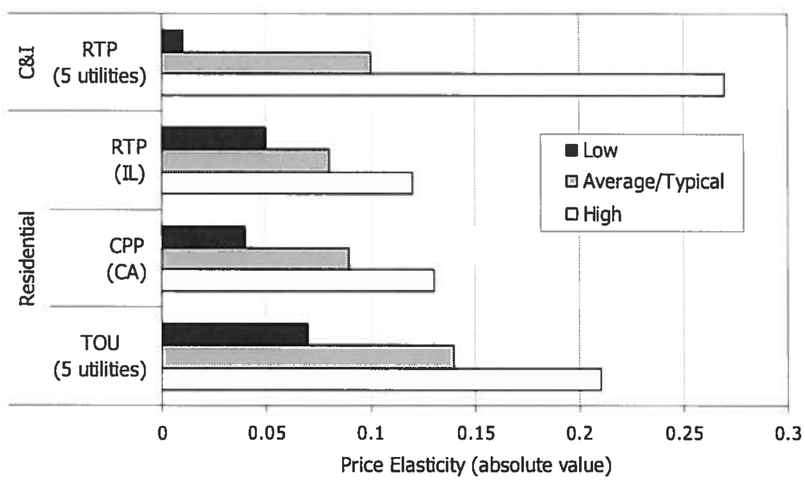

Figure 4-1. Customer Response to Time-Varying Prices: Price Elasticity Estimates

For each study, the low, average (or typical), and high estimates of price response are illustrated, although the interpretation of the low to high range values varies somewhat across studies. For example, the range in price elasticity values for a residential RTP pilot in Illinois are attributed to demographic differences within the pilot group, while for a pilot CPP program in California, the range in elasticity values primarily reflects climatic differences and saturation of air conditioning equipment among participant groups. For the residential TOU studies, the range of elasticity values reflects results across the five pilots.

Average price elasticities among the studies are fairly similar, ranging from 0.08 to 0.14 (in absolute value). The average elasticity value for RTP for large industrial and commercial customers (0.10) represents a typical value reported by several studies. The low and high elasticity values for commercial and industrial RTP customers exhibit the largest variation (i.e., 0.01 to 0.27) and reflect differences in the price responsiveness of

[40] See Appendix C for a more in-depth description of these studies and their results.

various market segments. Studies of large customers' response to RTP consistently find large differences in price elasticity across business categories. For example, a recent study of about 150 customers on RTP at Niagara Mohawk reported average elasticities of 0.16 for manufacturing customers, 0.10 for government/education customers, 0.06 for commercial/retail and 0.04 for healthcare facilities (Goldman et al. 2005).

The Residential RTP study (Illinois) reported similar price elasticities as the California residential CPP study (i.e., 0.08 to 0.09); both studies were conducted during a comparable time period (2004) but in different markets. Studies of residential customer response to time-varying prices often report that price elasticity is driven in part by the number of electricity devices present in the home. Climate also has a discernable affect, as do occupant characteristics and circumstances that affect when they are home and likely to be able to shut off devices or reduce usage.

Customer Response to Load Control Programs

Over one hundred U.S. utilities report that they currently offer residential or small commercial DLC programs that primarily target customers with air conditioning or domestic water heating load-control devices (EIA 2004).[41] A number of these programs have conducted relatively recent measurement and evaluation studies with results that are publicly available.

In some demand response programs (e.g., where customers do not directly respond to prices), their response is typically measured by the amount of load reduced.

For DLC programs and other types of demand response programs where customers are not directly responding to a price, the intensity of customers' response is typically measured in terms of an absolute or relative load impact (e.g., kW of load curtailed or percent of the customer's total load that is curtailed, either through equipment cycling or shedding).

Figure 4-2 summarizes reported load reduction estimates for large groups of customers with water heating load controls and various types of control strategies for air conditioning equipment (e.g., cycling the device on and off at a specified time interval, shutting the device off for a period of time, or resetting a thermostat set point) [see Appendix C for more detailed information].[42] Residential water heating DLC programs have typically yielded load reductions in the range of 0.3 to 0.6 kW per house; the magnitude and timing of the load impact depends on household and equipment size, ground water temperature and household usage patterns. DLC programs targeting residential air conditioning (A/C) have reported load reductions ranging from approximately 0.4 to 1.5 kW per customer over the course of an event. The magnitude of the load reduction per customer can strongly depend on climate, the control strategy deployed (e.g. 100% shed, duty cycling, thermostat reset) and the customer's air

[41] Demand-side management efforts include energy efficiency and/or load management programs.
[42] The results indicate the range of possible load impacts, although the values across studies are not readily comparable because of differences in program design features, cycling strategies, and climate.

conditioning usage levels absent load control. This is illustrated in Figure 4-2 by several studies that reported low and high load reduction values based on testing different cycling strategies at various temperature levels.

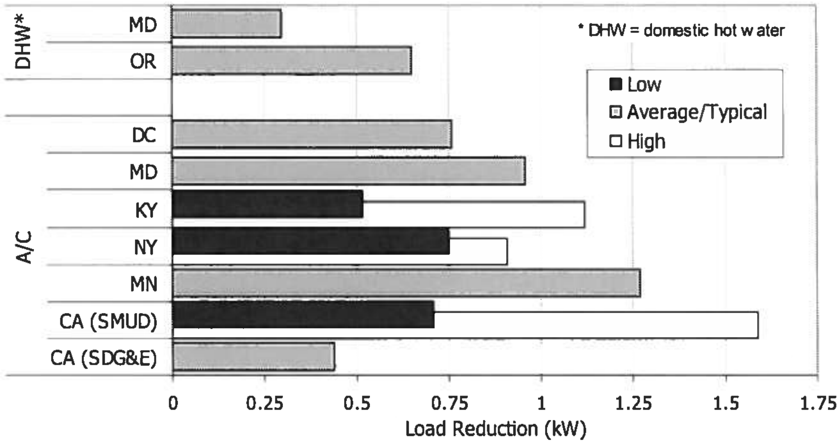

Figure 4-2. Estimated Load Impacts from Direct Load Control Programs

Impact of Enabling Technologies on Price Response

> *Studies of pilot programs combining pricing with enabling technologies provide important insights on the technical potential for demand response.*

Some utilities have offered pilot programs targeted to mass-market customers that integrate CPP with enabling technology, specifically load control devices that receive price signals and can be programmed by customers to reduce A/C or other loads during critical peak periods (see Figure 4-3 and Appendix C). Several of these programs have obtained promising results. For example, in Florida, Gulf Power reported average load reductions of 40% during critical peak periods for groups of customers that could control multiple loads (e.g. A/C, water heating, pool pumps) (Levy Associates 1994). In California, a recent Statewide Pricing Pilot (SPP) sought to quantify the impact of "smart thermostats" with critical peak prices. The average load reduction of 220 residential customers with smart thermostats during critical peak days was approximately 0.64 kW, a 27% reduction during peak periods, approximately two-thirds of which was attributed to use of the smart thermostat. Among the 235 small business customers in the California SPP, the average peak period load reduction was about 14%, although the relative impact of the enabling technology was even more pronounced. These studies may reveal the technical potential for demand response in certain market segments when time-varying pricing is combined with enabling technology.

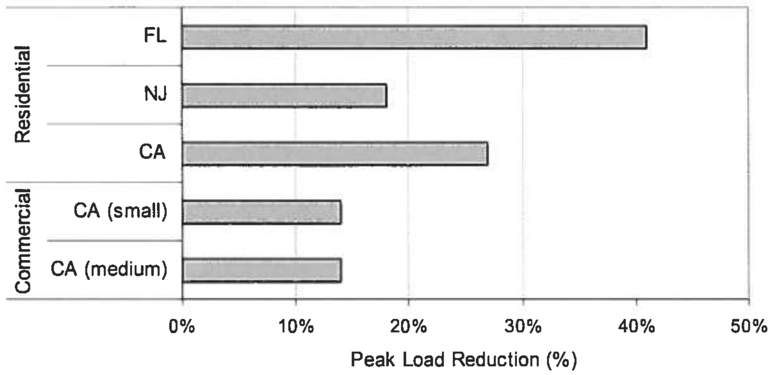

Figure 4-3. Load Response from Critical Peak Pricing and Demand Response Enabling Technologies

<u>Summary</u>

The following key findings and lessons can be drawn from this review of studies that examine customer response to time-varying prices and different types of demand response programs:

- Many initiatives have been undertaken that quantify the price-to-quantity relationship for various types of dynamic pricing and demand response programs. These data are critical because policymakers require price elasticity and load impact estimates as an input in estimating the benefit of specific demand response programs.
- Based on several of the more comprehensive studies, it is reasonable to assume that a group of large customers participating in well-designed RTP tariffs respond with a substitution elasticity of around 0.10 on average, which means that when peak prices rise by 50%, these customers will lower or shift their load to other times of the day by 5%.[43]
- Elasticities for groups of residential customers enrolled in TOU rates with significant differentials in peak to off-peak prices (e.g. factor of three) are also about 0.10—0.15.
- A small number of studies of residential customers on CPP rates, with very high critical peak prices ($.50/kWh or higher) report that that customers reduce load by an even greater amount than is reported in other studies for TOU. The recent California pilot, where the two designs were tested side-by-side, reports that the difference is almost a factor of two. However, the difference may be due to the large price differences between the two rate offerings.[44]

[43] The ability of customers enrolled in RTP tariffs to respond to prices is varied. Several studies report that 65-75% of the total measured price response is provided by about 20% of the customers on RTP rates.
[44] Two customers with identical price response capability (price elasticity) may exhibit different levels of load response if they face vastly different prices. This is because the nature of the response may increase with the nominal level of prices. The price elasticities estimated for TOU rates may be smaller than for CPP rates, because the customers never faced the higher CPP prices.

- Studies of customer response to time-varying prices should be construed as representing short-term price response. Relatively few participants on RTP or CPP tariffs automate their response behaviors and actions, either because they do not have the necessary equipment or because they do not have the technical expertise, time, or sufficient incentive to implement such changes. As a result, customers tend to rely on manual actions to shut down equipment or curtail usage. This surely constrains the frequency and extent to which loads can be reduced. As demand response becomes more widespread and time-varying prices become the default (or standard) service, some customers can be expected to make cost-effective investments in enabling technology to improve their marginal ability to respond, and thereby increase the price elasticity (or the percentage of load reduced).
- Some jurisdictions have enrolled large numbers of customers in direct load control programs. For mature load management strategies (e.g. cycling of residential air conditioners, water heaters), there are well-developed models, based on actual field studies and program evaluations, that can predict per-unit load impacts reasonably accurately and allow characterization of factors that influence the intensity of customers' response (e.g. household size, income, equipment characteristics, schedule, weather).
- There has been relatively little emphasis on measuring and verifying the impacts of interruptible rates. The response of some customer market segments (e.g., small and medium-size business customers) has also received little research attention.
- Areas that warrant additional evaluation include: quantifying the impact of information and/or enabling technologies in customer decisions to participate in demand response options and the intensity of their response in specific market segments, understanding customer participation and response in markets that offer dynamic pricing and demand response (and energy efficiency) programs in order to assess potential synergies.

Quantifying the Value of Demand Response

Initial attempts to quantify the benefits of demand response arose after the passage of the Public Utilities Regulatory Policy Act (PURPA) in the early 1980s. PURPA set in motion initiatives to promote load management programs, using both pricing and load control mechanisms. Utilities needed to establish that paying loads to curtail was cost-effective; thus load management programs were justified on the specific cost savings they produced. The benefits were defined by the avoided capital and operating costs; utilities used available planning methods to establish how dispatched curtailments reduced the use of generation units.[45] Utilities evaluated these load management programs using an equivalence standard: load management had to produce service equivalent to the displaced generation but at a lower cost.

[45] Utility planning methods ranged from simple what-if calculations to in-depth and complex studies of the impacts on system operation.

During the 1980s, integrated resource planning initiatives further refined the process and tools used by utility planners to evaluate investments in load management and energy efficiency in lieu of constructing generation plant. Standardized cost-effectiveness tests were developed that specified both the scope of and methods to estimate the benefits, expressed in terms of avoided costs. The standardized tests were used to facilitate screening of programs and help establish a threshold criterion for program spending. Load management programs were also offered in states that did not require utilities to develop and file formal IRP plans. Utilities had to show that load management programs would reduce supply costs relative to an all-generation solution. In all states, program costs were ultimately allocated to consumers, as new generation would have been.

In the 1990s, as problems arose with the introduction of competition in wholesale (and retail) markets, demand response was seen as a critical feature of competitive wholesale markets. However, a measure of the benefits was needed to justify expenditures to achieve greater demand response. Efforts to estimate the benefits of demand response have proceeded on three parallel tracks.

First, studies were undertaken to demonstrate the benefits of demand response by comparing the operation of markets with and without adequate levels of customer response to hourly prices (Borenstein 2002). Theorists argued that demand response should be fostered as a matter of principle, because any market where customers are not exposed to changes in the costs of supplying power is by definition inefficient and not robustly competitive. Experimental trials in economic laboratories contributed to verifying these contentions (Smith and Kiesling 2005, Adilov et al. 2004).

Second, studies commissioned to assess the benefits of organized, competitive wholesale markets specifically quantified the benefits that might be attributable to demand response (ICF Consulting 2002, DOE 2003). Others sought to verify the extent of financial benefits by conducting simulations to link specific levels of demand response to decreases in market prices, some of which indicated that the benefits might be quite significant, in the billions of dollars even in regional markets (Braithwait and Faruqui 2001, Caves et al. 2000). The push to identify the role and value of demand response also found its way into regions that largely retained the vertically integrated structure. IRP studies began to look more closely at how demand response creates cost savings (NPPC 2005, Orans et al. 2004, Violette et al. 2006).

Third, as programs were introduced in organized markets to foster demand response, analytical methods were needed to determine the value of those load curtailments. Policymakers and market participants wanted assurances that the programs produced net benefits and were interested in the distribution of the benefits (e.g. reduced energy market prices and reliability impacts) among market participants (Boisvert and Neenan 2003).

There has been no coordinated effort to compare and synthesize contemporary methods of quantifying demand response benefits.

In summary, there have been a number of efforts to quantify the benefits of demand response in a variety of market settings and conditions. However, to date there has been no coordinated effort to determine whether this body of work allows us to estimate these benefits at the national level or provides detailed methods to quantify those benefits. EPACT places that obligation upon DOE.

Benefits of Demand Response: Review of Existing Studies

A literature review was undertaken to identify the body of information available to estimate the national benefits of demand response. Ten studies were selected to provide insight into how demand response benefits are quantified to analyze the methods used and to assess their impact on the results (see Table 4-1). They encompass most recent empirical studies of demand response benefits and can be classified into three categories:

- *Illustrative analyses* demonstrate the potential importance and/or quantify the economic impacts of demand response in a proposed market structure or hypothetical market circumstance. All four examples examined the potential for demand response benefits in organized wholesale markets. The approach taken is to create a base case reflecting the current market structure and conditions, estimate impacts of the proposed market structure changes (in the Standard Market Design [SMD] examples in Table 4-1), project how the electricity market would evolve with and without a specified amount of demand response, and then compare the results. In these studies, the benefits are hypothetical and speculative. The means for accomplishing demand response is often not explicitly addressed—it is presumed that demand response either occurs naturally in response to hourly prices or is induced through demand response programs—and the accuracy of the results depends on how well actual circumstances match assumptions used in the analysis.
- *Integrated Resource Planning* (IRP) studies assess whether and how much demand response resources ought to be acquired in a long-term resource plan based on avoided supply costs. They are typically undertaken by utilities in markets without retail competition. Demand response programs or dynamic pricing initiatives found to avoid capital and operating costs in excess of their implementation costs may be included in a utility's resource plan. Because vertically integrated utilities are responsible for securing additional capacity to meet anticipated customer loads, as well as administering proposed demand response programs or pricing initiatives, they have the ability to defer or eliminate other potential capacity additions to realize the avoided capacity (and energy) benefits. Three IRP studies are included in this analysis.
- *Program performance analyses* measure actual outcomes of demand response programs and provide an estimate of delivered value, rather than a forecast of benefits. The three program performance studies were conducted in states or regions with organized wholesale markets administered by ISOs/RTOs. These

studies estimate the impacts of load curtailments on market prices, quantify the level and distribution of benefits, and explicitly account for reliability benefits.

Demand Response Benefit Case Studies: Comparison of Key Features

The ten studies were assessed and compared along several key features that contextualize results and provide insight into issues that must be addressed to ensure more consistent, standardized approaches for valuing the benefits of demand response going forward. The following discussion refers to Table 4-1.

Market Character. The selected studies include examples from both organized spot markets and vertically integrated systems. The four illustrative analyses focus primarily on organized markets. Two of them (B and C in Table 4-1) look at nation-wide demand response impacts, because they were commissioned to quantify the benefits of the adoption of FERC's proposed standard market design (SMD). These studies included scenarios that examined the benefits of demand response over and above what the SMD was expected to deliver. The third study (D) provides a regional New England perspective, and the fourth focused on the California electricity market (A). Conversely, the three IRP studies (E, F and G) reflect a vertically integrated utility perspective, in which utilities define alternative strategies and assess their relative merits over a long planning horizon as a basis for up-front planning decisions. The three program performance studies (H, I and J) were conducted in regions where an ISO or RTO administers organized spot markets; they draw heavily on transparent market prices to measure actual performance benefits.

Market Analyzed. The selected studies vary considerably in their spatial scope and include national, regional, state, and individual utility system assessments. However, results from studies in more geographically focused settings (e.g., a utility, state or region) are sufficiently general that the results may apply elsewhere, after adjusting for program design features.

Peak Demand. The system peak demand of the market described in each study indicates market size. System peak load also serves as the denominator used to normalize reported gross benefits across studies; this helps reveal factors that affect reported demand response benefits.

Demand Response Mechanism. Eight of the studies either modeled or reported demand response benefits for specific types of demand response mechanisms. Four (A, D, E and F) estimated benefits for either RTP or CPP. Another four (C, H, I and J) estimated benefits for emergency demand response programs offered by utilities or ISOs. Six of these studies (C, F, G, H, I and J) also estimated benefits for demand bidding programs in which customers participate in day-ahead or real-time energy markets. Two studies (C and F) reported aggregated benefits for more than one demand response option. Aggregated benefit estimates for individual demand response programs were developed

Table 4-1. Benefits of Demand Response: Review of Selected Studies

		Illustrative Analyses				Integrated Resource Planning			Program Performance Analyses		
		Market Equilibrium DR[1]	FERC SMD[2]	DOE SMD[3]	Default RTP[4]	Mass Market DR[5]	IEA/DRR[6]	NPCC[7]	NYISO[8]	ISO-NE[9]	PJM[10]
1	Study	A	B	C	D	E	F	G	H	I	J
2	Market Character	Organized Wholesale Markets				Vertically Integrated Utility			Organized Wholesale Market		
3	Market Analyzed	CA	U.S.	U.S.	New England States	Midwest Utility	Sub-set of the MAAC Region	Northwest States	NY State	New England States	Mid-Atlantic States
4	Peak Demand (MW)	46,000	700,000	700,000	26,000	7,500	30,000	30,000	31,000	26,000	53,000
5	DR Mechanism	RTP	Price response only	DA-LBAR, EDR	Default Service RTP	CPP	DLC, DA-LBAR, CPP	DA-LBAR	DA-LBAR, EDR	DA-LBAR, EDR	DA-LBAR, EDR
6	Time Horizon (start)	Equilibrium	17 years (2004)	one year (2003)	5 yrs (2006)	20 years (2002)	20 years(2004)	20 years (2006)	Results for 2001-2004		
7	Participating Load	33% or more of load, no segment distinction	50% of customers in all regions	2% of load in economic, 2.5% in reliability	about 2% of system load	About 900,000 residential customers (100% participation)	15% penetration top-end	6% of peak demand (in 2020)	Participants in 1) emergency, 2) ICAP, or 3) energy DR programs. Subscribed load reduction from participating customers for all classes, ranging from 1 to 6%of system load		
8	Implementation Costs	Not reported	Not reported	Not reported	Implementation cost estimated (~10% of gross benefits)	Implementation and incentive costs estimated (~25% of gross benefits)	Implementation and incentive costs estimated (90% of gross benefits)	Implementation and incentive costs estimated (~53% of gross benefits)	Report B/C ratio by program for incentives-all exceed 1; separately report implem. cost	Report B/C ratio by program for incentives-all exceed 1.	Report B/C based on incentives. Separately report implementation costs
9	Analysis Method	Simulated dispatch and capacity adjustments	Simulated market equilibrium	Simulated dispatch	Simulated LMP adjustments to RTP	Simulation of market impacts	Simulated optimal capacity expansion plan and corresponding energy dispatch: stochastic market characterization		Simulated LMP and Reliability adjustments to demand response		Redispatch LMP change
10	Gross Benefits (Million $)	$302	$52,236	$362	$350	$1,000	$1,476	$718	$7	$1	$15
11	Gross Benefits ($/kW yr)	$6.57	$4.39	$0.52	$2.69	$6.67	$2.46	$1.20	$0.22	$0.04	$0.29
12	Normalized Gross Benefits ($/kW-yr.)	$1.99	$0.88	$2.07	$1.35	$2.02	$1.64	$1.99	$0.45	$0.30	$0.66

References:

[1] Borenstein 2005
[2] ICF Consulting 2002
[3] DOE 2003
[4] Neenan et al. 2005
[5] Faruqui and George 2002
[6] Violette et al. 2006
[7] NPCC 2005
[8] NYISO 2004
[9] RLW Analytics and Neenan Associates 2004
[10] PJM Interconnection 2004

Abbreviations:

DLC	Direct Load Control
DA-LBAR	Day-ahead Load Bidding as a Resource (demand bidding)
EDR	Emergency Demand Response
CPP	Critical Peak Pricing
RTP	Real-time Pricing
LMP	Locational Marginal Price

from the ISO/RTO program performance studies (H, I and J). Two studies (B and G) did not specify the type of demand response mechanism studied.

> *The ten reviewed studies' time horizons vary considerably, from one to twenty years.*

Time Horizon. The studies' time horizons vary considerably, ranging from one to 20 years. These differences are driven by differing study contexts, analysis methods, and market structure. Prospective studies tend to span a multi-year period. For example, the FERC SMD study (B) assesses cumulative impacts over a 17-year period because its primary focus was on the long-term benefits of SMD. In a somewhat different approach, the DOE SMD analysis (C) reports annualized estimates of demand response benefits for the 20-year study time horizon. IRP studies are by definition long-term planning exercises and all three examples (E, F and G) cover approximately 20 years. In contrast, the three ISO/RTO program performance studies (H, I and J) are retrospective evaluations that measure the actual benefits of demand response; all of these studies examine the benefits of programs that have operated over several years.

> *The types of customers targeted and assumed (or actual) market penetration rates varied significantly among the ten studies.*

Participating Load. There are significant differences in the targeted population and the assumed or actual demand response market penetration rates among the ten studies. Two of the illustrative analysis studies (A, B) assume high market penetration rates; this contributes to relatively high estimates of gross savings (row 11 in Table 4-1). Participation rates are affected to a great extent by the assumed tariff design. For example, the mass market demand response study (E) evaluates the benefits arising from placing the subject utility's entire residential customer group on CPP to assess the impacts of a mandatory tariff. In contrast, the Default RTP study (D) estimates the potential benefits of implementing RTP as the default service for large industrial and commercial customers (with peak demand greater than 1 MW) in the New England states that have adopted retail choice (although customers can opt out in favor of alternative supply products that may offer fixed rates).

> *Forecasting levels of customer acceptance, participation and load response is critical to evaluating the impacts of voluntary demand response programs.*

Forecasting levels of customer acceptance, participation, and load response are critical variables in voluntary demand response programs. The NPCC study (G) assumes that demand response will constitute about 6% of the resources used to meet the Pacific Northwest system peak after a 20-year ramp-up. The IEA/DRR study (F) assumes that demand response resources from three demand response programs and a dynamic pricing tariff will comprise about 15% of system peak demand after 20 years. The three ISO/RTO program performance studies draw on actual experience in enrolling customers in voluntary programs, rather than forecasts. However, estimating participation rates is complicated by difficulties in defining the eligible population.[46] In this analysis, subscribed load reductions as a fraction of system peak load are used to estimate participation rates; the results range from 1% to 6%.

> *Three out of ten studies did not report costs; cost reporting was inconsistent or incomplete among several other studies.*

Implementation Costs. Practices for reporting participant and system costs necessary to achieve demand response vary significantly among the ten studies (see Table 3-1 for demand response cost reporting categories). Three of the illustrative analyses (A, B and C) did not report costs at all. Among studies that included costs, demand response costs were not reported uniformly or were incomplete. Four studies included *estimates* of costs (D, E, F and G). In two of them, both IRP studies (F and G), demand response was modeled as a generation resource by specifying its product characteristics (availability period, capacity, number and duration of event calls) and cost. The costs to the utility system of acquiring this "resource" (e.g., initial costs, on-going program administration, and payments to participating customers) were well characterized. Initial participant costs were partially accounted for through incentives to subsidize their initial equipment or other costs, but event-specific costs were not (see Table 4-1). The two studies that focused on pricing options (D and E) estimated incremental metering and billing costs. Study E also included customers' investments in enabling technologies.

The three ISO/RTO program performance studies (H, I and J) reported *actual* implementation costs to varying degrees. These studies highlight some of the issues involved in reporting and accounting for costs. All three reported direct incentive payments made to customers for curtailing load. Some ISOs/RTOs reported their program administration costs. Most participant costs were not reported, including event-specific costs incurred by participating customers (NYISO 2004, PJM Interconnection 2004).[47]

Analysis Methods. All of the studies used simulation techniques to derive estimates of demand response benefits.[48] Simulation involves characterizing how the market works in a base-case scenario through cause and effect relationships. Demand is modeled as a function of prevailing economic conditions, the presence of electricity-using devices, and the prices consumers pay. Other factors, such as weather, can have predictable influences, but only under known (after-the-fact) or hypothesized conditions. The modeling of

[46] To be eligible for ISO emergency demand response programs, customers must be able to shed 100 kW of load, although aggregations of small customers are typically allowed. As a result, the eligible population could be defined as: all customers, all customers over a certain size range (this requires assumptions about the percent of load that can be shed), or customers that can shed 100 kW. As a practical matter, larger industrial, institutional and commercial customers account for most of the subscribed load in ISO demand response programs.

[47] It can be challenging for ISOs to collect information on participant costs because they often do not interact directly with customers. Instead load aggregators enroll customers in ISO programs. Collecting participant cost information would require placing additional reporting requirements on load aggregators.

[48] Study E utilized a Total Resource Cost (TRC) test to determine the cost-effectiveness of implementing mass-market demand response.

energy supply costs is influenced by market structure and incorporates information on available generation units and their performance characteristics and fuel costs.

The illustrative analyses, all targeted to organized markets, focus on whether energy and (where applicable) capacity market prices would be sufficient to attract enough capacity to meet reliability standards at least cost. The goal of such simulations is to explore the conditions under which competitive market equilibrium is reached (as in study A) or to simulate market transactions within different market designs and measure key performance indicators such as capacity investment and market-clearing prices. The focus is on minimizing the resulting market prices.

The IRP planning studies were undertaken to answer the question of how much capacity to add, at what time, and to what extent energy efficiency or demand response resources should be implemented to meet capacity needs. The IRP simulations (F and G) explored the cost implications of alternative supply strategies over an extended period and analyzed major uncertainties (e.g. load growth, weather, capability of generation units, fuel prices) using probabilistic techniques to identify a risk-constrained, least-cost strategy.

The program performance studies (H, I and J) analyzed the extent to which wholesale market prices were influenced by customer load curtailments in response to program events and estimated the direct and collateral benefits of these lower prices (see Table 3-2 for a typology of demand response benefits). This involved simulating price formation at a sufficient degree of detail to estimate reductions in market prices. Reliability benefits were also simulated for the program performance studies using assumptions about the value of lost load (VOLL) to customers and the impact of emergency demand response program curtailments in restoring system reserves.[49]

Gross Benefits. The gross benefits reported are the total estimated dollar benefits from each study, without any offset for the costs associated with achieving the hypothesized or measured level of demand response. It is important to note that many individual studies reported a range of benefits, although there were differences in how these ranges were developed. For example, in several of the illustrative analyses and IRP studies, the range of reported demand response benefits were derived from scenarios based on differences in assumed price elasticities, participation rates, or the set of demand response programs offered. In contrast, in the program performance analyses, the ranges of benefits were primarily based on differences in the assumed value of lost load or expected un-served energy in emergency programs.

In Table 4-1, a single representative value for gross benefits is reported for each study, rather than the complete ranges. The choice of values was intended to place the studies on as comparable a basis as possible. For example, for illustrative analysis and IRP studies, the reported benefits estimates correspond to scenarios that most closely approximate a

[49] Reliability benefits are discussed in section 3 and Appendix B.

price elasticity of 0.10 for dynamic pricing options—a typical level of response based on the results of demand response impact studies discussed above.[50]

The ISO/RTO program performance studies present a different type of challenge for reporting gross benefits because these studies report actual customer response, and the programs have only been in existence for several years. Unlike the other studies, these estimated benefits reflect actual program outcomes, not an average of those expected over many years, which the other studies report (see the textbox below).

Estimating Normalized Demand Response Benefits from Program Performance Studies

- In Table 4-1, the demand response benefits reported for the NYISO study involve two components: (1) the weighted average of the annual reliability benefits for 2001-2004, where the weights represent market circumstances relative to expectations over a ten-year period, and (2) benefits from price reductions from scheduled day-ahead load curtailments. The majority of the reported benefits derive from reliability impacts, primarily from the 2003 Northeast blackout events.
- ISO-NE reported reliability benefits from its emergency demand response program for 2003 and 2005, but declared no events in 2004. The benefits reported are from 2003, which are approximately equal to the preliminary values for 2005.
- PJM attributes virtually all of its benefits to reduced real-time prices from customer self-scheduled curtailments that are paid the real-time market price. The reported benefits are averaged for 2003 and 2004.

Demand Response Benefit Case Studies: Discussion of Results

Gross benefits estimates vary widely, from $1 million to $52 billion.

The gross demand response benefits estimated by the ten studies span a very large range, from $1 million (M) to $52 billon (B) (see Table 4-1). Even among studies of similar scope, the estimates differ substantially. For the two national studies (B and C), annual gross benefits vary by a factor of eight (estimated at $3B and $360M). Differences in market scope and size, time horizon, analytic methods, the type and number of demand response resources represented, and assumed market penetration and customer responsiveness all affect the differing gross benefit estimates.

Normalization can make comparison of these results more informative. Accordingly, a gross benefit metric was devised to normalize the study results, incorporating and adjusting for several factors: market size, time horizon, and the assumed level of customer participation in a demand response program or pricing initiative. The gross benefits value (row 10 in Table 4-1) was first divided by the market's peak demand in

[50] Some studies included a scenario with that exact price elasticity assumption. In illustrative analysis studies where price elasticity was not an explicit variable included in the sensitivity analysis, a judgment was made as to the most comparable scenario in terms of customer price responsiveness.

2004 (row 4).[51] This removes some of the scale bias. However, there are also significant differences in the time horizon over which demand response benefits were calculated and the assumed level of participation in demand response programs that were simulated. To address these factors, the size-adjusted gross benefits were divided by the number of years in the study and then by a factor that normalized each study to an equivalent demand response participation rate of 10%.

Gross benefits of demand response reported in each study were normalized to adjust for differences in time horizon, level of customer participation, and market size to facilitate comparing different studies' estimates.

The resulting estimates of normalized gross benefits, measured in \$/kW-year, provide a more comparable basis for understanding the methodological and market structure factors that influence the estimates of demand response benefits (see row 12 of Table 4-1). This metric, which gives an estimate of dollar value per kW of *system peak load* is different from avoided capacity costs, which are measured in the same units but represent a dollar value per kW of *avoided capacity* (see the textbox, below). These two metrics should not be directly compared.

Avoided-Cost Benefits of Demand Response vs. Normalized Gross Benefits

Some demand response programs (e.g., direct load control) have traditionally been regarded and analyzed as an effective capacity equivalent of generation in which the primary source of benefits is the avoided capacity cost from displacing a generation resource. Often, demand response programs are evaluated against an avoided cost standard: the costs of a demand response program are compared to a capacity alternative on the basis of their costs per kW-year. For example, if a peaking unit requires revenues to cover investment costs of \$75/kW-year, which can be interpreted as the utility's avoided capacity costs. If a demand response program costs \$50/kW-year, then the net benefits are about \$25/kW-year. In this example, the annualized benefits of demand response are expressed in terms of net benefits (\$) per *unit of avoided capacity* (kW); this is how the industry typically quantifies the value or cost of demand response.

Although the *units* are the same, it is important not to confuse the industry approach described above with the *normalized gross benefits* estimated for the ten studies included in this report. This metric expresses the studies' annual gross benefits in terms of dollars per unit of system peak load. It is calculated by dividing estimated benefits by the number of years covered by the study and the peak demand (kW) of the target market. The meaning and interpretation of this metric is different from avoided-cost benefits. Because normalized gross benefits are divided by the peak demand *of the entire market*, the values estimated for these ten studies (\$0.30-2.00/kW-year) are much lower than the avoided capacity benefits of demand response, and they should not be compared with the value or cost of demand response used in conventional analyses of capacity or supply costs. Rather, this indicator was constructed solely to facilitate a comparative review of these demand response benefit studies.

[51] This adjustment approach, using system peak demand as a proxy for market size, may produce some bias across studies, particularly for studies that cover 20 years because peak system demand is likely to increase over that period. However, given data availability constraints, peak demand in 2004 was adopted for forward-looking studies with long time horizons and peak demand at the time of study completion was used for other studies.

The normalized gross benefits are plotted for the ten studies in Figure 4-4, and the average and range of values for each type of study are shown in Figure 4-5.

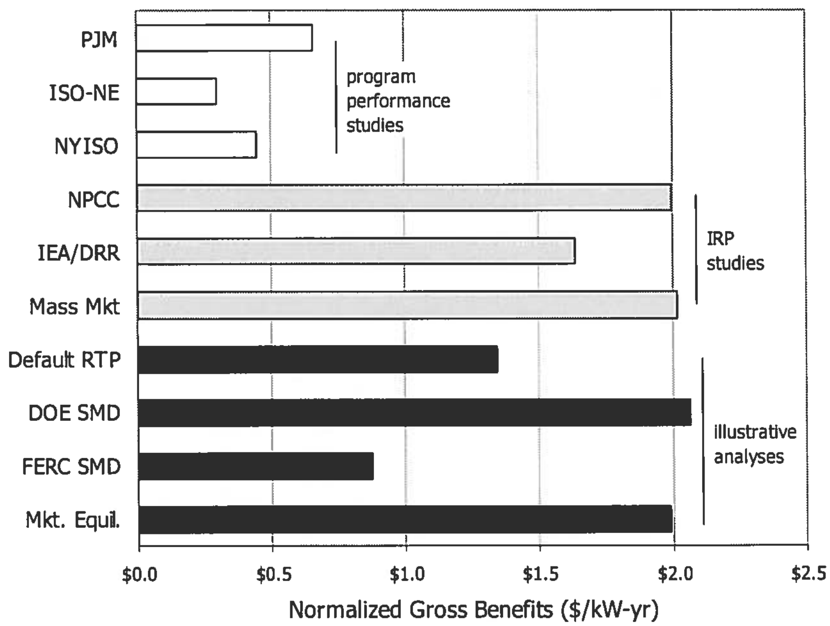

Figure 4-4. Normalized Gross Demand Response Benefits: Estimates of Ten Selected Studies

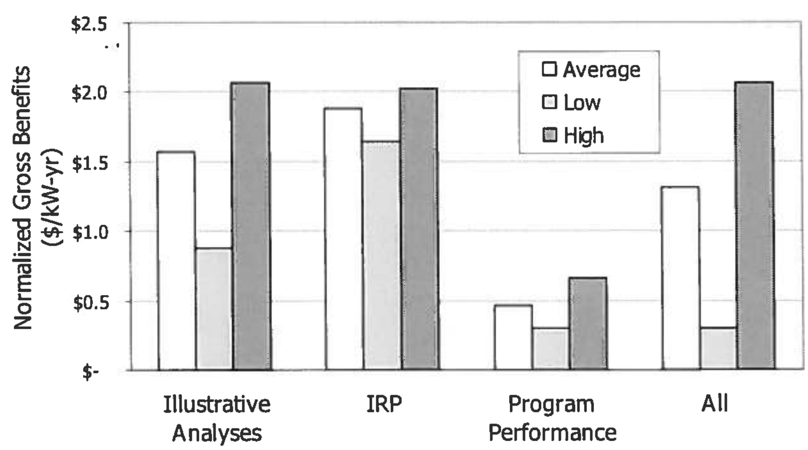

Figure 4-5. Normalized Gross Demand Response Benefits by Type of Study

DOE highlights the following key findings and observations based on this comparative review and analysis of these benefit studies.

There is a noticeable difference in the normalized demand response benefits of program performance analysis studies in organized markets relative to those of the illustrative and IRP studies (see Figure 4-4). This is largely attributable to differences in analytic methods.

The demand response benefit values estimated by program performance analyses, in normalized gross savings ($0.30 to 0.65/kW-year), are 70-75% lower than the average values for the other two types of studies (see Figure 4-4 and Figure 4-5), even after adjusting for differences in participation rates. This is largely attributable to the analytic methodology employed, which looks backward at limited, observable demand response program results. The illustrative and IRP studies typically estimate the *forward* market value of demand response over many years with assumed perfect foresight about demand response penetration and impact. These studies conduct market simulations over the full distribution of possible electricity market conditions in which demand response is deployed, during years when its value is small and others with extreme conditions where demand response provides significant value. In IRP studies, the long planning horizon in conjunction with the explicit treatment of key uncertainties allows demand response resources to be deployed during low probability but high consequence events (NPPC 2004; Violette et al. 2006).

In contrast, the program performance studies reflect market conditions over a very short time period, with only one instance of an extreme condition (the 2003 blackout, captured in the NYISO study only). These studies do not fully reflect the distribution of market circumstances likely to be encountered over a 20-year period, so they represent market conditions that are on average less favorable for demand response.

Lower estimated benefits for ISO programs illustrate the challenge of fostering demand response without a way to fully recognize its potential long-term value to the electricity system under the full range of market circumstances and conditions.

The difference between the average values reported in the three ISO/RTO program studies and the other two types of studies does not mean that demand response is less valuable in organized regional markets, but only demonstrates the challenge of fostering demand response absent the ability to recognize and reward the full forward value of demand response over a long planning horizon.

Under current practices, the market-impact value attributed to demand response is significantly affected by market structure (e.g. organized market vs. vertically integrated systems (Figure 4-4).

The market-impacts value of a demand response mechanism in a vertically integrated utility system may be different—perhaps significantly—from its valuation in an organized market with a similar customer base, resource mix, and supply/demand balance. In vertically integrated systems, demand response is valued largely according to avoided capacity costs, determined by the amortization of a peaking capacity unit ($70-100/kW-year), with some incremental savings (typically 5-15%) attributable to avoided short-term energy production costs. Moreover, qualified demand response resources are essentially deemed to achieve the pre-established avoided capacity benefits, or some portion thereof, for several years in the future.[52]

[52] Updated avoided cost methods for the Standard Practice Manual tests traditionally used for energy efficiency and some load management programs have incorporated market prices for time periods that they

In organized wholesale markets administered by an ISO or RTO, demand response is typically valued over the short term, based on prevailing market prices or reliability circumstances at the time of an event. For example, in some organized markets, customers can offer curtailable load as capacity resources (e.g., through capacity-based demand response programs). Capacity market prices, which are an indication of the value of these resources, have recently been much lower than the reference cost of a new peaking unit in most ISOs and RTOs (ISO-NE 2005b, PJM Interconnection 2005c). At times, the value of capacity, as reflected in capacity or energy market prices, may be substantially higher in regions with organized markets than in vertically integrated systems, although currently the reverse is true; this is reflected in the three ISO/RTO program performance studies.

Assumptions about customer acceptance and participation rates significantly affect estimated gross demand response benefits.

Among studies that examined impacts of demand response pricing strategies (A, D and E), gross savings estimates (row 11 in Table 4-1) are much higher in those studies that assumed higher market penetration rates (i.e., percent of customers facing dynamic prices compared to overall system loads). Studies A and E, which assumed either mandatory CPP or high customer acceptance of RTP, exhibited higher gross savings than study D, which did not.

The reporting and accounting of participant and utility/ISO/RTO system demand response costs are inconsistent.

Evaluations of existing ISO/RTO demand response programs report system costs, but not participant costs. Utility experience evaluating energy efficiency programs demonstrates that it is possible to collect and report information on initial participant costs (e.g., investments in enabling technologies or energy audits).[53] On-going (event-specific) participant costs are unlikely to be explicitly included in future analyses. As a practical matter, customers quantify these types of costs and indicate their acceptance of the participation costs when they enroll in a voluntary demand response program or optional pricing tariff and respond during events.[54] It is probably most feasible to reflect these costs in estimating participation rates and the aggregate price elasticity of program participants, rather than directly in benefit/cost tests.

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are available (e.g. observable forward prices) and use costs of an existing peaking plant for periods prior to the need to construct a new peaking unit (Orans et al. 2004).

[53] However, in contrast to a utility-sponsored program, it is often more difficult for the ISO to communicate directly with customers to establish their costs. Customers typically enroll through a utility, competitive retailer or a demand responses service provider. The ISOs can request that these entities collect customer data, but are hard-pressed to make it a condition of participation.

[54] Violette et al (2005) suggests that it can be assumed that the upfront and ongoing payments to customers for participating in a demand response program fully account for the value of foregone electricity consumption and any costs incurred by the customer related to the demand response event or curtailment call. Otherwise the customer would not have decided to enroll and participate.

The ten studies reviewed also differed significantly in their treatment and estimates of advanced metering costs. This is partly attributable to differences in the availability of advanced metering systems among utilities, and the target markets and types of demand response mechanisms assumed in the studies. For example, among IRP analyses, Study E assumed relatively low incremental meter reading and data management costs to support dynamic pricing among residential customers because the subject utility already had a fixed network, automated meter reading system in place. Study F included costs of metering and incremental data management for business customers only, while Study G did not appear to have explicitly accounted for these costs at all.

Given the lack of standardized or generally accepted techniques and frameworks to estimate demand response benefits and report program costs, it is not particularly useful to report net benefits for our sample of ten studies (several of which included no cost estimates).

> *Quantitative assess-ments should estimate and report* ***net*** *demand response benefits.*

Quantitative assessments should ideally estimate *net* demand response benefits; this is not possible given the information provided by existing studies. Three studies did not account for costs at all. The three IRP studies and one of the illustrative analyses provided ranges of estimated benefits and compared them to ranges in estimated costs. While they draw general conclusions about the relative merits of including specific demand response pricing or program options in the modeled systems, these studies are not framed in terms of achieving specific levels of benefits. As a result, they do not provide any direct insights for DOE to use in recommending specific levels of demand response benefits as directed by Section 1252 of EPACT.

Establishing Protocols and Practices for Estimating Demand Response Benefits

Fostering demand response is an industry responsibility and obligation. Doing so requires that stakeholders make informed decisions on the financial and non-financial implications of introducing (or mandating) time-varying rates (i.e., price-based demand response) and programs to acquire demand response under specific circumstances (i.e., incentive-based demand response). To do this, policymakers need reliable and consistent methods for estimating the implications of the alternatives available to them. Current practices and protocols for valuing demand response provide a foundation for developing these methods, but are ill adapted to valuing demand response in several important ways. There is still work to be done to develop appropriate valuations tools and standard practices for evaluating demand response options.

> *It is premature to focus on setting national demand response goals or specific achievement targets.*

Based on the findings of this study it is premature to focus on setting national demand response goals or specific achievement targets as EPACT instructs DOE to do. Nonetheless, demand response can and should be fostered in all market structures because it plays a vital role in achieving efficient market operation.

An immediate goal should be refining analytic methods and practices to recognize the full benefits of demand response.

Thus, one immediate goal should be refining analytic methods and practices to recognize the full benefits of demand response. Improvements in methods used to quantify and report the benefits and costs of demand response are needed and achievable. These improved analytic methods and practices will provide policymakers and market participants with tools to establish program performance standards, measure progress, and assess the performance and value of demand response initiatives.

Drawing from the body of literature on demand response valuation and the findings of this report, DOE offers the following recommendations for establishing standardized methods and protocols that enhance practices for estimating the benefits of demand response (see Appendix D for more detailed discussion):

1. DOE recommends that stakeholders collaborate to adopt conventions and protocols for estimating the benefits of demand response and, where appropriate, develop standardized tests that evaluate demand response program potential and performance.

2. DOE recommends that these protocols: (1) clarify the relationships and potential overlap among categories of benefits attributed to demand response to minimize double counting, (2) quantify various types of benefits to the extent possible, and (3) establish qualitative or ranking indices for benefits that are found to be too difficult to quantify.

3. DOE recommends that FERC and state regulatory agencies work with interested ISOs/RTOs, utilities, other market participants, and customer groups to examine how much demand response is needed to improve the efficiency and reliability of wholesale and retail markets.[55]

4. DOE recommends that regional planning initiatives examine how demand response resources are characterized in supply planning models and how the benefits are quantified. More accurate characterization of certain types of demand response resources may require modifications to existing models or development of new tools.

5. DOE recommends that, in regions with organized wholesale markets, ISOs and RTOs should work with regional state committees to undertake studies that assess the benefits of demand response *under foreseeable future circumstances* as part of their regional transmission expansion plans as well as under current market conditions.

[55] Issues to consider in this assessment include ability of demand response to obviate the need for active market mitigation, and potential impact of demand response on supplier market power and system reliability.

SECTION 5. RECOMMENDATIONS FOR ACHIEVING THE BENEFITS OF DEMAND RESPONSE

Section 1252(d) of EPACT requires DOE to submit a report that (1) "identifies and quantifies the national benefits of demand response," and (2) "makes a recommendation on achieving specific levels of such benefits by January 1, 2007."

Sections 3 and 4 of this report identify and quantify demand response benefits. Based on the findings of this study, DOE has determined that it is not appropriate to develop recommendations on achieving specific levels of demand response benefits by January 1, 2007. The eleven months between submission of this report and January 2007 do not allow time for meaningful recommendations to be successfully implemented. Instead, DOE offers a set of recommendations for consideration by state, regional and federal agencies, electric utilities and consumers to enhance demand response in a manner consistent with state and regional conditions.

The recommendations are organized as follows:

- *Fostering Price-Based Demand Response*—by making available time-varying pricing plans that let customers take control of their electricity costs;
- *Improving Incentive-Based Demand Response*—to broaden the ways in which load management contributes to the reliable, efficient operation of electric systems;
- *Strengthening Demand Response Analysis and Valuation*—so that program designers, policymakers and customers can anticipate how demand response delivers benefits;
- *Integrating Demand Response into Resource Planning*—so that the full impacts of demand response are recognized, and the maximum level of resources benefits are realized;
- *Adopting Enabling Technologies*—to realize the full potential for managing usage on an ongoing basis; and
- *Enhancing Federal Demand Response Actions*—to take advantage of existing channels for disseminating information and forming public-private collaboratives.

DOE developed these recommendations after a public input process in which interested parties were asked to provide suggestions in response to a web survey for "how to advance demand response in all markets." DOE considered the recommendations from the 40 organizations that submitted responses,[56] looked at other recent demand response studies,[57] and developed its own views. The recommendations reflect DOE's best judgment of the actions needed to advance demand response across the nation.

[56] Appendix A identifies the contributing organizations.
[57] These are listed in the References.

The primary audiences for the recommendations include:

- regional entities and market stakeholders (such as ISOs, RTOs, and multi-state entities involved in the electricity sector);
- Federal and State legislative and regulatory authorities (including FERC, public utility commissions, public service commissions, and state utilities boards);[58]
- electric utilities (such as those regulated by the states, as well as electric cooperatives, municipal utilities, and public utility districts) and load serving entities;
- electricity customers; and
- other stakeholders such as consumer and environmental groups, curtailment service providers, energy services companies, and equipment manufacturers.

Fostering Price-Based Demand Response

Retail electricity prices that are linked to contemporaneous supply costs or prices are one of the principal mechanisms for accomplishing demand response. Since the passage of the Public Utilities Regulatory Policy Act of 1978 (Public Law 95-617) there has been interest in and support for efforts to implement retail rates that reflect the marginal costs of providing electricity. The aim is to provide time-varying price signals that encourage customers to reduce demand when the costs of providing electricity are relatively high. Section 1252 of EPACT (under Subtitle E—Amendments to PURPA) directs State regulatory authorities to decide whether their utilities should offer customers time-based rate schedules (i.e., RTP, CPP and TOU rates) and advanced metering and communications.

<u>Large Customers</u>

RTP is an effective means of facilitating demand response for large commercial and industrial customers.[59] Default service RTP tariffs that index hourly prices to day-ahead markets support demand response and retail market development by giving customers more notice and certainty of the financial consequences of their response. RTP tariff designs that offer customers a fairly predictable financial benefit, and allow them to financially hedge their exposure to price risks (e.g., through a two-part RTP with a consumer baseline and/or financial risk management products), are effective in vertically integrated systems.

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[58] A recent study by the Government Accountability Office (GAO 2004) concluded that a majority of the actions to address demand response involve retail markets and thus come under the jurisdiction of the states, based on provisions of the Federal Power Act. In EPACT, Congress did not require the states to do demand response but instead required them to consider and investigate demand response and time-based metering based on changes to the Public Utility Regulatory Policies Act of 1978. Congress also authorized DOE and FERC to encourage demand response through information and education on benefits, barriers, and technologies as well as technical assistance. Absent additional legislative changes from Congress, actions of Federal [regulatory] agencies that affect demand response are limited to wholesale markets.
[59] See Barbose et al. (2004 and 2005) and Goldman et al. (2005).

- *In states that allow retail competition, state regulatory authorities and electric utilities should consider adopting RTP as their default service option for large customers.*

- *In states that do not allow retail competition, state regulatory authorities and electric utilities should consider offering RTP to large customers as an optional service for large customers.*

Customers on RTP need to understand their electricity consumption patterns in substantial detail and also need to be aware of their capabilities to curtail or shift discretionary usage. For example, facility audits can help identify and assess operational strategies and/or technologies for responding to hourly prices. Financial incentives for energy management control systems, distributed energy systems, or automated controls may, in certain cases, be warranted.

> **Customer Sizes**
>
> There is no standard classification of customer size. The following classifications are adopted for this report:
>
> *Large customers* are those with electric demand **exceeding 1,000 kilowatts** and generally include manufacturing plants, office and large hospital complexes, skyscrapers, and university campuses.
>
> *Medium business customers* are those with electric demand of **100-1,000 kilowatts** and generally include many types of commercial buildings such as 'big box" retail stores and office buildings, warehouses, and light industrial facilities.
>
> *Small business customers* are those with electric demand **below 100 kilowatts** and generally include small commercial buildings, retail stores, and restaurants.
>
> *Residential customers* are a subset of small customers and include single-family homes, town houses, and apartments, most of which have electric demand below **10 kilowatts**.

- *Regional entities and collaborative processes, state regulatory authorities, and electric utilities should provide education, outreach, and technical assistance to customers to maximize the effectiveness of RTP tariffs.*

<u>Medium and Small Business Customers</u>

Medium and small business customers comprise a highly diverse mix of businesses and types of buildings. These customers are not typically targeted for price-based demand response to the same extent as large commercial and industrial customers. As a result, the experience base about what does and does not work is much less developed, and this lack is a deterrent to the implementation of price-based or other demand response mechanisms.

The diversity of medium and small business customers makes it relatively difficult to design pricing approaches that can elicit predictable and cost-effective demand response across diverse customer circumstances, (e.g., schools, grocery stores, "big box" retail outlets, private sector office buildings, government facilities, warehouses, and restaurants). Each of these has different decision-making processes, patterns of demand, and types of equipment. A library of case studies about customer and utility experiences with price-based demand response would help customers see how demand response can work in their business by seeing how it works in comparable businesses.

- *State regulatory authorities and electric utilities should investigate new strategies for segmenting medium and small business customers to identify relatively homogeneous sub-sectors that might make them better candidates for price-based demand response approaches.*

There is evidence that RTP could be suitable for medium-sized businesses, particularly among the larger customers in this group (e.g., those with demand above 300-500 kW).[60] CPP may also provide an effective means for introducing demand response to medium and small businesses, particularly those served by vertically integrated systems. There may be circumstances where policy or business cases can be made for offering RTP or CPP as the standard rate (vertically integrated systems) or as the default service (competitive retail markets).

- *State regulatory authorities and electric utilities should consider conducting business case analysis of CPP for medium and small business customers. Results from existing pilot programs should be carefully evaluated and included in the analysis.*

- *State regulatory authorities and electric utilities should consider conducting policy or business case analysis of RTP for medium business customers. Results from existing pilot programs should be carefully evaluated and included in the analysis.*

Residential Customers

Several electric utilities have conducted large-scale CPP pilots that included residential customers and found encouraging results, including high acceptance and demand reduction in certain customer segments.[61]

- *State regulatory authorities and electric utilities should consider conducting business case analysis of CPP for residential customers. Results from existing pilot programs should be carefully evaluated and included in the analysis.*

Residential (and small business) customers represent a special challenge for price-based demand response. Most residences (and small businesses) lack information on their electricity-using appliances and equipment and are not familiar with demand response enabling technologies that can facilitate effective energy management.

- *State regulatory authorities and electric utilities should investigate the cost-effectiveness of offering technical and/or financial assistance to small business*

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[60] See Barbose et al. (2005).
[61] See Charles River Associates (2005).

and residential customers to enable their participation in CPP or TOU tariffs and enhance their abilities to reduce demand in response to higher prices.

Improving Incentive-Based Demand Response

Experience has shown that the effectiveness of incentive-based demand response programs is closely correlated to how programs are designed and offered to customers.[62] Program design considerations include eligibility criteria, curtailment terms and conditions (e.g., notice, duration, and frequency of events), incentive payments, cost recovery, and procedures to measure and verify demand reductions.

- *Traditional load management (LM) programs such as direct load control of residential and small commercial equipment and appliances (e.g., air conditioners, water heaters, and pool pumps) with an established track record of providing cost-effective demand response should be maintained or expanded.*

In some cases, these LM programs must be adapted to new market structures or circumstances, which involves rethinking program design features related to triggering events (e.g., only system emergencies or other economic and emergency criteria), linking payments to actual performance, considering improvements or enhancements to control technologies, improving system communications, or enhancing monitoring/verification capabilities to allow LM programs to participate in various wholesale electricity markets (e.g., capacity, reserves). When adapting LM from vertically integrated systems to other market structures (e.g. markets with retail competition and vertical de-integration), a key issue to address is the fact that with the proliferation of market actors (e.g. competitive retailers, "wires-only" utilities), no single entity has the incentive to pursue the full benefits of demand response.

- *State regulatory authorities and electric utilities should consider offering existing and new participants in these LM programs "pay-for-performance" incentive designs, similar to those implemented by ISOs/RTOs and some utilities, which include a certain level of payment to customers who successfully reduce demand when called upon to do so during events.*

Some emergency demand response programs have been able to provide reliability benefits to regional entities, electric utilities, and customers in a cost-effective manner. Certain program design features have been particularly effective in achieving both consumer enrollment and performance during times of system need.

- *Regional entities, state regulatory authorities, and electric utilities should consider including the following emergency demand response program features:*
    - *Payments that are linked to the higher of real-time market prices or an administratively-determined floor payment that exceeds customers' transaction costs;*

[62] Policymakers need to recognize that it takes at least six months and often up to several years to build demand response capability, depending on the type of program adopted.

- *"Pay-for-performance" approaches that include methods to measure and verify demand reductions;*
- *Low entry barriers for demand response providers, and in vertically integrated systems, procedures to ensure that customers have access to these programs; and*
- *Multi-year commitments from regional entities for emergency demand response programs so that customers and aggregators can make decisions about committing time and resources.*

Electric utilities that own and operate distribution systems only may have limited interest in implementing demand response programs for customers that remain on default service, especially in cases where supply for those customers is contracted out to another entity.

- *State regulatory authorities should investigate whether it would be cost-effective for default service providers to implement demand response. They should also provide cost recovery for demand response investments undertaken by distribution utilities.*

Strengthening Demand Response Analysis and Valuation

Additional work is needed to standardize reporting of demand response costs, benefits, and valuation methods before it will be possible to establish appropriate levels of demand response benefits. A stronger analytical infrastructure for demand response will help electric utilities, customers, retail suppliers, ISOs/RTOs, and state, regional, and federal agencies to properly assess demand response capabilities, business cases, and resource plans.

- *A voluntary and coordinated effort should be undertaken to strengthen demand response analysis capabilities. This effort should include participation from regional entities, state regulatory authorities, electric utilities, trade associations, demand response equipment manufacturers and providers, customers, environmental and public interest groups, and technical experts. The goal should be to establish universally applicable methods and practices for quantifying the benefits of demand response.*

Public-private partnerships of this type have been successful in addressing similar challenges by fostering better information exchange and helping to build consensus. DOE can help to facilitate the formation of such a partnership, but the objectives, work plans, experts, and resources need to come from the members. Appendix D of this report contains additional information on needed demand response analysis and valuation information, tools, and techniques. Key needed activities include:

- Developing standardized methods to evaluate demand response potential and performance and identify appropriate tests for foreseeable programs and circumstances;

- Clarifying the different categories of demand response benefits, developing methods to quantify those benefits that can be quantified and qualitative or ranking indices for those that are difficult to quantify;
- Developing methods to estimate demand response impacts on wholesale electricity costs and reliability, and the benefits and savings that are passed through to retail customers, thus clarifying the link that demand response provides between wholesale and retail markets;
- Documenting the impact of price-based demand response on wholesale electric market prices and costs based on actual demand response program results; and
- Establishing a database of existing demand response programs to (1) document a track record of program performance with respect to reliability protection, (2) gain insight into the factors that influence performance, and (3) identify ways to use demand response most effectively to deal with reliability challenges.

Integrating Demand Response into Resource Planning

Electric resource adequacy is paramount to ensuring reliable, secure, and affordable electric market operations. It is appropriate for regional entities, state regulatory authorities, and electric utilities to ask how much demand response is needed (and is enough) for ensuring resource adequacy, given market structures and system conditions.

Existing studies confirm the view that even low levels of demand response can improve resource adequacy and the efficiency of market operations. However, existing studies do not address, nor provide methods for, establishing optimal levels or target goals for demand response in specific market settings.

- *FERC and state regulatory agencies should work with interested ISOs/RTOs, utilities, other market participants and customer groups to examine how much demand response is needed to improve the efficiency and reliability of their wholesale and retail markets.*[63]

Current resource planning methods often fail to characterize demand response resources properly. For example, RTP is often evaluated as a resource that can be dispatched to serve demand, rather than as reductions in the timing and level of demand. Also, the flexibility of being able to add, or limit, certain types of demand response resources, from one year to the next, based on system needs, is often not fully reflected in resource plans.

- *Resource planning initiatives should review existing demand response characterization methods and improve existing planning models to better incorporate different types of demand response as resource options.*

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[63] Issues to consider in this examination include the ability of demand response to obviate the need for active market mitigation, the impact of demand response on supplier market power, and the ability of demand response to enhance reliability.

In wholesale markets where ISOs/RTOs administer organized spot markets, the primary focus is on short-term demand response impacts and benefits. More effort should be devoted to characterizing long-term impacts and potential benefits. In the absence of forward markets for demand response, and the potential for a stream of benefits, demand response value will depend primarily on current market conditions.

- *ISOs and RTOs, in conjunction with other stakeholders, should conduct studies to understand demand response benefits under foreseeable future circumstances as part of regional transmission planning and under current market conditions in their demand response performance studies.*

Adopting Enabling Technologies

Recent advances in information and communication technologies have expanded metering functionality, and increased the potential for lower metering costs. DOE believes these enabling technologies have the potential to produce demand response offerings that are more attractive and cost-effective for electric utilities and customers.

Advanced metering systems are one of the most important demand response enabling technologies, particularly for mass-market customers.[64] They can also improve regional grid operators and electric utilities' grid management and operations capabilities because they enable access to real-time and disaggregated information on demand conditions in local areas. While a number of U.S. utilities have committed to system-scale deployment of advanced metering systems, in many of those cases the business case focused primarily on the utility's operational and business benefits (e.g., reduced meter reading costs, outage and tamper detection, and energy profiling).

- *State regulatory authorities and electric utilities should assure that utility consideration of advanced metering systems includes evaluation of their ability to support price-based and reliability-driven demand response, and that the business case analysis includes the potential impacts and benefits of expanded demand response along with the operational benefits to utilities.*

There are other key demand-response enabling technologies, including advanced HVAC and lighting controls, "grid friendly" appliances,[65] smart thermostats, and distributed

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[64] Advanced metering systems encompass a range of solid-state devices that are capable of measuring electricity consumption for whatever time interval is desired (e.g., minute-by-minute, hourly, or for specified "critical peak periods"). They often include equipment and software for communicating consumption and other relevant customer information to utilities automatically, thus eliminating the need for meter readers. The infrastructure that is needed to support advanced metering systems can be extensive and typically includes the meter manufacturers, distributors, and services providers; software developers; communications equipment and services providers (e.g., radio, cable, telephone, and power lines); and electric utilities.

[65] The grid-friendly appliance is a concept that includes refrigerators and other home appliances which contain special computer chips that enable utilities and/or demand response providers, with the use of wide-area data acquisition and control systems, to determine the operational status of home appliances and provide the ability to control its electricity consumption during times of system need.

energy devices such as advanced turbines and micro-turbines, high efficiency engines, thermal and electric energy storage, thermally-activated heating and cooling equipment, fuel cells, photovoltaic arrays, and small-scale combined heat and power (CHP) systems. In addition, advanced designs for integrating and configuring these devices for "whole building," or multi-building applications need to be evaluated, particularly those that can be optimized for energy, economic, and environmental performance. These include building automation systems and concepts such as "zero-energy homes," "low-peak communities," "district CHP systems," "GridWise™," "Intelligrid," and "microgrids."

- *State regulatory authorities and electric utilities should evaluate enabling technologies that can enhance the attractiveness and effectiveness of demand response to customers and/or electric utilities, particularly when they can be deployed to leverage advanced metering, communications, and control technologies for maximum value and impact.*

- *State legislatures should consider adopting new codes and standards that do not discourage deployment of cost-effective demand response and enabling technologies in new residential and commercial buildings and multi-building complexes.*

Enhancing Federal Actions

Sections 1252 (d), (e), and (f) of EPACT contain provisions for DOE, FERC, and other federal agencies to encourage demand response. DOE has been encouraging demand response through information exchange, technical assistance, and technology development and transfer activities. In wholesale markets, FERC has been encouraging the increased use of demand response. For example, FERC and the ISOs/RTOs have been addressing the integration and use of demand response in regions with organized spot markets, and the potential impact of demand response on the market power of suppliers.

- *DOE, to the extent annual appropriations allow, should continue to provide technical assistance on demand response to states, regions, electric utilities, and the public including activities with stakeholders to enhance information exchange so that lessons learned, best practices, new technologies, barriers, and ways to mitigate the barriers can be identified and discussed.*[66]

- *DOE and FERC should continue to coordinate their respective demand response and related activities.*

[66] Information exchange topics include, for example, how the states are addressing the Section 1252 provisions of EPACT for advanced metering and demand response, how demand response potentially affects utility revenues and profits, and how utility ratemaking and incentive mechanisms potentially affect demand response adoption and program success.

- *FERC should continue to encourage demand response in the wholesale markets it oversees.*[67]

Section 103 of EPACT includes a provision whereby all federal facilities are to have metering capabilities—and to the extent practical, advanced meters or advanced metering devices—by October 1, 2012.

- *DOE, through its Federal Energy Management Program, should explore the possibility of conducting demand response audits at Federal facilities.*

Although not always the case, in certain circumstances it is possible for demand response programs and pricing approaches to have a favorable impact on energy efficiency and the environment.

- *DOE and the Environmental Protection Agency should explore efforts to include appropriate demand response programs and pricing approaches, where appropriate, in the ENERGY STAR® and other voluntary programs.*

[67] Examples of this include: encouraging expanded efforts by the ISOs and RTOs to (1) find ways for customers to participate in spot, day-ahead, and ancillary service markets; (2) determine whether current or proposed reliability rules need to be changed to accommodate demand response; and (3) support even greater levels of information exchange and collaboration on demand response across regions of the country.

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APPENDIX A. ORGANIZATIONS THAT PROVIDED INPUT ON RECOMMENDATIONS

American Council for an Energy-Efficient Economy
American Public Power Association
Apogee Interactive, Inc.
Arkansas Public Service Commission
Battelle-Pacific Northwest National Laboratory
BP Solar
California Department of Water Resources State Water Project
California Energy Commission
California Public Utilities Commission
Constellation Energy
Consumer Energy Council of America
Cornell University
Demand Response and Advanced Metering Coalition
Distributed Energy Financial Group
Duke Power
East Kentucky Power Cooperative
Edison Electric Institute
Energy Connect Inc.
Grid Services, Inc.
Hunt Technologies, Inc.
Idaho Public Utilities Commission
Invensys Controls
ISO New England, Inc.
Itron
Louisville Gas and Electric
M.Cubed
National Rural Electric Cooperative Association
New York State Department of Public Service
PJM Interconnection, LLC
San Francisco Community Power Cooperative
Solar Turbines, Inc.
Southern California Edison Company
Steel Manufacturers Association
SUEZ Energy NA
The Cool Solutions Company
The Stella Group, Ltd.
U.S. Department of Energy—Building Technologies Program
United States Demand Response Coordinating Committee
Utilipoint International, Inc.
Utility Economic Engineers

APPENDIX B. ECONOMIC AND RELIABILITY BENEFITS OF DEMAND RESPONSE

This Appendix provides a more detailed conceptual discussion of the economic and reliability benefits of demand response than was included in Section 3. First, short-term market impacts are described, drawing on economic theory to show how demand response can result in improved economic efficiency, and distinguishing how these benefits are manifested under different market structures. Next, long-term economic benefits from avoided capacity investments are discussed along with issues in designing and implementing programs designed with this goal in mind. Differences in how short-term and long-term economic benefits are realized and passed on to consumers are then described for vertically integrated utilities and regions with ISO/RTO spot markets. Finally, reliability benefits are described along with concepts used to value them.

Short-Term Market Impacts: Supply Costs and Market Prices

This section provides a detailed discussion of how customer load reductions lower energy supply costs in the short term. First, the basic source of short-term market benefits—improved economic efficiency brought about by allowing consumers to make electricity usage decisions based on marginal, rather than average, supply costs—is described. Differences in how these benefits are manifested in regions with differing market structures are then discussed.

Societal Benefits

In evaluating policies or structural changes that impact how markets work, economists distinguish between societal gains, which benefit everyone, and financial flows that involve gains by some at the expense of others, called transfers. In the absence of a way to weigh the relative impact on individuals of gains and losses (i.e., a change in utility), economists argue that policies should primarily be judged on their net outcome, which is defined by the level of societal benefits (see the textbox below).

Demand response produces societal benefits, which are resource savings, by reducing the gap between time-varying marginal supply costs and retail electricity rates based on average costs. Economic theory asserts that the most efficient use of resources occurs when consumption decisions are based on prices that reflect the marginal cost of supply. In a competitive market, this is defined by the intersection of a good's supply and demand curves (see Figure B-1). In electricity markets, the marginal electricity supply curve is constructed by ordering generators from lowest to highest operating costs (often referred to as "merit order").[68] Due to the technical characteristics of electricity generation equipment, the supply curve—the upward curving line in Figure B-1—tends

[68] Certain generators may be required to run, regardless of their marginal operating costs, to maintain reliability in areas with constrained generating and/or transmission capacity, which limits the ability of least-cost resources to serve local demand.

to increase very steeply at its upper end.[69] This means that when demand approaches the industry's installed capacity, each additional increment of demand imposes increasingly more cost than the previous one. In other words, the marginal cost of electricity becomes most sensitive to changes in demand when demand is already high.[70]

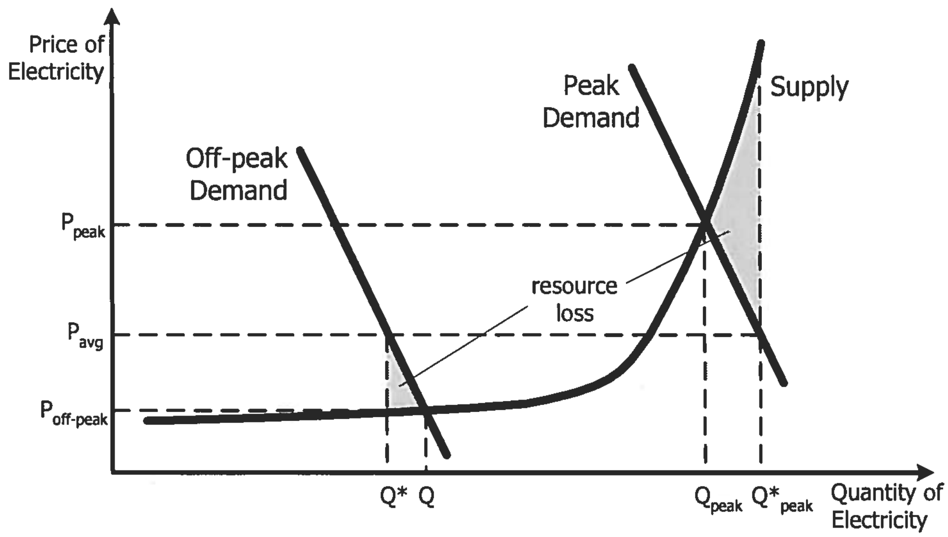

Figure B-1. Inefficiencies of Average-Cost Pricing

Like most goods, the demand for electricity exhibits declining marginal value (i.e., the marginal value of additional consumption declines as consumption increases). Electricity demand is characterized by a downward-sloping line, regardless of how electricity is priced. But, if the price that consumers pay never varies, demand appears to be perfectly inelastic, and is characterized by a vertical line. Moreover, consumers' demand for electricity also depends on the time of day, with more usage typically occurring during the "peak" afternoon and early evening hours and less at other times. This phenomenon is driven by the economic activity of businesses and residential customer lifestyles and usage patterns, but is also influenced by electricity rates that are the same throughout the day. For simplicity, the two lines labeled "peak" and "off-peak" in Figure B-1 represent consumer demand.

The most efficient pricing and usage of electricity is determined by the intersection of the supply and demand curves in Figure B-1. In other words, during off-peak periods, the efficient price of electricity should equal $P_{off\text{-}peak}$ and consumers would use an amount of

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[69] The long, flat portion of the electricity supply curve represents "base-load" power plants, such as nuclear, hydroelectricity and coal plants that have very low operating costs and are run most hours of the year. Base-load plants are typically large with similar characteristics. The steeply inclining portion of the supply curve represents "peaking" plants that are used to meet peak demand needs and may be run only a few hours per year. These plants are typically natural gas- or oil-fired combustion turbines that are less expensive to build than most base-load technologies but have higher operating costs. Peaking plants are typically smaller units with varied operating characteristics.

[70] High demands do not always lead to high prices. If the entire portfolio of capacity is available, then the marginal unit may be relatively low cost. The steepest part of the supply curve is encountered when demands are especially high (e.g. a heat wave) or generation is short due to forced outages, or both.

electricity equal to Q, and during peak hours, the efficient price should equal P_{peak} and consumers would use Q_{peak} units of electricity. However, most consumers currently pay electricity tariffs that reflect average, rather than marginal, electricity supply costs; this is represented by P_{avg} in Figure B-1. Actual usage therefore reflects the intersection of the demand curves with this average price, resulting in less than the social optimal usage in off-peak periods (Q*) and more than the social optimal usage in peak periods (Q^*_{peak}) relative to the optimally efficient system.

Distinguishing Societal Benefits from Rent Transfers

Economists make a distinction between *transfers*—the benefits of a policy initiative that amount to gains for some at the expense of others—and *social welfare gains* that inure to society as a whole. Social welfare gains are desirable because they derive from efficiency improvements that benefit all market participants. These benefits provide a strong rationale for policymakers to invest consumers' money in initiatives to realize such gains. Transfers result in some market participants being better off than others. In the case of demand response, lower market prices reduce revenue to suppliers and lower costs to consumers. The economists' task is to quantify the relative marginal gains and losses to the individuals involved.

Some economists caution that treating market price reductions as benefits is misleading, and may result in policies that undermine, rather than enhance, market efficiency (Ruff 2002). Specifically, they contend that using the bill savings from price reductions, which largely amount to transfers, to justify demand response incentive payments to customers actually raises electricity prices in the long term. They contend that merchant generators count on the profits (called scarcity rents) realized when prices are high to recoup their capital costs and achieve the rate of return their investors require. If these profits are reduced because policymakers use them to justify customer curtailment incentives, then investors will become more skeptical and require higher returns, which, the argument concludes, results in higher prices in the long run.

This is the basis for many of the objections to allowing customers to bid load curtailments as resources into ISO/RTO spot markets, called "demand bidding as a resource." However, other economists contend that if demand response moves the wholesale market to greater economic efficiency and the result is a more appropriate supply and demand balance, then the elimination of those artificial rents to generators corrects a market distortion and prevents investments that are not needed based on how customers value electricity.

Another objection to demand bidding raised by some economists is their claim that customers on default service have no right to the energy, since the utility rates require that it be served, but do not give the customer any contractual rights to that supply. This could be corrected by requiring that in order to bid curtailments into spot energy markets, the customer would have to demonstrate that it has contractual rights to that power. As an alternative, these critics propose "self-financing" demand response whereby the inherent savings from avoiding paying high market prices is the inducement for customers to curtail, and no payment has to be made to achieve that result (Braithwait 2003).

These arguments have only been raised for demand response programs that allow customers to offer curtailments as resources in centrally organized spot markets. Yet, substantially the same transactions characterize demand bidding and CPP programs run by vertically integrated utilities.

Economists refer to the inefficiencies that arise when retail prices do not reflect marginal supply costs as "dead-weight losses" or resource losses (i.e., the loss of societal welfare when resources are not used optimally). The resource losses from average cost pricing are illustrated by the shaded triangles in Figure B-1. In the off-peak period, electricity that would have value to consumers if it were priced according to its marginal supply cost is not consumed—this represents a loss to society in economic activity that would have occurred but did not. In the peak period, consumers that do not pay the full marginal cost of power consume excessive amounts of electricity at a cost in excess of the value it provides them. Because this occurs at the steeply inclining portion of the electricity supply curve, these costs can be substantial.[71]

The short-term market-impacts benefit of demand response lies in reducing or eliminating this resource loss, thereby improving net social welfare. The combined resource loss from all peak and off-peak hours—and thus the potential for short-term demand response benefits—depends on how widely average and marginal electricity costs vary. For example, in a tightly constrained market, where peak demand is often very close to supply limits, the potential short-term efficiency benefit from implementing demand response can be substantial.

Supply Cost and Market Price Impacts in Regions with Differing Market Structures

Short-term market impacts are illustrated for vertically integrated utilities in Figure B-2. The supply curve typically reflects the utility's supply costs, including its own generation plants and any incremental wholesale power purchases. If demand is forecast to be Q, then a demand reduction that moves consumption to Q_{DR} results in an avoided utility supply cost equal to the shaded area in Figure B-2.

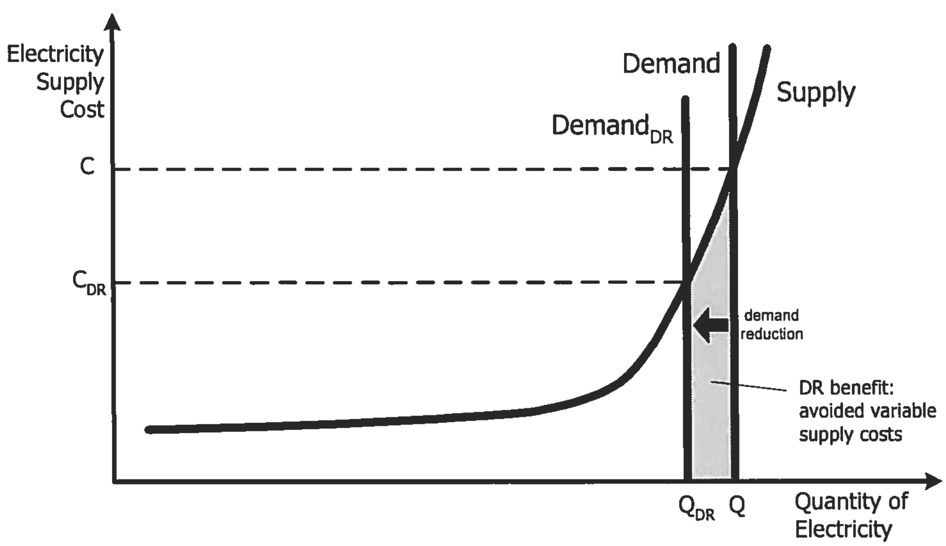

Figure B-2. Impact of Demand Response on Vertically Integrated Utility Supply Costs

The same load reduction produces more extensive impacts in regions with organized wholesale markets because of the way these wholesale markets are designed. The supply curve is developed by arranging generators' offer bids in merit order from lowest to

[71] Electricity pricing that does not reflect supply costs results in societal losses both when costs are high, and when they are low. However, the extent of these losses is greater at elevated supply costs, and therefore correcting prices in these periods has captured the attention of policymakers and market designers.

highest. Because of competition among generators, generators' offer bids reflect their marginal operating and maintenance costs and in some circumstances additional margins to recover fixed costs. LSEs also bid their expected load requirements into the market, producing a demand curve.[72] The bid price of last generator needed to serve the LSE's purchases sets the market clearing price for the whole market. This means that a demand reduction from Q to Q_{DR} not only provides the avoided variable cost savings observed for vertically integrated utilities (the shaded area to the right in Figure B-3), but it also lowers the price of all other energy purchased in the market. This second market impact, represented by the shaded rectangle in Figure B-3, is dependent on the level of price reduction—the difference between P and the new price P_{DR}—and the amount of energy bought in the applicable market. LSEs typically commit their expected energy requirements with a mix of bilateral forward contracts with generators and purchases in day-ahead and real-time markets. This is represented by the dotted line in Figure B-3. The extent of customer savings from price reductions thus depends on how much energy is purchased in spot markets.[73]

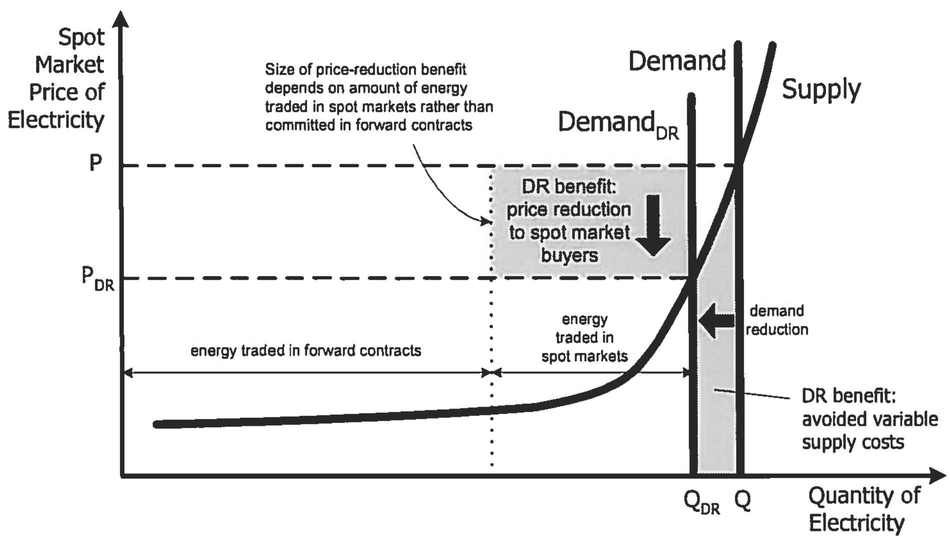

Figure B-3. Impact of Demand Response in Regions with Organized Wholesale Markets

In regions with organized wholesale markets, if, over time, customers routinely respond to high prices by curtailing or shifting loads, then additional, longer-term savings will result. Thus, if demand response consistently reduces market prices and volatility, bilateral contract prices will also drop over time, as reduced price risk in day-ahead and real-time markets pushes longer-term contract prices down. This is because LSEs may be willing to pay less for hedged forward contracts and will buy instead from the spot market if generators do not offer lower forward contract prices. In this way, lower energy

[72] In this example, demand is represented by a vertical line for simplicity (i.e., it is presumed to be fixed). Currently, most LSEs bid fixed quantities of electricity in spot markets, so this characterization is appropriate.
[73] In New York, a state with organized wholesale markets and retail competition, over 50% of electricity is traded in day-ahead and real-time spot markets, with the rest settled in forward contracts. In New England, about 40% of the electricity volume is traded in ISO-NE's spot markets, with about 60% committed in forward contracts.

prices resulting from short-term demand response market impacts can eventually extend to the entire market.[74]

Long-term Market Impacts: Capacity Benefits

The long-term market impacts of demand response hinge on reducing the *system peak demand*—the highest instantaneous usage by consumers in a particular market. Reducing system peak demand can avoid or defer the need to construct new generating, transmission and distribution capacity, resulting in savings to consumers. This applies for both vertically integrated utilities and organized wholesale markets, although capacity costs are allocated differently. This benefit can be specifically elicited from customers through capacity-based demand response programs (e.g., DLC, I/C rates or ISO/RTO capacity based programs) or may result from consistent load reductions from price-based demand response options (e.g., RTP). For example, in a capacity-based demand response program, load reductions timed to reduce load from a level that otherwise would have established the system maximum demand can yield large benefits for all consumers. Historical system maximum demand, adjusted for planned reserves, establishes ongoing generating capacity requirements, usually on an annual or semi-annual basis. For example, if the maximum demand served in a control area during the past summer was 5,000 MW, then that demand would serve as the basic capacity target for the next summer, to which an additional reserve margin (e.g., 18%) would be added.[75] If the existing infrastructure were insufficient to serve the resulting 5,900 MW capacity requirement, additional capacity would be necessary. Since generating capacity is expensive, ranging from about $50,000 to over $100,000 per MW-year (depending on the type and location of generating units), demand response that displaces the need for new infrastructure can produce substantial avoided cost savings.

Demand response programs designed to reduce capacity needs are valued according to the marginal cost of capacity. By convention, marginal capacity is assumed to be a "peaking unit", a generator specifically added to run in relatively few hours per year to meet peak system demand. Currently, peaking units are typically natural gas turbines with annualized capital costs on the order of $75/kilowatt-year (kW-year) (Orans et al. 2004, Stoft 2004). Thus, if demand response programs avoid 100 MW of generating capacity, the avoided capacity cost savings would be $7.5 million per year in this example. If the total program costs were $50/kW-year, including incentive payments to participating customers, then other customers realize the rest as savings (e.g., $2.5 million per year in this example), which may eventually be reflected in lower rates and bills. As long as there is some sharing of benefits, all customers benefit from others' participation in a capacity demand response program.

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[74] Whether or not savings from short-term market price impacts and reduced forward contract prices brought about by incentive-based demand response programs should be treated as societal benefits is a subject of controversy (see the textbox on "Distinguishing Societal Benefits from Rent Transfers", earlier in this Appendix).

[75] Reserve margins vary in electricity markets across the U.S., but are typically 15-18%.

Transmission and distribution system capacity investments are also capital-intensive, and demand response that reduces local maximum demand in areas nearing infrastructure capacity can also provide significant avoided cost savings.

Realizing Capacity Benefits: Establishing and Reducing System Peak Demand

Capacity-based demand response programs are designed to replace generation investments and participants receive up-front capacity payments tied to this avoided cost. To realize this benefit and justify making the capacity payments, system operators must be able to dispatch curtailments that actually avoid building new capacity. This is accomplished in one of two ways: (1) predicting when system peak demand will exceed historic levels and dispatching load reductions accordingly or (2) dispatching curtailments when a designated peaking generation unit would otherwise be in service.

Dispatching demand response to avoid increasing system peak demand involves predicting when peak demand is likely to exceed historic levels absent any curtailments. Electric systems are generally either winter or summer peaking, meaning that annual demand is seasonal. However, demand can exceed historic peak levels several times during the peak season, which may span several months. To ensure that a capacity program truly does reduce peak demand, operators may need to dispatch the program several times during the peak season to account for forecast error. For participating customers, multiple curtailment obligations can be burdensome. To improve the attractiveness of capacity programs to customers, limits are sometimes are placed on how many curtailments can be called in a particular season.

The alternative method is to dispatch capacity-based demand response programs when an existing plant designated to meet peak demand would be needed to serve expected demand, absent any curtailments. This practice is somewhat more straightforward in regions with organized wholesale markets because transparent market rules direct dispatch operations. However, vertically integrated utilities have similar unit dispatch rules that could be used. Here too, limits may be placed on how frequently curtailments are called for.

Both methods of dispatching demand response to realize capacity value require provisions for periodic testing of customer response as well as penalties for non-performance. Testing is necessary to certify that customers truly have the capability to deliver the contracted curtailments on an on-going basis. Penalties serve to reinforce their obligation to be available and deliver load reductions when called. However, establishing appropriate penalty levels can be challenging. Increased penalty levels make demand response commitments more reliable and more valuable to the system operator, but are likely to reduce the amount of demand response committed by customers.[76] Program designers must balance the attractiveness of the program to customers against the potential consequences of forced outages that affect a large number of customers at costs well in excess of the avoided cost payment participating customers receive.

Because the avoided capacity cost savings calculation is prospective, so is the value of a capacity-based demand response program. This raises issues in forecasting the timing of system peak demand, or the highest 10-30 load hours of the year, so that calls for demand reductions actually moderate system maximum demand as designed. Since forecasting involves errors, program administrators/sponsors must make provisions to ensure the

[76] One useful strategy may be to recruit larger numbers of customer participants by dropping or reducing penalties for non-performance. Even though each customer is a less reliable source of demand response in the absence of penalties, the larger number of participants could increase the total expected demand response. The adoption of such a strategy would require evaluation of accumulated experience on the effect of various levels of penalties on customer performance.

demand response program is called often enough to effectively lower the forecast of system peak demand (see the textbox above).

Timing and Distribution of Market Impacts of Demand Response

Differences in market structure influence the timing and distribution of short-term and long-term market impacts of demand response in important ways. These differences are illustrated in this section by tracing the market impacts and resulting benefits of demand response in two types of market structure: 1) "vertically integrated systems", in which a vertically integrated utility with a retail monopoly franchise engages in some wholesale market transactions but operates in a region without an ISO or RTO, and 2) regions with organized wholesale markets in which ISOs/RTOs administer spot markets and retail competition is enabled at the state level. These illustrative combinations of retail and wholesale market structures reflect the current situation in many states or regions, although other retail/wholesale market structures are prevalent in the U.S.[77]

In this section, the examples suggest that the market impacts of demand response within organized spot markets produce benefits in a *shorter* timeframe than those for a vertically integrated, monopoly utility.

<u>Market Impacts of Demand Response for Vertically Integrated Utilities</u>

Vertically integrated utilities are responsible for making capacity investment decisions (whether to build new generation itself or to purchase supply contracts from other sources such as independent power producers), subject to regulatory oversight and approval, and for planning and operating the electricity grid and ensuring reliability. Retail rates are determined administratively, based on the average cost of supplying all three major facets of electricity production and delivery—production, transmission and distribution—and expected sales volumes. Embedded in retail rates are marginal costs to supply power, such as fuel, operating and maintenance costs, as well as a return on investment for un-depreciated utility-owned generation.

The economic impacts of demand response for a vertically integrated utility operating with a retail monopoly franchise are depicted in Figure B-4. Short-term demand response benefits may be traced as follows:

- Depending on the timing and type of demand response option, customers' load changes may be integrated into the utility's scheduling and dispatch decisions on a day-ahead or near-real-time basis.
- Changes in load (e.g., reductions in usage during high-priced peak periods) offset a portion of usage that otherwise would have been met by production from high-

[77] For example, utilities in some states are still vertically integrated and retain a retail monopoly franchise but are part of an organized regional wholesale market administered by an ISO or RTO (e.g., some parts of MISO, Vermont).

operating-cost power plants or purchases during the load response event (see Figure B-2).[78]

- This lowers the average variable electricity cost, which should be manifested eventually as customer bill savings through lower regulated electricity rates.

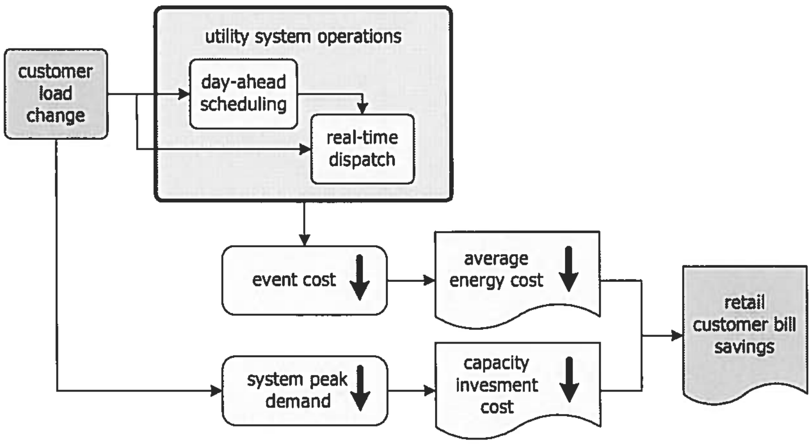

Figure B-4. Market Impacts of Demand Response for Vertically Integrated Utilities

The utility's return on capacity investments is recovered separately from its marginal costs to produce or purchase electricity and operate the electric grid. Thus, in vertically integrated systems, in the absence of a mechanism to reveal marginal capacity or reliability costs in unit operating costs, the short-term market impacts of demand response are limited to efficiency improvements in operating costs (including energy production and purchase costs) alone.[79]

In the long term, demand response that reduces peak demand growth directly averts the need for utilities to build more power plants, power lines and other capacity-driven infrastructure or to buy new capacity and energy from other suppliers (see Figure B-4). Because capacity investments are usually fully recovered—along with a pre-established return on investment—through higher retail electricity rates, these long-term benefits are realized over a multi-year period and can result in significant savings to consumers.

In vertically integrated, stand-alone utility systems, demand response is most useful to improve generation and transmission asset usage, avoid new capacity construction or purchases, and create more flexibility to assure reliable system operations. This influences the types of demand response programs preferred by vertically integrated utilities, as well as how they value and compensate demand response program participants.

[78] The converse is true for increases in load at times when the marginal cost of electricity is lower than the average retail price.
[79] Some utilities quantify the marginal value of reliability in their RTP tariffs quoting hourly prices to participants for changes in their usage from an established base amount; those hourly prices contain an explicit ($/kWh) marginal reliability (outage cost) element to reflect exigent reserve conditions (Barbose et al. 2004)

Market Impacts of Demand Response in Regions with Organized Wholesale Markets

About 60% of U.S. load is served by utilities or load serving entities that operate in regions with wholesale markets administered by ISOs/RTOs. Retail competition is also allowed in many of the states in these regions. These last-price wholesale electric commodity markets pay all competitively dispatched load a price determined by the last successful bid, which also sets the market clearing price. The market clearing price covers operating or production costs for the dispatched load (if each generator bids at least its marginal supply cost). If supply is very tight relative to demand, spot market energy prices will rise as more expensive units set the market clearing price. As a result, all units get the higher price, which includes creating "scarcity rents" for suppliers with costs below that of the marginal, price-setting unit.[80] Accordingly, spot energy prices serve as signals about whether additional supply- or demand-side capacity investments are needed, and what level of return to expect.

Three organized markets (NYISO, PJM, and ISO-NE) have established capacity payment mechanisms to create an additional stream of revenues for generators to recoup their investment costs. LSEs are required to purchase capacity in these markets to meet the expected peak demand of the customers they serve.

The impacts of demand response in an organized wholesale spot market are depicted in Figure B-5.[81]

The short-term market impacts of specific demand response events can be traced as follows:

- Depending on the timing and type of demand response option, customers' load changes may be integrated into day-ahead or real-time energy markets [as indicated by the arrows at the top of Figure B-5).
- Reductions in load during high-priced peak periods move marginal usage down the electricity supply curve (see Figure B-3), lowering market clearing prices during the demand response event (the event price in Figure B-5).
- This lowers LSEs' purchasing costs in the applicable wholesale market during the event. These savings may be captured by the LSE initially, but ultimately a significant share should be passed on to their customers (LSE event energy cost in Figure B-5).[82]

[80] This argument assumes that generators must recovery all of their revenue requirements and variable running costs, from energy sales at spot market prices. Some markets impose capacity requirements on LSEs that constitute a form of investment cost recovery for generators selling in those markets.
[81] The Midwest ISO (MISO), ERCOT and the California ISO (CAISO) all do not operate capacity markets.
[82] In some states, public utility commissions have adopted tariffs that specify the percent of savings that a regulated LSE providing default service must pass on to their customers. Eventually, competitive pressures should motivate LSEs to pass a significant portion of purchase cost savings to their customers.

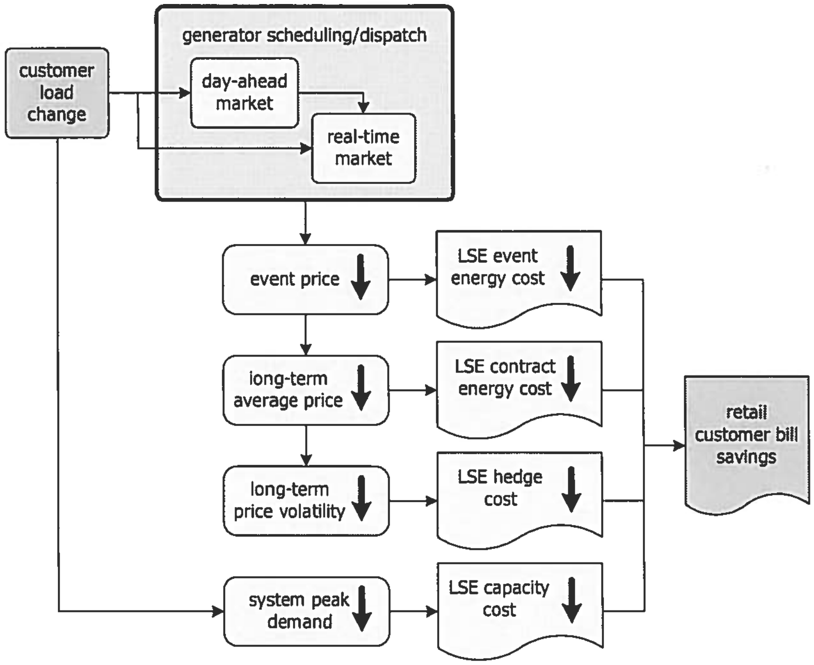

Figure B-5. Market Impacts of Demand Response in Regions with Organized Wholesale Markets

In regions with organized spot markets, demand response can produce cascading positive market impacts in the medium or long-term, realized over months or years (see Figure B-5):

- Reduced average market clearing prices can reduce forward contract costs for LSEs; these savings are then passed on to their customers (LSE contract energy cost in Figure B-5)
- Reduced volatility in market clearing prices puts downward pressure on risk premiums incorporated into hedged pricing products offered by competitive LSEs (LSE hedge cost in Figure B-5) and may lower transaction prices
- Lower forecast peak demand, resulting from demand response, also reduces LSEs' capacity acquisition requirements (LSE capacity cost in Figure B-5).

Long-term market impacts are less clear in organized wholesale and competitive retail markets compared to a vertically integrated utility system. A vertically integrated utility is allowed to directly pass through its capacity investment to customers in rates and likely most of its purchased energy and capacity costs as well; savings realized from demand response that avoids "uneconomic" investments or expenditures for peaking capacity are a direct source of cost savings to customers. In contrast, in organized spot markets, investment risk for new resources is assumed by the private sector. The combination of lower market clearing prices and reduced capacity requirements will dampen capacity investment signals, which should reduce construction of unneeded new power plants.

In summary, because organized spot markets use energy market clearing prices to pay generators for operating, but often only a fraction of the committed capacity costs, the long-term capacity savings benefits of demand response may not be fully monetized and paid to demand response providers. Because the spot market valuation of demand response is linked to wholesale market clearing prices (for energy and capacity) rather than avoided capacity costs, this creates different payment streams and priorities between the two market structures. Policymakers need to recognize these differences in designing demand response options and evaluating benefits derived from market impacts under these different market structures.

Reliability Benefits

In addition to improving the efficiency of electricity markets, demand response can provide value in responding to system contingencies that compromise the dispatcher's ability to sustain system-level reliability, and increase the likelihood and extent of forced outages. Electric systems in the U.S. conduct long-term planning exercises to specify the level of resources required to serve the system's anticipated maximum load reliably in the long term. Typically, planning reserve margins are 15-18% of historic maximum system demand.

System operators arrange for some of the available generation resources to serve as reserves to cover real-time load-serving requirements and avoid outages; operating reserves of 5-7% of forecast demand must be maintained at all times. The system operator typically uses standby generators, ready to be run in less than 30 minutes, to deal with abrupt changes in load or unexpected loss of generator or transmission availability. Demand-response based load reductions can be used to replace some of this stand-by generation to rebalance load and supply.

Demand response can supplement system reliability by providing load curtailments that help restore reserves, providing incremental reliability benefits to the system.[83] Customers participating in emergency demand response programs receive incentive payments for reducing load when called upon by the system operator. They receive no up-front capacity payments in some program designs because they are not counted on as system resources for planning purposes. Instead, they are supplemental resources, the need for which is not foreseeable, or even likely, but possible. They represent an additional resource for reliability assurance, distinct from capacity-based demand response programs (see the textbox below).

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[83] The capacity they provide can be particularly valuable if located in what operators call "load pockets", localized areas with a shortage of available resources to serve load when a generator is out of service.

Roles of Capacity and Emergency Demand Response Programs

Emergency demand response programs provide benefits distinct from capacity-based demand response programs. In capacity programs, customers are paid incentives based on the avoided cost of new generation capacity and are counted among planned reserves. As such, they become part of the overall portfolio of resources assembled to meet system reserve requirements. Capacity-based demand response does not provide incremental system reliability—it supplants conventional resources in meeting established reliability goals, simply replacing what a generator that was not built would have provided.

In contrast, emergency demand response programs provide incremental reliability benefits at times of unexpected shortfalls in reserves. When all available resources, including capacity demand response programs, have been deployed and reserve margins still cannot be maintained, curtailments under an emergency demand response program reduce the likelihood and extent of forced outages. Load curtailments under emergency demand response programs are therefore valued according to their impact on system reliability.[84]

System operators generally dispatch emergency demand response programs only after exhausting all available capacity and operating reserves. When operating reserves are called upon to go from standby status to actually producing energy to serve load, the level of remaining operating reserves drops if additional replacement resources are not available. This is analogous to a consumer drawing down savings to pay an unexpected bill, leaving them more vulnerable to consequences from further unanticipated expenses.

System operators can reduce this vulnerability by asking emergency program participants to curtail load, thereby reducing system demand and operating reserve requirements. This means that some generating resources can revert to their standby status and be ready for another contingency event, and can be likened to a cash infusion to restore savings in the consumer analogy. The curtailment allows the operator to maintain reliability at prescribed or target levels (Kueck et al. 2001). At the margin, this form of demand response provides value, although it is not priced in any market.

Figure B-6 illustrates this impact, and provides a way to estimate these reliability benefits. The portrayed system has been scheduled to provide D_1 units of energy (including required reserves) at a price of P_1 at a specific time.[85] As the delivery time approaches, a system contingency arises that effectively pushes the supply curve to the left (e.g., a generator outage) or customer demand to the right (e.g., an unexpected surge in demand, as portrayed in the figure by the move from D_1 to D_2), so that supply and demand no longer intersect. This reserve shortfall is represented by the demand curve D_2. Activating an incentive-based demand response program initiates customer demand reductions that bring system demand back to D_1, thereby eliminating the reserve shortfall.

[84] It is possible that an emergency demand response program, while not explicitly designed to fulfill capacity requirements , may nonetheless be capable of providing some level of capacity benefits as well.
[85] In this example, customer demand is represented by a vertical line, because in a reliability event, which occurs within minutes or seconds of power delivery, demand may be viewed as fixed.

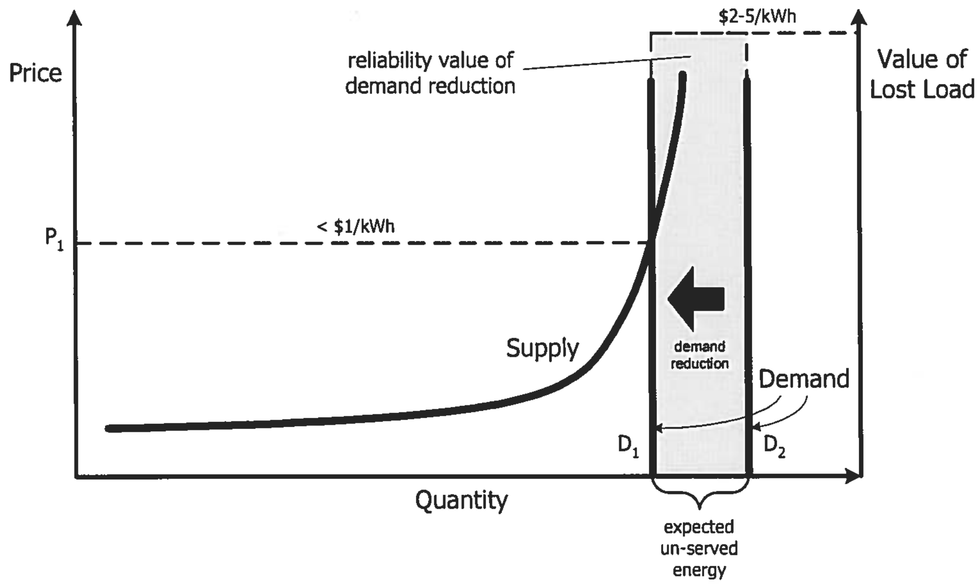

Figure B-6. Valuing the Reliability Benefits of Demand Response

While the price of served energy is determined by market conditions (P_1 in Figure B-6), the value of the demand reduction is defined by the decreased likelihood of a forced outage. Economists define the concept of *value of lost load* (VOLL) as the proper measure of improved reliability, since it reflects customer's marginal value for electricity under these circumstances. The product of VOLL and the *expected un-served energy* (EUE), the load that otherwise would not have been served, monetizes the value of the load curtailments (see the textbox below). This is represented by the shaded rectangle in Figure B-6 in the case where the curtailed load corresponds exactly to the amount of expected un-served energy.

Emergency demand response programs can provide low-cost, incremental resources to preserve reliability in various market structures; at present, the most prominent examples are implemented by the Northeast ISOs.

Value of Lost Load and Expected Un-Served Energy

"Value of lost load" (VOLL) is a measure of how customers value electric reliability, or what they would be willing to pay to avoid a loss of service. It varies among customers but is almost always greater than the retail price of electricity because customers incur costs from being disconnected without notice. Customer values factored into VOLL include inconvenience or discomfort, loss of sales or productivity (e.g., at retail premises or factories), large cleanup and restart costs (e.g., at pharmaceutical companies), and overtime costs to make up for lost production. Given the wide range of customer circumstances and difficulties in predicting which customers will be affected by a particular outage, the accepted industry practice is to adopt a VOLL of $2-5/kilowatt-hour (kWh), which represents an average value across the entire market.

"Expected un-served energy" (EUE) is a measure of the magnitude of a reserve shortfall. It takes into account the change in the likelihood of a curtailment and the consequences of such an event: how much load would have been forced off-line by dispatchers in such circumstances if the curtailments had not been undertaken. NYISO concluded that during the service restoration effort following the 2003 northeast blackout, demand response curtailments reduced forced outages kWh for kWh, because they enabled smoother service restoration. However, under other, less extreme conditions, curtailments were found to produce less than proportional reductions in EUE (NYISO 2003).

APPENDIX C. INTENSITY OF CUSTOMER DEMAND RESPONSE

This Appendix summarizes DOE's review of selected studies that have attempted to quantify the intensity of customer response to time-varying prices and demand response programs. First, different types of price elasticity used to measure demand response intensity are introduced. Next, the results of studies that estimated price elasticities for large and small customers exposed to time-varying rates are summarized. Some studies have examined the demand response intensity of programs targeting demand response-enabling technologies; these results are compared next. Finally, the results of studies that estimated load impacts from direct load control programs are summarized.

Indicators of Demand Response Intensity

For rate options and demand response programs that elicit load modifications directly in response to price changes, the intensity of customers' demand response is typically expressed in terms of their *price elasticity* (see the textbox below). Price elasticity provides a normalized measure of the intensity of customers' load changes in response to price circumstances. In analyzing price response, it is important to not confuse reported own-price and elasticity of substitution values. *Own-price elasticity* is defined as the percentage reduction in electricity usage in response to a one percent increase in the price of electricity. In analyzing price response among large industrial and commercial customers, it is common instead to estimate the *elasticity of substitution*, which measures the propensity of customers to shift electricity usage from peak to off-peak periods in response to changes in relative peak and off-peak prices. The substitution elasticity is defined as the percentage change in the ratio of peak to off-peak electricity usage in response to a one percent change in the ratio of off-peak to peak electricity prices. Various factors may influence customers' price elasticity, including the nominal level of prices. For example, some customers may be relatively unresponsive when prices are low but find it worthwhile to reduce load at very high prices. This characteristic of price elasticity has important implications for the design and evaluation of time-varying pricing and demand response programs.[86]

For DLC programs or other types of demand response programs where customers are not directly responding to a price, the intensity of customers' response is typically measured in terms of an absolute or relative load impact (e.g., kW or percent load reduction).

[86] If price response increases with relative prices, then it is important to account for this factor when estimating how customers will respond to prices or to a demand response program incentive. A specific price threshold may be necessary to obtain a significant response among a group of customers.

Price Elasticity: Insights and Sources of Confusion

Price elasticity is a normalized (for the relative price change) measure of the intensity of how usage of a good (in this case electricity) changes when its price changes by one percent. It facilitates a comparison of the intensity of load changes among customers since the price change has been factored out; the price elasticity is a relative measure of response. For example, Customer A, with an elasticity of 0.25, responds to the same relative price change much more than Customer B, who has an elasticity of 0.05 (i.e., five times more relative to the customer's usage level). But, not five times greater than another customer in absolute terms, unless they have exactly the same load. This highlights the relative comparison of intensity that a price elasticity response provides; the basis is each customer's load. Consequently, some studies prefer to report and compare customers' actual percentage changes in load. This is insightful, as long as the load changes were in response to the same change in prices.

A potential source of confusion comes from differences in how price elasticity is reported. Some analysts report the *own-price elasticity*, which is expected to be negative, since a one percent increase in price would be expected to cause usage to go down, all other things equal. It is a useful measure of how customers adjust to increases in the price of electricity by adjusting the consumption of other goods. This is especially useful when evaluating longer-term adjustments to changes in electricity price. Other analysts report the *substitution elasticity*, which takes on only positive values. The substitution elasticity focuses on how consumers substitute one good for another, or goods in different time periods for one another, when relative prices change. Specifically, if the price of electricity varies substantially from one time period to another, and customers can shift usage among those periods, then the appropriate measure of price response is how relative usage changes in those periods. The substitution elasticity is therefore defined as the relative change in usage in the two periods (e.g., the ratio of the peak to off-peak usage) for a one percent change in the relative prices in those periods (the ratio of the off-peak to peak price). Note that the price term uses the inverse price ratio, which is why substitution elasticities are positive (e.g., a higher peak price decreases the off-peak to peak price ratio, causing peak load to be reduced and therefore the peak to off-peak load ratio to decline).

On an absolute value basis, ignoring the sign, own-price and substitution elasticities are similar in that they both measure relative changes, so a value of zero corresponds to no change in usage regardless of the change in price (i.e., perfectly price inelastic), and absolute values progressively greater than zero indicate relatively higher price response. They are roughly similar measures of intensity on a nominal basis—a substitution or an own-price elasticity of 0.50 both indicate relatively high changes in load in response to price changes. But because these two elasticity values measure a different characterization of how usage is adjusted to price changes (i.e., price in one period vs. relative prices in two periods), there is no simple way to cross-map reported values. They should be used in the appropriate context: the own-price elasticity when the circumstances involve reduced electricity usage and the substitution when shifting from one time to another characterizes price response.

In this report, substitution elasticities are always reported as a positive number and own-price elasticities as a negative number.

Price Elasticity Estimates

For mass-market (residential and small commercial) customers, there is an extensive price elasticity literature examining the load impacts from TOU rates. Not surprisingly, the estimates produced by these various studies span a wide range, reflecting both methodological differences and situational factors (e.g., related to customer characteristics or program design). Caves et al. (1984) pooled data from five residential TOU pilots implemented in the U.S. in the latter half of the 1970s (see Table C-1). The average elasticity of substitution derived from this pooled data set was 0.14, but elasticities varied by a factor of three, from 0.07 to 0.21, depending on the household's electric appliance holdings (Faruqui and George 2002). King and Chatterjee (2003) reviewed price elasticity estimates from 35 studies of residential and small commercial customers published between 1980 and 2003. They report an average own-price elasticity of –0.3 among this group of studies, with most studies ranging between –0.1 and –0.4. Several studies have also examined the intensity of residential (and small business) customers' response to CPP and RTP tariffs and isolated the affect of various factors and customer circumstances. A recent study at Commonwealth Edison in Illinois of the first residential RTP pilot in the U.S. found notably lower demand response intensity than has been observed for small customers; own-price elasticities were –0.04 in 2003 and –0.08 in 2004 (Summit Blue Consulting 2005). However, the weather during these two summers was unseasonably cool and A/C usage and hourly prices were correspondingly low, which suggests that the price response may be higher under more extreme conditions.

An evaluation of a recent residential CPP pilot in California estimated a statewide average elasticity of substitution of 0.09 on critical peak days occurring between July and September and reported that the average statewide reduction in peak period energy use on critical peak days was about 13% (Faruqui and George 2005).[87] However, the elasticity varied by more than a factor of three across five climate zones, reflecting regional trends in temperature and A/C saturation (which varies from 7% to 73% of households). The study also found substantial differences between customers' price elasticities during the hotter summer months (July—September) and during the shoulder months of May, June and October—also indicative of differences in A/C usage.

Information on the price elasticity of large commercial and industrial (C&I) customers is based primarily on studies that examined customers' response to RTP. These studies have employed several types of demand models producing different types of price elasticity measures and have examined variations with time of day, price level, and customer characteristics (e.g., business type, presence of onsite generation, number of years on RTP).

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[87] Impacts varied across climate zones, from 7.6% in the relatively cool coastal climate zone (e.g. which includes San Francisco) to 15.8% in inland, hot climates of California (Faruqui and George 2005).

Table C-1. Demand Response Program and Pricing Studies: Estimated Price Elasticity of Demand

Type of Program	Target Market	Region (Utility)	Demand Response Impact (average per customer)	Comments
TOU	Residential	U.S (utilities in five states)	Elasticity of Substitution **0.14** average; **0.07** to **0.21** range depending on electric appliance holdings	Pooled results from five residential TOU pilots in the late 1970s. Sources: Caves *et al.* (1984) and Faruqui and George (2002).
TOU/ CPP	Residential and Small Commercial	U.S. and International (various utilities)	Own-Price Elasticity **-0.3** (average of 35 studies); **-0.1** to **-0.8** range across the studies	The authors calculated the simple average of own-price elasticity estimates from 35 studies of TOU or CPP. Source: King and Chatterjee (2003)
CPP	Residential	California (PGE, SCE, SDG&E)	Elasticity of Substitution **0.09** average (July-Sept.); **0.04** to **0.13** range across climate zones	Population of about 1,000 residential customers, including control groups, in 2003/4 California Statewide Pricing Pilot. Elasticity range across climate zones attributed to differences in A/C saturation (7-73%). Source: Charles River Associates (2005)
Day ahead RTP	Residential	Illinois (Com Ed, Community Energy Cooperative)	Own-Price Elasticity **-0.04** average (2003); **-0.08** average (2004); **-0.05** to **-0.12** range across customer segments (2004).	Population of about 1,000 customers in 2004; $0.12/kWh maximum hourly price. Own-price elasticities were reported for six different customer segments defined in terms of housing type (single- or multi-family) and A/C equipment type (window, central, or none). Source: Summit Blue Consulting (2005)
	Med./Large C&I (>200 kW)	Georgia (Georgia Power)	Own-Price Elasticity **-0.01** to **-0.28** range across customer segments and hourly price levels	Population of about 1,600 customers. Elasticities were estimated for seven different customer segments at four different price levels, ranging from $0.15 to $1.00/kWh. Source: Braithwait and O'Sheasy (2002)
	Med./Large C&I (>100 kW)	U.K. (Midlands Electric)	Hourly Own-Price Elasticity **-0.01** to **-0.27** range in maximum hourly elasticities, across customer segments	Population of about 500 customers, most with peak demand >1 MW. Hourly own-price and substitution elasticities were calculated for each of five different industry classifications. Source: Patrick and Wolak (2001)
	Large C&I (>1 MW)	North and South Carolina (Duke Power)	Average Peak-Period Own-Price Elasticity < **-0.01** to **-0.38** range across customers	Population of about 50 customers, some with 8 years experience on RTP. Hourly own-price were calculated for each customer, and averaged over the peak period (2:00-9:00 p.m.). Source: Taylor *et al.* (2005)
	Large C&I (>1 MW)	Southwest U.S. (Central and Southwest Services)	Elasticity of Substitution **0.10 to 0.27** range across customer segments and definitions of the peak period	Population of 54 customers, segmented into two groups, with firm day-ahead hour-ahead notice of hourly prices. Elasticities estimated for each group and for different definitions of the peak period. Source: Boisvert *et al.* (2004)
	Large C&I (>2 MW)	New York (Niagara Mohawk)	Elasticity of Substitution **0.11** (average); **0.02** to **0.16** range across customer segments	Population of about 150 customers. Individual customer elasticities vary substantially within sectors: e.g., most manufacturing customers are either highly responsive or not at all. Source: Goldman *et al.* (2005)

Note: Elasticity values are the averages of all participants' elasticity at all price levels, unless otherwise noted. Elasticity of substitution values are for intraday substitution between peak and off-peak periods, while own-price elasticities are the average value, unless noted as hourly.

Braithwait and O'Sheasy (2002) analyzed data from participants in Georgia Power's RTP program, the largest in the country. The authors estimated own-price elasticities for seven different business customer segments and examined differences across hourly price levels. Most customer segments exhibited larger price elasticities at higher prices. The most responsive customer segment was a group of very large industrial customers (peak demand > 5 MW) who, in exchange for slightly lower base rates, had opted to receive notification of hourly prices on an hour-ahead (rather than day-ahead) basis. This group exhibited a price elasticity of –0.18 to –0.28 across the range of reported prices ($0.15/kWh to $1.00/kWh), which was double the elasticity of any other group. The least responsive customer segments, consisting of smaller C&I customers that neither had onsite generation nor had previously participated in the utility's curtailable rate, exhibited price elasticities of –0.06 or lower at all price levels.

A study of about 150 large customers at Niagara Mohawk estimated an average substitution elasticity of 0.11 among those that faced day-ahead hourly prices (Goldman et al. 2005). However, the average elasticity varied substantially across business categories (e.g., average elasticities were 0.16 for manufacturing customers, 0.10 for government/education customers, and 0.02 for health care facilities) and even more within them (e.g., half of the industrial customers were very inelastic, and half were relatively elastic).

Studies of the large C&I RTP programs offered by Duke Power and Midlands Electric (in the U.K.) estimated average hourly own-price and substitution elasticities (Taylor et al. 2005, Patrick and Wolak 2001). Both studies found a substantial range in own-price elasticity values over the course of the day and among customers. Among the 50 or so participants in Duke's program, the average hourly price elasticity during peak period hours ranged from less than –0.01 to –0.38. This study also concluded that many large C&I customers exhibit complementary electricity usage across blocks of afternoon hours. That is, high prices in one hour result in reduced usage in that hour as well as in adjacent hours. This is consistent with industrial batch process loads that, once started, must continue for a specified period, and with other business practices that exhibit similar relationships (e.g., rescheduling of labor shifts). Usage in many other hours of the day was found to be a substitute to the afternoon hours. The study of Midlands Electric's customers also found substantial variation in the magnitude and hourly pattern of price elasticity among different industrial classifications. Customers in the water supply industry were the most price-responsive, with a maximum hourly own-price elasticity of –0.27, while all of the other industrial classifications in the participant population exhibited price elasticities of less than –0.05 in all hours.

Impact of Enabling Technologies on Price Response

A small number of utilities have offered pilot programs targeted at mass market customers that integrate CPP with enabling technology, specifically load control devices that receive price signals and can be programmed by customers to reduce A/C or other loads during critical peak periods (see Table C-2).

Table C-2. Load Response from Enabling Technologies in Combination with CPP

Enabling Technology	Target Market	Region (Utility)	Demand Response Impact (average per customer)	Comments
Thermostat reset	Residential	California (SDG&E)	**0.64 kW (27%)** average peak period load reduction on critical peak days; **0.4 kW** attributed to enabling technology.	2003/2004 pilot program with about 220 residential customers and about 235 C&I customers, including control groups. Customers had "smart thermostats" that could be programmed to raise the temperature set point during critical peak periods. Analysis distinguished between enabling technology and behavioral components of price response. Peak period prices on critical peak days averaged $0.65/kWh for residential customers, $0.87/kWh for customers with <20 kW peak demand and $0.71/kWh for larger C&I customers. Source: Charles River Associates (2005)
	Small/Med. C&I (<200 kW)	California (SCE)	Customers with <20 kW peak demand: **0.95 kW (14%)** average peak period load reduction on critical peak days; attributed entirely to enabling technology. Customers with 20-200 kW peak demand: **3.1 kW (14%)** average peak period load reduction on critical peak days; **2.5 kW** attributed to enabling technology.	
Control of multiple loads (A/C, heat pump, water heater, pool pump, and/or appliances)	Residential	New Jersey (GPU)	Elasticity of Substitution **0.3** (average)	Pilot program results from summer 1997. Critical peak price was $0.50/kWh. Source: Braithwait (2000)
	Residential	Florida (Gulf Power)	**2.7 kW (41%)** average load reduction during critical peak periods	Estimated response from current *GoodCents Select* program. Source: Borenstein *et al.* (2002).
	Residential	Upper Midwest (AEP)	Winter: **3.5-6.6 kW** Summer: **1.5-2.0 kW**	Pilots conducted at three AEP utilities in the early 1990s with about 600 customers, including control groups. Critical peak price ranged from $0.15-$0.29/kWh among the three utilities. Source: Levy Associates (1994)

An evaluation of the recent Statewide Pricing Pilot in California sought to quantify the incremental impact of this type of technology on customers' demand response. Groups of residential and small commercial participants in this pilot faced CPP and had "smart thermostats," which customers could pre-program to automatically raise their temperature settings by a specified number of degrees during critical peak periods. The statistical model used in the evaluation decomposed these customers' total load reduction during critical peak periods into a "technology component" (i.e., the portion of the load reduction attributable to use of the smart thermostat) and a "price component" (i.e., the portion attributable to manually-implemented actions). The average load reduction by residential customers with smart thermostats during critical peak days was approximately 0.64 kW, approximately two-thirds of which was attributed to use of the smart thermostat. Among small business customers, the relative impact of the enabling technology was even more pronounced.

A handful of utilities elsewhere in the U.S. have implemented residential CPP pilots in which participants were provided with thermostats that they could program to control their A/C and other appliances (pool pumps, heat pumps, and electric water heaters) during critical peak periods. Studies of these programs have typically found that participants exhibited a relatively high intensity of demand response. For example, an analysis of GPU's pilot (in New Jersey) measured a substitution elasticity of 0.3, which is higher than most elasticity of substitution values estimated from residential TOU pilots (Braithwait 2000). Studies at Gulf Power and American Electric Power (AEP) where multiple loads could be controlled in response to critical peak prices reported that average load reductions among a sample of customers were in the 35-40% range (Levy Associates 1994).

Load Impacts from Direct Load Control

Approximately 180 U.S. utilities (out of the 1,118 investor-owned, municipal, and rural cooperative utilities that reported demand-side management efforts) report that they currently offer residential DLC programs that primarily target specific appliances, such as air conditioners or water heaters, of mass market customers (EIA 2004).[88] Various control strategies (e.g., cycling the device on and off at a specified frequency, shutting the device off, or resetting a thermostat set-point) are utilized during prescribed conditions depending on end use, control equipment vintage, and program design.[89] Several of these programs have conducted relatively recent measurement and evaluation studies with results that are publicly available. In DLC programs, because the utility controls the switch, the customer cannot be said to exhibit price response, per se, although the change in the customer's load is measurable. The most appropriate measure of demand response impact for this program type is simply the average or expected load reduction (in absolute or percentage terms), rather than the price elasticity.

Table C-3 summarizes the measured impact from selected evaluations of DLC programs that targeted customers with air conditioning or water heating load control devices. The results indicate the range of possible load impacts, although the individual values are not readily comparable because of the differences in program design features, cycling strategies, and climate. DLC programs targeting residential A/C have reported load reductions ranging from approximately 0.4 to 1.5 kW per customer over the course of an event. The magnitude of the load reduction per customer can strongly depend on climate, the corresponding level of A/C usage that would occur absent load control, and the control strategy deployed (e.g. 100% shed, duty cycling). Furthermore, when customers have the ability to over-ride the curtailment via their thermostat, the average response per customer has generally been found to decline (sometimes substantially) over the course of each event. Residential water heating DLC programs have yielded load reductions in the range of 0.2 to 0.6 kW per house. The magnitude and timing of the load impact depends on equipment size, ground water temperature and household size and operating use patterns.

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[88] Demand-side management efforts include energy efficiency and/or load management programs.

[89] In newer DLC programs, particularly those that use thermostat-based controls, customers can typically over-ride curtailments on an event-by-event basis, either by pushing an "over-ride" button on their thermostat, logging onto a program website, or calling the utility. If they do over-ride a curtailment event, customers typically forfeit a portion of their incentive payment or are charged a penalty.

Table C-3. Direct Load Control Programs: Estimated Load Impacts

Type of Program	Target Market	Region (Utility)	Demand Response Impact (average per customer)	Comments
A/C temp. reset (with over-ride option)	Residential	SDG&E	**0.44 kW** (average); **0.10-0.81 kW** (range over 12 events)	Sample of about 100 customers (including control group) with 12 test events in summer 2004. Source: KEMA-Xenergy (2004)
A/C cycling (with over-ride option)	Residential and Small Commercial	New York (LIPA)	**0.75-0.91 kW** (residential) **1.01-1.43 kW** (small commercial)	Ranges in average hourly load reductions over a single event day with 50% cycling. Based on 12,000 residential customers and 2,000 commercial customers. Source: Lopes (2004)
A/C cycling (no over-ride option)	Residential	Minnesota (Xcel Energy)	**1.27 kW**	Based on interval metering at large number of customer sites; 50% cycling frequency. Source: Xcel Energy (2004)
		California (SMUD)	**0.71-1.59 kW**	Pilot program results from summer 2002. The lower bound corresponds to a cycling frequency of 33% and outdoor temperature of 96-100° F; the upper bound corresponds to a cycling frequency of 66% and an outdoor temperature of >100° F. Source: Violette and Ozog (2003).
		Kentucky (LG&E, KU)	**0.52-1.12 kW**	Interval metering measurements at 20 customer sites. The lower bound corresponds to a cycling frequency of 33% and outdoor temperature of 90-95° F; the upper bound corresponds to a cycling frequency of 66% and an outdoor temperature of >95° F. Source: Violette and Ozog (2003).
		Maryland and D.C. (Pepco)	**0.96 kW** (MD) **0.76 kW** (DC)	Measured impact for hour ending 17:00, based on 20-year average system peak day weather; 43% cycling off strategy. Source: Horowitz (2002)
Electric water heater cycling		Oregon (PGE)	**0.65 kW**	Load reductions measured at 0800. Source: PGE (2004)
		Maryland (BGE)	**0.2 kW** (at 5 PM) **0.3 kW** (at 7 PM)	Load reductions measured at 1700 and 1900. Source: BGE (2002, 2003)

APPENDIX D. STANDARDS, PROTOCOLS AND PRACTICES FOR ESTIMATING THE BENEFITS OF DEMAND RESPONSE

In Section 4 of this report, DOE offers several recommendations on establishing standardized methods and protocols and enhancing practices for estimating the benefits of demand response. This Appendix provides further discussion that supports these recommendations.

1. DOE recommends that stakeholders collaborate to adopt conventions and protocols for estimating the benefits of demand response and, where appropriate, develop standardized tests that evaluate demand response program potential and performance.

Policymakers and industry participants should develop standardized tests that are applicable and appropriate for the evaluation and cost-effectiveness screening of demand response resources. Standard Practice Manual (SPM) tests are widely used among state regulatory commissions and utilities to evaluate and screen energy efficiency programs (CPUC 2001).[90] Historically, a number of states and utilities have also used these tests for cost-effectiveness screening of load management programs and, recently, there have been some efforts to modify the SPM tests to enhance their usefulness for evaluating demand response resources in the context of competitive wholesale markets (CPUC 2003; Violette et al. 2006, Orans et al. 2004). However, there is general consensus that a more comprehensive evaluation framework is needed to fully capture the benefits of demand response (PIER DRRC, 2005).

Some of the challenges in developing standardized tests appropriate for demand response are revealed by comparing energy efficiency and demand response resources. While it is relatively straightforward to identify and estimate the peak demand and energy reduction impacts of energy efficiency, this is much more difficult for most demand response options. Because most demand response options are relatively new, our ability to predict program participation rates and assess how specific program designs and dynamic pricing affect customer behavior is still rudimentary.[91] Moreover, many forms of demand response turn on behaviors that are price- or incentive-driven, and may change in response to changing market circumstances. Uncertainties in estimating demand response impacts over a multi-year period mean that demand response benefit (and cost) estimates are equally uncertain.

[90] The SPM describes several tests that evaluating demand-side management programs from various perspectives: Participant Test, Ratepayer Impact Measure (RIM) Test, Total Resource Cost (TRC) Test, and Program Administrator (formerly Utility) Test.

[91] Load reduction impacts are well characterized for residential DLC programs that have operated for many years, although there have been issues in determining the extent to which customers remove load control switches or over-ride load curtailments. For interruptible/curtailable programs, little information exists from which long-term performance can be predicted. For thermostat-based programs, limited information gathered through several large pilots is available to shed light on customer behavior. For optional RTP tariffs, substantial evidence shows that customer attrition can be a significant problem when major price shocks occur.

In contrast, 15-20 years of implementation experience and tens of millions of dollars spent evaluating energy efficiency programs has produced well-developed methods for forecasting market penetration and estimating first-year energy savings, expected economic lifetime and the persistence of savings for most energy-efficiency measures and programs. This task is further eased because most energy efficiency measures produce savings that are not dependent upon customer behavior.

The SPM tests, which use avoided costs to characterize benefits, have shortcomings in the way in which they characterize the value of demand response to the electric system and customers. Despite recent advances, these tests are not well suited to estimating the value of dispatchable demand response resources. For example, SPM tests have limited ability to reflect the value of capacity in critical peak hours, and the potential of demand response to mitigate episodic, high spot market prices is therefore undervalued. Other aspects of demand response benefits, such as quick ramp-up (relative to constructing new generation resources), and reliability benefits, are also not captured by SPM tests. A more comprehensive analytic framework is needed to fully evaluate and assess the benefits of demand response. At present, summarizing the benefits and costs for some types of demand response resources by means of a standardized test may be premature.

2. DOE recommends that these protocols: (1) clarify the relationships and potential overlap among categories of benefits attributed to demand response to minimize double counting, (2) quantify various types of benefits to the extent possible, and (3) establish qualitative or ranking indices for benefits that are found to be too difficult to quantify.

Policymakers and analysts assessing the merits of demand response mechanisms need to clarify the relative importance of benefits that are difficult to quantify.

Some demand response advocates allude to benefits, such as market power deterrence, risk mitigation and avoided pollutant emissions—that are not quantified but are presumed to be substantial (PLMA 2002; NEDRI 2003; Violette et al. 2006).[92] Not only are such benefits difficult to quantify, but care must be taken to avoid double-counting benefits from other sources (e.g., market-power reduction benefits must be disentangled from other market price impacts). Parties seeking to justify greater expenditures on demand response often assert the existence of such benefits. Policymakers, however, are often wary of including these benefits as criteria for designing policies to foster demand response. Research to determine the magnitude of these impacts and to develop methods for quantifying or incorporating them into benefit/cost analyses, without double counting, is needed.

3. DOE recommends that FERC and state regulatory agencies work with interested ISOs/RTOs, utilities, other market participants, and customer groups to examine

[92] These non-quantified demand-response benefits are discussed in more detail in section 3 (see *Other Benefits*).

how much demand response is needed to improve the efficiency and reliability of wholesale and retail markets.

It is appropriate for state and regional policymakers to ask how much demand response is sufficient for their specific market structure and system conditions. A number of demand response studies confirm that a little demand response can go a long way towards improving the efficiency and operations of electricity markets, both in theory and practice. However, existing studies do not address how to identify optimal, or target, levels of demand response in specific market settings. Initiatives should be launched at the appropriate market level (e.g. state or region) to establish relevant goals and appropriate targets for demand response.

As part of the process of determining how much demand response is needed, it is also important to address the appropriate mix of different types of demand response options (e.g. emergency demand response programs, direct load control, time-varying pricing) and any timing issues related to demand response resource deployment and ramp-up (Violette et al. 2006). Although this is not a problem today given the low participation rates in dynamic pricing and demand response programs, it is important to acknowledge that there may be a potential for diminishing returns in the value of demand response beyond certain levels of saturation. For example, the level of price-based demand response is somewhat self-limiting—if at some point demand response becomes widespread, customers may find that their savings from load response actions deteriorate as the impact of their collective response on market prices grows.

4. DOE recommends that regional planning initiatives examine how demand response resources are characterized in supply planning models and how the benefits are quantified. More accurate characterization of certain types of demand response resources may require modifications to existing models or development of new tools.

Resource planning methods currently used to characterize demand response resources are too constraining and rigid to capture the full benefits of all types of demand response resources. In vertically integrated systems, long-term resource planning models characterize demand response as a way to avoid generation (and in some cases transmission and distribution) investment costs. Demand response is typically portrayed as a generation unit, which can either be dispatched indiscriminately or with some restrictions on the total frequency or hours of service. This characterization does not fully describe the differences between generation and demand response resources.

Certain types of demand response resources provide benefits that generation cannot. For example, capacity-based demand response programs can provide equivalent capacity to generation investments but with greater flexibility. This is because some types of demand response resources can be implemented more quickly than a power plant can be sited and built, and customers often prefer or are willing to accept a shorter time commitment than is necessary to amortize a power plant.[93] These flexibility benefits are particularly important from a system cost perspective that includes and explicitly accounts for the uncertainties in demand growth or generation unit retirement schedules and costs. Resource planners' avoided cost studies should explore the implications and value of flexible demand response program options as both long-term and short-term operational resources to deal with generation load balance and transmission and distribution adequacy challenges.

Moreover, long-term resource planning models often do not fully recognize or represent the benefits of price-based options such as RTP. RTP ties hourly retail prices to prevailing wholesale market supply costs. To fully account for its potential benefits, RTP should be portrayed as a change in demand in response to prices, not as a resource dispatched to serve demand. Moreover, the RTP prices in tariffs offered by vertically integrated utilities often reflect both marginal supply costs and reliability value of load curtailments. These hour-by-hour impacts, which are carefully measured in ISO/RTO demand response program performance studies, can get overlooked in a long-term resource planning exercise.[94]

On the other hand, peaking generation resources have some characteristics that are more desirable to resource planners than demand response resources. For example, system operators have high confidence that generation resources will come online when needed, whereas customers may decide not to respond when a demand response resource is called. This makes it more difficult to predict the precise amount of available resources on a given day. Another advantage of supply resources is that they can provide certain ancillary services, such as voltage support and re-starting the electrical grid after a blackout, that demand response resources cannot. These considerations should also be incorporated into planning models to appropriately characterize and assess available resources.

5. DOE recommends that, in regions with organized wholesale markets, ISOs and RTOs should work with regional state committees to undertake studies that characterize the benefits of demand response under foreseeable future circumstances as part of their regional transmission expansion plans as well as under current market conditions in their demand response program performance studies.

[93] The capacity programs implemented by several ISOs do not involve long-term customer commitments (customers may participate for only a few months if they wish). These programs have demonstrated reasonably predictable and stable performance without putting "iron in the ground"—generation assets whose costs must be recovered over 20 years or more (NYISO 2003). Emergency programs that require no commitment on the customer's part have attracted substantial participation by customers that delivered curtailments on a pay-for-performance basis, and are a potentially cost-effective way to increase system reliability.

[94] Moreover, RTP may result in increased usage during off-peak periods when prices are lower. Increased unit utilization lowers the overall average cost of capital, another important source of benefits that may not be adequately reflected in current study practices.

In regions with organized spot markets, analytic methods focus primarily on assessing the short-term impacts of ISO/RTO demand response programs; more work is needed to assess the potential long-term benefits of demand response resources. ISOs/RTOs that offer demand response programs provide annual performance assessments to FERC that focus primarily on realized, short-term impacts. These assessments provide policymakers, market participants, and customers with information on both the level and distribution of demand response benefits and resource costs.[95] However, in the absence of a forward electricity market that would create a steady stream of guaranteed annual benefits, the value of demand response necessarily depends primarily on current market conditions.

However, ISOs and RTOs can and should provide information on the future value of demand response within their regional markets. Most ISOs and RTOs conduct or coordinate long-range planning studies that focus on developing coordinated system expansion plans that identify projects that can ensure electric system reliability, reduce congestion and also provide market signals for planning and running generation and transmission systems and demand-side management projects (ISO-NE 2005b; PJM Interconnection 2005b). One goal of the studies is to use forecasts of regional load/resource balance to identify needed investments to forestall potential supply shortfalls that could lead to high price volatility. The extent to which demand response is considered in these regional transmission expansion plans is evolving over time. ISOs, RTOs and regional state committees are well positioned to recognize the long-term benefits of demand response and incorporate demand response into their long-term system plans.[96] Another option would be to facilitate a forward market in demand response, as PJM has proposed (PJM Interconnection 2005c).

[95] Because benefits can vary from year to year and opportunities to participate are not always available, it is important that load aggregators and customers are made aware of how benefits and costs (i.e., incentive payments) may vary with market circumstances.

[96] Efforts are already beginning in this area. A recent pilot study by ISO-NE that compared the value of RTP and other types of demand response programs under alternative market circumstances was intended to facilitate discussions of this issue among policymakers, ISOs, load serving entities, and customer groups (Neenan Associates 2005).

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Estimating Demand Response Market Potential among Large Commercial and Industrial Customers: A Scoping Study

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January 2007

The work described in this report was funded by the Permitting, Siting and Analysis Division of the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.
The authors are solely responsible for any omissions or errors contained herein.

LBNL-61498

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Office of Electricity Delivery and Energy Reliability
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The work described in this report was funded by the Permitting, Siting and Analysis Division of the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The authors are solely responsible for any omissions or errors contained herein.

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We thank Richard Sedano (Regulatory Assistance Project), Hossein Haeri (Quantec LLC), Steven Braithwait (Christensen Associates), Roger Levy and Mary Ann Piette (Demand Response Research Center), Larry Mansueti (DOE), Joe Eto (Lawrence Berkeley National Laboratory) and Dan Engel (FSC Group) for their comments on a draft of this report. We also acknowledge Henry Yoshimura (ISO-New England), Michael Kelliher, Catherine McDonough and Art Hamlin (National Grid), Dave Lawrence (NYISO), Mike Gravely (CEC) and Mike Rufo (Itron) for providing the data and information used in this study.

Table of Contents

Acknowledgements i

Table of Contents ii

List of Figures iii

List of Tables iv

Acronyms and Abbreviations v

Executive Summary vii

1. Introduction 1

2. Methods and Concepts for Estimating Demand Response Market Potential 5
   - 2.1 What is Market Potential? 5
   - 2.2 Approaches Used to Study Demand Response Market Potential 7
   - 2.3 What Makes Demand Response Different from Energy Efficiency? 9
   - 2.4 A Different Approach to Demand Response Market Potential for Large Customers 11

3. A Framework for Estimating Large Customer Demand Response Market Potential 13
   - 3.1 Establishing the Study Scope 13
   - 3.2 Customer Segmentation 15
   - 3.3 Estimating Net Program Penetration Rates 15
   - 3.4 Estimating Price Response 19
     - 3.4.1 Selecting a Measure of Price Response 19
     - 3.4.2 Calculating Elasticity Values 23
     - 3.4.3 Accounting for Factors that Influence Price Response 23
   - 3.5 Estimating Load Impacts 25
     - 3.5.1 Estimating Load Impacts from Arc Elasticities 26
     - 3.5.2 Estimating Load Impacts from Substitution Elasticities 26

4. Applying the Framework: Large Customer Demand Response Market Potential 27
   - 4.1 Data Sources 29
   - 4.2 Estimating Program Participation from Large Customer Program Experience 29
   - 4.3 Developing Elasticity Values and Adjustment Factors from Large Customer Response Data 32
     - 4.3.1 Average Elasticity Values 32
     - 4.3.2 Elasticities Adjusted for Onsite Generation 32
     - 4.3.3 Elasticities Refined to Reflect Response at High Prices 34
     - 4.3.4 Elasticities Refined for Within-Sector Variation in Price Response 36
   - 4.4 Putting it All Together: Market Potential Simulation Results 37
     - 4.4.1 Base Case 39
     - 4.4.2 Impact of Participation Rates 39
     - 4.4.3 Accounting for Onsite Generation 40
     - 4.4.4 Accounting for Response at High Prices 41
     - 4.4.5 Accounting for Within-Sector Variations in Customer Response 42
   - 4.5 Summary: Discussion 43

5. Advancing the State of the Art: A Market Assessment Research Agenda 45

References 49

Appendix A. Review of Methods for Estimating Demand Response Potential 53

Appendix B. Methods for Establishing Customer Baseline Loads 61

Appendix C. Programs and Tariffs Used as Data Sources 63

Appendix D. Factors Found to Influence Demand Response Program Participation 67

List of Figures

Executive Summary:
Figure ES-1. Impact of Program Participation Rates on Demand Response Market Potentials xiii

Report:
Figure 2-1. Relative Relationships of Energy-Efficiency Potential Definitions 6
Figure 3-1. Steps for Estimating Demand Response Market Potential 14
Figure 3-2. Features of Price Elasticity Measures 20
Figure 4-1. Impact of Program Participation Rates on Demand Response Market Potentials 40

List of Tables

Executive Summary:

Table ES-1. Data Sources xi
Table ES-2. Average Elasticity Values xi
Table ES-3. Market Potential Results: Base Case xii

Report:

Table 3-1. Methods of Estimating Demand Response Penetration Rates 17
Table 3-2. Factors that May Influence Demand Response 24
Table 4-1. Demand Response Options Included in Market Potential Simulation 28
Table 4-2. Data Sources 29
Table 4-3. Participation Rates in Demand Response Programs and Dynamic Pricing Tariffs 31
Table 4-4. Average Elasticity Values 33
Table 4-5. Availability of Data on External and Customer-Specific Factors 33
Table 4-6. Elasticity Values Adjusted for Onsite Generation 34
Table 4-7. Elasticities Based on Customer Response to High Prices ($500/MWh) 35
Table 4-8. Low, Medium and High Elasticity Seed Values 37
Table 4-9. Prices Used in Market Potential Simulations 38
Table 4-10. Market Potential Results: Base Case 39
Table 4-11. Market Potential Results: Onsite Generation 41
Table 4-12. Market Potential Results: Response at High Prices 42
Table 4-13. Market Potential Results: Response Distribution Effects 43

Appendices:

Table D-1. Churn Rates for ISO-NE and NYISO Demand Response Programs 68

Acronyms and Abbreviations

C&I	commercial and industrial (utility customers)
CBL	customer baseline load
DOE	(U.S.) Department of Energy
DR	demand response
EDRP	Emergency Demand Response Program
EPACT	Energy Policy Act (of 2005)
ISO-NE	ISO-New England
ISO	Independent System Operator
kW	kilowatt
kWh	kilowatt-hour
MW	Megawatt
MWh	Megawatt-hour
NMPC	Niagara Mohawk Power Corporation (a National Grid company)
NYISO	New York Independent System Operator
RTO	Regional Transmission Organization
RTP	real-time pricing

Executive Summary

Demand response is increasingly recognized as an essential ingredient to well functioning electricity markets. This growing consensus was formalized in the Energy Policy Act of 2005 (EPACT), which established demand response as an official policy of the U.S. government, and directed states (and their electric utilities) to consider implementing demand response, with a particular focus on "price-based" mechanisms.[1] The resulting deliberations, along with a variety of state and regional demand response initiatives, are raising important policy questions: for example, *How much demand response is enough? How much is available? From what sources? At what cost?*

The purpose of this scoping study is to examine analytical techniques and data sources to support demand response market assessments that can, in turn, answer the second and third of these questions. We focus on demand response for large (> 350 kW), commercial and industrial (C&I) customers, although many of the concepts could equally be applied to similar programs and tariffs for small commercial and residential customers.[2]

A number of utilities and regional groups have performed demand response market potential studies in recent years.[3] Such studies have been conducted primarily to develop the demand-side section of utility resource plans, or to assist with planning or screening of potential demand response programs. Going forward, in addition to these motivations, we anticipate that market assessments may be useful to utilities and state policymakers in their response to EPACT, as a means to help determine the feasibility of various demand response options in their service territories. Additionally, some states and regions have begun to set demand response goals[4]; market assessment studies could serve as a foundation to ensure that such goals are achievable, and help identify market segments and strategies to meet them.

In this scoping study, we review analytical methods and data that can support market assessments (e.g., for dynamic pricing tariffs) or market potential studies (e.g., for programmatic demand response) that can support these functions. We present a conceptual framework for estimating market potential for large customer demand response, compile participation rates and elasticity values from six large customer dynamic pricing and demand response programs and apply them to estimate demand response market potential in an illustrative utility service territory. Finally, we present a research agenda that identifies additional information and improved methods that would support more reliable demand response market assessments.

---

[1] Energy Policy Act of 2005, Section 1252(b).
[2] Our proposed approach may not be appropriate for direct load control programs, which are widespread demand response approaches offered to small commercial and residential customers (see section 2.2).
[3] See Haeri and Gage (2006), Quantum Consulting and Summit Blue Consulting (2004), SCE (2003), and EPRI Solutions (2005).
[4] For example, the California Public Utilities Commission (CPUC) has set demand response goals for the state's investor-owned utilities (CPUC 2004 and 2006b) and the Northwest Power and Conservation Council proposed a regional goal of 500 MW of demand response in its 5th Power Plan (NPCC 2005).

What is Demand Response Market Potential?

Demand response market potential is *the amount of demand response—measured as short-term load reductions in response to high prices or incentive payment offerings—that policymakers can expect to achieve by offering a particular set of demand response options to customers in a particular market or market segment under expected market or operating conditions.*[5]

In this report, we use the terms "market potential" and "market assessment" interchangeably. *Market potential* studies are typically undertaken by policymakers to determine the achievable market penetration, benefits, and costs of a policy or program (such as a ratepayer-funded energy efficiency program). In assessing the merits of dynamic pricing *tariffs,* policymakers may nonetheless be interested in many of the same issues addressed by a market potential study—customer acceptance rates, level of price response, etc.—and often will conduct *market assessments* to forecast likely market penetration (and electric sales and revenues) in cases where customers can choose among several tariffs. The methods discussed in this report are equally applicable to both market potential studies of demand response programs and market assessments of dynamic pricing tariffs.

Approaches Used to Study Demand Response Market Potential

Studies of demand response market potential necessarily involve estimating two separate elements: *participation*, the number of customers enrolling in programs or taking service on a dynamic pricing tariff; and *response*, quantities of load reductions at times of high prices or when curtailment incentives are offered. Among seven reviewed demand response market potential studies[6], four distinct approaches were used:

- *Customer surveys*—Participation rates and expected load curtailments are obtained from surveys of utility customers about their expected actions if offered hypothetical demand response options and used to estimate market potential.
- *Benchmarking*—Participation rates and load reductions observed among customers in other jurisdictions are applied to the population of interest.
- *Engineering approach*—Four of the seven reviewed studies used bottom-up engineering techniques, similar to those used to estimate energy efficiency market potential. All are variations on the approach of applying assumed participation and response rates to data on local customers, loads or equipment stock.
- *Elasticity approach*—This approach involves estimating price elasticities from the usage data of customers exposed to demand response programs and/or dynamic pricing tariffs. After determining an expected participation level, price elasticities are applied to the population of interest to estimate load impacts under an expected range of prices or level of financial incentives to curtail load.

---

[5] It can be expressed as a percentage reduction in market demand that can be expected at, for example, a price (or offered curtailment incentive) of $500/MWh.
[6] See Appendix A for a summary of the reviewed studies.

What Makes Demand Response Different from Energy Efficiency?

While energy efficiency and demand response both involve modifying large customers' use of and demand for electricity, they differ in the following important ways:

- *The nature of participation*—For demand response options, participation involves two steps: enrolling in a program or tariff, usually on an annual (or other periodic) basis; and providing load reductions during specific events (e.g., system emergencies or periods of high prices). For energy efficiency, "participation" consists of a one-time decision to invest in energy-efficiency measures or equipment.
- *The drivers of benefits*—Demand-response benefits often hinge on customer behavior (i.e., ability and willingness to curtail) in response to hourly prices, financial incentives, and/or system emergencies. Energy efficiency savings are largely a function of the technical characteristics and performance of the installed equipment or measures.
- *The time horizon and valuation of benefits*—From a customer perspective, demand-response benefit streams may be highly variable and are often short-term. For example, customers on hourly or critical-peak pricing can save on their utility bills by shifting or curtailing load in response to peak and off-peak prices. They can also receive incentive payments for emergency demand response program events, but these tend to be relatively infrequent. In contrast, investments in energy efficiency measures typically produce a fairly certain stream of savings over a multi-year period (i.e. the economic lifetime of the measure) which the customer can value at expected retail energy rates.

A Framework for Estimating Large Customer Demand Response Market Potential

For large customer demand response options, that rely on customer-initiated response to prices (e.g. hourly or critical-peak pricing) or curtailment incentives (e.g. short-notice emergency program, price response event program), we recommend an elasticity approach for estimating load reductions in market potential studies. The elasticity approach explicitly links response to prices and customer behavior. When demand models are used to estimate elasticities, they also enable the translation of experience from other jurisdictions with adjustments for differences in customer- and market-specific factors.[7]

We propose a framework for estimating large customer demand response market potential in a given jurisdiction or utility service territory that involves five steps:

- *Establishing the study scope*—identifying the target population and types of demand response options to be considered;

[7] For direct load control (DLC) programs, which are commonly offered to small commercial and residential customers, bottom-up engineering approaches are appropriate; these methods are commonly used to estimate energy efficiency potential.

- *Customer segmentation*—identifying "customer market segments" (groups of customers with similar characteristics that are expected to respond in similar ways) among the target population;
- *Estimating net program penetration rates*—using available data to estimate customer enrollment in voluntary programs and customer exposure to default pricing programs; participation is often the most difficult aspect of demand response options to estimate at present due to a limited experience base;
- *Estimating price response*—selecting an appropriate measure of price response (price elasticity of demand, substitution elasticity or arc elasticity) given available data, and developing elasticity estimates for various demand response options, customer market segments, and factors found to influence price response from the observed load response of customers exposed to demand response options; and
- *Estimating load impacts*—combining the above steps to estimate the expected demand response that can be expected from the target population at a reference price.

Applying the Framework: Large Customer Demand Response Market Potential

We applied the above framework, using available data on large customer participation and response, to estimate the market potential of several types of demand response programs and dynamic pricing tariffs at an illustrative urban utility.

We limited our analysis to large, non-residential customers with peak demand greater than 350 kW and examined five different types of demand response option.[8] We developed separate data inputs and results for five market segments: manufacturing, government/education, commercial/retail, healthcare, and public works.

<u>Data Sources and Simulation Inputs</u>

We gathered data from six demand response programs and dynamic pricing tariffs offered to large commercial and industrial customers by utilities and regional grid operators in recent years (see Table ES-1).

We compiled participation rates by market segment and customer size for each demand response option. Our goal was to gather data on program participation based on relatively mature programs with 3–4 years of operation. Where possible, we used actual program participation data from the data sources in Table ES-1. We filled in gaps by surveying program managers of similar programs and tariffs, and inferring data from other market segments or programs.

[8] We only had access to individual customer level data from several large-customer demand response options, which facilitated estimation of participation rates and customer response for large customers, but not smaller commercial or residential customers. We analyzed these options *independently* and did not account for possible interactions between different options should they be offered simultaneously to a given set of customers. Program designers that intend to offer a variety of demand response options should ensure that such interactions are accounted for in market potential studies

Table ES-1. Data Sources

DR Option	Data Source(s)	Eligible Customers (peak demand)
Optional hourly pricing	Central and Southwest (CSW) Utilities' (now American Electric Power) two-part RTP rate	<1500 kW
Default hourly pricing	Niagara Mohawk Power Corporation (NMPC), a National Grid Company, SC-3A tariff	> 2000 kW
Short-notice emergency program	NYISO Emergency Demand Response Program (EDRP)	> 100 kW
	ISO-NE Real-Time Demand Response (RTDR) Program	> 100 kW
Price-response event program	ISO-NE Real-Time Price Response (RTPR) Program	> 100 kW
Critical-peak pricing	California Utilities[1] Critical Peak Pricing Program	> 200 kW; > 100 kW for SDG&E

[1] Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E)

We also calculated elasticity values for each demand response option, disaggregated by market segment, using individual customer load and price data. For the two hourly pricing tariffs, we estimated demand models to calculate *substitution elasticities*. For the other programs, insufficient numbers of observations covering too small a range of prices were available to estimate a fully specified demand model, so we calculated *arc elasticities* instead.[9]

The average elasticity values estimated for each program and market segment are presented in Table ES-2. For some of our market potential scenarios, we refined these average elasticity estimates to reveal differences in customer response associated with onsite generation ownership, high prices, and variations in responsiveness within market segments.

Table ES-2. Average Elasticity Values

Customer Market Segment	Demand Response Option				
	Optional Hourly Pricing	Default Hourly Pricing	Short-notice Emergency Program	Price Response Event Program	Critical-peak Pricing
Commercial/retail	0.01	0.06	-0.03	-0.09	-0.10
Government/education	0.01	0.10	-0.02	-0.16	-0.06
Healthcare	0.01	0.04	-0.04	-0.05	-0.01
Manufacturing	0.26	0.16	-0.04	-0.16	-0.05
Public works	0.07	0.02	-0.08	-0.22	-0.08

Note: Elasticity of substitution values are shown for optional and default hourly pricing and are typically positive; arc elasticity values are shown for all other demand response options and are typically negative.

[9] See section 3.4.1 for a discussion of various elasticity measures. Substitution-elasticity and arc-elasticity values are not directly comparable, although the market potential impacts derived from them are.

Market Potential Simulations

We applied the elasticity values to information on the customer population of an urban utility in the Northeastern U.S. (see the adjacent textbox) to develop market potential estimates. We also analyzed several alternative scenarios to demonstrate the effects of various factors on demand response market potential. We highlight a selection of the results here.

Overview of our Sample Utility

We selected an urban utility in the Northeastern U.S., for which we had access to large customer characteristics and usage data, to demonstrate market potential simulations.

The selected utility is relatively small; the peak demand of its large, non-residential customers is only ~1,700 MW. These customers represent about 40% of the utility's peak demand, and consist largely of commercial/retail, government/education and healthcare facilities. Manufacturing customers are less prevalent than for utilities that serve suburban or rural communities.

Base Case

The overall base-case results range from 0% to 3% of the peak demand of the target population of customers larger than 350 kW (see Table ES-3). The load reductions for the largest customers (>1 MW) enrolled in the default hourly pricing and price response event programs represent 5-6% of their aggregate peak demand. The highest market potential (3% of peak demand) corresponds to the default hourly pricing tariff—this is largely due to relatively high customer acceptance rates for this tariff.

Table ES-3. Market Potential Results: Base Case

Customer Size (MW)	Optional Hourly Pricing		Default Hourly Pricing		Short-notice Emergency Program		Price Response Event Program		Critical-peak Pricing	
	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]	MW	% of class peak demand[1]
0.35–0.5	1.0	0%	2.8	0%	0.4	0%	1.6	0%	1.3	0%
0.5–1	1.1	0%	3.9	1%	4.3	1%	3.0	1%	1.7	1%
1–2	1.9	1%	14.4	6%	3.8	2%	3.9	2%	1.9	1%
> 2	21.6	4%	34.8	6%	11.5	2%	29.1	5%	2.4	0%
Total	**25.6**	**2%**	**55.9**	**3%**	**19.9**	**1%**	**37.6**	**2%**	**7.3**	**0%**

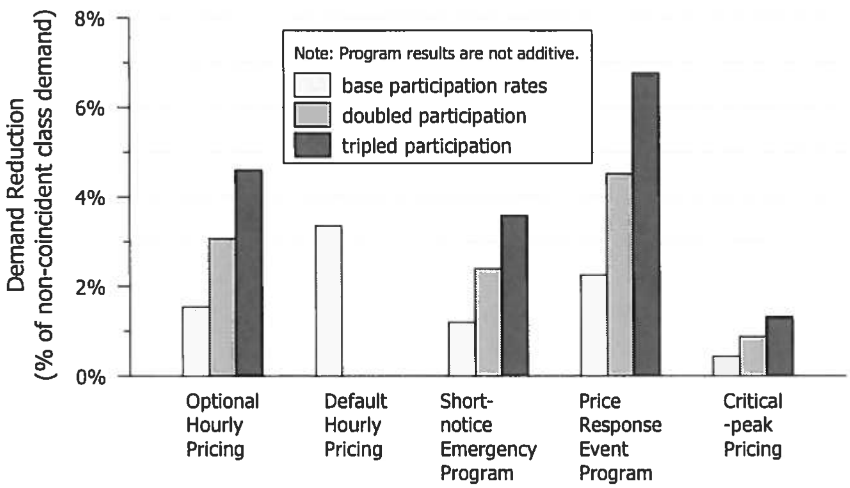
[1] Peak demand is non-coincident.
Note: Each demand response option was evaluated separately—the results are not additive.

Impact of Program Participation Rates

Market assessments often examine the impact of differing rates of participation on program potential. Figure ES-1 illustrates the impact of aggressively marketing programs or promoting optional tariffs to achieve two and three times the base-case participation rates, which reflect current demand response experience. The results, on the order of 3–6 percent of non-residential peak demand, can be viewed as an approximate upper bound on demand response potentials.[10] For default hourly pricing, which by definition would

[10] These results assume that the additional enrolled customers are just as responsive to price signals or emergencies as the relatively "early adopters" observed among our data sources. In reality, it may be that

not be marketed to customers, we do not show enhanced participation, although the base case results are included in the figure for comparison.



Note: The level of demand response (elasticity) is assumed to be the same for all scenarios—this assumption has yet to be evaluated with actual program experience.

Figure ES-1. Impact of Program Participation Rates on Demand Response Market Potentials

Accounting for Onsite Generation

We examined the impact of refining the elasticity estimates for the short-notice emergency program to account for differences in response by customers with and without onsite generation technology.[11] On average, customers in this demand response program with onsite generators had arc elasticities about 40% higher than customers that did not. This translates to elasticity values for customers without onsite generation that are 14% lower than the average elasticities for each market segment. For those with onsite generation, the elasticity values are 52% higher than the average.

Applying these refined and more disaggregated elasticity estimates to the population of customers in our illustrative utility resulted in slightly lower market potential estimates than the base case for this demand response option (i.e., 17.6 versus 19.9 MW). This is due to differences in our assumptions about the distribution of onsite generators among

---

the most responsive customers are also the first to sign up, leading to declining average elasticities as more customers are enrolled. On the other hand, strategies that combine program marketing with technical assistance to develop fully automated demand response could enhance both participation rates and response to prices or emergencies. An automated demand response pilot in California with a sample of ~30 medium and large commercial, institutional, and high-tech buildings demonstrated this potential, achieving consistent average load curtailments of ~10% with high customer satisfaction (Piette et al. 2005). California's investor-owned utilities will be ramping up automated demand response in 2007-08 to several hundred facilities (CPUC 2006a).

[11] Data were not available on the presence of onsite generation among customers in the other demand response options.

the customer population at the illustrative urban utility compared to the observed distribution among the customers from whom the elasticity estimates were estimated.

Summary: Discussion

The results of our simulations illustrate possible ranges of demand response market potential for large commercial and industrial customers at an urban Northeast utility, as well as several key methodological and data issues. The results are specifically tied to the characteristics of this urban utility's large customer base as well as the specific assumptions we made about prices and other factors in the various scenarios. Nonetheless, we draw the following insights and conclusions from our scoping study of demand response market potential:

- We believe that the results provide a **reasonable first approximation of the range of demand response market potential among non-residential customers** if offered similar demand response options by similar utilities. The aggregate load reductions for our urban, northeast utility ranged from less than 1% to 3% of the peak demand of the target population of large customers. While these load reductions are modest, a number of studies suggest that a little demand response can often go a long way towards ameliorating system emergencies or high prices. If policymakers or regulators establish higher demand response goals (e.g. California's goal of 5% of price-responsive load), then our results suggest that the demand response market potential of all customer classes should be considered—not just the large commercial and industrial customers included in this study. Pilot program results suggest that enabling technologies and automated demand response can also increase both the number of customers willing to participate in demand response options as well as the predictability and consistency of their load response.
- The simulations illustrate the **relative impact of certain factors, particularly customer participation rates, on potential aggregate load reductions** of large customers. Participation rates currently represent the largest data uncertainty for analysts undertaking market potential studies. Yet achieving higher participation rates among eligible large customers is critical for obtaining a significant amount of price-responsive load. Any assessment of demand response potential can not ignore the level of program resources that will be devoted to its implementation.
- The scenarios also demonstrate **the importance of refining elasticity estimates rather than applying average values**. In several cases, this resulted in *lower* market potential estimates in our simulations. Policymakers considering establishing demand response goals would be well advised to be cautious, as goals extrapolated from pilot programs or demand response potential study estimates based only on small samples of very responsive customers may not be achievable.
- Finally, we emphasize that **all demand response market potential studies should examine a range of scenarios**—not necessarily limited to those demonstrated here—in estimating the potential of demand response options to deliver load reductions when needed.

Advancing the State of the Art: A Market Assessment Research Agenda

To advance the state of knowledge about customer response to demand response programs and dynamic pricing tariffs, and facilitate demand response market assessments, we recommend that state and federal policymakers and regulators encourage utilities, other load serving entities, Independent System Operators/Regional Transmission Organizations, program evaluators and analysts to conduct the following activities:

1. ***Link Program Evaluation to Market Potential Studies***: Evaluations of demand response programs should systematically collect data on the characteristics of participating customers; hourly customer loads, prices and response; other factors found to be relevant drivers of customer participation and response; and information on the size and characteristics of the target or eligible population.
2. ***Program Participation***: Develop predictive methods for estimating participation rates in demand response programs and dynamic pricing tariffs that incorporate customer characteristics and other factors that drive participation. Where applicable, studies should include interactive effects of multiple program offerings in estimating market penetration rates.
3. ***Price Response:*** Estimate price elasticity values for different market segments, accounting for the relative impact of driving factors, and report methods and results transparently. Where possible, we recommend that provisions be made to estimate demand or substitution elasticities, using fully specified demand models, rather than arc elasticities.
4. ***Assess the Impacts of Demand Response Enabling Technologies:*** *For large customers, there is still a need to document the impacts of specific demand response enabling technologies on customer participation and load response, given limited evidence and mixed results from existing evaluations. At a minimum, program evaluators should gather information on customer's load curtailment strategies that involve onsite generation,*[12] *peak load controls, energy management control systems, energy information systems, and any other technologies disseminated as part of technical assistance programs.*
5. ***Publicize Results:*** *Explore ways to pool customer-level data, while protecting customer confidentiality, so that information to support demand response market assessments is available in a standardized format.*

[12] Information on diesel-fired emergency back-up generators should be tracked separately from cogeneration, combined heat and power, and other distributed energy technologies.

1. Introduction

Demand response is increasingly recognized as an essential ingredient to well functioning electricity markets, both in the context of organized wholesale markets and more traditional market structures. This growing consensus was formalized in the Energy Policy Act (EPACT) of 2005, which states that it is the policy of the United States to encourage time-based pricing and other forms of demand response. The legislation also charges state regulatory authorities with conducting investigations to determine whether to adopt widespread time-based pricing and advanced metering for retail customers of electric utilities.[13] The resulting deliberations, along with a variety of state and regional demand response initiatives, are raising important policy questions: for example, *How much demand response is enough? How much is available? From what sources? At what cost?*

The purpose of this scoping study is to examine analytical techniques and data sources to support demand response market assessments that can, in turn, answer some of these questions. We focus on demand response for large (> 350 kW), commercial and industrial (C&I) customers, although many of the concepts could equally be applied to similar programs and tariffs for small commercial and residential customers.[14]

The U.S. Department of Energy (DOE) defines demand response as:

> *changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized* (DOE 2006).

Customers can be induced to provide demand response either through *dynamic pricing tariffs*—retail electric rates that reflect short-term changes in wholesale electricity costs (e.g., hourly pricing or critical-peak pricing)—or *demand response programs* that offer customers payments in return for reducing consumption when called upon to mitigate high market prices or reserve shortfalls.[15]

Among large C&I customers, recent evaluations of demand response programs offered by Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs) and case studies of dynamic pricing tariffs (e.g., Niagara Mohawk, a National Grid Company, Central and Southwest Services, Duke Power, Georgia Power) provide information on observed customer adoption rates and levels of demand response.[16] For

[13] Energy Policy Act of 2005, Section 1252(b).

[14] Our proposed approach may not be appropriate for direct load control programs, which are widespread demand response approaches offered to small commercial and residential customers (see section 2.2).

[15] Customer response to these two types of demand response option can be thought of as *price-responsive demand* (for dynamic pricing tariffs and price-triggered programs), and *emergency demand response* (for programs designed to mitigate shortfalls in system reserves and reduce the likelihood of rotating outages).

[16] For example, demand response program evaluations have been conducted for NYISO (Neenan et al. 2002 and 2003) and ISO-NE (RLW Analytics and Neenan Associates 2003, 2004 and 2005). Case studies of large customer dynamic pricing have been conducted for the following utilities' programs: Niagara

small customers, a larger body of information is available on response to direct load control programs,[17] and several critical-peak pricing pilots have published results[18] or are in progress (e.g., PSEG, Washington DC). These studies of large customer and mass market demand response provide insights into customer acceptance of and response to a variety of demand response offerings, although their results are typically not sufficiently disaggregated to apply them to market assessments in other jurisdictions.

A number of utilities and regional groups have performed demand response market potential studies in recent years.[19] Such studies have been conducted primarily in two contexts: to develop the demand-side section of a utility's integrated resource plan, and to assist with planning or screening of potential demand response programs (Gunn 2005).[20]

Going forward, we anticipate that market assessments may also be useful to utilities and state policymakers in their response to EPACT, as a means to help determine the feasibility of various demand response options in their service territories. Finally, a few states and regions have begun to set or consider demand response goals[21]; market assessment studies could serve as a foundation to ensure that such goals are achievable, and help identify market segments and strategies to meet them.

In these contexts, a number of policy questions arise, some of which we address in this study, and others not. Chief among them are:

- **What is the value of demand response?** A recent DOE study developed an analytic framework for assessing the net benefits of demand response and conducted a comparative analysis of existing studies of demand response benefits (DOE 2006). We do not address this question in this report.
- **How much demand response is enough (or needed)?** There is currently no consensus on this issue, and this study does not address it. We note that the answer depends in part on which policy goals motivate the question (e.g., enhancing wholesale market competition, mitigating high energy prices, avoiding rolling blackouts, or deferring the need to build new peaking generation or distribution system infrastructure).

Mohawk, a National Grid Company (Goldman et al. 2005), Central and Southwest Services (Boisvert et al. 2004), Duke Power (Schwarz et al. 2002), and Georgia Power (Braithwait and O'Sheasy 2001).

[17] Section 4 of DOE (2006) summarizes the results of these small-customer demand response evaluations.

[18] For example, see California's Statewide Pricing Pilot results (Charles River Associates 2005) and Ameren's Critical Peak Pricing Pilot results (Voytas 2006).

[19] See Haeri and Gage (2006), Quantum Consulting (2004), SCE (2003), and EPRI Solutions (2005).

[20] Gunn (2006) also cites contributing to the certificate of need for new generating plants as another motivation for undertaking demand response market potential studies; however, we are unaware of any such examples.

[21] For example, the California Public Utilities Commission (CPUC) has set demand response goals for the state's investor-owned utilities (CPUC 2004 and 2006b), and the Northwest Power and Conservation Council proposed a regional goal of 500 MW of demand response in its 5th Power Plan (NPCC 2005).

- How much demand response is available? From which customer market segments? From which strategies (e.g., hourly pricing, emergency programs, economic programs, etc.)? <u>These are the primary questions addressed by demand response market assessments. This report focuses on methods and data to answer them.</u>
- **At what cost can demand response be obtained?** Although this question is often addressed by market potential studies or as part of resource planning processes that involve comparing the size and costs of various resources, it is out of the scope of this study. This is in large part because costs are highly situation-specific.[22]

In this scoping study, we review methods for addressing the third question above through market assessments or market potential studies. Our approach is as follows:

- we review and compare methods and concepts for estimating demand response and energy efficiency market potential (section 2 of this report);
- we present a conceptual framework and explore methods and tools for estimating large customer demand response market potential that account for customer behavior and prices through the use of price elasticities (section 3);
- we compile participation rates and elasticity values from six large customer dynamic pricing and demand response programs and apply them to estimate demand response market potential in an illustrative utility service territory (chapter 4); and
- we present a research agenda that identifies additional information and improved methods that would support more reliable demand response market assessments (section 5).

Market Potential and Market Assessment

We use the terms "market potential" and "market assessment" somewhat loosely and interchangeably in this report.

Market potential studies are typically undertaken by policymakers to determine the achievable market penetration, benefits, and costs of a policy or program (such as a ratepayer-funded energy efficiency program). For demand response programs that involve incentive payments to participating customers, policymakers may wish to undertake market potential studies.

For dynamic pricing tariffs, policymakers may nonetheless be interested in many of the same issues addressed by a market potential study—customer acceptance rates, level of price response, etc. *Market assessments* fulfill much the same role.

The methods discussed in this report are equally applicable to both market potential studies of demand response programs and market assessments of dynamic pricing tariffs.

[22] See DOE (2006) for a description of the types of costs that need to be accounted for in assessing demand response programs.

2. Methods and Concepts for Estimating Demand Response Market Potential

As interest in demand response has grown in recent years, a number of analysts have endeavored to estimate demand response market potential and/or develop methods and tools for doing so. However, their numbers are few and, as Gunn (2005) observes, their methods have not been well vetted.

We began this scoping study with a literature review of seven recent studies and tools designed to estimate demand response market potential.[23] These studies (and tools) and their methodologies are detailed in Appendix A; in this section, we draw from this literature review to discuss methods for estimating demand response market potential. First, we frame the discussion by defining market potential, in the context of both energy efficiency—for which methods and concepts are well vetted—and demand response. We then summarize the approaches used in the reviewed studies. Since most of these studies have adapted methods used to estimate energy-efficiency potential, we identify fundamental differences between energy efficiency and demand response, and from this discussion introduce and make the case for our recommended methodology for demand response options offered to large, non-residential customers.

2.1 What is Market Potential?

Put simply, demand response market potential is *the amount of demand response—measured as short-term load reductions in response to high prices or incentive payment offerings—that policymakers can expect to achieve by offering a particular set of demand response options to customers in a particular market or market segment under expected market or operating conditions.*[24]

To delve deeper into this question, it is useful to examine the concept of market potential as it is applied to energy efficiency programs or activities. Energy efficiency has a number of similarities to demand response. Both involve affecting customers' usage of or demand for energy. From a resource perspective, both are demand-side resources (DSM) that can defer the need to build new energy supply, transmission or delivery infrastructure. Energy efficiency and demand response are, therefore, often classified along a spectrum of demand-side management strategies.

Energy efficiency potential studies, like energy efficiency programs, have a long history spanning almost three decades, and the motivations, methodologies and definitions of efficiency potential have evolved over this time.

Initially, analysts estimated the *technical potential* for energy efficiency in order to demonstrate to policymakers that savings from a large number of investments in end use equipment could add up to a large aggregate resource. Technical savings potential was

[23] We were aware of a few additional studies, but were unable to obtain enough information to include them (see Appendix A).

[24] Demand response market potential can be expressed as a percentage reduction in market demand that can be expected at a given price or offered curtailment incentive (e.g., $500/MWh).

typically defined as the complete penetration of all energy efficiency measures that were technically feasible (Rufo and Coito 2002). Technical potential was typically estimated using a bottom-up, end use approach—ex ante engineering estimates of savings from replacing the existing stock of equipment and appliances in buildings with high-efficiency options, where feasible and applicable, were applied to information about the distribution of energy-using equipment in the population.

Over time, energy efficiency potential studies evolved to answer questions about the cost of acquiring energy efficiency resources, to estimate the size of resources that could be acquired at less than the cost of new supply infrastructure, and to establish goals. This required estimating *economic potential*, that subset of the technical potential that is cost-effective to implement (given reasonable assumptions about the incremental costs of energy efficiency measures and savings from measures). Over time, this was further refined to estimate *market potential*, the subset of economic potential that is deemed achievable, taking into account factors such as customer cost-effectiveness criteria, awareness, willingness to adopt (which is influenced by various market barriers) and assumed levels of program incentives and activity (Rufo and Coito 2002).[25] The relationship of these three concepts is shown in Figure 2-1.

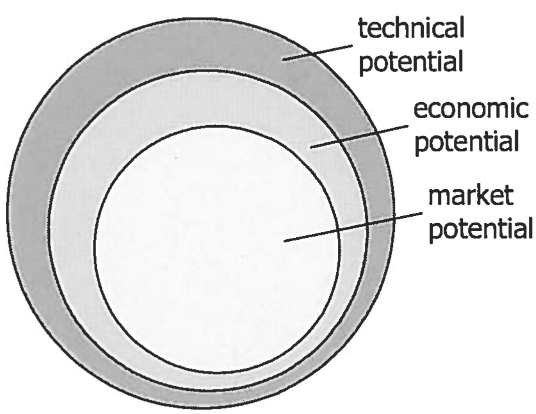


Figure 2-1. Relative Relationships of Energy-Efficiency Potential Definitions

Although economic and market potential studies incorporate economic (e.g., costs and economic savings) and market (e.g., assumed uptake rates) as well as technical factors (e.g., energy savings), these studies are still essentially bottom-up engineering approaches. In economic potential studies, customers are typically expected to adopt a particular measure if the investment meets an economic hurdle rate (e.g., a certain

[25] Analysts describe the existence of an energy efficiency "gap"—that customers and firms do not undertake investments in energy efficient equipment that appears cost-effective on an estimated life-cycle basis and customers appear to require returns for investments in energy efficiency equipment that significantly exceed market interest rates for saving or borrowing (Sanstad et al. 2006). A number of market barriers and failures have been proffered to explain this gap (Brown 2001, Levine et al. 1995, Golove and Eto 1996, Jaffe and Stavins 1994, Sanstad and Howarth 1994). Market potential represents the amount of energy efficiency that can be achieved if policies and programs are put in place to overcome these barriers, recognizing that no interventions will be able to overcome all impediments to full realization of economic potential.

benefit/cost threshold) that is assumed to match customers' implicit required investment payback times.[26] Market potential studies account for additional factors that may limit uptake—even in the face of policies and programs to support energy efficiency—such as lack of access to information, limited availability of energy-efficient equipment in the marketplace, and "split incentive" barriers in which the person investing in the equipment is not in a position to receive the savings (e.g., landlord and tenant relationship).

The notion of energy efficiency as an attractive, low-cost resource is increasingly accepted by state and federal policymakers and a track record has been established in many states.[27] Several recent energy efficiency market potential studies focus on estimating maximum achievable market potential, often drawing upon the "best practices" experience of energy efficiency program administrators to estimate annual market penetration and saturation rates.[28]

The context and motivations for estimating demand-response market potential are somewhat different. To a large extent, federal and state policymakers are convinced that demand response is a critical feature of a well-functioning and efficient wholesale and retail electricity market.29 However, there is no consensus on how much demand response is necessary or desirable, in part because of limitations in analytic methods.

2.2 Approaches Used to Study Demand Response Market Potential

Studies of demand response market potential necessarily involve estimating two separate elements: *participation*, or the number of customers enrolling in programs or taking service on a dynamic pricing tariff; and *response*, quantities of load reductions at times of high prices or when curtailment incentives are offered. Among the seven demand response market potential studies and tools reviewed for this study, four distinct approaches were used (see Appendix A for a summary of the studies). We introduce these approaches below, commenting briefly on their main advantages and disadvantages.

Customer surveys

One approach is to survey utility customers about their expected actions if offered hypothetical demand response options. Resulting participation rates and expected load curtailments are used to estimate market potential. This approach has the advantage of using information obtained locally, but its major drawback is that the responses are highly subjective—customers may not know what they would actually do (particularly if

[26] Despite years of experience estimating the economic potential for energy efficiency, there is still considerable debate regarding customers' actual economic decision-making thresholds. For example, Sanstad et al. (2006) estimated implicit discount rates from energy efficiency investments presented in several studies conducted between 1978 and 1984, and found a range from 25% to 300% across a range of measures.

[27] For example, the National Action Plan for Energy Efficiency (2006) represents a broad consensus of policymakers, regulators, utilities and stakeholders on energy efficiency benefits and best practices.

[28] See, for example, WGA CDEAC (2006).

[29] For example, Section 1252 of the U.S. Energy Policy Act (EPACT 2005) recognizes demand response as a high priority federally, and provides guidance to states to do so as well.

they have no prior demand response experience), or may respond strategically. We found only one example of this approach.

Benchmarking

Benchmarking approaches apply participation rates and load reductions observed among customers in other jurisdictions to the population of interest. The advantage of this approach, relative to customer surveys, is that it relies on actual customer experience and actions. However, it assumes that any differences in the customers and market context have an insignificant impact on participation and load response. In reality, variables such as the mix of customers (e.g., size, end uses, business activity), market structure (e.g., vertically integrated utility, organized wholesale markets), the specific tariff or program design, and the level and volatility of prices or incentives may impact actual response. Only one of the reviewed studies adopted this approach.

Engineering approach

Four of the seven studies used bottom-up engineering techniques, similar to those used to estimate energy efficiency market potential. They are all variations on the approach of applying assumed participation and response rates to data on local customers, loads or equipment stock. The participation and response rates may come from actual data observed in other jurisdictions, a "Delphi" approach, in which experts are surveyed, or customer surveys.[30] These rates are typically assumed to be constant, regardless of price or incentive levels. This approach may be appropriate for *dispatched* demand response programs (e.g., direct load control) in which a utility or program operator remotely controls a customer's energy-using equipment. However, demand response options for large customers—in which customers initiate load reductions in response to a price signal or a specified incentive payment (and sometimes a penalty provision)—are significantly different. Behavior, not physical circumstances, dictates the outcomes, making the engineering approach less tractable for this type of demand response option.

Elasticity approach

This approach, adopted by one of the reviewed studies, involves estimating price elasticities, preferably using an econometric demand model, from the usage data of customers exposed to demand response options. After determining an expected participation level (using a benchmarking or other approach), price elasticities are applied to the population of interest to estimate load impacts under an expected range of prices or level of financial incentives to curtail load. Like the benchmarking approach, elasticities are based on actual customer response. They also quantify the relationship between customer behavior (load reductions) and price (the primary motivation for undertaking changes in consumption). When demand models are used to estimate elasticities, variables can be introduced to account for customer- or market-specific factors that influence price response, enabling the translation of results to other jurisdictions that may vary in these factors.

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[30] See Appendix A for descriptions of the individual approaches.

2.3 What Makes Demand Response Different from Energy Efficiency?

While energy efficiency and demand response both involve modifying large customers' use of and demand for electricity, they differ in the following important ways:

The nature of participation

The installation of high-efficiency equipment or appliances typically involves a one-time investment decision by the customer, and program operators recruit new customers (or new projects with repeat customers) in each year. For demand response, participation involves two steps: enrolling in a program or tariff, usually on an annual (or other periodic) basis; and providing load reductions during specific events (e.g., system emergencies or periods of high prices). Demand response participation is ongoing and typically changes on a yearly (or seasonal) basis as some customers drop out of programs (or tariffs) and new participants sign up. At the same time, participation by all customers is probably not necessary to achieve the goals of reducing market price spikes, mitigating market power, or averting blackouts. This is in contrast to energy efficiency, where more is usually better (up to an avoided-cost or cost-effectiveness threshold). Finally, customer participation in certain energy-efficiency programs is often tied to equipment replacement cycles or new construction, which affects penetration rates. For demand response, this is typically not the case.

The drivers of benefits

Once customers have made the decision to participate in a program (or tariff), the benefits of that participation—energy or demand savings—derive from very different sources. For energy efficiency measures, the level and persistence of savings are largely a function of the technical characteristics of the high-efficiency equipment or appliance relative to current practice or existing equipment (with some complicating customer-usage factors).[31] Amenity and service levels are assumed to remain constant. In contrast, demand response load reductions are largely a function of customer behavior—their willingness and ability to curtail loads for short periods of time in response to high prices or system emergency events, while minimizing any negative impacts on amenity and service levels. More widespread adoption of automated demand-response technologies and strategies could make demand response load curtailments more predictable and sustainable, diminishing some of these differences.

The time horizon and valuation of benefits

With some exceptions, energy efficiency measures result in a reasonably certain benefit stream of energy (kWh) savings with multi-year duration.[32] Energy-efficiency potential

[31] Customer behavior may affect the energy efficiency technical savings potential in a variety of ways. For example, customers may change their usage of the equipment or building, remove or replace the equipment before the end of its economic lifetime, or provide improper or insufficient equipment maintenance. For certain types of energy efficiency measures, decay rates in equipment performance are assumed over the measure lifetime.

[32] A wide body of literature is available on the persistence of savings from energy efficiency measures, making it possible to model expected savings decay rates due to a range of technical and social factors.

studies typically value benefits to participants using expected retail electricity rates with escalation factors over a specified time horizon.[33] In contrast, from a customer perspective, benefits from demand response programs may be highly variable and are often short-term.[34] They are driven by short-term load curtailments or demand (kW) savings and these benefits last only as long as the customer remains a participant in the program (or is exposed to and responds to dynamic prices). Modeling demand response benefits to customers requires examining short-term price fluctuations (e.g., peak/off-peak price differentials on a given day) or estimating the value of lost load (for demand response programs that lower the probability of outages).

Level of uncertainty regarding benefits (and costs)

The level of uncertainty that large customers face in evaluating the costs and, particularly, the benefits of demand response participation is much higher than for energy efficiency. For example, in some years, emergency demand response programs are called infrequently if at all, while in other years there may be upwards of 20-30 hours of curtailments events. Customers enrolled in dynamic pricing tariffs may not face high prices for several years, but then experience volatile and/or sustained price increases for several months in a row during other years. This probably translates to higher investment hurdle rates—customers may expect much higher benefit/cost thresholds as compensation for the inherent risk. Over time, this should become less of an issue, as more customers develop demand-response experience.

Important interactions

Another, less critical, but nonetheless important, difference is the type of interactive effects that must be accounted for in the modeling process. For energy efficiency, interactions between measures can affect outcomes. For example, the installation of high efficiency lighting may reduce the space-conditioning savings potential in the same building, because waste heat from the lights is removed.[35] For demand response, interactions may arise between different demand response options, depending on program rules (e.g., customers may be allowed to simultaneously elect a dynamic pricing tariff and participate in an emergency demand response program). Another possible source of interaction is the frequency, duration and timing of high prices or curtailment calls. For example, "response fatigue", or a reduction in willingness or ability to curtail, may occur if customers are asked to curtail for several consecutive days.

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[33] Energy efficiency savings are often characterized as the difference between a baseline energy usage level and a high-efficiency scenario. This potential may then be modified by incorporating customer acceptance rates (e.g., based on an assumed benefit threshold) or other factors.

[34] However, customers on hourly pricing tariffs can also benefit from lower prices, relative to a revenue-neutral fixed price tariff, in the majority of hours. Moreover, to the extent that fixed-price tariffs include a risk premium relative to hourly pricing, this can represent another source of savings to customers.

[35] It is common to include a 5–10% correction for this effect in energy-efficiency potential studies.

2.4 A Different Approach to Demand Response Market Potential for Large Customers

Given differences in the motivations for undertaking energy efficiency and demand response potential studies, and in the features of these two demand-side resources, it is clear that merely translating or adapting methods from one to the other may not be appropriate for all options. We summarize this conceptual discussion with the following observations and recommendations on methods for estimating demand response market potential:

- **For residential and small commercial direct load control programs, customer load impact estimates can be derived from bottom-up engineering approaches or statistical evaluations of samples of participating customers with appropriate metering.** These approaches are also commonly used to estimate energy efficiency savings potential.
- **For large customer demand response options, that rely on customer-initiated response to prices (e.g., hourly or critical-peak pricing) or curtailment incentives (e.g., short notice emergency program, price response event program), we recommend an elasticity approach for estimating load reductions in market potential studies.**[36] The elasticity approach explicitly links response to prices and customer behavior. When demand models based upon economic theory are used to estimate elasticities, they also enable the translation of experience from other jurisdictions with adjustments for differences in customer- and market-specific factors.
- **Participation should be thought of in terms of market *penetration*** in a given year (or other relevant time period). Unfortunately, participation is the most difficult aspect of demand response options to estimate, due to a limited experience base. With time and experience, however, this should improve.
- With the current limited experience base on which to draw, **approaches that rely on customer survey response to hypothetical demand response options, or benchmarking, are probably not all that meaningful.** The "best practices" approach, which has been used in some energy efficiency market potential studies, makes most sense when there is a larger experience base (i.e., mature programs offered by many utilities or ISOs over a lengthy period).

The remainder of this report focuses on a framework, centered on the use of price elasticities, for estimating the market potential of demand response options, such as dynamic pricing tariffs (e.g., real-time pricing, critical-peak pricing), emergency

[36] We note, however, that demand response programs involving reserve or capacity payments and/or penalties for non-response (e.g., interruptible rates, capacity programs) present difficulties in estimating elasticities, because customer incentives are less clearly tied to individual events.

programs, and economic/demand bidding programs, that are typically offered to large commercial and industrial customers.