COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	)	CASE NO. 2013-00259

NOTICE OF FILING

Notice is given to all parties that the following materials have been filed into the record of this proceeding:

- The digital video recordings of the evidentiary hearing conducted January 14 – January 15, 2014 in this proceeding;

- Certifications of the accuracy and correctness of the digital video recordings;

- All exhibits introduced at the evidentiary hearing conducted January 14 – January 15, 2014 in this proceeding;

- The written logs listing, *inter alia*, the date and time of where each witness' testimony begins and ends on the digital video recordings of the evidentiary hearing conducted January 14 – January 15, 2014.

A copy of this Notice, the certifications of the digital video records, exhibit lists, and hearing logs have been served by first class mail upon all persons listed at the end of this Notice. Parties desiring electronic copies of the digital video recordings of the hearing in Windows Media format may download copies at:

http://psc.ky.gov/av_broadcast/2013-00259/2013-00259_14Jan14_Inter.asx

http://psc.ky.gov/av_broadcast/2013-00259/2013-00259_15Jan14_Inter.asx

Parties wishing annotated digital video recordings may submit a written request by electronic mail to pscfilings@ky.gov. A minimal fee will be assessed for copies of these recordings.

The exhibits introduced at the evidentiary hearing may be downloaded at http://psc.ky.gov/pscscf/2013%20cases/2013-00259/.

Done at Frankfort, Kentucky, this 27th day of January 2014.

Linda Faulkner

Linda Faulkner
Director, Filings Division
Public Service Commission of Kentucky

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COMMONWEALTH OF KENTUCKY

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In the Matter of:

APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	)))) CASE NO. 2013-00259)))

CERTIFICATE

I, Sonya Harward, hereby certify that:

1. The attached DVD contains a digital recording of the hearing conducted in the above-styled proceeding on January 14, 2014; (excluding any confidential segments, which were recorded on a separate DVD and will be maintained in the non-public records of the Commission, along with the Confidential Exhibits and Hearing Log). The hearing was recorded on two consecutive days, January 14, 2014 and January 15, 2014, separately. (Confidential portions were also recorded separately).

2. I am responsible for the preparation of the digital recording;

3. The digital recording accurately and correctly depicts the hearing of January 14, 2014 (excluding any confidential segments);

4. The "Exhibit List" attached to this Certificate correctly lists all exhibits introduced at the hearing of January 14, 2014 (excluding any confidential exhibits).

5. The "Hearing Log" attached to this Certificate accurately and correctly states the events that occurred at the hearing of January 14, 2014 (excluding any confidential segments) and the time at which each occurred.

Given this 16th day of January, 2014.

Sonya Harward (Boyd)

Sonya Harward (Boyd), Notary Public
State at Large
My commission expires: August 27, 2017

Session Report - Detail

2013-00259_14Jan2014

East Kentucky Power Cooperative, Inc.

Date:	Type:	Location:	Department:
1/14/2014	Other	Public Service Commission	Hearing Room 1 (HR 1)

Judge: David Armstrong; Linda Breathitt; Jim Gardner
Witness: Block Andrews - for EKPC; Anthony Campbell - EKPC; Jerry Purvis - EKPC; James Read - for EKPC; Julia Tucker - EKPC
Clerk: Sonya Harward

Event Time	Log Event	
10:04:13 AM	Session Started	
10:04:16 AM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Introductions of Commissioners and preliminary remarks.
10:04:58 AM	Introduction of Parties	
	Note: Ernst, Melinda	For EKPC - Mark David Goss and David Samford; For Sierra Club - Joe Childers, Kristin Henry, Shannon Fisk, Susan Williams, and Randy Gerhart; For Gallatin Steel - Mike Kurtz; and for PSC - Quang Nguyen.
10:05:44 AM	Public Notice	
	Note: Ernst, Melinda	Proof of Public Notice filed into record on 1/13/14, per Atty. Goss.
10:06:27 AM	Public Comments	
	Note: Ernst, Melinda	No public present to speak.
10:06:56 AM	Witness Anthony Campbell (EKPC) takes the stand and is sworn in.	
	Note: Ernst, Melinda	President and CEO of EKPC.
10:07:32 AM	Atty. Goss (EKPC) direct exam. of Witness Campbell	
	Note: Ernst, Melinda	Witness adopts his testimony with no changes.
10:08:08 AM	Atty. Henry (SC) cross exam. of Witness Campbell	
	Note: Ernst, Melinda	Asking about RFP.
10:10:39 AM	SC - Exhibit 1 - CONFIDENTIAL	
	Note: Ernst, Melinda	Letter from The Brattle Group to David Crews of EKPC, dated Jan. 28, 2013.
10:11:54 AM	Atty. Goss	
	Note: Ernst, Melinda	Comments that SC - Exhibit 1 needs to be confidential.
10:12:31 AM	Vice Chairman Gardner	
	Note: Ernst, Melinda	All Exhibits will be discussed at the end of the Hearing and the determination as to being kept confidential and accepted into the record will be decided then. Also notes that if questions of confidential nature are asked then we'll go into confidential session.
10:13:32 AM	Atty. Henry to Witness Campbell	
	Note: Ernst, Melinda	Continues questioning.
10:14:26 AM	SC - Exhibit 2 - CONFIDENTIAL	
	Note: Ernst, Melinda	Letter from Tony Campbell of EKPC from David Crews of EKPC, dated Jan. 28, 2013.
10:16:52 AM	Atty. Goss Objection	
	Note: Ernst, Melinda	Witness is not qualified to answer the question as to how long Mr. Crews had to review The Brattle Group's recommendation.
10:17:40 AM	Vice Chairman Gardner Overrulled	
10:18:42 AM	Atty. Henry to Witness Campbell	
	Note: Ernst, Melinda	Asking if staff had already chosen to accept The Brattle Group's recommendation prior to recieving it.

10:19:51 AM	Atty. Goss Objection	
	Note: Ernst, Melinda	Question has already been answered.
10:20:09 AM	Atty. Henry to Witness Campbell	
	Note: Ernst, Melinda	Referencing Witness's Testimony, page 4, lines 7-8.
10:21:51 AM	SC - Exhitbit 3	
	Note: Ernst, Melinda	EKPC Response to Intervenors' Supplemental Request for Information, dated 11/4/13, Item 5.
10:24:46 AM	Atty. Henry to Witness Campbell	
	Note: Ernst, Melinda	Questioning about criteria for choosing the bids.
10:29:50 AM	SC - Exhibit 4	
	Note: Ernst, Melinda	EKPC'S All Source Long-Term Request for Proposals 2012 - also labeled as Exhibit JJT-1.
10:32:49 AM	SC - Exhibit 5	
	Note: Ernst, Melinda	Congressional Testimony of Anthony S. Campbell, President & CEO for EKPC, dated Nov. 14, 2013
10:34:19 AM	Atty. Goss Objection	
	Note: Ernst, Melinda	This testimony has nothing to do with this case.
10:35:07 AM	Atty. Henry Response to Objection	
10:35:30 AM	Vice Chairman Gardner Ruling	
	Note: Ernst, Melinda	Allows questioning about the document.
10:36:39 AM	Atty. Henry to Witness Campbell	
	Note: Ernst, Melinda	Referencing Witness's Direct Testimony, page 4, lines 5-7.
10:40:34 AM	Atty. Henry to Witness Campbell	
	Note: Ernst, Melinda	Referencing SC - Exhibit 5 of this Hearing.
10:47:10 AM	Atty. Henry to Witness Campbell	
	Note: Ernst, Melinda	Discussing Green House Gas Rules.
10:47:35 AM	Atty. Henry to Witness Campbell	
	Note: Ernst, Melinda	Discussing a Climate Action Address by President Obama.
10:48:17 AM	SC -Exhibit 6	
	Note: Ernst, Melinda	Memorandum for the Administrator of the Environmental Protection Agency, Regarding Power Sector Carbon Pollution Standards, from The White House, Office of the Secretary, dated June 25, 2013.
10:52:17 AM	Atty. Kurtz (Gallatin Steel) cross exam. of Witness Campbell	
	Note: Ernst, Melinda	Discussing the project details.
10:55:22 AM	Atty. Kurtz to Witness Campbell	
	Note: Ernst, Melinda	Asking about number of employees at Cooper Station, and how many employees lose jobs if Cooper Unit 1 is retired.
10:57:51 AM	Atty. Kurtz to Witness Campbell	
	Note: Ernst, Melinda	Referencing the Application, page 10.
11:00:24 AM	POST HEARING DATA REQUEST by Atty. Kurtz	
	Note: Ernst, Melinda	In additon to the enviromental surchage impact, what will be the total costs to EKPC for doing this project, net of fuel savings, scrubber savings on unit 2, and RPM value.
11:02:10 AM	Atty. Nguyen (PSC) cross exam. of Witness Campbell	
11:03:01 AM	Atty. Nguyen to Witness Campbell	
	Note: Ernst, Melinda	Asking about wind contract that EKPC almost entered into and why seller backed out.
11:03:50 AM	Atty. Goss Interjection	
	Note: Ernst, Melinda	Information that is being requested may be confidential.
11:04:06 AM	POST HEARING DATA REQUEST by Atty. Nguyen	
	Note: Ernst, Melinda	Provide the terms of the initial offer regarding the wind contract.
11:04:23 AM	Atty. Nguyen to Witness Campbell	
	Note: Ernst, Melinda	Referencing Witness's Direct Testimony, page 4, line 8.

11:06:06 AM	POST HEARING DATA REQUEST by Atty. Nguyen	
	Note: Ernst, Melinda	Provide the Unappreciated Value of the Cooper project.
11:06:16 AM	Commissioner Breathitt cross exam. of Witness Campbell	
11:07:40 AM	Chairman Armstrong cross exam. to Witness Campbell	
11:08:11 AM	POST HEARING DATA REQUEST by Chairman Armstrong	
	Note: Ernst, Melinda	Provide the amount of coal that Cooper would run if it were retrofitted.
11:08:58 AM	Commissioner Breathitt to Witness Campbell	
	Note: Ernst, Melinda	Discussing the use of renewables.
11:10:58 AM	Vice Chairman Gardner cross exam. of Witness Cambell	
	Note: Ernst, Melinda	Asking who should recieve questions about the new Smith facility that has been proposed and the IRP.
11:12:40 AM	POST HEARING DATA REQUEST by Vice Chairman Gardner	
	Note: Ernst, Melinda	Provide the Consent Decree.
11:14:55 AM	Vice Chairman Gardner to Witness Campbell	
	Note: Ernst, Melinda	Referencing the Application, page 7, paragraph 19.
11:16:32 AM	Vice Chairman Gardner to Witness Campbell	
	Note: Ernst, Melinda	Asking if Company has decided to retire Dale Station.
11:18:18 AM	POST HEARING DATA REQUEST by Vice Chairman Gardner	
	Note: Ernst, Melinda	Provide the capacity factor for Dale, Cooper 1, and Cooper 2 Stations for 2012-2013.
11:20:34 AM	Vice Chairman Gardner to Witness Campbell	
	Note: Ernst, Melinda	Asking about prime contractor on work done on Cooper 2.
11:22:47 AM	Vice Chairman Gardner to Witness Campbell	
	Note: Ernst, Melinda	Asking about the initial need for capacity and how the purpose seems to have changed during the course of this proceeding.
11:25:59 AM	Atty. Henry re-cross of Witness Campbell	
	Note: Ernst, Melinda	Asking about fixed cost.
11:27:10 AM	Commissioner Breathitt re-cross of Witness Campbell	
	Note: Ernst, Melinda	Referencing the Application, page 7, paragraph 19.
11:30:55 AM	Vice Chairman Gardner re-cross of Witness Campbell	
	Note: Ernst, Melinda	Asking about capacity from PJM to meet extra 8 percent last week and the low reserve in the summer.
11:33:56 AM	Witness Campbell excused.	
11:34:41 AM	Witness Jerry Purvis (EKPC) takes stand and is sworn in.	
	Note: Ernst, Melinda	Director of Enviornmental Affairs for EKPC.
11:35:29 AM	Atty. Goss direct exam. of Witness Purvis	
	Note: Ernst, Melinda	Witness adopts his testimony with no changes.
11:35:49 AM	Atty. Gerhart (SC) cross exam. of Witness Purvis	
	Note: Ernst, Melinda	Asking about environmental rules.
11:37:51 AM	Atty. Gerhart to Witness Purvis	
	Note: Ernst, Melinda	Asking questions about bids with respect to MPVs.
11:39:47 AM	Atty. Gerhart to Witness Purvis	
	Note: Ernst, Melinda	Asking again about environmental rules.
11:40:48 AM	SC - Exhibit 7	
	Note: Ernst, Melinda	EKPC Response to Intervenors' Initial Request for Information, dated 10/4/13, Item 61.
11:42:59 AM	SC - Exhibit 8	
	Note: Ernst, Melinda	Letter from Jerry Purvis of EKPC to Environmental Protection Agency, Regarding Docket ID No. EPA-HQ-RCRA-2009-0640, Harzardous Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utiliities, dated Nov. 19, 2010
11:46:36 AM	Atty. Gerhart to Witness Purvis	
	Note: Ernst, Melinda	Referencing SC - Exhibit 7 of this Hearing.

11:48:51 AM	Vice Chairman Gardner interjects with a clarifying question.	
11:50:02 AM	SC - Exhibit 9	
	Note: Ernst, Melinda	EKPC Response to Intervenors' Initial Request for Information, dated 10/4/13, Item 60.
11:52:11 AM	SC - Exhibit 10	
	Note: Ernst, Melinda	Letter from Jerry Purvis of EKPC to U. S. Environmental Protection Agency, Regarding Docket ID No. EPA-HQ-OW-2008-0667, National Pollutant Discharge Elimination System - Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, dated Aur. 15, 2011
11:56:00 AM	Atty. Gerhart to Witness Purvis	
	Note: Ernst, Melinda	Referencing SC - Exhibit 9 of this Hearing.
11:57:45 AM	Atty. Gerhart to Witness Purvis	
	Note: Ernst, Melinda	Questioning about carbon regulation.
11:57:57 AM	SC - Exhibit 11	
	Note: Ernst, Melinda	EKPC Response to Intervenors' Initial Request for Information, dated 10/4/13, Item 62.
12:03:32 PM	Atty. Gerhart to Witness Purvis	
	Note: Ernst, Melinda	Asking if Witness agrees that most, if not all, coal units may have to retired due to GHG.
12:08:03 PM	Atty. Gerhart to Witness Purvis	
	Note: Ernst, Melinda	Asking about the prospect of the 111(d) rule.
12:08:38 PM	SC - Exhibit 12	
	Note: Ernst, Melinda	EKPC Response to Intervenors' Supplemental Request for Information, dated 11/4/13, Item 31.
12:11:59 PM	Atty. Gerhart to Witness Purvis	
	Note: Ernst, Melinda	Asking what fuel costs of Cooper Station will be in 2020.
12:13:17 PM	Vice Chairman Gardner interjects questoin about who could answer specific questions.	
12:14:36 PM	Atty. Goss Objection	
	Note: Ernst, Melinda	Question is not fair. Not sure if he means generally or asking about a specific project.
12:15:00 PM	Vice Chairman Gardner Ruling	
	Note: Ernst, Melinda	Asks if the Witness can answer the question.
12:15:50 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Asks Atty. Garrett to move on from line of questioning.
12:16:07 PM	Atty. Gerhart to Witness Purvis	
	Note: Ernst, Melinda	Referencing SC - Exhibit 12 of this Hearing.
12:19:24 PM	Atty. Gerhart to Witness Purvis	
	Note: Ernst, Melinda	Asking if EKPC retained outside Engineers and Legal Counsel to esitmate costs but they did not produce the reports.
12:21:02 PM	Atty. Gerhart to Witness Purvis	
	Note: Ernst, Melinda	Asking about RFP and the seven projects on the short list and the composition of the bids and the resources.
12:22:41 PM	Vice Chairman Gardner interjects questions.	
	Note: Ernst, Melinda	Asking questions about regulations and asks Witness to answer the questions being asked by Atty. Gerhart.
12:25:10 PM	Atty. Gerhart to Witness Purvis	
	Note: Ernst, Melinda	Questioning about compliance costs.
12:26:45 PM	Atty. Kurtz cross exam. of Witness Purvis	
12:28:03 PM	Atty. Kurtz to Witness Purvis	
	Note: Ernst, Melinda	Asking about cost to go through a compliance cost analysis.
12:28:34 PM	Vice Chairman Gardner cross exam. of Witness Purvis	
	Note: Ernst, Melinda	Asking if permit has been recieved from Air Quality for the project and an extension under MATS.

12:30:40 PM	Vice Chairman Gardner to Witness Purvis	
	Note: Ernst, Melinda	Asking for some clarification about questions asked by Sierra Club.
	Note: Ernst, Melinda	Referencing SC - Exhibits 7 and 9 of this Hearing.
12:34:20 PM	Vice Chairman Gardner to Witness Purvis	
	Note: Ernst, Melinda	Referencing SC - Exhibit 8 of this Hearing.
12:34:59 PM	POST HEARING DATA REQUEST by Vice Chairman Gardner	
	Note: Ernst, Melinda	From SC - Exhibit 8 of this Hearing, provide any updated costs for Table 1 since the date of the letter.
12:36:00 PM	POST HEARING DATA REQUEST by Vice Chairman Gardner	
	Note: Ernst, Melinda	From SC - Exhibit 10 of this Hearing, provide any changes to numbers on pages 5 and 6 since the date of this letter.
12:36:46 PM	Atty. Goss re-direct of Witness Purvis	
	Note: Ernst, Melinda	Asking follow-up questions to those asked in cross exam. of Witness.
12:40:03 PM	Atty. Goss to Witness Purvis	
	Note: Ernst, Melinda	Referencing Anthony Campbell's Congressional Testimony, SC - Exhibit 5 of this Hearing.
12:47:24 PM	Atty. Goss to Witness Purvis	
	Note: Ernst, Melinda	Asking Witness to provide significance of Exhibit JBP-3 of Witness's Testimony.
12:49:01 PM	Atty. Goss to Witness Purvis	
	Note: Ernst, Melinda	Asking Witness to provide significance of Exhibit JBP-1 of Witness's Testimony.
12:53:48 PM	Atty. Gerhart re-cross of Witness Purvis	
	Note: Ernst, Melinda	Asking if letters (Exhibits JBP-3 and JBP-1 of Witness's Testimony) say whether retro fit projects are least cost.
12:56:58 PM	Witness Purvis dismissed from the stand.	
12:57:03 PM	BREAK	
12:57:19 PM	Camera Lock Camera 1 Activated	
12:57:22 PM	Session Paused	
2:01:04 PM	Session Resumed	
2:01:09 PM	Witness Julia Tucker (EKPC) takes the stand and is sworn in.	
	Note: Ernst, Melinda	Director of Power Supply Planning for EKPC.
2:01:39 PM	Atty. Samford (EKPC) direct exam. of Witness Tucker	
	Note: Ernst, Melinda	Witness adopts her testimony with no changes.
2:02:07 PM	Atty. Williams (SC) cross exam. of Witness Tucker	
2:02:27 PM	SC - Exhibit 13 - CONFIDENTIAL	
	Note: Ernst, Melinda	Titled Intervenors Request 6, page 3 of 3
2:06:14 PM	Atty. Williams to Witness Tucker	
	Note: Ernst, Melinda	Referencing Block Andrew's Testimony, page 13, line 1.
2:09:25 PM	Vice Chairman Gardner interjected a question.	
	Note: Ernst, Melinda	Who prepared the exhibit (SC - Exhibit 13). Witness responded that the sources is from EKPC's Internal Financial Forecast.
2:10:54 PM	Atty. Williams to Witness Tucker	
	Note: Ernst, Melinda	Referencing Witness's Direct Testimony, page 3, lines 6 and 8.
2:12:25 PM	Atty. Williams to Witness Tucker	
	Note: Ernst, Melinda	Referencing Witness's Direct Testimony, page 4, line 5.
2:14:28 PM	Vice Chairman Gardner interjects a question.	
	Note: Ernst, Melinda	Asking about reserve margin in winter.
2:15:09 PM	SC - Exhibit 14	
	Note: Ernst, Melinda	EKPC's Response to Intervenors' Initial Request for Information, dated 10/4/13, Item 24.
2:17:09 PM	SC - Exhibit 15	
	Note: Ernst, Melinda	EKPC's 2012 Load Forecast, prepared by Load Forecasting Department, November 2012

2:19:20 PM	BREAK	
	Note: Ernst, Melinda	Atty. Goss asked for a brief break to decide if SC - Exhibit 15 of this Hearing is confidential.
2:19:24 PM	Session Paused	
2:20:06 PM	Session Resumed	
2:20:12 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Confirmed that SC - Exhibit 15 of this Hearing is not confidential.
2:20:32 PM	Atty. Williams to Witness Tucker	
	Note: Ernst, Melinda	Continues questioning Witness
2:22:14 PM	SC - Exhibit 16	
	Note: Ernst, Melinda	PJM Load Forecast Report, Janurary 2013, prepared by PJM Resource Adequacy Planning Department
2:27:05 PM	SC - Exhibit 17	
	Note: Ernst, Melinda	PJM Load Forecast Report, January 2014, prepared by PJM Resource Adequacy Planning Department
2:30:18 PM	Atty. Williams to Witness Tucker	
	Note: Ernst, Melinda	Referencing Witness's Direct Testimony, page 9, line 1.
2:33:33 PM	Atty. Samford Objection	
	Note: Ernst, Melinda	This question has already been answered.
2:33:37 PM	Vice Chairman Ruling	
	Note: Ernst, Melinda	Asks that Atty. Williams move on.
2:33:51 PM	Atty. Williams to Witness Tucker	
	Note: Ernst, Melinda	Referencing SC - Exhibit 16 of this Hearing, page 48.
2:37:45 PM	Atty. Williams to Witness Tucker	
	Note: Ernst, Melinda	Asking about energy forecast, referencing SC - Exhibits 14 and 15.
2:39:35 PM	Atty. Williams to Witness Tucker	
	Note: Ernst, Melinda	Referencing SC - Exhibit 16 of this Hearing, page 82.
2:42:01 PM	SC - Exhibit 18 - CONFIDENTIAL	
	Note: Ernst, Melinda	Document filed in Response to PSC Request for Information, Item 5, Ratio of Generation to Load tab, prepared by The Brattle Group.
2:43:15 PM	Private Recording Activated	
2:43:22 PM	Atty. Williams to Witness Tucker	
3:07:11 PM	Session Paused	
3:27:11 PM	Session Resumed	
3:46:38 PM	Public Recording Activated	
3:46:42 PM	Resuming Hearing in Public Session.	
3:46:47 PM	SC - Exhibit 22 (Denied as an Exhibit)	
	Note: Ernst, Melinda	Not titled and source unknown. Vice Chairman Gardner denied entry of this Exhibit into the record.
3:48:38 PM	Atty. Samford Objection	
	Note: Ernst, Melinda	Exhibit not marked as to where it's from, who created it, etc.
3:48:49 PM	Vice Chairman Gardner Ruling	
	Note: Ernst, Melinda	Will allow questioning on the Exhibit and will determine at the end if accepted into the record.
3:50:02 PM	POST HEARING DATA REQUEST ADDITION by Vice Chairman Gardner	
	Note: Ernst, Melinda	In addition to the requested information the Vice Chairman asked for from Witness Campbell, provide June 1 through the end of year as a seperate category for each Station. See Post Hearing Data Request at 11:18:18 AM earlier in this day.
3:51:58 PM	Atty. Williams to Witness Tucker	
	Note: Ernst, Melinda	Discussing short list selection process of RFP.
3:56:20 PM	SC - Exhibit 23	
	Note: Ernst, Melinda	EKPC's Response to Intervenors' Initial Request for Information, dated 10/4/13, Item 58.

3:57:35 PM	SC - Exhibit 24	
	Note: Ernst, Melinda	EKPC's Response to Commission Staff's Request for Information, dated 10/4/13, Item 14.
4:00:41 PM	Atty. Kurtz cross exam. of Witness Tucker	
	Note: Ernst, Melinda	Referencing the Application, pages 9-10, paragraph 31.
	Note: Ernst, Melinda	Referencing the Application, page 8, paragraph 25.
4:05:58 PM	Atty. Nguyen cross exam. of Witness Tucker	
	Note: Ernst, Melinda	Referencing SC - Exhibit 14 of this Hearing.
4:10:48 PM	Vice Chairman Gardner cross exam. of Witness Tucker	
4:14:03 PM	Vice Chairman Gardner to Witness Tucker	
	Note: Ernst, Melinda	Asking questions about IRP.
4:16:40 PM	Vice Chairman Gardner to Witness Tucker	
	Note: Ernst, Melinda	Asking about bidding in 80 mW and having a broker to help.
4:19:00 PM	Vice Chairman Gardner to Witness Tucker	
	Note: Ernst, Melinda	Asking about PSC's Staff Report on EKPC's IRP. Anything EKPC will not be able to carry out?
4:20:52 PM	Vice Chairman Gardner to Witness Tucker	
	Note: Ernst, Melinda	Referencing Witness's Direct Testimony, page 9.
4:22:07 PM	Atty. Samford re-direct of Witness Tucker	
	Note: Ernst, Melinda	Asking follow-up questions about questions previously asked, starting with some asked of Witness Campbell.
4:26:15 PM	Atty. Samford to Witness Tucker	
	Note: Ernst, Melinda	Asking about RFP and DSM projects.
4:30:26 PM	Atty. Kurtz re-cross of Witness Tucker	
	Note: Ernst, Melinda	Asking about buying and selling at RPM market prices.
4:31:38 PM	Vice Chairman Gardner re-cross of Witness Tucker	
	Note: Ernst, Melinda	Asking if Dale and Cooper 1 are retired, how many mW would EKPC need in the winter?
4:34:25 PM	Witness Tucker excused from the stand.	
4:34:31 PM	Witness James Read (EKPC) takes the stand and is sworn in.	
	Note: Ernst, Melinda	Principal with The Brattle Group
4:35:30 PM	Atty. Samford direct exam. of Witness Read	
	Note: Ernst, Melinda	Adopts testimony with changes.
	Note: Ernst, Melinda	Corrections to Witness's Direct Testimony, page 2, line 20, "Institute" should be inserted between "Massachusetts" and "of"; Direct Testimony on page 4, line 5, should be May "2012"; Exhibit 1-A of Application, page 12, 4th line from bottom, over "$50M" should read "$46M"; Exhibit 1-A of Application, page 12, the last sentence is incorrect and should be stricken.
4:38:55 PM	Atty. Fisk (SC) cross exam. of Witness Read	
	Note: Ernst, Melinda	Asking about capacity prices.
4:44:25 PM	SC - Exhibit 25 - CONFIDENTIAL	
	Note: Ernst, Melinda	Document filed in Response to PSC Request for Information, Item 5, Capacity Prices Tab
4:45:27 PM	Hearing going into Confidential Session.	
4:45:30 PM	Private Recording Activated	
5:37:11 PM	Public Recording Activated	
5:37:20 PM	Private Recording Activated	
5:38:52 PM	BREAK	
5:38:54 PM	Session Paused	
5:56:18 PM	Session Resumed	
5:56:26 PM	Public Recording Activated	
5:56:27 PM	Hearing Resumed in Public Session	
5:56:29 PM	Atty. Fisk to Witness Read	
	Note: Ernst, Melinda	Referencing Exhibit 1-A of Application, page 10.

6:02:15 PM	Atty. Fisk to Witness Read	
	Note: Ernst, Melinda	Asking about Witness Campbell's testimony about Cooper and Dale units dispatching less.
6:03:10 PM	Vice Chairman Gardner interjects for clarity.	
6:03:59 PM	Atty. Fisk to Witness Read	
	Note: Ernst, Melinda	Referencing Exhibit 1-A of Application, page 10.
6:04:48 PM	Witness Read	
	Note: Ernst, Melinda	Correction to line just read by Atty. Fisk in Exhibit 1-A of Application, page 10. Instead of "been" it shoud read "seen".
6:09:17 PM	Atty. Fisk to Witness Read	
	Note: Ernst, Melinda	Asking about energy price forecast.
6:11:33 PM	Atty. Fisk to Witness Read	
	Note: Ernst, Melinda	Referencing Witness's Rebuttal Testimony, page 7, starting at line 9.
6:20:35 PM	Atty. Nguyen cross exam. of Witness Read	
	Note: Ernst, Melinda	Asking about capacity factor for Cooper being 90 percent, per response to Vice Chairman Gardner.
6:21:58 PM	Vice Chairman Gardner interjects a clarifying question.	
6:22:39 PM	Atty. Nguyen to Witness Read	
	Note: Ernst, Melinda	Referencing Witness's Rebuttal Testimony, page 14, line 10.
6:25:19 PM	Atty. Kurtz cross exam. of Witness Read	
	Note: Ernst, Melinda	Asking about calculation of annual capacity revenue.
6:26:53 PM	Vice Chairman Gardner cross exam. of Witness Read	
	Note: Ernst, Melinda	Asking about process - retaining Witness, RFP going out, etc.
6:29:38 PM	Vice Chairman Gardner to Witness Read	
	Note: Ernst, Melinda	Asking about how many RFPs Witness has been involved in for other utilities.
6:36:48 PM	Vice Chairman Gardner to Witness Read	
	Note: Ernst, Melinda	Referencing Witness's Rebuttal Testimony, page 3.
6:43:35 PM	Atty. Samford re-direct of Witness Read	
	Note: Ernst, Melinda	Asking follow-up questions asked by other Parties and PSC.
6:47:50 PM	Atty. Samford to Witness Read	
	Note: Ernst, Melinda	Any reason to reconsider recommendation to EKPC.
6:48:13 PM	Atty. Fisk re-cross of Witness Read	
6:50:14 PM	Atty. Samford	
	Note: Ernst, Melinda	Providing location to an answer for Vice Chairman Gardner regarding disclosure in RFP about EKPC planning to do a self-build bid. JJT-1, RFP document, page 3, third line from the bottom.
6:50:53 PM	Witness Read dismissed from the stand.	
6:51:06 PM	Witness Block Andrews (EKPC) takes the stand and is sworn in.	
	Note: Ernst, Melinda	Strategic Environmental Solutions Director for Burns and McDonnell
6:51:43 PM	Atty. Goss direct exam. of Witness Andrews	
	Note: Ernst, Melinda	Adopts testimony his testimony with no changes.
6:52:24 PM	Atty. Kurtz cross exam. to Witness Andrews	
6:53:22 PM	Vice Chairman Gardner cross exam. of Witness Andrews	
	Note: Ernst, Melinda	Asking about his work with EKPC and when he was retained for this project.
6:56:48 PM	Vice Chairman Gardner to Witness Read	
	Note: Ernst, Melinda	Asking about concept coming from Craig Johnson.
6:57:29 PM	Vice Chairman Gardner to Witness Read	
	Note: Ernst, Melinda	Asking if there were other self-build options considered.
6:57:39 PM	Atty. Samford interjection.	
	Note: Ernst, Melinda	Clarifying that Vice Chairman is asking about other self-build options and that some of this information is confidential.

6:59:22 PM	Vice Chairman Gardner to Witness Read	
	Note: Ernst, Melinda	Referencing Witness's Direct Testimony, page 6, beginning on line 15.
7:07:24 PM	Vice Chairman Gardner to Witness Read	
	Note: Ernst, Melinda	Referencing Witness's Testimony, Exhibit BA-1.
7:09:26 PM	Vice Chairman Gardner to Witness Read	
	Note: Ernst, Melinda	FNTP stands for Final Notice to Proceed.
7:10:18 PM	Vice Chairman Gardner to Witness Read	
	Note: Ernst, Melinda	Will this proposal comply with MATS?
7:11:26 PM	Vice Chairman Gardner to Witness Read	
	Note: Ernst, Melinda	If US Supreme Court decides that CASPER is valid, does that impact this project?
7:13:50 PM	Atty. Kurtz re-cross of Witness Andrews	
	Note: Ernst, Melinda	Referencing page 40 of 43 of Exhibit 1 of Witness's Testimony.
7:15:27 PM	Witness Andrews is dismissed from the stand.	
7:15:49 PM	Hearing adjourned for the day.	
7:15:58 PM	Session Paused	
7:16:05 PM	Session Resumed	
7:16:14 PM	Atty. Goss	
	Note: Ernst, Melinda	Asking if various Witness's can be excused.
7:16:48 PM	Hearing again adjourned for the day.	
7:16:52 PM	Session Paused	
9:06:01 AM	Session Ended	

Name:	Description:
SC - Exhibit 01 - CONFIDENTIAL	Letter from The Brattle Group to David Crews of EKPC, dated Jan. 28, 2013.
SC - Exhibit 02 - CONFIDENTIAL	Letter from Tony Campbell of EKPC from David Crews of EKPC, dated Jan. 28, 2013.
SC - Exhibit 03	EKPC Response to Intervenors' Supplemental Request for Information, dated 11/4/13, Item 5.
SC - Exhibit 04	EKPC'S All Source Long-Term Request for Proposals 2012 - also labeled as Exhibit JJT-1.
SC - Exhibit 05	Congressional Testimony of Anthony S. Campbell, President & CEO for EKPC, dated Nov. 14, 2013
SC - Exhibit 06	Memorandum for the Administrator of the Environmental Protection Agency, Regarding Power Sector Carbon Pollution Standards, from The White House, Office of the Secretary, dated June 25, 2013.
SC - Exhibit 07	EKPC Response to Intervenors' Initial Request for Information, dated 10/4/13, Item 61.
SC - Exhibit 08	Letter from Jerry Purvis of EKPC to Environmental Protection Agency, Regarding Docket ID No. EPA-HQ-RCRA-2009-0640, Harzardous Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric
SC - Exhibit 09	EKPC Response to Intervenors' Initial Request for Information, dated 10/4/13, Item 60.
SC - Exhibit 10	Letter from Jerry Purvis of EKPC to U. S. Environmental Protection Agency, Regarding Docket ID No. EPA-HQ-OW-2008-0667, National Pollutant Discharge Elimination System - Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, d
SC - Exhibit 11	EKPC Response to Intervenors' Initial Request for Information, dated 10/4/13, Item 62.
SC - Exhibit 12	EKPC Response to Intervenors' Supplemental Request for Information, dated 11/4/13, Item 31.
SC - Exhibit 13 - CONFIDENTIAL	Titled Intervenors Request 6, Page 3 of 3
SC - Exhibit 14	EKPC's Response to Intervenors' Initial Request for Information, dated 10/4/13, Item 24.
SC - Exhibit 15	EKPC's 2012 Load Forecast, prepared by Load Forecasting Department, November 2012
SC - Exhibit 16	PJM Load Forecast Report, Janurary 2013, prepared by PJM Resource Adequacy Planning Department
SC - Exhibit 17	PJM Load Forecast Report, January 2014, prepared by PJM Resource Adequacy Planning Department
SC - Exhibit 18 - CONFIDENTIAL	Document filed in Response to PSC Request for Information, Item 5, Ratio of Generation to Load tab, prepared by The Brattle Group.
SC - Exhibit 19 - CONFIDENTIAL	Document filed in Response to PSC Request for Information, Item 5, Energy Data Tab
SC - Exhibit 20 - CONFIDENTIAL	Document filed in Response to PSC Request for Information, Item 5, Energy Prices tab
SC - Exhibit 21 - CONFIDENTIAL	EKPC's 2012 Request for Proposals, Summary of Results, Feb. 11, 2013
SC - Exhibit 22 (Denied as an Exhibit)	Not titled and source unknown. Vice Chairman Gardner denied entry of this Exhibit into the record.
SC - Exhibit 23	EKPC's Response to Intervenors' Initial Request for Information, dated 10/4/13, Item 58.

SC - Exhibit 24	EKPC's Response to Commission Staff's Request for Information, dated 10/4/13, Item 14.
SC - Exhibit 25 - CONFIDENTIAL	Document filed in Response to PSC Request for Information, Item 5, Capacity Prices Tab
SC - Exhibit 26 - CONFIDENTIAL	EKPC's Response to Commission Staff's Second Request for Information, dated 10/30/13, Item 1.
SC - Exhibit 27	EKPC's Response to Intervenors' Initial Request for Information, dated 10/4/13, Item 16.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	) CASE NO. 2013-00259

CERTIFICATE

I, Sonya Harward, hereby certify that:

1. The attached DVD contains a digital recording of the hearing conducted in the above-styled proceeding on January 15, 2014; (excluding any confidential segments, which were recorded on a separate DVD and will be maintained in the non-public records of the Commission, along with the Confidential Exhibits and Hearing Log). The hearing was recorded on two consecutive days, January 14, 2014 and January 15, 2014, separately. (Confidential portions were also recorded separately).

2. I am responsible for the preparation of the digital recording;

3. The digital recording accurately and correctly depicts the hearing of January 15, 2014 (excluding any confidential segments);

4. The "Exhibit List" attached to this Certificate correctly lists all exhibits introduced at the hearing of January 15, 2014 (excluding any confidential exhibits).

5. The "Hearing Log" attached to this Certificate accurately and correctly states the events that occurred at the hearing of January 15, 2014 (excluding any confidential segments) and the time at which each occurred.

Given this 16th day of January, 2014.

Sonya Harward (Boyd)

Sonya Harward (Boyd), Notary Public
State at Large
My commission expires: August 27, 2017

Session Report - Detail

2013-00259_15Jan2014

Easr Kentucky Power Cooperative, Inc.

Date:	Type:	Location:	Department:
1/15/2014	Other	Public Service Commission	Hearing Room 1 (HR 1)

Judge: David Armstrong; Linda Breathitt; Jim Gardner
Witness: Tyler Comings - Sierra Club; David Crews - EKPC; Scott Drake - EKPC; Jeffrey Loiter - Sierra Club; Isaac Scott - EKPC
Clerk: Sonya Harward

Event Time	Log Event	
9:08:40 AM	Session Started	
9:08:41 AM	Session Paused	
9:37:14 AM	Session Resumed	
9:37:18 AM	Vice Chairman resumes Hearing.	
9:37:24 AM	Witness Isaac Scott (EKPC) takes the stand and is sworn in.	
	Note: Harward, Sonya	Manager of Pricing at EKPC
9:37:54 AM	Atty. Samford (EKPC) direct exam. of Witness Scott	
	Note: Harward, Sonya	Witness adopts his testimony with no changes.
9:38:25 AM	Atty. Fisk (SC) cross exam. of Witness Scott	
9:39:28 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 5.
9:43:11 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 6, starting on line 18.
9:48:17 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Continuing to ask about the five choices that Mr. Loiter made.
9:48:38 AM	Vice Chairman Gardner interjects clarifying question.	
9:50:43 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Resumes questioning Witness.
9:51:24 AM	SC - Exhibit 28	
	Note: Harward, Sonya	Excerpt from "Loads and Resources Final Supplemental.xlsx", produced by Loiter Supplemental Testimony, revising response to EKPC Request No. 49
9:55:28 AM	Commissioner Breathitt interjects with clarifying questions.	
9:57:14 AM	Vice Chairman Gardner interjects with a clarifying question.	
9:57:49 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Resumes questioning Witness.
9:59:32 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 7, line 12.
10:02:43 AM	Commissioner Breathitt interjects and asks Witness to repeat his answer.	
10:03:30 AM	Vice Chairman Gardner interjects with clarifying question.	
10:03:54 AM	Commissioner Breathitt asks a clarifying question.	
10:05:20 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Resumes questioning Witness.
10:07:36 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Continuing to question about demand response.
10:09:32 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Back to asking about combining versus averaging the five DSM programs.
10:15:22 AM	Vice Chairman Gardner	
	Note: Harward, Sonya	Ask that Atty. Fisk move on, question has been answered.

10:15:31 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 7.
10:18:37 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 9, line 5.
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 8, line 8.
10:24:30 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 16, line 18.
10:25:38 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Referencing Loiter Supplemental Testimony, page 5, starting at line 30.
10:28:34 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 2, at bottom of page.
10:32:02 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Discussing various ways to get people to participate in efficiency programs.
10:33:46 AM	Vice Chairman Gardner	
	Note: Harward, Sonya	Asks that Atty. Fisk move on, point has been made.
10:34:07 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 4, starting around line 18.
10:35:29 AM	SC - Exhibit 29	
	Note: Harward, Sonya	2012 Report on the Implementation of P.A. 295 Utility Energy Optimization Programs, from Michigan Public Service Commission, Department of Licensing and Regulatory Affairs, dated November 30, 2012
10:36:42 AM	Atty. Samford	
	Note: Harward, Sonya	Asking if this exhibit is anywhere in the record.
10:38:39 AM	Vice Chairman Gardner	
	Note: Harward, Sonya	To Atty. Fisk, getting a bit far fetched from issues in front of us.
10:39:31 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Continues questioning Witness. Referencing SC - Exhibit 29 of this Hearing, page 6, figures 1 and 2.
10:42:32 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Referencing SC - Exhibit 29 of this Hearing, page 8, first paragraph, 3rd sentence.
10:43:49 AM	SC - Exhibit 30	
	Note: Harward, Sonya	From CN 2012-00149, EKPC's Response to Movants' Supplemental Request for Information, dated 8/3/12, Item 1.
10:44:26 AM	Atty. Samford	
	Note: Harward, Sonya	Points out that this is not the Witness to whom this DR was directed.
10:46:15 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Questioning about EKPC's IRP.
10:50:46 AM	Vice Chairman Gardner	
	Note: Harward, Sonya	Asks Atty. Fisk to move on with line of questioning.
10:53:22 AM	Atty. Kurtz (Gallatin Steel) cross exam. of Witness Scott	
10:53:57 AM	Atty. Kurtz to Witness Scott	
	Note: Harward, Sonya	Referencing the Application, page 8.
	Note: Harward, Sonya	Referencing the Application, pages 9 to 10.
10:55:48 AM	Atty. Kurtz to Witness Scott	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, Exhibit 1, page 2, Project 11.
10:58:50 AM	Atty. Kurtz to Witness Scott	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, Exhibit 4.

11:00:28 AM	Atty. Kurtz to Witness Scott	
	Note: Harward, Sonya	Referencing Andrew's Testimony, page 40 of 43.
11:03:40 AM	Vice Chairman Gardner interjects a clarifying question.	
11:04:47 AM	Atty. Kurtz to Witness Scott	
	Note: Harward, Sonya	Referencing Andrew's Testimony, page 28 of 43.
	Note: Harward, Sonya	Referencing Andrew's Testimony, page 19 of 43.
11:07:20 AM	Atty. Kurtz to Witness Scott	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, Exhibit 4.
11:08:34 AM	Vice Chairman Gardner interjects a clarifying question.	
11:10:21 AM	Atty. Kurtz to Witness Scott	
	Note: Harward, Sonya	Continues questioning Witness about his Exhibit 4.
11:12:05 AM	Witness Scott	
	Note: Harward, Sonya	May have an error in his calculation.
11:12:33 AM	POST HEARING DATA REQUEST by Atty. Kurtz	
	Note: Harward, Sonya	Provide corrected schedules for some items in Witness's Direct Testimony, Exhibit 4.
11:16:45 AM	Vice Chairman Gardner	
	Note: Harward, Sonya	Interrupts to make sure that the information about to be discussed is not confidential.
11:17:50 AM	Vice Chariman Gardner	
	Note: Harward, Sonya	Asking if Witness would have knowledge of this area of questioning.
11:18:13 AM	Atty. Nguyen (PSC) cross exam. of Witness Scott	
11:18:56 AM	Commissioner Breathitt cross exam. of Witness Scott	
	Note: Harward, Sonya	Asking about the fixed cost in Witness's Exhibit.
11:23:57 AM	Vice Chairman Gardner cross exam. of Witness Scott	
	Note: Harward, Sonya	Asking about his position as Pricing Manager.
11:28:27 AM	Vice Chairman Gardner to Witness Scott	
	Note: Harward, Sonya	Asking about qualifications and knowledge of standards in the industry.
11:29:48 AM	Atty. Samford re-direct of Witness Scott	
	Note: Harward, Sonya	Asking follow-up questions of those asked by Atty. Fisk about Loiter Testimony.
11:41:19 AM	Atty. Samford to Witness Scott	
	Note: Harward, Sonya	Referencing Loiter Testimony, page 10. line 17.
11:43:29 AM	Atty. Samford to Witness Scott	
	Note: Harward, Sonya	Referencing SC - Exhibit 29 of this Hearing.
11:50:09 AM	Atty. Samford to Witness Scott	
	Note: Harward, Sonya	Asking about incentives increasing participation in efficency programs.
11:52:45 AM	Vice Chairman Gardner	
	Note: Harward, Sonya	Asking about nature of re-cross of Atty. Fisk to Witness Scott.
11:53:37 AM	Atty. Fisk	
	Note: Harward, Sonya	Response about questions for Witness Scott.
11:54:19 AM	Atty. Fisk re-cross of Witness Scott	
	Note: Harward, Sonya	Asking about five programs used by Mr. Loiter.
11:56:17 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Discussing replacing load if Cooper 1 is retired.
11:59:36 AM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Referencing SC - Exhibit 29 of this Hearing, page 16.
12:03:05 PM	Atty. Fisk to Witness Scott	
	Note: Harward, Sonya	Asking about capacity payments from PJM, as asked by Atty. Kurtz in cross.
12:07:36 PM	Witness Scott dismissed from the stand.	
12:07:57 PM	Vice Chairman Gardner asking about order of upcoming witnesses for EKPC	

12:09:25 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	The following EKPC Witness's are dismissed due to no one having questions for them: Mary Jane Warner, Dana Cox, and Darrin Adams.
12:09:36 PM	BREAK	
12:09:46 PM	Session Paused	
1:16:35 PM	Session Resumed	
1:16:47 PM	Witness David Crews (EKPC) takes the stand and is sworn in.	
	Note: Harward, Sonya	Senior VP of Power Supply for EKPC
1:17:15 PM	Atty. Goss direct exam. of Witness Crews	
	Note: Harward, Sonya	Witness adopted his testimony with no corrections.
1:17:45 PM	Atty. Henry (SC) cross exam. of Witness Crews	
	Note: Harward, Sonya	Referencing SC - Exhibit 1 of this Hearing.
1:18:22 PM	Camera Lock Deactivated	
1:18:42 PM	Atty. Henry to Witness Crews	
	Note: Harward, Sonya	Referencing SC - Exhibit 2 of this Hearing.
1:20:24 PM	Private Recording Activated	
2:02:59 PM	Public Recording Activated	
2:03:01 PM	Hearing Resumed in Public Session	
2:03:29 PM	Atty. Henry continues with cross exam. of Witness Crews in Public Session.	
2:03:36 PM	SC - Exhibit 31	
	Note: Harward, Sonya	EKPC's Response to Intervenors' Initial Request for Information, dated 10/4/13, Item 12.
2:07:15 PM	Atty. Henry to Witness Crews	
	Note: Harward, Sonya	Asking about why certain information was not provided when asked for it in SC - Exhibit 31 of this Hearing, Item 12.c.
2:08:10 PM	Vice Chairman Gardner to Witness Crews	
	Note: Harward, Sonya	Asking about his responsibilities in his job.
2:12:30 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	He will no longer have questions for Craig Johnson since they have been answered.
2:13:34 PM	Vice Chairman Gardner to Witness Crews	
	Note: Harward, Sonya	Asking about Collaberative Report dated October 2012 and if another has been completed yet.
	Note: Harward, Sonya	Per Witness Crews, one is being worked on and Vice Chairman Gardner says the filing of the 2013 Collabertive Report will be fine.
2:16:52 PM	Atty. Henry re-cross of Witness Crews	
	Note: Harward, Sonya	Asking about Collaberative and focus group within.
2:18:56 PM	POST HEARING DATA REQUEST by Atty. Henry	
	Note: Harward, Sonya	Provide the amount of savings for energy efficiency programs in 2012 and 2013.
2:19:09 PM	Atty. Goss Objection	
	Note: Harward, Sonya	Asking about the relevance of the request to this Hearing.
2:19:11 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	A decision as to relevance of the Post Hearing Request will be decided.
2:20:04 PM	BREAK	
2:20:12 PM	Session Paused	
2:28:28 PM	Session Resumed	
2:28:32 PM	Witness Scott Drake (EKPC) takes the stand and is sworn in.	
	Note: Harward, Sonya	Manager of Corporate Technical Services at EKPC
2:29:00 PM	Atty. Goss direct exam. of Witness Drake	
	Note: Harward, Sonya	Witness adopted his testimony with no corrections.
2:29:28 PM	Atty. Fisk cross exam. of Witness Drake	

2:31:03 PM	SC - Exhibit 32	
	Note: Harward, Sonya	Stimulating Energy Efficiency in Kentucky, Kentucky's Action Plan for Energy Efficiency, prepared by The Kentucky Department for Energy Development and Independence, the Midwest Energy Efficiency Alliance, dated May 15, 2013
2:35:07 PM	Vice Chairman Gardner cross exam. of Witness Drake	
2:40:46 PM	Witness Drake dismissed from stand.	
2:41:08 PM	Witness Tyler Comings (SC) takes the stand and is sworn in.	
	Note: Harward, Sonya	Associate with Synapse Energy Economics, Inc.
2:41:50 PM	Atty. Gerhart (SC) direct exam. of Witness Comings	
	Note: Harward, Sonya	Witness adopts testimony with change to Supplemental Testimony, page 8, and provided an exhibit, SC - Exhibit 33.
2:42:44 PM	SC - Exhibit 33 - CONFIDENTIAL	
	Note: Harward, Sonya	Change provided in the Supplemental Testimony of Tyler Comings, page 8.
2:44:00 PM	Camera Lock Deactivated	
2:44:05 PM	Atty. Goss cross exam. of Witness Comings	
	Note: Harward, Sonya	Asking about Witness's work at Synapse.
2:47:54 PM	Atty. Goss to Witness Comings	
	Note: Harward, Sonya	Referencing Witness's Testimony, Exhibit TFC-1.
2:50:42 PM	Atty. Goss to Witness Comings	
	Note: Harward, Sonya	Asking about the Witness creating his Energy Price Forecast.
2:55:40 PM	Atty. Goss to Witness Comings	
	Note: Harward, Sonya	Continuing to ask about Witness's assocation with others involved in this case.
2:56:14 PM	EKPC - Exhibit 1	
	Note: Harward, Sonya	SC's Response to EKPC Requests, Item 20, Respondent :Tyler Comings
3:00:10 PM	Atty. Goss to Witness Comings	
	Note: Harward, Sonya	Asking how Mr. Fisher, Witness's co-worker at Synapse, assisted the Witness in the preparation of his Testimony.
3:04:38 PM	EKPC - Exhibit 2	
	Note: Harward, Sonya	SC's Response to EKPC Requests, Item 21, Respondent :Tyler Comings
3:07:21 PM	Atty. Goss to Witness Comings	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 13, line 3, regarding ACES.
3:13:09 PM	Atty. Goss to Witness Comings	
	Note: Harward, Sonya	Asking about the Witness's Adjusted Energy Price Forecast.
3:15:50 PM	Atty. Goss to Witness Comings	
	Note: Harward, Sonya	Asking about a previous forecast Witness created in a Duke Energy Indiana case.
3:17:32 PM	Atty. Gerhart Objection	
	Note: Harward, Sonya	Asks that Atty. Goss allow Witness to complete his answers.
3:18:03 PM	Atty. Goss to Witness Comings	
	Note: Harward, Sonya	Referencing Witness's Testimony, Exhibit TFC-1.
3:20:06 PM	Atty. Goss to Witness Comings	
	Note: Harward, Sonya	Asking how to create an Energy Price Forecast and how the Witness created his.
3:25:45 PM	Atty. Goss to Witness Comings	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 15, figure 3.
3:37:18 PM	EKPC - Exhibit 3	
	Note: Harward, Sonya	SC's Response to EKPC Requests, Item 29, Respondent :Tyler Comings

3:42:03 PM	EKPC - Exhibit 4	
	Note: Harward, Sonya	SC's Response to EKPC Requests, Item 37 Respondent : Kristen Henry and Tyler Comings
3:44:58 PM	Atty. Goss to Witness Comings	
	Note: Harward, Sonya	Referencing Witness's Supplemental Testimony, pages 6 and 7.
3:52:26 PM	Atty. Kurtz cross exam. of Witness Comings	
	Note: Harward, Sonya	Asking about capacity values.
3:57:28 PM	Atty. Kurtz to Witness Comings	
	Note: Harward, Sonya	Discussing market prices.
4:01:21 PM	Atty. Kurtz to Witness Comings	
	Note: Harward, Sonya	Asking how Commission should choose which energy price forecast it should use in making its decision.
4:02:21 PM	Hearing going into Confidential Session	
4:02:29 PM	Private Recording Activated	
4:03:55 PM	Public Recording Activated	
4:03:56 PM	Resuming Hearing in Confidential Session	
4:04:12 PM	Atty. Kurtz to Witness Comings	
	Note: Harward, Sonya	Asking if the Utility should get more consideration for its energy price forecast than the Witness's by the Commission.
4:08:07 PM	Commissioner Breathitt cross exam.of Witness Comings	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 4, line 18-20, regarding the difference between providing and selling.
4:10:15 PM	Atty. Gerhart re-direct of Witness Comings	
	Note: Harward, Sonya	Asking follow-up questions discussed in cross exam.
4:15:28 PM	Hearing going into Confidential Session.	
4:15:31 PM	Private Recording Activated	
4:17:08 PM	Public Recording Activated	
4:17:10 PM	Hearing Resumed in Public Session	
4:17:14 PM	Atty. Gerhart to Witness Comings	
	Note: Harward, Sonya	Asking follow-up questions about the range of environmental costs.
4:18:45 PM	Vice Chairman Gardner asks to have question repeated.	
4:20:09 PM	Atty. Goss re-cross to Witness Comings	
	Note: Harward, Sonya	Asking about ACES forecast and Wood MacKenzie forecast and the methodology behind these not being provided in EKPC's case.
4:22:34 PM	POST HEARING DATA REQUEST by Atty. Goss	
	Note: Harward, Sonya	Provide each and every case where Wood MacKenzie provided Synapse Energy Economics with methodolgy and proprietary information regarding energy pricing forecasts.
4:23:37 PM	Witness Comings dismissed from the stand.	
4:23:39 PM	BREAK	
4:23:52 PM	Session Paused	
4:42:01 PM	Session Resumed	
4:42:06 PM	Witness Jeffrey Loiter (SC) takes the stand and is sworn in.	
	Note: Harward, Sonya	Managing Consultant at Optical Energy, Inc.
4:42:43 PM	Atty. Williams (SC) direct exam. of Witness Loiter	
	Note: Harward, Sonya	Witness adopts testimony with changes. Change in Witness's Direct Testimony, page 15, line 8, has a change that was made in Witness's Supplemental Testimony, page 4, line 16.
	Note: Harward, Sonya	Change to Witness's Supplemental Testimony, page 4, line 15, should be 4 new and 1 existing.
4:44:56 PM	Atty. Samford cross exam. of Witness Loiter	
	Note: Harward, Sonya	Asking about professional experience.
4:50:40 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Asking about Beyond Coal Campaign of Sierra Club.

4:53:28 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Asking if Witness has worked for any cooperatives in Kentucky.
4:54:44 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 4, line 31.
5:00:12 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 5, lines 3-5.
5:01:14 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Asking what the factors are that Witness relied on in the response being referenced in the Witness's Direct Testimony, page 5, lines 3-5.
5:07:01 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Asking about $0.27 rate increase.
5:13:43 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Asking if Witness knows how much coal would be used in a 116 mW facility and employment impacts if jobs are eliminated.
5:15:32 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, pages 15 and 16, regarding why listed items were not quantified.
5:24:23 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Asking for reason why Witness picked the five programs he used in his Testimony.
5:27:26 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Asking about the residential program that the Witness used in his analysis.
5:31:22 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 10-11.
5:32:27 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Asking if Witness used any Census information about Kentucky income levels.
5:35:05 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Asking if Witness believes education is an important part of an efficiency program and if he's seen any studies with correlation between education and participation.
5:38:10 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 15, regarding change from 24 to 44 mWh.
5:39:49 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Referencing ACEEE Study attached to Witness's Direct Testimony, Executive Summary, regarding two documents mentioned but not provided.
5:41:39 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Referencing ACEEE Study attached to Witness's Direct Testimony, page 2, footnote 3.
5:43:49 PM	Atty. Samford to Witness Loiter	
	Note: Harward, Sonya	Referencing ACEEE Study attached to Witness's Direct Testimony, page 1, footnote 1.
5:46:06 PM	Atty. Williams re-direct of Witness Loiter	
	Note: Harward, Sonya	Referencing Exhibit 28, Witness's Workbook.
5:49:23 PM	Atty. Williams to Witness Loiter	
	Note: Harward, Sonya	Asking Witness to describe the differences between the Average Levelized Cost and Combined Levelized Cost.
5:50:32 PM	Atty. Williams to Witness Loiter	
	Note: Harward, Sonya	Asking if Witness could have picked five other programs instead of the those he chose.

5:55:49 PM	Atty. Williams to Witness Loiter	
	Note: Harward, Sonya	Asking if Witness's analysis is based on any energy price forecast.
5:59:56 PM	Witness Loiter is dismissed from the stand.	
6:00:09 PM	Vice Chairman Gardner - Exhibits	
	Note: Harward, Sonya	Exhibits accepted or denied into the Record.
6:08:01 PM	Deadlines	
	Note: Harward, Sonya	Briefs due 2/3/14, no page limit.
	Note: Harward, Sonya	Post Hearing Requests due 1/24/14.
6:09:12 PM	Atty. Samford to Vice Chairman Gardner	
	Note: Harward, Sonya	In response to SC - Exhibits 8 and 10 of this Hearing, Vice Chairman Gardner requested more recent analyses and this information is priviledged. Discussion between parties. Vice Chairman asked that EKPC repeat what he has requested and any places in the record where some of the information may be found, not in a brief, just a short paragraph, and then flag it and a decision will be made as to whether it can be kept priviledged or needs to be provided.
6:12:54 PM	Vice Chairman Closing Statements	
6:13:06 PM	Hearing Adjourned	
6:13:11 PM	Session Paused	
6:21:49 PM	Session Ended	

Exhibit List Report

2013-00259_15Jan2014

Easr Kentucky Power Cooperative, Inc.

Name:	Description:
EKPC - Exhibit 01	SC's Response to EKPC Requests, Item 20, Respondent :Tyler Comings
EKPC - Exhibit 02	SC's Response to EKPC Requests, Item 21, Respondent :Tyler Comings
EKPC - Exhibit 03	SC's Response to EKPC Requests, Item 29, Respondent :Tyler Comings
EKPC - Exhibit 04	SC's Response to EKPC Requests, Item 37 Respondent : Kristen Henry and Tyler Comings
SC - Exhibit 28	Excerpt from "Loads and Resources Final Supplemental.xlsx", produced by Loiter Supplemental Testimony, revising response to EKPC Request No. 49
SC - Exhibit 29	2012 Report on the Implementation of P.A. 295 Utility Energy Optimization Programs, from Michigan Public Service Commission, Department of Licensing and Regulatory Affairs, dated November 30, 2012
SC - Exhibit 30	From CN 2012-00149, EKPC's Response to Movants' Supplemental Request for Information, dated 8/3/12, Item 1.
SC - Exhibit 31	EKPC's Response to Intervenors' Initial Request for Information, dated 10/4/13, Item 12.
SC - Exhibit 32	Stimulating Energy Efficiency in Kentucky, Kentucky's Action Plan for Energy Efficiency, prepared by The Kentucky Department for Energy Development and Independence, the Midwest Energy Efficiency Alliance, dated May 15, 2013
SC - Exhibit 33 - CONFIDENTIAL	Change provided in the Supplemental Testimony of Tyler Comings, page 8.

Request No. 20: Refer to page 12 of the Comings Direct Testimony. In discussing the energy price forecasts used in EKPC's analysis, Mr. Comings states that the approach used for a specific two- year period appears "unreasonable and arbitrary".

a. Please provide the basis for Mr. Comings' contention the approach is "unreasonable and arbitrary". Include any analysis, studies, or other evaluations performed by Mr. Comings that support his contention.
b. Is this conclusion based solely on Mr. Comings' professional experience and opinion? Please explain the response.
c. Please provide all energy price forecasts that are publicly available and are from recognized sources that he is personally familiar with and accepts as reasonable.

Response No. 20:

a. See Mr. Comings' direct testimony pages 12 through 16.
b. No. Mr. Comings also consulted others who were subject to the confidentiality agreement with the Company.
c. Almost all utility energy price forecasts reviewed by Mr. Comings in the past have been confidential, with binding confidentiality agreements; the only exception is the Energy Information Administration's Annual Energy Outlook, which can be found here http://www.eia.gov/oiaf/aeo/tablebrowser/. It is notable that the EIA AEO Early Release 2014 projects (for the SERC Central region where EKPC is located) that end-use energy prices for all consumer classes (residential, commercial, industrial and transportation) and costs of generation alone are expected to fall or stay flat in real terms from 2012 through 2040-in contrast to the Company's expectations.

KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 21
Respondent: Tyler Coming

Request No. 21: Refer to page 13 of the Comings Direct Testimony. In response to the question "Where does the Company obtain its energy market price forecasts?" Mr. Comings responds "The energy price forecast is produced by ACES Power Marketing ('ACES'), an 'energy marketing agent' owned by EKPC and other cooperatives. EKPC President and CEO, Mr. Anthony Campbell, serves as a board member of ACES." Mr. Comings further points out that an independent auditor "expressed some concern ... that ACES may not be sufficiently independent."

a. How does Mr. Comings think the independence of ACES Power Marketing, or lack thereof, affects the energy price forecasts it provides to EKPC? What is the basis for your opinion?
b. How does Mr. Comings think the independence of ACES Power Marketing, or lack thereof, affects the energy price forecasts Wood Mackenzie provides to ACES Power Marketing? What is the basis for your opinion?

Response No. 21:

a. An independent energy price forecast, which many utilities choose to procure, could provide more credibility since it could not be seen as generating a conflict of interest.
b. Mr. Comings cannot speculate on how the independence of ACES affects the energy price forecasts.

EKPC - EXHIBIT 2

Request No. 29: Refer to pages 23 through 25 of the Comings Direct Testimony, where Mr. Comings discusses the capacity price projections. In this discussion, Mr. Comings states that he substituted the projected capacity price for the 2016/2017 delivery year with the May 24, 2013 results from the PJM capacity auction for 2016/2017. However, for the remaining years of the analysis, Mr. Comings did not adjust or alter the capacity price projections.

a. Please explain in detail why it is reasonable to adjust only the 2016/2017 projected capacity price to the actual results of the PJM capacity auction for that time period.
b. If the results of the PJM capacity auction for 2016/2017 had been higher than the projected capacity price, would Mr. Comings have adjusted the projected capacity price for that year? Please explain the response.
c. Given how the results of the 2016/2017 PJM capacity auction were different than the projected capacity price for that period, please explain in detail why Mr. Comings was willing to keep the capacity prices the same as the EKPC forecast for delivery years after 2016/2017. Include any analysis, studies, or other evaluations performed by Mr. Comings that support this approach.

Response No. 29:

a. Mr. Comings updated the capacity prices to incorporate the latest data available. He does not offer an alternative capacity price forecast past the 2016/2017 delivery year.
b. Yes. The most up-to-date capacity price would have been included regardless of whether it had been higher or lower than the Company's estimate.
c. Mr. Comings does not have a sufficient basis for offering an alternative capacity price forecast to the Company's forecast past the 2016/2017 delivery year.

Request No. 37: Refer to pages 41 through 49 of the Comings Direct Testimony.

a. Despite all the activity concerning the mitigation of carbon dioxide ("CO_2") pollution, would Mr. Comings agree that to date there has been no regulations finalized or in force dealing with CO_2?
b. Would Mr. Comings agree that regardless of how regulations addressing CO_2 pollution are developed and what statutory authority is utilized to support those regulations, it is likely that any finalized regulations will be challenged in the court system?
c. Have there already been legal challenges to the EPA's interpretation of the Clean Air Act as it applies to CO_2?
d. If the regulations are not finalized and are not in force, can Mr. Comings at this time identify the exact compliance strategy and the specific compliance costs for C02 EKPC would incur? If yes, please identify the compliance strategy and provide a detailed breakdown of the specific compliance costs. Include any analysis, studies, workpapers, or other evaluations performed by Mr. Comings to support his identified compliance strategy and compliance costs.

Response No. 37:

a. No. (Tyler Comings)
b. Parties are able to file court challenges to finalized EPA rules. Therefore, it is possible that parties will challenge the rule, just as some parties continue to challenge the MATS rule for which EKPC is proposing a compliance plan in this proceeding. (Tyler Comings)
c. In 2007, the United States Supreme Court held that greenhouse gases are an "air pollutant" subject to regulation under the Clean Air Act. *Massachusetts v. EPA*, 549 U.S. 497 (2007). In the subsequent years, parties have filed scores of lawsuits challenging EPA's ability to regulate greenhouse gas emissions under its existing Clean Air Act authority. To date, every one of those lawsuits has failed.

   Most notably, the United States Court of Appeals for the District of Columbia Circuit upheld in their entirety four major EPA rules: the finding that greenhouse gases endanger public health and welfare (the so-called "endangerment finding"); EPA's regulation of greenhouse gas emissions from motor vehicles; EPA's finding that the regulation of GHGs from motor vehicles triggers PSD and Title V permitting requirements for major stationary sources; and EPA's tailoring rule (which modifies the PSD permitting requirements as applied to greenhouse gases). *Coalition for Responsible Regulation v. EPA*, 684 F.3d 102 (D.C. Cir. 2012).

On October 15, 2013, the United States Supreme Court granted a petition for certiorari to review the narrow question of whether EPA's regulation of greenhouse gas emissions from new motor vehicles triggers PSD permitting requirements for stationary sources. The Supreme Court denied petitions to review the D.C. Circuit's decision to uphold EPA's endangerment finding and EPA's regulation of greenhouse gas emissions from motor vehicles. (Kristin Henry)

d. Mr. Comings discusses possibilities for compliance throughout his direct testimony. The 2013 Synapse Carbon Dioxide Price Forecasts are meant to provide a proxy for future costs of compliance with carbon regulations, and sets forth a reasonable range of potential future costs. By contrast, EKPC has offered certainty on this topic by assuming that there will be no costs related to its plants' carbon emissions over the entire planning period. (Tyler Comings)

SC – EXHIBIT 1

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

Or

In the Confidential File Materials at PSC

SC – EXHIBIT 2

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

Or

In the Confidential File Materials at PSC

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2013-00259

RESPONSE TO INFORMATION REQUEST

INTERVENORS' SUPPLEMENTAL REQUESTS FOR INFORMATION DATED 11/04/13

REQUEST 5

RESPONSIBLE PARTY: David Crews

Request 5. Please provide a breakdown of EKPC's historical annual costs from 2002 through 2013 associated with each plant including:

a. Variable O&M

b. Fixed O&M

c. Fuel Costs

d. Depreciation

e. Interest

f. Capital additions

g. Other costs

Responses 5a-g. EKPC objects to providing the historical annual costs for its plants because the analysis is not germane to the determination of whether or not EKPC should be granted a CPCN for the proposed Cooper Unit 1 project. The historic annual costs for the plants have no bearing on determining the reasonableness of the Cooper Unit 1 project.

Any analysis related to the CPCN should be performed on a forward-looking basis based on the bids received.

EAST KENTUCKY POWER COOPERATIVE

ALL SOURCE LONG-TERM
REQUEST FOR PROPOSALS 2012

[JULY 5, 2012: TWO DATES REVISED; SEE ALSO THE FAQs ON WEBSITE FOR AMENDMENTS AND CLARIFICATIONS.]

RFP Issued:	**June 8, 2012**
Supporting, Required Forms Issued:	**June 15, 2012**
Notice of Intent to Submit Proposal Due:	**July 10, 2012**
Required Forms with Revisions Issued:	**July 13, 2012**
Proposal Submittal Deadline:	**August 30, 2012**
RFP website:	**www.ekpc-rfp2012.com**
RFP email:	**ekpc-rfp@brattle.com**

TABLE OF CONTENTS

1. INTRODUCTION

1.1 OVERVIEW

East Kentucky Power Cooperative (EKPC) is issuing this All Source Long-Term Request for Proposals 2012 (RFP) to obtain new resources through a solicitation of interest from utilities, power marketers, project owners and project developers who desire to place a bid or bids and meet the minimum qualifications as described herein (Bidders or Participants). EKPC has formally applied to the Kentucky Public Service Commission for approval to transfer functional control of its system into the PJM Interconnection (PJM) and will systematically assume for purposes of this RFP that EKPC is a full member of PJM.[1] Thus, all Bidders should assume that they will deliver the capacity and/or energy resources to EKPC within PJM and under the PJM rules and procedures.

Subject to this and other conditions discussed below, EKPC will consider the following resources in this RFP:

- New construction of conventional generation technologies and all fuel types to include turnkey ownership, joint ownership or other alternatives;
- Existing conventional generation (a share of a plant could be accepted);
- New and existing renewable generation (as discussed below).

Pursuant to policies of the Kentucky Public Service Commission (PSC) and consistent with EKPC's Integrated Resource Plan (IRP) filed with the PSC on April 20, 2012,[2] EKPC seeks to acquire up to 300 megawatts (MW) of new resources, with an on-line date of October 2015. EKPC will consider resources that come on-line up to two years later, on or about October 2017, but will have to evaluate any additional costs it may incur under this later on-line date. As discussed in the IRP, one reason for the need for new resources is the impact of the EPA's Mercury and Air Toxics Standards (MATS) regulation. EKPC will evaluate the costs of retrofitting its older coal plants to comply with MATS. EKPC intends to offer a self-build option for this RFP.[3] EKPC is not soliciting and will not accept capacity from PJM Demand Response resources. EKPC is developing its own demand side management resources.

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1 EKPC intends that during the full period of the contracts that come from this RFP it would be a signatory to the PJM OATT, the PJM Reliability Assurance Agreement, and the PJM Operating Agreement.

2 EKPC, *2012 Integrated Resource Plan*, with Technical Appendices, all Redacted, April 20, 2012.

3 EKPC has established a wall to ensure that no cost information will be shared between its Power Production business unit, which will prepare the self-build proposal, and its Power Supply business unit, which will be involved in evaluating the bids that are received. The Brattle Group, as Independent Procurement Manager, also

For new conventional and/or renewable generation facilities, Participants may submit Bids in two forms. The first form is a Power Purchase Agreement (PPA) with EKPC, which is contained in the set of Required, Supporting Forms (Required Forms), which will be put on the RFP website on June 15, 2012. This is discussed below in Section 5. EKPC will consider PPAs for capacity in the EKPC Locational Deliverability Area (LDA) in PJM. EKPC will consider PPAs for energy delivered to:

- the EKPC load zone in PJM;
- the AEP-Dayton (AD) Hub;
- other delivery points that are fully described such that EKPC can determine the equivalent costs for delivery in comparing alternatives.

A PPA for bundled energy and capacity would need to specify both the energy delivery point and the LDA. EKPC would consider a bundled bid with the energy delivered to the AEP-Dayton Hub and the capacity delivered to the PJM LDA for AEP, and would evaluate any incremental costs or benefits from that arrangement. EKPC will consider energy and capacity from new or existing renewable generation resources.

One of the Required Forms is a signed draft PPA, which at the Bidder's discretion will contain terms, such as pricing terms, that are binding for 60 days from August 30, 2012. This signed form must be submitted for each PPA Bid. The conditions for the PPA Bids are discussed below in Section 2.3.4. Again, all Required Forms with their terms will be posted to the "ekpc-rfp2012" website on Friday, June 15, 2012. The final revisions to the Forms will be posted to the website by Tuesday, July 10, 2012.

The second form of the Bid is Facility Ownership by EKPC. For Facility Ownership, the sale would be conducted pursuant to a Purchase and Sale Agreement (PSA) and related documentation, which is found in Required Forms. This is the contract form under which a Participant would sell full or part ownership in an existing plant or would develop and cause to be constructed a fully permitted, operational generation facility, which would be sold in entirety or in part to EKPC at project completion. EKPC solicits both full and partial ownership shares, as long as the MWs of the project are within the minimum and maximum bounds for MW discussed below and other conditions are met. The Required Forms for Facility Ownership Bids would not need to be executable, but the conditions as discussed in the Required Forms would have to be met by any Bidder, or a Facility Ownership Bid may not be deemed acceptable to EKPC.

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will have no contact with the Power Production business unit staff that are involved in the preparation of a self-build proposal.

EKPC has three sites in its service territory suitable for locating a gas-fired combined cycle combustion turbine facility (CCGT) or a gas-fired single cycle combustion turbine facility. A Participant could propose to build at any of these sites under the Facility Ownership and PSA arrangement. EKPC is not accepting a Bid for a PPA at any of these sites. For these three sites, EKPC will be responsible for building the fuel pipeline from the nearest natural gas pipeline interconnection to the input point of the generation plant. The three sites have different expected costs for this fuel pipeline connection, which the Bidders may wish to consider. EKPC will also secure the air and water permits. Additional information and the conditions for the use of the EKPC sites are described in a Required Form on development and siting status. EKPC may submit self-build proposals at one or more of its sites.

Additional general conditions are that Contracts for new resources should have a minimum of 50 MW for any conventional resource and 5 MW for any renewable resource, as further specified in Section 2.3.2 below. This is a long-term procurement, so the length of any PPA should be at least five years and can be longer at Bidder's discretion. EKPC's 2012 IRP showed a preference for dispatchable and operationally flexible resources, but EKPC will evaluate any reasonable and fully described resource that a Bidder offers.

East Kentucky Power Cooperative, Inc. is committed to environmental stewardship while safely providing affordable, reliable power to its members. Therefore, EKPC will also consider proposals for energy and capacity from renewable generation resources. The renewable resources' bids must be a minimum of 5 MW (single resource or an aggregate in one Bid that is greater than or equal to 5 MW). The duration of the renewable energy resource contract(s) should range from a minimum of 5 years to the life of the facility. The capacity and/or energy must be deliverable to EKPC's Delivery Points as described herein. Renewable energy resources may include, but are not limited to:

- Wind
- Biomass
- Solar (electric or thermal)
- Hydro
- Geothermal
- Recycled energy (waste heat, etc.)

This RFP is open to those parties who currently own, propose to develop, or have rights to a renewable energy generating facility 5 MW or larger. Preference will be given to renewable projects that are in the state of Kentucky. Bidders may submit multiple proposals to fulfill the resource request. The proposal must be based upon a proven technology.

EKPC will retain all environmental attributes associated with Bidder's proposed bid energy, including but not limited to renewable energy credits, green tags, greenhouse gas or carbon credits, and any other emissions attributes. EKPC has engaged the services of The Brattle Group to act as an independent procurement manager and perform a comparative analysis and evaluation of proposals received under this solicitation. EKPC reserves the right to retain any other independent consulting service that it may deem necessary or advisable. The final decisions with regard to acceptance or rejection of any or all proposals are specifically reserved to EKPC, subject to the approval of the Kentucky PSC.

1.2 SCHEDULE

The schedule for this RFP process is set forth in Table 1. This schedule is subject to adjustment and any changes will be posted immediately on the website.

Table 1: Major Milestones for the RFP

No.	Major Milestones for the RFP	Dates
1	RFP document and Form 1 issue date	Friday, 6/8/2012
2	RFP Website live	Friday, 6/8/2012
3	Date to register at the Website to receive all further information with respect to the RFP. Potential bidders can continue to register up to Tuesday, 7/3/2012.	Wednesday, 6/13/2012
4	On the website, all Required Forms for a Bid will be posted, which will explain the information requirements for the Bids. An objective is to allow Bidders to fully explain their Bids, while systematically collecting as much information as possible in machine-readable format. Suggestions for improvements will be accepted by email through Tuesday, 7/3/2012, and the final Forms distributed on Tuesday, 7/10/2012	Friday, 6/15/2012
5	Webinar to answer questions of prospective bidders	Wednesday, 6/27/2012
6	**Due date for Notice of Intent to Submit Proposal (Reset on July 2, 2012)**	**Tuesday, 7/10/2012**
7	**Final versions of Bidder Response Forms, including Excel Forms 10 - 13 that should include binding values for 60 days, except as explicitly indicated by bidder, as discussed in Draft Forms 10 - 13.**	**Friday, 7/13/2012**
8	Proposals due in electronic form	Thursday, 8/30/2012
9	Proposals due with wet signed orginal in hardcopy	Wednesday, 9/5/2012
10	Date up to which the executable PPA Bids must be good, which is 60 days after the PPA Bids are submitted. EKPC may exercise the right to execute any such PPA Bid.	Sunday, 10/28/2012
11	Select Short Listed proposals, assuming that the RFP is going to continue.	Thursday, 11/1/2012
12	Execute Project Agreements, if not executed earlier.	1/1 - 1/15/2013

1.3 DISCLAIMER FOR REJECTING BIDS AND/OR TERMINATING THIS RFP

This RFP does not constitute an offer to buy and creates no obligation to execute any Agreement or to enter into a transaction under an Agreement as a consequence of the RFP. EKPC shall retain the right at any time, in its sole discretion, to reject any Bid on the grounds that it does not conform to the terms and conditions of this RFP and reserves the right to request information at any time during the solicitation process. EKPC also retains the discretion, in its sole judgment, to: (a) reject any Bid on the basis that it does not provide sufficient ratepayer benefit or that it would impose conditions that EKPC determines are impractical or inappropriate; (b) implement the appropriate criteria for the evaluation and selection of Bids; (c) negotiate with any Participant to maximize ratepayer benefits; (d) modify this RFP as it deems appropriate to implement the RFP and to comply with applicable law or other direction provided by the PSC; and (e) terminate the RFP should the PSC not authorize EKPC to execute Agreements of the type sought through this RFP. In addition, EKPC reserves the right to either suspend or terminate this RFP at any time for any reason whatsoever. EKPC will not be liable in any way, by reason of such withdrawal, rejection, suspension, termination or any other action described in this paragraph to any Participant, whether submitting a Bid or not.

1.4 CONTACT INFORMATION

The Brattle Group (Brattle) is serving as the Independent Procurement Manager (IPM) for this RFP process. Proposals in response to this RFP are due at the IPM's offices no later than 4PM Pacific Daylight Time (PDT) on Thursday, August 30, 2012.

Proposals are to be submitted by mail, e-mail, fax, or hand delivery to the IPM. Faxed or e-mailed proposals must be followed up by a signed original that is delivered by mail or overnight courier no later than 4PM PDT on September 5, 2012.

All correspondence should be directed to the IPM at the following address:

EKPC All Source RFP c/o The Brattle Group
201 Mission St., Suite 2800
San Francisco, CA 94105
Phone: 415.217.1000
Fax: 415.217.1099
E-mail: ekpc-rfp@brattle.com
Web Site: www.ekpc-rfp2012.com

2. EKPC SITUATION AND THE RFP GOALS

2.1 HISTORY

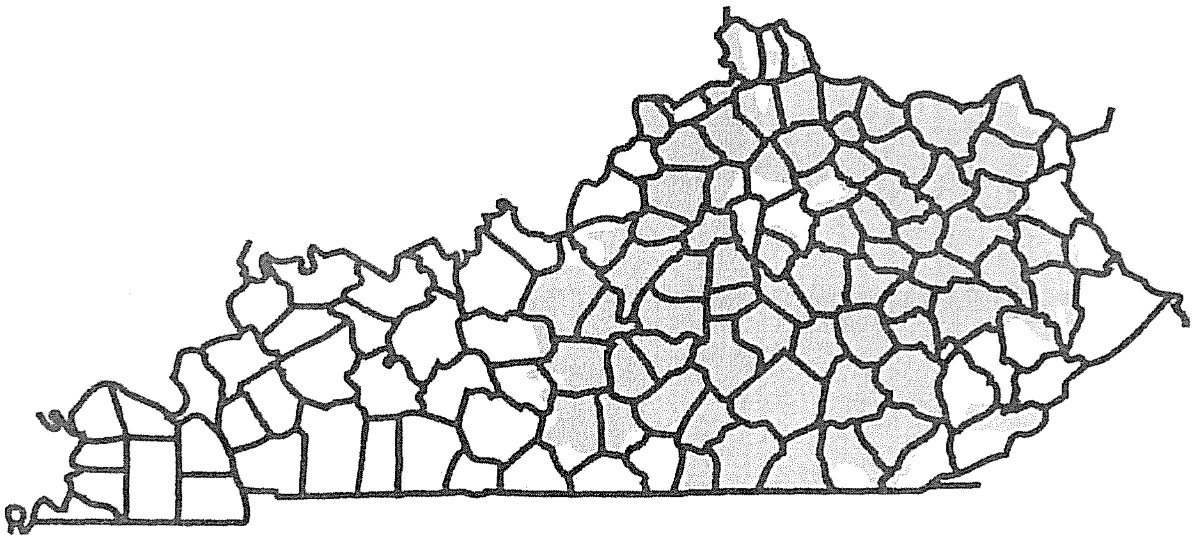
East Kentucky Power Cooperative, Inc. (EKPC) is headquartered in Winchester, KY and provides electric power and energy to 16 member distribution cooperatives serving approximately 511,000 meters in 87 Kentucky counties. EKPC is a member of the National Renewable Cooperative Organization. EKPC's existing resource portfolio consists of approximately 2,500 MW of coal and gas generating capacity, 15 MW of Landfill Gas generation, 170 MW of South East Power Administration (SEPA) hydro power, and various power purchase contracts. EKPC has applied for membership in PJM, and expects to be a member during the entire period of any contracts that result from this RFP. In addition to being a member of PJM, EKPC expects to maintain interconnections with the following other utilities/markets:

- KU/LG&E/PPL
- Tennessee Valley Authority (TVA)

Pursuant to policies of the Kentucky Public Service Commission (PSC) and consistent with EKPC's Integrated Resource Plan (IRP) filed with the PSC on April 20, 2012,[4] EKPC seeks to acquire up to 300 megawatts (MW) of new resources, with on-line date on October 2015. EKPC will consider resources that come on-line up to two years later, on or about October 2017, but must evaluate any additional costs it may incur under this later on-line date. As discussed in the IRP, one reason for the need for new resources is the impact of the U.S. EPA's MATS policy. EKPC will evaluate the costs of retrofitting its older coal plants to comply with MATS. EKPC intends to offer a self-build option for this RFP. EKPC is not soliciting and will not accept bids for capacity from PJM Demand Response resources. EKPC has its own demand side management resources that it is developing.

[4] EKPC, *2012 Integrated Resource Plan*, with Technical Appendices, all Redacted, April 20, 2012.

2.2 SYSTEM MAP



The above map shows the territory of EKPC and its member systems.

2.3 RFP GOALS

2.3.1 EKPC Resource Needs

EKPC submitted its Integrated Resource Plan (IRP) to the Kentucky Public Service Commission on April 20, 2012. Based on its IRP, EKPC projects it will need approximately 300 MWs of capacity by October 2015. As mentioned previously, EKPC will consider resources that come on-line up to two years later, that is, on or about October 2017, but must consider any additional costs it may incur under a later on-line date.

To meet this projected need, EKPC is seeking Bids from resources that meet the specifications set forth in Section 4 "Submission of Proposals and Eligibility Requirements." Attractive bids will be those that allow EKPC to produce energy and capacity products compatible with EKPC's requirements, and contribute to the other criteria specified in Section 6 "Proposal Evaluations."

In this solicitation, EKPC is willing to consider a wide range of intermediate and long-term resources that meet all or part of its requirements. EKPC will evaluate the benefits and costs of Bids in light of its existing portfolio of supply and demand-side resources.

EKPC must fully understand operational limitations of each Bid due to environmental constraints, such as air quality limitations. If applicable, Participants should specify all operational constraints the resource will be required to meet, such as those needed to comply with local Air Board requirements as well as other permitting requirements.

In addition, EKPC intends to bid any resources selected as a result of this RFP into the PJM market. EKPC will rely on any selected Bidder's attestations as to expected commercial operations date (COD), delivery date, or other time sensitive information contained in the response. As such, it is expected that any negotiated agreement will contain terms including but not limited to liquidated damages and/or replacement capacity costs at the prevailing market price for capacity at the time of expected delivery and until such time as performance is satisfied under the terms of said agreement.

2.3.2 Resources

EKPC will consider proposals (1) to enter into power purchase agreements and (2) to purchase new or existing generation resources (full or partial). Also, EKPC will consider Bids from conventional and renewable generation resources. EKPC has a preference for physical resources or PPAs that are based on physical resources. EKPC is not willing to enter into purely financial contracts to satisfy this RFP.

Conventional Generation

For purposes of this solicitation, the term "conventional generation" includes combined cycle and simple cycle (combustion turbine) technologies fueled by natural gas or bio-fuels. It also includes existing coal, nuclear and hydro facilities. Minimum Bid size is 50 MW from each facility.

Renewable Resources

EKPC will consider energy and capacity from new or existing renewable generation resources, including facilities burning biodiesel, digester gas, landfill gas or municipal solid waste, fuel cells using renewable fuels, geothermal facilities, ocean wave, ocean thermal and tidal current facilities, solar photovoltaic and solar thermal facilities, small hydroelectric (30 megawatts or less) facilities and wind generators. The minimum Bid size is 5 MW from each facility.

2.3.3 Facility Ownership: Generation Characteristics

Each facility will be operated to provide products as needed to conform to the requirements of PJM. For some resources, this is expected to include multiple daily starts and stops, rapid turndown of and ramp up within the unit's capabilities and full compliance with environmental permit conditions. This is to be satisfied by fully and accurately completing the Required Forms.

Load Following Generation

Bids to develop and sell a shaping or load following facility to EKPC will be expected to have the Generation Operating Characteristics described in a Required Form on combined cycle plants. The ability to meet these characteristics will be given additional weight in the evaluation process. Bids other than natural gas-fired technologies should respond to the appendices in a full and complete manner indicating where information is not applicable and provide additional information where appropriate in order to allow EKPC to fully evaluate its bids. Bids must meet all federal and state laws and be able to secure all permits.

Peaking Generation

Bids to develop and sell a peaking facility to EKPC will be expected to have the Generation Operating Characteristics described in a Required Form on simple cycle combustion turbines. The ability to meet these characteristics will be given significant weight in the evaluation process. Bids other than gas-fired technologies should respond to the appendices in a full and complete manner indicating where information is not applicable and provide additional information where appropriate in order to allow EKPC to fully evaluate its Bid. Bids must meet all federal and state laws and be able to secure all permits.

Baseload Generation

Bids to develop and sell baseload generation to EKPC will be expected to have the Generation Operating Characteristics described in a Required Form. Bids must meet all federal and state laws and be able to secure all permits.

2.3.4 Contract Options

All PPA Bids should include a draft PPA as part of the bid. Unless clearly set forth in the draft PPA to the contrary, the terms of the PPA shall be binding upon the Participant for 60 days from the date of submission, August 30, 2012,which is until October 28, 2012. Any section(s) or terms of the draft PPA which the Participant intends to be non-binding on the Participant (and subject to further negotiation) shall be clearly designated in the draft PPA. At the end of that period on October 29, 2012, EKPC may ask the Bidder to refresh the Bid for another 60 days, and the Bidder can respond accordingly, including any updates as to the binding nature of the terms of the draft PPA, so as to continue to be considered in the Short List negotiation of this RFP. Failure of a Bidder to provide a draft Purchase Power Agreement as set forth herein may result in disqualification of the Participant's Bid.

All Facility Ownership/PSA Bids must fully meet the conditions that are imposed on that kind of bid. These conditions will be stated in the Forms on Facility Ownership/PSA Bids that will be issued on June

15, 2012. EKPC wants to be certain that Facility Ownership Bidders planning to use an EKPC site are providing accurate and complete cost numbers on which they are prepared to execute. However, EKPC recognizes that building on one of its sites is likely to require additional negotiations, so EKPC is not expecting a fully-executable Facility Ownership Bid. Failure of a Participant to fill the details of the Required Forms for Facility Ownership/PSA option may result in disqualification of the Participant's Bid.

PPAs

EKPC is seeking PPA Bids for new and existing renewables and new and existing conventional generation technologies, including technologies capable of running on multiple fuels. The Required Forms will contain all forms for the PPA Bids. EKPC will provide the Required Forms on the website on June 15, 2012 and update certain of the Required Forms by July 10, 2012. As discussed above, each PPA Bid at the Bidder's discretion can have terms, such as price terms, that are binding for 60 days from its submission on August 30, 2012, which is until October 28, 2012.

For PPA Bids from natural gas-fired facilities, EKPC's preferred contract structure is a fuel conversion (tolling) structure. The documentation requested in the Required Forms will be generally structured to accommodate gas-fired units and a fuel conversion agreement. Participants offering a PPA other than a fuel conversion agreement for a gas-fired facility should adapt the documentation by selecting or deleting the optional elements as appropriate or making such other adjustments as necessary and appropriate for the technology and fuel-type offered. See the Required Forms.

Regardless of the contract structure offered, Participants are requested to specify contract quantities, fixed O&M costs, variable O&M costs, contract heat rate(s) (where applicable), and other parameters to aid EKPC in comparing Bids, which will be requested on the Required Forms.

Participants can submit fixed-price PPA Bids. Participants can also submit PPA Bids that use indexed pricing, as described below.

- PPAs must meet all of PJM requirements for Capacity transactions, as contained in the PJM Business Manuals,
- PPA must meet all of the PJM requirements for Energy transaction, as contained in the PJM Business Manuals,
- Variable O&M, Fixed O&M, Variable Energy and Fired Hour Charge: A Participant shall indicate in its Bid an initial price for each of these components. If the Participant elects to use indexed pricing, the Participant should fully describe the indexation approach by filling out the appropriate Required Forms, which will be sent out on June 15, 2012,

- Capacity Payment Rate: A Participant shall indicate in its Bid an initial price for capacity. If the Participant elects to use indexed pricing, the Participant should fully describe the indexation approach by filling out the appropriate Required Forms, which will be sent out on June 15, 2012.

Purchase and Sale Agreements (PSAs)

EKPC is seeking PSA Bids for Facility Ownership of new conventional generation technologies, including technologies capable of running on multiple fuels, whereby the Participant would design, develop, permit, construct and commission the facility. EKPC has three existing sites for such a facility, as discussed in the Required Forms. EKPC would take ownership of the facility once it is constructed, tested and accepted. Bids must include milestone guarantees and performance guarantees for the completed facility. Participants must completely fill out, but will not have to provide any executable Required Forms for a PSA.

Participants can submit fixed-price PSA Bids, as will be described in the Required Forms.

The PSA term sheet will be provided in the Required Forms. Generation characteristics that EKPC is seeking are described in Section 2.3.3 "Facility Ownership." EKPC plans to update the Required Form for the PSA Bids by July 10, 2012.

Purchase Price: A Participant shall indicate in its Bid a purchase price, as of the date the Agreement is executed by EKPC, for a Project offered in a PSA Bid.

The Delivery Points are:

- The EKPC load zone for energy and EKPC LDA for capacity,
- The AEP-Dayton (AD) Hub for energy and PJM LDA for AEP for capacity,
- other delivery points that are fully described such that EKPC can determine the equivalent costs for delivery in comparing alternatives.

As part of an individual Bid, a Participant may submit Bid variations, with each Bid variation indexing certain components. For example a Participant offering a PPA could offer one variation with a fixed capacity price and another variation may index the capacity price, while both Bid variations index the other pricing components. This information should be provided in the Required Forms.

3. TRANSMISSION AND DELIVERY INFORMATION

3.1. PJM MEMBERSHIP TO BE ASSUMED

EKPC considers transmission reliability to be of utmost importance, and the Bidder should specify what arrangements it intends to make to deliver the power reliably. EKPC has formally applied to the Kentucky Public Service Commission to join and is expecting to be a full member of PJM during the term of any contract resulting from this RFP. If the Bidder is also a member of PJM, then the transmission arrangements will be governed by the PJM protocols. If the Bidder is outside of PJM, the Bidder will have to explain the expected cost and reliability of transmission to the PJM system and to the EKPC Delivery Points.

Any modifications or additions to EKPC's system, including interconnection, transmission, or communications facilities, required by a Bidder for power delivery to EKPC's system, shall be subject to review and approval by EKPC. Expenses relating to any such modifications or additions will be included or inferred by EKPC in the price evaluation of the Bidder's proposal.

4. SUBMISSION OF PROPOSALS AND ELIGIBILITY REQUIREMENTS

4.1. OVERVIEW OF PROCESS

The bid process will include the events as indicated on the schedule in Section 1.2. June 8, 2012 is the release of the RFP and the opening of the website. On July 3, 2012, interested Bidders will be requested to submit a Notice of Intent to Submit Proposal form. Proposals will due August 30, 2012. The proposals will be screened and non-conforming offers will be rejected. Bidders for a short list can expect to be notified on or about November 1, 2012. There will begin negotiations of final offers. Final negotiation and the signing of offers will occur if the negotiations are successful.

4.2. NOTICE OF INTENT TO SUBMIT PROPOSAL

A Notice of Intent to Submit a Proposal is requested from all prospective Bidders. This notice includes a Confidentiality Agreement. This will be Form 1 in the Required Forms and should be returned to the IPM Official Contact as listed in Section 1.4. This form is due to the IPM at The Brattle Group offices by no later than by 4PM PDT on July 3, 2012. In addition to postal mail, fax, and email are sufficient as means to return the Notice of Intent to Submit Proposal. Potential Bidders should make their best effort to provide accurate information about their planned Proposal; however, Bidders will not be bound by the information provided in the completed Form 1, Notice of Intent to Submit Proposal.

4.3. DEADLINE AND METHOD PROPOSAL SUBMISSION

Proposals are due to the IPM no later than 4PM PDT on August 30, 2012. Proposals are to be submitted by mail, e-mail, fax, or hand delivery. Faxed or e-mailed proposals must be followed up by mail with a signed original which must be received no later than 4PM PDT on September 5, 2012. All correspondence should be directed to the IPM, as indicated in Section 1.4 of this RFP document.

5. PROPOSAL CONTENT

A proposal should contain responses on all of the Required Forms, which will be provided in the website on June 15, 2012. The Forms will encourage Bidders to provide additional information or other supporting documentation to provide a complete description of the proposal. The Brattle Group will receive suggestions on how the Forms can be enhanced to allow more complete descriptions of the Bids and, at the discretion of EKPC, use those suggestions to finalize the Forms on July 10, 2012. EKPC retains the right to combine any Bid with any other Bid to determine a mix of resources that will provide a total economical and reliable resource package.

The Required Forms will deal with the following issues:

- Conditions on the Firmness of the Offers
- General Project Characteristics
- Development Status and Site Description, which describes three EKPC sites that will be offered for Facility Ownership / Purchase and Sale Agreement
- Capacity and Energy Profile
- Technical Description and Data by Resource Type
- Description of Pricing Methodology
- Pricing Information
- Transmission and Interconnection
- Financing and Credit Arrangements
- References
- Project Team
- EEI Master Purchase Power and Sale Agreement
- Power Purchase Agreement for the RFP, and the relationship to the EEI Master Agreement
- Purchase and Sales Agreement for the Facility Ownership

EKPC will provide the Required Forms on the website on June 15, 2012. On July 10, 2012, EKPC will provide final updates to the Required Forms.

6. PROPOSAL EVALUATION

6.1. SCREENING

All proposals will be evaluated for completeness and technical viability as a part of initial screening. Non-competitive bids will be eliminated based on this preliminary analysis.

6.2. EVALUATION

EKPC and The Brattle Group will specifically take into account the price, type and location of project, reliability, dispatchability, transmission availability, financial stability, and any other factor which relates to the suitability of the proposed project for meeting EKPC's power supply needs. EKPC reserves the right to consider any and all aspects of any bid in its evaluation as well.

6.3 FINANCIAL STABILITY AND PERFORMANCE GUARANTEES

Financial stability of the Bidder, demonstrated ability to fulfill its contractual obligations and historical project and contract performance are of utmost importance to EKPC and will be an integral part of EKPC's evaluation process. EKPC requires secure and reliable physical delivery of the capacity and associated energy corresponding to all PPAs. A performance bond, or some other form of security acceptable to EKPC, will be required to ensure the consistency and reliability of the physical delivery of energy and capacity.

For equipment and/or erection contracts, successful Bidders shall secure, upon contract award, performance bond(s) to provide financial assurance that the project will meet schedule and proposed performance targets. EKPC reserves the right to determine, in its sole judgment, the sufficiency of any performance bond (or other form of security) proposed by Bidder.

The Bidder should discuss in detail the type and amount of proposed credit enhancements or other means proposed to guarantee performance under any contract that might result from this RFP. This discussion should identify the entity providing such performance security and provide all relevant terms of such security mechanism. Bidder must provide audited financial statements from the previous three years in order to demonstrate its financial viability. Such financial information shall also be provided for any entity which would provide a performance bond or other form of security.

Bidders proposing "greenfield" sites or new generation at one of EKPC's 3 suggested locations must provide a description of the Bidders' ability to execute such projects as demonstrated by previously applicable experience and examples of operating facilities caused to be designed, permitted, constructed, tested and achieving successful commercial operation within a time frame typical for such type of project. Other means of satisfying EKPC's concerns regarding the Bidders expertise and experience may be considered but will be at EKPC's sole discretion in determining the Bidders qualifications and acceptance or rejection.

Failure by Bidders to not address the requirements herein may result in rejection of the Bid(s).

6.4. CONFIDENTIALITY

Form 1 Notice of Intent to Submit a Proposal is part of the Required Forms and will contain a Confidentiality Agreement. The Bidder must return a signed Required Form including the Confidentiality Agreement on July 3, 2012, as discussed above Section 4.2.

EKPC will not disclose any information contained in the Bidder's proposal that is marked "Confidential" to another party unless such disclosures are required by law or by a court or governmental or regulatory agency having appropriate jurisdiction. As a regulated utility and electric cooperative, EKPC may be required to release proposal information to various government agencies and/or others as part of a regulatory review or legal proceeding. EKPC also reserves the right to disclose proposals to any EKPC consultant(s) for the purpose of assisting in evaluating proposals. In the event EKPC is required to submit copies of proposals to the Kentucky Public Service Commission (PSC) or other governmental or regulatory agency, EKPC will attempt to file such information labeled as "Confidential" on a confidential basis. Designating specific information as confidential, rather than the entire proposal, may facilitate such efforts. However, EKPC cannot guarantee that such information will be deemed confidential by the agency or court the information is filed with.

By submitting a proposal to EKPC under this RFP, Bidder certifies that it has not divulged, discussed, or compared its proposal with other bidders and has not colluded whatsoever with any other bidder or parties with respect to this proposal.

6.5. ACCEPTANCE OF PROPOSALS

EKPC reserves the right, without qualification, to select or reject any or all proposals and to waive any formality, technicality, requirement, or irregularity in the proposals received. EKPC also reserves the right to request further information, as necessary, to complete its evaluation of the proposals received, and to negotiate with Bidders selected for the short list, prior to any selection of any winning proposals. Bidders who submit proposals do so without recourse against EKPC for either rejection by EKPC or failure to execute an agreement for purchase of capacity and/or energy for any reason. EKPC will not reimburse any Bidders for any cost incurred in the preparation or submission of a proposal and/or any subsequent negotiations regarding a proposal. All hard copies of proposals once submitted will become the property of EKPC.

6.6. SHORT LIST DEVELOPMENT

EKPC will develop a short list of potential proposals based on the benefit to EKPC's members. EKPC will then refine its analyses and develop its final decision. Acceptance of final bids will most likely be subject to approval by the Kentucky Public Service Commission, permitting agencies and potentially the Rural Utilities Service or other lenders. All respondents to the PPA Bid options must keep the terms of their bids firm and in effect until October 28, 2012, after which the Bidders can refresh the Bids if EKPC wants to put the Bidder on the Short List.

Testimony of Anthony S. "Tony" Campbell
President & CEO
East Kentucky Power Cooperative

November 14, 2013

SUMMARY

EKPC is a generation and transmission cooperative based in Winchester, KY. Our mission is to provide safe, reliable, affordable electric power to the 16 electric distribution cooperatives that own EKPC. Nationwide, not for profit electric cooperatives serve 42 million people in 47 states.

We do not believe Congress ever intended for the Clean Air Act to regulate greenhouse gas emissions from power plants.

The proposed Section 111 regulations have already had a chilling impact on electricity generation in the U.S. When that proposed rule was issued, approximately 15 coal-fired power plants had received a PSD permit, but had not yet commenced construction. By the time the rule was withdrawn and re-proposed in 2013, most of those plants had been scrapped due to regulatory uncertainty, despite the exemption EPA included in the proposed rule.

In recent years electric utilities have faced a daunting array of environmental regulations on all fronts – air, water, and waste – that have contributed to widespread unit retirements. Coal-fired generation is essential to ensure energy diversity and to keep electricity prices low. Although natural gas prices are currently low, recent data from the United States Energy Information Administration ("EIA") shows that natural gas prices have increased by more than 50% since April 2012.

In addition to the realities and risks of rising natural gas prices, it is not feasible for the nation's existing coal-fired generating capacity to be transitioned to natural gas. Natural gas generation requires transportation from natural gas wells to power plants via an intricate network of interstate pipelines and compressor stations. These requirements raise infrastructure and national security concerns.

EKPC's greatest apprehension relates to regulations for existing sources. EKPC operates three baseload power plants fueled by coal and one plant operated by natural gas-fired combustion turbines. EKPC has invested almost $1 billion in retrofitting existing coal-fired power plants with modern air pollution control equipment. Further, EKPC spent another $1 billion to construct two of the cleanest coal units in the country. An existing source rule that requires CCS would leave EKPC, with no choice but to convert these units to natural gas, essentially wasting the extensive capital investments that have been made to lower pollutants from the coal-fired units.

EKPC is very worried about the supply of electricity to its rural cooperative members and its cost. There is a lack of technology that would allow EKPC to control GHG emissions, and a lack of demonstrated benefits to the environment. Most if not all coal-fired units will be forced to retire as a result of the regulation of GHG emissions, which would astronomically increase electricity rates and ultimately cause further job losses.

SC - EXHIBIT 5

TESTIMONY OF ANTHONY S. "TONY" CAMPBELL
PRESIDENT & CHIEF EXECUTIVE OFFICER
EAST KENTUCKY POWER COOPERATIVE

BEFORE THE
SUBCOMMITTEE ON ENERGY AND POWER
COMMITTEE ON ENERGY AND COMMERCE
UNITED STATES HOUSE OF REPRESENTATIVES

REGARDING

EPA'S PROPOSED GREENHOUSE GAS STANDARDS FOR ELECTRIC POWER PLANTS

November 14, 2013

A. Introduction

Chairman Whitfield, Ranking Member Rush and members of the Subcommittee, thank you for the opportunity to appear before you today. My name is Anthony S. "Tony" Campbell. I am the President and CEO of East Kentucky Power Cooperative ("EKPC"), and I have served in that position since 2009. I have previously served as CEO of Citizens Electric Cooperative in Missouri, and my career has also included positions at Corn Belt Energy and Soyland Power Cooperative, both in Illinois. I have a Bachelor's degree in Electrical Engineering from Southern Illinois University and a Master's degree in Business Administration from the University of Illinois.

Nationwide, not for profit electric cooperatives serve 42 million people in 47 states. While about 12 percent of the nation's meters are members of a rural electric cooperative, those co-ops own and maintain 42 percent of the nation's electric distribution lines, covering three quarters of the nation's landmass. Electric cooperatives employ about 70,000 people nationwide.

EKPC is a generation and transmission cooperative based in Winchester, Ky. Our mission is to provide safe, reliable, affordable electric power to the 16 electric distribution cooperatives that own EKPC. EKPC generates electricity at three baseload power plants fueled by coal and one peaking plant fueled by natural gas. More than 90 percent of the power we generate is fueled by coal. EKPC's total generating capacity is about 3,000 megawatts, and that power is delivered over a network of high-voltage transmission lines totaling about 2,800 miles. EKPC employs about 700 people.

More than 1 million Kentucky residents and businesses in 87 counties depend on the power we generate. Our 16 owner-member cooperatives serve mainly rural areas in the Eastern and Central two-thirds of Kentucky. EKPC and its member cooperatives exist only to serve their members. Our electric cooperatives serve some of the most remote parts of Kentucky. The terrain in this region varies from rolling farmland in Central Kentucky to mountains in the eastern portion. On average, our cooperatives have about 9 consumers per mile of power line, while investor-owned utilities average 37 consumers per mile and municipal utilities average 48 consumers. We also serve some of the neediest Kentuckians. The household income of Kentucky cooperative members is 7.4 percent below the state average, and 22 percent below the national average.

B. Use of the Clean Air Act to Regulate Greenhouse Gases from Electric Utility Units

Congress never intended for the Clean Air Act to regulate greenhouse gas emissions ("GHG") from power plants. This fact is illustrated by EPA's attempts to promulgate GHG new source performance standards ("NSPS") under Section 111. The Administration's proposed GHG NSPS, first issued in April 2012, demonstrated unequivocally that the Administration seeks to end new coal generation through regulation. In that proposal EPA chose not to establish a separate standard for coal-fired units; instead, it lumped coal units together with natural-gas fired units into a new NSPS subcategory, and established a GHG emission limit that only some natural gas combined cycle units can achieve. These proposed Section 111 regulations have already had a chilling impact on electricity generation in the U.S. When that proposed rule was issued, approximately 15 coal-fired power plants had received a PSD permit but had not yet commenced construction. By the time the rule was withdrawn and re-proposed in 2013, most of those plants had been scrapped due to regulatory uncertainty, despite the exemption EPA included in the proposed rule. The impact of the proposed GHG NSPS on already permitted new coal plants was fully realized when EPA did not finalize the proposed GHG NSPS rule within a year after proposing it, and instead, re-proposed the rule in September without any exemption for transitional sources. EPA recognized in the preamble to the rule that there are only three new coal units under development that would not include carbon capture and sequestration ("CCS"), the proposed Wolverine project in Michigan, the Washington County project in Georgia, and the Holcomb project in Kansas.

Just last month the Supreme Court agreed to hear a challenge to EPA's regulations requiring major sources to obtain permits for GHG emissions along with traditional pollutants. The specific issue for which the Court granted certiorari is "whether the Agency's regulation of GHGs from new motor vehicles triggered permitting requirements under the Clean Air Act for stationary sources." This case, *Utility Air Regulatory Group v. EPA*, tests EPA's authority to use the Endangerment Finding and the determination that GHGs from new motor vehicles must be regulated to protect public health and welfare as the basis to require PSD permits for new major sources of GHGs and major modifications to existing major sources of GHGs. Although this appeal will likely not directly address the regulations EPA is developing under Section 111 of the Clean Air Act, the real possibility that EPA's regulation of GHG emissions under the PSD permitting program may be struck down by the Supreme Court underscores the importance of Congressional guidance in this area.

While the current low price of natural gas has contributed to the decline in coal-fired electricity generation and the resurgence of natural gas-fired units, EPA's new regulations are an equally important factor in this trend. In recent years electric utilities have faced a daunting array of environmental regulations on all fronts – air, water, and waste – that have contributed to widespread unit retirements. According to the American Coalition for Clean Coal Electricity, EPA's rules have contributed to the closure of some 300 existing coal-fired units in 33 states.

Coal-fired generation is essential to ensure energy diversity and to keep electricity prices low. Although natural gas prices are currently low, recent data from the United States Energy Information Administration ("EIA") shows that natural gas prices have increased by more than 50% since April 2012. EIA's Annual Energy Outlook for 2013 projects that natural gas prices for the electric power sector will continue to increase by about 3.7% each year until 2040, and that total electricity demand will increase by 28% by 2040.[1] These estimates underscore the need for a diverse fuel mix that includes coal to meet these energy demands.

In addition to the realities and risks of rising natural gas prices, it is simply not feasible for the nation's entire existing coal-fired generating capacity to be transitioned to natural gas. Natural gas generation requires transportation from natural gas wells to power plants via an intricate network of interstate pipelines and compressor stations that allow the gas to be constantly pressurized. These requirements raise not only infrastructure concerns but also safety and national security concerns. If a key compressor station were to fail or be targeted in a terrorist attack, the nation's electric grid would be placed in jeopardy. When these natural gas supply requirements are contrasted with coal which is plentiful in supply, can be stockpiled at a 30-45 day supply, and can be transported via several different methods without the use of interstate pipelines, it makes no sense to require wholesale conversions from coal-fired generation to natural gas, particularly in areas of the country that are rich in coal resources and are not located in close proximity to natural gas wells.

Further regulations limiting GHG emissions from fossil fuel electric generating units are unnecessary and unreasonable. Coal-fired power plants in the U.S. contribute only approximately 4% to global GHG emissions.[2] The U.S. power fleet has already reduced CO_2 emissions by 16% below 2005 levels, with CO_2 from coal-fired power plants reduced by almost 25%.[3] These reductions are a result of the utility sector's shift to natural gas generation. EPA should allow coal-fired power plants to continue to make these reductions in a reasonable manner and in response to market pressures, instead of by regulatory fiat. Furthermore, the regulations at issue will not have a meaningful impact on global climate change. The minimal impact that these regulations will have on the environment further underscores the need for all GHG regulations to be economically achievable. Currently, EPA is developing GHG regulations for new and existing power plants without adequate input from coal states. None of EPA's listening sessions are located in Kentucky or any other coal state. Congressional action is necessary to keep EPA from regulating all coal-fired electricity generation out of existence.

C. The Whitfield-Manchin Discussion Draft Bill

EKPC supports the bipartisan Whitfield-Manchin discussion draft bill as common-sense legislation that provides important guidelines and parameters for EPA to follow in developing GHG regulations for new and existing power plants without causing irreparable harm to the U.S. economy. The Whitfield-Manchin discussion draft is different from many of the other bills and

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[1] EIA, *Annual Energy Outlook 2013*, April 2013, http://www.eia.gov/forecasts/aeo/.
EPA *Greenhouse Gas Reporting Program Data*, available at http://epa.gov/ghgreporting/ghgdata/reported/powerplants.html and Ecofys, *World GHG Emissions Flow Chart 2010*, available at http://www.ecofys.com/files/files/asn-ecofys-2013-world-ghg-emissions-flow-chart-2010.pdf.
[3] EIA, *Monthly Energy Review*, October 2013.

legislative riders that have been introduced in recent years, in that it does not seek to strip EPA entirely of its authority to regulate GHGs under the Clean Air Act. It narrowly responds to only one regulatory initiative by EPA – EPA's proposed regulation of GHG emissions from power plants under Section 111 of the Clean Air Act. This bipartisan bill is badly needed to ensure EPA does not promulgate a rule that jeopardizes the country's energy future, puts electricity reliability at risk, and severely harms the economy.

Although EPA's re-proposed GHG NSPS rule purportedly addressed many of the concerns raised in comments to the 2012 proposal, there are still many troubling aspects of the rule that require Congressional action. First, the proposed rule assumes that no new traditional coal-fired units will be built in the future and considers only IGCC and synfuel units in the rule's Best System of Emission Reduction (BSER) analysis for new coal-based unit CO_2 limits. Second, the proposed rule eliminated the 30-year compliance option that would have allowed utilities time to phase in use of carbon capture and storage (CCS). Instead, at least partial CCS is required to be implemented in new coal-fired power plants if new coal units are to achieve the BSER CO_2 limits. EPA identifies CCS projects that are currently being developed as evidence that CCS technology has been adequately demonstrated. However, none of the U.S. projects involve traditional coal units. Three of those projects are IGCC facilities that can more readily sequester CO_2 than conventional coal-fired power plants, and one project is a demonstration project at the Boundary Dam power station in Saskatchewan, Canada. In addition, EPA points to the Great Plains Synfuels project and a pilot CCS project that was operated at American Electric Power's Mountaineer Station in 2009 but subsequently cancelled, as examples of projects that have successfully implemented CCS. None of the generation projects are complete or currently operational and the synfuels project should not be used as a comparison for the electric generation industry.

All of the four CCS projects identified by EPA as currently under development[4] have received government funding. The Kemper IGCC project, which received a \$270 million federal grant and \$412 million in federal tax credits, recently announced that it will miss its May 2014 completion deadline. Delays at the Kemper IGCC project have contributed to an almost \$5 billion cost that is almost double the original estimated cost of around \$2.8 billion.[5] In addition, the Boundary Dam project recently announced a \$115 million cost overrun despite receiving \$240 million in funding from the Canadian government.[6] All of the four projects plan to sell captured CO_2 for enhanced oil recovery. EPA has not considered the taxpayer-funded portion of these project costs and does not appear to have accounted for cost overruns in its BSER analysis.

Any GHG emissions limit under Section 111 must reflect "the application of the best system of emission reduction which … the Administrator determines has been adequately demonstrated." EPA has not presented any real evidence that CCS is adequately demonstrated. EKPC supports

[4] EPA identified Southern Company's Kemper County Energy Facility, SaskPower's Boundary Dam CCS Project, Summit Power Group's Texas Clean Energy Project (recipient of a \$450 million federal grant), and Hydrogen Energy California, LLC's proposed IGCC facility (recipient of a \$408 million federal grant).

[5] Associated Press, *Kemper County power project cost approaches \$5 billion with latest rise* (updated Oct. 29, 2013 at 10:19 pm), http://blog.gulflive.com/mississippi-press-business/2013/10/kemper_county_power_project_co.html.

[6] Bruce Johnstone, *SaskPower CEO says ICCS project \$115M over budget*, Regina Leader-Post (Oct. 18, 2013), http://www.leaderpost.com/business/energy/SaskPower+says+ICCS+project+115M+over+budget/9055206/story.html.

the language in the draft bill that would prevent EPA from imposing any GHG emission standard on new coal-fired units until such limit has been achieved by representative coal-fired units for at least a year, because EPA's determination that CCS has been adequately demonstrated does not reflect reality.

EKPC's greatest concern relates to regulations for existing sources. As stated earlier, EKPC operates three baseload power plants fueled by coal and one plant operated by natural gas-fired combustion turbines. Pursuant to a consent decree with EPA, EKPC has invested almost $1 billion in retrofitting existing coal-fired power plants with modern air pollution control equipment. Further, EKPC spent another $1 billion to construct two of the cleanest coal units in the country. An existing source rule that requires CCS would leave EKPC with no choice but to convert these units to natural gas, essentially wasting the extensive capital investments that have been made to lower pollutants from the coal-fired units. This would result because there is no demonstrated technology that would be able to control GHG emissions. In addition, EKPC has already expended all of its investment capital on pollution controls under the consent decree and has no additional funds to invest in new, expensive technologies such as CCS. The costs associated with such a transition would represent a devastating and unfair impact to our rural members who have already paid for pollution control upgrades to EKPC's existing generating units, only to deal with much higher electricity rates. Higher electricity rates would further harm Kentucky's economy, where coal production has decreased by 64% since 2000. Recent coal mining employment figures released by the Kentucky Energy and Environment Cabinet show only an estimated 12,342 individuals employed in Kentucky coal mines – the lowest level recorded since 1927 when the Commonwealth began keeping mining employment statistics.[7] With higher rates, manufacturing jobs would also disappear, further compounding the impact to the economy from the loss of mining jobs. These dire figures demonstrate that Congressional action is sorely needed to ensure that coal-fired generation can continue in states like Kentucky.

These concerns extend to Governor Beshear's Kentucky Climate Action Plan which proposes significant GHG emissions reductions from the electric generating sector beginning in 2020. Reductions at this level will result in the shutdown of EKPC's coal units for which hundreds of millions dollars have been spent on pollution controls to ensure that the units could comply with EPA's many new environmental regulations. EKPC, instead, favors an approach like the one that the Whitfield-Manchin discussion draft bill contemplates, which we believe will foster more flexible, creative approaches to reducing GHGs from new and existing sources.

Even if we ignore the economic devastation that will result from an adverse existing source rule, Congressional action is also necessary to prevent Section 111(d) from being used to regulate GHG emissions from existing power plants. It is EKPC's view that the discussion draft bill does not go far enough, since the bill seems to assume that Section 111(d) is an appropriate vehicle for regulating GHG emissions from existing stationary sources. The discussion draft bill requires only that Congress set an effective date for any standard of performance for existing sources under Section 111(d) and that such rules or guidelines may not take effect unless the Administrator has submitted to Congress a report containing:

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[7] Kentucky Energy and Environment Cabinet, *Kentucky Quarterly Coal Report*, Q2 2013, http://energy.ky.gov/Coal%20Facts%20Library/Kentucky%20Quarterly%20Coal%20Report%20(Q2-2013).pdf

(1) the text of such rule or guidelines;
(2) the economic impacts of such rule or guidelines, including potential effects on economic growth, competitiveness and jobs, and on electricity ratepayers; and
(3) the amount of GHG emissions that such rule or guidelines are projected to reduce as compared to overall GHG emissions.

While this may have the result of delaying indefinitely any regulations that EPA may promulgate under Section 111(d), EKPC supports a more permanent solution that clarifies that Section 111(d) cannot be used to regulate GHG emissions from existing power plants. Regardless of whether the utility sector may eventually succeed in challenging these regulations, Congress should put an end to the regulatory uncertainty surrounding existing power plants and clarify that Section 111(d) and, in fact, Section 111 as a whole, is not the appropriate mechanism for regulating GHG emissions from electric generating units.

C. Conclusion

EKPC appreciates the work of this Committee and the opportunity to present our views on EPA's regulation of GHGs from power plants. To summarize, EKPC's main concern is for our rural cooperative members. There is a lack of technology that would allow EKPC to control GHG emissions, and a lack of demonstrated benefits to the environment. Most if not all coal-fired units will be forced to retire as a result of the regulation of GHG emissions, which would astronomically increase electricity rates and ultimately cause further job losses. EKPC believes the transportation and national security concerns presented by natural gas pipelines and compressor stations, as well as the upward trend in natural gas prices make conversion to a gas-fired utility fleet much too risky for this country's energy security. I would like to reaffirm EKPC's support for the Whitfield-Manchin discussion draft bill. Congressional action is sorely needed to end the regulatory uncertainty surrounding the electric power sector and put the country back on a path toward full economic recovery.

THE WHITE HOUSE

Office of the Press Secretary

For Immediate Release June 25, 2013

June 25, 2013

MEMORANDUM FOR THE ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY

SUBJECT: Power Sector Carbon Pollution Standards

With every passing day, the urgency of addressing climate change intensifies. I made clear in my State of the Union address that my Administration is committed to reducing carbon pollution that causes climate change, preparing our communities for the consequences of climate change, and speeding the transition to more sustainable sources of energy.

The Environmental Protection Agency (EPA) has already undertaken such action with regard to carbon pollution from the transportation sector, issuing Clean Air Act standards limiting the greenhouse gas emissions of new cars and light trucks through 2025 and heavy duty trucks through 2018. The EPA standards were promulgated in conjunction with the Department of Transportation, which, at the same time, established fuel efficiency standards for cars and trucks as part of a harmonized national program. Both agencies engaged constructively with auto manufacturers, labor unions, States, and other stakeholders, and the resulting standards have received broad support. These standards will reduce the Nation's carbon pollution and dependence on oil, and also lead to greater innovation, economic growth, and cost savings for American families.

The United States now has the opportunity to address carbon pollution from the power sector, which produces nearly 40 percent of such pollution. As a country, we can continue our progress in reducing power plant pollution, thereby improving public health and protecting the environment, while supplying the reliable, affordable power needed for economic growth and advancing cleaner energy technologies, such as efficient natural gas, nuclear power, renewables such as wind and solar energy, and clean coal technology.

Investments in these technologies will also strengthen our economy, as the clean and efficient production and use of electricity will ensure that it remains reliable and affordable for American businesses and families.

By the authority vested in me as President by the Constitution and the laws of the United States of America, and in order to reduce power plant carbon pollution, building on actions already underway in States and the power sector, I hereby direct the following:

SC - EXHIBIT 6

Section 1. Flexible Carbon Pollution Standards for Power Plants. (a) Carbon Pollution Standards for Future Power Plants. On April 13, 2012, the EPA published a Notice of Proposed Rulemaking entitled "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units," 77 Fed. Reg. 22392. In light of the information conveyed in more than two million comments on that proposal and ongoing developments in the industry, you have indicated EPA's intention to issue a new proposal. I therefore direct you to issue a new proposal by no later than September 20, 2013. I further direct you to issue a final rule in a timely fashion after considering all public comments, as appropriate.

(b) Carbon Pollution Regulation for Modified, Reconstructed, and Existing Power Plants. To ensure continued progress in reducing harmful carbon pollution, I direct you to use your authority under sections 111(b) and 111(d) of the Clean Air Act to issue standards, regulations, or guidelines, as appropriate, that address carbon pollution from modified, reconstructed, and existing power plants and build on State efforts to move toward a cleaner power sector. In addition, I request that you:

(i) issue proposed carbon pollution standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants by no later than June 1, 2014;

(ii) issue final standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants by no later than June 1, 2015; and

(iii) include in the guidelines addressing existing power plants a requirement that States submit to EPA the implementation plans required under section 111(d) of the Clean Air Act and its implementing regulations by no later than June 30, 2016.

(c) Development of Standards, Regulations, or Guidelines for Power Plants. In developing standards, regulations, or guidelines pursuant to subsection (b) of this section, and consistent with Executive Orders 12866 of September 30, 1993, as amended, and 13563 of January 18, 2011, you shall ensure, to the greatest extent possible, that you:

(i) launch this effort through direct engagement with States, as they will play a central role in establishing and implementing standards for existing power plants, and, at the same time, with leaders in the power sector, labor leaders, non-governmental organizations, other experts, tribal officials, other stakeholders, and members of the public, on issues informing the design of the program;

(ii) consistent with achieving regulatory objectives and taking into account other relevant environmental regulations and policies that affect the power sector, tailor regulations and guidelines to reduce costs;

(iii) develop approaches that allow the use of market-based instruments, performance standards, and other regulatory flexibilities;

(iv) ensure that the standards enable continued reliance on a range of energy sources and technologies;

(v) ensure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power for consumers and businesses; and

(vi) work with the Department of Energy and other Federal and State agencies to promote the reliable and affordable provision of electric power through the continued development and deployment of cleaner technologies and by increasing energy efficiency, including through stronger appliance efficiency standards and other measures.

Sec. 2. General Provisions. (a) This memorandum shall be implemented consistent with applicable law, including international trade obligations, and subject to the availability of appropriations.

(b) Nothing in this memorandum shall be construed to impair or otherwise affect:

(i) the authority granted by law to a department, agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(c) This memorandum is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.

(d) You are hereby authorized and directed to publish this memorandum in the *Federal Register*.

BARACK OBAMA

# # #

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2013-00259
RESPONSE TO INFORMATION REQUEST

INTERVENORS' INITIAL REQUEST FOR INFORMATION DATED 10/04/13
REQUEST 61
RESPONSIBLE PARTY: Jerry B. Purvis

Request 61. State whether EKPC has prepared or caused to be prepared any study of the costs to bring Cooper Unit 1 and Cooper Unit 2 (either individually or jointly), or the Dale Station into compliance with the regulatory options being considered in EPA's proposed Coal Combustion Residuals rule.

a. If so:

i. Identify the costs that were identified.

ii. State whether such costs were factored into the NPV analysis for the Project.

1. If so, explain how.
2. If not, explain why not.

iii. Produce all such studies.

b. If not, explain why not.

Responses 61b. EPA has not promulgated the final rule for the Coal Combustion Residuals rule. Therefore, no costs can be developed in detail to address or be factored into a NPV analysis.

EAST KENTUCKY POWER COOPERATIVE

November 19, 2010

Environmental Protection Agency
Mailcode: 5305T
1200 Pennsylvania Ave., NW.
Washington, DC 20460.

RE: Docket ID No. EPA–HQ–RCRA–2009–0640
Hazardous Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities

Dear Sir/Madam,

The following comments are being supplied by East Kentucky Power Cooperative (EKPC) on the proposed rule for classifying coal combustion residuals (CCR)[1] as a hazardous waste under the Resource Conservation and Recovery Act.

Background

EKPC is a not-for-profit member-owned generation and transmission utility founded in 1941 whose headquarters are located in Winchester, Ky. Today, EKPC provides wholesale energy and services to 16 member distribution cooperatives through power plants, peaking units, hydro power and more than 2,900 miles of transmission lines. EKPC's purpose is to provide and transmit electricity to its member systems who in turn distribute energy to their retail consumers. EKPC's distribution cooperative members supply energy to approximately 519,000 Kentucky homes, farms, businesses and industries across 87 counties.

EKPC owns and operates three coal-fired generating facilities that would be impacted through promulgation of the proposed CCR rule:

- William C. Dale Power Station (Dale Station) – 195 net MW
- John Sherman Cooper Power Station (Cooper Station) - 341 net MW, and
- H.L. Spurlock Power Station (Spurlock Station) - 1346 net MW

Dale currently manages CCR's with a wet CCR handling system, three (3) surface impoundments, and one permitted landfill (which was recently filled and is beginning the process of closure). Dale produces approximately 30,000 – 40,000 tons of CCR per year depending upon its load.

[1] Kentucky classifies utility wastes (fly ash, bottom ash, scrubber sludge) as special wastes. Pursuant to Kentucky Revised Statute (KRS) 224.50-760(1), special wastes are defined as wastes of high volume and low hazard.

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Cooper currently manages CCR with a dry handling system and produces approximately 80,000 tons of CCR per year. Cooper converted to the dry CCR handling system in 1992. Prior to 1992 Cooper handled CCR wet and utilized two (2) surface impoundments to handle the material. Those surface impoundments were closed in 1992 and CCR produced since then are stored in a permitted, on-site landfill. EKPC recently submitted an application to the Kentucky Division of Waste Management (KYDWM) for a horizontal and vertical expansion of this landfill. EKPC is in the process of adding to Cooper Unit 2 a dry scrubber that will become operational in 2012. Cooper's production of CCR will increase to approximately 300,000 tons per year at that time requiring more disposal space for CCRs. The application to KYDWM calls for development of a leachate collection system in conjunction with a composite liner including a 60 mil Linear Low Density Polyethylene geomembrane for the landfill.

Spurlock handles CCR with both wet and dry handling systems. Spurlock Units 1 and 2 handle the bottom ash wet (with the capability of handling fly ash wet, if needed) to one (1) surface impoundment. The remainder of CCR produced in Spurlock Units 1 – 4 is handled dry. Spurlock produces approximately 1,500,000 tons of CCR per year which is disposed in a permitted, on-site special waste landfill.

In Kentucky, there are no listed Subtitle C Hazardous waste landfills available to industry. As a result, reclassification of CCR under Subtitle C would require all of utility CCR waste to be trucked on the interstate highway system to out-of-state permitted facilities. The nearest facilities identified to receive the utility Subtitle C waste are in Pennsylvania and Alabama. Those facilities would be filled to capacity in the matter of months based upon EKPC's CCR waste alone. This does not take into consideration all the waste from coal in Kentucky.

Impacts to EKPC and its members

EKPC does not believe the proposed regulations are necessary to manage the CCR produced at these facilities in an environmentally sound manner because:

- CCR are not hazardous wastes by characteristic under the federal Subtitle C regulations;
- The stigma of a hazardous waste listing will reduce the potential to utilize CCR for beneficial reuse;
- Kentucky currently provides a regulatory framework for the disposal of CCR in Title 401 of the Kentucky Administrative Regulations Chapter 45; and
- EKPC maintains its coal-fired generating facilities within this regulatory framework and oversight.

Implementation of these additional regulations will result in several operational changes in EKPC's facilities impacted by these regulations. Each of these changes brings additional costs which will ultimately be borne by EKPC's 519,000 residential consumers, without providing additional environmental protection.

IMPACTS TO EKPC FACILITIES FROM SUBTITLE C

Under the proposed regulations for Subtitle C, EKPC interprets the rule to force the following actions.

Dale Station

- Convert wet CCR handling systems to dry;
- Eventually close its three surface impoundments[2];
- Install groundwater monitoring systems in the interim for the existing impoundments
- Permit an additional landfill through the EPA;
- Until an additional landfill becomes available, EKPC would be required to transport CCR to an EPA permitted hazardous waste landfill at a higher cost;
- Permit and modify/construct storage buildings and create secondary containment facilities; and
- Permit CCR transfer points as hazardous waste emission sources.

Spurlock Station

- Convert bottom ash handling systems for Spurlock Units 1 & 2 to dry systems;
- Close its surface impoundment[2];
- Install groundwater monitoring systems in the interim for the existing impoundment;
- Permit and install a new hazardous waste treatment system for processing of wastewater which is currently handled through the existing impoundment;
- Permit its existing Kentucky permitted landfill through EPA;
- Begin permitting a new landfill through EPA for long term needs;
- Permit and modify/construct storage buildings and create secondary containment facilities; and
- Permit CCR transfer points as hazardous waste emission sources.

Cooper Station

- Obtain approval from the EPA for its existing groundwater monitoring plan which currently utilizes subsurface springs for monitoring or install a groundwater monitoring system if the current plan would not be accepted by EPA;
- Permit the existing Kentucky permitted landfill through EPA;
- Permit the horizontal and vertical expansion of the landfill through the EPA;
- Permit and modify/construct storage buildings and create secondary containment facilities; and
- Permit CCR transfer points as hazardous waste emission sources.

EKPC understands that compliance with proposed regulations promulgated under Subtitle C would be required once Kentucky has developed a state-approved plan through the EPA. EPA stated in the proposed rule it will take 2 – 5 years for Kentucky to develop and obtain approval for its plan. At that point, EKPC would have five years to permit its existing landfills, close its surface water impoundments, permit new landfills through the EPA, convert its existing wet CCR handling systems, and identify offsite facilities that are permitted to accept CCR for

[2] For the purposes of these comments, EKPC assumes the proposed regulations related to surface impoundments do not apply to settling basins, sedimentation basins, coal pile runoff ponds, lagoons, etc. that receive effluent from wet ash handling systems, landfills, and surface impoundments.

disposal as hazardous wastes. EKPC does not believe the regulations provide sufficient time to get this work permitted, constructed, inspected, and approved.

Initial cost estimates for compliance with the new regulations under Subtitle C if promulgated as they are currently proposed are estimated to be $13 million to convert wet CCR handling systems to dry and $644 million to make the modifications necessary to comply with the proposed regulations. These costs include transportation of CCR to facilities that are permitted and willing to accept the CCR for disposal as hazardous waste, lining existing facilities, and other construction considerations. These costs do <u>not</u> include costs related to: liability concerns from dealing with hazardous wastes; permitting additional landfills: permitting and constructing storage areas; permitting and constructing new water treatment systems, CCR handling structures with liners and secondary containment; installation of groundwater monitoring systems; implementing new maintenance requirements; or additional staff needed to ensure the work is completed and operated in compliance with the proposed regulations..

Another EKPC concern with Subtitle C relates to the utilization of CCR for beneficial reuse. EKPC understands the EPA would only approve beneficial reuses for CCRs that EPA believes CCR reuse:

- Provides a functional benefit;
- Results in the conservation of natural resources;
- When used in products, amounts utilized will not exceed standard product specifications; and
- Is used in agriculture when the use is consistent with standards for applications of biosolids.

Under the framework presented in the proposed rule, large-scale structural fills would be prohibited as a beneficial reuse as well as other small scale unencapsulated uses. EKPC is concerned the reduction in beneficial reuse of CCR will have a negative impact on businesses that rely on this product. There will be increased utilization of raw materials to make up for the absence of CCR in the marketplace. For example, drywall manufacturers may resort to utilizing mined gypsum instead of synthetic gypsum.

EKPC is concerned about the stigma associated with the proposed designation of CCR as hazardous waste. EKPC has stopped the practice of supplying CCR to individuals, organizations, or agencies due to liability concerns that may be associated with the materials if they are eventually designated as hazardous wastes.

IMPACTS TO EKPC FROM SUBTITLE D

Should EPA decide to promulgate the new regulations under the Subtitle D provision, EKPC's facilities would be impacted in a similar manner as those listed above under Subtitle C with the exceptions that:

Dale Station would not be required to:

- Permit an additional landfill though the EPA;

- Transport CCR to a Subtitle C EPA permitted landfill;
- Permit and modify/construct storage buildings and create secondary containment facilities; and
- Permit CCR transfer points as hazardous waste emission sources.

Spurlock Station would not be required to:
- Permit its existing Kentucky permitted landfill through EPA;
- Permit and modify/construct storage buildings and create secondary containment facilities; and
- Permit CCR transfer points as hazardous waste emission sources.

Cooper Station would not be required to:
- Permit the existing Kentucky permitted landfill through EPA;
- Permit the horizontal and vertical expansion of the landfill through the EPA;
- Permit and modify/construct storage buildings and create secondary containment facilities; and
- Permit CCR transfer points as hazardous waste emission sources.

An additional component of Subtitle D is that all facilities would be required to institute a publicly available recordkeeping system.

The costs to implement Subtitle D are anticipated to be dramatically less than those for Subtitle C because any CCR that would need to be transported to facilities off of EKPCs property for disposal would not be required to go to Subtitle C-permitted sites. Maintenance costs, construction costs, and costs associated with permitting issues and delays are also expected to be less than those associated with Subtitle C.

EKPC also believes the environmental benefits from regulating CCR pursuant to Subtitle D will not differ from those EPA anticipates to achieve by regulating CCR under Subtitle C. Subtitle D would still require conversions from wet to dry systems, closure of surface impoundments, structural integrity requirements, fugitive dust controls, groundwater monitoring for existing impoundments, financial responsibility, and institution of a national standard for storage and disposal of CCR.

IMPACTS TO EKPC FROM SUBTITLE D'

Should EPA decide to promulgate the new regulations under the Subtitle D' provision, EKPC's facilities would be impacted in a similar manner as those listed above under Subtitle D with the exceptions that:

- Existing surface impoundments would be allowed to operate for the remainder of their useful life, and
- New impoundments would be required to be lined.

EKPC understands that the remaining requirements under Subtitle D' would be the same as for the regulations proposed under Subtitle D. Due to these changes under D', EKPC believes dramatic cost savings could be seen for EKPC's consumers compared to the costs of Subtitle D and C because:

Dale Station would not be required to:

- Convert wet CCR handling systems to dry[3] and
- Close its three surface impoundments

Spurlock Station would not be required to:

- Convert its bottom ash handling systems for Spurlock Units 1 & 2 to dry systems[3] and
- Close its surface impoundment

EKPC believes the environmental benefits from implementing Subtitle D' will not differ from those EPA anticipates to achieve from regulating CCR under Subtitle C or Subtitle D. Subtitle D' would still require structural integrity requirements, fugitive dust controls, groundwater monitoring for existing impoundments, financial responsibility, and institution of a national standard for storage and disposal of CCR. If groundwater monitoring of the existing surface impoundments demonstrated releases, EKPC would be required to implement corrective actions.

An added benefit of implementation of D' would be the utilization of existing surface impoundment facilities for storage. Under Subtitle C and D, this storage space is eliminated as an option and would require the development of additional landfills. New landfills would likely be sited in areas that previously had not been disturbed resulting in greater environmental impacts than utilizing the existing facilities.

Summary

In conclusion, EKPC believes promulgation of CCR regulations is not needed because disposal of CCR in Kentucky is currently regulated, EKPC operates under those regulations, and classification of CCR as hazardous waste would effectively eliminate the beneficial reuse of these materials. If EPA chooses to promulgate CCR regulations, EKPC believes it would be most prudent to promulgate the regulations under the Subtitle D' option for several reasons.

Subtitle D' is just as protective of groundwater and provides the same environmental benefits with much lower costs (see attached Table 1) to our members as options C and D. All three options require groundwater monitoring, and corrective actions if a release is identified. D' would allow electric utilities to utilize their existing surface impoundments for storage, which would alleviate the immediate and long-term capacity issues that will occur under the Subtitle C and D options. D' would also include closure requirements, stability requirements, fugitive dust controls, financial responsibility, and the institution of a national standard for storing CCR.

[3] This assumes EKPC would install groundwater monitoring systems for the surface impoundments that ultimately demonstrate no releases to the environment requiring corrective actions and allows for continued operation of the systems.

Please take EKPC's comments into consideration, as the decision by EPA on CCR disposal will directly impact the 519,000 Kentucky homes, farms, businesses and industries our cooperative serves.

Rebuttal: In Harm's Way

EKPC would also like to take this opportunity to correct several inaccuracies contained in the document "In Harm's Way: Lack Of Federal Coal Ash Regulations Endangers Americans And Their Environment" dated August 26, 2010 produced by the Environmental Integrity Project, Earthjustice and the Sierra Club, Jeff Stant, Project Director, Editor and Contributing Author. These inaccuracies include:

- The aerial map (p. 69) does not show the correct location of the monitoring wells for the Spurlock landfill. MW-1 is shown in the location of MW-2, MW-2 is shown in the location of MW-3, and MW-3 is shown in the location of MW-1.
- The reference well, MW-1, is located side-gradient to the fill Areas in a location that is unaffected by landfill operations, as required by Kentucky regulations.
- MW-2 and MW-3 are located down-gradient of Areas A and B, respectively, within the permit boundary.
- Area C will be located down-gradient of Areas A and B. When Area C is constructed, MW-2 and MW-3 will be removed and replaced by MW-2A and MW-3A, which will be down-gradient from Areas A, B and C in the direction of documented groundwater flow.
- The permitted groundwater standard for arsenic is 0.050 ppm, not 0.010 ppm.
- The results of groundwater sampling do not indicate the presence of contamination in MW-1, MW-2 or MW-A.
- EKPC has been directed by the Kentucky Division of Waste Management to conduct an assessment to determine the cause of the detection of arsenic in MW-3 at a concentration exceeding the permit limit. The assessment is expected to be completed by the end of the year.
- Although MW-2A and MW-3A have not been fully developed, preliminary sampling of MW-2A does not indicate the presence of contamination.
- There is no demonstrated impact to groundwater beyond the permit boundary.
- The map (p. 73) shows a drinking water well within the plant boundary. No drinking water well exists on the site. The groundwater at the site is not used as a drinking water source.
- The total permitted area is 389 acres of which 177 acres are designated for fill. The horizontal expansion of Area C as permitted in 2005 is 54.48 acres.

OTHER PERTINENT INFORMATION:

- The landfill and the groundwater monitoring system are permitted by the Kentucky Division of Waste Management pursuant to the requirements of 401 KAR Chapter 45.
- The area of groundwater flow on the map provided in the document (p. 73) is away from the depicted drinking water wells.
- EKPC has followed all design requirements in force at the time of development of each phase of the landfill.
- There are no drinking water wells within one mile of the permit boundary as required by the permit conditions.
- EKPC conducts surface water monitoring as required by its permit, and the sample results do not indicate any contamination of surface water.

Sincerely,

Jerry Purvis
Environmental Affairs Manager

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Table 1. Estimated costs for Subtitle C, D, & D' options.

Plant	Description	Cost for Subtitle C ($)	Cost for Subtitle D ($)	Cost for Subtitle D'($)
Spurlock	Line existing landfill	$ -	$ -	$ -
	Line existing surface impoundment	$ -	$ 20,040,000	$ -
	Permit New Landfill	$ 2,500,000	$ 1,500,000	$ 1,500,000
	Construct New Landfill	$ 60,000,000	$ 60,000,000	$ 60,000,000
	Line coal pile runoff pond	$ 225,000	$ 225,000	$ -
	Dredge surface impoundment	$ 1,670,000	$ 1,670,000	$ -
	Subtitle C Dewatering Station	$ 5,000,000	$ -	$ -
	Subtitle C Transfer Station	$ 7,500,000	$ -	$ -
	Haul CCR to Subtitle C Landfill (2 years)	$ 350,000,000	$ -	$ -
	Independent Engineering	$ 2,500,000	$ 2,500,000	$ 2,500,000
	Groundwater monitoring	$ 500,000	$ 500,000	$ 500,000
	Convert to dry ash system	$ 3,000,000	$ 3,000,000	$ -
	Install water treatment system	$ 5,000,000	$ 5,000,000	
Totals		$ 437,895,000	$ 94,435,000	$ 64,500,000
Dale	Line existing landfill	$ -	$ -	$ -
	Line existing surface impoundment	$ -	$ 7,050,000	$ -
	Permit New Landfill	$ 2,500,000	$ 1,500,000	$ 1,500,000
	Construct New Landfill	$ 15,000,000	$ 15,000,000	$ 15,000,000
	Line coal pile runoff pond	$ -	$ -	$ -
	Dredge surface impoundment	$ 587,500	$ 587,500	$ -
	Subtitle C Dewatering Station	$ 5,000,000	$ -	$ -
	Subtitle C Transfer Station	$ 7,500,000	$ -	$ -
	Haul CCR to Subtitle C Landfill (2 years)	$ 14,000,000	$ -	$ -
	Independent Engineering	$ 2,500,000	$ 2,500,000	$ 2,500,000
	Groundwater monitoring	$ 500,000	$ 500,000	$ 500,000
	Convert to dry ash system	$ 6,000,000	$ 6,000,000	$ -
	Install water treatment system	$ 1,000,000	$ 1,000,000	$ -
Totals		$ 54,587,500	$ 34,137,500	$ 19,500,000
Cooper	Line existing landfill	$ 28,500,000	$ 28,500,000	$ 28,500,000
	Line existing surface impoundment	$ -	$ -	$ -
	Permit New Landfill	$ 2,500,000	$ -	$ -
	Construct New Landfill	$ -	$ -	$ -
	Line coal pile runoff pond	$ -	$ -	$ -
	Dredge surface impoundment	$ -	$ -	$ -
	Subtitle C Dewatering Station	$ 5,000,000	$ -	$ -
	Subtitle C Transfer Station	$ 7,500,000	$ -	$ -
	Haul CCR to Subtitle C Landfill (2 years)	$ 105,000,000	$ -	$ -
	Independent Engineering	$ 2,500,000	$ 2,500,000	$ 2,500,000
	Groundwater monitoring	$ 500,000	$ 500,000	$ 500,000
	Convert to dry ash system	$ -	$ -	$ -
	Install water treatment system	$ -	$ -	$ -
Totals		$ 151,500,000	$ 31,500,000	$ 31,500,000
EKPC total		$ 643,982,500	$ 160,072,500	$ 115,500,000

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2013-00259
RESPONSE TO INFORMATION REQUEST

INTERVENORS' INITIAL REQUEST FOR INFORMATION DATED 10/04/13
REQUEST 60
RESPONSIBLE PARTY: Jerry B. Purvis

Request 60. State whether EKPC has prepared or caused to be prepared any study of the costs to bring Cooper Unit 1 and Cooper Unit 2 (either individually or jointly), or the Dale Station into compliance with the regulatory options being considered in EPA's proposed Clean Water Act Section 316(b) rule.

a. If so:

i. Identify the costs that were identified.

ii. State whether such costs were factored into the NPV analysis for the Project.

1. If so, explain how.

2. If not, explain why not.

iii. Produce all such studies.

Response 60a. EPA has not promulgated the final rule for the Clean Water Act Section 316(b) rule. Therefore, no costs can be developed in detail to address or be factored into a NPV analysis.

EAST KENTUCKY POWER COOPERATIVE

August 15, 2011

U.S. Environmental Protection Agency
Mail Code: 4203M
1200 Pennsylvania Ave., NW
Washington, DC 20460

RE: Docket ID No. EPA-HQ-OW-2008-0667
National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities

Dear Sir/Madam,

The following comments are being supplied by East Kentucky Power Cooperative (EKPC) on the proposed rule under section 316(b) of the Clean Water Act (CWA). This rule establishes national requirements for intake structures at new and existing facilities that withdraw more than 2 million gallons per day (MGD) of water where 25% of the water withdrawn is used exclusively for cooling purposes. The national requirements under the proposed rule would be implemented through National Pollutant Discharge Elimination System (NPDES) permits and would be applicable to the location, design, construction, and capacity of cooling water intake structures (CWIS). The proposed rule would set requirements that reflect the best technology available (BTA) for minimizing adverse environmental impact from CWIS.

First, EKPC appreciates that EPA did not require all existing facilities to install closed-cycle cooling or otherwise require flow reduction to a level commensurate with closed-cycle cooling. EKPC agrees with EPA that closed-cycle cooling is not the best technology available (BTA) for all applications. Implementing closed-cycle cooling at EKPC's facilities would cost approximately $44 million per facility which may not provide a practical economical or environmental benefit sought by this rule. Given the Supreme Court's ruling in *Entergy Corp. v. Riverkeeper, Inc.*, 129 S.Ct. 1498 (2009) that EPA may conduct a cost-benefit analysis in promulgating rules under Section 316(b) of the CWA, EKPC urges EPA to retain this aspect of the proposed rule when it is finalized. As the Supreme Court stated, the "best technology" required by Section 316(b) of the CWA "also describe[s] the technology that most efficiently produces some good." EPA's decision not to require closed-cycle cooling as BTA is therefore firmly grounded in the statutory mandate as construed by the Supreme Court.

However, EKPC has identified several requirements set forth in the proposed rule that should be eliminated or revised because compliance would be overly burdensome, prohibitively costly, and provide no additional environmental benefit. EKPC is particularly concerned that EPA is requiring site-specific entrainment controls, which will undoubtedly result in disparities across the country as various permitting authorities impose diverse requirements. Instead, EPA should base national BTA on impingement controls only.

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SC - EXHIBIT 10

As detailed below, EKPC is also concerned about the impingement controls, protective measures, monitoring and study requirements that have been proposed.

Background

EKPC is a not-for-profit member-owned generation and transmission utility founded in 1941 whose headquarters are located in Winchester, Ky. Today, EKPC provides wholesale energy and services to 16 member distribution cooperatives through power plants, peaking units, hydro power and more than 2,900 miles of transmission lines. EKPC's purpose is to provide and transmit electricity to its member systems who in turn distribute energy to their retail consumers. EKPC's distribution cooperative members supply energy to approximately 519,000 Kentucky homes, farms, businesses and industries across 87 counties.

EKPC owns and operates three coal-fired generating facilities that would be impacted through promulgation of the proposed 316(b) rule:

- William C. Dale Power Station (Dale Station) – 195 net MW
- John Sherman Cooper Power Station (Cooper Station) - 341 net MW, and
- H.L. Spurlock Power Station (Spurlock Station) - 1346 net MW

Additionally, EKPC owns and operates the J.K. Smith Power Station (Smith Station) which would become subject to the proposed rule if EKPC added a new unit.

Dale Station

Dale Station is capable of withdrawing up to approximately 220 million gallons per day (MGD) of water from the Kentucky River through a single CWIS for use by the four generating units for condenser cooling purposes. A stop log and trash rack structure is located at the river bank, with the screenhouse structure being set back from the bank approximately 800 feet.

River water is withdrawn through the stop log and trash rack structure into two 72" diameter pipes. The pipes convey river water into the screenwell at the screenhouse structure. The screenhouse structure contains the screenwell, traveling water screens, and circulating water pumps for all four operating units. There are a total of six conventional traveling water screens with 3/8 inch mesh and six circulating water pumps, as described in Table 1 above.

Traveling screens are typically operated automatically and are triggered based upon the differential pressure across the screens. Screens typically rotate for approximately one hour per day. During periods of high river flow, which typically also results in higher debris load, (approximately 30 days per year), the screens rotate continuously. During screen rotation, the screens are washed to remove fish and debris from the screen surfaces. Fishes impinged on the existing traveling water screens are washed off the 3/8" mesh screens and into a trough below the traveling screens. The trough conveys the fish and debris into a pipe which leads from the screenhouse to a sluiceway which returns fish to the Kentucky River.

Cooper

The Cooper facility is capable of withdrawing up to approximately 208 MGD of water from the Cumberland River (Lake Cumberland) through separate offshore intake structures for use by each of the two generating units for condenser cooling purposes. Each intake structure is located approximately 25 feet from the shoreline and withdraws water from an elevation of 671 feet mean sea level (MSL), which is approximately 50 feet from the water's surface under normal reservoir level conditions.

The two intake structures for the Cooper units, which are similar in design concept and configuration, are of unique, innovative, energy saving design. This intake design takes advantage of the hydraulic energy in the heated circulating water discharge from the elevated station location to provide a portion of the pump energy necessary to pump the circulating water from the lake to the condensers. The design also provides for reliable water withdrawal over the wide range of water levels in Lake Cumberland. The circulating water pumps draw water through the traveling screen and deliver it to the condensers. The traveling water screens in the two intake facilities are of conventional design with 3/8inch mesh.

Each unit has two circulating water pumps, and the traveling screens are typically operated manually twice per day. The screens are also set to operate automatically when debris loads are high and cause an increase in the differential pressure across the screens. During screen rotation, the screens are washed to remove fish and debris from the screen surfaces. Fishes impinged on the existing traveling water screens are washed off the 3/8" mesh screens and into a trough below the traveling screens. The trough conveys the fish and debris into a pipe which exits the intake structure and releases fish to the Cumberland River (Lake Cumberland).

Spurlock

Spurlock Station is capable of withdrawing a maximum of 21.6 MGD for its makeup water system. The facility operates four wet cooling towers, and the makeup water system supplies untreated river water to the circulating water makeup pretreatment system. Water from the Ohio River flows by gravity through two submerged intake screens into the intake structure sump. Debris collecting on the intake screens is periodically cleaned by a compressed air backwash system. Compressed air is supplied from an existing air header. An air receiver located at the intake structure provides the surge capacity necessary to purge the intake screens of debris.

Two passive type intake screens keep fish and debris from entering the intake structure sump. The screens are manufactured by the Cook Screen Company and are all welded Type 304 stainless steel wedge wire strainer elements with circumferential slot construction. They are designed for the following conditions:

- Design flow rate – 14,050 GPM
- Maximum velocity through strainer element slots – 0.5 fps
- Actual velocity through strainer element slots – 0.466 fps
- Strainer element slot openings – 0.125 inches

Three pumps provide the necessary flow and pressure to pump river water from the intake structure pump basin to the circulating water makeup pretreatment system. The pumps are rated for 5,000 GPM.

Impacts to EKPC and its members

Under the proposed rule, EKPC would be required to prepare and submit CWIS data, source water physical data, source water biological characterization data, and prepare and submit impingement mortality reduction plans, and biological survival studies, etc. and establish monitoring based upon the results of these studies and data. The proposed rule also requires the development and submittal of an Entrainment Characterization Study (ECS), technical feasibility and cost evaluation study, benefits valuation study, and a study of non-water quality and other environmental impacts if actual intake flows (AIF) are greater than 125 MGD. Since the AIF of EKPC's Dale and Cooper facilities is greater than 125 MGD, they would be required to submit these studies.

The proposed rule requires a vast amount of information and data to be developed for the ECS. Under the proposed rule, the ECS would consist of a peer-reviewed entrainment mortality data collection plan that must be developed by each facility and submitted to the permitting director. The entrainment mortality data collection plan would include:

- the duration and frequency of monitoring;
- a description of the study area and the area of influence of the CWIS;
- a taxonomic identification of the sampled or evaluated biological assemblages (including all life stages of fish and shellfish);
- the organisms to be monitored, including species of concern and threatened or endangered species;
- any other organisms identified by the permitting director;
- the method in which latent mortality would be identified;
- documentation of all methods and quality assurance/quality control procedures for sampling and data analysis; and
- an explanation for any significant peer reviewer comments not accepted.

The entrainment mortality data collection plan would have to be implemented no later than 6 months after submission to the permitting director, and the ECS would have to include the following components:

- taxonomic identifications of all life stages of fish, shellfish, and any species protected under Federal, State, or Tribal Law (including threatened or endangered species) that are in the vicinity of the CWIS and are susceptible to entrainment;
- characterization of all life stages of fish, shellfish, and any species protected under Federal, State, or Tribal Law (including threatened or endangered species), including a description of the abundance and temporal and spatial characteristics in the vicinity of the CWIS, based on sufficient data to characterize annual, seasonal, and diel variations in entrainment; and

- documentation of the current entrainment of all life stages of fish, shellfish, and any species protected under Federal, State, or Tribal Law (including threatened or endangered species).

The proposed rule requires entrainment samples to support the facility's calculations to be collected during periods of representative operational flows for the CWIS and flows associated with the samples to be documented as part of the ECS.

It is our understanding that some of our facilities would be required to provide the following information to KY Division of Water (KDOW) on the following schedule:

Submittal requirements	**Compliance Timeframe** (After Effective Date of the Rule)
Source water physical data, 122.21(r)(2)	6 months
CWIS data, 122.21(r)(3)	6 months
Source water baseline biological characterization data, 122.21(r)(4)	6 months
Cooling water system data, 122.21(r)(5)	6 months
Proposed Impingement Mortality Reduction Plan (IMRP), 122.21(r)(6)	6 months
▪ Results of IMRP	3 years, 6 months
Performance studies, 122.21(r)(7)	6 months
Operational status, 122.21(r)(8)	6 months
ECS, 122.21(r)(9)	
▪ Information for 122.21(r)(9)(i)	6 months
▪ Information for 122.21(r)(9)(ii)	12 months
▪ Information for 122.21(r)(9)(iii)	4 years
Comprehensive technical feasibility and cost evaluation study, 122.21(r)(10)	5 years
Benefits valuation study, 122.21(r)(11)	5 years
Non-water quality impacts assessment, 122.21(r)(12)	5 years

The facilities would then be subject to BTA standards for entrainment mortality established by the permitting director after the director has reviewed this information. With respect to the impingement requirements, the Dale and Cooper facilities would be required to install state of the art screens with fish buckets, low pressure spray washes, and dedicated fish lines.

EKPC has arrived at the following estimates of its costs to comply with the information submittal, impingement and monitoring requirements set forth in the proposed rule:

- IMRP and ECS - \$100,000 - \$1,000,000 for each of the three facilities (Cooper, Dale, and Spurlock). Estimates were gathered from various credible sources such as environmental consultants and trade groups. Depending upon the level of effort, EKPC could be faced with additional costs of \$750,000 to \$3 million dollars in study efforts alone.

- Protective measures to comply with impingement requirements including new screens and fish return systems – $1.5 to $4.4 million for two facilities (Cooper and Dale).

- Monitoring, maintenance, and compliance costs

    - EKPC would incur additional labor costs to staff the operation and maintenance requirements for the equipment, to conduct the additional monitoring, and to develop compliance reports. No firm estimates regarding these costs have been developed since staffing levels are dependent upon the final equipment installation, but at a minimum, EKPC would incur a minimum of $100,000 per employee in costs per year including benefits and salary for a lab technician and an environmental scientist.

Additionally, if EPA were to require cooling towers to be installed at the Cooper and Dale facilities, EKPC would incur costs of approximately $44.4 million per facility. Based upon this analysis, EKPC believes it could cost nearly $90 million dollars to add cooling towers to these facilities. If a new unit was added to our Smith facility, EKPC would be required to install a cooling tower for that facility as well. The cumulative impacts of the proposed rule to EKPC reveal that even without requiring closed-cycle cooling, compliance costs could amount to approximately $8 million for the three facilities that currently would be impacted by the rule. These costs are still unreasonably high, particularly since a significant portion of these costs (potentially $2 million) are based on various study, analyses, and data collection obligations that are not necessary to prevent adverse environmental impacts, or have already been conducted. EKPC has previously prepared proposals for information collection (PICs) for the Phase II rule that included: 1) descriptions of proposed technologies, operational measures, and restoration measures to comply with the entrainment and impingement performance standards; 2) a list and description of historical studies characterizing impingement mortality and entrainment and/or the physical and biological conditions in the vicinity of the CWIS; 3) a summary of past and ongoing consultations with regulatory agencies and other stakeholders; and 4) a sampling plan for new field studies to estimate impingement mortality and entrainment. Furthermore, EKPC has already conducted impingement sampling and characterization studies at its Cooper and Dale facilities and entrainment studies at Dale Station. The PICs and entrainment and impingement characterization studies included much of the information and data that EPA is requiring facilities to submit in the proposed rule.

Proposed Rule Considerations

- EPA should only base national BTA on impingement controls and should not require any BTA standards for entrainment mortality. EPA indicated in the preamble to the proposed rule that requiring only BTA impingement mortality controls would achieve up to a 31% reduction in total adverse environmental impact. EPA did not select this option because it believed that some facilities might be able to do more to control entrainment. EKPC disagrees with this assessment. EKPC will have to incur significant costs ($1.4 million to $4.4 million for each affected facility) to comply with the impingement mortality standards set forth in the proposed rule. Any additional entrainment controls would be too costly to justify any ancillary benefits from implementing such controls, and could be technically infeasible for EKPC to implement.

- EKPC proposes industry be allowed to develop a BTA analysis that outlines the economic benefit to cost ratio. This would set a standard by which the industry could demonstrate an economic plan for compliance on a case by case basis, establish least cost BTA, and propose plans to the regulatory authority (KDOW) under the state program.

- EPA should allow facilities to comply by demonstrating that species of concern are adequately protected by maximum intake velocity requirements instead of using specific protective measures.

- The BTA standards of impingement mortality are unreasonable. The options are demonstrating compliance with the impingement mortality standards (12% annual average and 31% monthly average), or demonstrating compliance with the maximum intake velocity standard of 0.5 feet per second. If a facility chooses to comply with the impingement mortality standard, 1 (one) fish could be impinged all year and if that fish perishes, the mortality for the year is 100% and it would be out of compliance.

- EPA's proposed approach for calculating and implementing the annual standard for mortality impingement should be changed. The annual average standard requires that impingement mortality not exceed 12%, calculated as the average of monthly impingement mortality for 12 consecutive months as determined by the permitting authority. EPA did not apply a confidence or tolerance limit to the long-term average performance shown in its data as 12% impingement mortality, because EPA believed facilities can achieve better long-term performance than documented in the data. It is unreasonable to expect facilities to achieve better performance than has been documented.

- The monitoring requirements proposed are impracticable and should be limited or reduced. For example, the proposed rule requires facilities to either conduct weekly visual inspections or use remote monitoring devices to ensure the technologies installed to comply with the impingement and entrainment standards are operating as designed. Facilities are also required to collect monthly samples over a 24-hour period to monitor impingement rates. Many facilities will not be able to install remote monitoring devices due to cost concerns and will therefore have to comply with the monitoring requirements by conducting inspections. Weekly inspections to ensure the BTA standards are functioning as intended are too frequent and unnecessarily burdensome. EKPC requests that EPA require inspections to occur on a bimonthly basis, six times per year, because this frequency would be sufficient to ensure that BTA standards are met. In addition, the rule should allow for alternate inspection methods during inclement weather.

- The BTA requirements for entrainment mortality that apply to new units at existing facilities are prohibitively costly and/or infeasible. Under the proposed rule, facilities must either reduce actual intake flow at new units to a level commensurate to the level that can be attained through closed-cycle cooling, or demonstrate that it has installed technologies than can reduce entrainment mortality by 90% or greater of the reduction that could be achieved through closed-cycle cooling. EPA should only require BTA standards for impingement mortality, or, as an alternative, apply the same case-by-case determinations of BTA requirements for entrainment mortality to new units.

- Peer review of the ECS, comprehensive technical feasibility and cost evaluation study, benefits evaluation study, and non-water quality impacts assessment is redundant and unnecessary. The KY Division of Water and consultants preparing the information are qualified at reviewing the proposed data. Peer review just adds an extra step, time, and costs to the process.

- Some studies required to be provided are unnecessary and redundant. EKPC requests that EPA not require facilities to provide source water baseline biological characterization data, as it would require facilities to collect the same information required to be collected in the development of an ECS. EPA should therefore eliminate the requirement to provide source water baseline biological characterization data. However, if EPA retains this requirement, EPA should provide clarity on which facilities are required to provide source water baseline biological characterization data, currently set forth in Section 122.21(r)(4). Section 122.21(r)(1)(ii) of the proposed rule currently only requires existing facilities, depending on their AIF and whether they use closed cycle recirculating systems, to submit some or all of the information required by (r)(2), (3), (5), (6), (7), and (8), but Section 122.21(r)(4) states that "each facility" must submit the source water baseline biological characterization data. It is unclear which facilities are required to submit this data.

- Allow facilities that previously prepared entrainment mortality data and characterization studies to submit that information if it remains representative of conditions at the facility.

- If the study and information submittal requirements are left in the final rule as proposed, the timeframes for submittal should be extended. Existing facilities with a DIF of 50 MGD or more are required to submit various studies and data within 6 months of the effective date of the rule, and submit a peer-reviewed entrainment mortality data collection plan within 1 year of the effective date. These timeframes are impractical and should be extended by at least six months. If left in the rule, EKPC anticipates that it and numerous other regulated entities would have to seek extensions from permitting authorities, in our case KDOW.

- According to expert research scientists, virtually all the evidence from scientific studies conducted for permit renewal and fishery management purposes demonstrates that power plants with once-through cooling systems, rarely, if ever, have any significant adverse impacts on aquatic life populations. Site specific impingement studies conducted over a year at EKPC's Dale and Cooper facilities by an independent consultant indicated that the facilities removed aquatic organisms at a rate of less than a few hundred per year.

During the study period, the screens were in service longer than during normal operation to satisfy sample collection time requirements. This exaggerated the number of organisms that are impacted during normal operation of the facility, so even fewer organisms are being impacted by Dale and Cooper.

- EPA should revise the proposed rule to provide for *de minimis* levels of impact. Many facilities, including Dale and Cooper Stations, are located on impounded bodies of water which would have very small impacts on aquatic organisms. Requiring these facilities to meet the same standards as those located on productive estuaries or sensitive habitats will be extremely costly to consumers and provide little to no environmental benefit.

- EKPC believes that EPA should delegate regulatory authority to states to develop, permit, inspect, and oversee state programs under EPA regulations. States should have the right to decide on a case by case basis the applicability of the regulations, method of analysis and evaluation of BTA, indication and demonstration of compliance, and method/frequency of monitoring/recordkeeping pursuant to EPA regulations.

- State oversight of EPA programs would provide local resources by which industry could draw upon as needs arise.

- If cooling towers are required for EKPC facilities, it could result in an additional $134 million dollars in expenses to our members and member systems for Dale, Cooper, and a new unit at Smith.

Summary

In conclusion, EKPC believes promulgation of the proposed rule should only base national BTA on impingement controls. BTA standards should not be developed for entrainment mortality because the costs of such controls would not justify the benefits. The proposed BTA impingement mortality standards are unreasonable, and the study and monitoring requirements are unnecessarily burdensome. Promulgation of the rule as proposed will result in significantly increased costs to EKPC's members and have little net positive impact to the environment.

We appreciate the EPA extending EKPC, through the public process, an opportunity to provide comments in regards to the proposed rule under section 316(b) of the Clean Water Act (CWA). This rule will directly impact 519,000 Kentucky homes, farms, businesses and industries our cooperative serves.

Best Regards,

Jerry Purvis

Jerry Purvis
Environmental Affairs Manager

Cc: Don Mosier
Craig Johnson
Charles Leveridge
Larry Morris
David Elkins
Joseph VonDerHaar

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EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2013-00259
RESPONSE TO INFORMATION REQUEST

INTERVENORS' INITIAL REQUEST FOR INFORMATION DATED 10/04/13
REQUEST 62
RESPONSIBLE PARTY: Jerry B. Purvis

Request 62. State whether EKPC has prepared or caused to be prepared any study of the costs to bring Cooper Unit 1 and Cooper Unit 2 (either individually or jointly), or the Dale Station into compliance with any potential new source performance standards for greenhouse gases for existing power plants under the Clean Air Act.

a. If so:

i. Identify the costs that were identified.

ii. State whether such costs were factored into the NPV analysis for the Project.

1. If so, explain how.

2. If not, explain why not.

iii. Produce all such studies.

b. If not, explain why not.

Response 62b. EPA has not filed proposed or final guidance under Section 111(d) of the Clean Air Act. Existing Electric Generating Units do not have to comply with New Source Performance Standards.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2013-00259
RESPONSE TO INFORMATION REQUEST

INTERVENORS' SUPPLEMENTAL REQUESTS FOR INFORMATION DATED 11/04/13
REQUEST 31
RESPONSIBLE PARTY: Jerry B. Purvis

Request 31. Has EKPC reviewed any documents relating to the potential costs at Cooper Unit 1 and/or Cooper Unit 2 to comply with the forthcoming Clean Water Act section 316(b) regulation of cooling water intake structures?

Response 31. Yes.

Request 31a. If so, produce all such documents and state when they were reviewed.

Response 31a. EKPC objects to this request on the grounds that it is overly broad and will not result in relevant evidence concerning the reasonableness of the proposed Cooper Unit 1 project. As noted in EKPC response to the Sierra Club's Initial Request for Information, Response 60a, the EPA has not promulgated the final rule for the Clean Water Act Section 316(b). Any documents discussing the potential costs of compliance would be speculative in nature. Requesting copies of EKPC's research on a yet to be finalized regulation has no bearing on the determination of whether the proposed Cooper Unit 1 project should be granted a Certificate of Public Convenience and Necessity ("CPCN").

Request 31b. If not, explain why not.

Response 31b. See response to 31a.

<u>Request 31c.</u> Has EKPC prepared or caused to be prepared any estimates of the range of costs that Cooper unit 1 and/or Cooper unit 2 may face to comply with the forthcoming 316(b) rule?

i. If so, produce all such documents.
ii. If not, explain why not.

<u>Response 31c.</u> See response to the Sierra Club's Initial Request for Information, Response 60a.

<u>ADDITIONAL RESPONSE PURSUANT TO THE COMMISSION'S DECEMBER 10, 2013 ORDER</u>

<u>RESPONSIBLE PARTY:</u> **Jerry Purvis**

<u>Response a-b.</u> Documents responsive to this request are provided on the enclosed DVD. Inside the folder "DVD – PUBLIC" are copies of the Environmental Compliance Alert ("ECA") and Inside EPA Weekly Report ("IEPA") that were reviewed by EKPC personnel.

EKPC is not producing certain engineering reports and analyses, as well as communications from EKPC's legal department and outside legal counsel relating to the potential costs at Cooper Unit 1 and/or Cooper Unit 2 to comply with the forthcoming Clean Water Act section 316(b) regulation of cooling water intake structures because these engineering reports and analyses were generated as part of engineering studies performed at the request of and solely to provide attorneys representing EKPC with the technical information necessary to provide effective legal advice on compliance options. When engineers are retained to perform technical consulting work which is not intended to be disclosed to third parties, and is performed at the direction of and to provide attorneys representing EKPC with the technical information necessary to provide effective legal advice on compliance options, it is well established that this work and the data collected and analyzed as part of this work constitute Attorney-Client Communications which are Privileged and Confidential and are protected from disclosure. *Collins v. Braden*, 2012 WL, 5285717 (KY 2012), see also, *U.S. v. Adlman*, 68 F.3d 1495 (2d Cir.1995) ("[u]nder certain circumstances,. . . the privilege for communication with attorneys can shield communications to others when the purpose of the communication is to assist the attorney in rendering advice to the client." Id. at 1499.)

SC – EXHIBIT 13

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

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EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2013-00259
RESPONSE TO INFORMATION REQUEST

INTERVENORS' INITIAL REQUEST FOR INFORMATION DATED 10/04/13
REQUEST 24
RESPONSIBLE PARTY: Julia J. Tucker

Request 24. Refer to the Direct Testimony of Julia J. Tucker, page 4, lines 11-14. Please provide the following, with supporting workpapers (in electronic, machine-readable format):

a. EKPC's historical annual peak load since 2002 (or earliest available).

b. EKPC's historical annual capacity reserve requirement since 2002 (or earliest available).

c. EKPC's historical annual sales since 2002 (or earliest available).

d. EKPC's historical annual generation since 2002 (or earliest available).

e. EKPC's projected annual peak load assumed for each of the years of the NPV analysis.

f. EKPC's projected annual capacity reserve requirement assumed for each of the years of the NPV analysis.

g. EKPC's projected annual sales assumed for each of the years of the NPV analysis.

Responses 24a-g. See table on page 2 of this response.

Request 24h. EKPC's projected annual generation (by plant) assumed for each of the years of the NPV analysis.

Response 24h. Each alternative was run through the RTSim production cost model and plant operations were developed based on market and operating cost assumptions. See EKPC's response to the Staff's Initial Request, Response 5.

	24(a)	24(b)	24(c)	24(d)
Year	**Actual Peak Demand (MW)**	**Capacity Reserve Requirement (MW)**	**Actual Net Total Requirements (MWh)**	**Annual Generation**
2002	2,141	321.15	11,456,830	9,873,289
2003	2,487	373.05	11,568,314	9,049,905
2004	2,487	373.05	11,865,797	8,995,991
2005	2,601	390.15	12,527,829	10,943,175
2006	2,503	375.45	12,331,203	11,109,919
2007	2,783	417.45	13,080,146	11,400,065
2008	2,953	442.95	12,947,087	10,565,726
2009	3,130	469.50	12,371,602	10,539,491
2010	2,761	414.15	13,354,642	12,494,407
2011	2,851	427.65	12,674,890	12,350,289
2012	2,349	352.35	12,170,868	10,980,324

	24(e)	24(f)	24(g)
Year	**Weather-Normalized Net Peak Demand (MW)**	**Capacity Reserve Requirement (MW)**	**Weather-Normalized Net Total Requirements (MWh)**
2013	2,947	69.18	12,898,564
2014	2,980	70.11	13,078,179
2015	3,017	71.04	13,285,509
2016	3,056	72.06	13,540,771
2017	3,101	73.08	13,728,389
2018	3,140	74.01	13,931,887
2019	3,175	74.79	14,116,106
2020	3,196	75.36	14,286,199
2021	3,229	76.11	14,420,814
2022	3,258	76.83	14,590,107
2023	3,296	77.70	14,784,691

EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy Cooperative

2012
Load Forecast

Prepared by:
Load Forecasting Department

November 2012

SC - EXHIBIT 15

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A copy of the CD containing the appendices is available upon request.
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SECTION 1.0

EXECUTIVE SUMMARY

Section 1.0
Executive Summary

East Kentucky Power Cooperative Inc. (EKPC) is a generation and transmission electric cooperative headquartered in Winchester, Kentucky, and owned by its 16 member distribution cooperatives, which serve approximately 524,000 retail consumers.

EKPC's "2012 Load Forecast" was prepared pursuant to its "2011 Load Forecast Work Plan", which was approved by EKPC's Board of Directors in December 2011 and by the Rural Utilities Service in March 2012. Factors considered when preparing the forecast include regional economic growth, electric appliance saturation and efficiency trends, electricity rates, and weather. The EKPC Load Forecasting Department works with the staff of each member system to prepare its forecast and then aggregates the 16 member system forecasts, adds forecasts of own use and losses, and subtracts planned demand-side management to create EKPC's forecast.

EKPC and its member systems will use the "2012 Load Forecast" for all relevant types of long-term planning, including construction work plans and financial forecasts for the member systems and transmission, generation, demand-side management, and financial planning for EKPC.

1.1.1 Consumer Growth by Consumer Class

Average Growth Rates	Time Period	Residential	Seasonal Residential	Commercial and Industrial ≤ 1000 KVA	Commercial and Industrial > 1000 KVA	Public Street and Highway Lighting	Other Public Authorities	Total
5-Year	2006-2011	0.7%	0.7%	1.6%	-0.8%	-0.2%	3.1%	0.8%
	2012-2017	1.0%	1.4%	1.6%	1.6%	1.7%	1.3%	1.0%
10-Year	2001-2011	1.4%	1.8%	2.7%	1.5%	2.4%	2.3%	1.4%
	2012-2022	1.0%	1.6%	1.3%	1.3%	1.7%	1.1%	1.0%
15-Year	1996-2011	1.9%	2.5%	3.2%	3.3%	0.0%	2.3%	2.0%
	2012-2027	1.0%	1.6%	1.2%	1.2%	1.7%	1.1%	1.0%
20-Year	1991-2011	2.2%	1.8%	3.2%	3.4%	3.3%	2.3%	2.2%
	2012-2032	1.0%	1.5%	1.1%	1.2%	1.7%	1.0%	1.0%

The forecast indicates that, through 2032, total consumers served by member systems will increase from 524,322 to 636,282, an average of 1.0 percent per year.

1.1.2 Energy Sales Growth by Consumer Class

Average Growth Rates	Time Period	Residential	Seasonal Residential	Commercial and Industrial ≤ 1000 KVA	Commercial and Industrial > 1000 KVA	Public Street and Highway Lighting	Other Public Authorities	Total
5-Year	2006-2011	1.3%	-1.7%	1.1%	-1.1%	3.6%	11.6%	0.7%
	2012-2017	1.0%	-0.2%	2.4%	2.5%	2.2%	3.3%	1.6%
10-Year	2001-2011	1.9%	0.0%	2.3%	0.9%	4.2%	7.4%	1.7%
	2012-2022	1.1%	-0.3%	2.0%	2.1%	2.2%	3.3%	1.5%
15-Year	1996-2011	2.4%	0.2%	3.4%	3.1%	3.9%	5.7%	2.7%
	2012-2027	1.2%	-0.5%	1.8%	2.0%	2.2%	3.2%	1.5%
20-Year	1991-2011	3.2%	1.5%	4.0%	7.2%	4.6%	7.0%	4.0%
	2012-2032	1.3%	-0.6%	1.7%	2.0%	2.2%	3.1%	1.6%

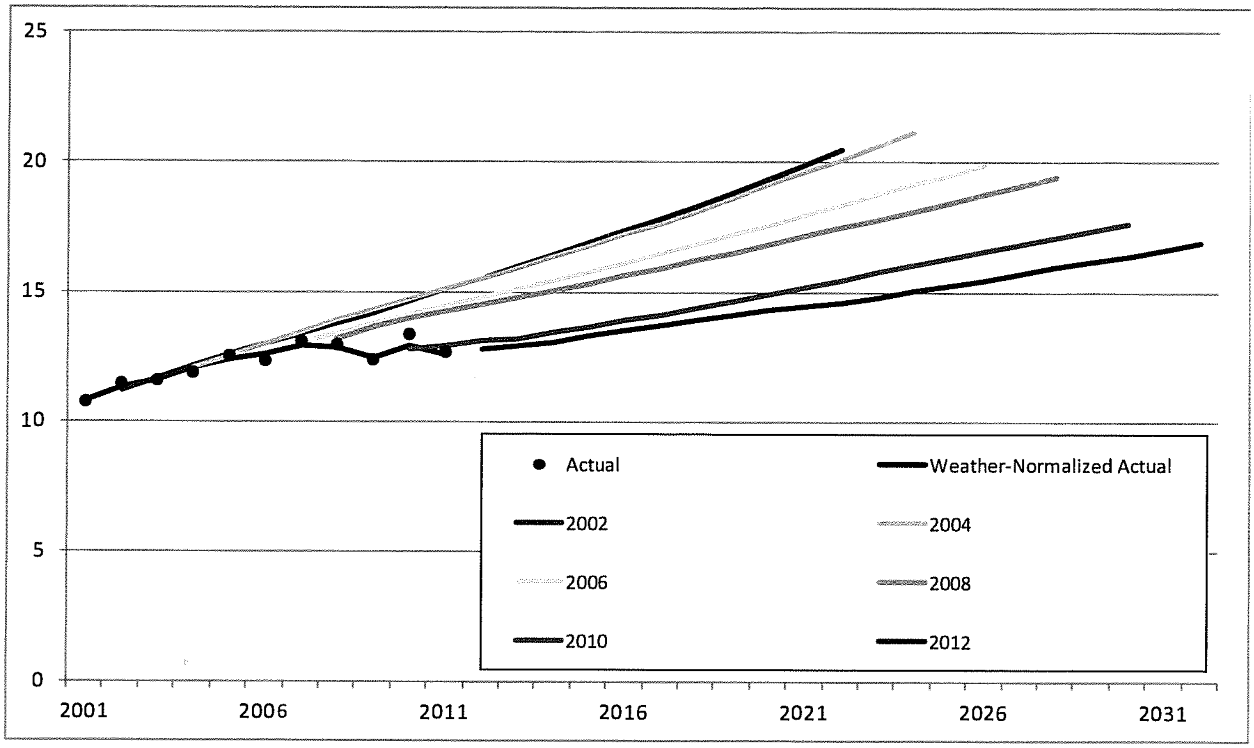
The forecast indicates that, through 2032, total energy sales by member systems will increase from 11.9 to 16.1 million MWh, an average of 1.6 percent per year.

While the growth rates for both consumers and energy sales forecast for the next 5 years are somewhat faster than those of the past 5 years including the recent recession, the growth rates forecast for the next 20 years are less than half of those of the past 20 years.

The commercial and industrial classes are forecast to grow more quickly than the residential class, as has been the case over the long term, such that the residential share of total sales will fall from 58 percent in 2012 to 55 percent in 2032. Despite their relatively fast growth rates, the other classes (in which many member systems do not report any consumers) will each remain less than 1 percent of total sales.

The "2012 Load Forecast" continues a decade-long pattern of downward revisions to forecasts of all major variables (consumers, total energy requirements, winter peak demand, and summer peak demand) in the most-distant years of the load forecast, as economic growth has generally fallen short of projections and long-term economic growth forecasts have been revised downward.

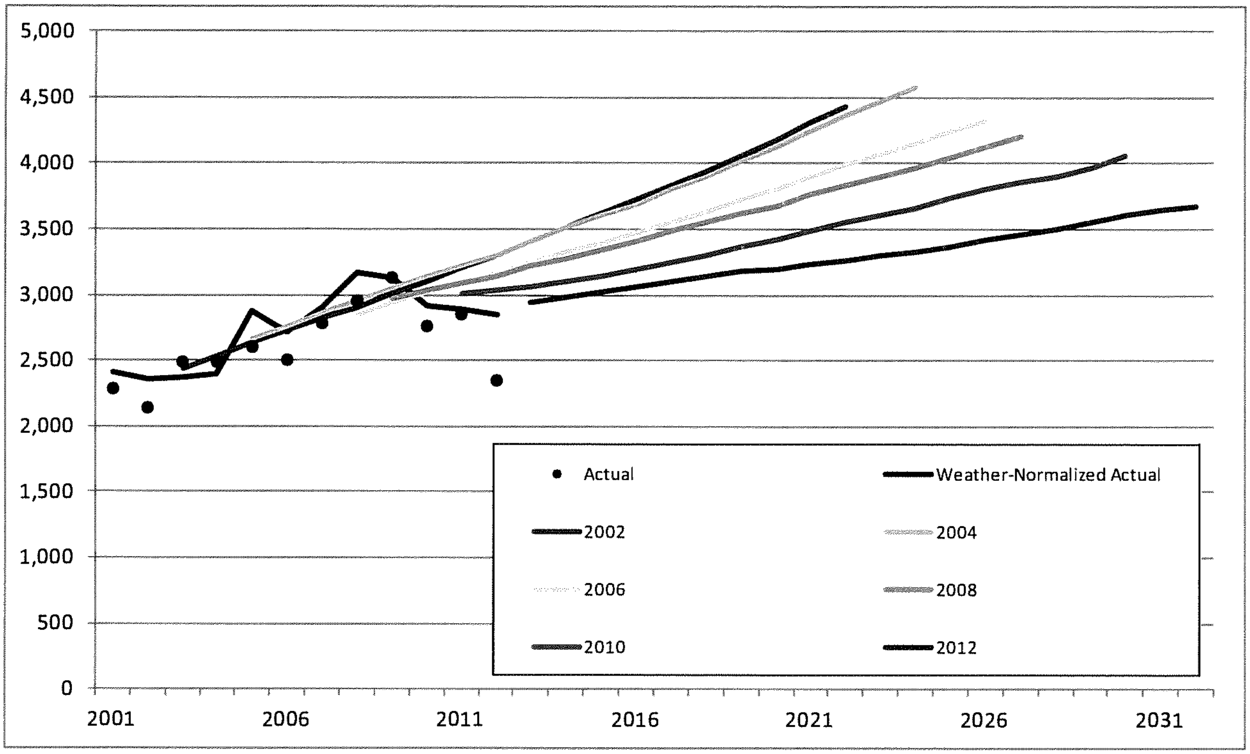
1.2.1 Net Total Energy Requirements (Million MWh) by Load Forecast Vintage



The "2012 Load Forecast" indicates that, through 2032, net total energy requirements will increase from 12.8 to 16.9 million MWh, an average of 1.4 percent per year.

This represents a downward revision from the 2010 Load Forecast by 2.4 percent in the short term and by 7.1 percent in the long term.

1.2.2 Net Winter Peak Demand (MW) by Load Forecast Vintage

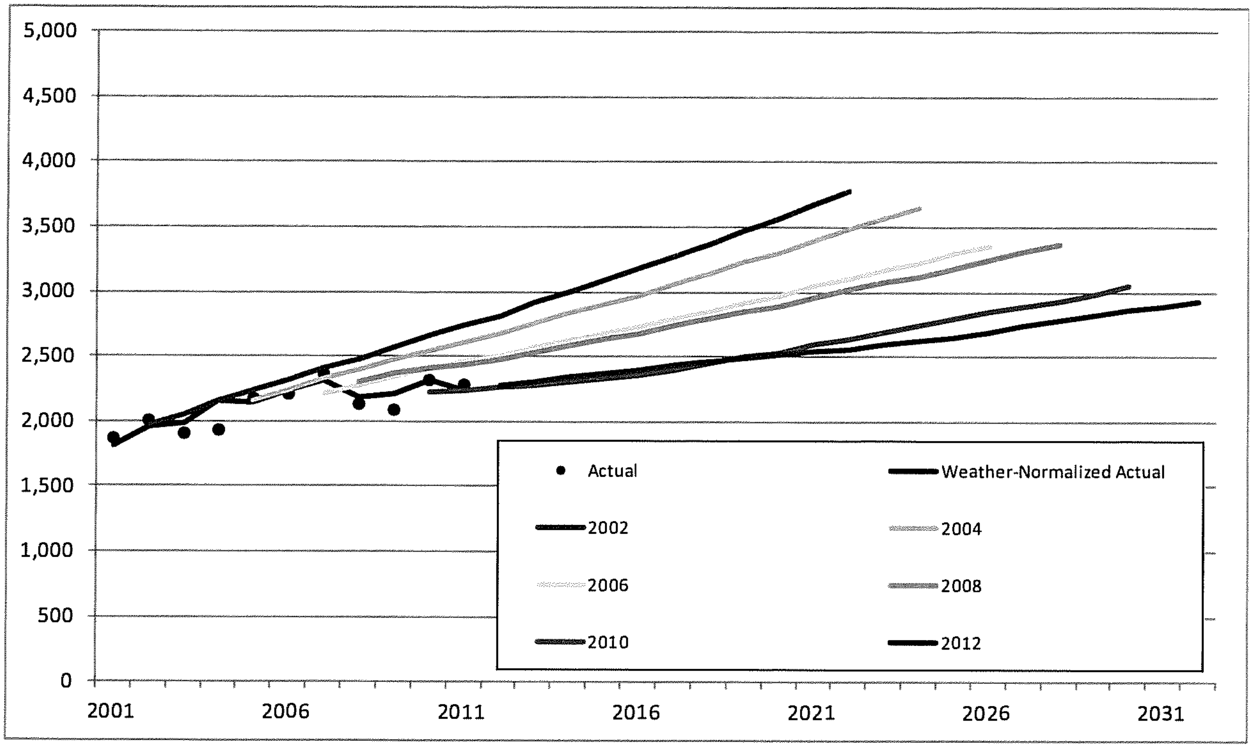


The "2012 Load Forecast" indicates that, through 2032, the net winter peak demand will increase from 2,947 to 3,674 MW, an average of 1.2 percent per year.

This represents a downward revision from the 2010 Load Forecast by 3.7 percent in the short term and by 11.1 percent in the long term.

Because the winter peak demand is forecast to grow less quickly than total energy requirements, the winter peak demand-based load factor will increase slightly, from 50.0 percent in 2013 to 52.3 percent by 2032. Because the EKPC system remains winter-peaking throughout the forecast period, this also represents EKPC's annual load factor.

1.2.3 Net Summer Peak Demand (MW) by Load Forecast Vintage



The "2012 Load Forecast" indicates that, through 2032, the net summer peak demand will increase from 2,277 to 2,925 MW, an average of 1.3 percent per year.

This represents an upward revision from the 2010 Load Forecast by 0.6 percent in the short term and a downward revision by 6.3 percent in the long term.

Because the summer peak demand is forecast to grow less quickly than total energy requirements, the summer peak demand-based load factor will increase slightly, from 63.8 percent in 2013 to 65.7 percent by 2032. While the EKPC system remains winter-peaking throughout the forecast period, EKPC's summer peak demand-based load factor will become more financially important than its winter peak demand-based load factor if EKPC integrates its system into the summer-peaking PJM Interconnection, as it has applied to do, pending regulatory and final EKPC Board of Directors approval.

SECTION 2.0

DESCRIPTION OF THE COOPERATIVE

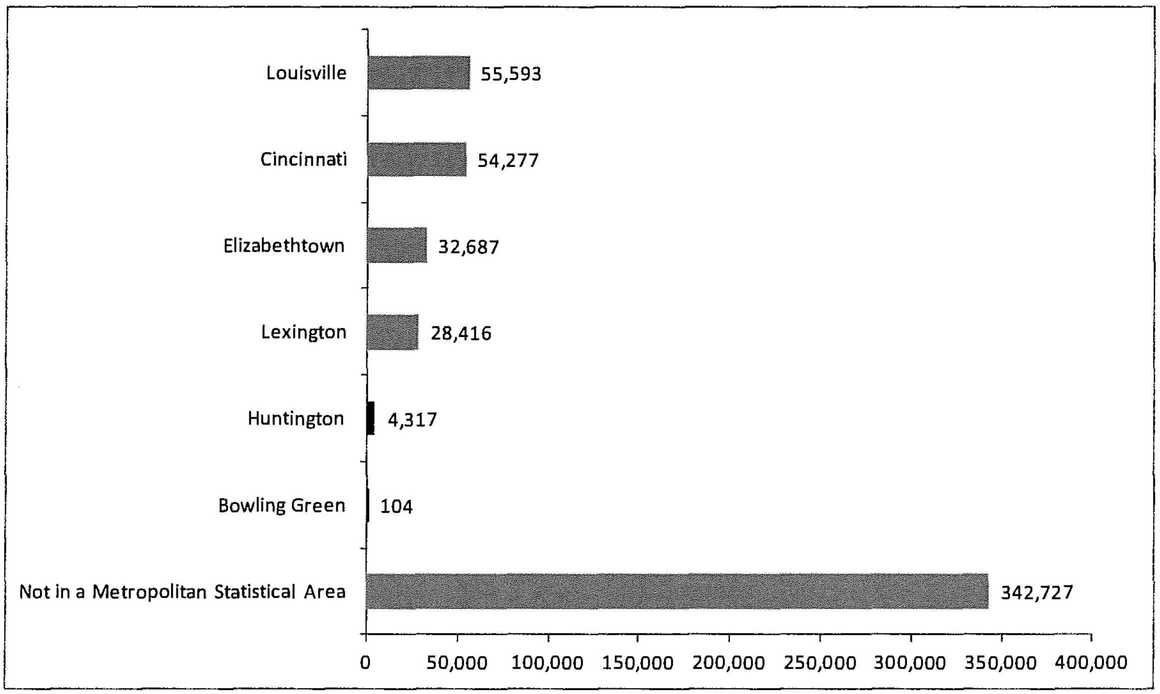
Section 2.0
Description of the Cooperative

East Kentucky Power Cooperative Inc. (EKPC) is a generation and transmission electric cooperative headquartered in Winchester, KY, and owned by its 16 member distribution electric cooperatives:

- Big Sandy RECC
- Blue Grass Energy Cooperative
- Clark Energy Cooperative
- Cumberland Valley Electric
- Farmers RECC
- Fleming-Mason Energy Cooperative
- Grayson RECC
- Inter-County Energy Cooperative
- Jackson Energy Cooperative
- Licking Valley RECC
- Nolin RECC
- Owen Electric Cooperative
- Salt River Electric Cooperative
- Shelby Energy Cooperative
- South Kentucky RECC
- Taylor County RECC

Together, EKPC and its member systems are branded as Kentucky's Touchstone Energy Cooperatives.

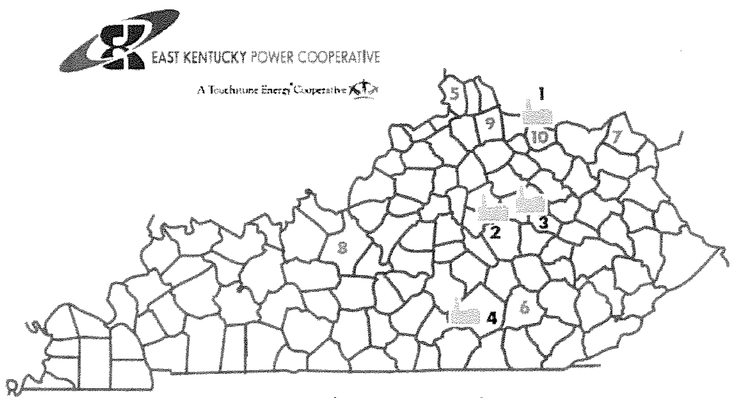
Consumers by Metropolitan Statistical Area, 2011



EKPC member systems serve approximately 524,000 consumers in 87 counties in Kentucky and 3 counties in Tennessee, including portions of the Louisville, Cincinnati, Elizabethtown, Lexington, Huntington, and Bowling Green Metropolitan Statistical Areas. EKPC member systems serve most of the rural areas, while investor-owned and municipal utilities serve most of the cities and towns. Interstates 64, 65, 71, and 75 and several limited-access parkways pass through the area. EKPC member systems' fixed service territory boundaries are on file with the Kentucky Public Service Commission.

EAST KENTUCKY POWER GENERATION

1	Spurlock	1,346 net MW
2	Dale	195 net MW
3	Smith Combustion Turbine Units	Summer 786 net MW Winter 1,016 net MW
4	Cooper	341 net MW
Landfill Gas Plants		
5	Bavarian	3.0 net MW
6	Laurel Ridge	3.8 net MW
7	Green Valley	2.3 net MW
8	Pearl Hollow	2.3 net MW
9	Pendleton	3.0 net MW
10	Mason	1.5 net MW
Southeastern Power Adm. (SEPA), hydro power		170 MW



shows system-wide service area

EKPC owns a generation fleet of more than 2,900 MW, including coal, natural gas, oil, and landfill gas units, and purchases up to 170 MW of hydro power from the Southeastern Power Administration. EKPC also owns more than 2,900 miles of transmission line and approximately 400 substations. EKPC has applied to integrate its winter-peaking system into the summer-peaking PJM Interconnection as soon as June 1, 2013, pending regulatory and final EKPC Board of Directors approval.

SECTION 3.0

DESCRIPTION OF THE FORECASTING METHOD

Section 3.0
Description of the Forecasting Method

EKPC's "2012 Load Forecast" was prepared pursuant to its "2011 Load Forecast Work Plan", which was approved by EKPC's Board of Directors in December 2011 and by the Rural Utilities Service in March 2012. Factors considered when preparing the forecast include regional economic growth, electric appliance saturation and efficiency trends, electricity rates, and weather. The EKPC Load Forecasting Department works with the staff of each member system to prepare its forecast and then aggregates the 16 member system forecasts, adds forecasts of own use and losses, and subtracts planned demand-side management to create EKPC's forecast.

EKPC and its member systems will use the "2012 Load Forecast" for all relevant types of long-term planning, including construction work plans and financial forecasts for the member systems and transmission, generation, demand-side management, and financial planning for EKPC.

3.1 Model Inputs

The following section describes the independent variables used in EKPC's models of consumers and energy sales by consumer class for each member system.

3.1.1 Regional Economic Growth

EKPC combines county-level forecasts from IHS Global Insight into regional economic forecasts based roughly on member system service territory boundaries. Member systems and counties are assigned to regions as follows:

- Central Region:
  member systems: Blue Grass Energy Cooperative
  counties: Anderson, Bourbon, Clark, Fayette, Franklin, Harrison, Jessamine, Madison, Mercer, Scott, and Woodford
- East Region:
  member systems: Big Sandy RECC, Cumberland Valley Electric, Jackson Energy Cooperative, and Licking Valley RECC
  counties: Bell, Breathitt, Clay, Estill, Floyd, Harlan, Jackson, Johnson, Knott, Knox, Laurel, Lee, Leslie, Letcher, Magoffin, Martin, Morgan, Owsley, Perry, Pike, Rockcastle, Whitley, and Wolfe
- North Region:
  member systems: Owen Electric Cooperative
  counties: Boone, Bracken, Campbell, Carroll, Gallatin, Grant, Kenton, Owen, and Pendleton
- North Central Region:
  member systems: Nolin RECC, Salt River Electric Cooperative, and Shelby Energy Cooperative
  counties: Bullitt, Hardin, Henry, Jefferson, Larue, Meade, Nelson, Oldham, Shelby, Spencer, Trimble, and Washington
- North East Region:
  member systems: Clark Energy Cooperative, Fleming-Mason Energy Cooperative, and Grayson RECC
  counties: Bath, Boyd, Carter, Elliott, Fleming, Greenup, Lawrence, Lewis, Mason, Menifee, Montgomery, Nicholas, Powell, Robertson, and Rowan
- South Region:
  member systems: Inter-County Energy Cooperative, South Kentucky RECC, and Taylor County RECC
  counties: Adair, Boyle, Casey, Garrard, Green, Lincoln, Marion, McCreary, Pulaski, Russell, Taylor, and Wayne
- South Central Region:
  member system: Farmers RECC
  counties: Allen, Barren, Butler, Cumberland, Edmonson, Grayson, Hart, Metcalfe, Monroe, Simpson, and Warren

EKPC calculates each member system's share of its region's economy by dividing its actual (as adjusted for reclassifications) and forecast residential consumer count by the total number of households in the region. The share is then applied to all economic variables (including households, employment, and real personal income) before they are used in other models.

The "2012 Load Forecast" is based on IHS Global Insight's county-level economic forecasts released on March 1, 2012.

3.1.2 Electric Appliance Saturation and Efficiency Trends

Every 2-3 years since 1981, EKPC has surveyed its member systems' residential consumers to gather information on electric appliance saturation and other factors affecting electricity demand. EKPC projects these saturations for each member system as a function of time. The "2012 Load Forecast" incorporates data from surveys through EKPC's "2011 Member System End-Use Survey".

EKPC is a member of Itron's Energy Forecasting Group and as such, receives from Itron electric appliance efficiency projections for the East South Central U.S. Census Division (which comprises the states of Alabama, Kentucky, Mississippi, and Tennessee) based on information from the Energy Information Administration (EIA). The projections used in the "2012 Load Forecast" are from Itron's "2011 Residential Statistically Adjusted End-use (SAE) Spreadsheets" and incorporate data from EIA's "Annual Energy Outlook 2011".

3.1.3 Electricity Rates

The wholesale power cost projections used in the "2012 Load Forecast" are from EKPC's "Twenty-Year Financial Forecast, 2011-2030", which was approved by EKPC's Board of Directors in July 2011, while distribution rate assumptions are based on information from member system staff.

3.1.4 Weather

The forecasts rely on NOAA's "1981-2010 U.S. Climate Normals" for weather stations located at seven airports in or near the EKPC system. Member systems are assigned to airports as follows:

- Blue Grass Airport (LEX) in Lexington, KY:
  member systems: Blue Grass Energy Cooperative, Clark Energy Cooperative, and Inter-County Energy Cooperative
- Bowling Green/Warren County Regional Airport (BWG) in Bowling Green, KY:
  member systems: Farmers RECC and Taylor County RECC
- Cincinnati/Northern Kentucky International Airport (CVG) in Covington, KY:
  member systems: Fleming-Mason Energy Cooperative and Owen Electric Cooperative
- Huntington Tri-State Airport (HTS) in Huntington, WV:
  member system: Grayson RECC
- Julian Carroll Airport (JKL) in Jackson, KY:
  member systems: Big Sandy RECC, Cumberland Valley Electric, Jackson Energy Cooperative, and Licking Valley RECC
- Louisville International Airport (SDF) in Louisville, KY:
  member systems: Nolin RECC, Salt River Electric Cooperative, and Shelby Energy Cooperative
- Pulaski County Airport (SME) in Somerset, KY:
  member system: South Kentucky RECC

3.2 Models of Consumers and Energy Sales by Consumer Class

The following section describes EKPC's models of consumers and energy sales by consumer class for each member system. In cases of reclassification of consumers or data errors on RUS Form 7, the models include binary variables to account for these shifts or spikes in the data.

3.2.1 Residential

As of 2011, residential consumers account for 59.0 percent of total energy sales at the EKPC system level.

EKPC models the annual change in residential consumers as a function of the annual change in regional households.

EKPC models monthly residential energy sales per consumer within Itron's statistically adjusted end-use (SAE) framework, which combines the strengths of end-use models and time-series analysis.

The SAE approach segments the average household use into end-use components as follows:

$$Use_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m},$$

where y = year and m = month.

Then, for example, the cooling use index is a function of cooling degree days, household size, real personal income, electricity rates, and an index accounting for the saturation and efficiency of various types of electric cooling appliances:

$$\begin{aligned} Cool_{y,m} = \quad & (CDD_{y,m} / CDD_{normal})^{e1} * (HHSize_{y,m} / HHSize_{b})^{e2} * \\ & (Income_{y,m} / Income_{b})^{e3} * (Rate_{y,m} / Rate_{b})^{e4} * \\ & (\textstyle\sum_{type} Weight_{type} * (Sat_{y,type} / Sat_{b,type}) / (Eff_{y,type} / Eff_{b,type})) \end{aligned}$$

where y = year, m = month, b = base year, and e1-e4 are elasticities estimated by Itron.

$Heat_{y,m}$, $Cool_{y,m}$, and $Other_{y,m}$ then serve as independent variables in a linear regression explaining $Use_{y,m}$.

3.2.2 Seasonal Residential

As of 2011, only one member system reports seasonal residential consumers, which account for 0.1 percent of total energy sales at the EKPC system level.

EKPC combines the residential and seasonal residential classes within the SAE framework, then separates consumers using a model of the ratio of seasonal residential to residential consumers as a function of the total number of consumers in the two classes and separates energy sales using a model of the ratio of seasonal residential to residential energy sales as a function of the total number of consumers in the two classes and monthly binary variables.

3.2.3 Commercial and Industrial ≤ 1000 KVA

As of 2011, commercial and industrial ≤ 1000 KVA consumers account for 15.9 percent of total energy sales at the EKPC system level.

EKPC models the annual change in commercial and industrial ≤ 1000 KVA consumers as a function of the annual change in the cooperative portion of regional employment.

For two member systems reporting multiple substantial reclassifications of consumers between the residential and commercial and industrial ≤ 1000 KVA classes, EKPC models the annual change in the total number of consumers in these two classes as a function of the annual change in the cooperative portion of both regional households and regional employment, then separates consumers using a model of the ratio of commercial and industrial ≤ 1000 KVA to residential consumers as a function of the ratio of regional employment to households.

EKPC models monthly commercial and industrial ≤ 1000 KVA energy sales per consumer as a function of heating and cooling degree days, the number of days in the month, and a time trend.

3.2.4 Commercial and Industrial > 1000 KVA

As of 2011, commercial and industrial > 1000 KVA consumers account for 24.6 percent of total energy sales at the EKPC system level.

EKPC models the commercial and industrial > 1000 KVA class at its system level using models analogous to those used for the commercial and industrial ≤ 1000 KVA class at the member system level. Member systems remain in regular contact with their largest consumers and are generally aware of current production and future expansion plans, so they project energy sales for existing consumers and identified expected new consumers in this class for the next 3 years. EKPC assigns unallocated growth for the next 3 years and all growth in the long term to its member systems based on the change in the cooperative portion of regional employment.

3.2.5 Public Street and Highway Lighting

As of 2011, 12 member systems report public street and highway lighting consumers, which account for 0.1 percent of total energy sales at the EKPC system level.

EKPC models the change in public street and highway lighting consumers as a function of the change in the cooperative portion of regional households.

EKPC models monthly public street and highway lighting energy sales per consumer as a function of a time trend.

3.2.6 Other Public Authorities

As of 2011, only two member systems report other public authorities consumers, which account for 0.3 percent of total energy sales at the EKPC system level.

EKPC models the annual change in other public authorities consumers as a function of the annual change in the cooperative portion of regional households.

EKPC models monthly other public authorities energy sales per consumer as a function of heating and cooling degree days, the number of days in the month, and a time trend.

3.3 Calculations

The following section describes various calculations that are performed after consumers and energy sales by consumer class for each member system have been forecast.

3.3.1 Own Use

For EKPC and each member system, future own use is assumed to be the average of recent own use, unless there is a specific reason to assume otherwise, as in the temporary increase in EKPC own use related to the construction of Quality Control System ("AQCS") at Cooper Unit 2.

3.3.2 Losses

Future member system distribution and EKPC transmission losses are assumed to be the average of actual losses.

3.3.3 Seasonal Peaks

Within Itron's SAE framework, future seasonal peak demands are calculated by applying load factors to the forecasted heating, cooling, water heating, and other energy sales of the residential class and to the forecasted total energy sales of each other consumer class. EKPC adjusts these load factors to match recent data as closely as possible.

3.3.4 Demand-Side Management

For more than 30 years, EKPC and its member systems have proactively helped consumers identify opportunities to improve the energy efficiency of their homes and businesses and to shift their consumption from on-peak to off-peak hours, offering a variety of options to achieve these goals. EKPC considers these demand-side management (DSM) programs as part of its overall resource portfolio, as they can delay the need for additional generating capacity. The "2012 Load Forecast" incorporates EKPC's current 5-year DSM implementation plan and an assumption of similar levels of implementation in subsequent years.

3.4 Development of Alternative Economic and Weather Scenarios

EKPC presents three economic growth scenarios:

- Baseline: This is the most likely forecast scenario.
- Lower: The annual increase in energy sales falls short of the baseline by the same amount by which the average annual increase in energy sales in the slowest-growing 10-year period in the past 20 years falls short of the 20-year average annual increase.
- Higher: The annual increase in energy sales exceeds the baseline by the same amount by which the average annual increase in energy sales in the fastest-growing 10-year period in the past 20 years exceeds the 20-year average annual increase.

For each weather station, EKPC uses the distribution of weather during 1981-2010 to identify five scenarios:

- 1-in-30 mild,
- 1-in-2 normal,
- 1-in-5 extreme,
- 1-in-10 extreme, and
- 1-in-30 extreme,

for each of four weather concepts:

- winter minimum temperature,
- summer maximum temperature,
- annual heating degree days, and
- annual cooling degree days.

Total energy requirements, winter peak demand, and summer peak demand are modeled as functions of the appropriate weather concepts.

SECTION 4.0

KEY ASSUMPTIONS

Section 4.0
Key Assumptions

4.1.0 Regional Economic Growth

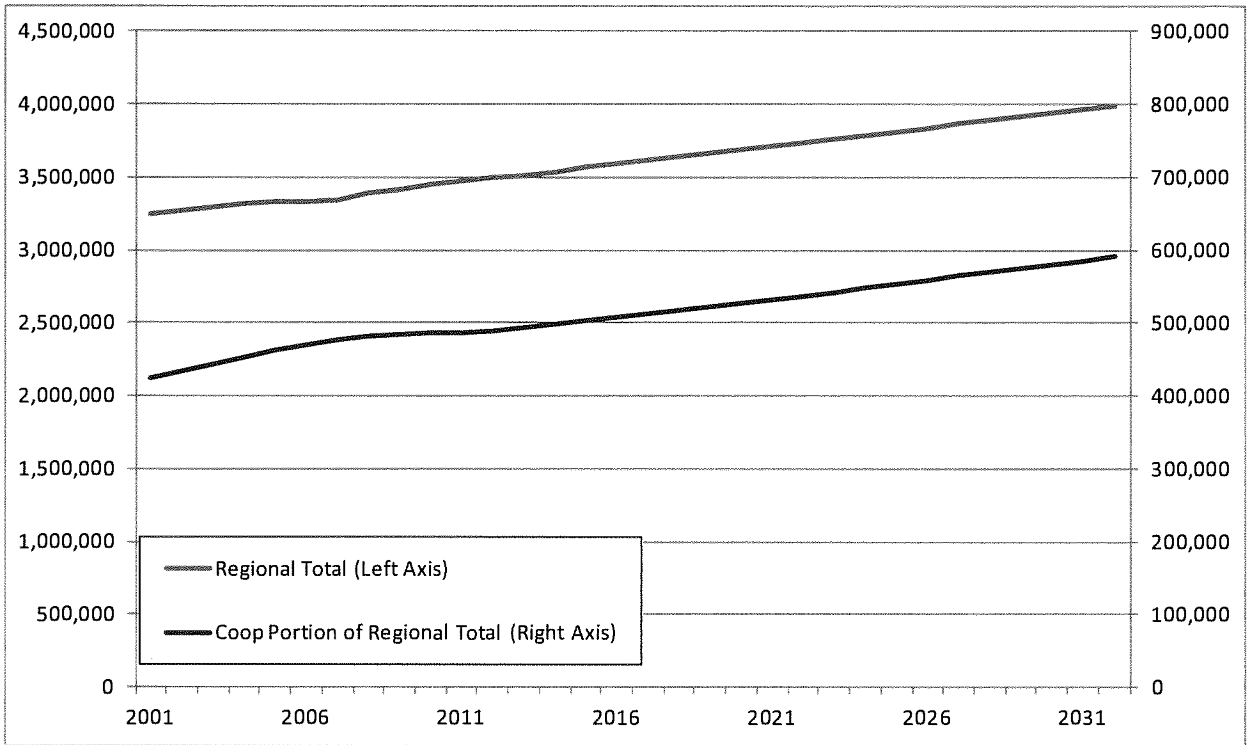
Average Growth Rates	Time Period	Households: Regional Total	Households: Coop Portion of Regional Total	Employment: Regional Total	Employment: Coop Portion of Regional Total	Real Personal Income per Household: Regional Total	Real Personal Income per Household: Coop Portion of Regional Total
5-Year	2006-2011	0.8%	0.7%	-0.6%	-0.8%	0.2%	0.3%
	2012-2017	0.7%	0.9%	1.4%	1.8%	1.8%	1.9%
10-Year	2001-2011	0.7%	1.4%	-0.1%	0.6%	0.7%	0.8%
	2012-2022	0.7%	0.9%	1.0%	1.4%	1.8%	1.8%
15-Year	1996-2011	0.8%	1.8%	0.4%	1.6%	1.4%	1.5%
	2012-2027	0.7%	1.0%	0.9%	1.3%	1.8%	1.8%
20-Year	1991-2011	1.0%	2.1%	0.9%	2.1%	1.4%	1.4%
	2012-2032	0.7%	1.0%	0.8%	1.2%	1.8%	1.8%

Average growth rates in the member systems' service territories are expected to exceed those in the region as a whole, as has been the case over the long term.

While the growth rates for both households and employment in the member systems' service territories forecasted for the next 5 years are somewhat faster than those of the past 5 years including the recent recession, the growth rates forecast for the next 20 years are about half of those of the past 20 years.

Employment is forecast to growth faster than households, as has been the case over the long term. Real personal income per household is forecast to grow more quickly than it has in the past, primarily due to the increased number of employees per household.

4.1.1 Regional Households



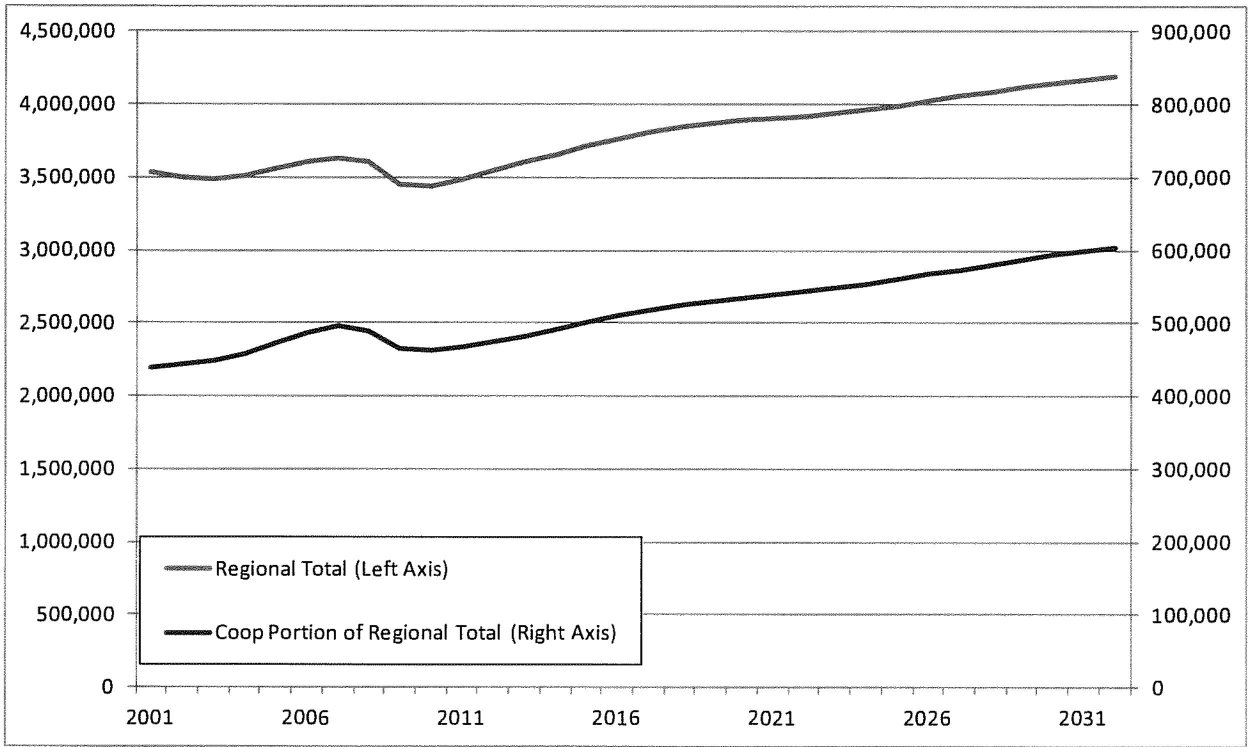
The forecast indicates that, through 2032, total regional households will increase from 3,492,348 to 3,992,785, an average of 0.7 percent per year, while the cooperative portion of the regional total will increase from 489,145 to 590,998, an average of 1.0 percent per year.

The Central and North Regions are forecast to grow most quickly, at 1.1 percent per year, while the East Region is forecast to grow least quickly, at 0.1 percent per year.

Regional Households

Year	Central	East	North	North Central	North East	South	South Central
2001	238,506	213,925	155,709	104,305	104,305	104,986	104,082
2002	241,314	214,318	157,174	104,469	104,469	105,818	105,458
2003	244,625	213,401	158,985	104,417	104,417	106,811	106,946
2004	247,806	212,813	161,125	104,426	104,426	108,019	108,571
2005	252,206	210,099	162,178	104,456	104,456	107,694	108,285
2006	255,449	207,159	162,990	103,812	103,812	106,739	108,132
2007	259,573	207,953	165,531	104,733	104,733	107,555	110,827
2008	263,470	210,034	167,654	106,453	106,453	109,446	112,408
2009	265,814	211,261	170,097	107,070	107,070	110,704	113,419
2010	269,503	210,687	172,366	107,170	107,170	111,114	114,162
2011	272,199	209,529	173,771	106,830	106,830	110,978	114,630
2012	275,828	209,093	175,663	106,833	106,833	111,413	115,459
2013	279,184	208,674	177,530	107,000	107,000	111,864	116,295
2014	282,788	208,568	179,717	107,357	107,357	112,526	117,258
2015	286,472	208,971	181,903	107,799	107,799	113,505	118,592
2016	289,689	209,292	183,912	108,387	108,387	114,514	119,825
2017	292,529	209,329	185,594	108,883	108,883	115,437	120,716
2018	295,700	209,590	187,574	109,517	109,517	116,527	121,784
2019	298,864	209,767	189,525	110,175	110,175	117,641	122,892
2020	302,009	209,794	191,564	110,709	110,709	118,663	123,851
2021	305,054	209,705	193,579	111,127	111,127	119,580	124,722
2022	308,284	209,698	195,550	111,630	111,630	120,586	125,751
2023	311,635	209,766	197,621	112,184	112,184	121,662	126,767
2024	314,866	209,703	199,638	112,660	112,660	122,678	127,727
2025	318,344	209,766	201,828	113,224	113,224	123,830	128,826
2026	322,099	210,223	204,138	113,937	113,937	125,109	130,104
2027	325,519	210,427	206,353	114,492	114,492	126,116	131,287
2028	328,494	210,300	208,328	114,929	114,929	126,923	132,347
2029	331,777	210,495	210,507	115,486	115,486	127,847	133,566
2030	335,065	210,777	212,697	115,972	115,972	128,745	134,608
2031	338,376	211,139	214,923	116,411	116,411	129,586	135,635
2032	341,707	211,411	217,176	116,911	116,911	130,410	136,918

4.1.2 Regional Employment



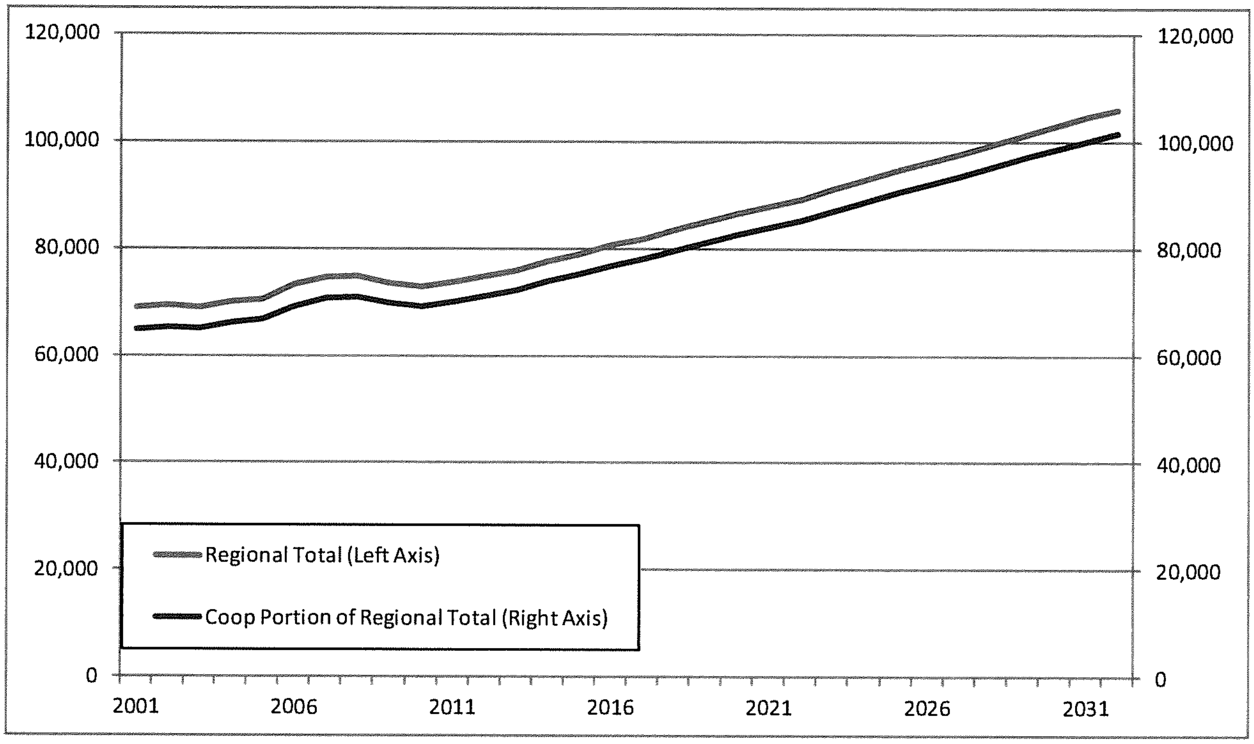
The forecast indicates that, through 2032, total regional employment will increase from 3,547,340 to 4,191,398, an average of 0.8 percent per year, while the cooperative portion of the regional total will increase from 474,052 to 603,688, an average of 1.2 percent per year.

The North Region is forecast to grow most quickly, at 1.5 percent per year, while the East Region is forecast to grow least quickly, at 0.6 percent per year.

Regional Employment

Year	Central	East	North	North Central	North East	South	South Central
2001	326,208	169,931	177,677	90,956	90,956	94,106	111,589
2002	324,099	165,573	180,430	92,898	92,898	93,158	111,247
2003	323,591	164,339	183,117	93,733	93,733	92,195	111,529
2004	328,280	167,456	187,538	93,561	93,561	93,417	114,561
2005	335,357	168,486	190,937	94,324	94,324	95,241	115,854
2006	339,876	168,043	192,628	94,896	94,896	96,420	116,831
2007	342,122	168,345	197,555	95,641	95,641	96,449	118,493
2008	329,219	166,081	191,503	91,684	91,684	92,590	112,604
2009	319,732	161,440	183,839	89,000	89,000	90,122	108,204
2010	325,431	161,277	187,854	89,889	89,889	91,466	110,666
2011	329,877	162,220	191,356	89,635	89,635	91,415	110,758
2012	335,909	164,359	194,873	91,528	91,528	93,092	112,731
2013	341,372	166,625	198,338	92,832	92,832	94,549	114,653
2014	347,342	168,859	201,860	94,503	94,503	96,274	116,688
2015	352,822	170,953	205,339	96,092	96,092	97,899	118,609
2016	357,646	172,469	208,977	97,558	97,558	99,441	120,309
2017	361,781	173,480	212,297	98,822	98,822	100,671	121,661
2018	364,981	174,272	215,122	99,762	99,762	101,661	122,766
2019	368,155	175,081	217,892	100,527	100,527	102,674	123,893
2020	370,957	175,645	220,929	101,167	101,167	103,569	124,863
2021	372,939	175,726	223,393	101,562	101,562	104,295	125,570
2022	375,306	175,967	225,854	101,987	101,987	105,126	126,349
2023	378,359	176,515	228,933	102,602	102,602	106,122	127,298
2024	381,501	177,155	232,211	103,363	103,363	107,277	128,364
2025	384,970	177,878	235,845	104,189	104,189	108,535	129,537
2026	388,813	178,685	239,521	105,132	105,132	109,823	130,746
2027	392,320	179,511	243,224	105,967	105,967	110,982	131,820
2028	395,666	180,464	246,877	106,822	106,822	112,140	132,912
2029	399,084	181,395	250,562	107,673	107,673	113,268	133,959
2030	402,202	182,231	254,084	108,383	108,383	114,252	134,888
2031	404,708	182,925	256,984	108,940	108,940	115,057	135,662
2032	407,086	183,479	259,970	109,435	109,435	115,807	136,342

4.1.3 Regional Real Personal Income per Household (2005 U.S. Dollars)



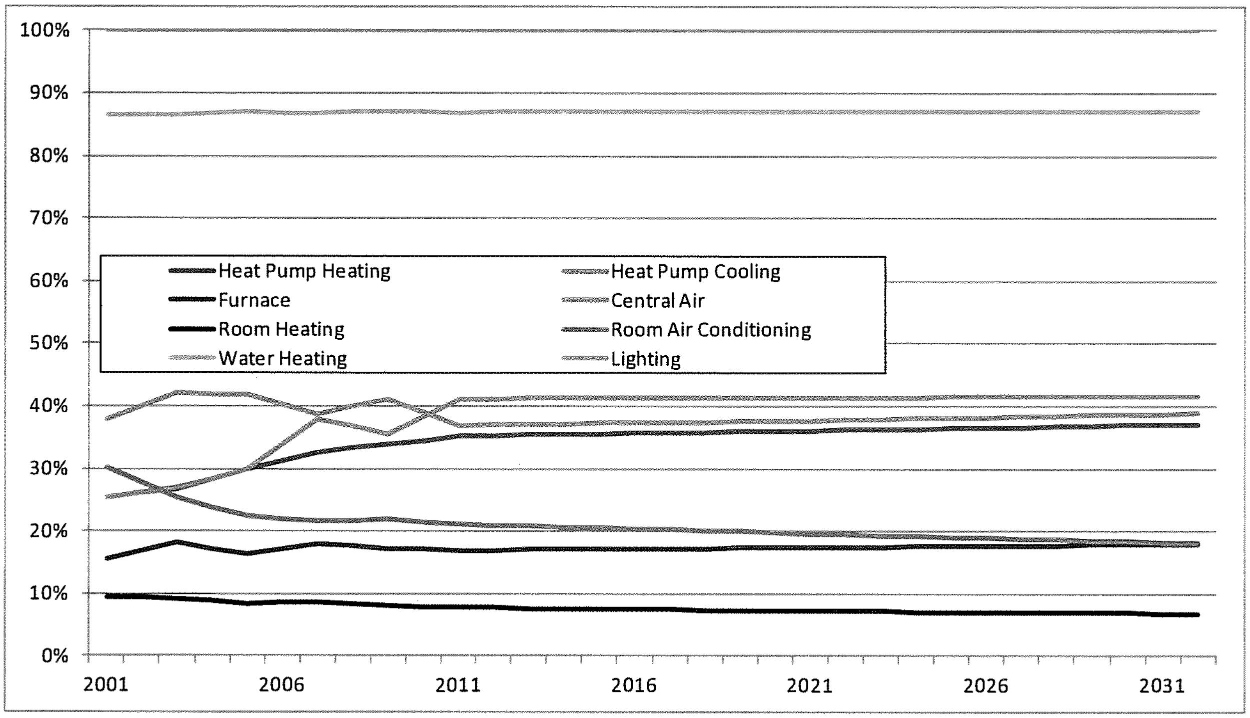
The forecast indicates that, through 2032, total regional real personal income per household (2005 U.S. dollars) will increase from $74,725 to $106,010, an average of 1.8 percent per year, while the cooperative portion of the regional total will increase from $71,030 to $101,575, an average of 1.8 percent per year.

The South Region is forecast to grow most quickly, at 2.0 percent per year, while the South Central Region is forecast to grow least quickly, at 1.6 percent per year.

Regional Real Personal Income per Household (2005 U.S. Dollars)

Year	Central	East	North	North Central	North East	South	South Central
2001	77,520	51,902	81,301	56,988	56,988	54,955	59,049
2002	77,510	51,353	81,743	58,413	58,413	54,900	59,452
2003	77,413	51,913	82,390	58,664	58,664	54,940	60,381
2004	77,591	53,379	83,330	58,878	58,878	55,555	61,307
2005	78,513	55,112	84,773	59,758	59,758	56,353	62,789
2006	81,110	56,922	86,482	61,981	61,981	58,587	64,594
2007	80,781	58,920	86,690	63,433	63,433	60,142	65,124
2008	78,832	60,786	84,830	63,689	63,689	59,725	64,403
2009	76,544	60,513	81,095	63,051	63,051	59,121	62,848
2010	76,094	60,863	80,682	63,605	63,605	59,704	63,389
2011	76,914	62,204	81,224	64,970	64,970	60,769	64,205
2012	77,627	63,283	81,814	66,369	66,369	61,897	65,217
2013	79,032	64,948	83,211	68,036	68,036	63,538	66,648
2014	80,556	66,531	84,570	69,578	69,578	65,154	68,025
2015	81,790	67,905	85,601	71,201	71,201	66,545	69,127
2016	83,098	69,295	86,766	72,647	72,647	68,064	70,570
2017	84,426	70,567	88,153	73,856	73,856	69,421	71,889
2018	85,950	72,070	89,748	75,350	75,350	70,880	73,228
2019	87,636	73,284	91,527	76,674	76,674	72,024	74,336
2020	89,070	74,609	92,990	78,097	78,097	73,334	75,472
2021	90,287	75,845	94,207	79,394	79,394	74,663	76,538
2022	92,012	77,404	95,986	80,943	80,943	76,286	77,791
2023	94,008	78,888	98,112	82,393	82,393	77,809	79,051
2024	95,795	80,379	100,148	83,951	83,951	79,447	80,483
2025	97,592	81,781	102,018	85,292	85,292	81,004	81,802
2026	99,326	82,876	103,826	86,542	86,542	82,289	82,711
2027	100,997	84,247	105,625	88,067	88,067	83,809	83,841
2028	102,905	85,755	107,537	89,461	89,461	85,365	85,023
2029	104,752	87,143	109,663	90,814	90,814	86,840	86,123
2030	106,489	88,567	111,645	92,186	92,186	88,340	87,272
2031	108,021	89,896	113,202	93,543	93,543	89,749	88,300
2032	109,495	91,197	114,757	94,792	94,792	91,133	89,101

4.2.1 Electric Appliance Saturation Trends



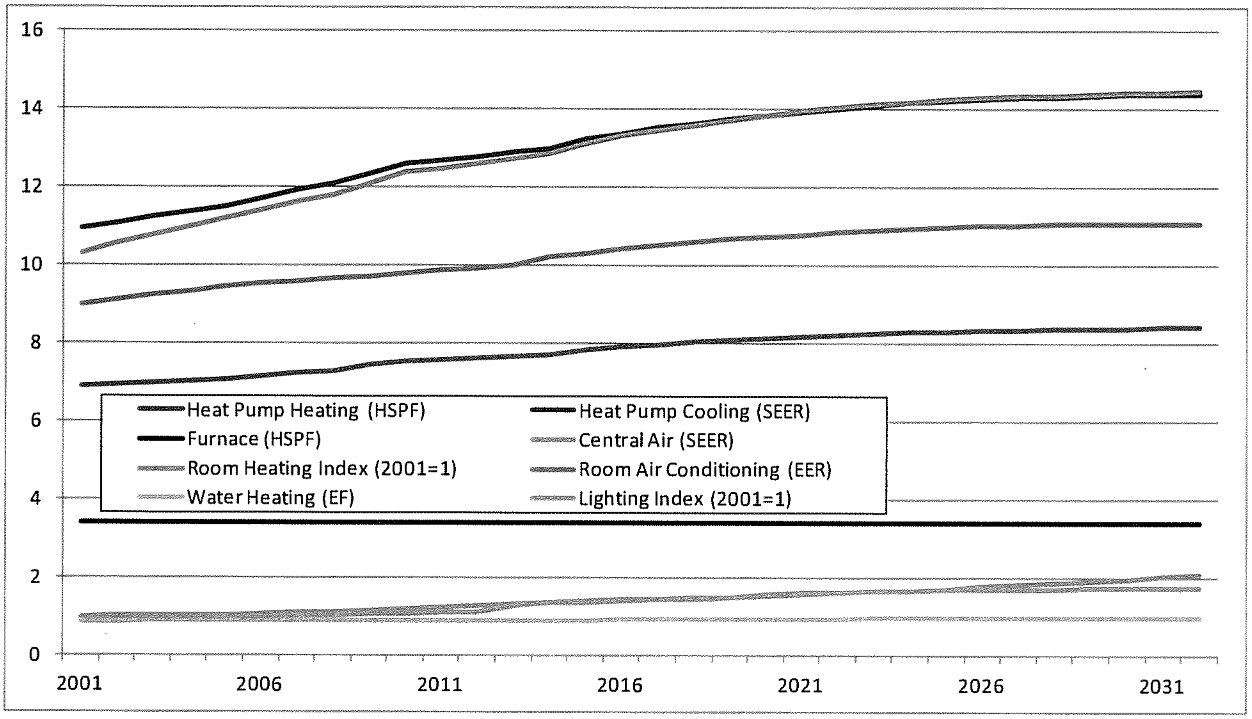
The saturation of electric heating is projected to continue to increase, with consumers installing more-efficient heating appliances such as heat pumps rather than individual room heaters.

Nearly all homes now have electric cooling of some type, with the saturation of room air conditioning projected to continue to decline in favor of heat pump and central air in new homes.

Electric Appliance Saturation Trends

Year	Heat Pump Heating	Furnace	Room Heating	Heat Pump Cooling	Central Air	Room Air Conditioning	Water Heating	Lighting
2001	25%	16%	9%	25%	38%	30%	86%	100%
2002	26%	17%	9%	26%	40%	28%	86%	100%
2003	27%	18%	9%	27%	42%	25%	86%	100%
2004	28%	17%	9%	28%	42%	24%	87%	100%
2005	30%	16%	8%	30%	42%	22%	87%	100%
2006	31%	17%	8%	34%	40%	22%	87%	100%
2007	33%	18%	9%	38%	39%	22%	87%	100%
2008	33%	18%	8%	37%	40%	22%	87%	100%
2009	34%	17%	8%	36%	41%	22%	87%	100%
2010	35%	17%	8%	38%	39%	21%	87%	100%
2011	35%	17%	8%	41%	37%	21%	87%	100%
2012	35%	17%	8%	41%	37%	21%	87%	100%
2013	35%	17%	8%	41%	37%	21%	87%	100%
2014	35%	17%	8%	41%	37%	21%	87%	100%
2015	36%	17%	8%	41%	37%	20%	87%	100%
2016	36%	17%	7%	41%	37%	20%	87%	100%
2017	36%	17%	7%	41%	37%	20%	87%	100%
2018	36%	17%	7%	41%	37%	20%	87%	100%
2019	36%	17%	7%	41%	38%	20%	87%	100%
2020	36%	17%	7%	41%	38%	20%	87%	100%
2021	36%	17%	7%	41%	38%	20%	87%	100%
2022	36%	17%	7%	41%	38%	19%	87%	100%
2023	36%	17%	7%	41%	38%	19%	87%	100%
2024	36%	18%	7%	41%	38%	19%	87%	100%
2025	36%	18%	7%	41%	38%	19%	87%	100%
2026	37%	18%	7%	41%	38%	19%	87%	100%
2027	37%	18%	7%	42%	38%	19%	87%	100%
2028	37%	18%	7%	42%	38%	19%	87%	100%
2029	37%	18%	7%	42%	39%	19%	87%	100%
2030	37%	18%	7%	42%	39%	18%	87%	100%
2031	37%	18%	7%	42%	39%	18%	87%	100%
2032	37%	18%	7%	42%	39%	18%	87%	100%

4.2.2 Electric Appliance Efficiency Trends



The efficiency of electric lighting is expected to increase quickly during the forecast period as the standards contained in the Energy Independence and Security Act of 2007 phase in.

Electric Appliance Efficiency Trends

Year	Heat Pump Heating (HSPF)	Furnace (HSPF)	Room Heating Index (2001=1)	Heat Pump Cooling (SEER)	Central Air (SEER)	Room Air Conditioning (EER)	Water Heating (EF)	Lighting Index (2001=1)
2001	6.88	3.41	1.00	10.95	10.33	8.99	0.87	1.00
2002	6.93	3.41	1.01	11.09	10.54	9.11	0.88	1.00
2003	6.97	3.41	1.01	11.24	10.76	9.22	0.88	1.00
2004	7.02	3.41	1.02	11.38	10.97	9.34	0.88	1.00
2005	7.06	3.41	1.03	11.52	11.19	9.46	0.88	1.00
2006	7.15	3.41	1.06	11.73	11.40	9.52	0.89	1.00
2007	7.24	3.41	1.09	11.94	11.62	9.58	0.89	1.02
2008	7.30	3.41	1.12	12.09	11.80	9.65	0.89	1.04
2009	7.45	3.41	1.16	12.36	12.11	9.73	0.89	1.06
2010	7.56	3.41	1.20	12.61	12.38	9.81	0.89	1.07
2011	7.57	3.41	1.24	12.68	12.46	9.87	0.90	1.10
2012	7.62	3.41	1.29	12.79	12.61	9.94	0.90	1.11
2013	7.67	3.41	1.32	12.90	12.75	10.01	0.90	1.27
2014	7.71	3.41	1.35	13.00	12.88	10.21	0.90	1.35
2015	7.84	3.41	1.37	13.25	13.14	10.32	0.92	1.40
2016	7.91	3.41	1.40	13.39	13.31	10.42	0.92	1.43
2017	7.98	3.41	1.44	13.53	13.47	10.51	0.93	1.47
2018	8.04	3.41	1.47	13.65	13.60	10.59	0.94	1.49
2019	8.10	3.41	1.50	13.76	13.73	10.67	0.94	1.52
2020	8.14	3.41	1.53	13.85	13.86	10.74	0.95	1.58
2021	8.19	3.41	1.57	13.95	13.96	10.79	0.95	1.62
2022	8.23	3.41	1.61	14.03	14.06	10.85	0.96	1.64
2023	8.27	3.41	1.65	14.10	14.14	10.90	0.96	1.66
2024	8.30	3.41	1.68	14.16	14.20	10.94	0.97	1.67
2025	8.33	3.41	1.73	14.21	14.26	10.98	0.98	1.69
2026	8.35	3.41	1.77	14.26	14.30	11.01	0.98	1.71
2027	8.37	3.41	1.82	14.29	14.34	11.04	0.98	1.72
2028	8.38	3.41	1.86	14.32	14.37	11.05	0.99	1.73
2029	8.39	3.41	1.92	14.35	14.40	11.06	0.99	1.74
2030	8.41	3.41	1.97	14.37	14.42	11.06	0.99	1.75
2031	8.42	3.41	2.03	14.40	14.44	11.06	1.00	1.76
2032	8.42	3.41	2.09	14.42	14.46	11.06	1.00	1.76

4.3 Demand-Side Management Plan

	Additional Effect[1] of Demand-Side Management		
Year	Total Energy Requirements (MWh)	Winter Peak Demand (MW)	Summer Peak Demand (MW)
2012	-11,234		-126
2013	-28,853	-129	-134
2014	-46,538	-138	-143
2015	-67,648	-149	-156
2016	-92,395	-161	-168
2017	-120,242	-172	-181
2018	-148,090	-184	-194
2019	-175,938	-195	-207
2020	-203,785	-207	-220
2021	-231,633	-218	-232
2022	-259,481	-230	-245
2023	-287,328	-241	-258
2024	-315,176	-253	-271
2025	-343,024	-264	-284
2026	-370,872	-276	-296
2027	-398,719	-288	-298
2028	-426,567	-299	-307
2029	-454,415	-311	-315
2030	-482,261	-313	-324
2031	-510,110	-315	-336
2032	-538,442	-338	-347

[1] In order to avoid double-counting, additonal effects do not include energy efficiency measures installed prior to 2012, which are assumed to be embeded in the historical data used for modeling purposes. Additional effects do include energy efficiency measures installed from 2012 onward and all demand response regardless of the participant start date.

SECTION 5.0

KEY RESULTS

Section 5.0
Key Results

5.1 Total Energy Requirements

Year	EKPC Sales to Members (MWh)	EKPC Own Use (MWh)	Transmission Losses (MWh)	Actual Net Total Requirements (MWh)	Gross Total Requirements (MWh)	Additional Demand Side Management (MWh)	Weather-Normalized Net Total Requirements (MWh)
2001	10,426,995	8,205	315,700	10,750,900			10,751,395
2002	11,071,862	8,818	376,150	11,456,830			11,322,046
2003	11,190,870	9,123	368,321	11,568,314			11,569,542
2004	11,537,505	9,106	319,186	11,865,797			12,032,530
2005	12,060,460	8,902	458,467	12,527,829			12,410,850
2006	11,892,304	7,568	431,331	12,331,203			12,561,140
2007	12,582,260	7,491	490,395	13,080,146			12,885,901
2008	12,646,146	7,912	293,029	12,947,087			12,849,764
2009	11,981,909	8,247	381,446	12,371,602			12,454,354
2010	12,811,906	8,654	534,082	13,354,642			12,918,009
2011	12,289,071	10,146	375,673	12,674,890			12,612,430
2012	12,417,037	8,394	349,422		12,774,853	-11,234	12,763,619
2013	12,564,237	8,436	354,744		12,927,417	-28,853	12,898,564
2014	12,755,351	8,478	360,887		13,124,717	-46,538	13,078,179
2015	12,975,943	8,521	368,693		13,353,156	-67,648	13,285,509
2016	13,245,748	8,521	378,897		13,633,165	-92,395	13,540,771
2017	13,454,077	8,563	385,991		13,848,631	-120,242	13,728,389
2018	13,677,586	8,606	393,785		14,079,977	-148,090	13,931,887
2019	13,882,133	8,649	401,262		14,292,044	-175,938	14,116,106
2020	14,073,489	8,693	407,803		14,489,984	-203,785	14,286,199
2021	14,231,056	8,736	412,655		14,652,447	-231,633	14,420,814
2022	14,422,437	8,780	418,370		14,849,587	-259,481	14,590,107
2023	14,647,332	8,824	425,864		15,082,019	-287,328	14,794,691
2024	14,898,910	8,868	434,023		15,341,801	-315,176	15,026,625
2025	15,107,115	8,912	440,834		15,556,861	-343,024	15,213,837
2026	15,362,882	8,957	450,080		15,821,919	-370,872	15,451,047
2027	15,638,955	9,001	460,625		16,108,581	-398,719	15,709,862
2028	15,912,241	9,046	469,463		16,390,751	-426,567	15,964,184
2029	16,136,723	9,092	477,265		16,623,080	-454,415	16,168,665
2030	16,390,830	9,137	465,211		16,865,179	-482,261	16,382,918
2031	16,623,661	9,183	495,326		17,128,170	-510,110	16,618,060
2032	16,897,656	9,229	505,318		17,412,203	-538,442	16,873,761

The "2012 Load Forecast" indicates that, through 2032, net total energy requirements will increase from 12.8 to 16.9 million MWh, an average of 1.4 percent per year.

5.2 Winter Peak Demand

Year	Actual Peak Demand (MW)	Gross Peak Demand (MW)	Additional Demand-Side Mangement (MW)	Weather-Normalized Net Peak Demand (MW)
2001	2,283			2,407
2002	2,141			2,358
2003	2,487			2,363
2004	2,487			2,394
2005	2,601			2,880
2006	2,503			2,720
2007	2,783			2,907
2008	2,953			3,170
2009	3,130			3,130
2010	2,761			2,916
2011	2,851			2,882
2012	2,349			2,845
2013		3,076	-129	2,947
2014		3,117	-138	2,980
2015		3,166	-149	3,017
2016		3,217	-161	3,056
2017		3,274	-172	3,101
2018		3,324	-184	3,140
2019		3,370	-195	3,175
2020		3,403	-207	3,196
2021		3,447	-218	3,229
2022		3,488	-230	3,258
2023		3,538	-241	3,296
2024		3,582	-253	3,329
2025		3,637	-264	3,373
2026		3,693	-276	3,417
2027		3,754	-288	3,466
2028		3,802	-299	3,503
2029		3,861	-311	3,550
2030		3,916	-313	3,603
2031		3,965	-315	3,649
2032		4,012	-338	3,674

The “2012 Load Forecast” indicates that, through 2032, the net winter peak demand will increase from 2,947 to 3,674 MW, an average of 1.2 percent per year.

Because the winter peak demand is forecast to grow less quickly than total energy requirements, the winter peak demand-based load factor will increase slightly, from 50.0 percent in 2013 to 52.3 percent by 2032. Because the EKPC system remains winter-peaking throughout the forecast period, this also represents EKPC’s annual load factor.

5.3 Summer Peak Demand

Year	Actual Peak Demand (MW)	Gross Peak Demand (MW)	Additional Demand-Side Mangement (MW)	Weather-Normalized Net Peak Demand (MW)
2001	1,866			1,817
2002	2,004			1,955
2003	1,903			1,989
2004	1,930			2,155
2005	2,174			2,149
2006	2,208			2,235
2007	2,367			2,318
2008	2,131			2,187
2009	2,086			2,204
2010	2,316			2,316
2011	2,281			2,232
2012		2,403	-126	2,277
2013		2,439	-134	2,306
2014		2,481	-143	2,337
2015		2,524	-156	2,368
2016		2,571	-168	2,402
2017		2,617	-181	2,436
2018		2,661	-194	2,467
2019		2,700	-207	2,493
2020		2,732	-220	2,512
2021		2,769	-232	2,537
2022		2,806	-245	2,561
2023		2,849	-258	2,590
2024		2,889	-271	2,618
2025		2,937	-284	2,653
2026		2,986	-296	2,690
2027		3,039	-298	2,741
2028		3,083	-307	2,776
2029		3,134	-315	2,819
2030		3,183	-324	2,859
2031		3,228	-336	2,893
2032		3,272	-347	2,925

The "2012 Load Forecast" indicates that, through 2032, the net summer peak demand will increase from 2,277 to 2,925 MW, an average of 1.3 percent per year.

Because the summer peak demand is forecast to grow less quickly than total energy requirements, the summer peak demand-based load factor will increase slightly, from 63.8 percent in 2013 to 65.7 percent by 2032. While the EKPC system remains winter-peaking throughout the forecast period, EKPC's summer peak demand-based load factor will become more financially important than its winter peak demand-based load factor if EKPC integrates its system into the summer-peaking PJM Interconnection, as it has applied to do, pending regulatory and final EKPC Board of Directors approval.

SECTION 6.0

RESULTS BY CONSUMER CLASS

Section 6.0
Results by Consumer Class

6.1 Residential

	Consumers			Use Per Consumer			Class Sales			
	Annual Average	Annual Change	Percent Change	Monthly Average (kWh)	Change (kWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change	Percent of Total Sales
2001	421,353	9,780	2.4	1,147	7	0.7	5,797,895	171,395	3.0	58.0
2002	431,129	9,776	2.3	1,192	45	3.9	6,166,723	368,828	6.4	58.2
2003	441,589	10,460	2.4	1,171	-21	-1.8	6,205,364	38,641	0.6	58.1
2004	451,047	9,458	2.1	1,171	0	0.0	6,337,737	132,372	2.1	57.5
2005	455,943	4,896	1.1	1,234	63	5.4	6,751,547	413,810	6.5	58.5
2006	465,468	9,525	2.1	1,172	-62	-5.0	6,545,582	-205,964	-3.1	57.3
2007	471,495	6,027	1.3	1,237	65	5.5	6,998,166	452,584	6.9	58.2
2008	478,951	7,456	1.6	1,228	-9	-0.8	7,055,279	57,113	0.8	58.8
2009	480,398	1,447	0.3	1,178	-50	-4.1	6,789,142	-266,137	-3.8	59.2
2010	481,691	1,293	0.3	1,278	101	8.5	7,388,901	599,759	8.8	60.4
2011	482,351	660	0.1	1,204	-75	-5.8	6,967,428	-421,473	-5.7	59.0
2012	485,100	2,749	0.6	1,186	-18	-1.5	6,903,076	-64,352	-0.9	58.2
2013	488,993	3,893	0.8	1,179	-7	-0.6	6,917,937	14,861	0.2	57.7
2014	493,552	4,559	0.9	1,176	-3	-0.2	6,964,989	47,052	0.7	57.2
2015	498,765	5,213	1.1	1,177	1	0.1	7,043,219	78,231	1.1	56.8
2016	504,206	5,441	1.1	1,183	6	0.5	7,157,047	113,827	1.6	56.6
2017	508,755	4,549	0.9	1,188	5	0.4	7,252,604	95,558	1.3	56.5
2018	513,480	4,725	0.9	1,194	6	0.5	7,358,298	105,694	1.5	56.3
2019	518,695	5,215	1.0	1,197	3	0.3	7,452,189	93,890	1.3	56.2
2020	523,818	5,123	1.0	1,196	-1	-0.1	7,517,904	65,715	0.9	55.9
2021	528,680	4,862	0.9	1,197	1	0.1	7,594,056	76,151	1.0	55.9
2022	533,465	4,785	0.9	1,201	4	0.3	7,689,479	95,424	1.3	55.8
2023	538,719	5,254	1.0	1,208	7	0.6	7,808,136	118,657	1.5	55.8
2024	543,782	5,063	0.9	1,215	7	0.6	7,927,888	119,753	1.5	55.7
2025	549,088	5,306	1.0	1,219	4	0.4	8,034,595	106,707	1.3	55.7
2026	554,996	5,908	1.1	1,225	6	0.5	8,161,669	127,074	1.6	55.6
2027	561,073	6,077	1.1	1,234	9	0.7	8,309,314	147,645	1.8	55.6
2028	565,972	4,899	0.9	1,243	8	0.7	8,439,371	130,057	1.6	55.5
2029	571,042	5,070	0.9	1,249	6	0.5	8,556,449	117,078	1.4	55.5
2030	576,408	5,366	0.9	1,256	7	0.5	8,684,341	127,893	1.5	55.5
2031	581,635	5,227	0.9	1,261	6	0.4	8,802,299	117,958	1.4	55.5
2032	587,061	5,426	0.9	1,270	8	0.7	8,943,581	141,282	1.6	55.4

6.2 Residential Seasonal

	Consumers			Use Per Consumer			Class Sales			
	Annual Average	Annual Change	Percent Change	Monthly Average (kWh)	Change (kWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change	Percent of Total Sales
2001	3,799	86	2.3	280	0	0.0	12,769	290	2.3	0.1
2002	3,956	157	4.1	297	16	5.9	14,076	1,307	10.2	0.1
2003	4,046	90	2.3	277	-20	-6.6	13,445	-631	-4.5	0.1
2004	4,162	116	2.9	277	0	0.1	13,846	402	3.0	0.1
2005	4,297	135	3.2	281	4	1.4	14,501	655	4.7	0.1
2006	4,371	74	1.7	265	-17	-5.9	13,882	-619	-4.3	0.1
2007	4,459	88	2.0	274	10	3.7	14,679	797	5.7	0.1
2008	4,463	4	0.1	271	-3	-1.1	14,531	-149	-1.0	0.1
2009	4,420	-43	-1.0	247	-25	-9.1	13,080	-1,451	-10.0	0.1
2010	4,490	70	1.6	259	12	5.1	13,959	879	6.7	0.1
2011	4,518	28	0.6	236	-23	-9.1	12,774	-1,185	-8.5	0.1
2012	4,517	-1	0.0	248	12	5.1	13,419	645	5.1	0.1
2013	4,548	31	0.7	244	-4	-1.5	13,309	-110	-0.8	0.1
2014	4,614	66	1.5	240	-4	-1.6	13,285	-24	-0.2	0.1
2015	4,682	68	1.5	236	-4	-1.5	13,279	-7	-0.1	0.1
2016	4,770	88	1.9	232	-4	-1.7	13,298	20	0.1	0.1
2017	4,851	81	1.7	228	-4	-1.7	13,292	-6	0.0	0.1
2018	4,938	87	1.8	224	-4	-1.8	13,285	-7	-0.1	0.1
2019	5,033	95	1.9	219	-5	-2.4	13,216	-69	-0.5	0.1
2020	5,122	89	1.8	213	-6	-2.6	13,106	-110	-0.8	0.1
2021	5,197	75	1.5	209	-4	-2.1	13,025	-81	-0.6	0.1
2022	5,271	74	1.4	205	-4	-1.8	12,970	-55	-0.4	0.1
2023	5,354	83	1.6	201	-4	-1.9	12,917	-52	-0.4	0.1
2024	5,433	79	1.5	197	-4	-1.9	12,858	-59	-0.5	0.1
2025	5,510	77	1.4	193	-4	-2.1	12,768	-90	-0.7	0.1
2026	5,603	93	1.7	188	-5	-2.7	12,634	-134	-1.0	0.1
2027	5,695	92	1.6	183	-5	-2.7	12,491	-143	-1.1	0.1
2028	5,767	72	1.3	180	-3	-1.8	12,427	-65	-0.5	0.1
2029	5,843	76	1.3	176	-3	-1.8	12,362	-65	-0.5	0.1
2030	5,923	80	1.4	172	-4	-2.4	12,229	-132	-1.1	0.1
2031	5,992	69	1.2	168	-4	-2.2	12,104	-125	-1.0	0.1
2032	6,065	73	1.2	165	-4	-2.2	11,986	-118	-1.0	0.1

6.3 Commercial and Industrial ≤ 1000 KVA

	Consumers			Use Per Consumer			Class Sales			
	Annual Average	Annual Change	Percent Change	Annual Average (MWh)	Change (MWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change	Percent of Total Sales
2001	25,129	1,395	5.9	60	-2	-2.9	1,505,480	41,188	2.8	15.1
2002	27,070	1,941	7.7	58	-2	-3.2	1,569,579	64,099	4.3	14.8
2003	26,660	-410	-1.5	58	0	0.3	1,550,248	-19,331	-1.2	14.5
2004	28,125	1,465	5.5	57	-1	-2.3	1,598,111	47,864	3.1	14.5
2005	30,594	2,469	8.8	57	0	-0.3	1,733,410	135,298	8.5	15.0
2006	30,193	-401	-1.3	59	2	3.9	1,777,897	44,487	2.6	15.6
2007	30,981	788	2.6	60	1	2.1	1,861,952	84,055	4.7	15.5
2008	32,036	1,055	3.4	58	-2	-2.7	1,872,811	10,859	0.6	15.6
2009	32,386	350	1.1	55	-3	-5.6	1,786,459	-86,352	-4.6	15.6
2010	32,553	167	0.5	59	4	7.8	1,936,337	149,877	8.4	15.8
2011	32,651	98	0.3	58	-2	-3.1	1,881,733	-54,604	-2.8	15.9
2012	33,063	412	1.3	59	1	1.7	1,937,511	55,778	3.0	16.3
2013	33,603	540	1.6	59	1	1.3	1,994,879	57,368	3.0	16.6
2014	34,170	567	1.7	60	1	0.9	2,046,695	51,816	2.6	16.8
2015	34,726	556	1.6	60	0	0.7	2,094,722	48,027	2.3	16.9
2016	35,265	539	1.6	61	1	0.9	2,145,836	51,114	2.4	17.0
2017	35,741	476	1.3	61	0	0.4	2,182,421	36,586	1.7	17.0
2018	36,164	423	1.2	61	0	0.6	2,220,732	38,310	1.8	17.0
2019	36,552	388	1.1	62	0	0.5	2,256,780	36,048	1.6	17.0
2020	36,932	380	1.0	62	0	0.8	2,297,996	41,216	1.8	17.1
2021	37,253	321	0.9	62	0	0.3	2,324,739	26,743	1.2	17.1
2022	37,562	309	0.8	63	0	0.5	2,356,060	31,320	1.3	17.1
2023	37,895	333	0.9	63	0	0.5	2,389,403	33,343	1.4	17.1
2024	38,255	360	0.9	64	0	0.8	2,430,429	41,026	1.7	17.1
2025	38,622	367	1.0	64	0	0.3	2,460,751	30,322	1.2	17.1
2026	39,016	394	1.0	64	0	0.5	2,498,906	38,155	1.6	17.0
2027	39,397	381	1.0	64	0	0.5	2,536,511	37,605	1.5	17.0
2028	39,762	365	0.9	65	0	0.8	2,579,264	42,753	1.7	17.0
2029	40,124	362	0.9	65	0	0.3	2,609,744	30,480	1.2	16.9
2030	40,479	355	0.9	65	0	0.5	2,646,172	36,428	1.4	16.9
2031	40,787	308	0.8	66	0	0.5	2,679,600	33,428	1.3	16.9
2032	41,081	294	0.7	66	0	0.7	2,718,663	39,062	1.5	16.9

6.4 Commercial and Industrial > 1000 KVA

	Consumers			Use Per Consumer			Class Sales			
	Annual Average	Annual Change	Percent Change	Annual Average (MWh)	Change (MWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change	Percent of Total Sales
2001	111	7	6.7	23,951	506	2.2	2,658,529	220,310	9.0	26.6
2002	111	0	0.0	25,319	1,369	5.7	2,810,446	151,917	5.7	26.5
2003	133	22	19.8	21,668	-3,652	-14.4	2,881,780	71,334	2.5	27.0
2004	136	3	2.3	22,333	665	3.1	3,037,246	155,466	5.4	27.6
2005	138	2	1.5	21,838	-494	-2.2	3,013,679	-23,567	-0.8	26.1
2006	134	-4	-2.9	22,815	977	4.5	3,057,184	43,505	1.4	26.8
2007	121	-13	-9.7	25,819	3,004	13.2	3,124,043	66,859	2.2	26.0
2008	131	10	8.3	22,936	-2,883	-11.2	3,004,594	-119,449	-3.8	25.1
2009	138	7	5.3	20,521	-2,415	-10.5	2,831,935	-172,660	-5.7	24.7
2010	124	-14	-10.1	22,944	2,422	11.8	2,844,999	13,065	0.5	23.3
2011	129	5	4.0	22,477	-467	-2.0	2,899,500	54,500	1.9	24.6
2012	129	0	0.0	22,899	422	1.9	2,953,917	54,418	1.9	24.9
2013	131	2	1.6	23,057	159	0.7	3,020,503	66,585	2.3	25.2
2014	133	2	1.5	23,330	273	1.2	3,102,870	82,368	2.7	25.5
2015	136	3	2.3	23,425	95	0.4	3,185,743	82,872	2.7	25.7
2016	138	2	1.5	23,744	320	1.4	3,276,689	90,946	2.9	25.9
2017	140	2	1.4	23,870	126	0.5	3,341,833	65,144	2.0	26.0
2018	141	1	0.7	24,180	309	1.3	3,409,319	67,486	2.0	26.1
2019	143	2	1.4	24,285	106	0.4	3,472,815	63,496	1.9	26.2
2020	144	1	0.7	24,630	344	1.4	3,546,701	73,886	2.1	26.4
2021	146	2	1.4	24,606	-24	-0.1	3,592,521	45,819	1.3	26.4
2022	147	1	0.7	24,807	201	0.8	3,646,641	54,120	1.5	26.5
2023	148	1	0.7	25,051	244	1.0	3,707,496	60,856	1.7	26.5
2024	150	2	1.4	25,233	182	0.7	3,784,931	77,435	2.1	26.6
2025	151	1	0.7	25,463	230	0.9	3,844,913	59,981	1.6	26.7
2026	153	2	1.3	25,634	171	0.7	3,921,947	77,034	2.0	26.7
2027	155	2	1.3	25,796	162	0.6	3,998,396	76,450	1.9	26.8
2028	157	2	1.3	26,016	220	0.9	4,084,567	86,171	2.2	26.9
2029	159	2	1.3	26,098	82	0.3	4,149,573	65,006	1.6	26.9
2030	160	1	0.6	26,413	315	1.2	4,226,020	76,448	1.8	27.0
2031	162	2	1.3	26,513	100	0.4	4,295,120	69,099	1.6	27.1
2032	163	1	0.6	26,836	323	1.2	4,374,313	79,194	1.8	27.1

6.5 Public Street and Highway Lighting

	Consumers			Use Per Consumer			Class Sales			
	Annual Average	Annual Change	Percent Change	Annual Average (MWh)	Change (MWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change	Percent of Total Sales
2001	330	14	4.4	20	0	1.7	6,545	385	6.3	0.1
2002	353	23	7.0	20	0	1.5	7,107	562	8.6	0.1
2003	366	13	3.7	20	0	1.1	7,447	340	4.8	0.1
2004	377	11	3.0	20	0	-2.3	7,498	51	0.7	0.1
2005	388	11	2.9	20	0	-0.1	7,713	214	2.9	0.1
2006	420	32	8.2	20	0	-1.4	8,236	523	6.8	0.1
2007	434	14	3.3	19	0	-0.6	8,457	221	2.7	0.1
2008	440	6	1.4	22	2	10.5	9,477	1,020	12.1	0.1
2009	425	-15	-3.4	21	0	-1.0	9,065	-412	-4.3	0.1
2010	423	-2	-0.5	22	1	5.3	9,503	438	4.8	0.1
2011	416	-7	-1.7	24	1	5.3	9,845	342	3.6	0.1
2012	417	1	0.2	23	-1	-3.4	9,537	-308	-3.1	0.1
2013	423	6	1.4	23	0	0.3	9,705	168	1.8	0.1
2014	431	8	1.9	23	0	0.4	9,923	218	2.2	0.1
2015	439	8	1.9	23	0	0.6	10,163	240	2.4	0.1
2016	447	8	1.8	23	0	0.6	10,411	248	2.4	0.1
2017	454	7	1.6	23	0	0.5	10,631	220	2.1	0.1
2018	461	7	1.5	24	0	0.6	10,860	229	2.1	0.1
2019	470	9	2.0	24	0	0.3	11,109	250	2.3	0.1
2020	478	8	1.7	24	0	0.5	11,359	250	2.2	0.1
2021	486	8	1.7	24	0	0.5	11,603	244	2.1	0.1
2022	494	8	1.6	24	0	0.4	11,846	243	2.1	0.1
2023	502	8	1.6	24	0	0.6	12,108	262	2.2	0.1
2024	510	8	1.6	24	0	0.5	12,366	258	2.1	0.1
2025	519	9	1.8	24	0	0.4	12,635	269	2.2	0.1
2026	528	9	1.7	24	0	0.6	12,929	294	2.3	0.1
2027	538	10	1.9	25	0	0.4	13,232	303	2.3	0.1
2028	546	8	1.5	25	0	0.5	13,494	262	2.0	0.1
2029	554	8	1.5	25	0	0.5	13,764	270	2.0	0.1
2030	562	8	1.4	25	0	0.6	14,047	284	2.1	0.1
2031	571	9	1.6	25	0	0.4	14,326	279	2.0	0.1
2032	580	9	1.6	25	0	0.4	14,617	291	2.0	0.1

6.6 Other Public Authorities

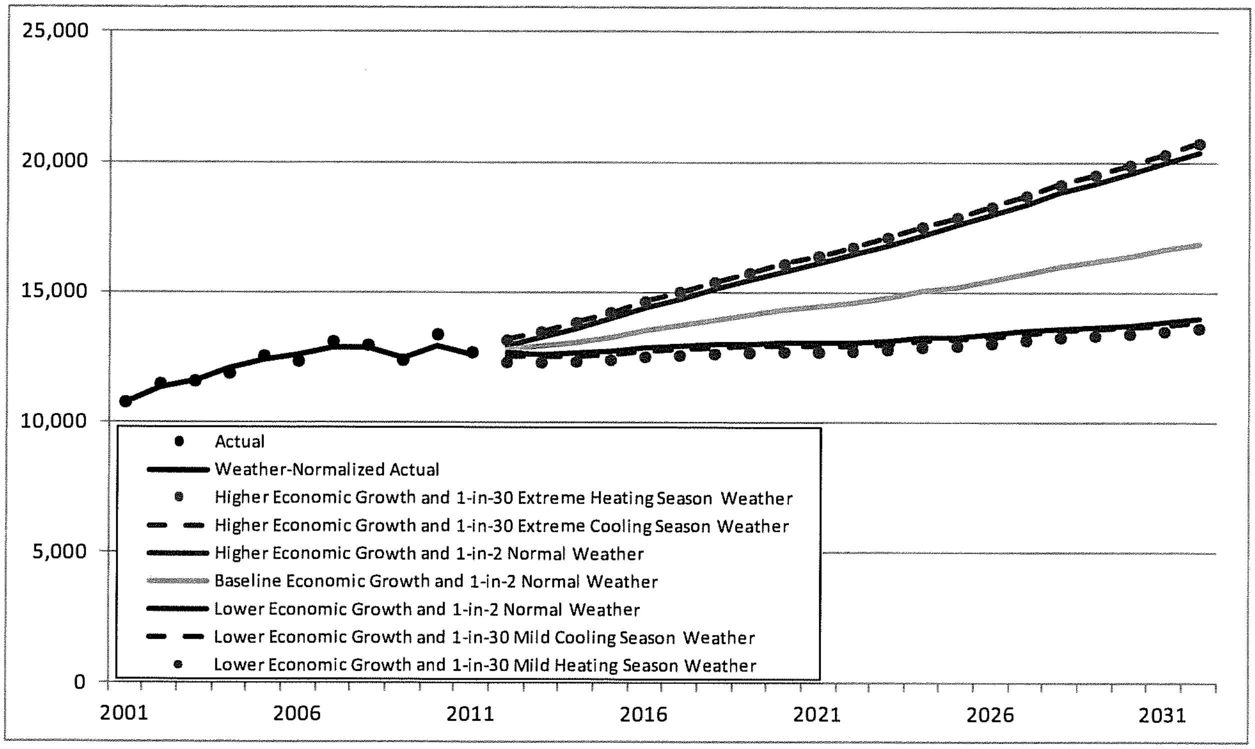
	Consumers			Use Per Consumer			Class Sales			
	Annual Average	Annual Change	Percent Change	Monthly Average (kWh)	Change (kWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change	Percent of Total Sales
2001	865	26	3.1	1,817	2	0.1	18,865	584	3.2	0.2
2002	889	24	2.8	1,917	100	5.5	20,453	1,588	8.4	0.2
2003	907	18	2.0	1,999	81	4.3	21,754	1,301	6.4	0.2
2004	916	9	1.0	2,090	91	4.6	22,974	1,220	5.6	0.2
2005	910	-6	-0.7	2,063	-27	-1.3	22,530	-444	-1.9	0.2
2006	931	21	2.3	1,987	-76	-3.7	22,196	-334	-1.5	0.2
2007	969	38	4.1	2,273	286	14.4	26,427	4,231	19.1	0.2
2008	993	24	2.5	2,860	587	25.8	34,074	7,647	28.9	0.3
2009	998	5	0.5	2,965	105	3.7	35,507	1,433	4.2	0.3
2010	1,047	49	4.9	3,168	204	6.9	39,809	4,301	12.1	0.3
2011	1,084	37	3.5	2,957	-211	-6.7	38,468	-1,341	-3.4	0.3
2012	1,095	11	1.0	2,942	-15	-0.5	38,654	187	0.5	0.3
2013	1,110	15	1.4	2,992	51	1.7	39,860	1,205	3.1	0.3
2014	1,125	15	1.4	3,047	55	1.8	41,138	1,278	3.2	0.3
2015	1,139	14	1.2	3,111	64	2.1	42,526	1,388	3.4	0.3
2016	1,154	15	1.3	3,184	72	2.3	44,087	1,562	3.7	0.3
2017	1,167	13	1.1	3,245	62	1.9	45,447	1,360	3.1	0.4
2018	1,180	13	1.1	3,315	70	2.2	46,946	1,498	3.3	0.4
2019	1,193	13	1.1	3,389	74	2.2	48,517	1,571	3.3	0.4
2020	1,205	12	1.0	3,471	82	2.4	50,193	1,676	3.5	0.4
2021	1,216	11	0.9	3,544	73	2.1	51,713	1,520	3.0	0.4
2022	1,226	10	0.8	3,624	80	2.3	53,312	1,599	3.1	0.4
2023	1,238	12	1.0	3,701	78	2.1	54,989	1,677	3.1	0.4
2024	1,249	11	0.9	3,788	87	2.3	56,774	1,785	3.2	0.4
2025	1,260	11	0.9	3,862	74	2.0	58,392	1,618	2.8	0.4
2026	1,272	12	1.0	3,943	81	2.1	60,183	1,791	3.1	0.4
2027	1,284	12	0.9	4,025	82	2.1	62,019	1,836	3.1	0.4
2028	1,294	10	0.8	4,115	90	2.2	63,899	1,880	3.0	0.4
2029	1,303	9	0.7	4,193	77	1.9	65,555	1,655	2.6	0.4
2030	1,313	10	0.8	4,277	85	2.0	67,395	1,840	2.8	0.4
2031	1,323	10	0.8	4,362	85	2.0	69,252	1,858	2.8	0.4
2032	1,332	9	0.7	4,460	98	2.3	71,294	2,042	2.9	0.4

SECTION 7.0

RESULTS BY ECONOMIC AND WEATHER SCENARIO

Section 7.0
Results by Economic and Weather Scenario

7.1.1 Net Total Energy Requirements (MWh) by Economic and Weather Scenario

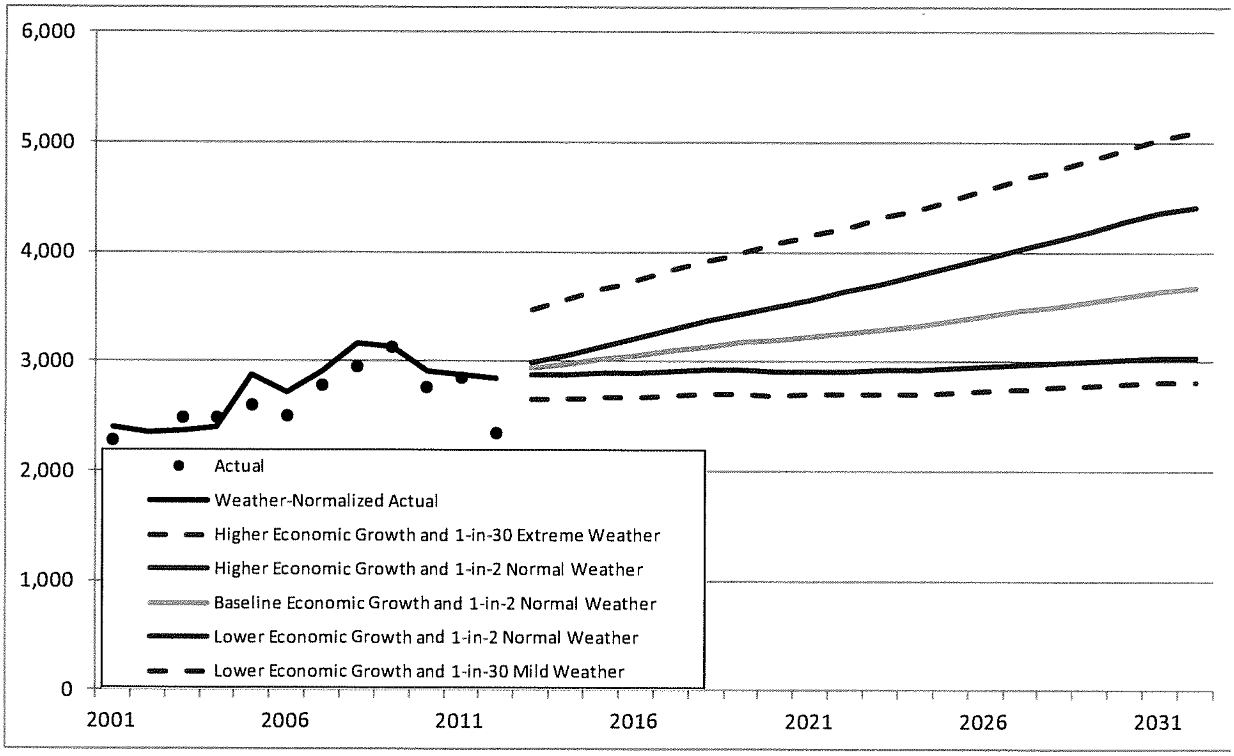


The higher economic growth scenario begins 1.3 and ends 20.8 percent greater than the baseline economic growth scenario. The lower economic growth scenario begins 1.1 and ends 17.3 percent less than the baseline economic growth scenario.

On average, the 1-in-30 mild heating season weather scenario is 2.6 percent less and the 1-in-30 extreme heating season weather scenario is 1.6 greater than the 1-in-2 normal weather scenario.

On average, the 1-in-30 mild cooling season weather scenario is 0.9 percent less and the 1-in-30 extreme cooling season weather scenario is 1.8 greater than the 1-in-2 normal weather scenario.

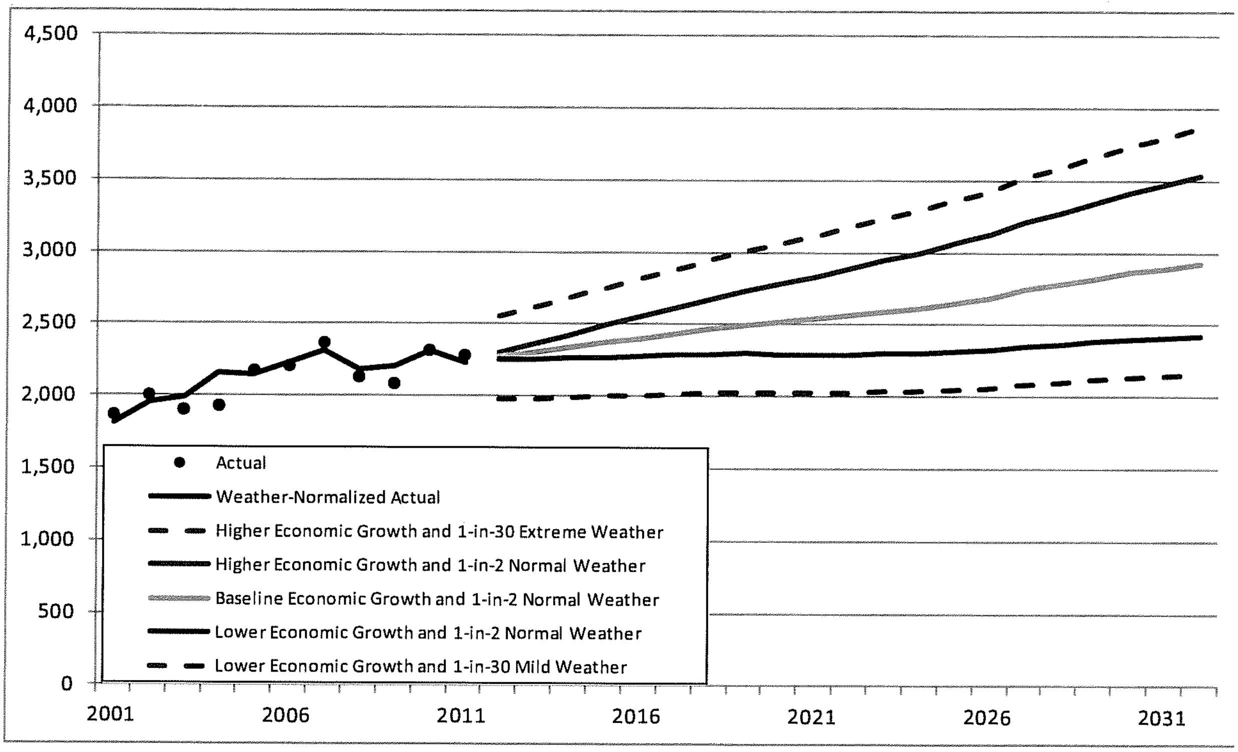
7.1.2 Net Winter Peak Demand (MW) by Economic and Weather Scenario



The higher economic growth scenario begins 2.6 and ends 20.8 percent greater than the baseline economic growth scenario. The lower economic growth scenario begins 2.2 and ends 17.3 percent less than the baseline economic growth scenario.

On average, the 1-in-30 mild weather scenario is 7.6 percent less and the 1-in-30 extreme weather scenario is 16.0 percent greater than the 1-in-2 normal weather scenario.

7.1.3 Net Summer Peak Demand (MW) by Economic and Weather Scenario



The higher economic growth scenario begins 1.3 and ends 20.8 percent greater than the baseline economic growth scenario. The lower economic growth scenario begins 1.1 and ends 17.3 percent less than the baseline economic growth scenario.

On average, the 1-in-30 mild weather scenario is 11.5 percent less and the 1-in-30 extreme weather scenario is 10.0 percent greater than the 1-in-2 normal weather scenario.

7.2.1 Baseline Economic Growth Heating Season Weather Scenarios

	Mild	Normal		Extreme	
HDD55 at LEX	1,968	2,634	2,871	2,945	3,044
Occurs Once in ...	30 Years	2 Years	5 Years	10 Years	30 Years

Net Total Energy Requirements - Thousand MWh

Year	Mild	Normal		Extreme	
2012	12,428	12,764	12,883	12,920	12,970
2013	12,552	12,899	13,022	13,060	13,112
2014	12,720	13,078	13,206	13,245	13,298
2015	12,919	13,286	13,416	13,457	13,511
2016	13,171	13,541	13,672	13,713	13,768
2017	13,355	13,728	13,861	13,903	13,958
2018	13,557	13,932	14,065	14,107	14,163
2019	13,738	14,116	14,251	14,293	14,349
2020	13,904	14,286	14,422	14,464	14,521
2021	14,035	14,421	14,558	14,601	14,658
2022	14,203	14,590	14,728	14,771	14,829
2023	14,403	14,795	14,934	14,977	15,036
2024	14,632	15,027	15,167	15,211	15,270
2025	14,814	15,214	15,356	15,400	15,460
2026	15,049	15,451	15,594	15,639	15,699
2027	15,303	15,710	15,855	15,900	15,960
2028	15,553	15,964	16,110	16,156	16,217
2029	15,754	16,169	16,316	16,362	16,424
2030	15,966	16,383	16,531	16,578	16,640
2031	16,197	16,618	16,768	16,815	16,877
2032	16,450	16,874	17,025	17,072	17,135

7.2.2 Baseline Economic Growth Cooling Season Weather Scenarios

	Mild	Normal		Extreme	
CDD65 at LEX	938	1,177	1,474	1,539	1,648
Occurs Once in ...	30 Years	2 Years	5 Years	10 Years	30 Years
Net Total Energy Requirements - Thousand MWh					
Year	Mild	Normal		Extreme	
2012	12,648	12,764	12,913	12,946	13,001
2013	12,781	12,899	13,051	13,085	13,141
2014	12,959	13,078	13,233	13,267	13,324
2015	13,165	13,286	13,442	13,476	13,534
2016	13,419	13,541	13,699	13,734	13,792
2017	13,605	13,728	13,888	13,923	13,981
2018	13,808	13,932	14,093	14,128	14,187
2019	13,991	14,116	14,279	14,314	14,374
2020	14,160	14,286	14,450	14,486	14,546
2021	14,293	14,421	14,586	14,622	14,683
2022	14,461	14,590	14,757	14,793	14,855
2023	14,665	14,795	14,963	15,000	15,062
2024	14,895	15,027	15,197	15,234	15,297
2025	15,081	15,214	15,385	15,423	15,486
2026	15,317	15,451	15,625	15,663	15,726
2027	15,575	15,710	15,885	15,924	15,988
2028	15,828	15,964	16,141	16,180	16,245
2029	16,031	16,169	16,347	16,386	16,452
2030	16,244	16,383	16,563	16,603	16,669
2031	16,478	16,618	16,800	16,840	16,906
2032	16,732	16,874	17,057	17,097	17,165

7.2.3 Baseline Economic Growth Winter Peak Weather Scenarios

	Mild	Normal		Extreme	
Degrees at LEX	10	-3	-12	-17	-25
Occurs Once in ...	30 Years	2 Years	5 Years	10 Years	30 Years
	Net Winter Peak Demand - MW				
Season	Mild	Normal		Extreme	
2012 - 13	2,717	2,947	3,142	3,263	3,427
2013 - 14	2,746	2,980	3,181	3,305	3,475
2014 - 15	2,780	3,017	3,222	3,348	3,522
2015- 16	2,817	3,056	3,263	3,390	3,565
2016 - 17	2,861	3,101	3,310	3,438	3,614
2017 - 18	2,899	3,140	3,349	3,477	3,653
2018 - 19	2,932	3,175	3,385	3,514	3,691
2019 - 20	2,952	3,196	3,407	3,537	3,715
2020 - 21	2,982	3,229	3,441	3,572	3,752
2021 - 22	3,011	3,258	3,471	3,602	3,782
2022 - 23	3,047	3,296	3,510	3,642	3,824
2023 - 24	3,078	3,329	3,545	3,678	3,861
2024 - 25	3,120	3,373	3,590	3,724	3,909
2025 - 26	3,163	3,417	3,635	3,770	3,955
2026 - 27	3,210	3,466	3,687	3,823	4,011
2027 - 28	3,245	3,503	3,726	3,863	4,052
2028 - 29	3,290	3,550	3,774	3,912	4,103
2029 - 30	3,340	3,603	3,828	3,967	4,158
2030 - 31	3,384	3,649	3,877	4,017	4,211
2031 - 32	3,408	3,674	3,902	4,043	4,237

7.2.4 Baseline Economic Growth Summer Peak Weather Scenarios

	Mild	Normal		Extreme	
Degrees at LEX	89	96	98	100	104
Occurs Once in ...	30 Years	2 Years	5 Years	10 Years	30 Years
	Net Summer Peak Demand - MW				
Season	Mild	Normal		Extreme	
2012	2,002	2,277	2,359	2,424	2,516
2013	2,028	2,306	2,389	2,454	2,548
2014	2,056	2,337	2,421	2,487	2,582
2015	2,086	2,368	2,452	2,519	2,615
2016	2,117	2,402	2,487	2,554	2,651
2017	2,150	2,436	2,521	2,589	2,685
2018	2,178	2,467	2,552	2,620	2,717
2019	2,203	2,493	2,579	2,647	2,745
2020	2,221	2,512	2,598	2,667	2,765
2021	2,244	2,537	2,623	2,692	2,791
2022	2,267	2,561	2,647	2,717	2,816
2023	2,295	2,590	2,678	2,747	2,847
2024	2,321	2,618	2,706	2,776	2,877
2025	2,354	2,653	2,741	2,812	2,913
2026	2,388	2,690	2,778	2,850	2,951
2027	2,436	2,741	2,830	2,902	3,005
2028	2,469	2,776	2,867	2,939	3,043
2029	2,510	2,819	2,910	2,983	3,088
2030	2,547	2,859	2,951	3,024	3,130
2031	2,579	2,893	2,985	3,059	3,165
2032	2,609	2,925	3,017	3,092	3,199

7.3.1 Lower Economic Growth Heating Season Weather Scenarios

	Mild	Normal	Extreme		
HDD55 at LEX	1,968	2,634	2,871	2,945	3,044
Occurs Once in ...	30 Years	2 Years	5 Years	10 Years	30 Years
Net Total Energy Requirements - Thousand MWh					
Year	Mild	Normal	Extreme		
2012	12,293	12,625	12,743	12,780	12,829
2013	12,282	12,621	12,742	12,779	12,830
2014	12,315	12,662	12,785	12,824	12,875
2015	12,380	12,731	12,855	12,894	12,947
2016	12,496	12,847	12,972	13,011	13,063
2017	12,545	12,896	13,021	13,060	13,112
2018	12,612	12,961	13,085	13,124	13,175
2019	12,657	13,006	13,130	13,169	13,221
2020	12,689	13,037	13,161	13,200	13,252
2021	12,685	13,033	13,157	13,196	13,248
2022	12,717	13,064	13,187	13,226	13,277
2023	12,783	13,130	13,253	13,292	13,343
2024	12,875	13,223	13,347	13,385	13,437
2025	12,923	13,271	13,395	13,434	13,486
2026	13,022	13,370	13,494	13,532	13,584
2027	13,141	13,490	13,614	13,653	13,705
2028	13,255	13,606	13,730	13,769	13,821
2029	13,321	13,671	13,796	13,835	13,887
2030	13,397	13,747	13,871	13,910	13,962
2031	13,492	13,843	13,968	14,007	14,059
2032	13,609	13,960	14,085	14,124	14,176

7.3.2 Lower Economic Growth Cooling Season Weather Scenarios

	Mild	Normal		Extreme	
CDD65 at LEX	938	1,177	1,474	1,539	1,648
Occurs Once in ...	30 Years	2 Years	5 Years	10 Years	30 Years
Net Total Energy Requirements - Thousand MWh					
Year	Mild	Normal		Extreme	
2012	12,511	12,625	12,773	12,805	12,860
2013	12,506	12,621	12,770	12,803	12,858
2014	12,546	12,662	12,812	12,845	12,900
2015	12,615	12,731	12,881	12,914	12,969
2016	12,731	12,847	12,997	13,030	13,085
2017	12,780	12,896	13,046	13,078	13,133
2018	12,845	12,961	13,110	13,143	13,198
2019	12,891	13,006	13,156	13,189	13,243
2020	12,922	13,037	13,187	13,220	13,275
2021	12,918	13,033	13,183	13,215	13,270
2022	12,949	13,064	13,213	13,246	13,301
2023	13,014	13,130	13,279	13,312	13,367
2024	13,107	13,223	13,373	13,405	13,460
2025	13,156	13,271	13,421	13,454	13,509
2026	13,254	13,370	13,520	13,553	13,608
2027	13,374	13,490	13,641	13,674	13,729
2028	13,489	13,606	13,756	13,789	13,845
2029	13,555	13,671	13,822	13,855	13,910
2030	13,630	13,747	13,898	13,931	13,986
2031	13,726	13,843	13,995	14,028	14,083
2032	13,843	13,960	14,112	14,145	14,201

7.3.3 Lower Economic Growth Winter Peak Weather Scenarios

	Mild	Normal		Extreme	
Degrees at LEX	10	-3	-12	-17	-25
Occurs Once in ...	30 Years	2 Years	5 Years	10 Years	30 Years
	Net Winter Peak Demand - MW				
Season	Mild	Normal		Extreme	
2012 - 13	2,659	2,883	3,075	3,193	3,353
2013 - 14	2,658	2,885	3,080	3,200	3,364
2014 - 15	2,663	2,891	3,087	3,209	3,375
2015- 16	2,673	2,900	3,096	3,216	3,382
2016 - 17	2,687	2,913	3,109	3,229	3,395
2017 - 18	2,697	2,922	3,115	3,235	3,399
2018 - 19	2,701	2,925	3,119	3,238	3,401
2019 - 20	2,694	2,917	3,109	3,228	3,390
2020 - 21	2,695	2,918	3,110	3,228	3,391
2021 - 22	2,696	2,918	3,108	3,225	3,387
2022 - 23	2,704	2,925	3,115	3,232	3,394
2023 - 24	2,709	2,930	3,119	3,236	3,397
2024 - 25	2,722	2,942	3,132	3,249	3,410
2025 - 26	2,737	2,957	3,146	3,262	3,423
2026 - 27	2,756	2,977	3,166	3,283	3,444
2027 - 28	2,765	2,986	3,175	3,292	3,453
2028 - 29	2,782	3,002	3,191	3,308	3,469
2029 - 30	2,803	3,023	3,212	3,328	3,489
2030 - 31	2,819	3,040	3,230	3,346	3,508
2031 - 32	2,820	3,039	3,228	3,345	3,505

7.3.4 Lower Economic Growth Summer Peak Weather Scenarios

	Mild	Normal		Extreme	
Degrees at LEX	89	96	98	100	104
Occurs Once in ...	30 Years	2 Years	5 Years	10 Years	30 Years
	Net Summer Peak Demand - MW				
Season	Mild	Normal		Extreme	
2012	1,980	2,253	2,333	2,397	2,489
2013	1,984	2,256	2,337	2,401	2,493
2014	1,991	2,263	2,344	2,408	2,500
2015	1,998	2,269	2,350	2,414	2,506
2016	2,009	2,279	2,360	2,424	2,515
2017	2,019	2,289	2,368	2,432	2,522
2018	2,027	2,295	2,374	2,437	2,528
2019	2,030	2,297	2,376	2,439	2,529
2020	2,027	2,293	2,371	2,434	2,523
2021	2,028	2,293	2,371	2,433	2,522
2022	2,030	2,293	2,370	2,432	2,521
2023	2,037	2,299	2,376	2,438	2,527
2024	2,043	2,304	2,381	2,443	2,531
2025	2,054	2,314	2,391	2,453	2,541
2026	2,067	2,327	2,404	2,466	2,554
2027	2,092	2,353	2,430	2,492	2,581
2028	2,104	2,366	2,443	2,505	2,593
2029	2,122	2,384	2,461	2,522	2,611
2030	2,137	2,399	2,476	2,538	2,626
2031	2,148	2,410	2,486	2,548	2,636
2032	2,159	2,420	2,496	2,558	2,646

7.4.1 Higher Economic Growth Heating Season Weather Scenarios

	Mild	Normal	Extreme		
HDD55 at LEX	1,968	2,634	2,871	2,945	3,044
Occurs Once in ...	30 Years	2 Years	5 Years	10 Years	30 Years

Net Total Energy Requirements - Thousand MWh

Year	Mild	Normal	Extreme		
2012	12,591	12,931	13,052	13,090	13,141
2013	12,878	13,234	13,360	13,400	13,452
2014	13,209	13,581	13,713	13,754	13,809
2015	13,571	13,955	14,092	14,135	14,192
2016	13,985	14,378	14,518	14,562	14,620
2017	14,332	14,733	14,876	14,921	14,980
2018	14,698	15,104	15,249	15,294	15,355
2019	15,042	15,456	15,603	15,649	15,711
2020	15,372	15,794	15,944	15,991	16,053
2021	15,665	16,096	16,249	16,297	16,361
2022	15,996	16,432	16,588	16,636	16,701
2023	16,360	16,805	16,963	17,012	17,078
2024	16,752	17,204	17,365	17,415	17,482
2025	17,098	17,559	17,723	17,774	17,842
2026	17,496	17,963	18,130	18,182	18,251
2027	17,913	18,390	18,559	18,612	18,683
2028	18,327	18,811	18,984	19,038	19,110
2029	18,692	19,183	19,358	19,413	19,486
2030	19,067	19,565	19,742	19,798	19,872
2031	19,462	19,968	20,148	20,204	20,279
2032	19,878	20,391	20,573	20,630	20,706

7.4.2 Higher Economic Growth Cooling Season Weather Scenarios

	Mild	Normal		Extreme	
CDD65 at LEX	938	1,177	1,474	1,539	1,648
Occurs Once in ...	30 Years	2 Years	5 Years	10 Years	30 Years
	Net Total Energy Requirements - Thousand MWh				
Year	Mild	Normal		Extreme	
2012	12,814	12,931	13,083	13,116	13,172
2013	13,113	13,234	13,390	13,424	13,482
2014	13,456	13,581	13,742	13,777	13,836
2015	13,829	13,955	14,120	14,156	14,216
2016	14,249	14,378	14,546	14,583	14,645
2017	14,601	14,733	14,904	14,942	15,005
2018	14,970	15,104	15,279	15,317	15,381
2019	15,319	15,456	15,634	15,673	15,738
2020	15,654	15,794	15,975	16,015	16,081
2021	15,953	16,096	16,280	16,320	16,388
2022	16,288	16,432	16,620	16,661	16,730
2023	16,657	16,805	16,996	17,038	17,108
2024	17,054	17,204	17,399	17,441	17,513
2025	17,406	17,559	17,757	17,800	17,873
2026	17,808	17,963	18,165	18,209	18,283
2027	18,231	18,390	18,595	18,640	18,715
2028	18,651	18,811	19,020	19,066	19,142
2029	19,020	19,183	19,395	19,441	19,519
2030	19,399	19,565	19,780	19,827	19,906
2031	19,799	19,968	20,186	20,234	20,314
2032	20,220	20,391	20,613	20,661	20,743

7.4.3 Higher Economic Growth Winter Peak Weather Scenarios

	Mild	Normal		Extreme	
Degrees at LEX	10	-3	-12	-17	-25
Occurs Once in ...	30 Years	2 Years	5 Years	10 Years	30 Years
	Net Winter Peak Demand - MW				
Season	Mild	Normal		Extreme	
2012 - 13	2,753	2,985	3,183	3,306	3,472
2013 - 14	2,817	3,057	3,264	3,391	3,565
2014 - 15	2,886	3,133	3,346	3,477	3,657
2015- 16	2,959	3,210	3,427	3,561	3,744
2016 - 17	3,038	3,293	3,514	3,650	3,837
2017 - 18	3,111	3,370	3,594	3,732	3,921
2018 - 19	3,179	3,442	3,670	3,810	4,002
2019 - 20	3,232	3,500	3,730	3,873	4,068
2020 - 21	3,297	3,569	3,804	3,949	4,148
2021 - 22	3,361	3,637	3,874	4,021	4,222
2022 - 23	3,432	3,712	3,954	4,102	4,307
2023 - 24	3,497	3,781	4,027	4,177	4,385
2024 - 25	3,572	3,861	4,110	4,264	4,475
2025 - 26	3,650	3,943	4,196	4,351	4,565
2026 - 27	3,732	4,030	4,287	4,445	4,663
2027 - 28	3,798	4,101	4,361	4,522	4,743
2028 - 29	3,877	4,183	4,448	4,610	4,834
2029 - 30	3,963	4,274	4,542	4,706	4,934
2030 - 31	4,042	4,358	4,630	4,797	5,029
2031 - 32	4,095	4,414	4,689	4,857	5,091

7.4.4 Higher Economic Growth Summer Peak Weather Scenarios

	Mild	Normal	Extreme		
Degrees at LEX	89	96	98	100	104
Occurs Once in ...	30 Years	2 Years	5 Years	10 Years	30 Years
	Net Summer Peak Demand - MW				
Season	Mild	Normal	Extreme		
2012	2,028	2,307	2,390	2,455	2,549
2013	2,080	2,366	2,451	2,518	2,614
2014	2,135	2,427	2,514	2,583	2,682
2015	2,191	2,488	2,576	2,646	2,747
2016	2,248	2,551	2,641	2,712	2,815
2017	2,307	2,615	2,706	2,778	2,882
2018	2,362	2,674	2,767	2,840	2,946
2019	2,413	2,730	2,824	2,898	3,005
2020	2,455	2,777	2,872	2,948	3,057
2021	2,505	2,831	2,928	3,005	3,115
2022	2,553	2,884	2,982	3,060	3,171
2023	2,607	2,942	3,041	3,121	3,234
2024	2,658	2,998	3,098	3,179	3,294
2025	2,717	3,062	3,164	3,245	3,362
2026	2,777	3,127	3,230	3,313	3,431
2027	2,851	3,208	3,313	3,397	3,518
2028	2,910	3,272	3,378	3,463	3,586
2029	2,978	3,345	3,453	3,539	3,663
2030	3,042	3,414	3,524	3,612	3,737
2031	3,099	3,476	3,586	3,675	3,803
2032	3,153	3,534	3,646	3,737	3,866

SECTION 8.0

RESULTS BY MEMBER SYSTEM

Section 8.0
Results by Member System

The forecast indicates that total energy sales growth is higher for member systems located near large MSAs (Cincinnati, Lexington, and Louisville) or in the South Region. The higher growth is driven by the faster employment and income per household growth of those regions.

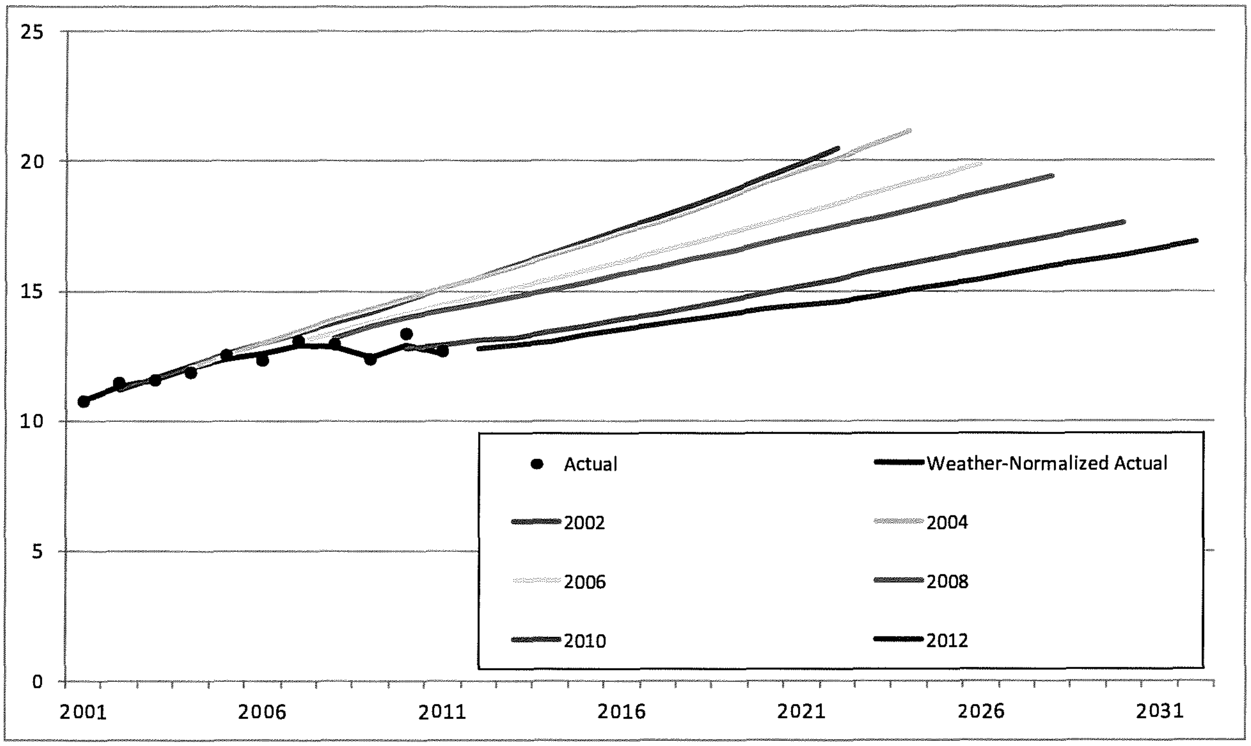
Member systems located in the East Region are forecast to grow least quickly, due to negligible household and slow employment growth.

The following table summarizes the results by member system.

Results by Member System

RUS #	Cooperative	Consumers			Total Energy Sales (MWh)			Winter Non-Coincident Peak Demand (MW)			Summer Non-Coincident Peak Demand (MW)		
		2012	2032	Growth	2012	2032	Growth	2013	2032	Growth	2012	2032	Growth
3	Jackson Energy Cooperative	51,290	54,452	0.3%	907,474	1,140,208	1.1%	278	329	0.9%	185	234	1.2%
21	Salt River Electric Cooperative Corporation	48,153	59,538	1.1%	1,097,216	1,579,768	1.8%	283	382	1.6%	258	376	1.9%
23	Taylor County Rural Electric Cooperative Corporation	25,805	33,106	1.3%	459,136	774,076	2.6%	135	208	2.3%	109	183	2.6%
27	Inter-County Energy Cooperative Corporation	25,438	32,136	1.2%	466,344	695,987	2.0%	148	212	1.9%	102	149	1.9%
30	Shelby Energy Cooperative	15,574	20,538	1.4%	441,865	604,374	1.6%	109	146	1.5%	92	123	1.5%
34	Farmers Rural Electric Cooperative Corporation	24,795	30,383	1.0%	473,835	609,661	1.3%	128	160	1.2%	102	121	0.9%
37	Owen Electric Cooperative	57,996	77,491	1.5%	2,203,168	2,957,096	1.5%	477	621	1.4%	462	638	1.6%
49	Clark Energy Cooperative	26,031	30,030	0.7%	426,771	584,962	1.6%	131	170	1.4%	93	121	1.4%
51	Nolin Rural Electric Cooperative Corporation	33,558	43,021	1.2%	732,655	977,894	1.5%	198	258	1.4%	153	193	1.2%
52	Fleming-Mason Energy Cooperative	23,870	28,726	0.9%	915,372	1,162,223	1.2%	198	248	1.2%	161	211	1.4%
54	South Kentucky Rural Electric Cooperative Corporation	66,528	80,322	0.9%	1,249,893	1,802,303	1.8%	397	532	1.6%	263	393	2.0%
56	Licking Valley Rural Electric Cooperative Corporation	17,438	18,394	0.3%	261,723	334,268	1.2%	78	94	1.0%	56	70	1.1%
57	Cumberland Valley Electric	23,627	25,624	0.4%	491,864	585,692	0.9%	138	161	0.8%	103	116	0.6%
58	Big Sandy Rural Electric Cooperative Corporation	13,214	14,347	0.4%	255,386	316,621	1.1%	81	92	0.7%	54	68	1.1%
61	Grayson Rural Electric Cooperative Corporation	15,420	17,150	0.5%	254,926	336,553	1.4%	75	98	1.4%	53	69	1.3%
64	Blue Grass Energy Cooperative	55,584	71,024	1.2%	1,218,487	1,672,768	1.6%	342	455	1.5%	261	345	1.4%
	Total	524,322	636,282	1.0%	11,856,115	16,134,455	1.6%						
	Member System Own Use				9,742	9,742	0.0%						
	Member System Distribution Losses				551,180	753,460	1.6%						
	Member System Purchased Power				12,417,037	16,897,656	1.6%	Winter Coincident Peak Demand (MW)			Summer Coincident Peak Demand (MW)		
59	East Kentucky Power Cooperative Own Use				8,417	9,229	0.5%						
59	East Kentucky Power Cooperative Transmission Losses				349,399	505,318	1.9%	2013	2032	Growth	2012	2032	Growth
59	Gross Total				12,774,853	17,412,203	1.6%	3,076	4,012	1.4%	2,403	3,272	1.6%
59	Additional Demand Side Management				-11,234	-538,442	21.3%	-129	-338	5.2%	-126	-347	5.2%
59	Net Total				12,763,619	16,873,761	1.4%	2,947	3,674	1.2%	2,277	2,925	1.3%

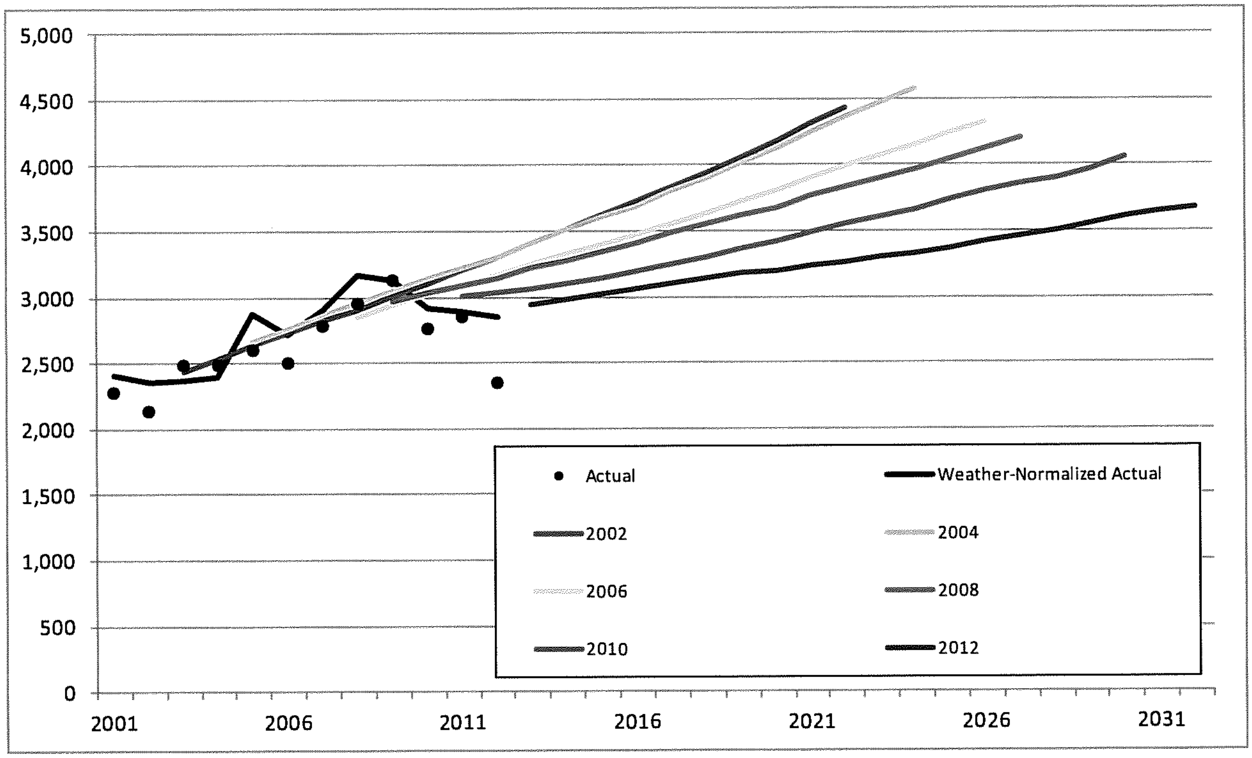
1.2.1 Net Total Energy Requirements (Million MWh) by Load Forecast Vintage



The "2012 Load Forecast" indicates that, through 2032, net total energy requirements will increase from 12.8 to 16.9 million MWh, an average of 1.4 percent per year.

This represents a downward revision from the 2010 Load Forecast by 2.4 percent in the short term and by 7.1 percent in the long term.

1.2.2 Net Winter Peak Demand (MW) by Load Forecast Vintage

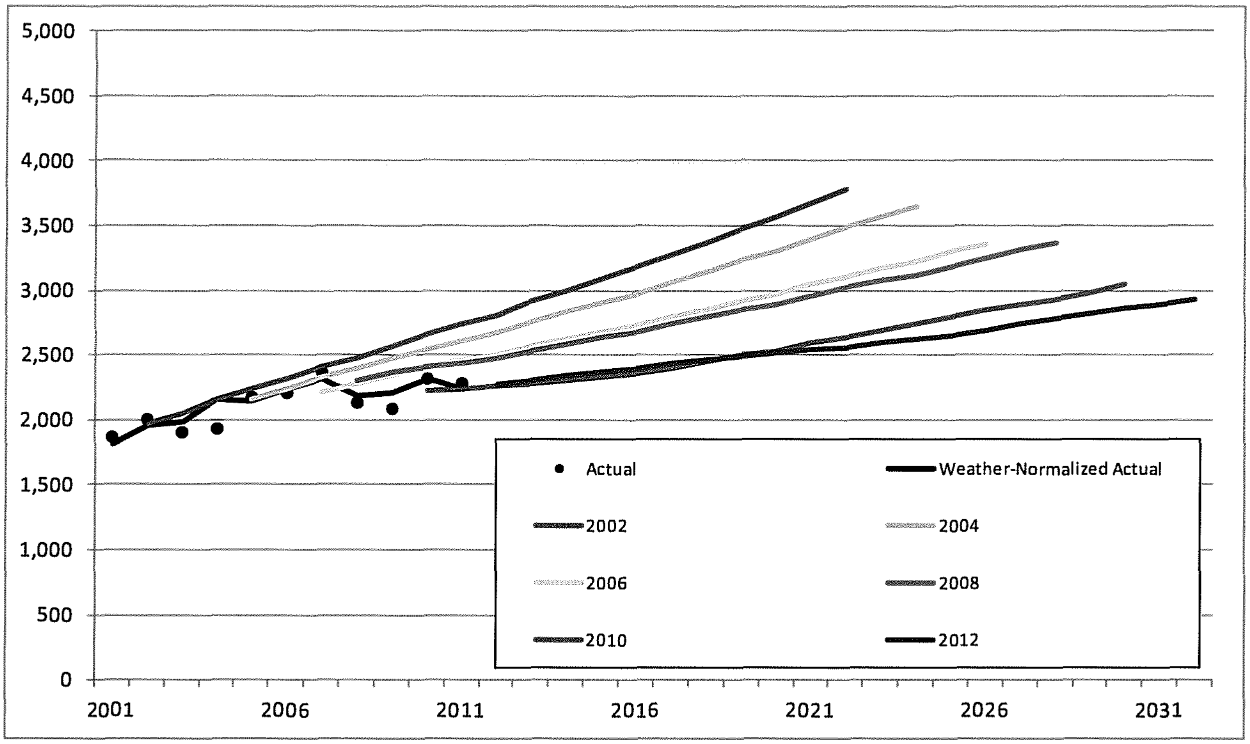


The "2012 Load Forecast" indicates that, through 2032, the net winter peak demand will increase from 2,947 to 3,674 MW, an average of 1.2 percent per year.

This represents a downward revision from the 2010 Load Forecast by 3.7 percent in the short term and by 11.1 percent in the long term.

Because the winter peak demand is forecast to grow less quickly than total energy requirements, the winter peak demand-based load factor will increase slightly, from 50.0 percent in 2013 to 52.3 percent by 2032. Because the EKPC system remains winter-peaking throughout the forecast period, this also represents EKPC's annual load factor.

1.2.3 Net Summer Peak Demand (MW) by Load Forecast Vintage

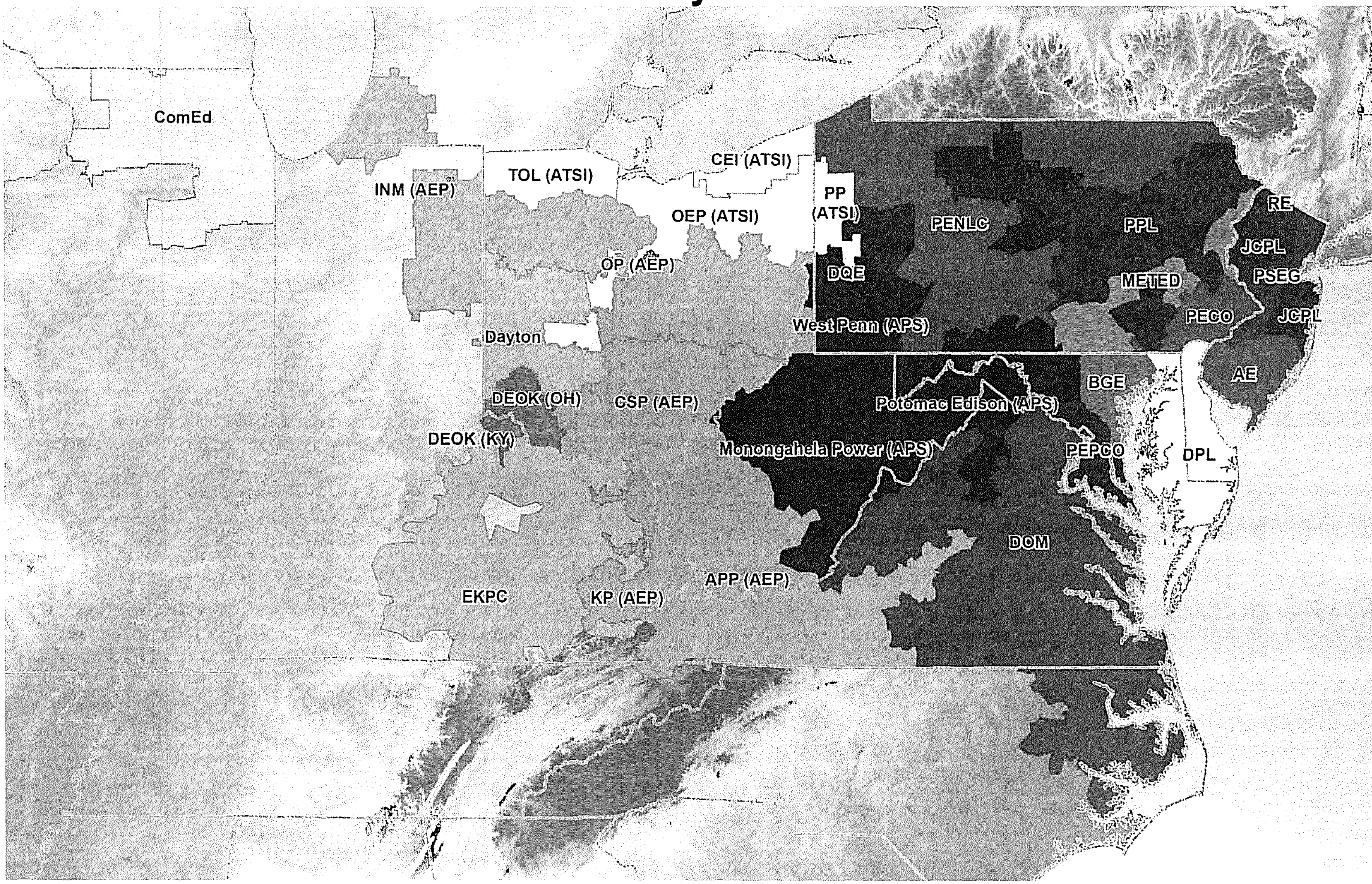


The "2012 Load Forecast" indicates that, through 2032, the net summer peak demand will increase from 2,277 to 2,925 MW, an average of 1.3 percent per year.

This represents an upward revision from the 2010 Load Forecast by 0.6 percent in the short term and a downward revision by 6.3 percent in the long term.

Because the summer peak demand is forecast to grow less quickly than total energy requirements, the summer peak demand-based load factor will increase slightly, from 63.8 percent in 2013 to 65.7 percent by 2032. While the EKPC system remains winter-peaking throughout the forecast period, EKPC's summer peak demand-based load factor will become more financially important than its winter peak demand-based load factor if EKPC integrates its system into the summer-peaking PJM Interconnection, as it has applied to do, pending regulatory and final EKPC Board of Directors approval.

PJM Load Forecast Report
January 2013



Prepared by PJM Resource Adequacy Planning Department

SC - EXHIBIT 16

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TERMS AND ABBREVIATIONS USED IN THIS REPORT

AE	Atlantic Electric zone (part of Pepco Holdings, Inc)
AEP	American Electric Power zone (incorporated 10/1/2004)
APP	Appalachian Power, sub-zone of AEP
APS	Allegheny Power zone (incorporated 4/1/2002)
ATSI	American Transmission Systems, Inc. zone (incorporated 6/1/2011)
Base Load	Average peak load on non-holiday weekdays with no heating or cooling load. Base load is insensitive to weather.
BGE	Baltimore Gas & Electric zone
CEI	Cleveland Electric Illuminating, sub-zone of ATSI
COMED	Commonwealth Edison zone (incorporated 5/1/2004)
Contractually Interruptible	Load Management from customers responding to direction from a control center
Cooling Load	The weather-sensitive portion of summer peak load
CSP	Columbus Southern Power, sub-zone of AEP
Direct Control	Load Management achieved directly by a signal from a control center
DAY	Dayton Power & Light zone (incorporated 10/1/2004)
DEOK	Duke Energy Ohio/Kentucky zone (incorporated 1/1/2012)
DLCO	Duquesne Lighting Company zone (incorporated 1/1/2005)
DOM	Dominion Virginia Power zone (incorporated 5/1/2005)
DPL	Delmarva Power & Light zone (part of Pepco Holdings, Inc)
EKPC	East Kentucky Power Cooperative (anticipated incorporation 6/1/2013)
FE-East	The combination of FirstEnergy's Jersey Central Power & Light, Metropolitan Edison, and Pennsylvania Electric zones (formerly GPU)
Heating Load	The weather-sensitive portion of winter peak load
INM	Indiana Michigan Power, sub-zone of AEP
JCPL	Jersey Central Power & Light zone
KP	Kentucky Power, sub-zone of AEP

METED	Metropolitan Edison zone
MP	Monongahela Power, sub-zone of APS
NERC	North American Electric Reliability Corporation
Net Energy	Net Energy for Load, measured as net generation of main generating units plus energy receipts minus energy deliveries
OEP	Ohio Edison, sub-zone of ATSI
OP	Ohio Power, sub-zone of AEP
PECO	PECO Energy zone
PED	Potomac Edison, sub-zone of APS
PEPCO	Potomac Electric Power zone (part of Pepco Holdings, Inc)
PL	PPL Electric Utilities, sub-zone of PLGroup
PLGroup/PLGRP	Pennsylvania Power & Light zone
PENLC	Pennsylvania Electric zone
PP	Pennsylvania Power, sub-zone of ATSI
PS	Public Service Electric & Gas zone
RECO	Rockland Electric (East) zone (incorporated 3/1/2002)
TOL	Toledo Edison, sub-zone of ATSI
UGI	UGI Utilities, sub-zone of PLGroup
Unrestricted Peak	Peak load prior to any reduction for load management, accelerated energy efficiency or voltage reduction.
WP	West Penn Power, sub-zone of APS
Zone	Areas within the PJM Control Area, as defined in the PJM Reliability Assurance Agreement

2013 PJM LOAD FORECAST REPORT

EXECUTIVE SUMMARY

- This report presents an independent load forecast prepared by PJM staff.

- The report includes long-term forecasts of peak loads, net energy, load management and energy efficiency for each PJM zone, region, locational deliverability area, and the total RTO.

- This year's report includes the load of East Kentucky Power Cooperative (EKPC), which is anticipated to be integrated into the PJM RTO on June 1, 2013. The report also reflects the integration of the DEOK zone on January 1, 2012.

- All load models were estimated with historical data from January 1998 through August 2012. The models were simulated with weather data from years 1973 through 2011, generating 507 scenarios. The economic forecast used was Moody's Analytics' November 2012 release.

- A downward revision to the economic outlook, especially in 2013 and 2014, has resulted in lower peak and energy forecasts in this year's report, compared to the same year in last year's report. See the Moody's Analytics summary report on economic assumptions on Page 4 for more detail.

- The PJM RTO (including EKPC) weather normalized summer peak for 2012 was 154,235 MW. The projection for the 2013 PJM RTO summer peak is 155,553 MW, an increase of 1,318 MW, or 0.9%, from the 2012 normalized peak.

- Summer peak load growth for the PJM RTO (including EKPC) is projected to average 1.3% per year over the next 10 years, and 1.2% over the next 15 years. The PJM RTO summer peak is forecasted to be 177,439 MW in 2023, a 10-year increase of 21,886 MW, and reaches 185,671 MW in 2028, a 15-year increase of 30,118 MW. Annualized 10-year growth rates for individual zones range from 0.6% to 1.9%.

- Winter peak load growth for PJM RTO (including EKPC) is projected to average 1.1% per year over the next 10-year period, and 1.0% over the next 15-years. The PJM RTO winter peak load in 2022/23 is forecasted to be 146,618 MW, a 10-year increase of 15,808 MW, and reaches 152,455 MW in 2027/28, a 15-year increase of 21,645 MW. Annualized 10-year growth rates for individual zones range from 0.5% to 1.9%.

- Compared to the 2012 Load Report, the 2013 PJM RTO (**excluding** the impact of EKPC) summer peak forecast shows the following changes for three years of interest:
    - The next delivery year – 2013 -2,538 MW (-1.6%)
    - The next RPM auction year – 2016 -2,515 MW (-1.5%)
    - The next RTEP study year – 2018 -2,222 MW (-1.3%)

- Assumptions for future Load Management (LM) have increased modestly from the 2012 Load Report (from approximately 14,200 MW to 14,600 MW). Energy Efficiency (EE) impacts have increased from approximately 800 MW to 1,100MW. Assumptions for both LM and EE are based on Reliability Pricing Model (RPM) auction results.

- Based on the forecast contained within this report, the PJM RTO will continue to be summer peaking during the next 15 years, with annual load factors growing from approximately 60.0% to approximately 61.5%.

NOTE:
Unless noted otherwise, all peak values are non-coincident, unrestricted peaks, which represent the peak load prior to reductions for load management or energy efficiency impacts.
All compound growth rates are calculated from the first year of the forecast.

Summary Table

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR PJM RTO AND SELECTED GEOGRAPHIC REGIONS

	METERED 2012	UNRESTRICTED 2012	NORMAL 2012		THIS YEAR 2013	RPM YEAR 2016	RTEP YEAR 2018
PJM RTO	154,339	156,319	152,405		153,716	163,176	166,810
				Growth Rate	0.9%		
Demand Resources + Energy Efficiency					-11,583	-15,539	-15,539
PJM RTO - Restricted					142,133	147,637	151,271
PJM RTO (with EKPC)	156,182	158,162	154,235		155,553	165,128	168,813
				Growth Rate	0.9%		
Demand Resources + Energy Efficiency					-11,583	-15,539	-15,539
PJM RTO - Restricted					143,970	149,589	153,274
PJM MID-ATLANTIC	58,945	60,067	59,230		59,736	63,051	64,184
				Growth Rate	0.9%		
Demand Resources + Energy Efficiency					-6,328	-6,626	-6,626
MID-ATL - Restricted					53,408	56,425	57,558
EASTERN MID-ATLANTIC	32,542	32,832	32,366		32,622	34,382	35,045
				Growth Rate	0.8%		
Demand Resources + Energy Efficiency					-2,664	-2,558	-2,558
EMAAC - Restricted					29,958	31,824	32,487
SOUTHERN MID-ATLANTIC	13,634	14,196	13,860		14,020	14,586	14,776
				Growth Rate	1.2%		
Demand Resources + Energy Efficiency					-1,851	-2,091	-2,091
SWMAAC - Restricted					12,169	12,495	12,685

Note:
Normal 2012 and all forecast values are non-coincident as estimated by PJM staff.
Except as noted, all values reflect the membership of the PJM RTO as of June 1, 2012.

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December 2012

Tim Daigle, 610-235-5214

Summary of the November 2012 U.S. Macro Forecast

The November U.S. macro forecast was completed as the economy was showing signs of stress following a lackluster year of growth. Partway through the fourth quarter, real GDP growth was tracking at a paltry 1.8% annualized rate, down noticeably from 2.7% in the previous quarter and slightly lower than the 2% year-to-date average. Job growth is indicative of a slowly improving labor market, with the underlying trend pace of gains pegged at around 150,000 jobs per month for close to two years now, but has been accompanied by weak wage growth. The unemployment rate has slowly declined throughout the year. Still, at 7.7%, it remains elevated and may overestimate improvement as labor force growth is sluggish.

Though the year started off on a high note, the economy underperformed expectations from the end of 2011 by most measures of growth. A relatively warm and storm-free winter helped the economy get off to a fast start in 2012, with some business and consumer spending usually scheduled for later in the year pulled forward. However, the early year boost gave way to another midyear slump as higher energy and gasoline prices exacerbated the expected payback. After peaking at a 2.5% annualized pace in the first quarter, real consumer spending growth has slowed to a disappointing 1.5% as recently as the third quarter. This is due in large part to subpar personal income growth linked to excess slack in the labor market suppressing wage and salary advances.

In addition to a weaker contribution from consumers, increasingly cautious businesses have played a role in the subpar performance. Concerns of slowing growth in China, the ongoing sovereign debt crisis in the euro zone, and uncertainty surrounding the presidential election and impending fiscal policy changes shook business confidence. Business investment growth slowed to a crawl midyear and actually has declined more recently.

The U.S. economy is in for a rough start to 2013 as the ongoing fiscal-cliff negotiations delay private business investment and hiring plans further and consumer spending is muted by impending tax hikes taking a bite out of disposable income growth. However, assuming federal policymakers come to an agreement on scaling back some of the spending cuts and tax provisions in a reasonable amount of time, as the baseline forecast predicts, the economy will quickly regain traction and be off and running as 2014 approaches. By that time, a renewed housing cycle will take off as household formation accelerates, stimulating construction as well other housing-related industries.

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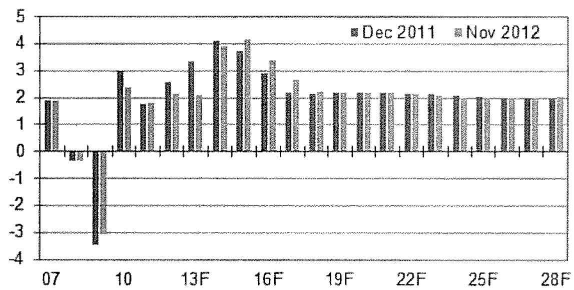
The headwinds in 2012, including the income-related slowdown in consumer spending growth and pullback in business investment, shaved about 0.4 percentage point off growth and put the economy on a weaker trajectory heading into 2013. Final numbers for 2012 are not yet available, but real GDP for the year will come in around 2.2%, versus 2.6% in the December 2011 forecast. Employment growth will finish the year at 1.4%, ahead of expectations for a 1% rate of growth. Growth in both manufacturing employment, up 1.8%, and nonmanufacturing employment, up 1.4%, easily beat expectations. Unfortunately, with the aforementioned slack in the labor market limiting upward pressure on wages and salaries, real personal income growth will finish the year at only 1.4%, versus expectations of 3.6%.

The weight of fiscal uncertainty as well as the phasing out of temporary tax breaks will suppress growth early in 2013 compared with the December 2011 forecast. However, once policymakers come to an agreement on important fiscal issues and greater clarity is provided to businesses, the recovery will accelerate quickly. As a result, the current forecast expects the economy to be nearly in the same place by 2016.

Political Uncertainty Weighs on Growth in 2013

U.S. real GDP growth, % change



Sources: BEA, Moody's Analytics

The most substantial difference between the two forecasts relates to demographics, specifically faster household formation. As the economic expansion matures and migration into the U.S. and between regions rebounds, household formation is projected to return to a pace consistent with long-run demographics. In particular, young individuals who delayed forming households because of the poor condition of the labor market will move out and establish their own households as the job market recovers. Moreover, the young-adult population will grow in the near term as more of the echo-boom generation enters adulthood; many of these individuals will form their own households in the next few years. Finally, the recession put a damper on net immigration, but growth in the foreign-born population is expected to pick up as the U.S. economy improves relative to others.

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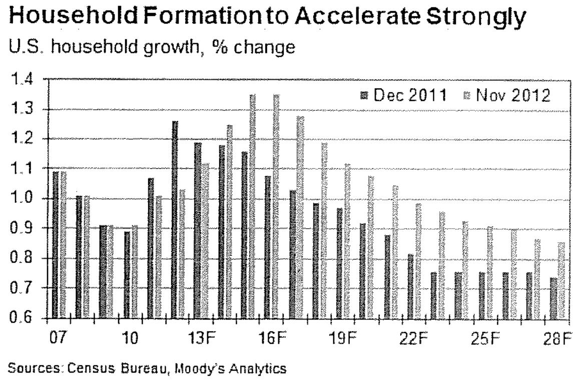

In the out-years, we adopted a higher headship rate than previously assumed. Different age, racial and ethnic groups have widely different headship rates, and the revision to the Moody's Analytics headship rate forecast better reflects the Census Bureau's projection of the nation's future age, racial and ethnic composition. The largest of these composition effects comes from the baby-boom generation passing into the 65-plus age cohort, which has historically had a high headship rate.

Summary of the Forecast for PJM Service Territories

The PJM service territory covers all or parts of 13 states and the District of Columbia, accounting for more than 52 million people, or about a sixth of the U.S. population. The regional economies of the service territory include metro areas in the Midwest, South and Northeast and are remarkably varied, running the gamut from extremely diversified economies such as Chicago to those highly dependent on one industry such as Elkhart IN.

Overall, the dominant industry in the service territory is education/healthcare. In addition to employing the largest share of the region's workers, it was also one of the few industries to add jobs during the recession. Consistent with this historical trend, education- and healthcare-related services will provide the lion's share of new jobs in the forecast period. On average, the concentration of manufacturing in the service territory is roughly in line with the national average, but more than half of the metro area's economies, mainly smaller old-line manufacturing localities in the Northeast and Midwest, rely more heavily on industrial production for growth. While the public sector has less of a presence in the service territory than it does nationally, it is a pillar of many of the territory's southern metro areas, including many state capitals, college towns, and military-reliant areas.

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Resource and mining represent a small portion of the service territory's economy, but provide significant upside risk, especially in eastern Ohio and western Pennsylvania. The potential for extraction of significant quantities of untapped natural resources offers the possibility of boosting long-term growth in several related industries, including construction, transportation and manufacturing.

Recent Performance

The November 2012 regional forecast was generated in the context of the U.S. macro forecast described above, with considerable political uncertainty weighing on business investment and hiring. The service territory's performance was mixed compared with the U.S. average. Based on metro area-level data, output underperformed expectations by a larger margin. Real income growth also came up short, with current estimates showing growth of 1.4%, compared with expectations of 2.2%. On the other hand, employment growth will finish the year better than expected, with an increase of 1.1% versus a forecast of 0.6% in December 2011.

With manufacturing an important driver, particularly in many of the territory's midwestern metal-production and auto-related metro areas, a rebound in auto demand boosted growth early in 2012. However, some of these economies are experiencing undesirable volatility as slower export demand, tepid domestic business investment spending, and rising inventories slow industrial output. On the whole, the service territory's manufacturing employment growth has slowed markedly; the most recent regional employment data show that industry-wide employment is only 0.7% above year-ago levels, about half the pace from six months ago.

Pennsylvania and Ohio account for a substantial portion of PJM's customers, and the two states continue to play a key role in the region's recovery. Though the states' economies have improved to varying degrees this year, with Ohio's noticeably outpacing the rest of the territory and Pennsylvania's flagging a bit, they have contributed disproportionately since the recovery began more than three years ago. The territory's Ohio and Pennsylvania metro areas make up approximately 20% to 25% of the territory's payroll employment, but they have been responsible for almost 60% of total job gains over the past 12 months.

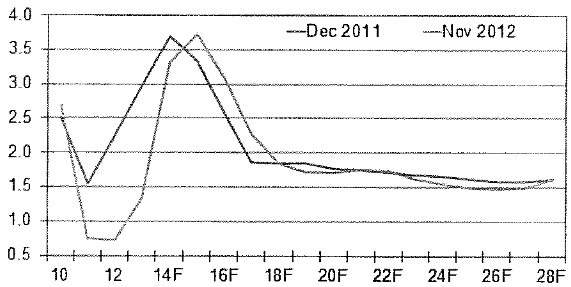
Near-Term Outlook and Changes to the Forecast

Changes to the near-term outlook for the PJM service territory are similar to those in the U.S. macro forecast. The drags of fiscal policy uncertainty on private business investment, as well as the hit to consumers from expected tax hikes and spending cuts, will keep growth muted in the first half of 2013 throughout the service territory.

The rebound in manufacturing will be more subdued as businesses deal with slow final demand and concerns over frothy inventories. Growth is expected to be more restrained in 2013 than was anticipated in the December 2011 forecast, but will quickly rebound in 2014 and 2015. Real GDP in the service territory is forecast to rise 1.4% in 2013 and 3.3% in 2014, compared with 2.2% and 3% growth expected in the forecast of one year ago, respectively. The forecast calls for job growth in the service territory of 0.5% and 1.9% over the next two years, lower than the previous forecast of 0.9% and 2.7%.

Long-Run Growth Expectations Unchanged

Real GDP growth in PJM service territory metro areas, % change



Sources: BEA, Moody's Analytics

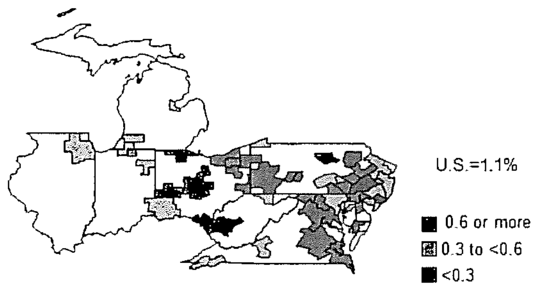
Long-Term Outlook

The November 2012 forecast shows similar long-term growth in metro areas in the PJM service territory compared with the forecast from last December. Growth in many key variables—output, employment and population—is relatively unchanged in the forecasts' out-years compared with that in the December 2011 forecast. For the metro areas in the service territory combined, the November 2012 forecast expects average annual real GDP growth of 2% in the region out to 2028, compared with 2.1% expected one year ago. Average annual job growth is forecast at 0.8%, versus 0.9% in the December 2011 forecast.

The southernmost metro areas are expected to be among the fastest growing in the PJM service territory. The biggest comparative advantage for these areas is their favorable demographic trends, which will help boost overall final demand. The aforementioned rebound in population growth and household formation will drive growth in all of the consumer-based services such as education/healthcare and leisure/hospitality. Virginia metro areas, including Lynchburg and Richmond, as well as Wilmington DE and Bowling Green KY, are expected to lead with average annual real GDP growth of 2.4% or more. Aside from favorable demographics, these metro areas will be driven by highly educated labor forces, productivity growth, and relatively low costs.

Stronger Demographics Benefit the South

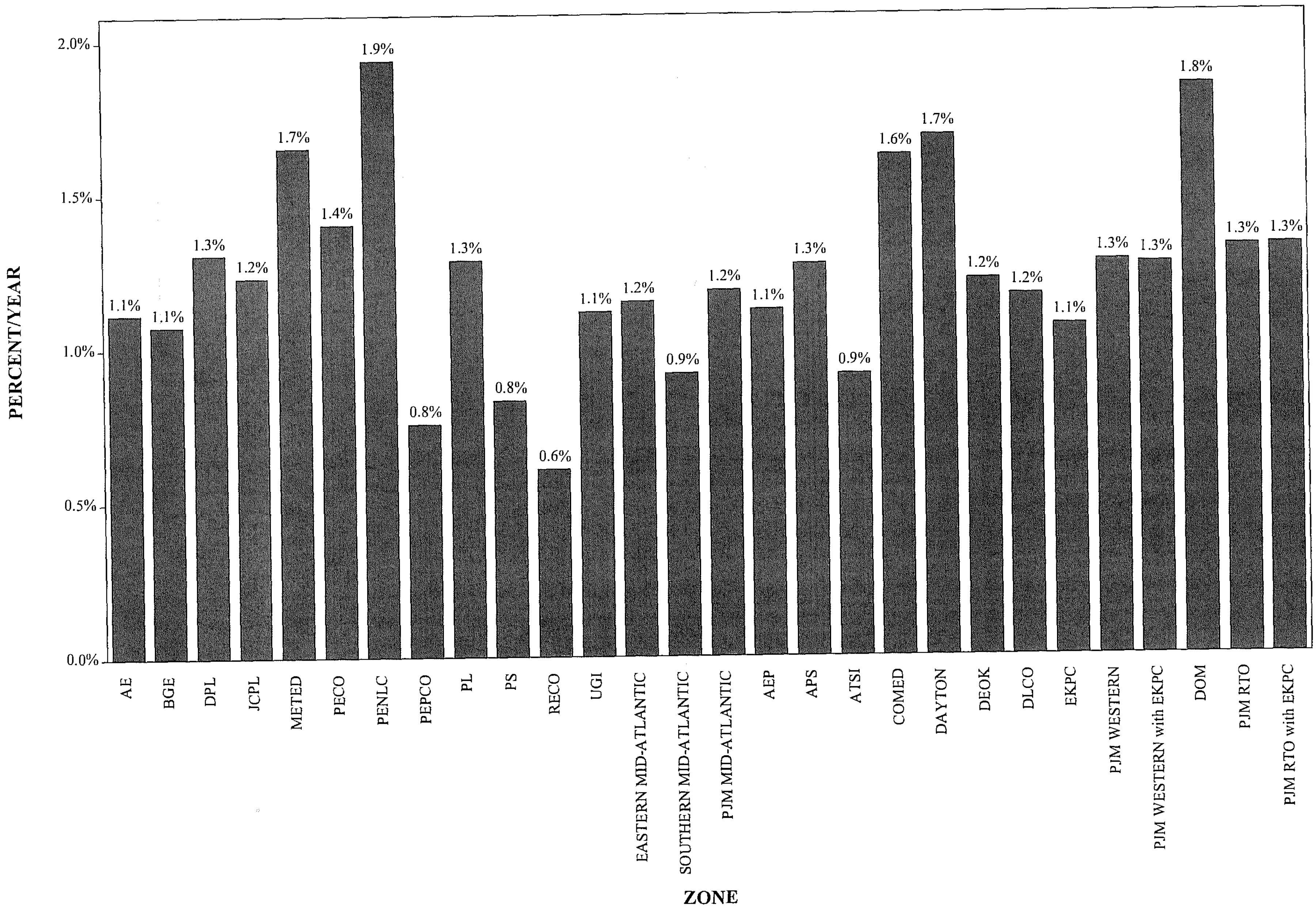
Avg annual household growth from 2013 to 2028, %



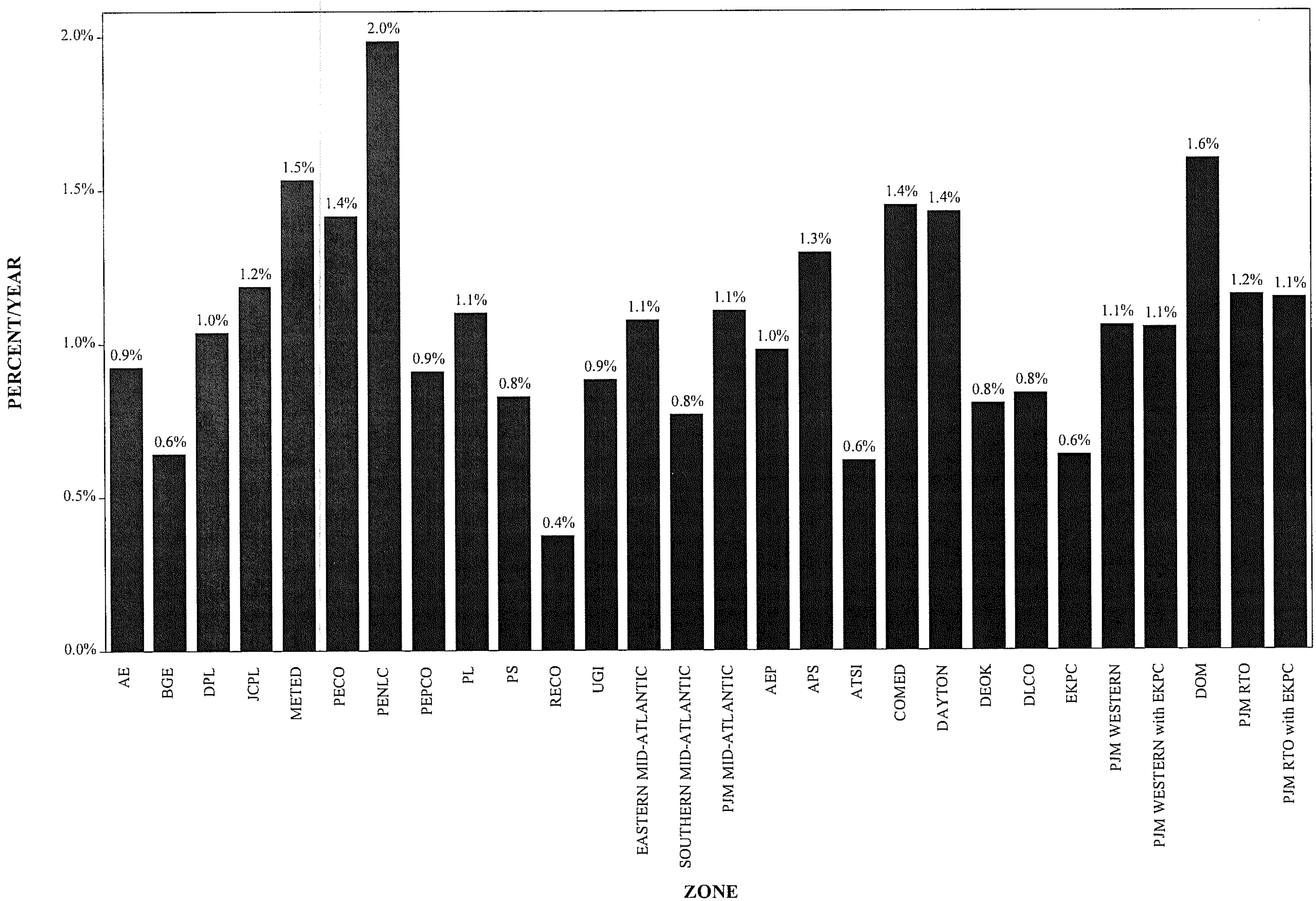
Sources: Census Bureau, Moody's Analytics

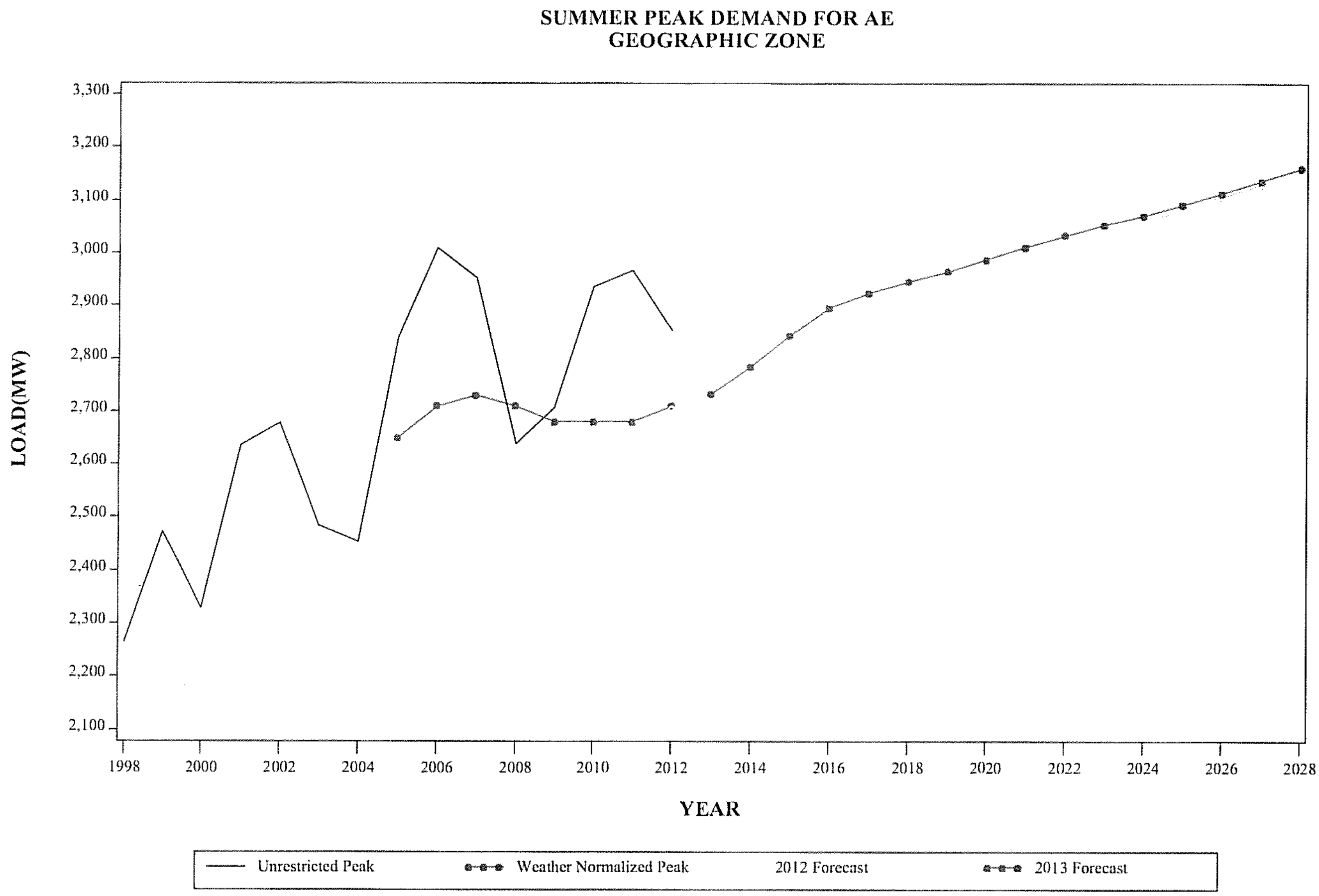
Metro areas in Ohio and Pennsylvania are expected to grow more slowly. Expansion in those states will be more restrained as regions transition away from manufacturing toward more service-oriented economies. With lower-value-added services accounting for a larger part of the regional economies, income growth is expected to be more restrained. Weaker demographics will also undermine long-term growth, as workers and their families are expected to seek opportunities in stronger labor markets outside of the slow-growth metro areas in the Midwest and Northeast.

PJM SUMMER PEAK LOAD GROWTH RATE
2013 - 2023



PJM WINTER PEAK LOAD GROWTH RATE
2013 - 2023




SUMMER PEAK DEMAND FOR AE
GEOGRAPHIC ZONE
3,300
3,200
3,100
3,000
2,900
2,800
2,700
2,600
2,500
2,400
2,300
2,200
2,100
LOAD(MW)
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
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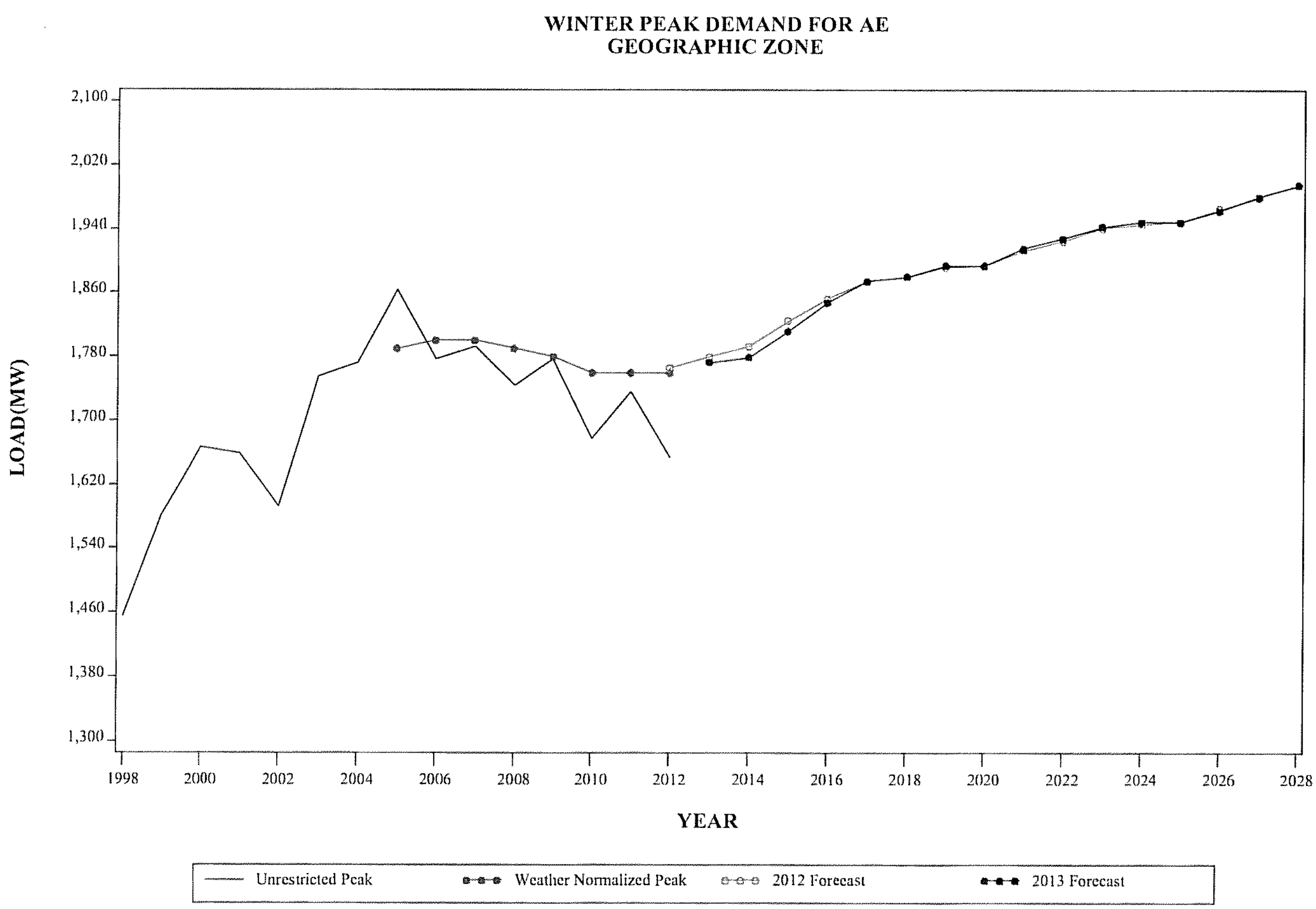
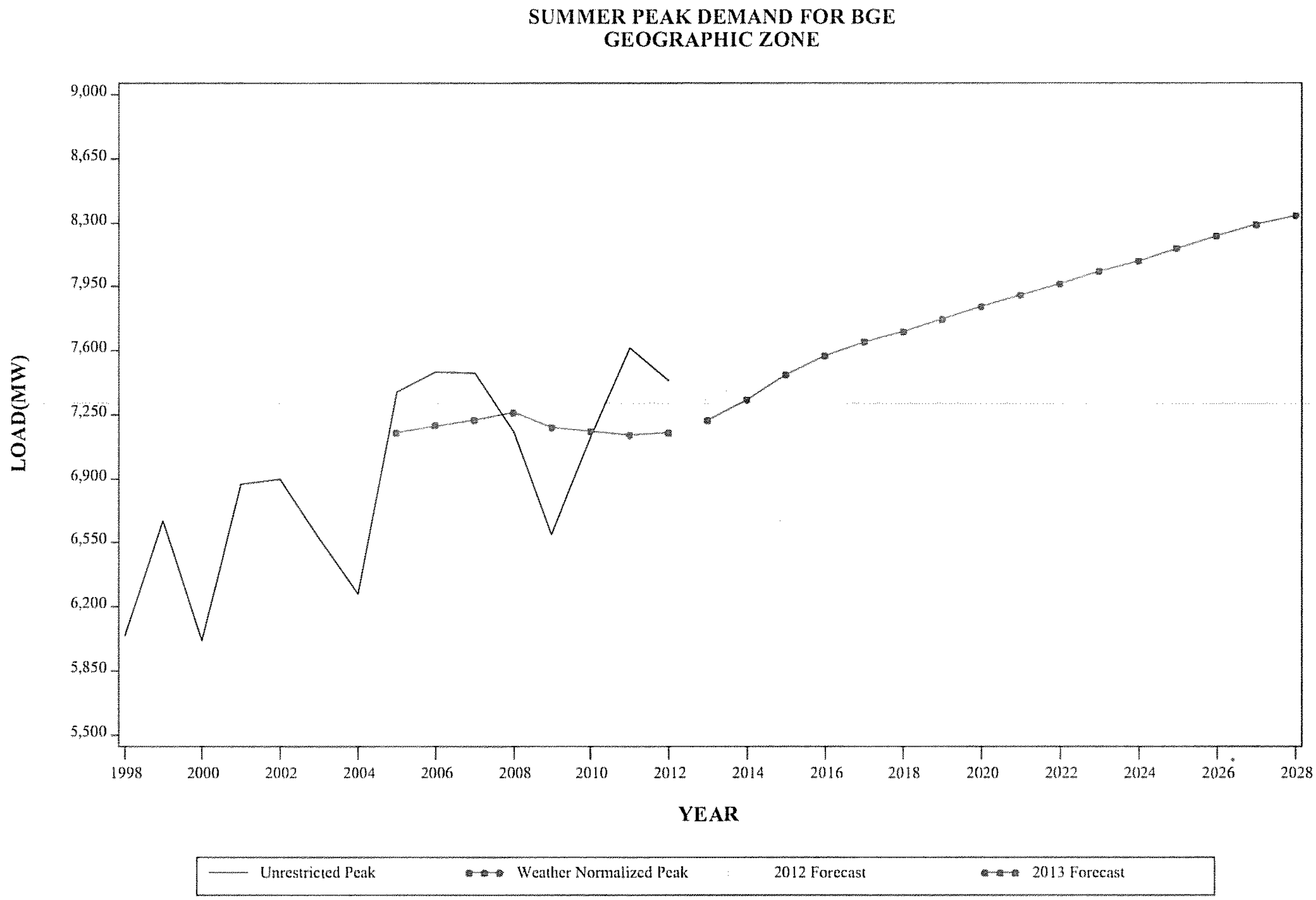
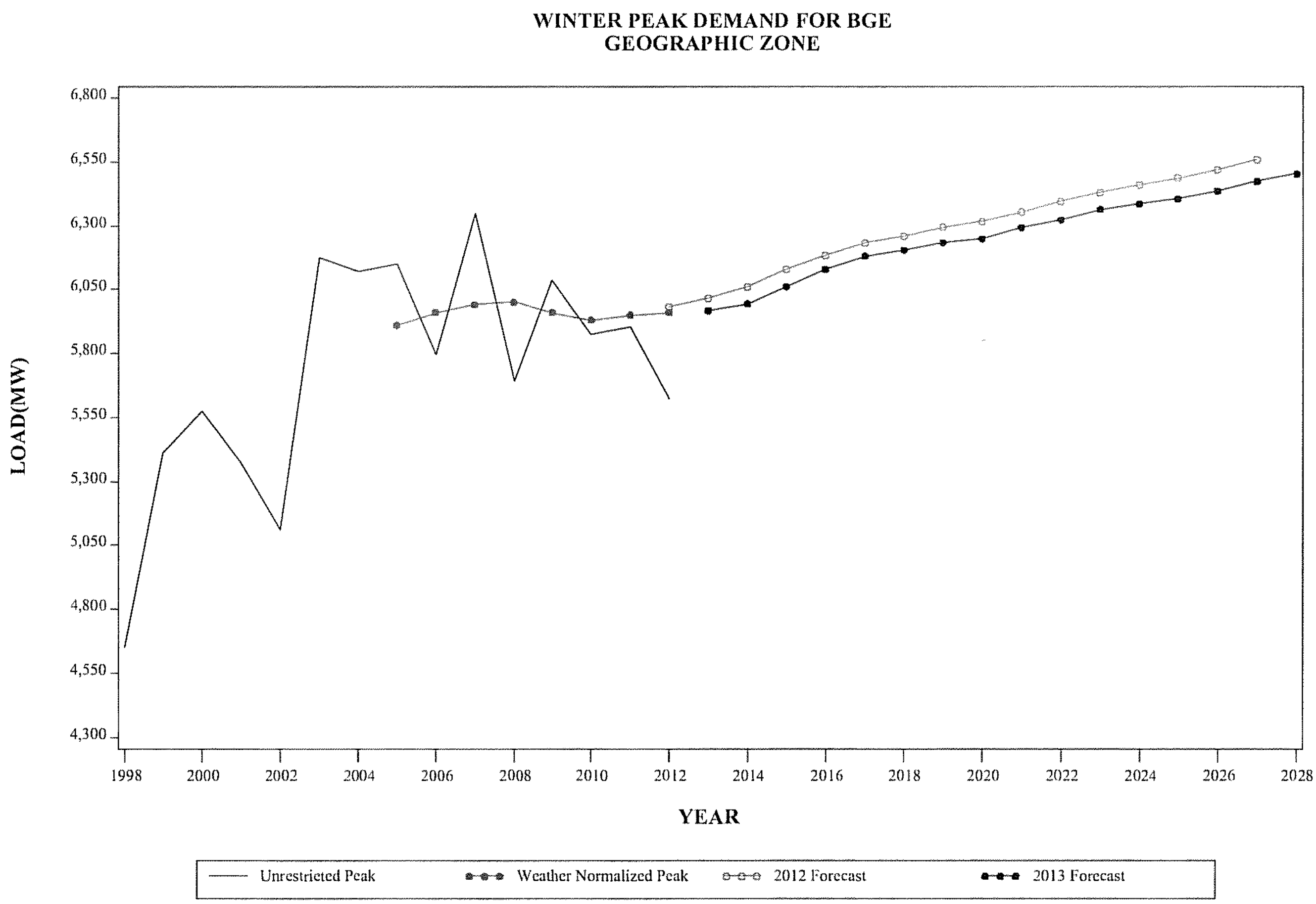
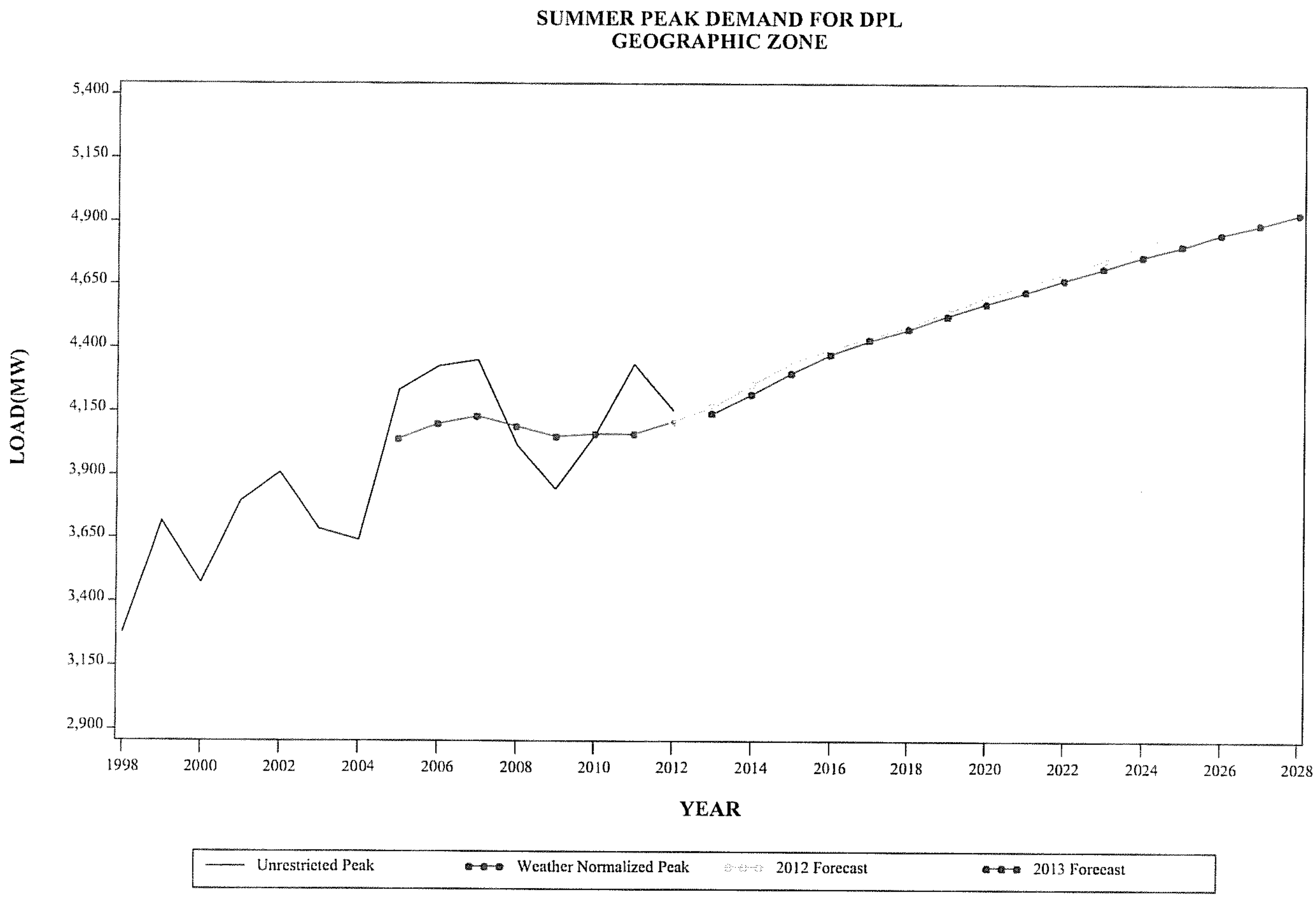
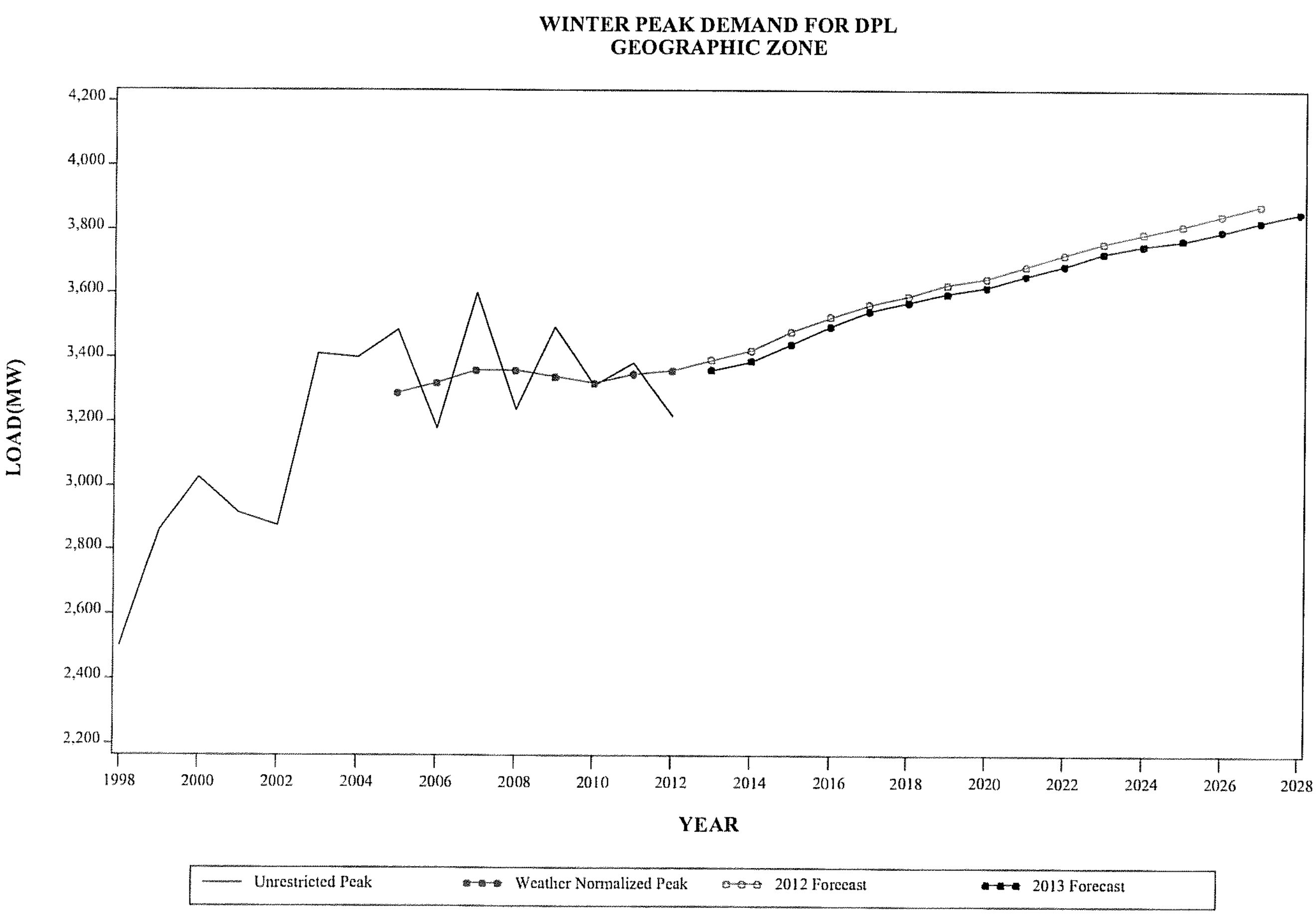
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast

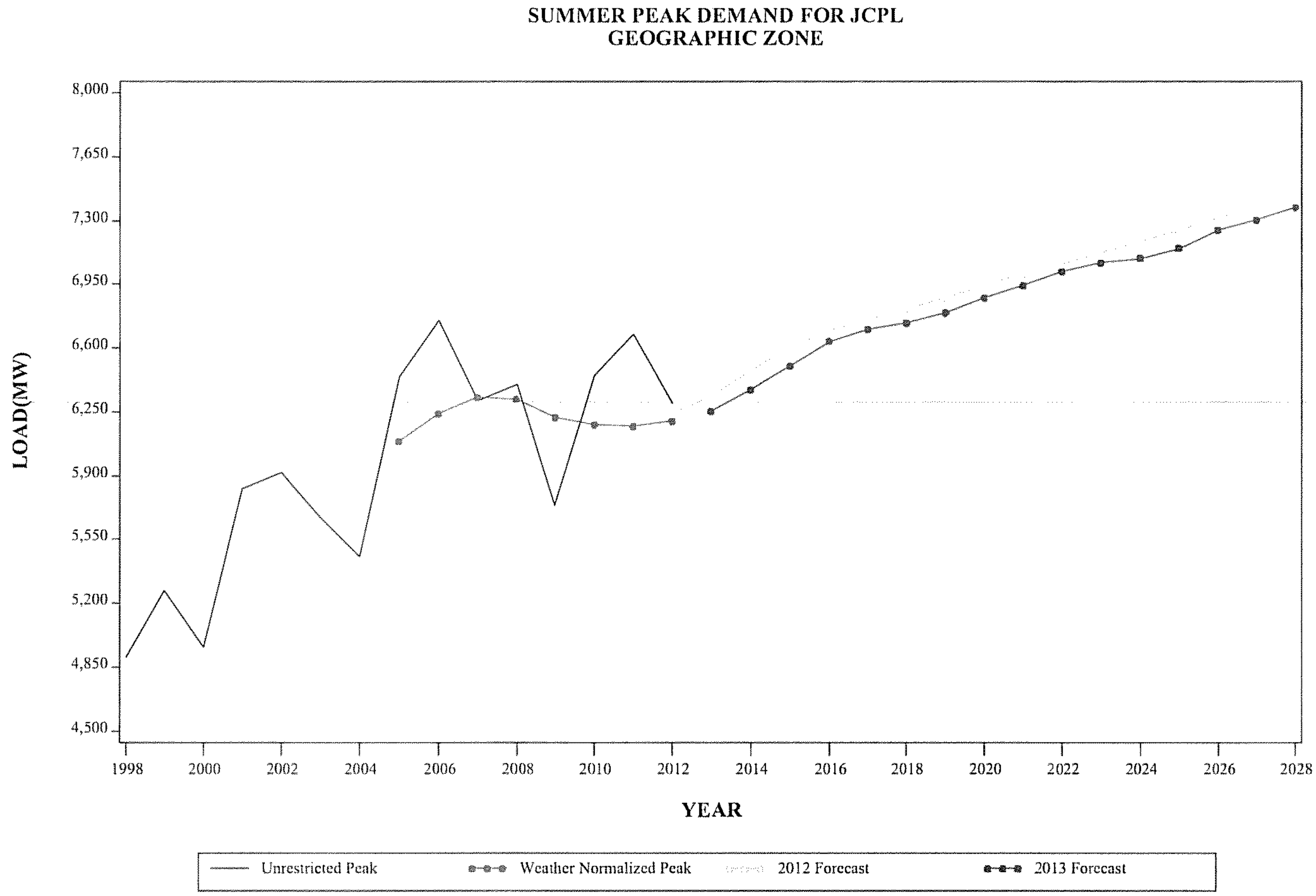

WINTER PEAK DEMAND FOR AE
GEOGRAPHIC ZONE
2,100
2,020
1,940
1,860
1,780
1,700
1,620
1,540
1,460
1,380
1,300
LOAD(MW)
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast

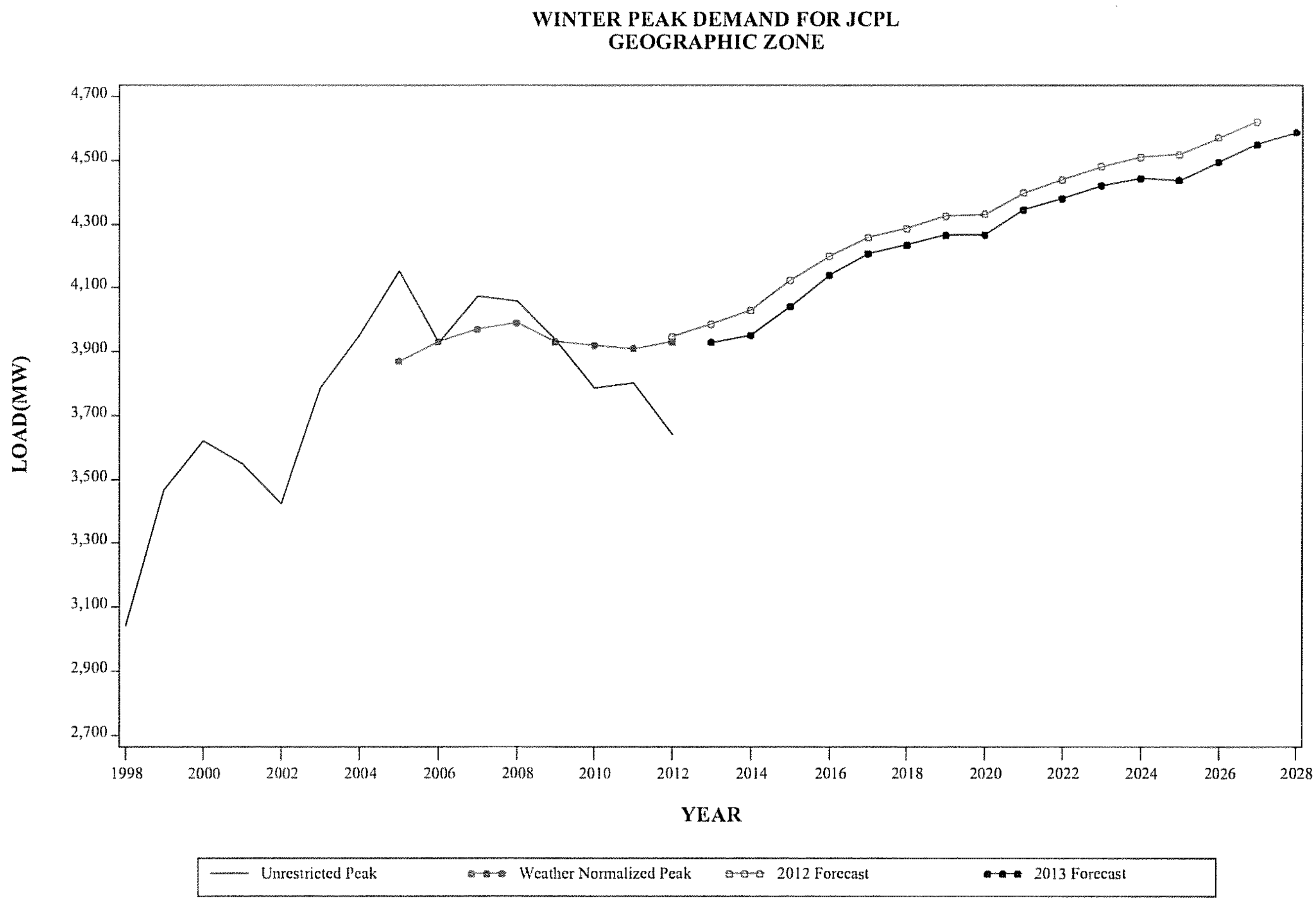

SUMMER PEAK DEMAND FOR BGE
GEOGRAPHIC ZONE
LOAD(MW)
9,000
8,650
8,300
7,950
7,600
7,250
6,900
6,550
6,200
5,850
5,500
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast


WINTER PEAK DEMAND FOR BGE
GEOGRAPHIC ZONE
LOAD(MW)
6,800
6,550
6,300
6,050
5,800
5,550
5,300
5,050
4,800
4,550
4,300
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast

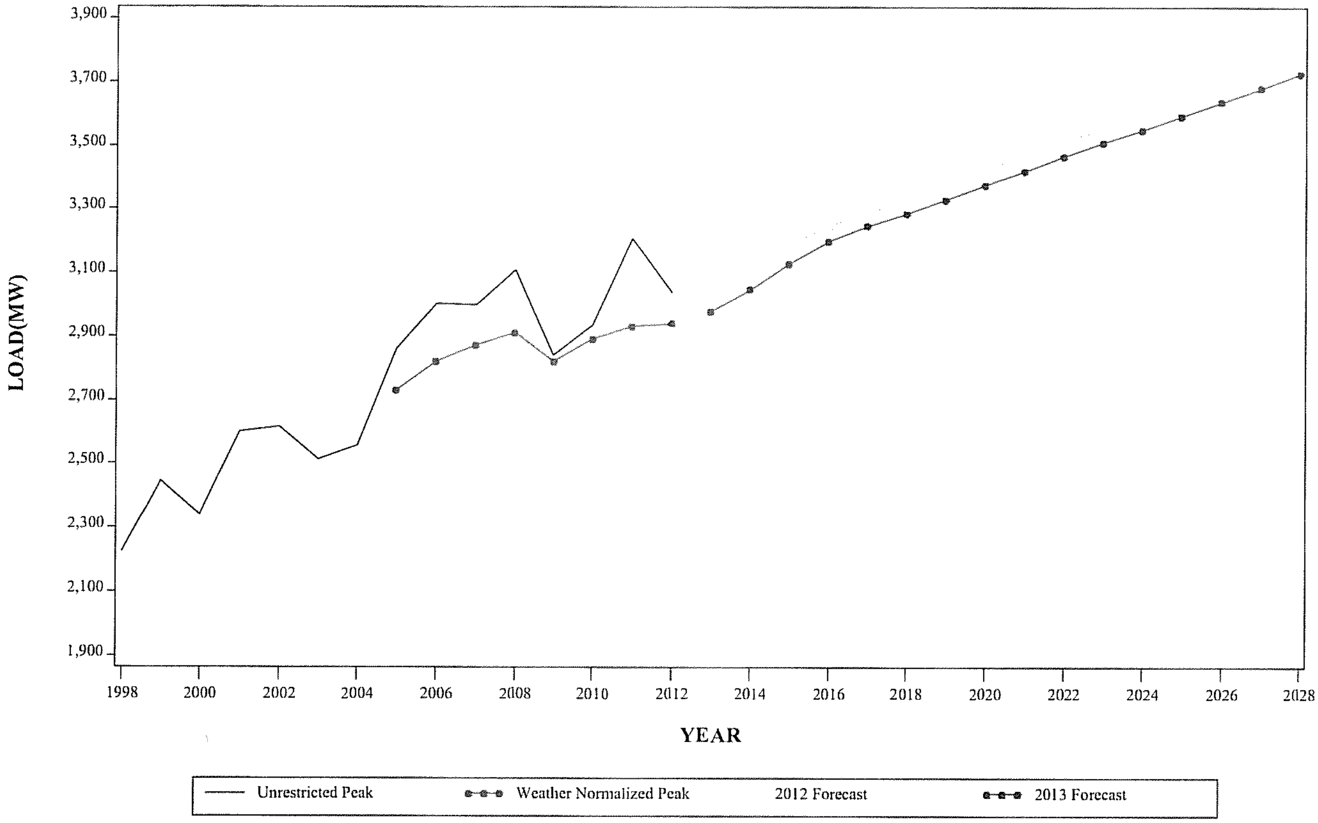

SUMMER PEAK DEMAND FOR DPL
GEOGRAPHIC ZONE
LOAD(MW)
5,400
5,150
4,900
4,650
4,400
4,150
3,900
3,650
3,400
3,150
2,900
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast


WINTER PEAK DEMAND FOR DPL
GEOGRAPHIC ZONE
LOAD(MW)
4,200
4,000
3,800
3,600
3,400
3,200
3,000
2,800
2,600
2,400
2,200
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast

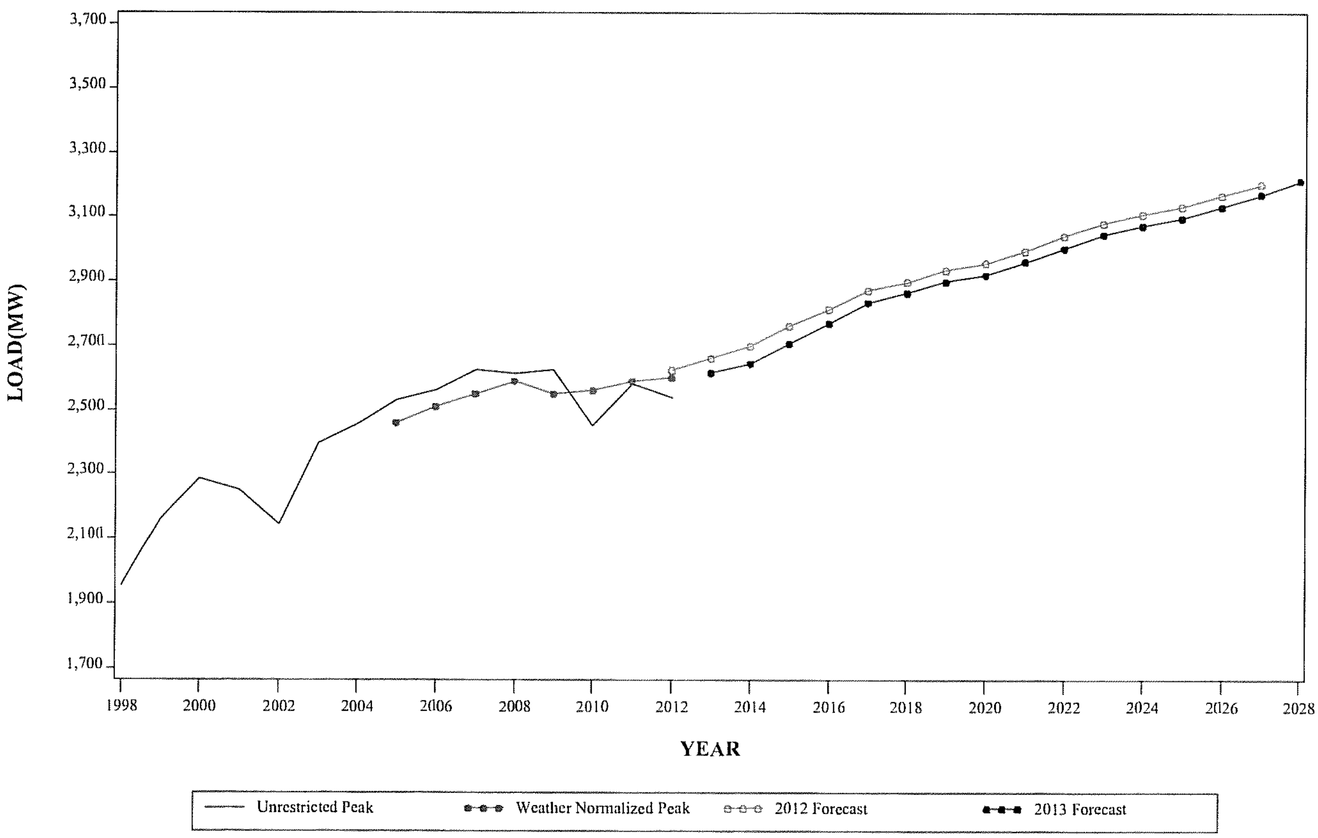

SUMMER PEAK DEMAND FOR JCPL
GEOGRAPHIC ZONE
LOAD(MW)
8,000
7,650
7,300
6,950
6,600
6,250
5,900
5,550
5,200
4,850
4,500
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast

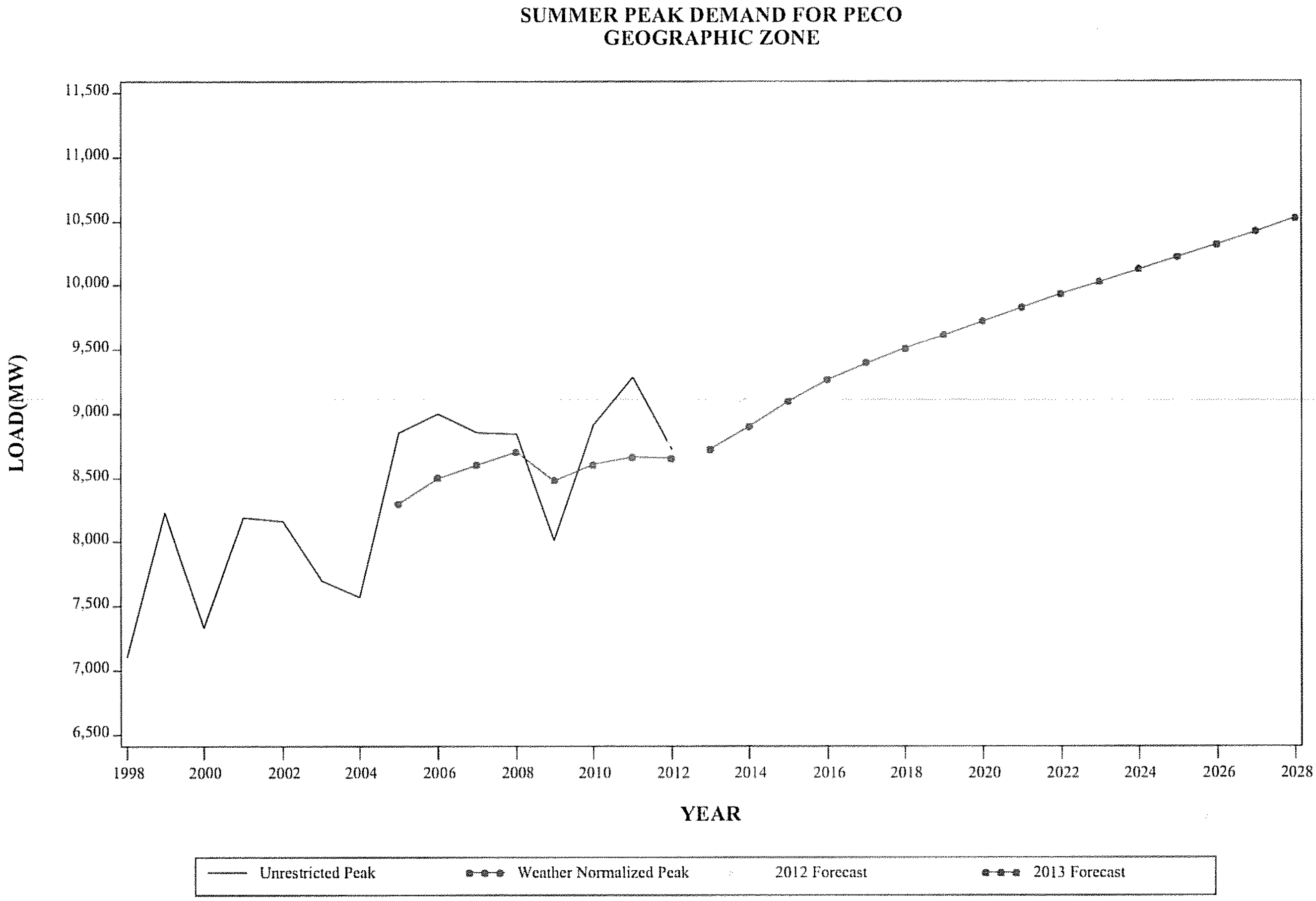

WINTER PEAK DEMAND FOR JCPL
GEOGRAPHIC ZONE
LOAD(MW)
4,700
4,500
4,300
4,100
3,900
3,700
3,500
3,300
3,100
2,900
2,700
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast

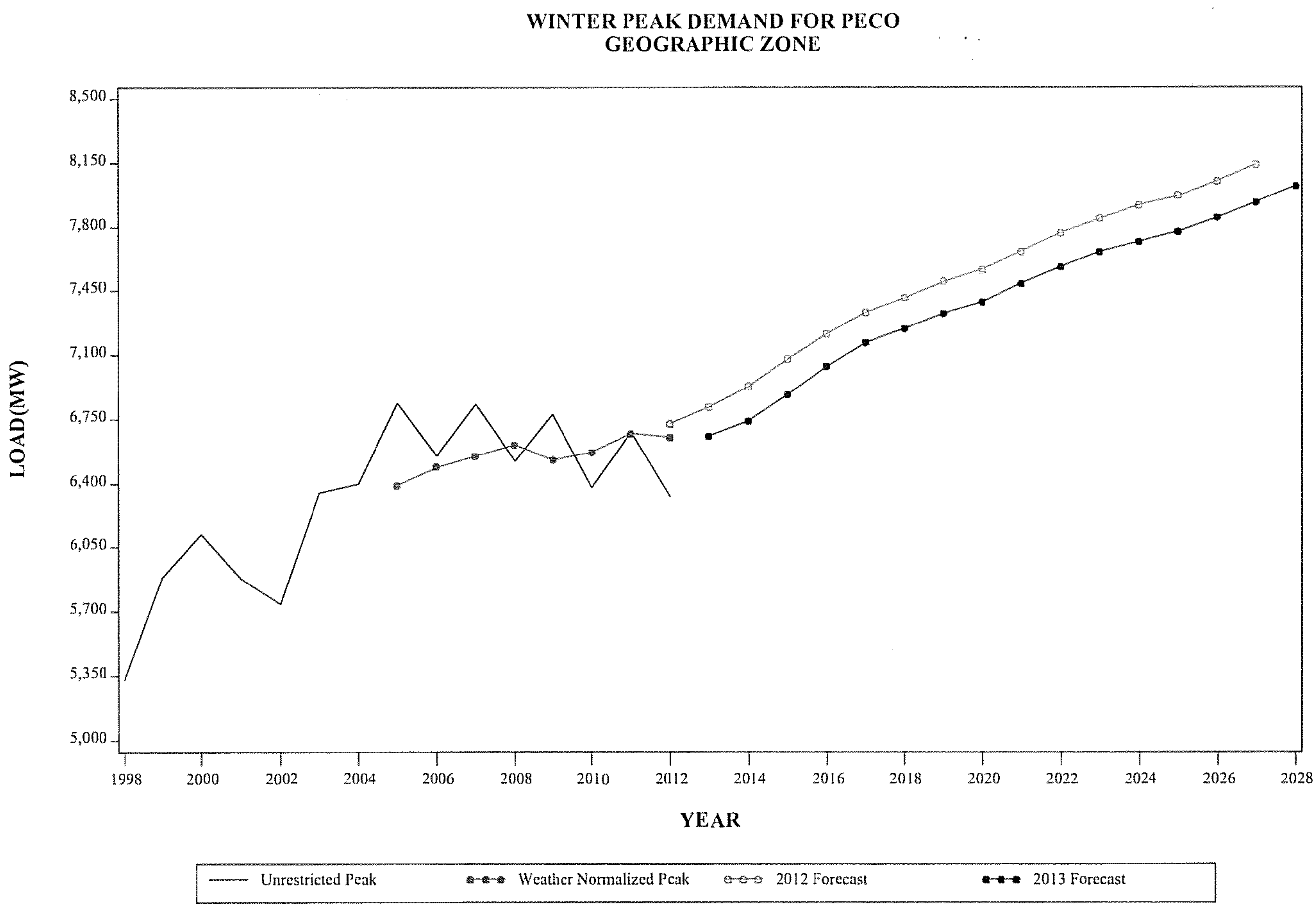
SUMMER PEAK DEMAND FOR METED
GEOGRAPHIC ZONE

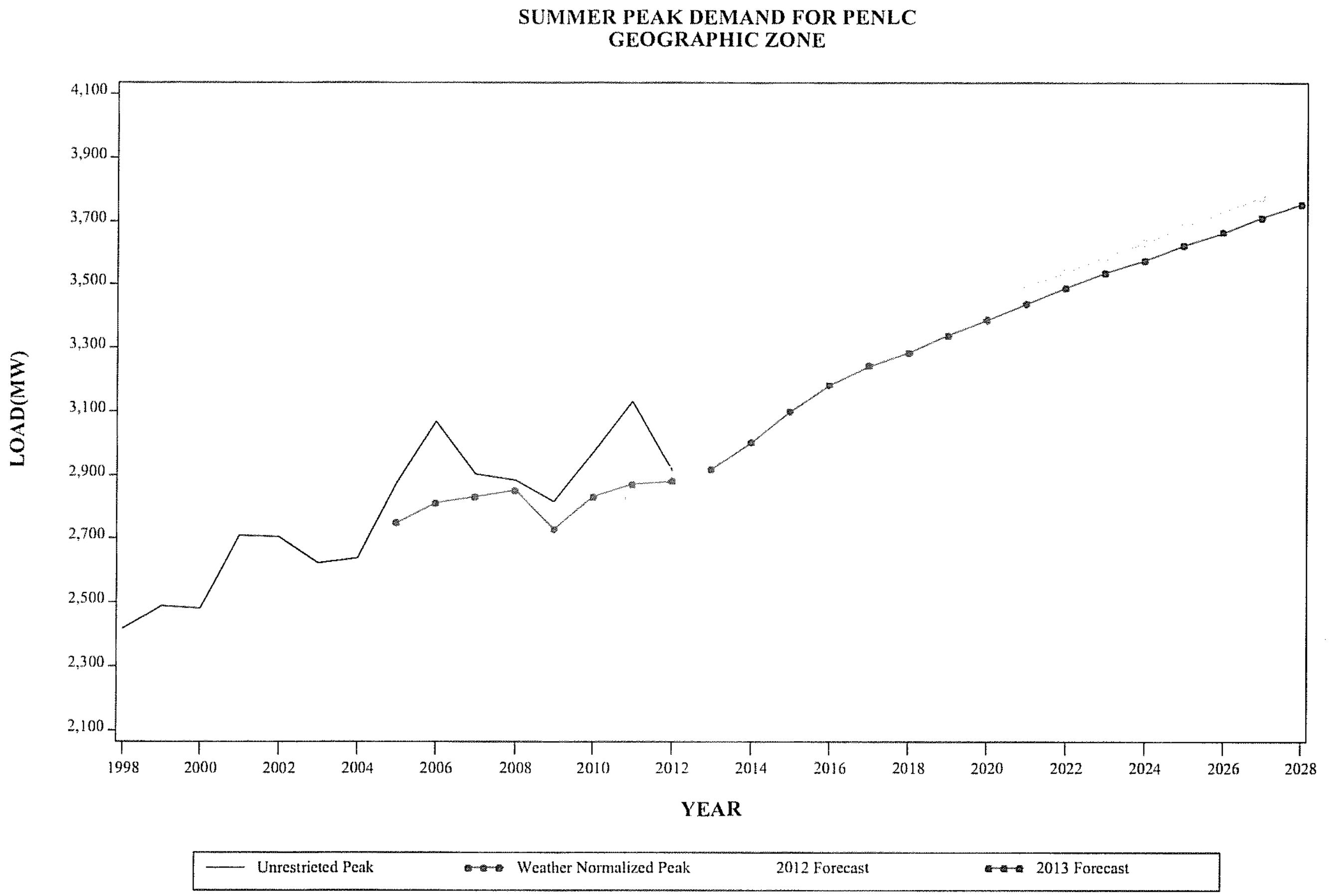


WINTER PEAK DEMAND FOR METED
GEOGRAPHIC ZONE

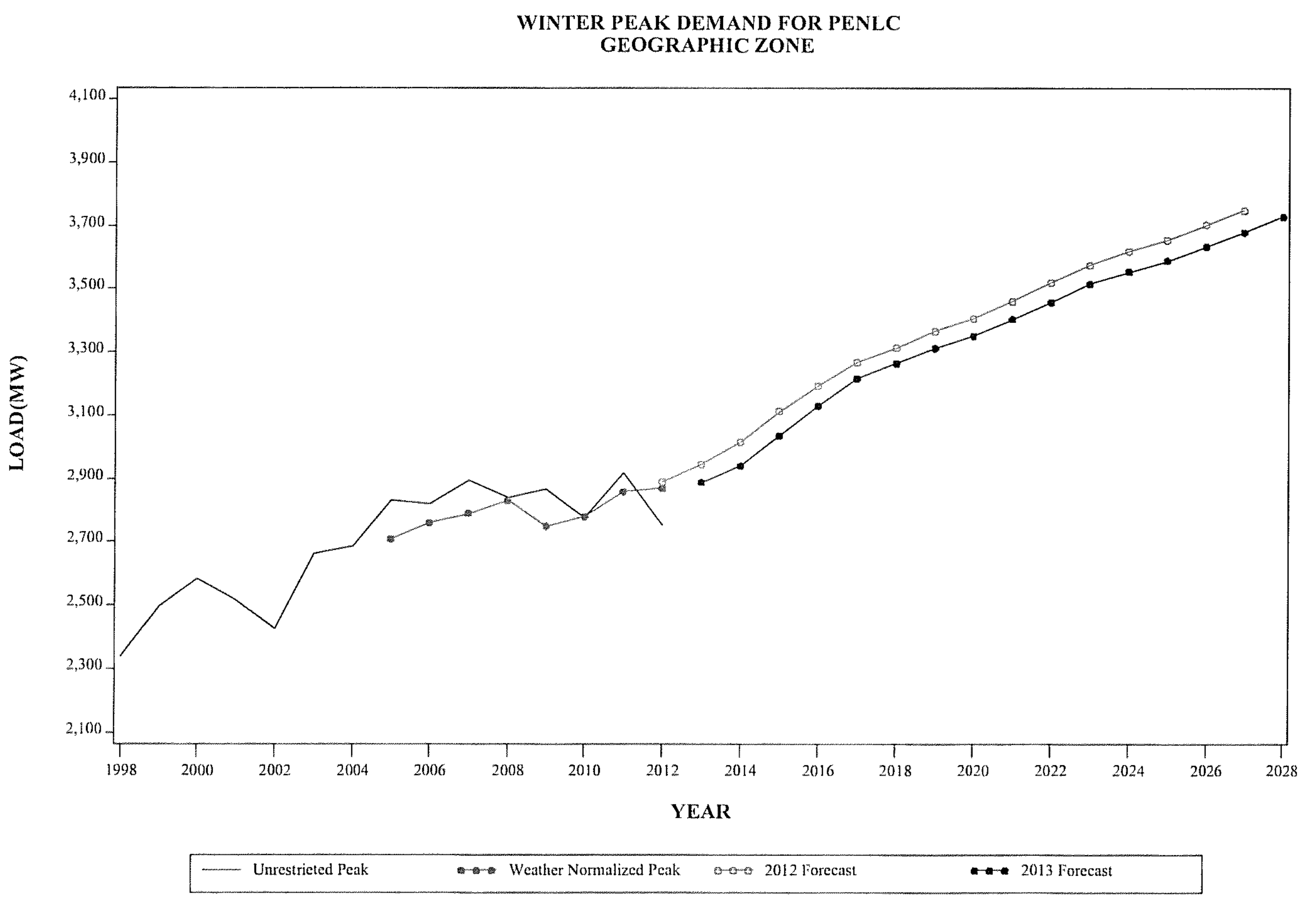



SUMMER PEAK DEMAND FOR PECO
GEOGRAPHIC ZONE
LOAD(MW)
11,500
11,000
10,500
10,000
9,500
9,000
8,500
8,000
7,500
7,000
6,500
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast

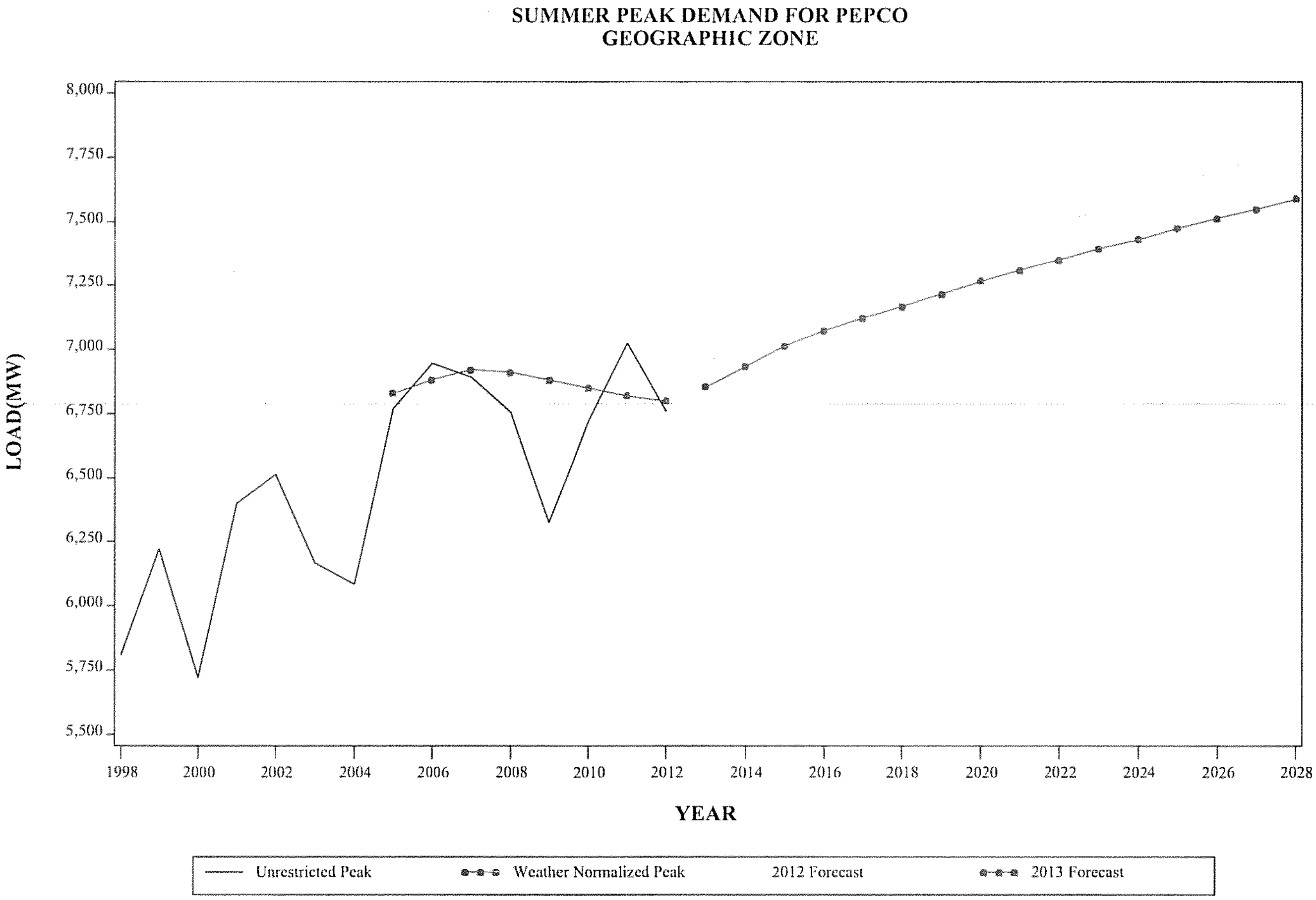

WINTER PEAK DEMAND FOR PECO
GEOGRAPHIC ZONE
LOAD(MW)
8,500
8,150
7,800
7,450
7,100
6,750
6,400
6,050
5,700
5,350
5,000
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast



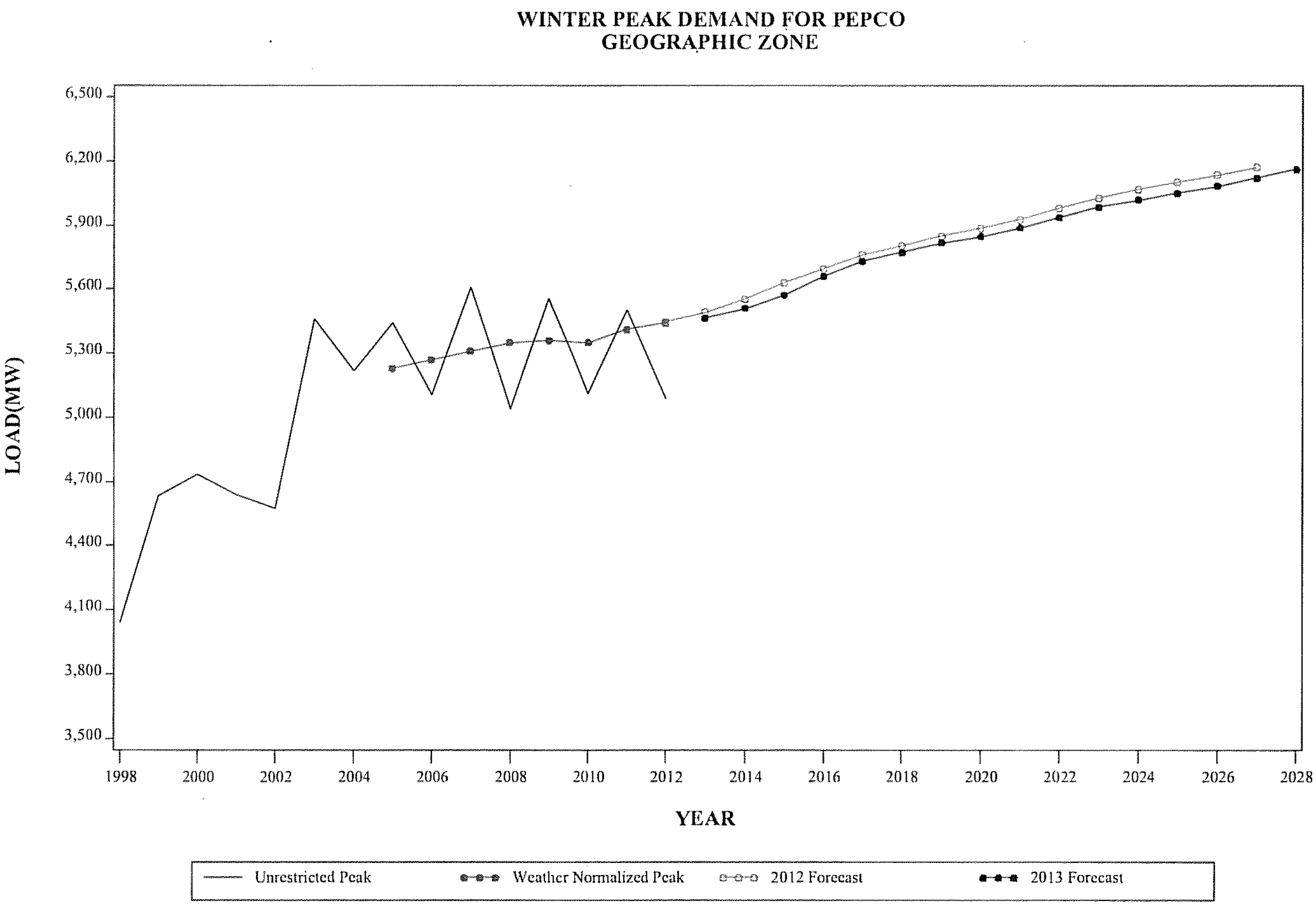
SUMMER PEAK DEMAND FOR PENLC
GEOGRAPHIC ZONE
LOAD(MW)
4,100
3,900
3,700
3,500
3,300
3,100
2,900
2,700
2,500
2,300
2,100
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast



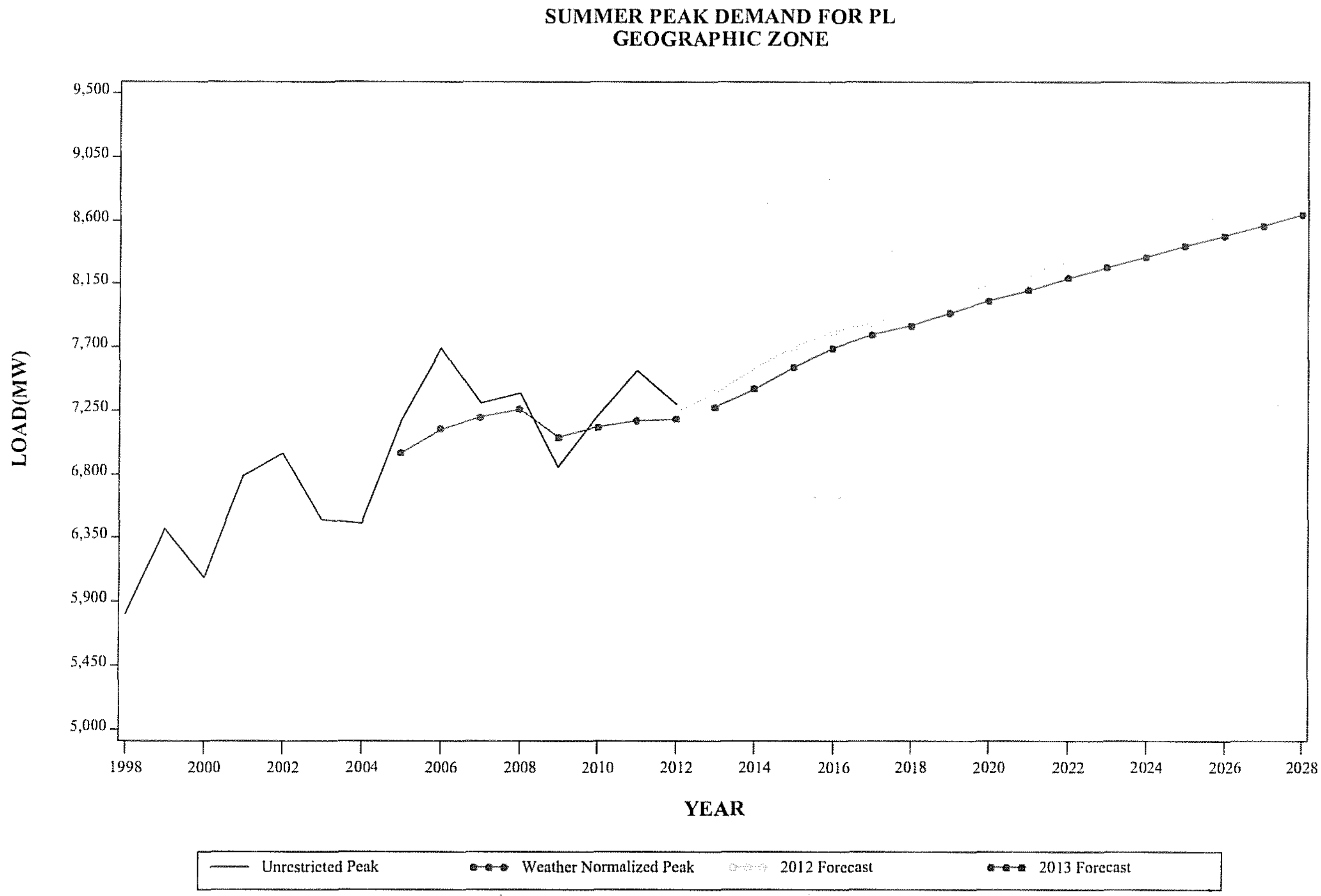
WINTER PEAK DEMAND FOR PENLC
GEOGRAPHIC ZONE
LOAD(MW)
4,100
3,900
3,700
3,500
3,300
3,100
2,900
2,700
2,500
2,300
2,100
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast

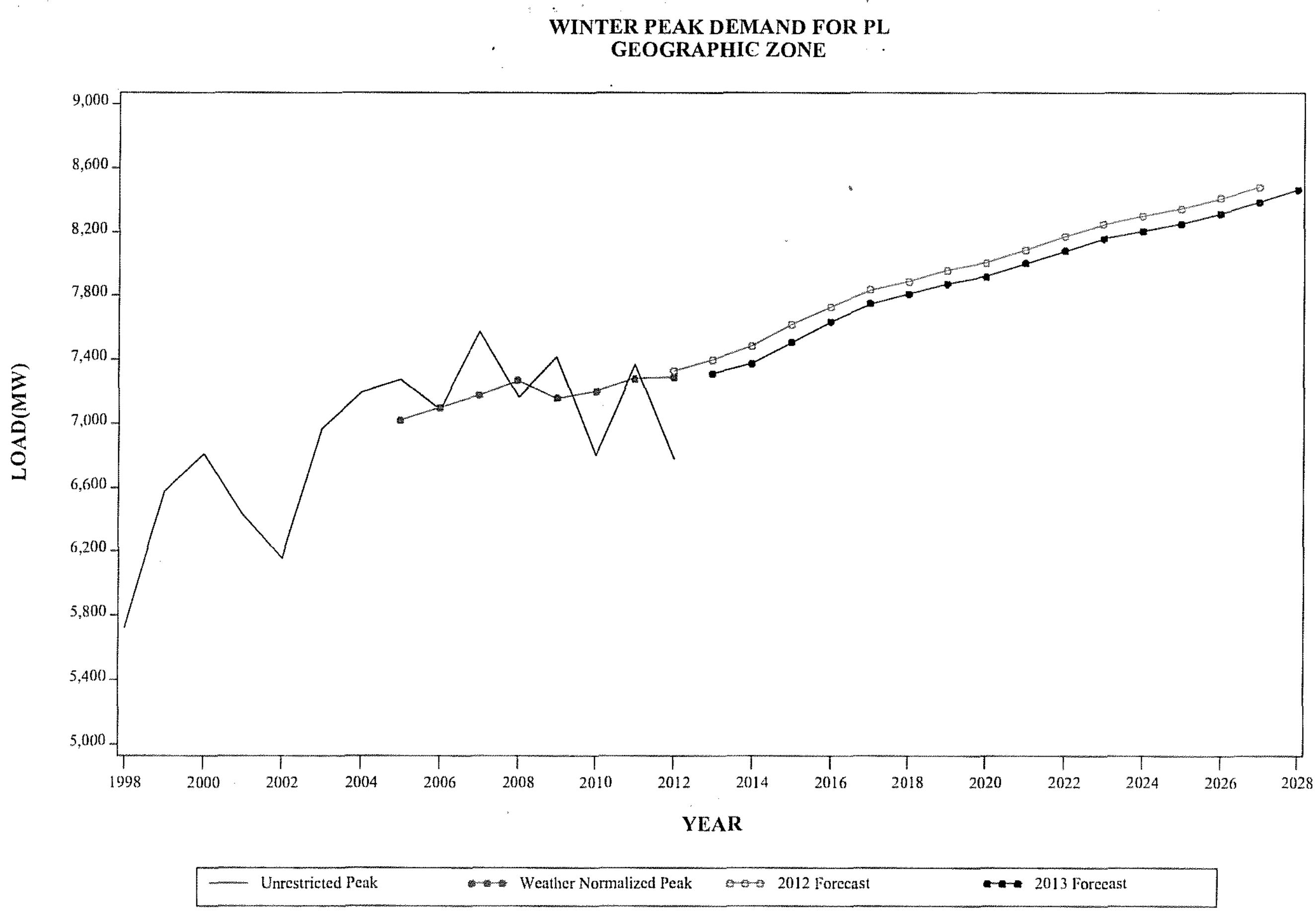


SUMMER PEAK DEMAND FOR PEPCO
GEOGRAPHIC ZONE
LOAD(MW)
8,000
7,750
7,500
7,250
7,000
6,750
6,500
6,250
6,000
5,750
5,500
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast

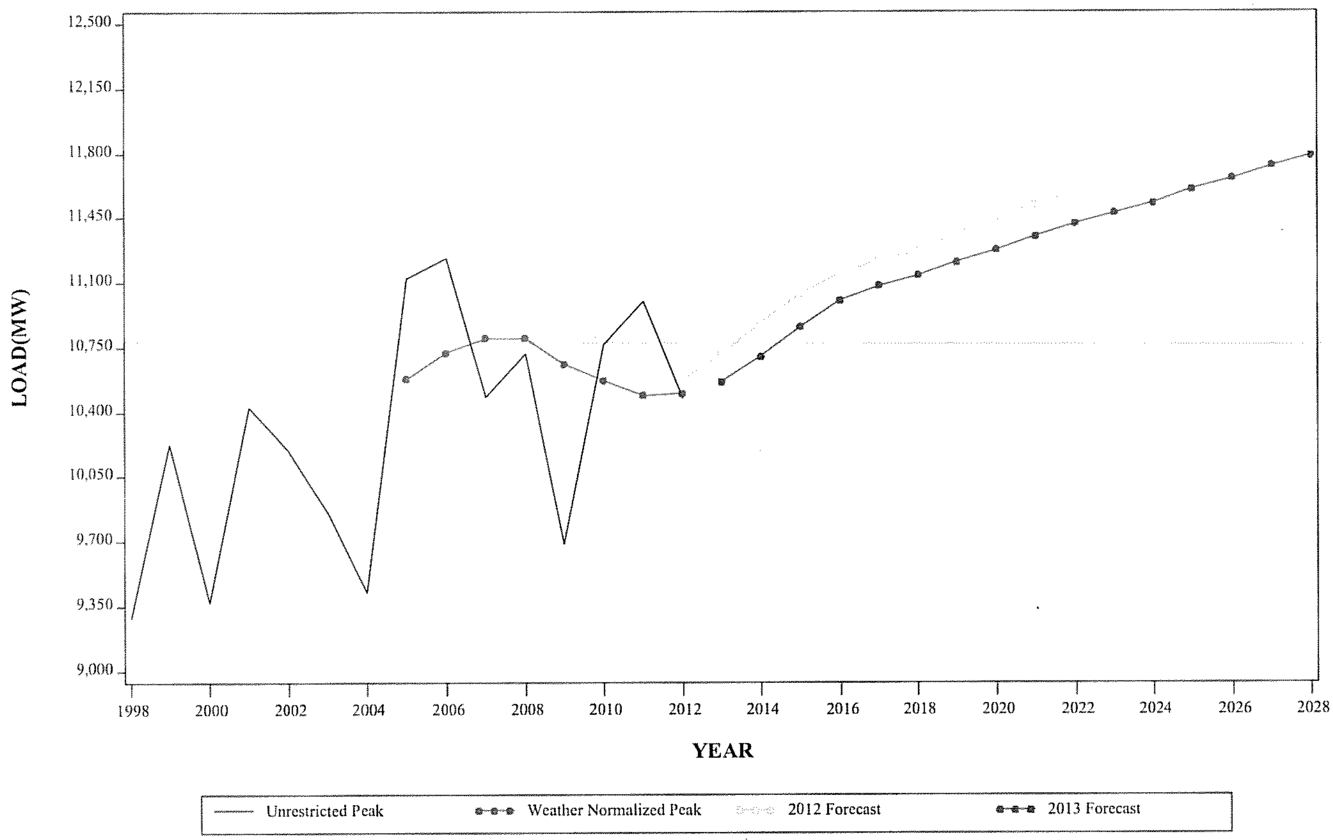


WINTER PEAK DEMAND FOR PEPCO
GEOGRAPHIC ZONE
LOAD(MW)
6,500
6,200
5,900
5,600
5,300
5,000
4,700
4,400
4,100
3,800
3,500
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast

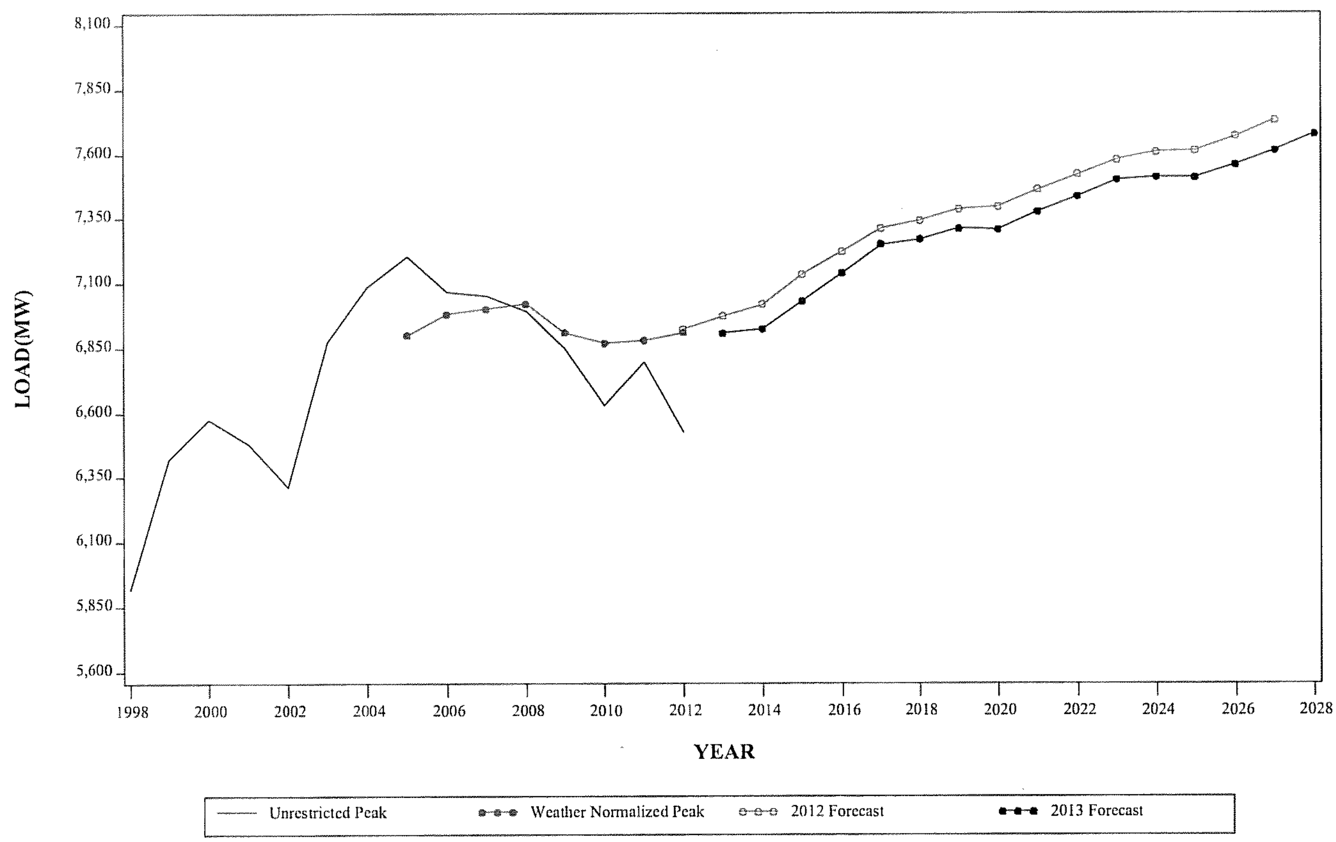

SUMMER PEAK DEMAND FOR PL
GEOGRAPHIC ZONE
LOAD(MW)
9,500
9,050
8,600
8,150
7,700
7,250
6,800
6,350
5,900
5,450
5,000
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast

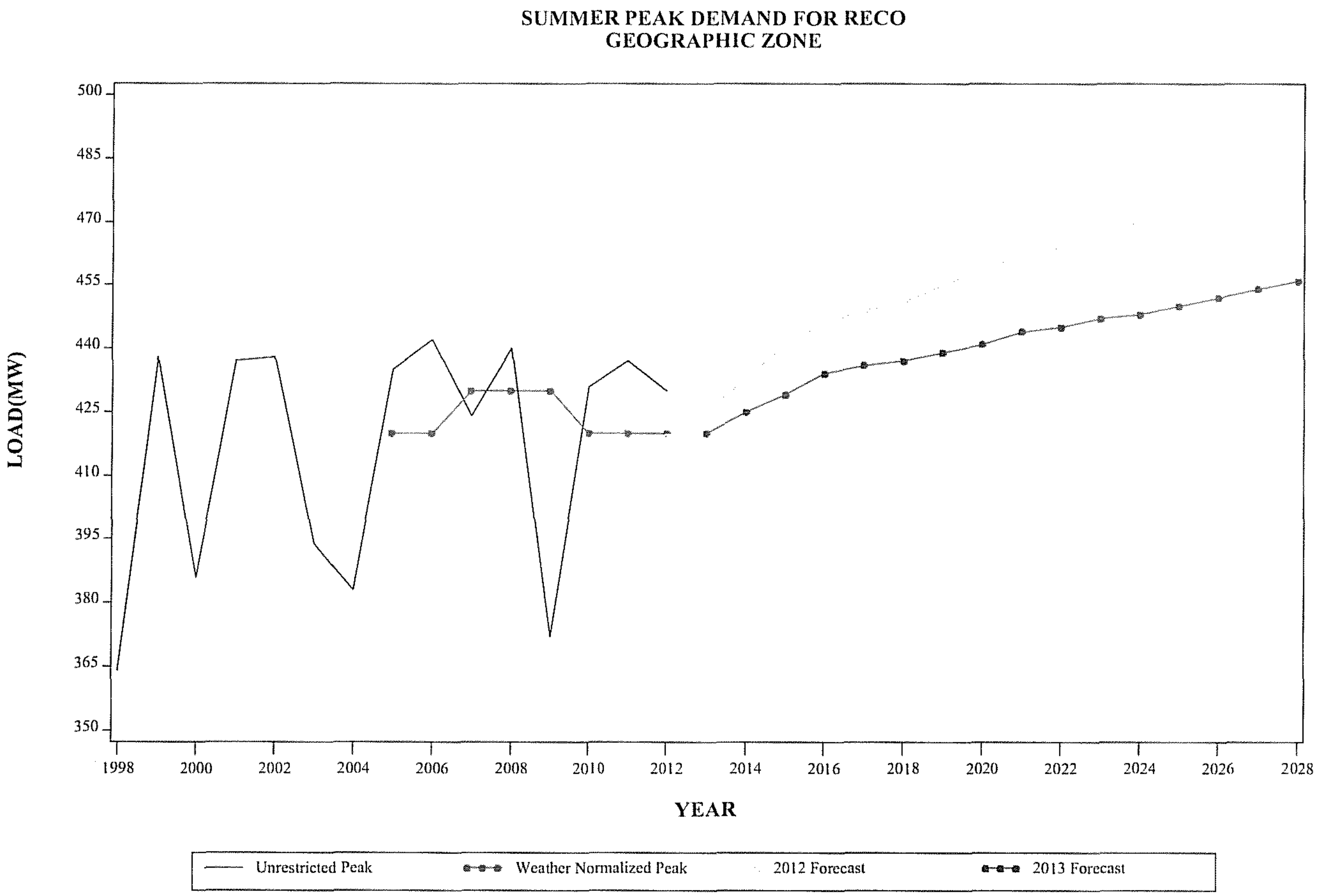

WINTER PEAK DEMAND FOR PL
GEOGRAPHIC ZONE
LOAD(MW)
9,000
8,600
8,200
7,800
7,400
7,000
6,600
6,200
5,800
5,400
5,000
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast

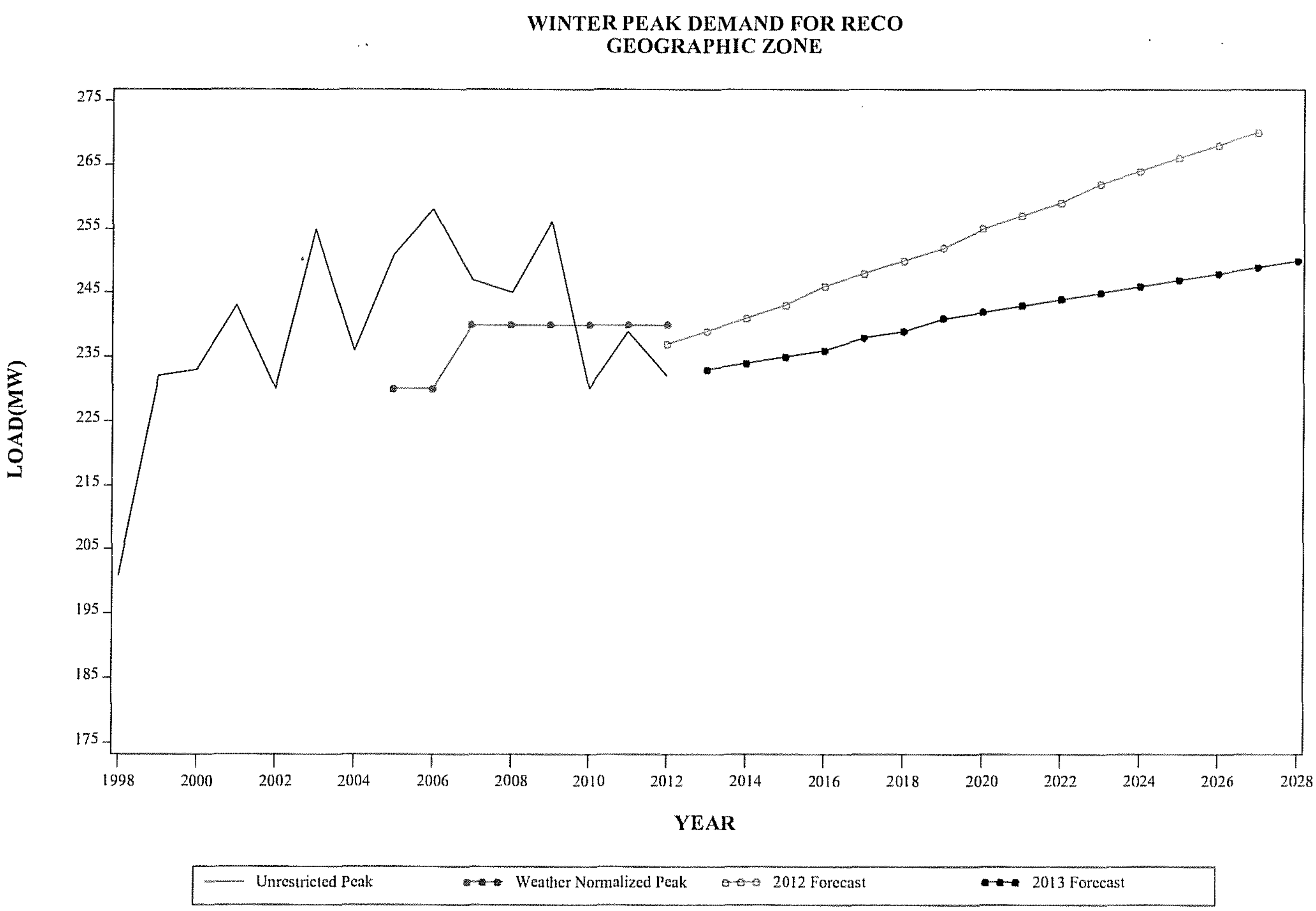
SUMMER PEAK DEMAND FOR PS GEOGRAPHIC ZONE



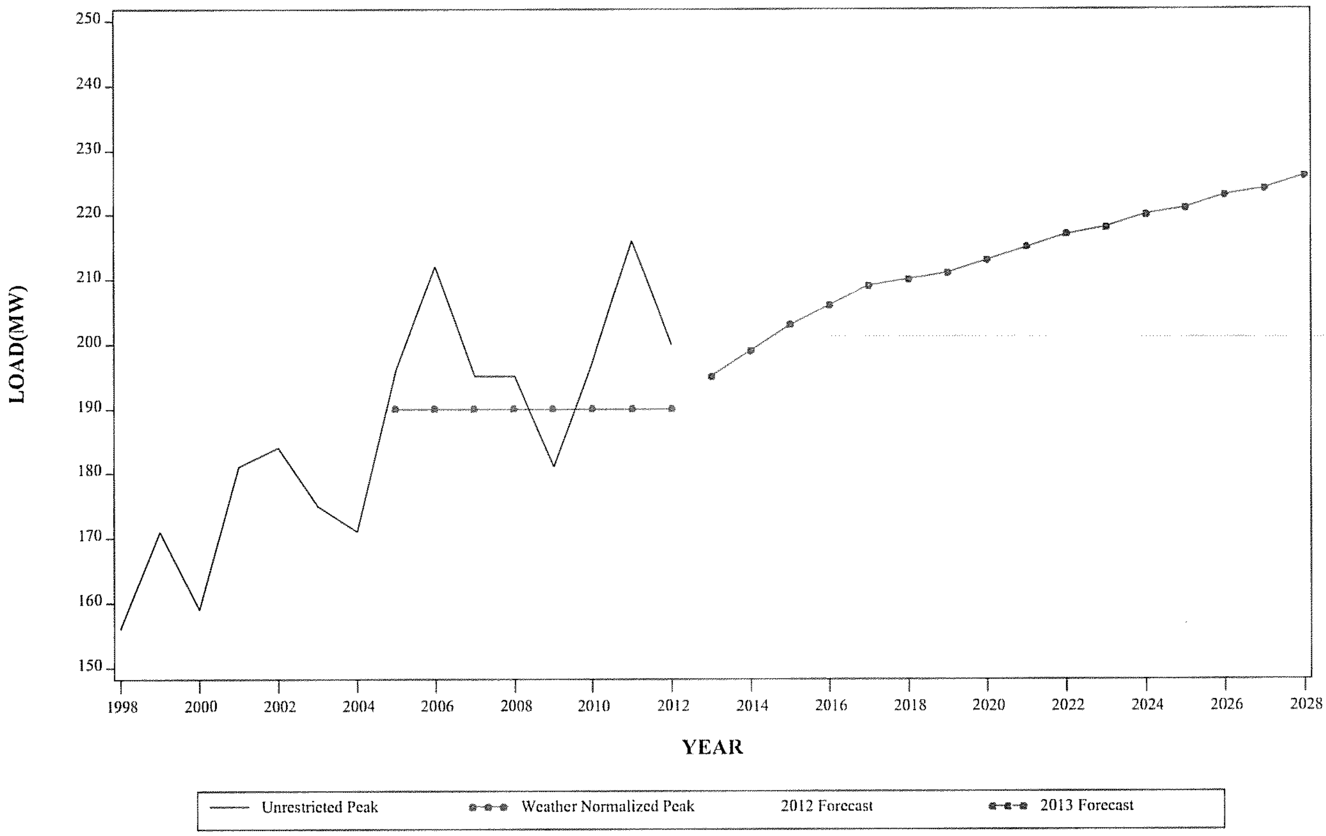
WINTER PEAK DEMAND FOR PS GEOGRAPHIC ZONE



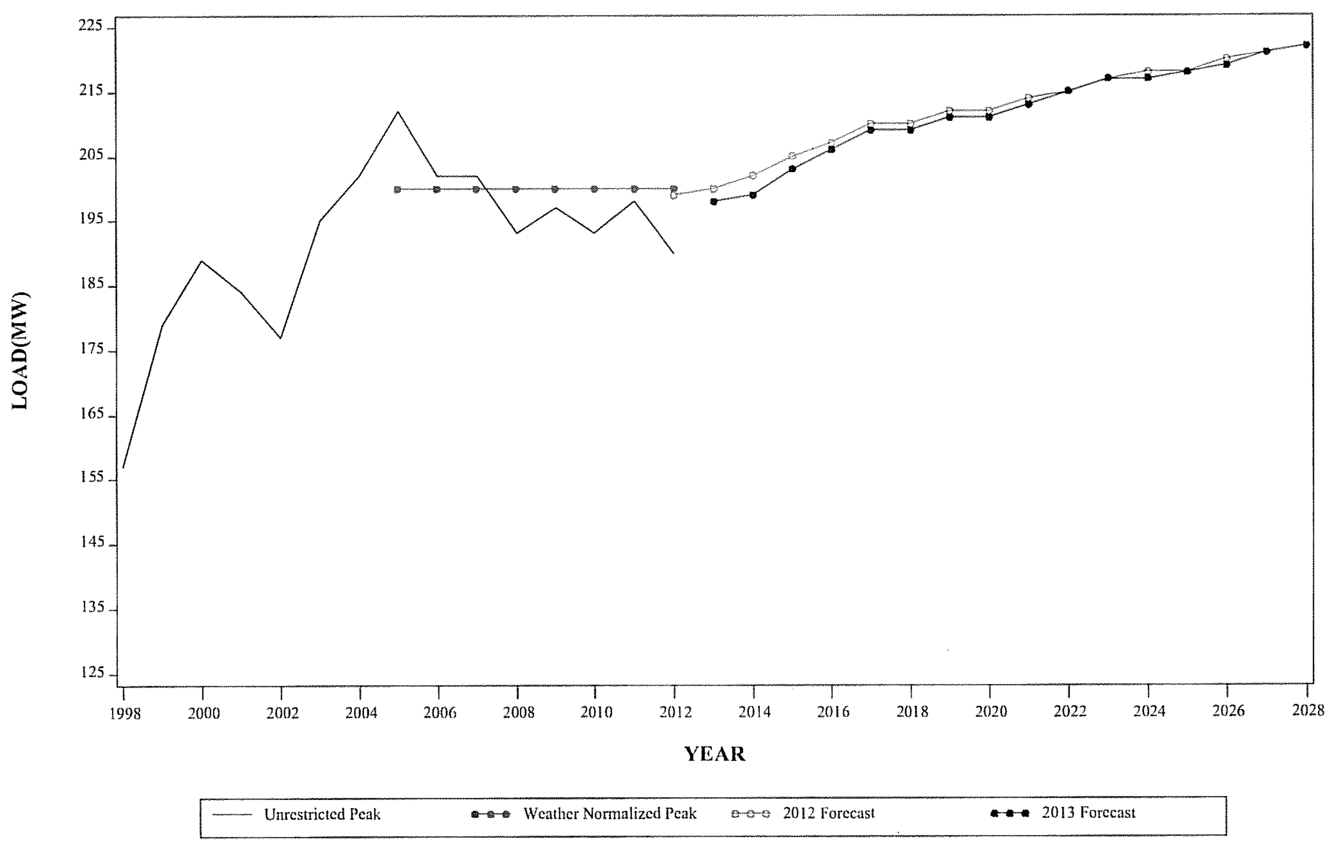

SUMMER PEAK DEMAND FOR RECO
GEOGRAPHIC ZONE
LOAD(MW)
500
485
470
455
440
425
410
395
380
365
350
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast


WINTER PEAK DEMAND FOR RECO
GEOGRAPHIC ZONE
LOAD(MW)
275
265
255
245
235
225
215
205
195
185
175
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast

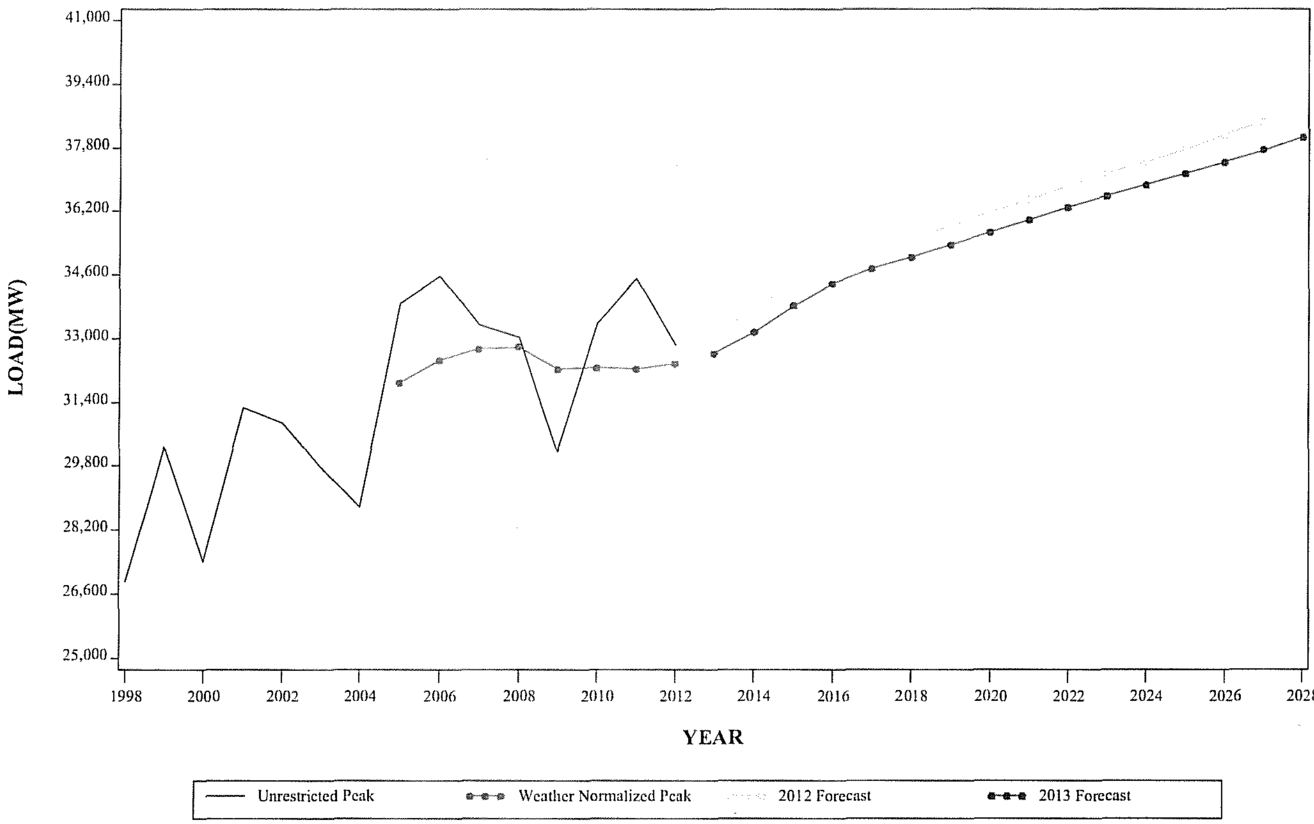
SUMMER PEAK DEMAND FOR UGI GEOGRAPHIC ZONE



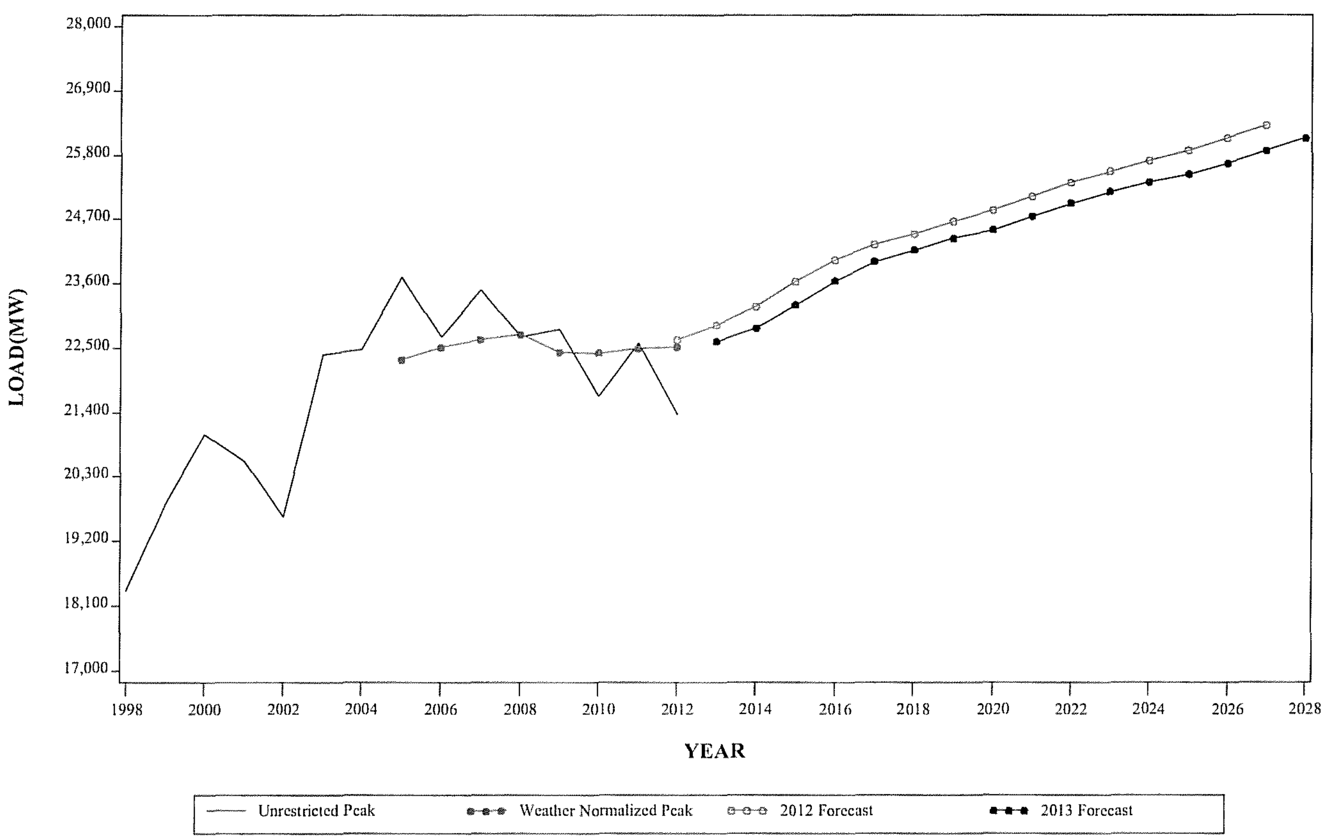
WINTER PEAK DEMAND FOR UGI GEOGRAPHIC ZONE



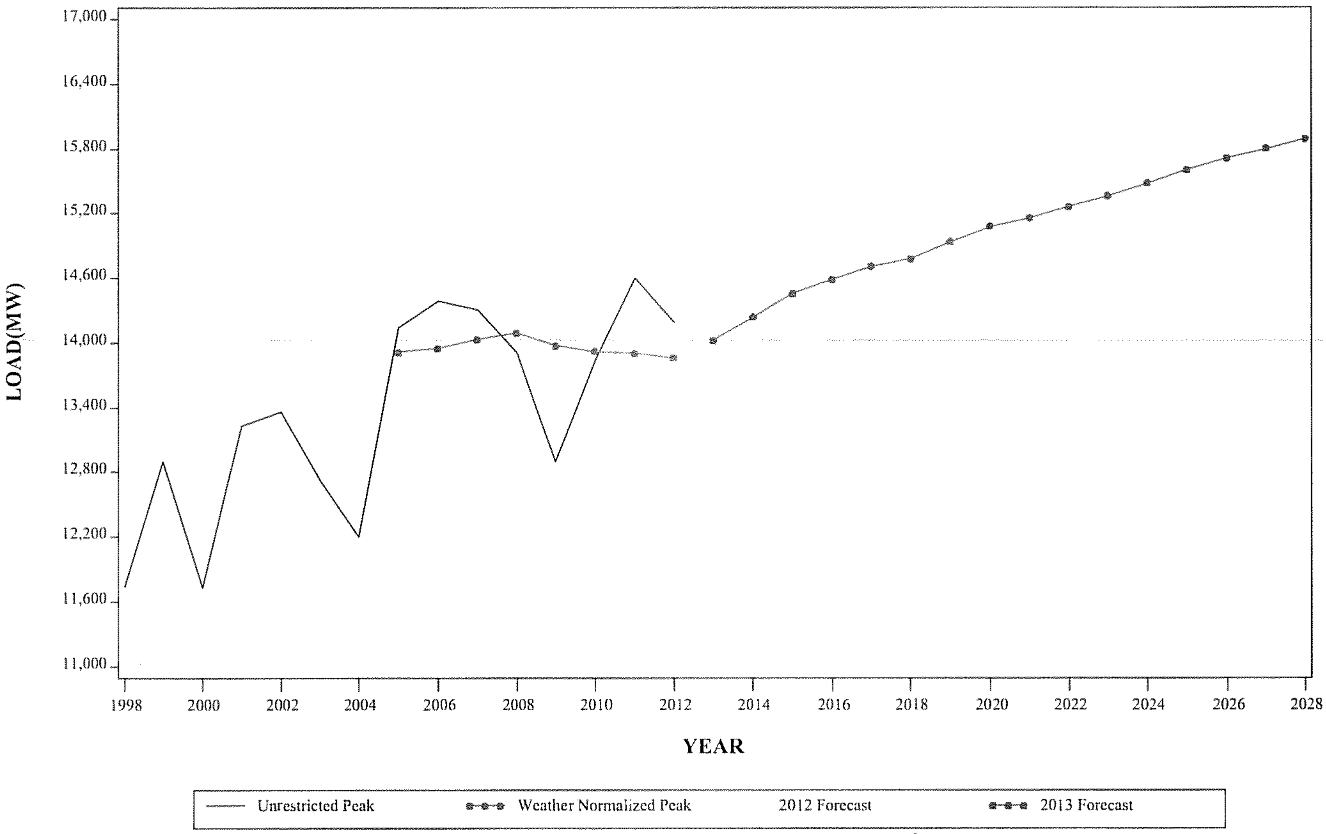
SUMMER PEAK DEMAND FOR EASTERN MID-ATLANTIC
GEOGRAPHIC ZONE



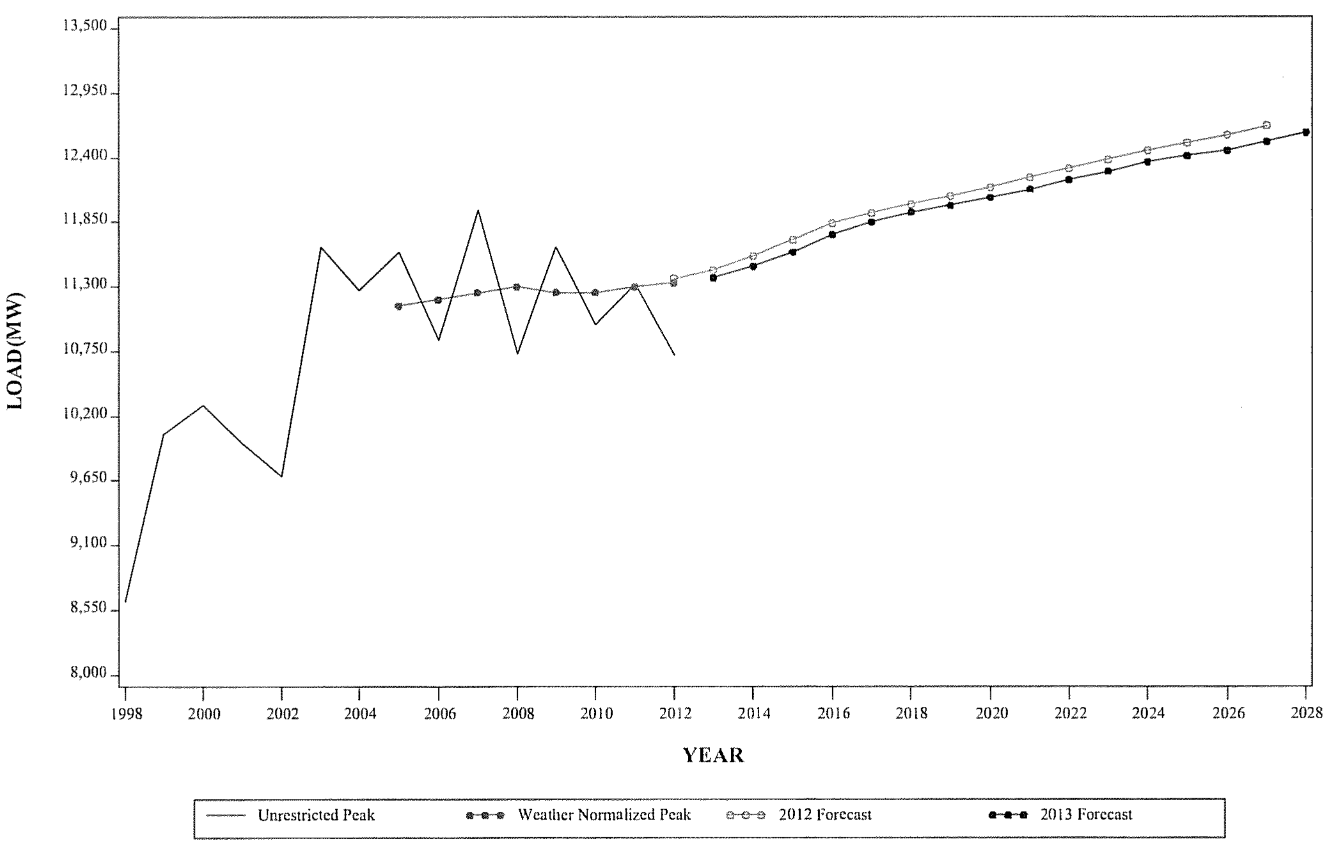
WINTER PEAK DEMAND FOR EASTERN MID-ATLANTIC
GEOGRAPHIC ZONE



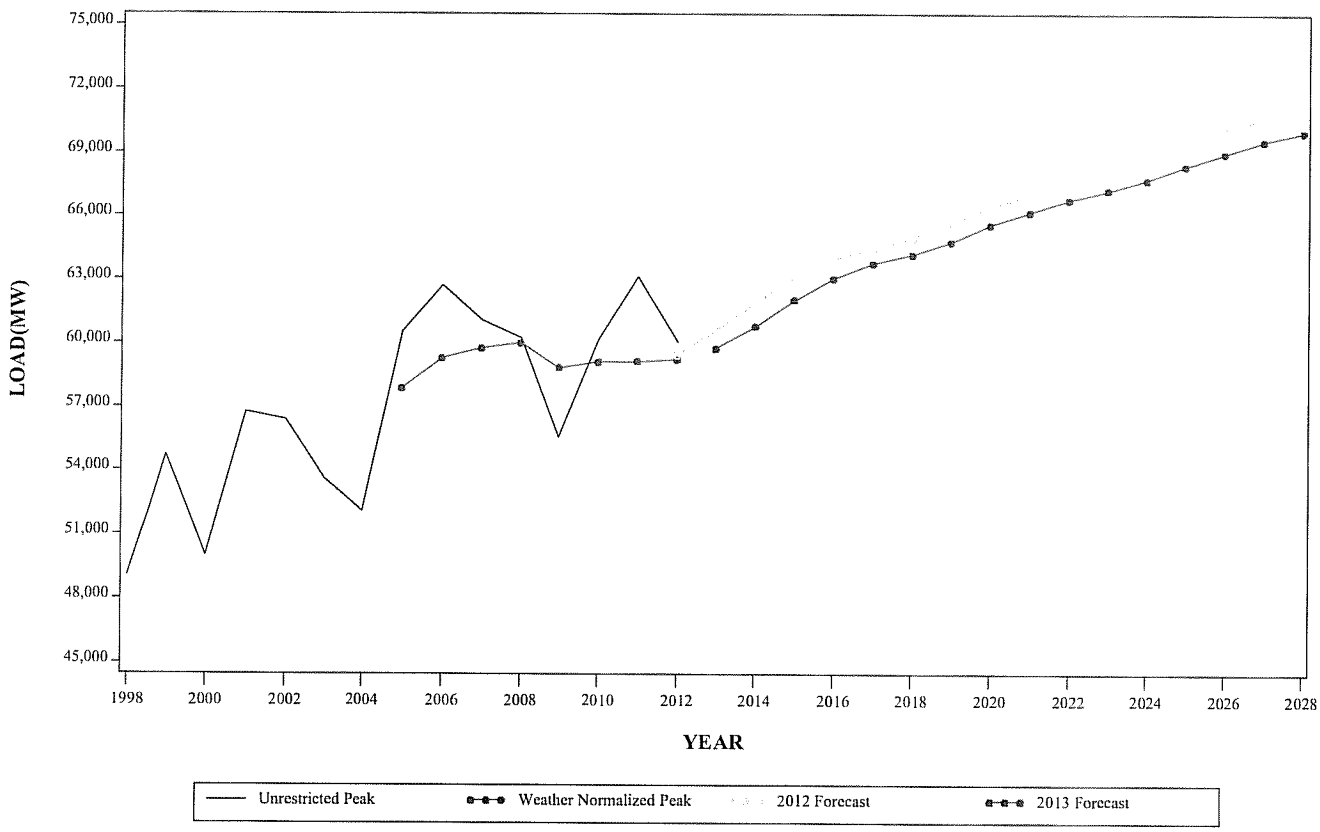
SUMMER PEAK DEMAND FOR SOUTHERN MID-ATLANTIC
GEOGRAPHIC ZONE



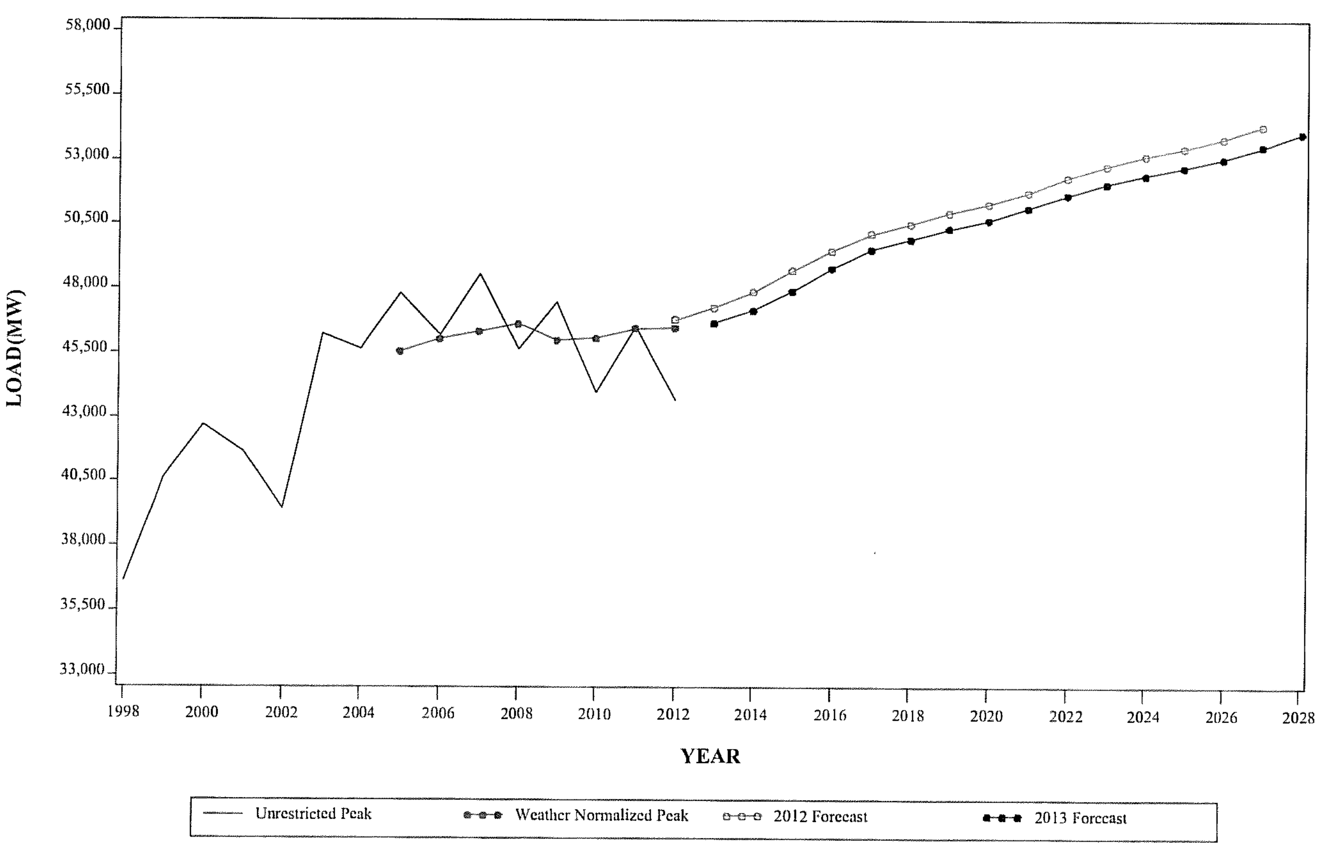
WINTER PEAK DEMAND FOR SOUTHERN MID-ATLANTIC
GEOGRAPHIC ZONE



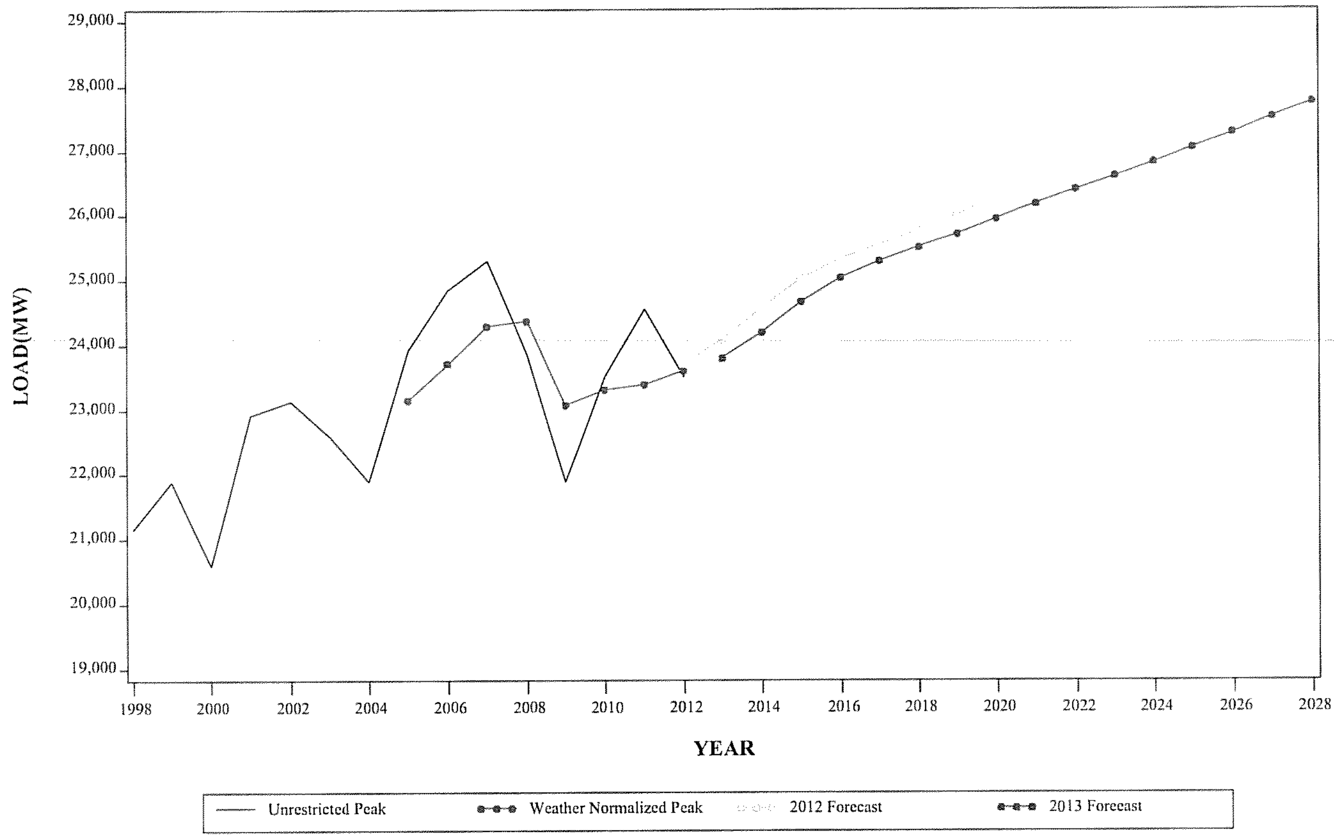
SUMMER PEAK DEMAND FOR PJM MID-ATLANTIC GEOGRAPHIC ZONE



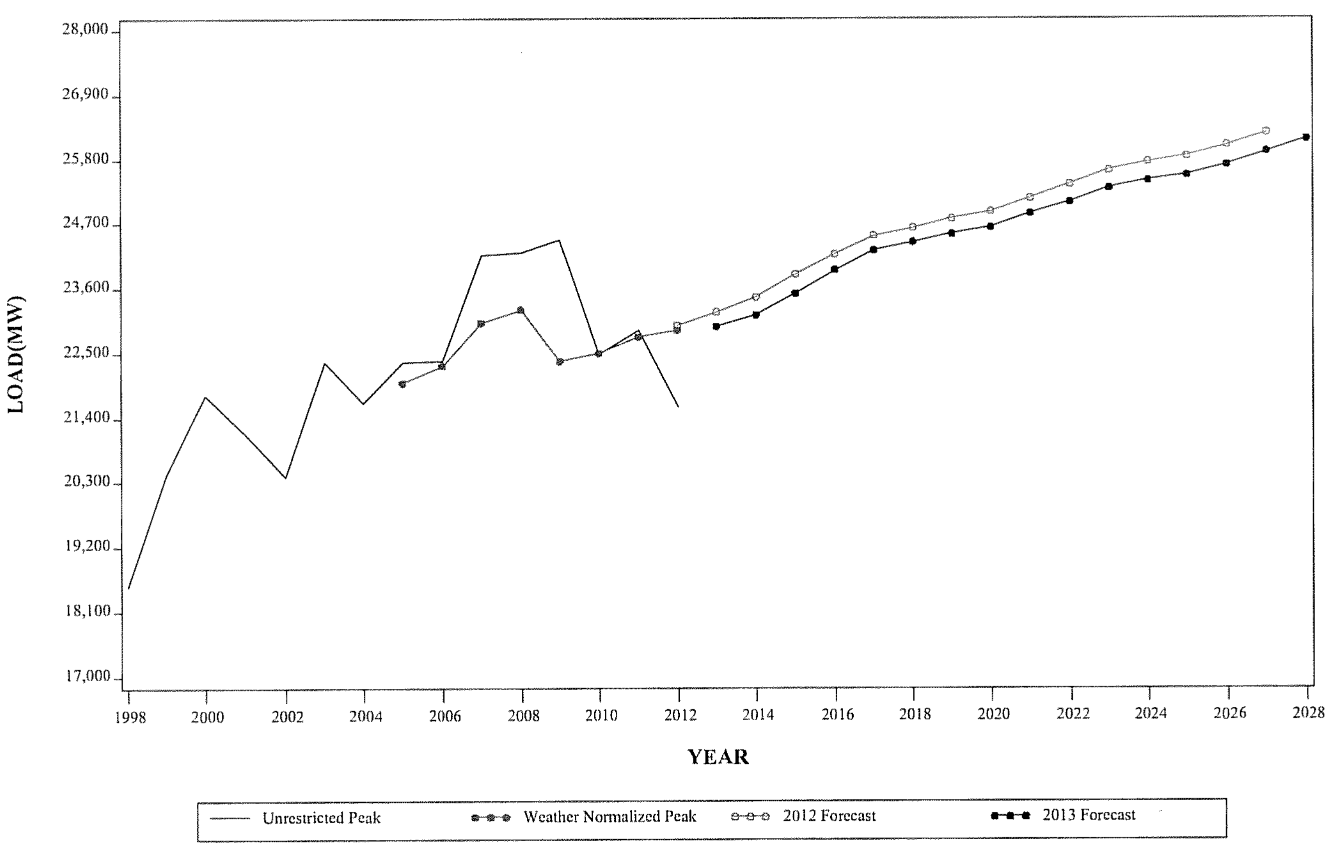
WINTER PEAK DEMAND FOR PJM MID-ATLANTIC GEOGRAPHIC ZONE



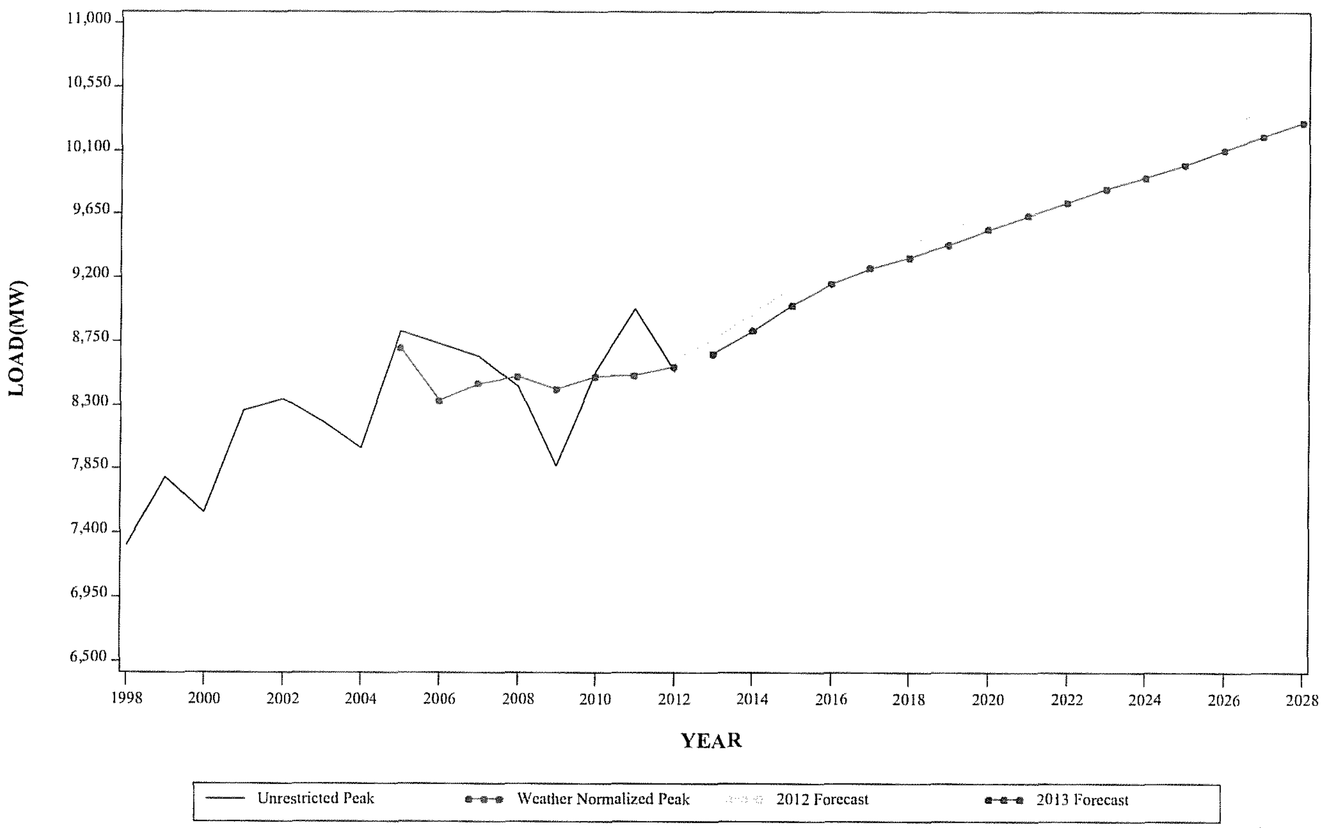
SUMMER PEAK DEMAND FOR AEP
GEOGRAPHIC ZONE



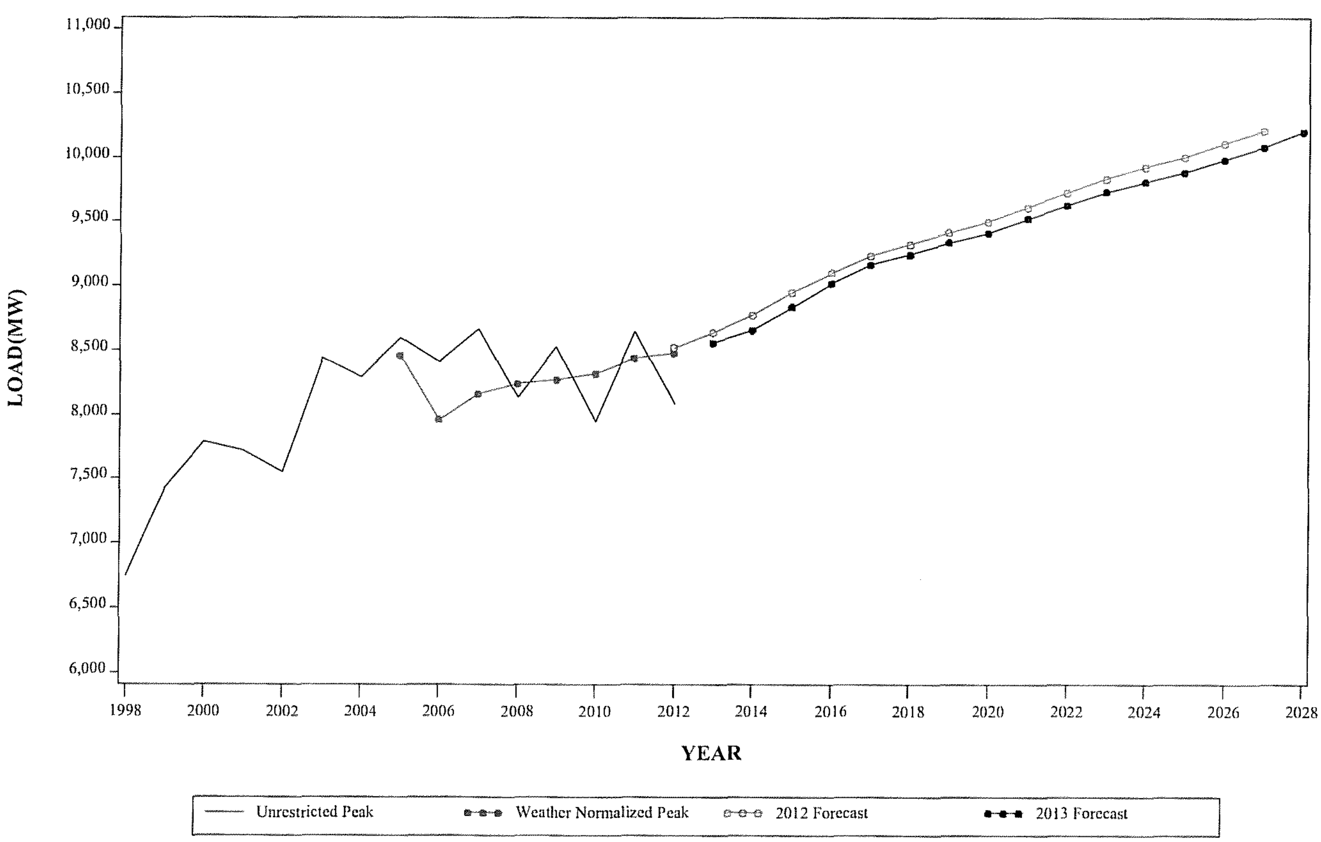
WINTER PEAK DEMAND FOR AEP
GEOGRAPHIC ZONE



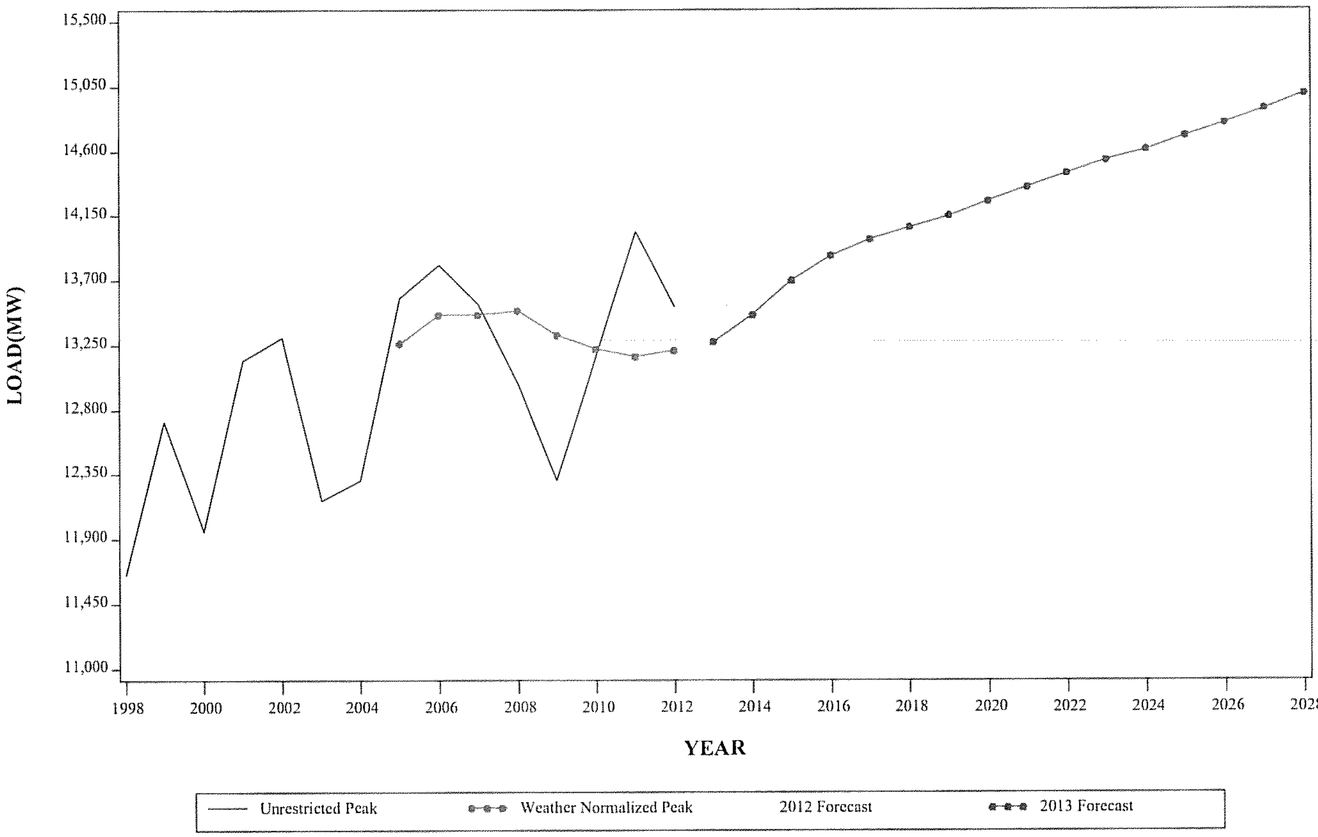
SUMMER PEAK DEMAND FOR APS
GEOGRAPHIC ZONE



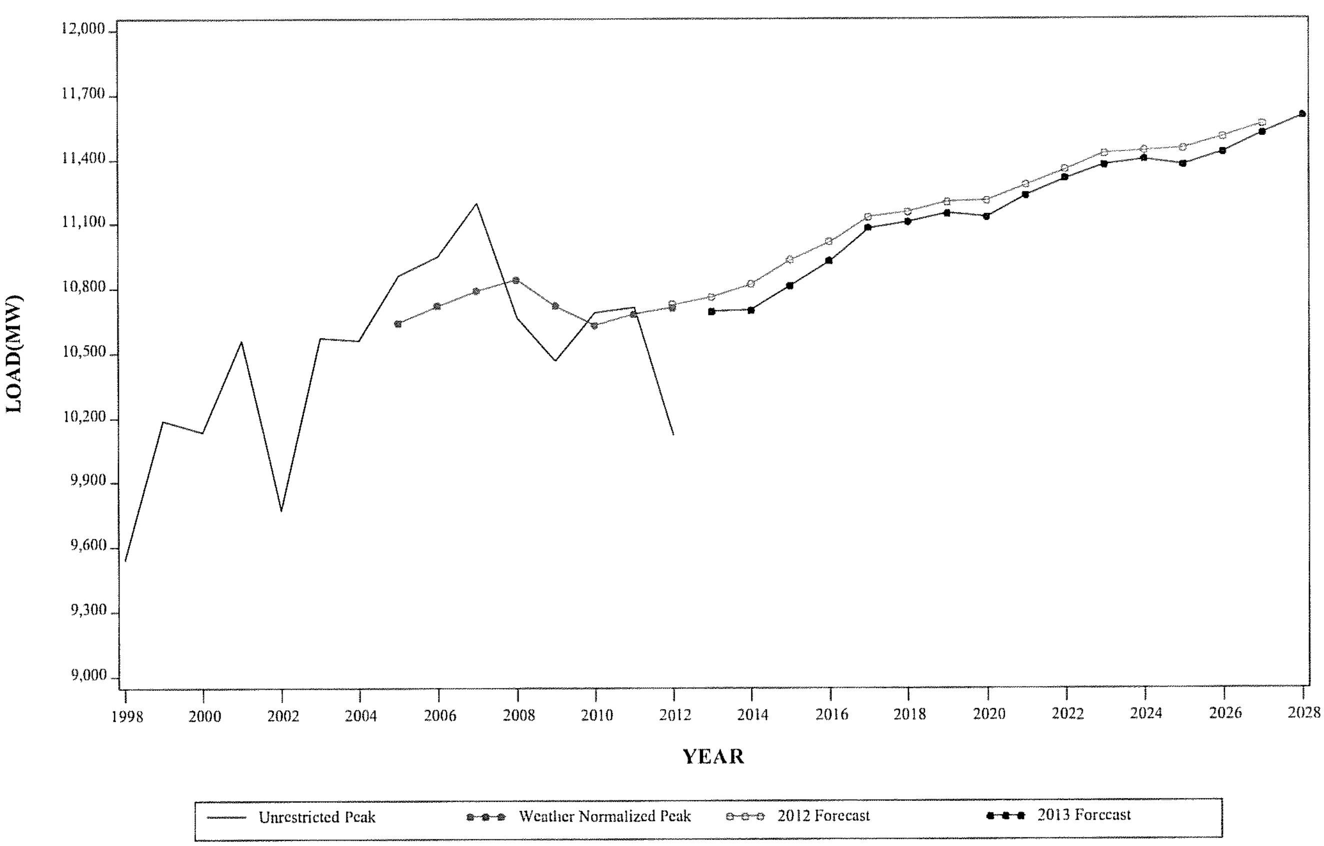
WINTER PEAK DEMAND FOR APS
GEOGRAPHIC ZONE

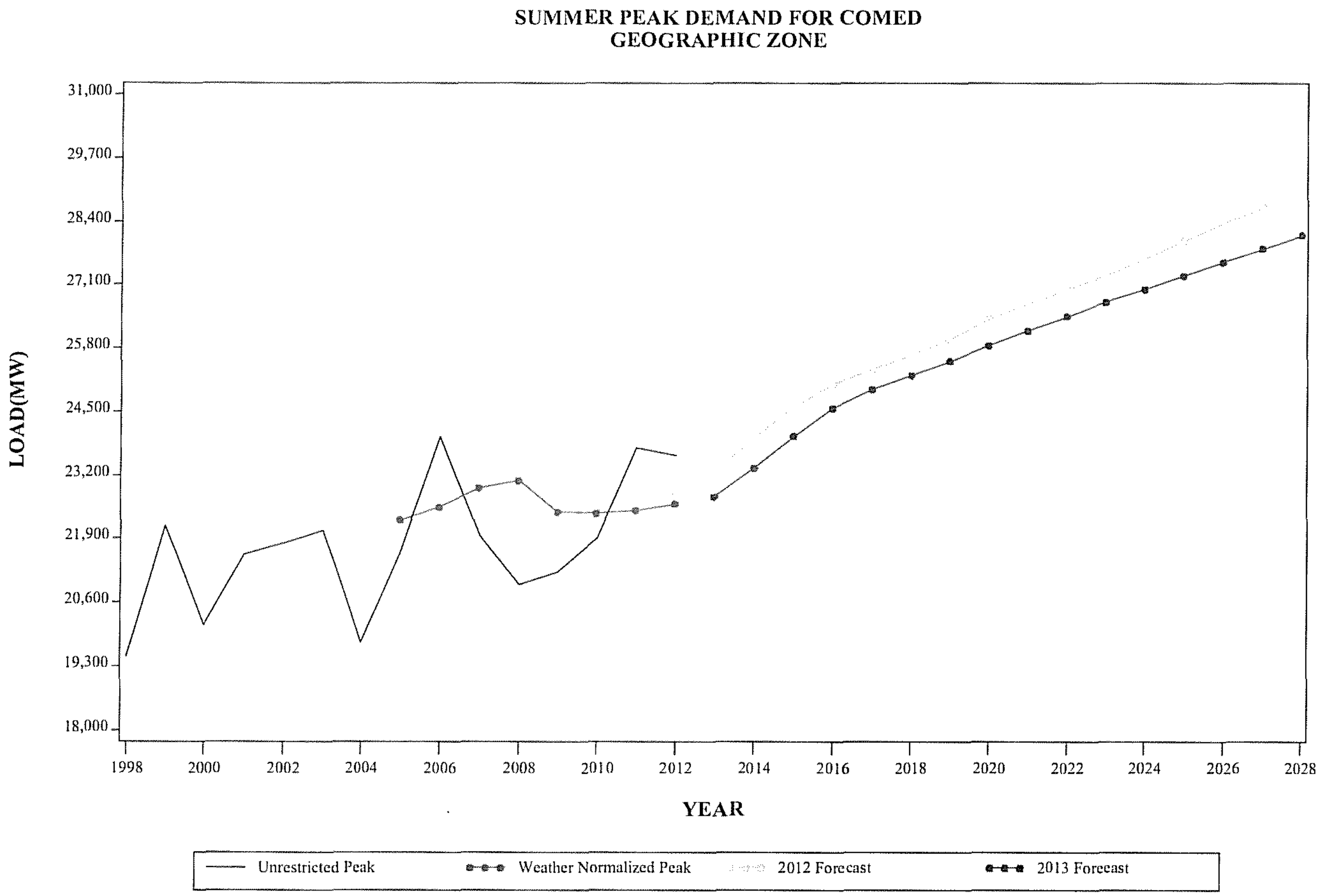


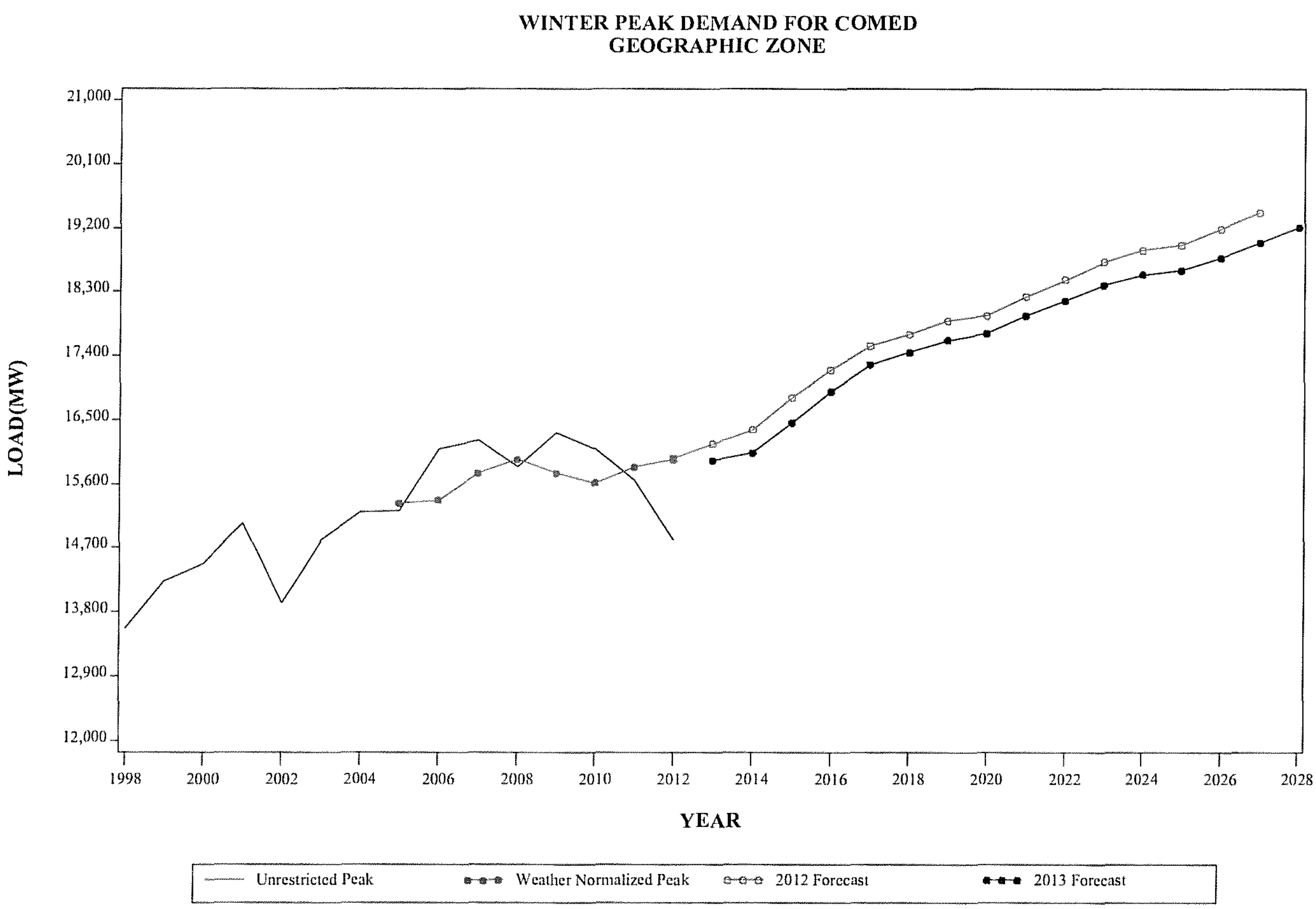
SUMMER PEAK DEMAND FOR ATSI
GEOGRAPHIC ZONE



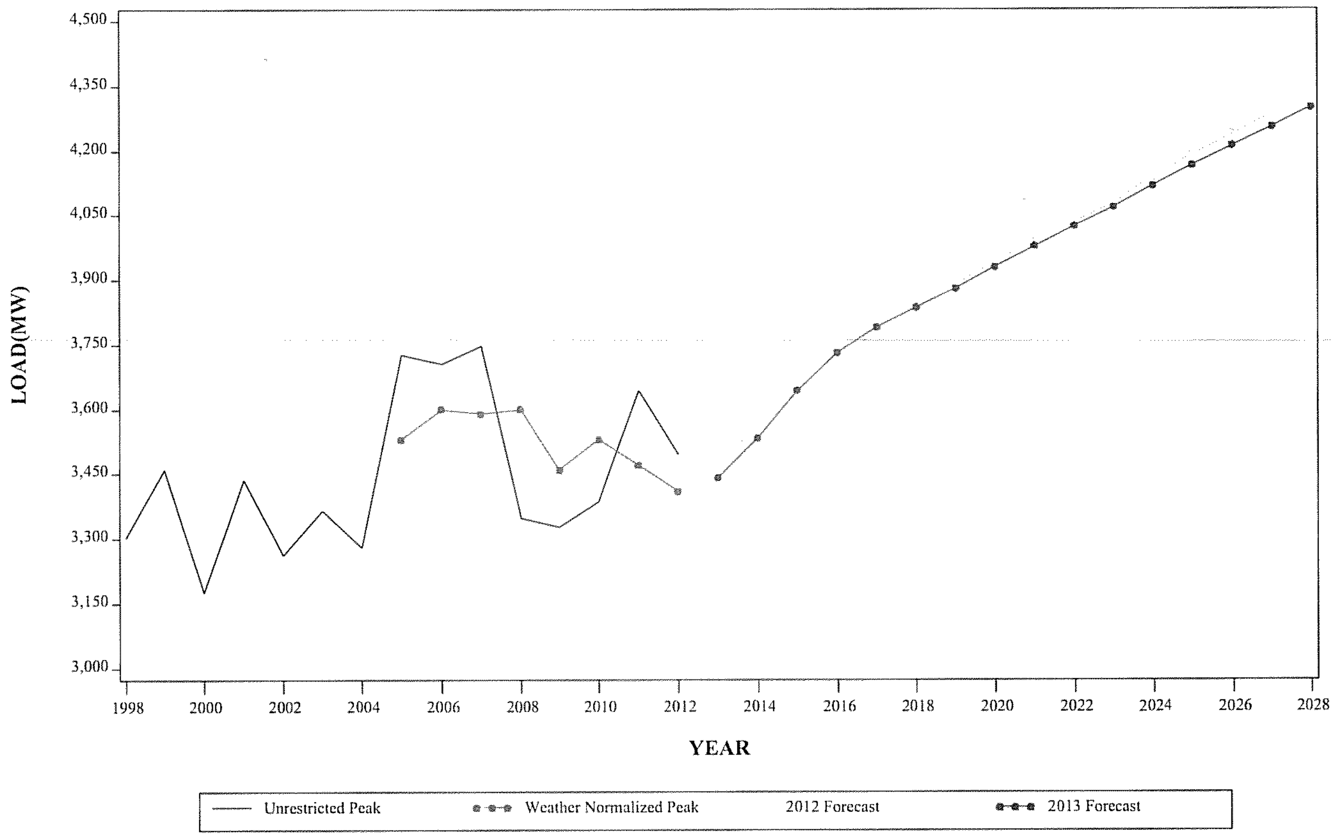
WINTER PEAK DEMAND FOR ATSI
GEOGRAPHIC ZONE



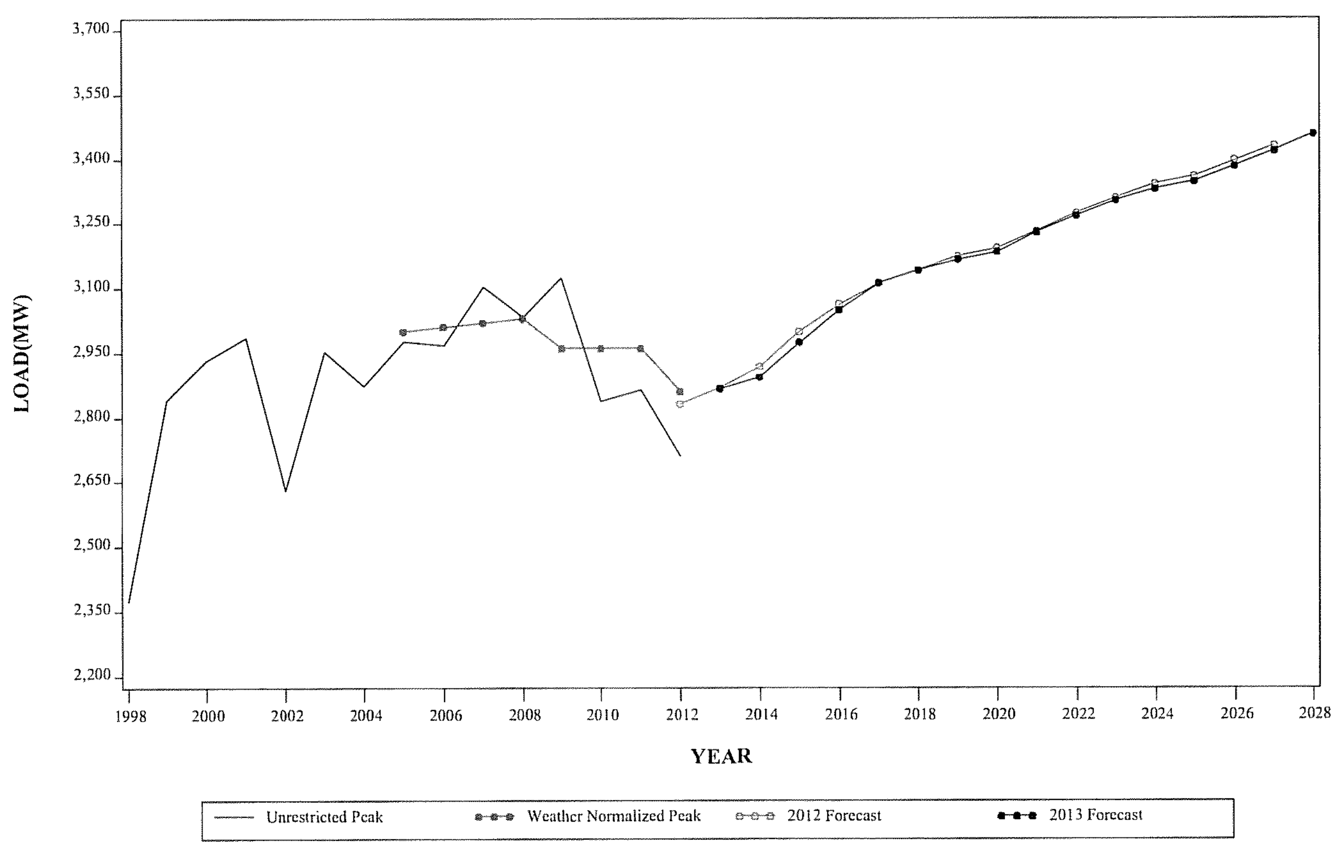

SUMMER PEAK DEMAND FOR COMED
GEOGRAPHIC ZONE
LOAD(MW)
31,000
29,700
28,400
27,100
25,800
24,500
23,200
21,900
20,600
19,300
18,000
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast


WINTER PEAK DEMAND FOR COMED
GEOGRAPHIC ZONE
LOAD(MW)
21,000
20,100
19,200
18,300
17,400
16,500
15,600
14,700
13,800
12,900
12,000
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
YEAR
Unrestricted Peak
Weather Normalized Peak
2012 Forecast
2013 Forecast

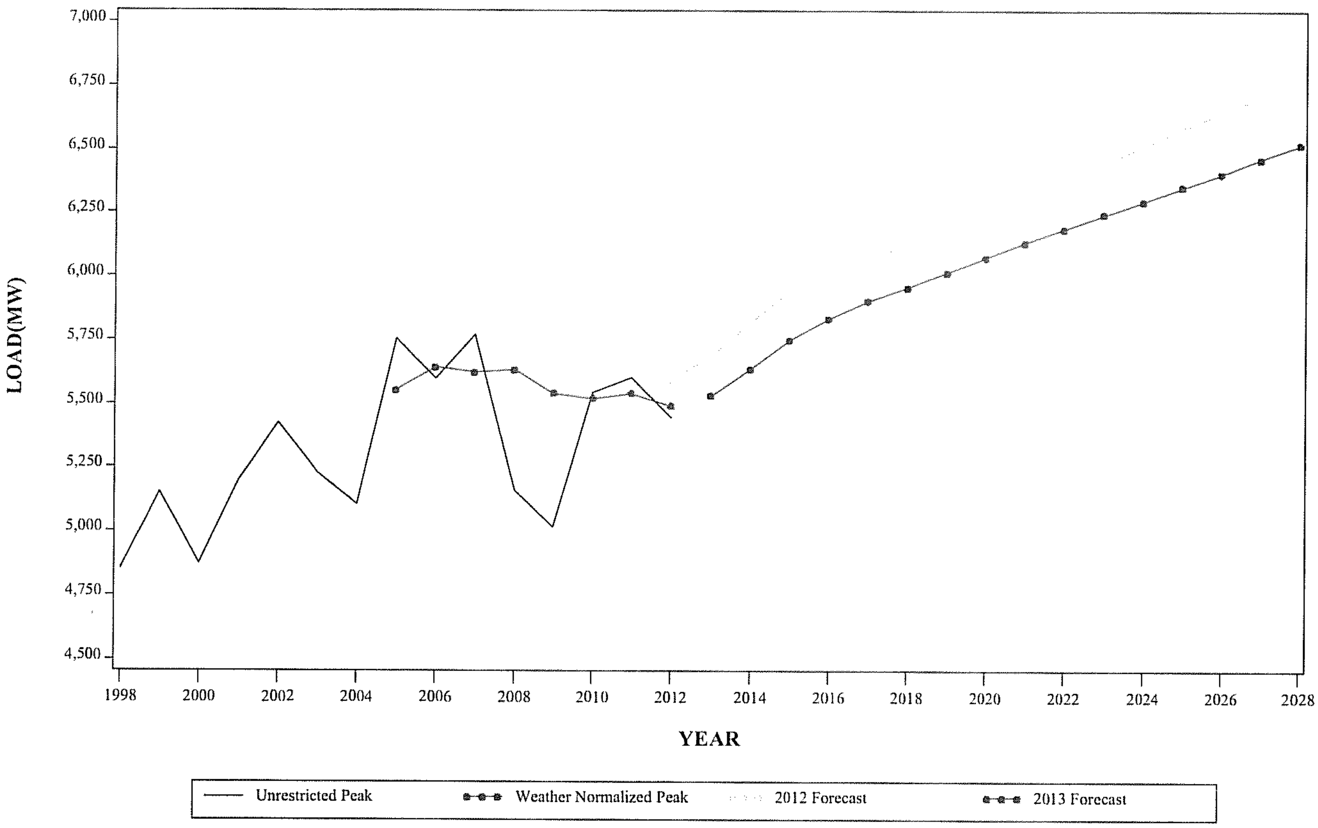
SUMMER PEAK DEMAND FOR DAYTON
GEOGRAPHIC ZONE



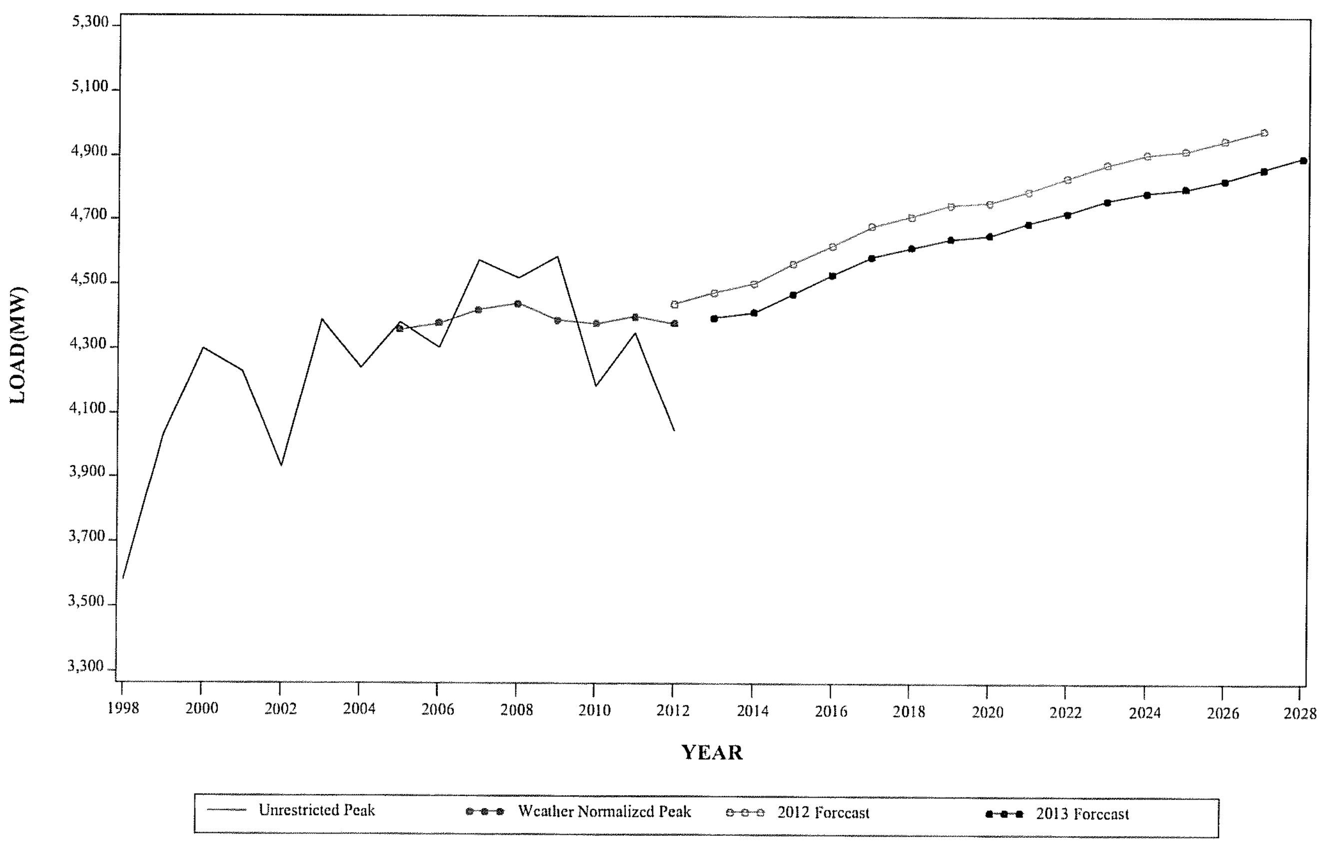
WINTER PEAK DEMAND FOR DAYTON
GEOGRAPHIC ZONE



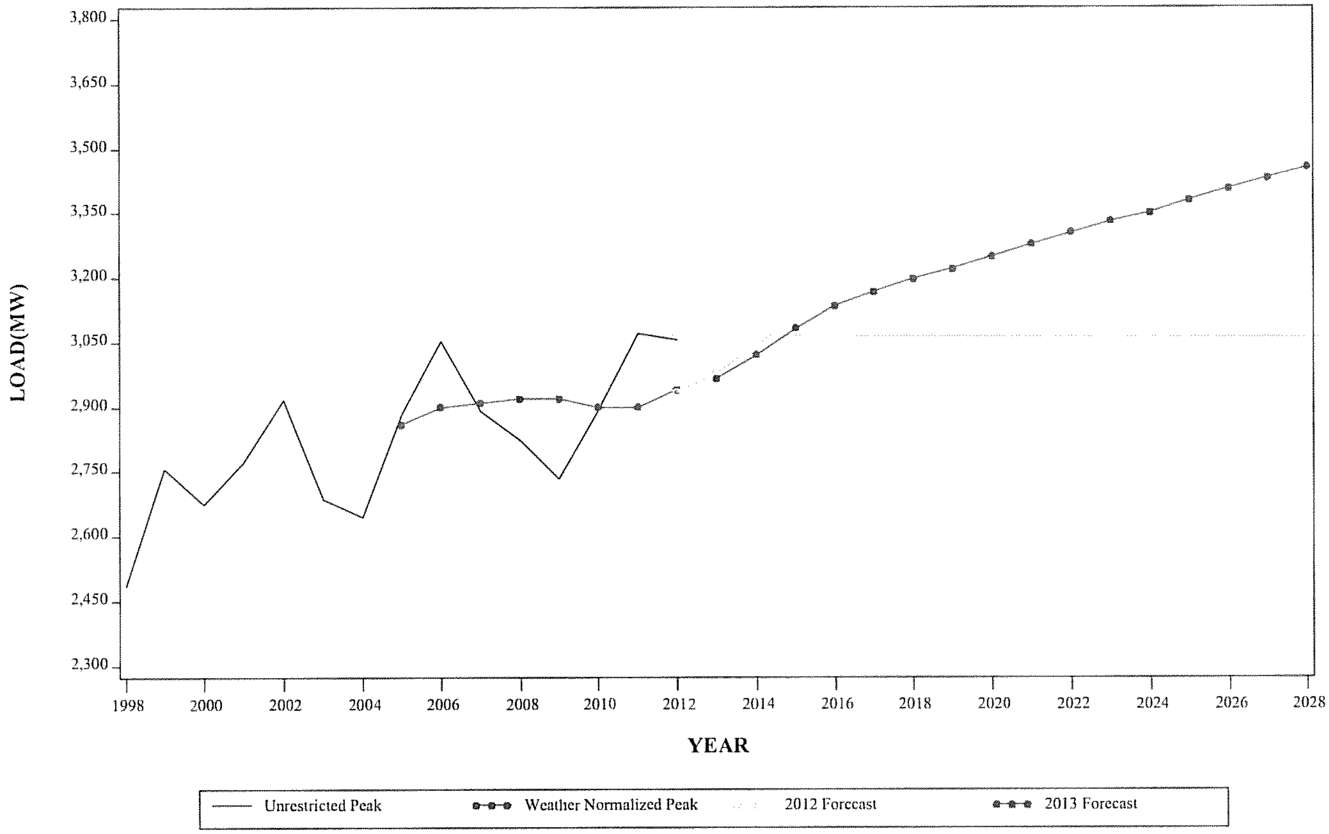
SUMMER PEAK DEMAND FOR DEOK
GEOGRAPHIC ZONE



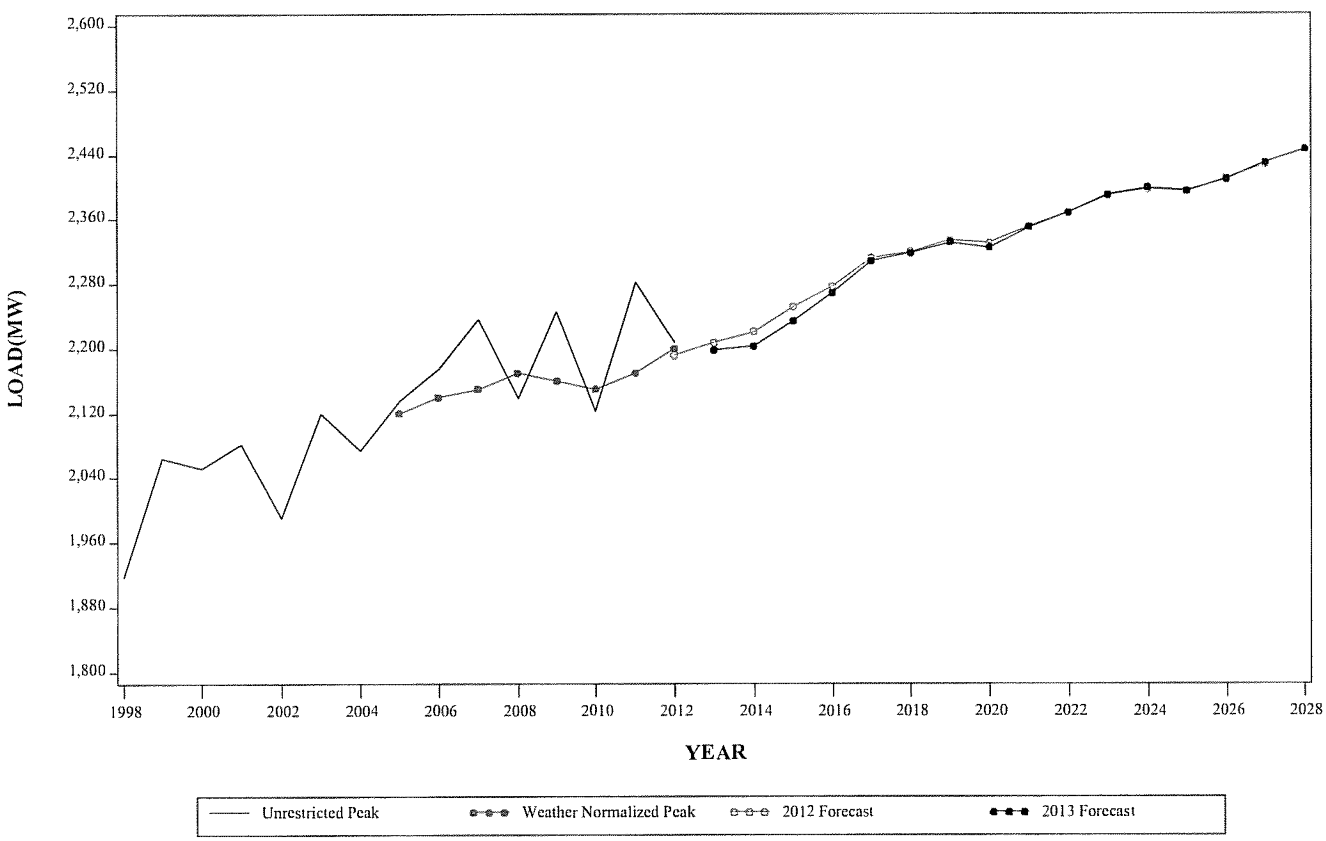
WINTER PEAK DEMAND FOR DEOK
GEOGRAPHIC ZONE



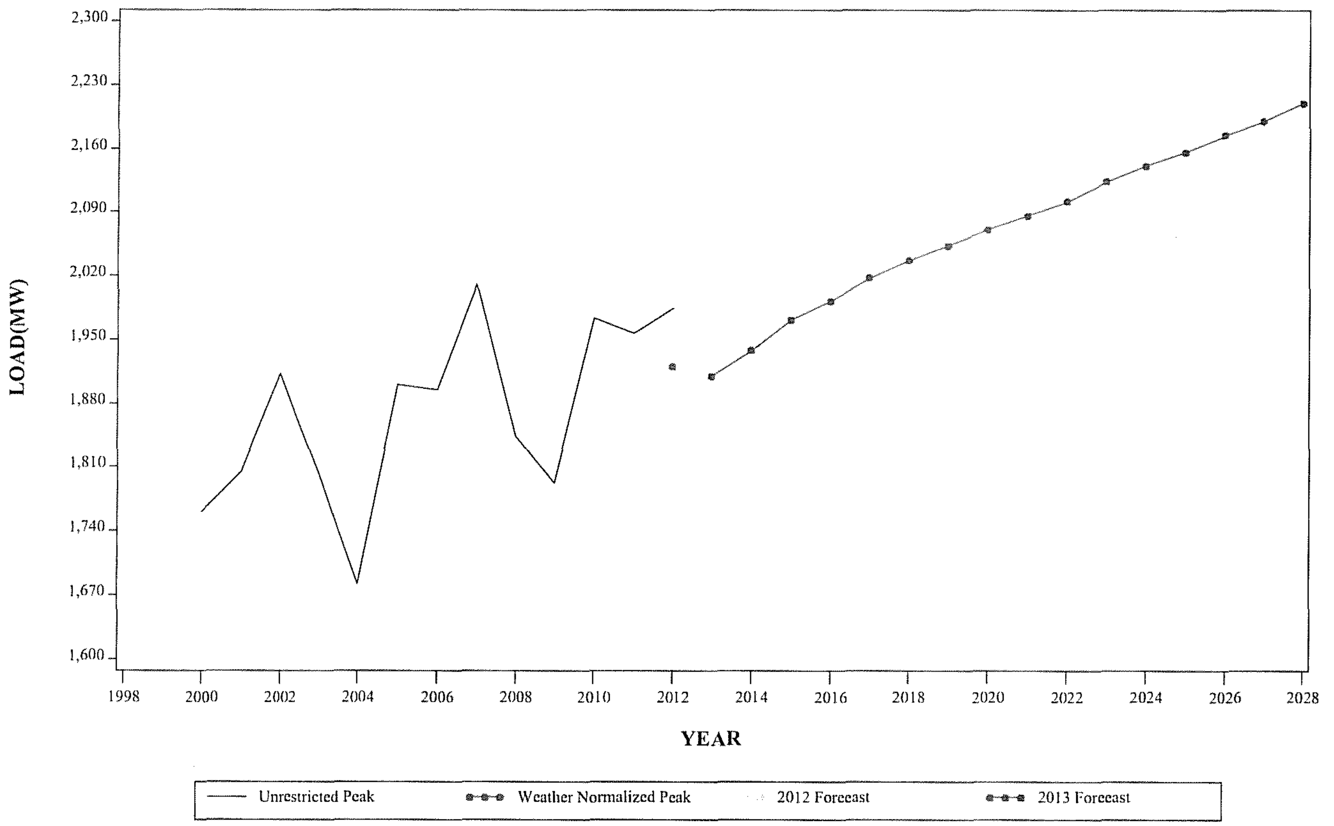
SUMMER PEAK DEMAND FOR DLCO
GEOGRAPHIC ZONE



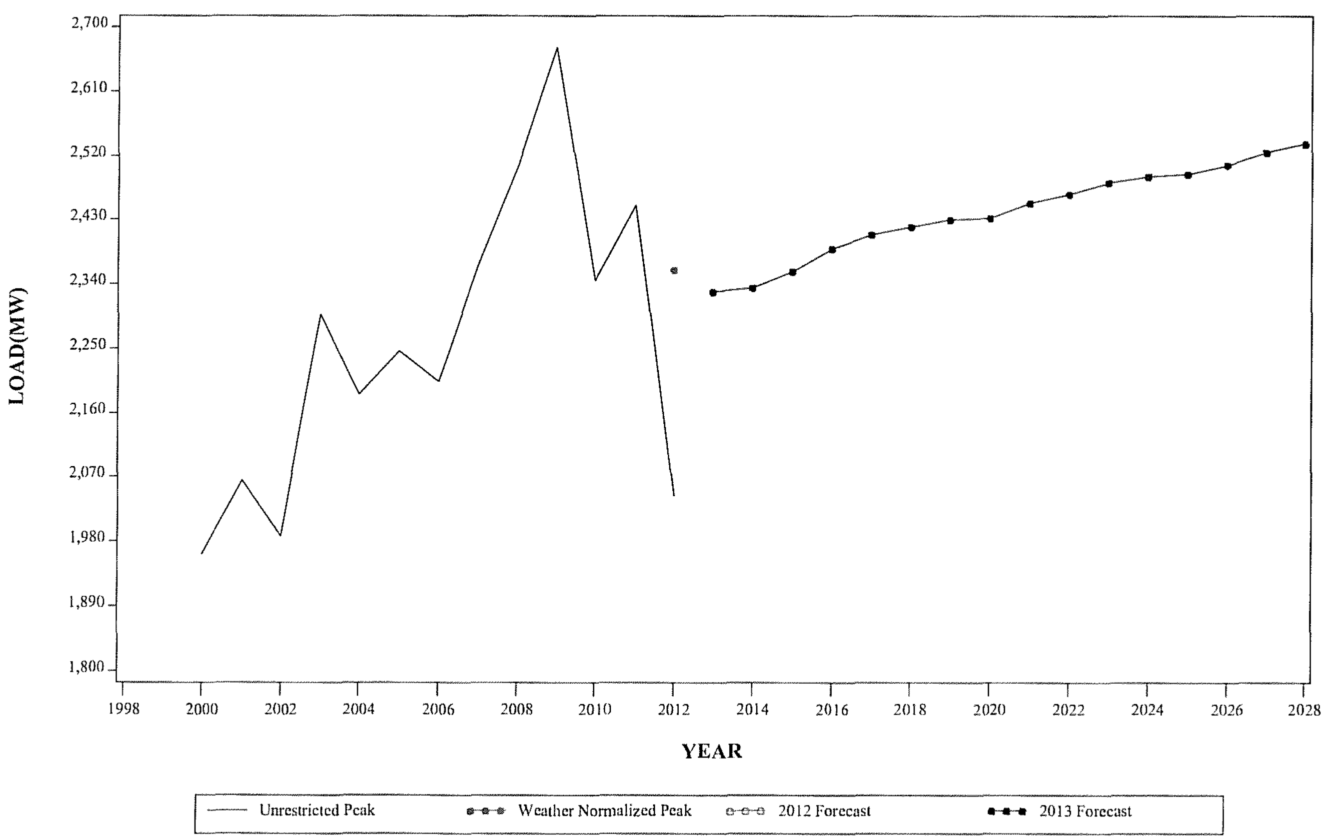
WINTER PEAK DEMAND FOR DLCO
GEOGRAPHIC ZONE



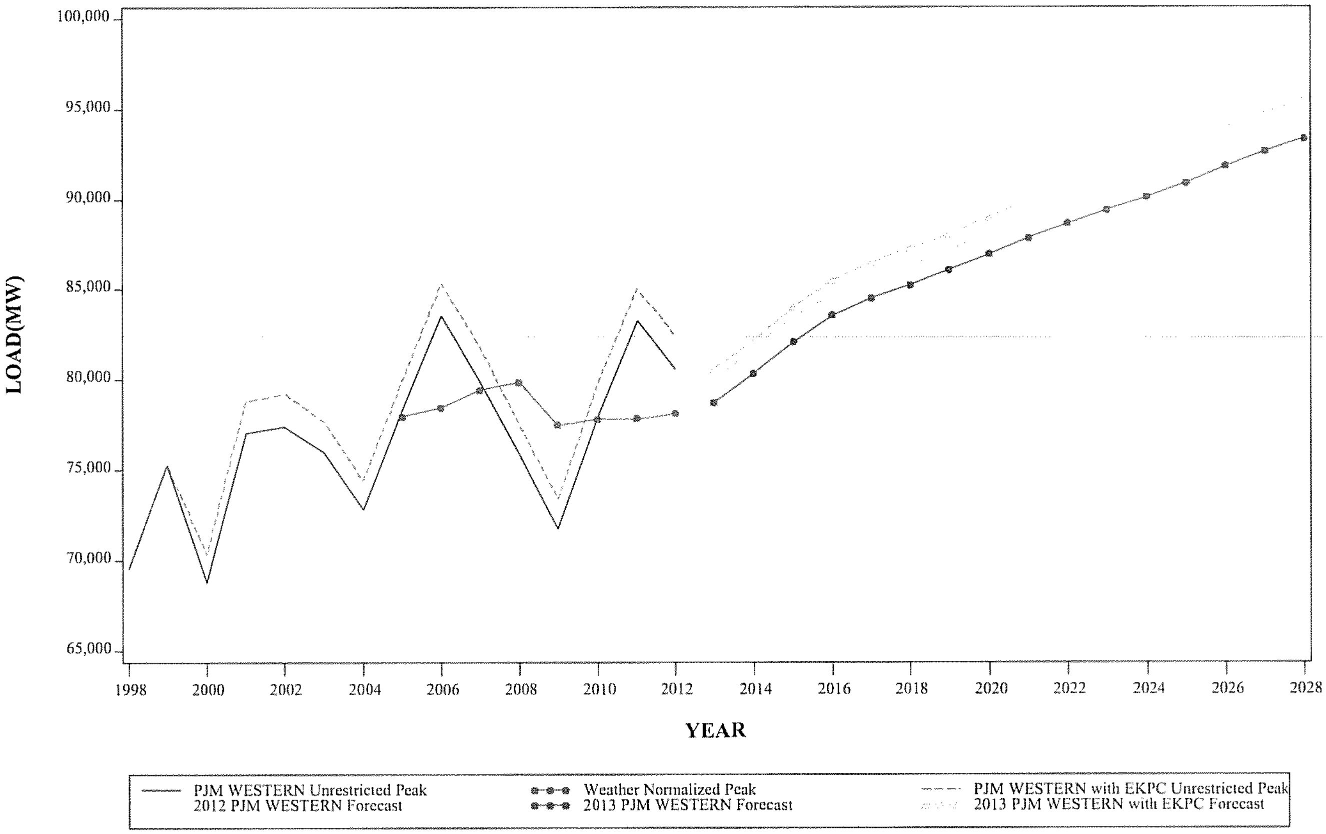
SUMMER PEAK DEMAND FOR EKPC GEOGRAPHIC ZONE



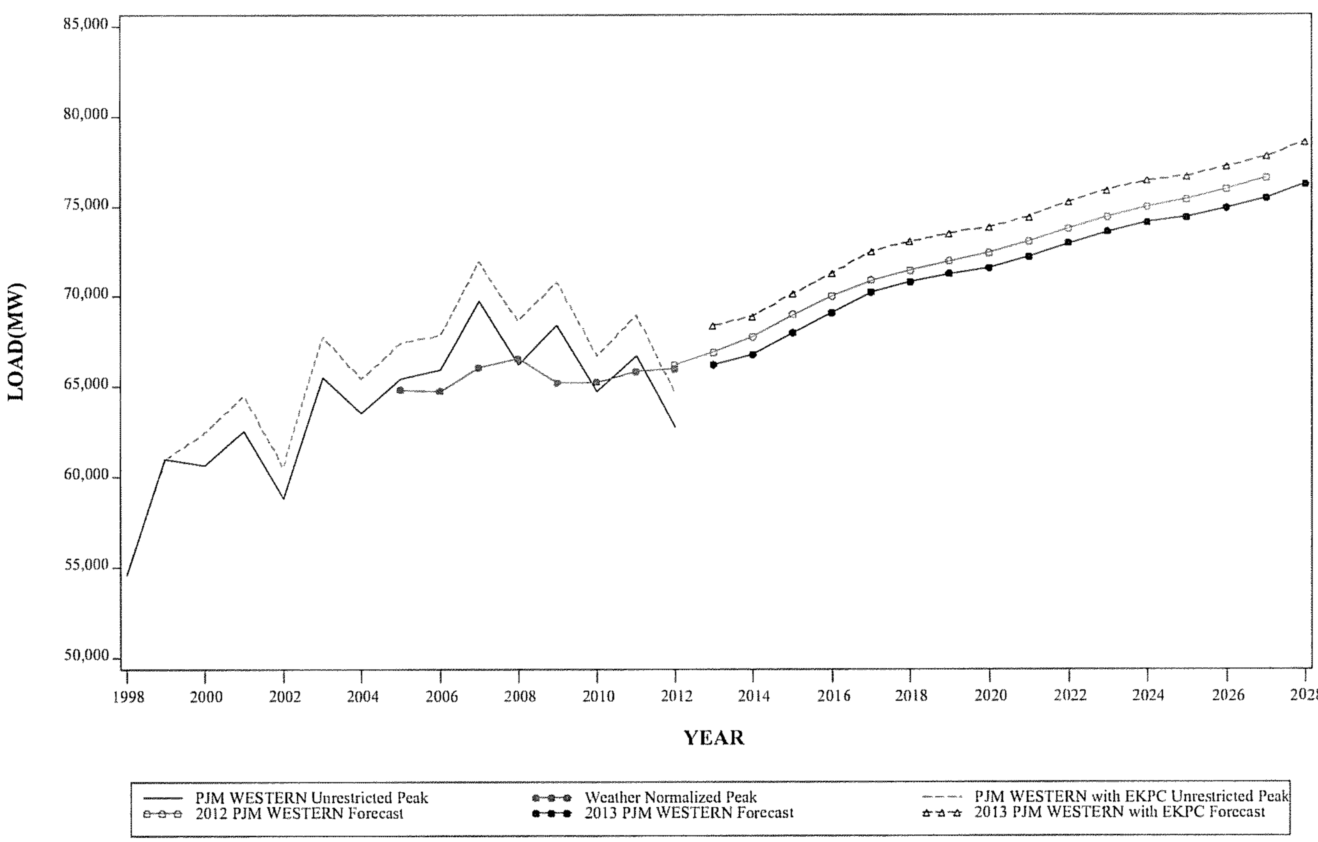
WINTER PEAK DEMAND FOR EKPC GEOGRAPHIC ZONE



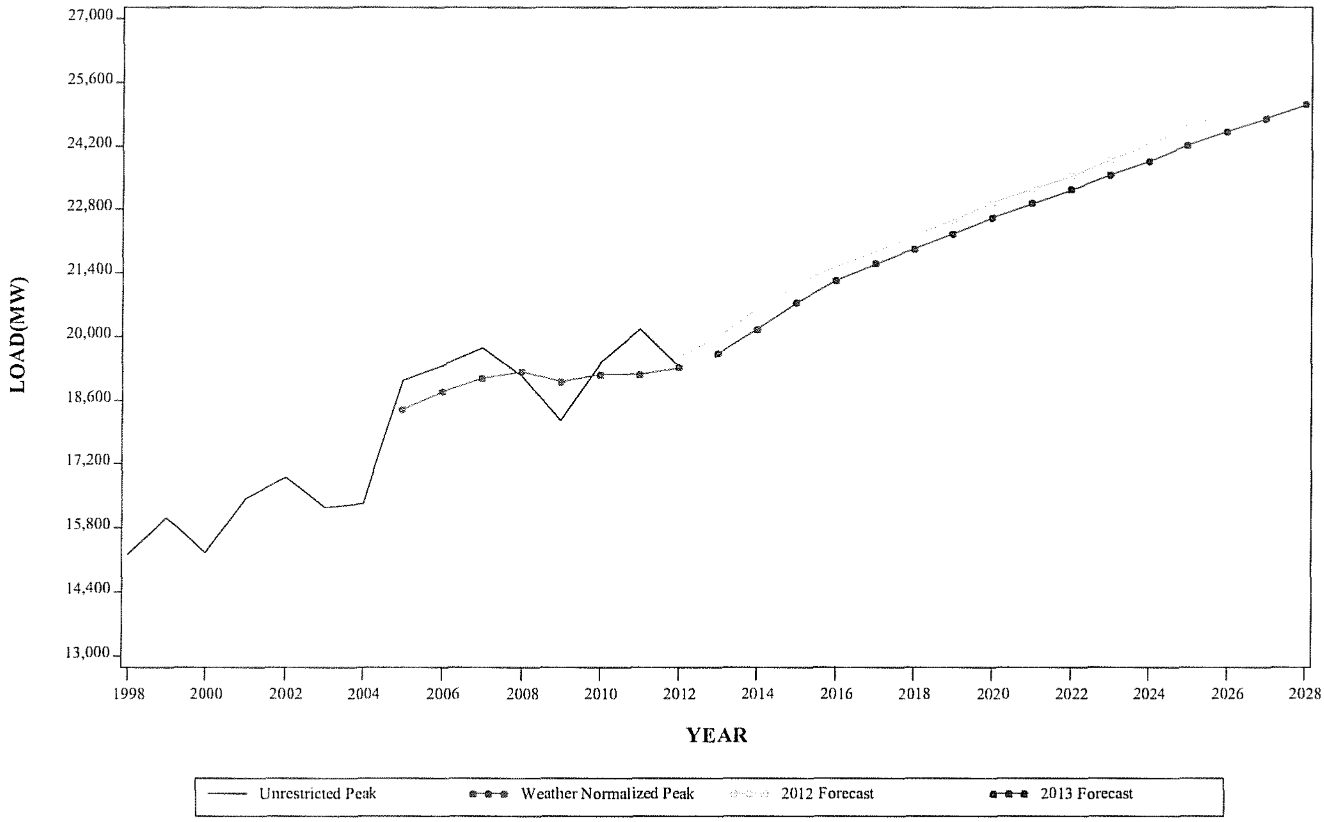
SUMMER PEAK DEMAND FOR PJM WESTERN GEOGRAPHIC ZONE



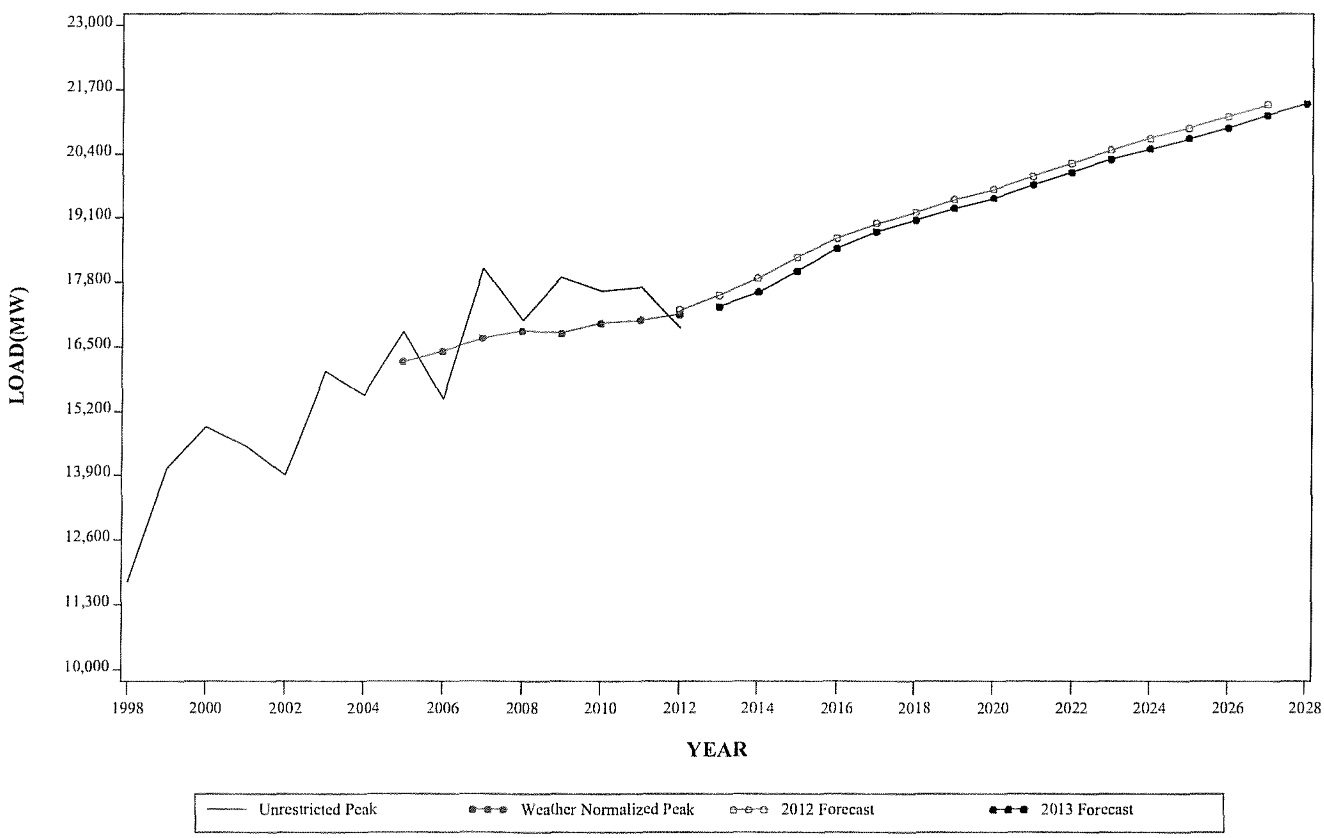
WINTER PEAK DEMAND FOR PJM WESTERN GEOGRAPHIC ZONE



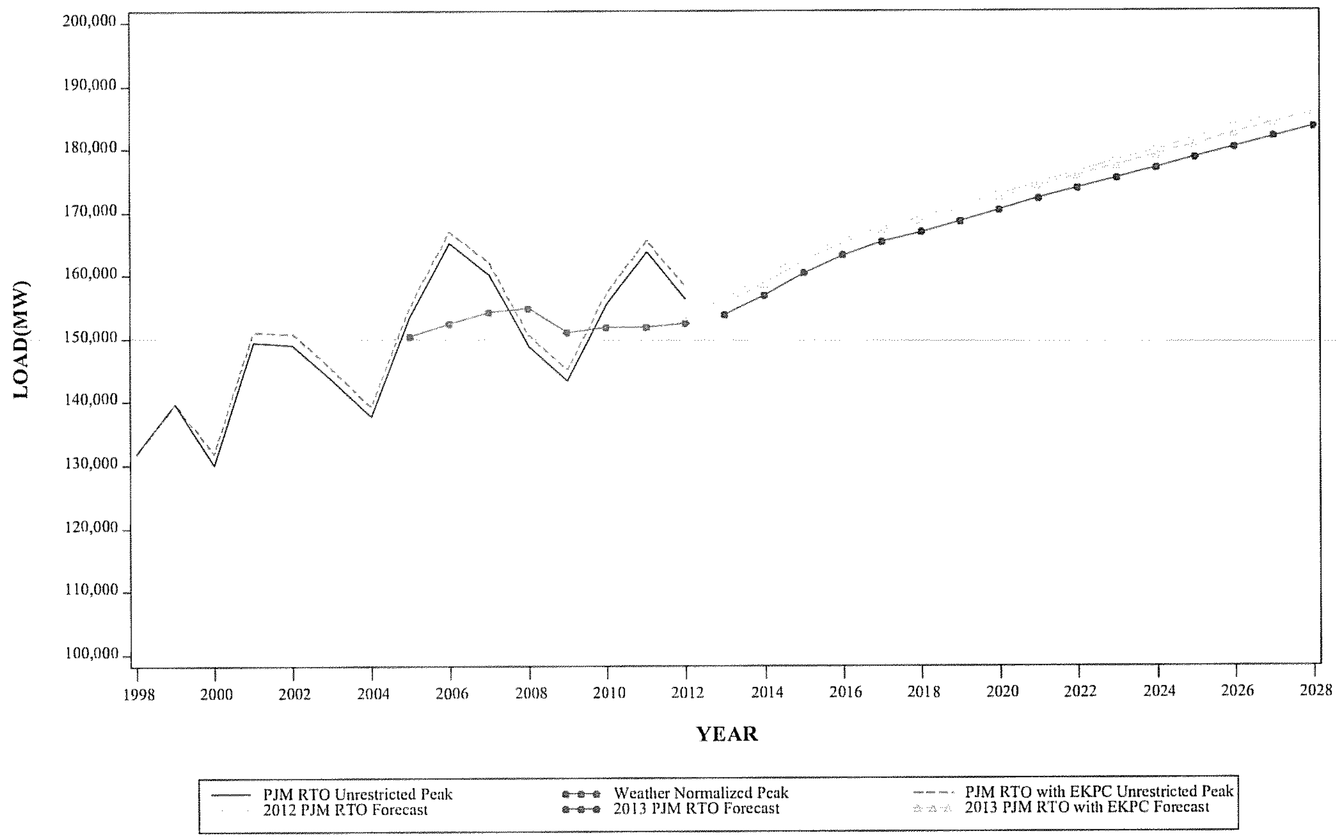
SUMMER PEAK DEMAND FOR DOM GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR DOM GEOGRAPHIC ZONE



SUMMER PEAK DEMAND FOR PJM RTO GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR PJM RTO GEOGRAPHIC ZONE

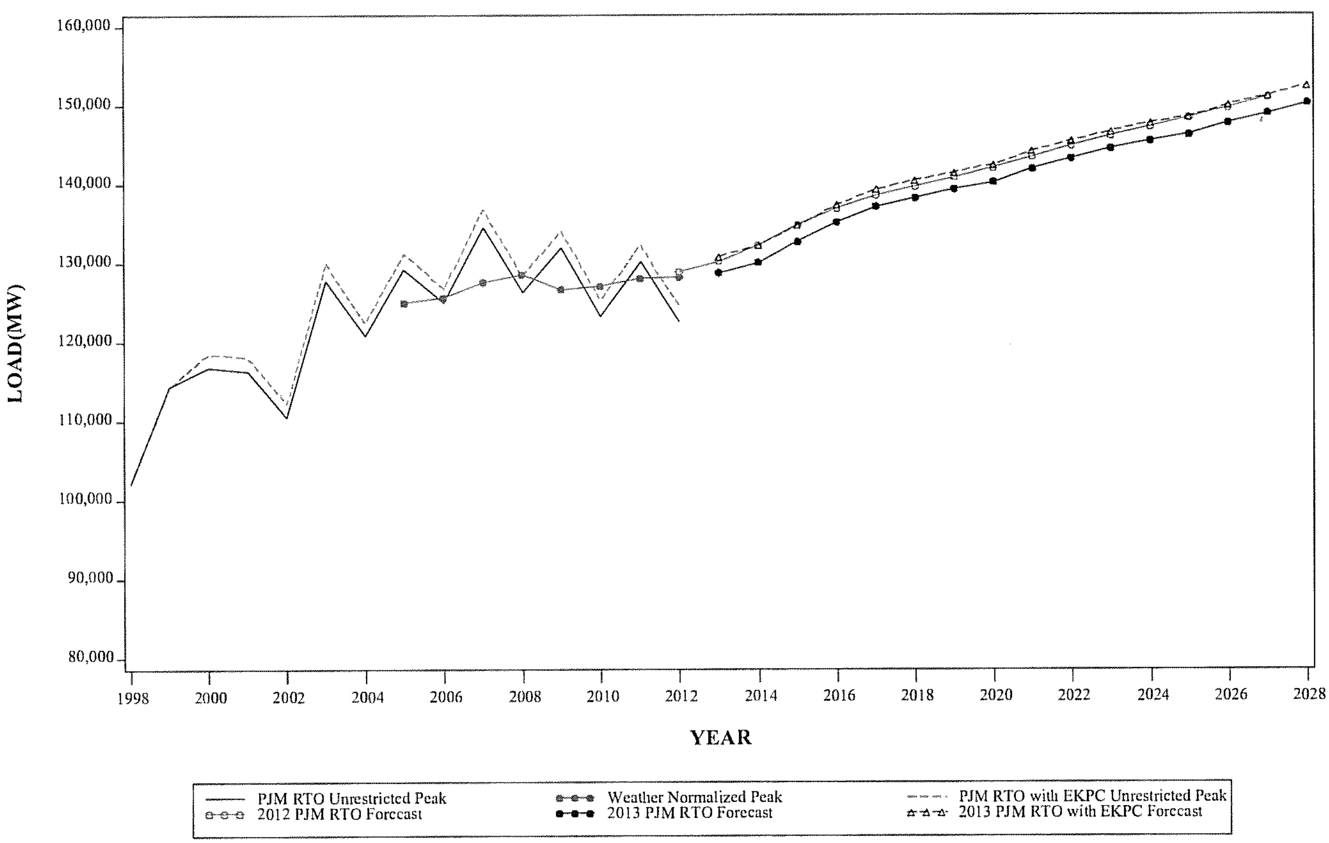


Table A-1

PJM MID-ATLANTIC REGION
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2012 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2013		2018		2023	
	MW	%	MW	%	MW	%
AE	(1)	-0.0%	19	0.6%	16	0.5%
BGE	(96)	-1.3%	(99)	-1.3%	(123)	-1.5%
DPL	(25)	-0.6%	(9)	-0.2%	(31)	-0.7%
JCPL	(85)	-1.3%	(78)	-1.1%	(54)	-0.8%
METED	(52)	-1.7%	(42)	-1.3%	(46)	-1.3%
PECO	(210)	-2.4%	(191)	-2.0%	(237)	-2.3%
PENLC	(66)	-2.2%	(45)	-1.4%	(51)	-1.4%
PEPCO	(85)	-1.2%	(116)	-1.6%	(148)	-2.0%
PL	(104)	-1.4%	(89)	-1.1%	(100)	-1.2%
PS	(145)	-1.4%	(131)	-1.2%	(165)	-1.4%
RECO	(5)	-1.2%	(14)	-3.1%	(20)	-4.3%
UGI	(2)	-1.0%	0	0.0%	0	0.0%
PJM MID-ATLANTIC	(833)	-1.4%	(770)	-1.2%	(965)	-1.4%
FE-EAST	(208)	-1.7%	(167)	-1.3%	(195)	-1.4%
PLGRP	(110)	-1.5%	(90)	-1.1%	(105)	-1.2%

Table A-1

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST TO THE JANUARY 2012 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2013		2018		2023	
	MW	%	MW	%	MW	%
AEP	(280)	-1.2%	(271)	-1.1%	(332)	-1.2%
APS	(101)	-1.2%	(99)	-1.0%	(122)	-1.2%
ATSI	(165)	-1.2%	(88)	-0.6%	(122)	-0.8%
COMED	(513)	-2.2%	(402)	-1.6%	(538)	-2.0%
DAYTON	(16)	-0.5%	3	0.1%	(8)	-0.2%
DEOK	(155)	-2.7%	(169)	-2.8%	(205)	-3.2%
DLCO	(14)	-0.5%	16	0.5%	18	0.5%
EKPC	~	~	~	~	~	~
PJM WESTERN	(1,172)	-1.5%	(1,030)	-1.2%	(1,257)	-1.4%
PJM WESTERN with EKPC	~	~	~	~	~	~
DOM	(361)	-1.8%	(274)	-1.2%	(313)	-1.3%
PJM RTO	(2,538)	-1.6%	(2,222)	-1.3%	(2,857)	-1.6%
PJM RTO with EKPC	~	~	~	~	~	~

Table A-2

PJM MID-ATLANTIC REGION
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2012 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	12/13		17/18		22/23	
	MW	%	MW	%	MW	%
AE	(7)	-0.4%	0	0.0%	2	0.1%
BGE	(48)	-0.8%	(54)	-0.9%	(67)	-1.0%
DPL	(32)	-0.9%	(20)	-0.6%	(30)	-0.8%
JCPL	(57)	-1.4%	(52)	-1.2%	(60)	-1.3%
METED	(45)	-1.7%	(34)	-1.2%	(34)	-1.1%
PECO	(161)	-2.4%	(167)	-2.3%	(184)	-2.3%
PENLC	(58)	-2.0%	(50)	-1.5%	(59)	-1.7%
PEPCO	(27)	-0.5%	(33)	-0.6%	(43)	-0.7%
PL	(87)	-1.2%	(78)	-1.0%	(89)	-1.1%
PS	(68)	-1.0%	(73)	-1.0%	(76)	-1.0%
RECO	(6)	-2.5%	(11)	-4.4%	(17)	-6.5%
UGI	(2)	-1.0%	(1)	-0.5%	0	0.0%
PJM MID-ATLANTIC	(611)	-1.3%	(605)	-1.2%	(704)	-1.3%
FE-EAST	(154)	-1.6%	(124)	-1.2%	(143)	-1.3%
PLGRP	(79)	-1.0%	(72)	-0.9%	(87)	-1.0%

Table A-2

**PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2012 LOAD FORECAST REPORT**

INCREASE OR DECREASE OVER PRIOR FORECAST

	12/13		17/18		22/23	
	MW	%	MW	%	MW	%
AEP	(244)	-1.1%	(242)	-1.0%	(306)	-1.2%
APS	(81)	-0.9%	(77)	-0.8%	(101)	-1.0%
ATSI	(68)	-0.6%	(46)	-0.4%	(52)	-0.5%
COMED	(236)	-1.5%	(257)	-1.5%	(326)	-1.7%
DAYTON	(3)	-0.1%	0	0.0%	(5)	-0.2%
DEOK	(79)	-1.8%	(96)	-2.0%	(112)	-2.3%
DLCO	(9)	-0.4%	(2)	-0.1%	1	0.0%
EKPC	~	~	~	~	~	~
PJM WESTERN	(671)	-1.0%	(625)	-0.9%	(826)	-1.1%
PJM WESTERN with EKPC	~	~	~	~	~	~
DOM	(238)	-1.4%	(160)	-0.8%	(185)	-0.9%
PJM RTO	(1,487)	-1.1%	(1,442)	-1.0%	(1,683)	-1.2%
PJM RTO with EKPC	~	~	~	~	~	~

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2013 - 2023

	METERED 2012	UNRESTRICTED 2012	NORMAL 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Annual Growth Rate (10 yr)
AE	2,810	2,853	2,710	2,733	2,784	2,843	2,896	2,924	2,946	2,965	2,987	3,011	3,034	3,053	1.1%
				0.8%	1.9%	2.1%	1.9%	1.0%	0.8%	0.6%	0.7%	0.8%	0.8%	0.6%	
BGE	7,003	7,435	7,150	7,218	7,333	7,467	7,572	7,649	7,703	7,770	7,840	7,905	7,966	8,034	1.1%
				1.0%	1.6%	1.8%	1.4%	1.0%	0.7%	0.9%	0.9%	0.8%	0.8%	0.9%	
DPL	4,115	4,152	4,110	4,141	4,218	4,301	4,376	4,432	4,476	4,527	4,576	4,624	4,671	4,717	1.3%
				0.8%	1.9%	2.0%	1.7%	1.3%	1.0%	1.1%	1.1%	1.0%	1.0%	1.0%	
JCPL	6,220	6,300	6,200	6,253	6,372	6,503	6,637	6,704	6,737	6,795	6,875	6,943	7,021	7,068	1.2%
				0.9%	1.9%	2.1%	2.1%	1.0%	0.5%	0.9%	1.2%	1.0%	1.1%	0.7%	
METED	3,037	3,039	2,940	2,978	3,047	3,127	3,197	3,247	3,286	3,328	3,375	3,420	3,466	3,509	1.7%
				1.3%	2.3%	2.6%	2.2%	1.6%	1.2%	1.3%	1.4%	1.3%	1.3%	1.2%	
PECO	8,549	8,727	8,650	8,722	8,901	9,098	9,266	9,397	9,508	9,612	9,720	9,828	9,932	10,026	1.4%
				0.8%	2.1%	2.2%	1.8%	1.4%	1.2%	1.1%	1.1%	1.1%	1.1%	0.9%	
PENLC	2,908	2,914	2,880	2,918	3,002	3,100	3,183	3,243	3,285	3,338	3,388	3,439	3,488	3,535	1.9%
				1.3%	2.9%	3.3%	2.7%	1.9%	1.3%	1.6%	1.5%	1.5%	1.4%	1.3%	
PEPCO	6,721	6,759	6,800	6,855	6,935	7,015	7,073	7,123	7,167	7,215	7,268	7,309	7,348	7,392	0.8%
				0.8%	1.2%	1.2%	0.8%	0.7%	0.6%	0.7%	0.7%	0.6%	0.5%	0.6%	
PL	7,182	7,290	7,190	7,271	7,403	7,556	7,691	7,785	7,850	7,942	8,027	8,102	8,191	8,264	1.3%
				1.1%	1.8%	2.1%	1.8%	1.2%	0.8%	1.2%	1.1%	0.9%	1.1%	0.9%	
PS	10,470	10,475	10,500	10,562	10,698	10,861	11,002	11,083	11,138	11,208	11,275	11,348	11,419	11,475	0.8%
				0.6%	1.3%	1.5%	1.3%	0.7%	0.5%	0.6%	0.6%	0.6%	0.6%	0.5%	
RECO	430	430	420	420	425	429	434	436	437	439	441	444	445	447	0.6%
				0.0%	1.2%	0.9%	1.2%	0.5%	0.2%	0.5%	0.5%	0.7%	0.2%	0.4%	
UGI	200	200	190	195	199	203	206	209	210	211	213	215	217	218	1.1%
				2.6%	2.1%	2.0%	1.5%	1.5%	0.5%	0.5%	0.9%	0.9%	0.9%	0.5%	
DIVERSITY - MID-ATLANTIC(-)				530	539	478	482	465	559	564	400	399	410	512	
PJM MID-ATLANTIC	58,945	60,067	59,230	59,736	60,778	62,025	63,051	63,767	64,184	64,786	65,585	66,189	66,788	67,226	1.2%
				0.9%	1.7%	2.1%	1.7%	1.1%	0.7%	0.9%	1.2%	0.9%	0.9%	0.7%	
FE-EAST	12,079	12,146	11,850	11,984	12,258	12,565	12,827	13,001	13,147	13,299	13,452	13,606	13,767	13,908	1.5%
				1.1%	2.3%	2.5%	2.1%	1.4%	1.1%	1.2%	1.2%	1.1%	1.2%	1.0%	
PLGRP	7,382	7,490	7,350	7,439	7,576	7,734	7,871	7,970	8,036	8,133	8,216	8,297	8,386	8,459	1.3%
				1.2%	1.8%	2.1%	1.8%	1.3%	0.8%	1.2%	1.0%	1.0%	1.1%	0.9%	

Notes:
Normal 2012 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2012 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Table B-1 (Continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2024 - 2028

	2024	2025	2026	2027	2028	Annual Growth Rate (15 yr)
AE	3,071	3,092	3,113	3,136	3,161	1.0%
	0.6%	0.7%	0.7%	0.7%	0.8%	
BGE	8,091	8,160	8,227	8,288	8,339	1.0%
	0.7%	0.9%	0.8%	0.7%	0.6%	
DPL	4,764	4,806	4,852	4,890	4,932	1.2%
	1.0%	0.9%	1.0%	0.8%	0.9%	
JCPL	7,093	7,148	7,249	7,302	7,373	1.1%
	0.4%	0.8%	1.4%	0.7%	1.0%	
METED	3,549	3,593	3,637	3,681	3,727	1.5%
	1.1%	1.2%	1.2%	1.2%	1.2%	
PECO	10,125	10,221	10,319	10,419	10,521	1.3%
	1.0%	0.9%	1.0%	1.0%	1.0%	
PENLC	3,576	3,623	3,664	3,709	3,752	1.7%
	1.2%	1.3%	1.1%	1.2%	1.2%	
PEPCO	7,430	7,474	7,510	7,547	7,588	0.7%
	0.5%	0.6%	0.5%	0.5%	0.5%	
PL	8,337	8,419	8,490	8,559	8,639	1.2%
	0.9%	1.0%	0.8%	0.8%	0.9%	
PS	11,527	11,601	11,661	11,730	11,784	0.7%
	0.5%	0.6%	0.5%	0.6%	0.5%	
RECO	448	450	452	454	456	0.5%
	0.2%	0.4%	0.4%	0.4%	0.4%	
UGI	220	221	223	224	226	1.0%
	0.9%	0.5%	0.9%	0.4%	0.9%	
DIVERSITY - MID-ATLANTIC(-)	517	429	415	400	513	
PJM MID-ATLANTIC	67,714	68,379	68,982	69,539	69,985	1.1%
	0.7%	1.0%	0.9%	0.8%	0.6%	
FE-EAST	14,056	14,199	14,342	14,492	14,637	1.3%
	1.1%	1.0%	1.0%	1.0%	1.0%	
PLGRP	8,539	8,616	8,695	8,766	8,845	1.2%
	0.9%	0.9%	0.9%	0.8%	0.9%	

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2013 - 2023

	METERED 2012	UNRESTRICTED 2012	NORMAL 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Annual Growth Rate (10 yr)
AEP	23,321	23,508	23,600	23,793	24,190	24,668	25,039	25,297	25,504	25,712	25,944	26,177	26,404	26,605	1.1%
				0.8%	1.7%	2.0%	1.5%	1.0%	0.8%	0.8%	0.9%	0.9%	0.9%	0.8%	
APS	8,525	8,537	8,570	8,661	8,823	9,003	9,158	9,266	9,341	9,433	9,541	9,638	9,732	9,829	1.3%
				1.1%	1.9%	2.0%	1.7%	1.2%	0.8%	1.0%	1.1%	1.0%	1.0%	1.0%	
ATSI	13,515	13,516	13,210	13,270	13,459	13,698	13,871	13,984	14,067	14,148	14,248	14,347	14,441	14,535	0.9%
				0.5%	1.4%	1.8%	1.3%	0.8%	0.6%	0.6%	0.7%	0.7%	0.7%	0.7%	
COMED	23,601	23,602	22,610	22,761	23,343	23,995	24,569	24,955	25,243	25,529	25,856	26,152	26,449	26,742	1.6%
				0.7%	2.6%	2.8%	2.4%	1.6%	1.2%	1.1%	1.3%	1.1%	1.1%	1.1%	
DAYTON	3,495	3,495	3,410	3,442	3,534	3,644	3,731	3,791	3,836	3,880	3,930	3,978	4,025	4,069	1.7%
				0.9%	2.7%	3.1%	2.4%	1.6%	1.2%	1.1%	1.3%	1.2%	1.2%	1.1%	
DEOK	5,445	5,445	5,490	5,530	5,634	5,747	5,833	5,903	5,954	6,013	6,075	6,131	6,186	6,244	1.2%
				0.7%	1.9%	2.0%	1.5%	1.2%	0.9%	1.0%	1.0%	0.9%	0.9%	0.9%	
DLCO	3,055	3,055	2,940	2,966	3,021	3,083	3,135	3,167	3,197	3,220	3,249	3,278	3,305	3,331	1.2%
				0.9%	1.9%	2.1%	1.7%	1.0%	0.9%	0.7%	0.9%	0.9%	0.8%	0.8%	
EKPC	1,984	1,984	1,920	1,910	1,938	1,972	1,992	2,018	2,037	2,053	2,071	2,086	2,102	2,124	1.1%
				-0.5%	1.5%	1.8%	1.0%	1.3%	0.9%	0.8%	0.9%	0.7%	0.8%	1.0%	
DIVERSITY - WESTERN(-)				1,665	1,660	1,742	1,756	1,831	1,889	1,836	1,883	1,854	1,876	1,948	
PJM WESTERN	79,490	80,598	78,140	78,758	80,344	82,096	83,580	84,532	85,253	86,099	86,960	87,847	88,666	89,407	1.3%
				0.8%	2.0%	2.2%	1.8%	1.1%	0.9%	1.0%	1.0%	1.0%	0.9%	0.8%	
DIVERSITY - WESTERN with EKPC(-)				1,721	1,769	1,782	1,806	1,883	1,921	1,913	1,937	1,860	1,972	2,047	
PJM WESTERN with EKPC	81,321	82,441	80,010	80,612	82,173	84,028	85,522	86,498	87,258	88,075	88,977	89,927	90,672	91,432	1.3%
				0.8%	1.9%	2.3%	1.8%	1.1%	0.9%	0.9%	1.0%	1.1%	0.8%	0.8%	
DOM	19,249	19,323	19,320	19,619	20,154	20,747	21,228	21,604	21,919	22,262	22,614	22,931	23,232	23,558	1.8%
				1.5%	2.7%	2.9%	2.3%	1.8%	1.5%	1.6%	1.6%	1.4%	1.3%	1.4%	
DIVERSITY - INTERREGIONAL(-)				4,397	4,463	4,547	4,683	4,677	4,546	4,638	4,869	4,886	4,966	4,863	
PJM RTO	154,339	156,319	152,405	153,716	156,813	160,321	163,176	165,226	166,810	168,509	170,290	172,081	173,720	175,328	1.3%
				0.9%	2.0%	2.2%	1.8%	1.3%	1.0%	1.0%	1.1%	1.1%	1.0%	0.9%	
DIVERSITY - INTERREGIONAL with EKPC(-)				4,414	4,388	4,584	4,673	4,658	4,548	4,602	4,808	4,872	4,901	4,777	
PJM RTO with EKPC	156,182	158,162	154,235	155,553	158,717	162,216	165,128	167,211	168,813	170,521	172,368	174,175	175,791	177,439	1.3%
				0.9%	2.0%	2.2%	1.8%	1.3%	1.0%	1.0%	1.1%	1.0%	0.9%	0.9%	

Notes:
Normal 2012 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2012 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Table B-1 (Continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2024 - 2028

	2024	2025	2026	2027	2028	Annual Growth Rate (15 yr)
AEP	26,820	27,047	27,275	27,512	27,744	1.0%
	0.8%	0.8%	0.8%	0.9%	0.8%	
APS	9,906	10,000	10,103	10,199	10,298	1.2%
	0.8%	0.9%	1.0%	1.0%	1.0%	
ATSI	14,608	14,704	14,792	14,891	14,993	0.8%
	0.5%	0.7%	0.6%	0.7%	0.7%	
COMED	26,999	27,287	27,560	27,834	28,118	1.4%
	1.0%	1.1%	1.0%	1.0%	1.0%	
DAYTON	4,118	4,165	4,211	4,255	4,299	1.5%
	1.2%	1.1%	1.1%	1.0%	1.0%	
DEOK	6,294	6,352	6,405	6,461	6,519	1.1%
	0.8%	0.9%	0.8%	0.9%	0.9%	
DLCO	3,351	3,380	3,406	3,431	3,455	1.0%
	0.6%	0.9%	0.8%	0.7%	0.7%	
EKPC	2,141	2,156	2,175	2,190	2,210	1.0%
	0.8%	0.7%	0.9%	0.7%	0.9%	
DIVERSITY - WESTERN(-)	1,969	2,054	1,923	1,921	2,086	
PJM WESTERN	90,127	90,881	91,829	92,662	93,340	1.1%
	0.8%	0.8%	1.0%	0.9%	0.7%	
DIVERSITY - WESTERN with EKPC(-)	2,002	2,060	1,960	1,975	2,121	
PJM WESTERN with EKPC	92,235	93,031	93,967	94,798	95,515	1.1%
	0.9%	0.9%	1.0%	0.9%	0.8%	
DOM	23,856	24,201	24,518	24,781	25,107	1.7%
	1.3%	1.4%	1.3%	1.1%	1.3%	
DIVERSITY - INTERREGIONAL(-)	4,778	4,888	5,108	5,078	4,964	
PJM RTO	176,919	178,573	180,221	181,904	183,468	1.2%
	0.9%	0.9%	0.9%	0.9%	0.9%	
DIVERSITY - INTERREGIONAL with EKPC(-)	4,763	4,964	5,073	5,039	4,936	
PJM RTO with EKPC	179,042	180,647	182,394	184,079	185,671	1.2%
	0.9%	0.9%	1.0%	0.9%	0.9%	

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2012/13 - 2022/23

	METERED 11/12	UNRESTRICTED 11/12	NORMAL 11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	Annual Growth Rate (10 yr)
AE	1,654	1,654	1,760	1,773	1,779	1,812	1,848	1,874	1,880	1,894	1,894	1,915	1,928	1,943	0.9%
				0.7%	0.3%	1.9%	2.0%	1.4%	0.3%	0.7%	0.0%	1.1%	0.7%	0.8%	
BGE	5,621	5,621	5,960	5,968	5,994	6,062	6,129	6,181	6,205	6,234	6,249	6,293	6,323	6,363	0.6%
				0.1%	0.4%	1.1%	1.1%	0.8%	0.4%	0.5%	0.2%	0.7%	0.5%	0.6%	
DPL	3,221	3,221	3,360	3,362	3,390	3,443	3,497	3,546	3,574	3,600	3,620	3,657	3,688	3,727	1.0%
				0.1%	0.8%	1.6%	1.6%	1.4%	0.8%	0.7%	0.6%	1.0%	0.8%	1.1%	
JCPL	3,640	3,640	3,930	3,929	3,952	4,042	4,140	4,208	4,234	4,265	4,266	4,345	4,380	4,421	1.2%
				-0.0%	0.6%	2.3%	2.4%	1.6%	0.6%	0.7%	0.0%	1.9%	0.8%	0.9%	
METED	2,539	2,539	2,600	2,616	2,645	2,707	2,770	2,834	2,864	2,899	2,920	2,961	3,003	3,046	1.5%
				0.6%	1.1%	2.3%	2.3%	2.3%	1.1%	1.2%	0.7%	1.4%	1.4%	1.4%	
PECO	6,329	6,329	6,650	6,658	6,740	6,884	7,039	7,170	7,246	7,329	7,389	7,490	7,580	7,663	1.4%
				0.1%	1.2%	2.1%	2.3%	1.9%	1.1%	1.1%	0.8%	1.4%	1.2%	1.1%	
PENLC	2,753	2,753	2,870	2,888	2,940	3,036	3,130	3,217	3,264	3,313	3,351	3,404	3,458	3,515	2.0%
				0.6%	1.8%	3.3%	3.1%	2.8%	1.5%	1.5%	1.1%	1.6%	1.6%	1.6%	
PEPCO	5,090	5,090	5,440	5,465	5,510	5,573	5,659	5,731	5,771	5,817	5,846	5,887	5,935	5,983	0.9%
				0.5%	0.8%	1.1%	1.5%	1.3%	0.7%	0.8%	0.5%	0.7%	0.8%	0.8%	
PL	6,776	6,776	7,290	7,313	7,376	7,507	7,638	7,750	7,810	7,874	7,917	8,003	8,081	8,158	1.1%
				0.3%	0.9%	1.8%	1.7%	1.5%	0.8%	0.8%	0.5%	1.1%	1.0%	1.0%	
PS	6,522	6,522	6,910	6,906	6,924	7,029	7,139	7,250	7,269	7,310	7,306	7,376	7,436	7,500	0.8%
				-0.1%	0.3%	1.5%	1.6%	1.6%	0.3%	0.6%	-0.1%	1.0%	0.8%	0.9%	
RECO	232	232	240	233	234	235	236	238	239	241	242	243	244	245	0.5%
				-2.9%	0.4%	0.4%	0.4%	0.8%	0.4%	0.8%	0.4%	0.4%	0.4%	0.4%	
UGI	190	190	200	198	199	203	206	209	209	211	211	213	215	217	0.9%
				-1.0%	0.5%	2.0%	1.5%	1.5%	0.0%	1.0%	0.0%	0.9%	0.9%	0.9%	
DIVERSITY - MID-ATLANTIC(-)				652	536	634	632	687	646	656	540	654	614	705	
PJM MID-ATLANTIC	43,684	43,684	46,480	46,657	47,147	47,899	48,799	49,521	49,919	50,331	50,671	51,133	51,657	52,076	1.1%
				0.4%	1.1%	1.6%	1.9%	1.5%	0.8%	0.8%	0.7%	0.9%	1.0%	0.8%	
FE-EAST	8,880	8,880	9,310	9,358	9,478	9,722	9,969	10,171	10,286	10,397	10,473	10,633	10,762	10,886	1.5%
				0.5%	1.3%	2.6%	2.5%	2.0%	1.1%	1.1%	0.7%	1.5%	1.2%	1.2%	
PLGRP	6,957	6,957	7,450	7,485	7,562	7,693	7,820	7,925	7,991	8,055	8,112	8,188	8,269	8,331	1.1%
				0.5%	1.0%	1.7%	1.7%	1.3%	0.8%	0.8%	0.7%	0.9%	1.0%	0.7%	

Notes:
Normal 11/12 and all forecast values are non-coincident as estimated by PJM staff.
Normal 11/12 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Table B-2 (Continued)

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2023/24 - 2027/28

	23/24	24/25	25/26	26/27	27/28	Annual Growth Rate (15 yr)
AE	1,949	1,948	1,963	1,980	1,995	0.8%
	0.3%	-0.1%	0.8%	0.9%	0.8%	
BGE	6,385	6,404	6,436	6,473	6,503	0.6%
	0.3%	0.3%	0.5%	0.6%	0.5%	
DPL	3,751	3,768	3,796	3,826	3,854	0.9%
	0.6%	0.5%	0.7%	0.8%	0.7%	
JCPL	4,443	4,437	4,495	4,549	4,587	1.0%
	0.5%	-0.1%	1.3%	1.2%	0.8%	
METED	3,073	3,097	3,131	3,170	3,213	1.4%
	0.9%	0.8%	1.1%	1.2%	1.4%	
PECO	7,718	7,773	7,853	7,935	8,022	1.3%
	0.7%	0.7%	1.0%	1.0%	1.1%	
PENLC	3,554	3,589	3,634	3,679	3,728	1.7%
	1.1%	1.0%	1.3%	1.2%	1.3%	
PEPCO	6,018	6,049	6,083	6,119	6,161	0.8%
	0.6%	0.5%	0.6%	0.6%	0.7%	
PL	8,205	8,248	8,315	8,386	8,464	1.0%
	0.6%	0.5%	0.8%	0.9%	0.9%	
PS	7,510	7,507	7,557	7,613	7,674	0.7%
	0.1%	-0.0%	0.7%	0.7%	0.8%	
RECO	246	247	248	249	250	0.5%
	0.4%	0.4%	0.4%	0.4%	0.4%	
UGI	217	218	219	221	222	0.8%
	0.0%	0.5%	0.5%	0.9%	0.5%	
DIVERSITY - MID-ATLANTIC(-)	648	555	677	660	612	
PJM MID-ATLANTIC	52,421	52,730	53,053	53,540	54,061	1.0%
	0.7%	0.6%	0.6%	0.9%	1.0%	
FE-EAST	10,986	11,061	11,188	11,313	11,439	1.3%
	0.9%	0.7%	1.1%	1.1%	1.1%	
PLGRP	8,393	8,445	8,508	8,577	8,656	1.0%
	0.7%	0.6%	0.7%	0.8%	0.9%	

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2012/13 - 2022/23

	METERED 11/12	UNRESTRICTED 11/12	NORMAL 11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	Annual Growth Rate (10 yr)
AEP	21,588	21,588	22,890	22,955	23,142	23,511	23,913	24,245	24,387	24,526	24,631	24,874	25,068	25,303	1.0%
				0.3%	0.8%	1.6%	1.7%	1.4%	0.6%	0.6%	0.4%	1.0%	0.8%	0.9%	
APS	8,081	8,081	8,480	8,558	8,658	8,838	9,021	9,165	9,244	9,339	9,412	9,527	9,631	9,734	1.3%
				0.9%	1.2%	2.1%	2.1%	1.6%	0.9%	1.0%	0.8%	1.2%	1.1%	1.1%	
ATSI	10,121	10,121	10,710	10,692	10,698	10,812	10,927	11,080	11,109	11,147	11,132	11,232	11,311	11,373	0.6%
				-0.2%	0.1%	1.1%	1.1%	1.4%	0.3%	0.3%	-0.1%	0.9%	0.7%	0.5%	
COMED	14,813	14,813	15,940	15,931	16,033	16,464	16,902	17,280	17,449	17,619	17,716	17,967	18,176	18,395	1.4%
				-0.1%	0.6%	2.7%	2.7%	2.2%	1.0%	1.0%	0.6%	1.4%	1.2%	1.2%	
DAYTON	2,710	2,710	2,860	2,867	2,894	2,974	3,049	3,112	3,141	3,166	3,184	3,229	3,268	3,304	1.4%
				0.2%	0.9%	2.8%	2.5%	2.1%	0.9%	0.8%	0.6%	1.4%	1.2%	1.1%	
DEOK	4,047	4,047	4,380	4,397	4,415	4,472	4,532	4,587	4,616	4,644	4,655	4,692	4,724	4,764	0.8%
				0.4%	0.4%	1.3%	1.3%	1.2%	0.6%	0.6%	0.2%	0.8%	0.7%	0.8%	
DLCO	2,207	2,207	2,200	2,198	2,203	2,234	2,269	2,308	2,318	2,331	2,325	2,350	2,368	2,390	0.8%
				-0.1%	0.2%	1.4%	1.6%	1.7%	0.4%	0.6%	-0.3%	1.1%	0.8%	0.9%	
EKPC	2,044	2,044	2,360	2,329	2,335	2,358	2,389	2,409	2,420	2,430	2,432	2,453	2,466	2,482	0.6%
				-1.3%	0.3%	1.0%	1.3%	0.8%	0.5%	0.4%	0.1%	0.9%	0.5%	0.6%	
DIVERSITY - WESTERN(-)				1,362	1,254	1,304	1,516	1,525	1,459	1,518	1,464	1,682	1,592	1,681	
PJM WESTERN	62,791	62,791	66,000	66,236	66,789	68,001	69,097	70,252	70,805	71,254	71,591	72,189	72,954	73,582	1.1%
				0.4%	0.8%	1.8%	1.6%	1.7%	0.8%	0.6%	0.5%	0.8%	1.1%	0.9%	
DIVERSITY - WESTERN with EKPC(-)				1,548	1,443	1,508	1,704	1,680	1,643	1,702	1,650	1,893	1,761	1,828	
PJM WESTERN with EKPC	64,655	64,655	68,200	68,379	68,935	70,155	71,298	72,506	73,041	73,500	73,837	74,431	75,251	75,917	1.1%
				0.3%	0.8%	1.8%	1.6%	1.7%	0.7%	0.6%	0.5%	0.8%	1.1%	0.9%	
DOM	16,881	16,881	17,150	17,311	17,606	18,026	18,485	18,828	19,054	19,299	19,500	19,779	20,018	20,288	1.6%
				0.9%	1.7%	2.4%	2.5%	1.9%	1.2%	1.3%	1.0%	1.4%	1.2%	1.3%	
DIVERSITY - INTERREGIONAL(-)				1,469	1,505	1,282	1,220	1,482	1,558	1,540	1,546	1,229	1,388	1,513	
PJM RTO	122,566	122,566	128,215	128,735	130,037	132,644	135,161	137,119	138,220	139,344	140,216	141,872	143,241	144,433	1.2%
				0.4%	1.0%	2.0%	1.9%	1.4%	0.8%	0.8%	0.6%	1.2%	1.0%	0.8%	
DIVERSITY - INTERREGIONAL with EKPC(-)				1,537	1,459	1,338	1,244	1,559	1,584	1,647	1,546	1,244	1,485	1,663	
PJM RTO with EKPC	124,430	124,430	130,380	130,810	132,229	134,742	137,338	139,296	140,430	141,483	142,462	144,099	145,441	146,618	1.1%
				0.3%	1.1%	1.9%	1.9%	1.4%	0.8%	0.7%	0.7%	1.1%	0.9%	0.8%	

Notes:
Normal 11/12 and all forecast values are non-coincident as estimated by PJM staff.
Normal 11/12 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Table B-2 (Continued)

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2023/24 - 2027/28

	23/24	24/25	25/26	26/27	27/28	Annual Growth Rate (15 yr)
AEP	25,434	25,520	25,705	25,925	26,131	0.9%
	0.5%	0.3%	0.7%	0.9%	0.8%	
APS	9,811	9,886	9,984	10,082	10,200	1.2%
	0.8%	0.8%	1.0%	1.0%	1.2%	
ATSI	11,400	11,374	11,433	11,519	11,600	0.5%
	0.2%	-0.2%	0.5%	0.8%	0.7%	
COMED	18,543	18,604	18,776	18,994	19,206	1.3%
	0.8%	0.3%	0.9%	1.2%	1.1%	
DAYTON	3,331	3,347	3,383	3,418	3,457	1.3%
	0.8%	0.5%	1.1%	1.0%	1.1%	
DEOK	4,787	4,801	4,827	4,861	4,897	0.7%
	0.5%	0.3%	0.5%	0.7%	0.7%	
DLCO	2,399	2,395	2,409	2,430	2,446	0.7%
	0.4%	-0.2%	0.6%	0.9%	0.7%	
EKPC	2,491	2,494	2,507	2,524	2,536	0.6%
	0.4%	0.1%	0.5%	0.7%	0.5%	
DIVERSITY - WESTERN(-)	1,604	1,549	1,599	1,769	1,726	
PJM WESTERN	74,101	74,378	74,918	75,460	76,211	0.9%
	0.7%	0.4%	0.7%	0.7%	1.0%	
DIVERSITY - WESTERN with EKPC(-)	1,773	1,753	1,825	1,979	1,904	
PJM WESTERN with EKPC	76,423	76,668	77,199	77,774	78,569	0.9%
	0.7%	0.3%	0.7%	0.7%	1.0%	
DOM	20,499	20,702	20,924	21,176	21,408	1.4%
	1.0%	1.0%	1.1%	1.2%	1.1%	
DIVERSITY - INTERREGIONAL(-)	1,558	1,581	1,194	1,270	1,467	
PJM RTO	145,463	146,229	147,701	148,906	150,213	1.0%
	0.7%	0.5%	1.0%	0.8%	0.9%	
DIVERSITY - INTERREGIONAL with EKPC(-)	1,613	1,600	1,210	1,347	1,583	
PJM RTO with EKPC	147,730	148,500	149,966	151,143	152,455	1.0%
	0.8%	0.5%	1.0%	0.8%	0.9%	

Table B-3

SPRING (APRIL) PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2013 - 2028

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AE	1,505	1,525	1,574	1,607	1,627	1,645	1,654	1,676	1,706	1,715	1,719	1,761	1,764	1,778	1,786	1,786
BGE	4,820	4,860	4,996	5,044	5,043	5,098	5,122	5,256	5,326	5,299	5,289	5,385	5,439	5,537	5,585	5,520
DPL	2,651	2,685	2,746	2,777	2,812	2,846	2,870	2,922	2,980	2,988	2,987	3,051	3,083	3,123	3,150	3,138
JCPL	3,311	3,382	3,497	3,546	3,584	3,665	3,693	3,766	3,888	3,858	3,796	3,977	4,015	4,091	4,128	3,994
METED	2,266	2,320	2,392	2,445	2,481	2,507	2,525	2,587	2,646	2,662	2,670	2,711	2,760	2,805	2,838	2,833
PECO	5,686	5,813	6,011	6,102	6,187	6,284	6,327	6,510	6,665	6,617	6,644	6,822	6,895	7,032	7,108	6,999
PENLC	2,521	2,594	2,706	2,780	2,838	2,887	2,922	2,996	3,050	3,082	3,117	3,157	3,203	3,266	3,306	3,330
PEPCO	4,499	4,547	4,636	4,664	4,693	4,742	4,760	4,834	4,937	4,886	4,862	4,932	4,965	5,030	5,107	5,011
PL	5,871	5,969	6,129	6,208	6,284	6,363	6,404	6,527	6,598	6,629	6,655	6,754	6,812	6,914	6,982	6,978
PS	6,209	6,294	6,491	6,506	6,525	6,602	6,609	6,781	6,878	6,805	6,794	6,943	6,965	7,065	7,129	6,983
RECO	220	221	226	226	225	227	226	232	233	231	230	230	232	236	238	233
UGI	154	156	160	163	164	166	167	169	172	171	172	176	177	179	180	178
DIVERSITY - MID-ATLANTIC(-)	1,567	1,654	1,927	1,917	1,804	1,719	1,504	2,071	2,337	1,946	1,643	1,428	1,400	2,233	2,296	1,716
PJM MID-ATLANTIC	38,146	38,712	39,637	40,151	40,659	41,313	41,775	42,185	42,742	42,997	43,292	44,471	44,910	44,823	45,241	45,267
FE-EAST	7,780	7,978	8,237	8,419	8,562	8,693	8,831	8,974	9,153	9,202	9,264	9,516	9,648	9,756	9,868	9,835
PLGRP	5,863	5,972	6,096	6,195	6,278	6,364	6,442	6,502	6,556	6,615	6,663	6,799	6,849	6,900	6,969	6,992

Table B-3

SPRING (APRIL) PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2013 - 2028

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AEP	18,904	19,140	19,577	19,862	20,062	20,259	20,322	20,592	20,806	20,948	21,018	21,173	21,341	21,618	21,823	21,902
APS	6,955	7,075	7,260	7,360	7,457	7,541	7,591	7,727	7,836	7,879	7,894	8,001	8,082	8,206	8,296	8,297
ATSI	9,519	9,647	9,882	9,870	9,935	10,020	10,024	10,243	10,353	10,281	10,277	10,441	10,591	10,665	10,679	10,583
COMED	13,786	14,205	14,816	15,195	15,433	15,762	15,922	16,297	16,650	16,665	16,782	17,195	17,422	17,699	17,927	17,754
DAYTON	2,381	2,442	2,547	2,604	2,653	2,692	2,711	2,773	2,823	2,842	2,864	2,909	2,946	2,999	3,033	3,035
DEOK	3,752	3,803	3,912	3,941	3,977	4,033	4,042	4,149	4,206	4,186	4,201	4,283	4,320	4,394	4,433	4,391
DLCO	2,036	2,073	2,144	2,162	2,156	2,205	2,213	2,273	2,298	2,281	2,273	2,325	2,338	2,387	2,412	2,369
EKPC	1,569	1,579	1,607	1,618	1,627	1,641	1,647	1,668	1,686	1,687	1,686	1,714	1,721	1,733	1,743	1,738
DIVERSITY - WESTERN(-)	2,276	2,392	2,855	2,594	2,521	2,590	2,506	3,393	3,382	3,043	2,767	2,791	2,858	3,662	3,596	3,276
PJM WESTERN	55,057	55,993	57,283	58,400	59,152	59,922	60,319	60,661	61,590	62,039	62,542	63,536	64,182	64,306	65,007	65,055
DIVERSITY - WESTERN with EKPC(-)	2,415	2,500	2,943	2,794	2,687	2,743	2,777	3,337	3,369	3,038	2,814	2,875	3,139	3,560	3,753	3,156
PJM WESTERN with EKPC	56,487	57,464	58,802	59,818	60,613	61,410	61,695	62,385	63,289	63,731	64,181	65,166	65,622	66,141	66,593	66,913
DOM	13,647	13,958	14,518	14,813	15,066	15,347	15,557	15,940	16,238	16,383	16,550	16,849	17,089	17,419	17,677	17,743
DIVERSITY - INTERREGIONAL(-)	2,637	2,065	2,227	2,330	2,647	2,820	2,517	1,917	1,752	2,207	3,014	2,695	2,633	1,448	2,064	2,615
PJM RTO	104,213	106,598	109,211	111,034	112,230	113,762	115,134	116,869	118,818	119,212	119,370	122,161	123,548	125,100	125,861	125,450
DIVERSITY - INTERREGIONAL with EKPC(-)	2,564	2,098	2,114	2,304	2,739	2,919	2,690	1,953	1,845	2,142	2,964	2,573	2,498	1,588	1,996	3,155
PJM RTO with EKPC	105,716	108,036	110,843	112,478	113,599	115,151	116,337	118,557	120,424	120,969	121,059	123,913	125,123	126,795	127,515	126,768

Table B-4

FALL (OCTOBER) PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2013 - 2028

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AE	1,562	1,602	1,644	1,667	1,693	1,713	1,730	1,739	1,748	1,768	1,789	1,812	1,822	1,835	1,842	1,872
BGE	4,691	4,761	4,822	4,859	4,937	4,981	5,022	5,042	5,057	5,131	5,218	5,297	5,334	5,348	5,308	5,435
DPL	2,626	2,675	2,724	2,744	2,809	2,839	2,874	2,901	2,917	2,960	3,004	3,059	3,080	3,094	3,092	3,152
JCPL	3,440	3,527	3,619	3,637	3,724	3,804	3,837	3,861	3,864	3,912	3,981	4,058	4,081	4,118	4,107	4,192
METED	2,178	2,233	2,288	2,331	2,377	2,409	2,447	2,475	2,498	2,548	2,593	2,635	2,665	2,692	2,703	2,766
PECO	5,707	5,826	5,960	6,049	6,184	6,307	6,399	6,426	6,489	6,576	6,705	6,809	6,870	6,919	6,945	7,078
PENLC	2,532	2,607	2,695	2,774	2,839	2,879	2,928	2,954	2,992	3,061	3,119	3,163	3,185	3,221	3,247	3,329
PEPCO	4,600	4,643	4,699	4,684	4,772	4,825	4,865	4,876	4,889	4,896	4,972	5,037	5,061	5,068	5,061	5,120
PL	5,698	5,807	5,929	6,016	6,104	6,147	6,201	6,283	6,321	6,419	6,494	6,570	6,617	6,690	6,678	6,791
PS	6,657	6,764	6,816	6,809	6,933	7,027	7,096	7,085	7,078	7,104	7,206	7,330	7,361	7,359	7,347	7,438
RECO	246	248	250	246	251	254	255	254	252	252	256	260	260	259	257	260
UGI	154	157	159	162	164	164	165	166	167	171	173	174	175	176	174	179
DIVERSITY - MID-ATLANTIC(-)	1,297	1,281	1,380	1,210	1,259	1,249	1,321	1,315	1,304	1,226	1,257	1,412	1,345	1,279	1,343	1,393
PJM MID-ATLANTIC	38,794	39,569	40,225	40,768	41,528	42,100	42,498	42,747	42,968	43,572	44,253	44,792	45,166	45,500	45,418	46,219
FE-EAST	7,955	8,166	8,380	8,556	8,708	8,856	8,961	9,055	9,147	9,343	9,515	9,676	9,770	9,858	9,827	10,083
PLGRP	5,827	5,937	6,055	6,167	6,239	6,293	6,334	6,411	6,463	6,567	6,642	6,701	6,755	6,820	6,840	6,937

Table B-4

FALL (OCTOBER) PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2013 - 2028

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AEP	18,205	18,522	18,774	19,006	19,276	19,481	19,549	19,644	19,689	19,963	20,210	20,396	20,520	20,610	20,632	20,998
APS	6,640	6,773	6,907	7,019	7,104	7,171	7,255	7,322	7,367	7,508	7,595	7,684	7,764	7,810	7,823	7,997
ATSI	9,198	9,312	9,431	9,501	9,606	9,651	9,730	9,756	9,777	9,924	10,045	10,131	10,179	10,221	10,126	10,353
COMED	13,936	14,407	14,900	15,214	15,562	15,803	16,045	16,261	16,431	16,675	16,959	17,367	17,559	17,716	17,723	18,046
DAYTON	2,368	2,441	2,518	2,570	2,623	2,660	2,698	2,724	2,746	2,798	2,857	2,904	2,934	2,963	2,962	3,036
DEOK	3,767	3,840	3,910	3,940	4,019	4,064	4,100	4,129	4,153	4,196	4,261	4,310	4,343	4,367	4,385	4,457
DLCO	1,964	2,004	2,044	2,058	2,095	2,116	2,140	2,153	2,156	2,178	2,212	2,240	2,254	2,265	2,263	2,303
EKPC	1,553	1,577	1,588	1,603	1,619	1,628	1,643	1,653	1,651	1,675	1,690	1,697	1,702	1,716	1,710	1,742
DIVERSITY - WESTERN(-)	1,423	1,577	1,659	1,527	1,745	1,706	1,690	1,810	1,754	1,684	1,926	2,146	2,188	2,105	1,972	2,165
PJM WESTERN	54,655	55,722	56,825	57,781	58,540	59,240	59,827	60,179	60,565	61,558	62,213	62,886	63,365	63,847	63,942	65,025
DIVERSITY - WESTERN with EKPC(-)	1,640	1,747	1,862	1,731	1,956	1,925	1,915	2,029	1,932	1,887	2,077	2,330	2,364	2,283	2,170	2,328
PJM WESTERN with EKPC	55,991	57,129	58,210	59,180	59,948	60,649	61,245	61,613	62,038	63,030	63,752	64,399	64,891	65,385	65,454	66,604
DOM	13,688	14,103	14,527	14,812	15,151	15,420	15,681	15,890	16,078	16,360	16,666	16,948	17,133	17,336	17,499	17,838
DIVERSITY - INTERREGIONAL(-)	1,692	1,647	1,696	1,900	1,869	1,990	2,175	2,075	2,124	2,156	1,837	1,701	1,951	1,965	2,233	1,913
PJM RTO	105,445	107,747	109,881	111,461	113,350	114,770	115,831	116,741	117,487	119,334	121,295	122,925	123,713	124,718	124,626	127,169
DIVERSITY - INTERREGIONAL with EKPC(-)	1,741	1,766	1,739	1,795	1,864	2,024	2,124	2,056	2,252	2,084	1,999	1,865	1,993	2,059	2,341	2,052
PJM RTO with EKPC	106,732	109,035	111,223	112,965	114,763	116,145	117,300	118,194	118,832	120,878	122,672	124,274	125,197	126,162	126,030	128,609

Table B-5

MONTHLY PEAK FORECAST (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC DIVERSITY	PJM MID-ATLANTIC
Jan 2013	1,772	5,968	3,362	3,912	2,616	6,658	2,888	5,465	7,313	6,906	229	198	630	46,657
Feb 2013	1,700	5,759	3,251	3,725	2,548	6,424	2,814	5,275	7,035	6,635	216	189	694	44,877
Mar 2013	1,563	5,107	2,863	3,464	2,396	5,894	2,648	4,592	6,390	6,202	207	170	1,286	40,210
Apr 2013	1,505	4,820	2,651	3,311	2,266	5,686	2,521	4,499	5,871	6,209	220	154	1,567	38,146
May 2013	1,849	5,636	3,085	4,396	2,432	6,717	2,457	5,490	5,912	8,088	321	149	1,726	44,806
Jun 2013	2,399	6,602	3,746	5,646	2,801	8,145	2,795	6,418	6,842	9,781	386	180	928	54,813
Jul 2013	2,733	7,218	4,141	6,253	2,978	8,722	2,918	6,855	7,271	10,562	420	195	530	59,736
Aug 2013	2,633	6,937	3,958	5,741	2,881	8,437	2,866	6,640	7,045	9,836	384	186	385	57,159
Sep 2013	2,156	6,171	3,381	4,873	2,537	7,251	2,654	5,880	6,347	8,694	336	169	697	49,752
Oct 2013	1,562	4,691	2,626	3,440	2,178	5,707	2,532	4,600	5,698	6,657	246	154	1,297	38,794
Nov 2013	1,530	4,781	2,685	3,442	2,267	5,819	2,639	4,470	6,148	6,269	216	169	479	39,956
Dec 2013	1,762	5,629	3,178	3,913	2,547	6,519	2,872	5,177	6,968	6,827	234	196	461	45,361

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2014	1,779	5,994	3,390	3,952	2,645	6,740	2,940	5,510	7,376	6,924	230	199	532	47,147
Feb 2014	1,707	5,774	3,269	3,767	2,575	6,500	2,866	5,296	7,098	6,657	217	190	603	45,313
Mar 2014	1,568	5,129	2,888	3,507	2,441	6,002	2,710	4,628	6,467	6,259	208	172	1,281	40,698
Apr 2014	1,525	4,860	2,685	3,382	2,320	5,813	2,594	4,547	5,969	6,294	221	156	1,654	38,712
May 2014	1,874	5,680	3,125	4,466	2,476	6,838	2,520	5,523	5,997	8,164	322	151	1,890	45,246
Jun 2014	2,439	6,694	3,815	5,733	2,868	8,295	2,868	6,488	6,970	9,877	389	183	676	55,943
Jul 2014	2,784	7,333	4,218	6,372	3,047	8,901	3,002	6,935	7,403	10,698	425	199	539	60,778
Aug 2014	2,675	7,013	4,008	5,827	2,927	8,565	2,934	6,666	7,142	9,907	386	188	320	57,918
Sep 2014	2,206	6,266	3,444	4,995	2,601	7,431	2,736	5,963	6,479	8,872	340	172	686	50,819
Oct 2014	1,602	4,761	2,675	3,527	2,233	5,826	2,607	4,643	5,807	6,764	248	157	1,281	39,569
Nov 2014	1,563	4,847	2,727	3,519	2,322	5,954	2,720	4,523	6,253	6,370	218	171	504	40,683
Dec 2014	1,808	5,734	3,257	4,039	2,624	6,721	2,972	5,288	7,150	6,987	235	201	567	46,449

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2015	1,812	6,062	3,443	4,042	2,707	6,884	3,036	5,573	7,507	7,029	231	203	630	47,899
Feb 2015	1,742	5,849	3,332	3,861	2,641	6,657	2,962	5,367	7,249	6,770	218	194	643	46,199
Mar 2015	1,611	5,252	2,946	3,611	2,517	6,194	2,820	4,723	6,631	6,444	212	176	1,424	41,713
Apr 2015	1,574	4,996	2,746	3,497	2,392	6,011	2,706	4,636	6,129	6,491	226	160	1,927	39,637
May 2015	1,919	5,776	3,175	4,560	2,536	7,001	2,606	5,564	6,119	8,287	324	155	1,801	46,221
Jun 2015	2,494	6,826	3,893	5,867	2,956	8,497	2,968	6,568	7,131	10,035	394	187	621	57,195
Jul 2015	2,843	7,467	4,301	6,503	3,127	9,098	3,100	7,015	7,556	10,861	429	203	478	62,025
Aug 2015	2,729	7,142	4,075	5,948	3,012	8,756	3,033	6,733	7,297	10,046	390	193	401	58,953
Sep 2015	2,272	6,406	3,535	5,134	2,691	7,653	2,848	6,063	6,657	9,044	346	177	905	51,921
Oct 2015	1,644	4,822	2,724	3,619	2,288	5,960	2,695	4,699	5,929	6,816	250	159	1,380	40,225
Nov 2015	1,608	4,969	2,815	3,632	2,413	6,159	2,829	4,619	6,449	6,517	220	177	617	41,790
Dec 2015	1,848	5,848	3,328	4,140	2,701	6,906	3,076	5,394	7,322	7,124	236	205	620	47,508

Table B-5

MONTHLY PEAK FORECAST (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	WESTERN DIVERSITY	PJM WESTERN	WESTERN DIVERSITY (w/ EKPC)	PJM WESTERN (w/EKPC)	DOM	INTER REGION DIVERSITY	PJM RTO	INTER REGION DIVERSITY (w/ EKPC)	PJM RTO (w/ EKPC)
Jan 2013	22,955	8,558	10,627	15,705	2,867	4,397	2,188	2,329	1,061	66,236	1,247	68,379	17,311	1,469	128,735	1,537	130,810
Feb 2013	22,267	8,270	10,401	15,186	2,772	4,229	2,117	2,238	1,091	64,151	1,328	66,152	16,663	1,946	123,745	1,889	125,803
Mar 2013	20,356	7,474	9,870	13,966	2,498	3,809	2,000	1,816	1,485	58,488	1,511	60,278	14,562	1,663	111,597	1,601	113,449
Apr 2013	18,904	6,955	9,519	13,786	2,381	3,752	2,036	1,569	2,276	55,057	2,415	56,487	13,647	2,637	104,213	2,564	105,716
May 2013	19,762	6,967	10,223	16,439	2,690	4,411	2,350	1,500	2,512	60,330	2,503	61,839	15,654	3,725	117,065	3,566	118,733
Jun 2013	22,756	8,213	12,579	20,900	3,212	5,261	2,812	1,801	2,263	73,470	2,339	75,195	18,345	4,359	142,269	4,321	144,032
Jul 2013	23,793	8,661	13,270	22,761	3,442	5,530	2,966	1,910	1,665	78,758	1,721	80,612	19,619	4,397	153,716	4,414	155,553
Aug 2013	23,467	8,440	12,854	22,024	3,356	5,438	2,871	1,899	1,977	76,473	1,974	78,375	19,147	5,462	147,317	5,511	149,170
Sep 2013	21,030	7,578	11,146	18,809	3,002	4,896	2,580	1,754	1,631	67,410	1,936	68,859	16,740	4,414	129,488	4,253	131,098
Oct 2013	18,205	6,640	9,198	13,936	2,368	3,767	1,964	1,553	1,423	54,655	1,640	55,991	13,688	1,692	105,445	1,741	106,732
Nov 2013	19,354	7,126	9,587	14,172	2,457	3,779	1,989	1,784	816	57,648	977	59,271	13,746	734	110,616	852	112,121
Dec 2013	21,885	8,188	10,619	16,033	2,766	4,258	2,187	2,155	900	65,036	1,034	67,057	16,334	1,862	124,869	1,884	126,868

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	DIVERSITY	WESTERN	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO	DIVERSITY	PJM RTO
Jan 2014	23,142	8,658	10,698	16,006	2,894	4,415	2,203	2,335	1,227	66,789	1,416	68,935	17,606	1,505	130,037	1,459	132,229
Feb 2014	22,387	8,360	10,468	15,492	2,800	4,248	2,134	2,247	1,149	64,740	1,381	66,755	16,902	1,992	124,963	1,970	127,000
Mar 2014	20,535	7,576	9,970	14,276	2,538	3,838	2,029	1,827	1,473	59,289	1,532	61,057	14,757	1,262	113,482	1,231	115,281
Apr 2014	19,140	7,075	9,647	14,205	2,442	3,803	2,073	1,579	2,392	55,993	2,500	57,464	13,958	2,065	106,598	2,098	108,036
May 2014	19,941	7,019	10,265	16,774	2,742	4,454	2,380	1,511	2,509	61,066	2,546	62,540	15,970	3,444	118,838	3,313	120,443
Jun 2014	23,136	8,391	12,787	21,513	3,302	5,354	2,864	1,827	2,255	75,092	2,410	76,764	18,711	3,858	145,888	3,679	147,739
Jul 2014	24,190	8,823	13,459	23,343	3,534	5,634	3,021	1,938	1,660	80,344	1,769	82,173	20,154	4,463	156,813	4,388	158,717
Aug 2014	23,697	8,552	12,972	22,488	3,425	5,507	2,911	1,918	1,730	77,822	1,838	79,632	19,532	5,285	149,987	5,080	152,002
Sep 2014	21,494	7,782	11,410	19,340	3,094	5,022	2,634	1,787	1,719	69,057	1,877	70,686	17,246	3,901	133,221	3,867	134,884
Oct 2014	18,522	6,773	9,312	14,407	2,441	3,840	2,004	1,577	1,577	55,722	1,747	57,129	14,103	1,647	107,747	1,766	109,035
Nov 2014	19,678	7,275	9,704	14,595	2,530	3,837	2,023	1,810	958	58,684	1,154	60,298	14,102	826	112,643	855	114,228
Dec 2014	22,365	8,426	10,761	16,464	2,858	4,341	2,227	2,200	969	66,473	1,148	68,494	16,861	1,616	128,167	1,642	130,162

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	DIVERSITY	WESTERN	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO	DIVERSITY	PJM RTO
Jan 2015	23,511	8,838	10,812	16,367	2,974	4,472	2,234	2,358	1,207	68,001	1,411	70,155	18,026	1,282	132,644	1,338	134,742
Feb 2015	22,755	8,542	10,581	15,870	2,880	4,307	2,167	2,275	1,087	66,015	1,308	68,069	17,320	1,761	127,773	1,786	129,802
Mar 2015	21,011	7,786	10,172	14,811	2,631	3,920	2,080	1,864	1,877	60,534	1,812	62,463	15,316	1,469	116,094	1,358	118,134
Apr 2015	19,577	7,260	9,882	14,816	2,547	3,912	2,144	1,607	2,855	57,283	2,943	58,802	14,518	2,227	109,211	2,114	110,843
May 2015	20,286	7,152	10,422	17,315	2,840	4,523	2,431	1,537	2,617	62,352	2,589	63,917	16,467	3,739	121,301	3,564	123,041
Jun 2015	23,627	8,569	13,002	22,185	3,417	5,454	2,929	1,862	2,276	76,907	2,282	78,763	19,309	3,885	149,526	3,883	151,384
Jul 2015	24,668	9,003	13,698	23,995	3,644	5,747	3,083	1,972	1,742	82,096	1,782	84,028	20,747	4,547	160,321	4,584	162,216
Aug 2015	24,199	8,694	13,112	23,141	3,537	5,613	2,968	1,958	1,917	79,347	1,961	81,261	20,147	5,098	153,349	5,087	155,274
Sep 2015	22,062	7,984	11,726	20,010	3,215	5,147	2,700	1,827	1,892	70,952	2,067	72,604	17,860	3,454	137,279	3,522	138,863
Oct 2015	18,774	6,907	9,431	14,900	2,518	3,910	2,044	1,588	1,659	56,825	1,862	58,210	14,527	1,696	109,881	1,739	111,223
Nov 2015	20,106	7,484	9,886	15,116	2,630	3,929	2,069	1,844	1,085	60,135	1,283	61,781	14,765	831	115,859	845	117,491
Dec 2015	22,921	8,641	10,912	16,902	2,949	4,425	2,269	2,244	1,337	67,682	1,530	69,733	17,373	1,487	131,076	1,522	133,092

Table B-6

MONTHLY PEAK FORECAST (MW) FOR
FE-EAST AND PLGRP

	FE_EAST	PLGRP
Jan 2013	9,358	7,485
Feb 2013	9,010	7,198
Mar 2013	8,262	6,437
Apr 2013	7,780	5,863
May 2013	8,939	5,934
Jun 2013	10,968	6,987
Jul 2013	11,984	7,439
Aug 2013	11,290	7,225
Sep 2013	9,894	6,509
Oct 2013	7,955	5,827
Nov 2013	8,275	6,312
Dec 2013	9,287	7,159

	FE_EAST	PLGRP
Jan 2014	9,478	7,562
Feb 2014	9,109	7,273
Mar 2014	8,426	6,528
Apr 2014	7,978	5,972
May 2014	9,131	6,033
Jun 2014	11,242	7,133
Jul 2014	12,258	7,576
Aug 2014	11,542	7,330
Sep 2014	10,176	6,651
Oct 2014	8,166	5,937
Nov 2014	8,485	6,412
Dec 2014	9,576	7,325

	FE_EAST	PLGRP
Jan 2015	9,722	7,693
Feb 2015	9,381	7,427
Mar 2015	8,702	6,666
Apr 2015	8,237	6,096
May 2015	9,384	6,158
Jun 2015	11,583	7,307
Jul 2015	12,565	7,734
Aug 2015	11,845	7,490
Sep 2015	10,457	6,821
Oct 2015	8,380	6,055
Nov 2015	8,765	6,595
Dec 2015	9,846	7,483

Note: FE_EAST contains JCPL, METED and PENLC zones. PLGRP contains PL and UGI zones.

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Table B-7

PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AE																
CONTRACTUALLY INTERRUPTIBLE	142	173	165	165	165	165	165	165	165	165	165	165	165	165	165	165
DIRECT CONTROL	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
TOTAL LOAD MANAGEMENT	178	209	201	201	201	201	201	201	201	201	201	201	201	201	201	201
BGE																
CONTRACTUALLY INTERRUPTIBLE	580	789	596	596	596	596	596	596	596	596	596	596	596	596	596	596
DIRECT CONTROL	505	505	505	505	505	505	505	505	505	505	505	505	505	505	505	505
TOTAL LOAD MANAGEMENT	1,085	1,294	1,101	1,101	1,101	1,101	1,101	1,101	1,101	1,101	1,101	1,101	1,101	1,101	1,101	1,101
DPL																
CONTRACTUALLY INTERRUPTIBLE	246	348	372	372	372	372	372	372	372	372	372	372	372	372	372	372
DIRECT CONTROL	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
TOTAL LOAD MANAGEMENT	292	394	418	418	418	418	418	418	418	418	418	418	418	418	418	418
JCPL																
CONTRACTUALLY INTERRUPTIBLE	297	428	338	338	338	338	338	338	338	338	338	338	338	338	338	338
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	297	428	338	338	338	338	338	338	338	338	338	338	338	338	338	338
METED																
CONTRACTUALLY INTERRUPTIBLE	311	384	335	335	335	335	335	335	335	335	335	335	335	335	335	335
DIRECT CONTROL	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
TOTAL LOAD MANAGEMENT	313	386	337	337	337	337	337	337	337	337	337	337	337	337	337	337
PECO																
CONTRACTUALLY INTERRUPTIBLE	629	772	741	741	741	741	741	741	741	741	741	741	741	741	741	741
DIRECT CONTROL	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
TOTAL LOAD MANAGEMENT	662	805	774	774	774	774	774	774	774	774	774	774	774	774	774	774
PENLC																
CONTRACTUALLY INTERRUPTIBLE	419	412	497	497	497	497	497	497	497	497	497	497	497	497	497	497
DIRECT CONTROL	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
TOTAL LOAD MANAGEMENT	429	422	507	507	507	507	507	507	507	507	507	507	507	507	507	507

Notes:
Forecast represents the amount of Demand Resources cleared in RPM auctions.
Winter load management is equal to Contractually Interruptible.

Table B-7 (Continued)

PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PEPCO																
CONTRACTUALLY INTERRUPTIBLE	478	716	677	677	677	677	677	677	677	677	677	677	677	677	677	677
DIRECT CONTROL	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160
TOTAL LOAD MANAGEMENT	638	876	837	837	837	837	837	837	837	837	837	837	837	837	837	837
PL																
CONTRACTUALLY INTERRUPTIBLE	999	1,262	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	999	1,262	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114
PS																
CONTRACTUALLY INTERRUPTIBLE	1,071	884	698	698	698	698	698	698	698	698	698	698	698	698	698	698
DIRECT CONTROL	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
TOTAL LOAD MANAGEMENT	1,141	954	768	768	768	768	768	768	768	768	768	768	768	768	768	768
RECO																
CONTRACTUALLY INTERRUPTIBLE	33	30	20	20	20	20	20	20	20	20	20	20	20	20	20	20
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	33	30	20	20	20	20	20	20	20	20	20	20	20	20	20	20
UGI																
CONTRACTUALLY INTERRUPTIBLE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM MID-ATLANTIC																
CONTRACTUALLY INTERRUPTIBLE	5,206	6,198	5,550	5,550	5,550	5,550	5,550	5,550	5,550	5,550	5,550	5,550	5,550	5,550	5,550	5,550
DIRECT CONTROL	861	861	861	861	861	861	861	861	861	861	861	861	861	861	861	861
TOTAL LOAD MANAGEMENT	6,067	7,059	6,411	6,411	6,411	6,411	6,411	6,411	6,411	6,411	6,411	6,411	6,411	6,411	6,411	6,411

Table B-7

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AEP																
CONTRACTUALLY INTERRUPTIBLE	1,405	2,016	1,897	1,897	1,897	1,897	1,897	1,897	1,897	1,897	1,897	1,897	1,897	1,897	1,897	1,897
DIRECT CONTROL	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
TOTAL LOAD MANAGEMENT	1,432	2,043	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924
APS																
CONTRACTUALLY INTERRUPTIBLE	643	865	902	902	902	902	902	902	902	902	902	902	902	902	902	902
DIRECT CONTROL	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
TOTAL LOAD MANAGEMENT	644	866	903	903	903	903	903	903	903	903	903	903	903	903	903	903
ATSI																
CONTRACTUALLY INTERRUPTIBLE	493	930	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699	1,699
DIRECT CONTROL	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
TOTAL LOAD MANAGEMENT	494	931	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
COMED																
CONTRACTUALLY INTERRUPTIBLE	874	1,410	1,566	1,566	1,566	1,566	1,566	1,566	1,566	1,566	1,566	1,566	1,566	1,566	1,566	1,566
DIRECT CONTROL	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
TOTAL LOAD MANAGEMENT	946	1,482	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638
DAYTON																
CONTRACTUALLY INTERRUPTIBLE	54	221	187	187	187	187	187	187	187	187	187	187	187	187	187	187
DIRECT CONTROL	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
TOTAL LOAD MANAGEMENT	57	224	190	190	190	190	190	190	190	190	190	190	190	190	190	190
DEOK																
CONTRACTUALLY INTERRUPTIBLE	154	34	258	258	258	258	258	258	258	258	258	258	258	258	258	258
DIRECT CONTROL	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
TOTAL LOAD MANAGEMENT	208	88	312	312	312	312	312	312	312	312	312	312	312	312	312	312
DLCO																
CONTRACTUALLY INTERRUPTIBLE	188	214	236	236	236	236	236	236	236	236	236	236	236	236	236	236
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	188	214	236	236	236	236	236	236	236	236	236	236	236	236	236	236
EKPC																
CONTRACTUALLY INTERRUPTIBLE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
Forecast represents the amount of Demand Resources cleared in RPM auctions.
Winter load management is equal to Contractually Interruptible.

Table B-7 (Continued)

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PJM WESTERN																
CONTRACTUALLY INTERRUPTIBLE	3,810	5,690	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745
DIRECT CONTROL	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159
TOTAL LOAD MANAGEMENT	3,969	5,849	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904
PJM WESTERN with EKPC																
CONTRACTUALLY INTERRUPTIBLE	3,810	5,690	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745
DIRECT CONTROL	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159
TOTAL LOAD MANAGEMENT	3,969	5,849	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904
DOM																
CONTRACTUALLY INTERRUPTIBLE	638	1,244	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,265
DIRECT CONTROL	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
TOTAL LOAD MANAGEMENT	706	1,312	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333
PJM RTO																
CONTRACTUALLY INTERRUPTIBLE	9,654	13,132	13,560	13,560	13,560	13,560	13,560	13,560	13,560	13,560	13,560	13,560	13,560	13,560	13,560	13,560
DIRECT CONTROL	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088
TOTAL LOAD MANAGEMENT	10,742	14,220	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648
PJM RTO with EKPC																
CONTRACTUALLY INTERRUPTIBLE	9,654	13,132	13,560	13,560	13,560	13,560	13,560	13,560	13,560	13,560	13,560	13,560	13,560	13,560	13,560	13,560
DIRECT CONTROL	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088
TOTAL LOAD MANAGEMENT	10,742	14,220	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648

Table B-8

PJM MID-ATLANTIC REGION ENERGY EFFICIENCY PROGRAMS
AND SUM OF ENERGY EFFICIENCY AND LOAD MANAGEMENT - SUMMER (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AE																
ENERGY EFFICIENCY	4	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
LOAD MANAGEMENT	178	209	201	201	201	201	201	201	201	201	201	201	201	201	201	201
TOTAL	182	210	202	202	202	202	202	202	202	202	202	202	202	202	202	202
BGE																
ENERGY EFFICIENCY	74	114	100	100	100	100	100	100	100	100	100	100	100	100	100	100
LOAD MANAGEMENT	1,085	1,294	1,101	1,101	1,101	1,101	1,101	1,101	1,101	1,101	1,101	1,101	1,101	1,101	1,101	1,101
TOTAL	1,159	1,408	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201
DPL																
ENERGY EFFICIENCY	9	10	15	15	15	15	15	15	15	15	15	15	15	15	15	15
LOAD MANAGEMENT	292	394	418	418	418	418	418	418	418	418	418	418	418	418	418	418
TOTAL	301	404	433	433	433	433	433	433	433	433	433	433	433	433	433	433
JCPL																
ENERGY EFFICIENCY	5	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LOAD MANAGEMENT	297	428	338	338	338	338	338	338	338	338	338	338	338	338	338	338
TOTAL	302	430	338	338	338	338	338	338	338	338	338	338	338	338	338	338
METED																
ENERGY EFFICIENCY	24	24	3	3	3	3	3	3	3	3	3	3	3	3	3	3
LOAD MANAGEMENT	313	386	337	337	337	337	337	337	337	337	337	337	337	337	337	337
TOTAL	337	410	340	340	340	340	340	340	340	340	340	340	340	340	340	340
PECO																
ENERGY EFFICIENCY	16	7	14	14	14	14	14	14	14	14	14	14	14	14	14	14
LOAD MANAGEMENT	662	805	774	774	774	774	774	774	774	774	774	774	774	774	774	774
TOTAL	678	812	788	788	788	788	788	788	788	788	788	788	788	788	788	788
PENLC																
ENERGY EFFICIENCY	30	30	3	3	3	3	3	3	3	3	3	3	3	3	3	3
LOAD MANAGEMENT	429	422	507	507	507	507	507	507	507	507	507	507	507	507	507	507
TOTAL	459	452	510	510	510	510	510	510	510	510	510	510	510	510	510	510

Notes:
Energy Efficiency values are impacts approved for use in PJM Reliability Pricing Model.
Load Management details appear in Table B-7.

Table B-8 (Continued)

PJM MID-ATLANTIC REGION ENERGY EFFICIENCY PROGRAMS
AND SUM OF ENERGY EFFICIENCY AND LOAD MANAGEMENT - SUMMER (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PEPCO																
ENERGY EFFICIENCY	54	50	54	54	54	54	54	54	54	54	54	54	54	54	54	54
LOAD MANAGEMENT	638	876	837	837	837	837	837	837	837	837	837	837	837	837	837	837
TOTAL	692	926	891	891	891	891	891	891	891	891	891	891	891	891	891	891
PL																
ENERGY EFFICIENCY	19	16	14	14	14	14	14	14	14	14	14	14	14	14	14	14
LOAD MANAGEMENT	999	1,262	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114
TOTAL	1,018	1,278	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128
PS																
ENERGY EFFICIENCY	26	15	10	10	10	10	10	10	10	10	10	10	10	10	10	10
LOAD MANAGEMENT	1,141	954	768	768	768	768	768	768	768	768	768	768	768	768	768	768
TOTAL	1,167	969	778	778	778	778	778	778	778	778	778	778	778	778	778	778
RECO																
ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LOAD MANAGEMENT	33	30	20	20	20	20	20	20	20	20	20	20	20	20	20	20
TOTAL	33	30	20	20	20	20	20	20	20	20	20	20	20	20	20	20
UGI																
ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LOAD MANAGEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM MID-ATLANTIC																
ENERGY EFFICIENCY	261	268	215	215	215	215	215	215	215	215	215	215	215	215	215	215
LOAD MANAGEMENT	6,067	7,059	6,411	6,411	6,411	6,411	6,411	6,411	6,411	6,411	6,411	6,411	6,411	6,411	6,411	6,411
TOTAL	6,328	7,327	6,626	6,626	6,626	6,626	6,626	6,626	6,626	6,626	6,626	6,626	6,626	6,626	6,626	6,626

Table B-8

PJM WESTERN REGION AND PJM SOUTHERN REGION ENERGY EFFICIENCY PROGRAMS
AND SUM OF ENERGY EFFICIENCY AND LOAD MANAGEMENT - SUMMER (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AEP																
ENERGY EFFICIENCY	8	10	206	206	206	206	206	206	206	206	206	206	206	206	206	206
LOAD MANAGEMENT	1,432	2,043	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924
TOTAL	1,440	2,053	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130	2,130
APS																
ENERGY EFFICIENCY	24	26	1	1	1	1	1	1	1	1	1	1	1	1	1	1
LOAD MANAGEMENT	644	866	903	903	903	903	903	903	903	903	903	903	903	903	903	903
TOTAL	668	892	904	904	904	904	904	904	904	904	904	904	904	904	904	904
ATSI																
ENERGY EFFICIENCY	31	33	43	43	43	43	43	43	43	43	43	43	43	43	43	43
LOAD MANAGEMENT	494	931	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
TOTAL	525	964	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743
COMED																
ENERGY EFFICIENCY	493	527	408	408	408	408	408	408	408	408	408	408	408	408	408	408
LOAD MANAGEMENT	946	1,482	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638
TOTAL	1,439	2,009	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046
DAYTON																
ENERGY EFFICIENCY	13	4	2	2	2	2	2	2	2	2	2	2	2	2	2	2
LOAD MANAGEMENT	57	224	190	190	190	190	190	190	190	190	190	190	190	190	190	190
TOTAL	70	228	192	192	192	192	192	192	192	192	192	192	192	192	192	192
DEOK																
ENERGY EFFICIENCY	3	2	5	5	5	5	5	5	5	5	5	5	5	5	5	5
LOAD MANAGEMENT	208	88	312	312	312	312	312	312	312	312	312	312	312	312	312	312
TOTAL	211	90	317	317	317	317	317	317	317	317	317	317	317	317	317	317
DLCO																
ENERGY EFFICIENCY	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
LOAD MANAGEMENT	188	214	236	236	236	236	236	236	236	236	236	236	236	236	236	236
TOTAL	190	218	240	240	240	240	240	240	240	240	240	240	240	240	240	240
EKPC																
ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LOAD MANAGEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
Energy Efficiency values are impacts approved for use in PJM Reliability Pricing Model.
Load Management details appear in Table B-7.

Table B-8 (Continued)

PJM WESTERN REGION AND PJM SOUTHERN REGION ENERGY EFFICIENCY PROGRAMS
AND SUM OF ENERGY EFFICIENCY AND LOAD MANAGEMENT - SUMMER (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PJM WESTERN																
ENERGY EFFICIENCY	573	605	669	669	669	669	669	669	669	669	669	669	669	669	669	669
LOAD MANAGEMENT	3,969	5,849	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904
TOTAL	4,542	6,454	7,573	7,573	7,573	7,573	7,573	7,573	7,573	7,573	7,573	7,573	7,573	7,573	7,573	7,573
PJM WESTERN with EKPC																
ENERGY EFFICIENCY	573	605	669	669	669	669	669	669	669	669	669	669	669	669	669	669
LOAD MANAGEMENT	3,969	5,849	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904
TOTAL	4,542	6,454	7,573	7,573	7,573	7,573	7,573	7,573	7,573	7,573	7,573	7,573	7,573	7,573	7,573	7,573
DOM																
ENERGY EFFICIENCY	7	51	7	7	7	7	7	7	7	7	7	7	7	7	7	7
LOAD MANAGEMENT	706	1,312	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333
TOTAL	713	1,363	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340
PJM RTO																
ENERGY EFFICIENCY	841	924	891	891	891	891	891	891	891	891	891	891	891	891	891	891
LOAD MANAGEMENT	10,742	14,220	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648
TOTAL	11,583	15,144	15,539	15,539	15,539	15,539	15,539	15,539	15,539	15,539	15,539	15,539	15,539	15,539	15,539	15,539
PJM RTO with EKPC																
ENERGY EFFICIENCY	841	924	891	891	891	891	891	891	891	891	891	891	891	891	891	891
LOAD MANAGEMENT	10,742	14,220	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648	14,648
TOTAL	11,583	15,144	15,539	15,539	15,539	15,539	15,539	15,539	15,539	15,539	15,539	15,539	15,539	15,539	15,539	15,539

Table B-9

ADJUSTMENTS TO SUMMER PEAK LOAD (MW) FOR
EACH PJM ZONE AND RTO
2013 - 2028

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BGE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JCPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
METED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PENLC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PEPCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UGI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AEP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
APS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ATSI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DAYTON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEOK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DLCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM RTO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM RTO with EKPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
Adjustment values presented here are reflected in Tables B-1 through B-6 and Tables B-10, B-11 and B12.
Adjustments are large, unanticipated load changes deemed by PJM to not be captured in the forecast model.

Table B-10

SUMMER COINCIDENT PEAK LOAD (MW) FOR
EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO
2013 - 2028

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AE	2,619	2,671	2,730	2,782	2,812	2,834	2,852	2,874	2,901	2,921	2,942	2,961	2,981	3,000	3,026	3,048
BGE	6,930	7,050	7,182	7,288	7,363	7,422	7,484	7,552	7,616	7,676	7,744	7,806	7,867	7,934	7,999	8,044
DPL	3,981	4,058	4,140	4,212	4,267	4,310	4,358	4,406	4,457	4,502	4,547	4,593	4,633	4,680	4,719	4,758
JCPL	6,012	6,132	6,263	6,381	6,451	6,493	6,546	6,611	6,667	6,757	6,806	6,843	6,891	6,979	7,030	7,105
METED	2,851	2,922	3,000	3,068	3,119	3,160	3,201	3,246	3,291	3,336	3,378	3,420	3,461	3,505	3,551	3,594
PECO	8,380	8,557	8,746	8,908	9,034	9,147	9,252	9,361	9,472	9,565	9,656	9,757	9,844	9,951	10,055	10,147
PENLC	2,780	2,865	2,960	3,044	3,101	3,143	3,195	3,245	3,296	3,343	3,390	3,433	3,476	3,519	3,564	3,606
PEPCO	6,580	6,654	6,731	6,800	6,850	6,892	6,937	6,986	7,032	7,071	7,109	7,152	7,194	7,232	7,274	7,305
PL	6,969	7,105	7,255	7,383	7,480	7,545	7,631	7,712	7,793	7,874	7,952	8,026	8,098	8,171	8,249	8,324
PS	10,168	10,304	10,464	10,600	10,682	10,736	10,803	10,867	10,942	11,009	11,063	11,120	11,185	11,247	11,320	11,367
RECO	401	406	411	416	418	419	421	423	426	427	429	430	432	433	436	437
UGI	187	190	194	198	200	201	203	204	206	208	210	211	212	214	216	217
AEP	22,822	23,211	23,657	24,014	24,256	24,466	24,669	24,874	25,114	25,289	25,503	25,717	25,909	26,118	26,375	26,577
APS	8,301	8,461	8,637	8,786	8,891	8,977	9,059	9,160	9,261	9,350	9,444	9,527	9,612	9,709	9,807	9,903
ATSI	12,730	12,918	13,127	13,295	13,390	13,471	13,553	13,664	13,771	13,851	13,928	14,012	14,097	14,193	14,296	14,385
COMED	21,777	22,349	22,966	23,504	23,892	24,147	24,435	24,756	25,054	25,319	25,583	25,837	26,098	26,398	26,638	26,897
DAYTON	3,273	3,364	3,471	3,556	3,613	3,655	3,700	3,747	3,796	3,839	3,883	3,931	3,976	4,022	4,066	4,107
DEOK	5,275	5,374	5,489	5,565	5,635	5,685	5,739	5,811	5,852	5,905	5,960	6,016	6,071	6,128	6,179	6,227
DLCO	2,832	2,887	2,947	2,996	3,030	3,057	3,080	3,108	3,137	3,163	3,188	3,211	3,236	3,263	3,290	3,310
EKPC	1,826	1,855	1,889	1,920	1,940	1,958	1,975	1,992	2,011	2,028	2,045	2,064	2,078	2,097	2,115	2,132
DOM	18,858	19,385	19,955	20,415	20,787	21,093	21,426	21,770	22,081	22,359	22,679	22,975	23,297	23,602	23,874	24,180
PJM RTO with EKPC	155,552	158,718	162,214	165,131	167,211	168,811	170,519	172,369	174,176	175,792	177,439	179,042	180,648	182,395	184,079	185,670
PJM MID-ATLANTIC	57,858	58,914	60,076	61,080	61,777	62,302	62,883	63,487	64,099	64,689	65,226	65,752	66,274	66,865	67,439	67,952
EASTERN MID-ATLANTIC	31,561	32,128	32,754	33,299	33,664	33,939	34,232	34,542	34,865	35,181	35,443	35,704	35,966	36,290	36,586	36,862
SOUTHERN MID-ATLANTIC	13,510	13,704	13,913	14,088	14,213	14,314	14,421	14,538	14,648	14,747	14,853	14,958	15,061	15,166	15,273	15,349
MID-ATLANTIC and APS	66,159	67,375	68,713	69,866	70,668	71,279	71,942	72,647	73,360	74,039	74,670	75,279	75,886	76,574	77,246	77,855

Notes:
Load values for Zones and Locational Deliverability Areas are coincident with the PJM RTO peak.
Assumes integration of EKPC zone into PJM RTO on 6/1/2013. EKPC load is included in all forecast years.
This table will be used for the Reliability Pricing Model.

Table B-11

PJM CONTROL AREA - JANUARY 2013
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2013 - 2023

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST	134,024	136,625	139,497	141,908	143,589	144,857	146,206	147,683	149,158	150,457	151,757	1.3%
		1.9%	2.1%	1.7%	1.2%	0.9%	0.9%	1.0%	1.0%	0.9%	0.9%	
PJM - SERC with EKPC	21,529	22,092	22,719	23,220	23,622	23,956	24,315	24,685	25,017	25,334	25,682	1.8%
		2.6%	2.8%	2.2%	1.7%	1.4%	1.5%	1.5%	1.3%	1.3%	1.4%	
PJM RTO with EKPC	155,553	158,717	162,216	165,128	167,211	168,813	170,521	172,368	174,175	175,791	177,439	1.3%
		2.0%	2.2%	1.8%	1.3%	1.0%	1.0%	1.1%	1.0%	0.9%	0.9%	

Notes:
Projected PJM seasonal peak load at normal peak weather conditions in the absense of any load reductions due to load management, voltage reductions or voluntary curtailments.
The above forecasts incorporate all load in the PJM Control Area, including members and non-members.
All growth rates are caculated from the first year of the forecast.

Table B-11 (Continued)

PJM CONTROL AREA - JANUARY 2013
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2024 - 2028

	2024	2025	2026	2027	2028	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST	153,045	154,290	155,701	157,108	158,354	1.1%
	0.8%	0.8%	0.9%	0.9%	0.8%	
PJM - SERC with EKPC	25,997	26,357	26,693	26,971	27,317	1.6%
	1.2%	1.4%	1.3%	1.0%	1.3%	
PJM RTO with EKPC	179,042	180,647	182,394	184,079	185,671	1.2%
	0.9%	0.9%	1.0%	0.9%	0.9%	

Table B-12

PJM CONTROL AREA - JANUARY 2013
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2012/13 - 2022/23

	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST	111,170	112,288	114,358	116,464	118,059	118,956	119,754	120,530	121,867	122,957	123,848	1.1%
		1.0%	1.8%	1.8%	1.4%	0.8%	0.7%	0.6%	1.1%	0.9%	0.7%	
PJM - SERC with EKPC	19,640	19,941	20,384	20,874	21,237	21,474	21,729	21,932	22,232	22,484	22,770	1.5%
		1.5%	2.2%	2.4%	1.7%	1.1%	1.2%	0.9%	1.4%	1.1%	1.3%	
PJM RTO with EKPC	130,810	132,229	134,742	137,338	139,296	140,430	141,483	142,462	144,099	145,441	146,618	1.1%
		1.1%	1.9%	1.9%	1.4%	0.8%	0.7%	0.7%	1.1%	0.9%	0.8%	

Notes:
Projected PJM seasonal peak load at normal peak weather conditions in the absense of any load reductions due to load management, voltage reductions or voluntary curtailments.
The above forecasts incorporate all load in the PJM Control Area, including members and non-members.
All growth rates are caculated from the first year of the forecast.

Table B-12 (Continued)

PJM CONTROL AREA - JANUARY 2013
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2023/24 - 2027/28

	23/24	24/25	25/26	26/27	27/28	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST	124,740	125,304	126,535	127,443	128,511	1.0%
	0.7%	0.5%	1.0%	0.7%	0.8%	
PJM - SERC with EKPC	22,990	23,196	23,431	23,700	23,944	1.3%
	1.0%	0.9%	1.0%	1.1%	1.0%	
PJM RTO with EKPC	147,730	148,500	149,966	151,143	152,455	1.0%
	0.8%	0.5%	1.0%	0.8%	0.9%	

Table C-1

PJM LOCATIONAL DELIVERABILITY AREAS
CENTRAL MID-ATLANTIC: BGE, METED, PEPCO, PL and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2013	17,059	24,249	16,761	21,407
2014	17,388	24,639	17,026	21,631
2015	17,689	25,096	17,314	21,956
2016	17,977	25,477	17,551	22,287
2017	18,111	25,743	17,798	22,543
2018	18,256	25,955	18,008	22,719
2019	18,444	26,205	18,163	22,877
2020	18,719	26,448	18,274	23,039
2021	18,909	26,681	18,378	23,236
2022	19,034	26,922	18,647	23,418
2023	19,110	27,135	18,931	23,589
2024	19,449	27,373	19,157	23,757
2025	19,657	27,591	19,287	23,899
2026	19,773	27,816	19,367	24,056
2027	19,894	28,032	19,335	24,240
2028	19,862	28,246	19,732	24,420

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2013	18,545	25,494	18,571	22,586
2014	18,880	25,955	18,877	22,745
2015	19,385	26,426	19,188	23,150
2016	19,607	26,779	19,409	23,464
2017	19,755	27,050	19,672	23,726
2018	20,071	27,306	19,962	23,918
2019	20,193	27,565	20,143	24,079
2020	20,548	27,859	20,218	24,182
2021	20,685	28,105	20,401	24,425
2022	20,872	28,312	20,610	24,619
2023	20,966	28,534	20,840	24,797
2024	21,257	28,811	21,122	24,967
2025	21,494	29,092	21,241	25,053
2026	21,678	29,326	21,396	25,283
2027	21,859	29,548	21,481	25,448
2028	21,914	29,726	21,712	25,629

Table C-2

PJM LOCATIONAL DELIVERABILITY AREAS
WESTERN MID-ATLANTIC: METED, PENLC, PL and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2013	10,492	13,225	10,419	12,942
2014	10,722	13,516	10,667	13,106
2015	10,977	13,855	10,957	13,386
2016	11,199	14,143	11,173	13,676
2017	11,390	14,352	11,319	13,928
2018	11,577	14,495	11,496	14,076
2019	11,751	14,689	11,598	14,225
2020	11,884	14,875	11,783	14,342
2021	12,024	15,047	11,896	14,512
2022	12,143	15,229	12,071	14,686
2023	12,270	15,399	12,209	14,845
2024	12,507	15,559	12,386	14,978
2025	12,626	15,719	12,518	15,089
2026	12,764	15,890	12,662	15,225
2027	12,911	16,052	12,718	15,387
2028	12,989	16,228	12,895	15,554

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2013	10,771	13,848	10,566	13,605
2014	11,012	14,183	10,801	13,683
2015	11,378	14,526	11,044	14,042
2016	11,559	14,786	11,285	14,332
2017	11,723	14,974	11,437	14,615
2018	11,964	15,147	11,648	14,773
2019	12,086	15,370	11,798	14,905
2020	12,306	15,586	11,858	14,934
2021	12,416	15,769	11,977	15,189
2022	12,563	15,909	12,218	15,390
2023	12,675	16,055	12,372	15,549
2024	12,883	16,273	12,586	15,687
2025	13,061	16,477	12,682	15,688
2026	13,204	16,642	12,791	15,921
2027	13,339	16,809	12,831	16,068
2028	13,412	16,913	13,056	16,266

Table C-3

PJM LOCATIONAL DELIVERABILITY AREAS
EASTERN MID-ATLANTIC: AE, DPL, JCPL, PECO, PS and RECO
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2013	18,779	32,622	20,113	22,613
2014	19,126	33,161	20,491	22,839
2015	19,521	33,827	20,732	23,241
2016	19,786	34,382	20,863	23,652
2017	20,087	34,750	21,340	23,979
2018	20,391	35,045	21,878	24,175
2019	20,604	35,351	22,101	24,374
2020	20,826	35,671	21,998	24,520
2021	21,335	35,980	22,042	24,754
2022	21,217	36,298	22,197	24,975
2023	21,327	36,578	22,640	25,169
2024	22,221	36,855	23,205	25,335
2025	22,333	37,140	23,265	25,470
2026	22,439	37,438	23,266	25,650
2027	22,618	37,737	23,296	25,869
2028	22,327	38,056	23,697	26,086

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2013	22,429	34,618	23,139	23,634
2014	22,878	35,288	23,523	23,784
2015	23,675	35,968	23,956	24,210
2016	23,796	36,481	24,268	24,609
2017	23,834	36,868	24,662	25,043
2018	24,418	37,082	25,140	25,235
2019	24,636	37,523	25,345	25,396
2020	25,184	37,940	25,357	25,470
2021	25,386	38,258	25,645	25,705
2022	25,414	38,509	25,788	26,008
2023	25,348	38,809	26,138	26,243
2024	25,931	39,119	26,559	26,403
2025	26,291	39,490	26,586	26,416
2026	26,603	39,786	26,807	26,633
2027	26,825	40,087	27,043	26,813
2028	26,520	40,363	27,301	27,117

Table C-4

PJM LOCATIONAL DELIVERABILITY AREAS
SOUTHERN MID-ATLANTIC: BGE and PEPCO
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2013	8,958	14,020	9,179	11,375
2014	9,104	14,239	9,306	11,472
2015	9,279	14,455	9,366	11,595
2016	9,396	14,586	9,415	11,741
2017	9,423	14,710	9,605	11,849
2018	9,539	14,776	9,763	11,933
2019	9,604	14,936	9,827	11,989
2020	9,754	15,079	9,779	12,059
2021	9,815	15,159	9,836	12,127
2022	9,877	15,259	9,920	12,206
2023	9,852	15,360	10,124	12,280
2024	10,043	15,480	10,223	12,361
2025	10,148	15,601	10,278	12,412
2026	10,231	15,713	10,328	12,460
2027	10,249	15,799	10,257	12,535
2028	10,214	15,891	10,476	12,610

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2013	10,231	14,657	10,483	12,046
2014	10,397	14,874	10,635	12,080
2015	10,646	15,100	10,785	12,276
2016	10,754	15,269	10,848	12,437
2017	10,803	15,412	10,997	12,541
2018	10,931	15,537	11,134	12,618
2019	10,970	15,633	11,212	12,678
2020	11,158	15,776	11,260	12,682
2021	11,226	15,902	11,365	12,843
2022	11,314	15,986	11,398	12,913
2023	11,339	16,110	11,511	12,985
2024	11,468	16,217	11,633	13,054
2025	11,570	16,351	11,688	13,040
2026	11,651	16,458	11,770	13,191
2027	11,737	16,565	11,844	13,258
2028	11,756	16,663	11,901	13,325

Table C-5

PJM LOCATIONAL DELIVERABILITY AREAS
MID-ATLANTIC and APS: AE, APS, BGE, DPL, JCPL, METED, PECO, PENLC, PEPCO, PL, PS, RECO and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2013	44,446	68,311	45,027	55,015
2014	45,582	69,533	45,867	55,522
2015	46,666	70,894	46,722	56,542
2016	47,259	72,049	47,410	57,546
2017	47,772	72,862	48,138	58,500
2018	48,306	73,495	48,815	58,890
2019	48,805	74,176	49,287	59,434
2020	49,792	74,864	49,518	59,801
2021	50,217	75,565	49,847	60,387
2022	50,659	76,269	50,685	61,050
2023	50,823	76,890	51,511	61,580
2024	51,730	77,558	52,196	61,931
2025	52,469	78,152	52,605	62,310
2026	52,928	78,836	52,887	62,784
2027	53,131	79,488	52,676	63,346
2028	53,149	80,117	53,838	63,958

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2013	49,980	71,996	50,898	57,802
2014	51,010	73,373	51,797	58,208
2015	52,249	74,783	52,742	59,421
2016	52,918	75,878	53,502	60,334
2017	53,545	76,742	54,254	61,568
2018	54,312	77,357	55,179	61,939
2019	54,870	78,257	55,695	62,251
2020	55,734	79,038	55,850	62,679
2021	56,344	79,726	56,440	63,217
2022	56,612	80,281	56,992	64,170
2023	57,132	80,971	57,678	64,694
2024	58,039	81,840	58,557	65,057
2025	58,584	82,593	58,787	65,229
2026	59,137	83,242	59,261	65,730
2027	59,666	83,889	59,627	66,218
2028	59,715	84,397	60,301	67,150

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Table D-1

SUMMER EXTREME WEATHER (90/10) PEAK LOAD FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2013 - 2028

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AE	2,889	2,950	3,012	3,059	3,092	3,121	3,137	3,166	3,188	3,207	3,230	3,253	3,278	3,299	3,323	3,347
BGE	7,515	7,643	7,781	7,885	7,968	8,037	8,094	8,172	8,249	8,300	8,374	8,439	8,515	8,581	8,647	8,709
DPL	4,268	4,360	4,445	4,524	4,576	4,629	4,676	4,737	4,788	4,841	4,885	4,932	4,990	5,032	5,076	5,118
JCPL	6,692	6,834	6,976	7,088	7,159	7,183	7,288	7,366	7,430	7,483	7,535	7,600	7,678	7,737	7,800	7,851
METED	3,089	3,172	3,252	3,310	3,365	3,411	3,456	3,513	3,558	3,592	3,639	3,687	3,744	3,788	3,832	3,868
PECO	9,186	9,381	9,593	9,747	9,886	10,009	10,116	10,268	10,376	10,450	10,561	10,664	10,785	10,887	10,988	11,087
PENLC	3,011	3,102	3,200	3,276	3,335	3,378	3,438	3,494	3,543	3,583	3,631	3,679	3,730	3,774	3,815	3,850
PEPCO	7,142	7,232	7,320	7,385	7,444	7,500	7,539	7,604	7,653	7,686	7,736	7,778	7,836	7,878	7,918	7,954
PL	7,543	7,700	7,861	7,984	8,056	8,139	8,255	8,357	8,443	8,508	8,557	8,678	8,771	8,847	8,928	8,959
PS	11,131	11,305	11,478	11,597	11,685	11,675	11,832	11,925	11,997	12,048	12,116	12,185	12,271	12,341	12,410	12,468
RECO	452	459	464	466	470	465	474	478	479	480	482	485	488	490	491	492
UGI	205	209	213	216	218	219	221	223	225	226	228	230	232	233	235	236
DIVERSITY - MID-ATLANTIC(-)	0	25	21	0	0	0	0	29	63	0	0	1	0	0	17	23
PJM MID-ATLANTIC	63,123	64,322	65,574	66,537	67,254	67,766	68,526	69,274	69,866	70,404	70,974	71,609	72,318	72,887	73,446	73,916
FE-EAST	12,792	13,107	13,428	13,674	13,859	13,972	14,182	14,373	14,531	14,658	14,805	14,966	15,152	15,299	15,447	15,569
PLGRP	7,748	7,909	8,073	8,199	8,274	8,358	8,476	8,580	8,667	8,734	8,785	8,907	9,003	9,080	9,163	9,195

Table D-1

SUMMER EXTREME WEATHER (90/10) PEAK LOAD FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2013 - 2028

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AEP	24,747	25,211	25,700	26,095	26,388	26,630	26,796	27,056	27,307	27,567	27,811	27,975	28,229	28,453	28,707	29,027
APS	8,961	9,136	9,322	9,472	9,595	9,702	9,775	9,887	9,993	10,079	10,190	10,275	10,381	10,477	10,581	10,686
ATSI	13,722	13,944	14,180	14,301	14,410	14,530	14,628	14,770	14,860	14,904	14,999	15,128	15,236	15,353	15,450	15,485
COMED	24,313	24,943	25,644	26,215	26,619	26,964	27,227	27,548	27,864	28,131	28,446	28,736	28,993	29,270	29,538	29,891
DAYTON	3,570	3,665	3,780	3,869	3,934	3,985	4,020	4,073	4,123	4,169	4,218	4,263	4,313	4,359	4,407	4,457
DEOK	5,751	5,862	5,983	6,108	6,161	6,231	6,278	6,339	6,403	6,487	6,522	6,569	6,629	6,688	6,748	6,815
DLCO	3,124	3,184	3,248	3,298	3,344	3,379	3,390	3,422	3,451	3,475	3,515	3,529	3,559	3,585	3,610	3,649
EKPC	2,025	2,061	2,098	2,126	2,150	2,175	2,191	2,214	2,233	2,250	2,270	2,292	2,313	2,332	2,350	2,370
DIVERSITY - WESTERN(-)	281	396	557	376	337	450	324	482	472	349	377	327	388	419	422	437
PJM WESTERN	83,907	85,549	87,300	88,982	90,114	90,971	91,790	92,613	93,529	94,463	95,324	96,148	96,952	97,766	98,619	99,573
DIVERSITY - WESTERN with EKPC(-)	343	455	505	378	369	492	366	510	523	399	417	375	430	479	482	482
PJM WESTERN with EKPC	85,870	87,551	89,450	91,106	92,232	93,104	93,939	94,799	95,711	96,663	97,554	98,392	99,223	100,038	100,909	101,898
DOM	20,128	20,691	21,302	21,792	22,184	22,543	22,842	23,210	23,553	23,849	24,192	24,510	24,856	25,167	25,476	25,786
DIVERSITY - INTERREGIONAL(-)	2,886	2,961	2,916	2,942	2,992	2,974	3,134	3,221	3,279	3,179	3,209	3,311	3,443	3,444	3,478	3,352
PJM RTO	164,272	167,601	171,260	174,369	176,560	178,306	180,024	181,876	183,669	185,537	187,281	188,956	190,683	192,376	194,063	195,923
DIVERSITY - INTERREGIONAL with EKPC(-)	2,894	2,974	3,038	3,006	3,049	3,003	3,160	3,263	3,299	3,195	3,235	3,333	3,472	3,455	3,489	3,377
PJM RTO with EKPC	166,227	169,590	173,288	176,429	178,621	180,410	182,147	184,020	185,831	187,721	189,485	191,178	192,925	194,637	196,342	198,223

Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2012/13 - 2027/28

	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28
AE	1,852	1,856	1,893	1,924	1,953	1,957	1,965	1,965	1,986	2,000	2,014	2,020	2,015	2,036	2,042	2,056
BGE	6,276	6,275	6,369	6,448	6,510	6,524	6,537	6,525	6,610	6,655	6,690	6,699	6,672	6,745	6,783	6,827
DPL	3,604	3,617	3,700	3,761	3,806	3,826	3,843	3,858	3,920	3,955	3,988	4,003	4,005	4,058	4,088	4,123
JCPL	4,053	4,076	4,190	4,261	4,325	4,349	4,382	4,396	4,455	4,495	4,531	4,551	4,565	4,616	4,656	4,698
METED	2,716	2,743	2,822	2,883	2,946	2,971	3,001	3,019	3,072	3,120	3,162	3,183	3,196	3,254	3,281	3,334
PECO	6,909	6,969	7,146	7,307	7,461	7,531	7,583	7,621	7,758	7,860	7,960	8,009	8,004	8,131	8,204	8,310
PENLC	2,976	3,018	3,128	3,231	3,324	3,359	3,409	3,434	3,509	3,565	3,628	3,654	3,675	3,742	3,785	3,840
PEPCO	5,771	5,805	5,908	6,003	6,078	6,111	6,141	6,157	6,245	6,302	6,349	6,371	6,368	6,446	6,486	6,545
PL	7,705	7,714	7,897	8,053	8,180	8,226	8,275	8,261	8,418	8,517	8,592	8,624	8,591	8,739	8,803	8,906
PS	7,053	7,085	7,220	7,332	7,397	7,428	7,462	7,463	7,571	7,606	7,648	7,668	7,661	7,754	7,805	7,847
RECO	238	239	240	241	242	243	244	245	246	247	248	249	250	251	251	252
UGI	208	208	212	216	219	219	220	220	223	225	226	227	226	229	230	232
DIVERSITY - MID-ATLANTIC(-)	486	391	503	643	589	567	479	303	653	617	607	558	297	605	626	634
PJM MID-ATLANTIC	48,875	49,214	50,222	51,017	51,852	52,177	52,583	52,861	53,360	53,930	54,429	54,700	54,931	55,396	55,788	56,336
FE-EAST	9,725	9,834	10,081	10,312	10,528	10,665	10,761	10,841	10,979	11,121	11,254	11,371	11,422	11,549	11,663	11,799
PLGRP	7,913	7,922	8,109	8,263	8,383	8,445	8,495	8,481	8,636	8,724	8,795	8,850	8,817	8,966	9,030	9,115

Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2012/13 - 2027/28

	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28
AEP	24,534	24,560	25,222	25,640	25,863	26,014	26,157	26,124	26,644	26,780	26,964	27,089	27,029	27,490	27,741	27,887
APS	9,056	9,152	9,389	9,587	9,746	9,825	9,898	9,958	10,124	10,254	10,361	10,431	10,457	10,628	10,723	10,859
ATSI	11,077	11,086	11,236	11,362	11,449	11,492	11,522	11,501	11,624	11,692	11,715	11,759	11,735	11,852	11,895	11,952
COMED	16,487	16,579	17,033	17,442	17,796	17,922	18,092	18,057	18,397	18,642	18,842	18,953	18,907	19,216	19,385	19,599
DAYTON	3,036	3,066	3,164	3,240	3,280	3,305	3,326	3,344	3,410	3,432	3,470	3,486	3,502	3,565	3,589	3,614
DEOK	4,707	4,713	4,809	4,871	4,899	4,926	4,935	4,943	5,016	5,044	5,071	5,087	5,079	5,147	5,171	5,206
DLCO	2,271	2,273	2,320	2,350	2,368	2,376	2,382	2,385	2,415	2,430	2,443	2,447	2,444	2,476	2,487	2,502
EKPC	2,626	2,632	2,671	2,701	2,720	2,728	2,733	2,735	2,770	2,786	2,800	2,804	2,797	2,829	2,843	2,861
DIVERSITY - WESTERN(-)	1,108	752	925	1,129	1,368	1,352	1,306	918	1,173	1,263	1,441	1,423	1,009	1,182	1,251	1,323
PJM WESTERN	70,060	70,677	72,248	73,363	74,033	74,508	75,006	75,394	76,457	77,011	77,425	77,829	78,144	79,192	79,740	80,296
DIVERSITY - WESTERN with EKPC(-)	1,293	889	1,077	1,290	1,570	1,559	1,504	1,065	1,341	1,547	1,652	1,637	1,176	1,351	1,422	1,613
PJM WESTERN with EKPC	72,501	73,172	74,767	75,903	76,551	77,029	77,541	77,982	79,059	79,513	80,014	80,419	80,774	81,852	82,412	82,867
DOM	18,677	18,826	19,348	19,829	20,293	20,493	20,691	20,762	21,148	21,482	21,800	21,974	21,977	22,338	22,572	22,903
DIVERSITY - INTERREGIONAL(-)	1,769	1,715	823	659	843	838	2,035	1,729	672	895	909	885	1,734	791	781	996
PJM RTO	135,843	137,002	140,995	143,550	145,335	146,340	146,245	147,288	150,293	151,528	152,745	153,618	153,318	156,135	157,319	158,539
DIVERSITY - INTERREGIONAL with EKPC(-)	1,772	1,770	743	695	794	941	2,051	1,837	705	798	911	996	1,817	783	756	842
PJM RTO with EKPC	138,281	139,442	143,594	146,054	147,902	148,758	148,764	149,768	152,862	154,127	155,332	156,097	155,865	158,803	160,016	161,264

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2013 - 2023

	ESTIMATED 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Annual Growth Rate (10 yr)
AE	11,070	11,408	11,597	11,831	12,058	12,153	12,240	12,313	12,435	12,524	12,610	12,692	1.1%
		3.1%	1.7%	2.0%	1.9%	0.8%	0.7%	0.6%	1.0%	0.7%	0.7%	0.7%	
BGE	33,578	34,756	35,250	35,819	36,425	36,677	36,941	37,180	37,571	37,824	38,119	38,401	1.0%
		3.5%	1.4%	1.6%	1.7%	0.7%	0.7%	0.6%	1.1%	0.7%	0.8%	0.7%	
DPL	18,950	19,462	19,765	20,097	20,458	20,644	20,837	21,010	21,275	21,475	21,679	21,870	1.2%
		2.7%	1.6%	1.7%	1.8%	0.9%	0.9%	0.8%	1.3%	0.9%	0.9%	0.9%	
JCPL	23,486	24,416	24,966	25,583	26,196	26,491	26,762	26,998	27,360	27,631	27,918	28,181	1.4%
		4.0%	2.3%	2.5%	2.4%	1.1%	1.0%	0.9%	1.3%	1.0%	1.0%	0.9%	
METED	15,706	16,320	16,731	17,202	17,668	17,927	18,185	18,407	18,747	18,979	19,255	19,504	1.8%
		3.9%	2.5%	2.8%	2.7%	1.5%	1.4%	1.2%	1.8%	1.2%	1.5%	1.3%	
PECO	40,730	42,362	43,347	44,471	45,591	46,262	46,907	47,506	48,279	48,800	49,413	49,976	1.7%
		4.0%	2.3%	2.6%	2.5%	1.5%	1.4%	1.3%	1.6%	1.1%	1.3%	1.1%	
PENLC	18,065	18,857	19,539	20,338	21,098	21,542	21,951	22,321	22,812	23,170	23,580	23,955	2.4%
		4.4%	3.6%	4.1%	3.7%	2.1%	1.9%	1.7%	2.2%	1.6%	1.8%	1.6%	
PEPCO	31,502	32,972	33,373	33,809	34,309	34,526	34,782	35,004	35,363	35,565	35,817	36,043	0.9%
		4.7%	1.2%	1.3%	1.5%	0.6%	0.7%	0.6%	1.0%	0.6%	0.7%	0.6%	
PL	40,769	42,340	43,186	44,175	45,168	45,679	46,200	46,643	47,346	47,772	48,306	48,790	1.4%
		3.9%	2.0%	2.3%	2.2%	1.1%	1.1%	1.0%	1.5%	0.9%	1.1%	1.0%	
PS	45,275	47,248	48,011	48,848	49,705	50,040	50,366	50,656	51,200	51,511	51,890	52,203	1.0%
		4.4%	1.6%	1.7%	1.8%	0.7%	0.7%	0.6%	1.1%	0.6%	0.7%	0.6%	
RECO	1,548	1,562	1,579	1,595	1,617	1,620	1,627	1,629	1,644	1,645	1,656	1,658	0.6%
		0.9%	1.1%	1.0%	1.4%	0.2%	0.4%	0.1%	0.9%	0.1%	0.7%	0.1%	
UGI	1,055	1,075	1,096	1,121	1,145	1,155	1,166	1,178	1,190	1,199	1,211	1,221	1.3%
		1.9%	2.0%	2.3%	2.1%	0.9%	1.0%	1.0%	1.0%	0.8%	1.0%	0.8%	
PJM MID-ATLANTIC	281,734	292,778	298,440	304,889	311,438	314,716	317,964	320,845	325,222	328,095	331,454	334,494	1.3%
		3.9%	1.9%	2.2%	2.1%	1.1%	1.0%	0.9%	1.4%	0.9%	1.0%	0.9%	
FE-EAST	57,257	59,593	61,236	63,123	64,962	65,960	66,898	67,726	68,919	69,780	70,753	71,640	1.9%
		4.1%	2.8%	3.1%	2.9%	1.5%	1.4%	1.2%	1.8%	1.2%	1.4%	1.3%	
PLGRP	41,824	43,415	44,282	45,296	46,313	46,834	47,366	47,821	48,536	48,971	49,517	50,011	1.4%
		3.8%	2.0%	2.3%	2.2%	1.1%	1.1%	1.0%	1.5%	0.9%	1.1%	1.0%	

Notes:
Estimated 2012 includes weather-normalized data through August.
All average growth rates are calculated from the first year of the forecast.

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2024 - 2028

	2024	2025	2026	2027	2028	Annual Growth Rate (15 yr)
AE	12,807	12,848	12,934	13,016	13,146	0.9%
	0.9%	0.3%	0.7%	0.6%	1.0%	
BGE	38,772	38,941	39,211	39,477	39,877	0.9%
	1.0%	0.4%	0.7%	0.7%	1.0%	
DPL	22,114	22,240	22,415	22,577	22,822	1.1%
	1.1%	0.6%	0.8%	0.7%	1.1%	
JCPL	28,495	28,689	28,965	29,243	29,621	1.3%
	1.1%	0.7%	1.0%	1.0%	1.3%	
METED	19,796	20,002	20,267	20,532	20,853	1.6%
	1.5%	1.0%	1.3%	1.3%	1.6%	
PECO	50,657	51,080	51,641	52,201	52,944	1.5%
	1.4%	0.8%	1.1%	1.1%	1.4%	
PENLC	24,380	24,674	25,039	25,399	25,814	2.1%
	1.8%	1.2%	1.5%	1.4%	1.6%	
PEPCO	36,371	36,504	36,710	36,906	37,229	0.8%
	0.9%	0.4%	0.6%	0.5%	0.9%	
PL	49,390	49,736	50,233	50,721	51,350	1.3%
	1.2%	0.7%	1.0%	1.0%	1.2%	
PS	52,601	52,821	53,172	53,520	54,031	0.9%
	0.8%	0.4%	0.7%	0.7%	1.0%	
RECO	1,666	1,669	1,676	1,682	1,692	0.5%
	0.5%	0.2%	0.4%	0.4%	0.6%	
UGI	1,233	1,240	1,248	1,260	1,275	1.1%
	1.0%	0.6%	0.6%	1.0%	1.2%	
PJM MID-ATLANTIC	338,282	340,444	343,511	346,534	350,654	1.2%
	1.1%	0.6%	0.9%	0.9%	1.2%	
FE-EAST	72,671	73,365	74,271	75,174	76,288	1.7%
	1.4%	1.0%	1.2%	1.2%	1.5%	
PLGRP	50,623	50,976	51,481	51,981	52,625	1.3%
	1.2%	0.7%	1.0%	1.0%	1.2%	

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2013 - 2023

	ESTIMATED 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Annual Growth Rate (10 yr)
AEP	136,556	139,064	141,238	143,685	146,142	147,141	148,272	149,182	150,906	151,727	152,946	154,024	1.0%
		1.8%	1.6%	1.7%	1.7%	0.7%	0.8%	0.6%	1.2%	0.5%	0.8%	0.7%	
APS	48,287	50,153	51,092	52,142	53,228	53,727	54,267	54,745	55,523	55,997	56,581	57,121	1.3%
		3.9%	1.9%	2.1%	2.1%	0.9%	1.0%	0.9%	1.4%	0.9%	1.0%	1.0%	
ATSI	68,787	70,733	71,791	72,949	74,098	74,506	74,969	75,300	76,157	76,610	77,142	77,553	0.9%
		2.8%	1.5%	1.6%	1.6%	0.6%	0.6%	0.4%	1.1%	0.6%	0.7%	0.5%	
COMED	101,128	104,931	108,057	111,666	115,207	117,128	118,768	120,211	122,307	123,766	125,434	126,953	1.9%
		3.8%	3.0%	3.3%	3.2%	1.7%	1.4%	1.2%	1.7%	1.2%	1.3%	1.2%	
DAYTON	17,413	17,735	18,278	18,951	19,565	19,897	20,165	20,377	20,750	21,012	21,312	21,579	2.0%
		1.8%	3.1%	3.7%	3.2%	1.7%	1.3%	1.1%	1.8%	1.3%	1.4%	1.3%	
DEOK	27,066	28,112	28,577	29,117	29,666	29,937	30,203	30,426	30,804	31,055	31,343	31,595	1.2%
		3.9%	1.7%	1.9%	1.9%	0.9%	0.9%	0.7%	1.2%	0.8%	0.9%	0.8%	
DLCO	15,078	15,193	15,506	15,858	16,204	16,366	16,521	16,647	16,861	16,988	17,149	17,291	1.3%
		0.8%	2.1%	2.3%	2.2%	1.0%	0.9%	0.8%	1.3%	0.8%	0.9%	0.8%	
EKPC	10,284	10,409	10,524	10,647	10,790	10,844	10,911	10,964	11,070	11,120	11,190	11,254	0.8%
		1.2%	1.1%	1.2%	1.3%	0.5%	0.6%	0.5%	1.0%	0.5%	0.6%	0.6%	
PJM WESTERN	414,315	425,921	434,539	444,368	454,110	458,702	463,165	466,888	473,308	477,155	481,907	486,116	1.3%
		2.8%	2.0%	2.3%	2.2%	1.0%	1.0%	0.8%	1.4%	0.8%	1.0%	0.9%	
PJM WESTERN with EKPC	424,599	436,330	445,063	455,015	464,900	469,546	474,076	477,852	484,378	488,275	493,097	497,370	1.3%
		2.8%	2.0%	2.2%	2.2%	1.0%	1.0%	0.8%	1.4%	0.8%	1.0%	0.9%	
DOM	94,969	97,454	100,194	103,257	106,331	108,107	109,784	111,392	113,464	115,041	116,818	118,510	2.0%
		2.6%	2.8%	3.1%	3.0%	1.7%	1.6%	1.5%	1.9%	1.4%	1.5%	1.4%	
PJM RTO	791,018	816,153	833,173	852,514	871,879	881,525	890,913	899,125	911,994	920,291	930,179	939,120	1.4%
		3.2%	2.1%	2.3%	2.3%	1.1%	1.1%	0.9%	1.4%	0.9%	1.1%	1.0%	
PJM RTO with EKPC	801,302	826,562	843,697	863,161	882,669	892,369	901,824	910,089	923,064	931,411	941,369	950,374	1.4%
		3.2%	2.1%	2.3%	2.3%	1.1%	1.1%	0.9%	1.4%	0.9%	1.1%	1.0%	

Notes:
Estimated 2012 includes weather-normalized data through August.
All average growth rates are calculated from the first year of the forecast.

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2024 - 2028

	2024	2025	2026	2027	2028	Annual Growth Rate (15 yr)
AEP	155,482	156,200	157,394	158,583	160,257	1.0%
	0.9%	0.5%	0.8%	0.8%	1.1%	
APS	57,800	58,191	58,756	59,308	60,061	1.2%
	1.2%	0.7%	1.0%	0.9%	1.3%	
ATSI	78,117	78,441	78,970	79,482	80,156	0.8%
	0.7%	0.4%	0.7%	0.6%	0.8%	
COMED	128,700	129,906	131,427	132,917	134,747	1.7%
	1.4%	0.9%	1.2%	1.1%	1.4%	
DAYTON	21,881	22,102	22,388	22,667	23,012	1.8%
	1.4%	1.0%	1.3%	1.2%	1.5%	
DEOK	31,914	32,098	32,368	32,629	32,988	1.1%
	1.0%	0.6%	0.8%	0.8%	1.1%	
DLCO	17,462	17,562	17,709	17,855	18,052	1.2%
	1.0%	0.6%	0.8%	0.8%	1.1%	
EKPC	11,348	11,382	11,448	11,508	11,611	0.7%
	0.8%	0.3%	0.6%	0.5%	0.9%	
PJM WESTERN	491,356	494,500	499,012	503,441	509,273	1.2%
	1.1%	0.6%	0.9%	0.9%	1.2%	
PJM WESTERN with EKPC	502,704	505,882	510,460	514,949	520,884	1.2%
	1.1%	0.6%	0.9%	0.9%	1.2%	
DOM	120,443	121,730	123,321	124,905	126,950	1.8%
	1.6%	1.1%	1.3%	1.3%	1.6%	
PJM RTO	950,081	956,674	965,844	974,880	986,877	1.3%
	1.2%	0.7%	1.0%	0.9%	1.2%	
PJM RTO with EKPC	961,429	968,056	977,292	986,388	998,488	1.3%
	1.2%	0.7%	1.0%	0.9%	1.2%	

Table E-2

MONTHLY NET ENERGY FORECAST (GWh) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	PJM MID-ATLANTIC
Jan 2013	975	3,250	1,806	2,131	1,507	3,789	1,740	2,989	4,095	4,014	129	108	26,533
Feb 2013	856	2,823	1,579	1,860	1,332	3,326	1,543	2,606	3,589	3,540	112	94	23,260
Mar 2013	863	2,763	1,524	1,894	1,348	3,374	1,598	2,553	3,581	3,674	118	93	23,383
Apr 2013	801	2,468	1,371	1,752	1,236	3,118	1,470	2,348	3,194	3,484	112	80	21,434
May 2013	852	2,578	1,437	1,846	1,275	3,235	1,502	2,481	3,247	3,672	122	80	22,327
Jun 2013	1,003	3,015	1,684	2,144	1,338	3,627	1,488	2,945	3,345	4,192	142	82	25,005
Jul 2013	1,264	3,481	1,982	2,598	1,502	4,218	1,609	3,375	3,738	4,903	168	94	28,932
Aug 2013	1,230	3,401	1,924	2,487	1,478	4,100	1,618	3,270	3,689	4,749	161	91	28,198
Sep 2013	920	2,735	1,542	1,924	1,262	3,338	1,493	2,672	3,239	3,813	129	78	23,145
Oct 2013	856	2,572	1,446	1,864	1,305	3,302	1,565	2,454	3,326	3,711	125	83	22,609
Nov 2013	838	2,603	1,459	1,837	1,289	3,259	1,542	2,444	3,386	3,599	118	88	22,462
Dec 2013	950	3,067	1,708	2,079	1,448	3,676	1,689	2,835	3,911	3,897	126	104	25,490

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2014	984	3,281	1,828	2,164	1,536	3,859	1,789	3,022	4,156	4,059	130	109	26,917
Feb 2014	865	2,852	1,600	1,892	1,358	3,390	1,587	2,635	3,645	3,581	113	95	23,613
Mar 2014	873	2,796	1,546	1,929	1,379	3,448	1,649	2,584	3,649	3,723	119	94	23,789
Apr 2014	815	2,502	1,392	1,792	1,264	3,187	1,520	2,375	3,250	3,536	113	82	21,828
May 2014	866	2,613	1,456	1,887	1,304	3,306	1,553	2,505	3,305	3,725	123	81	22,724
Jun 2014	1,019	3,061	1,709	2,193	1,374	3,712	1,543	2,985	3,419	4,263	144	84	25,506
Jul 2014	1,286	3,539	2,014	2,658	1,546	4,320	1,675	3,417	3,827	4,991	171	96	29,540
Aug 2014	1,249	3,441	1,947	2,531	1,507	4,174	1,668	3,289	3,743	4,798	162	93	28,602
Sep 2014	939	2,785	1,573	1,979	1,300	3,437	1,554	2,714	3,320	3,900	131	81	23,713
Oct 2014	875	2,616	1,472	1,915	1,340	3,389	1,627	2,486	3,400	3,777	126	85	23,108
Nov 2014	855	2,642	1,483	1,883	1,319	3,339	1,597	2,473	3,448	3,659	119	89	22,906
Dec 2014	971	3,122	1,745	2,143	1,504	3,786	1,777	2,888	4,024	3,999	128	107	26,194

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2015	1,000	3,317	1,854	2,210	1,571	3,941	1,851	3,055	4,228	4,109	130	111	27,377
Feb 2015	881	2,894	1,628	1,938	1,395	3,476	1,650	2,675	3,725	3,645	114	97	24,118
Mar 2015	890	2,842	1,574	1,981	1,422	3,547	1,723	2,624	3,744	3,801	121	97	24,366
Apr 2015	834	2,549	1,419	1,843	1,300	3,278	1,585	2,410	3,328	3,604	115	84	22,349
May 2015	886	2,657	1,481	1,938	1,339	3,396	1,617	2,534	3,376	3,790	124	83	23,221
Jun 2015	1,042	3,118	1,741	2,251	1,418	3,817	1,611	3,024	3,513	4,349	146	86	26,116
Jul 2015	1,309	3,594	2,043	2,714	1,585	4,420	1,740	3,451	3,909	5,065	172	98	30,100
Aug 2015	1,273	3,496	1,976	2,588	1,547	4,276	1,733	3,325	3,824	4,873	163	95	29,169
Sep 2015	959	2,828	1,597	2,026	1,336	3,522	1,617	2,740	3,393	3,958	132	83	24,191
Oct 2015	893	2,658	1,494	1,961	1,373	3,473	1,687	2,516	3,465	3,836	127	86	23,569
Nov 2015	874	2,691	1,512	1,933	1,361	3,433	1,667	2,517	3,540	3,730	121	92	23,471
Dec 2015	990	3,175	1,778	2,200	1,555	3,892	1,857	2,938	4,130	4,088	130	109	26,842

Table E-2

MONTHLY NET ENERGY FORECAST (GWh) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	PJM WESTERN	PJM WESTERN (w/ EKPC)	DOM	PJM RTO	PJM RTO (w/ EKPC)
Jan 2013	13,217	4,891	6,371	9,174	1,613	2,519	1,323	1,106	39,108	40,214	9,171	74,812	75,918
Feb 2013	11,551	4,287	5,678	8,094	1,416	2,197	1,169	941	34,392	35,333	7,929	65,581	66,522
Mar 2013	11,577	4,254	5,821	8,349	1,420	2,188	1,219	857	34,828	35,685	7,631	65,842	66,699
Apr 2013	10,471	3,767	5,475	7,851	1,327	2,057	1,149	715	32,097	32,812	6,855	60,386	61,101
May 2013	10,796	3,843	5,665	8,172	1,380	2,164	1,213	735	33,233	33,968	7,244	62,804	63,539
Jun 2013	11,276	3,979	5,795	8,826	1,493	2,475	1,300	837	35,144	35,981	8,540	68,689	69,526
Jul 2013	12,422	4,397	6,450	10,418	1,690	2,793	1,470	934	39,640	40,574	9,625	78,197	79,131
Aug 2013	12,400	4,373	6,420	10,101	1,677	2,751	1,444	928	39,166	40,094	9,394	76,758	77,686
Sep 2013	10,708	3,794	5,584	8,292	1,384	2,214	1,212	748	33,188	33,936	7,750	64,083	64,831
Oct 2013	10,963	3,900	5,756	8,370	1,410	2,180	1,215	734	33,794	34,528	7,233	63,636	64,370
Nov 2013	11,071	4,013	5,645	8,226	1,389	2,151	1,190	829	33,685	34,514	7,354	63,501	64,330
Dec 2013	12,612	4,655	6,073	9,058	1,536	2,423	1,289	1,045	37,646	38,691	8,728	71,864	72,909
	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	WESTERN	WESTERN	DOM	PJM RTO	PJM RTO
Jan 2014	13,383	4,967	6,434	9,375	1,645	2,548	1,343	1,114	39,695	40,809	9,376	75,988	77,102
Feb 2014	11,697	4,357	5,730	8,272	1,444	2,223	1,187	949	34,910	35,859	8,118	66,641	67,590
Mar 2014	11,755	4,333	5,890	8,559	1,455	2,221	1,243	866	35,456	36,322	7,833	67,078	67,944
Apr 2014	10,603	3,828	5,539	8,075	1,365	2,088	1,172	722	32,670	33,392	7,055	61,553	62,275
May 2014	10,931	3,900	5,731	8,407	1,419	2,195	1,236	742	33,819	34,561	7,444	63,987	64,729
Jun 2014	11,455	4,054	5,893	9,106	1,540	2,518	1,328	846	35,894	36,740	8,771	70,171	71,017
Jul 2014	12,662	4,488	6,572	10,771	1,750	2,847	1,504	945	40,594	41,539	9,895	80,029	80,974
Aug 2014	12,524	4,430	6,472	10,343	1,717	2,782	1,468	935	39,736	40,671	9,611	77,949	78,884
Sep 2014	10,913	3,877	5,684	8,582	1,436	2,263	1,241	759	33,996	34,755	8,005	65,714	66,473
Oct 2014	11,142	3,977	5,842	8,658	1,461	2,220	1,243	743	34,543	35,286	7,470	65,121	65,864
Nov 2014	11,228	4,088	5,714	8,478	1,434	2,186	1,213	839	34,341	35,180	7,587	64,834	65,673
Dec 2014	12,945	4,793	6,290	9,431	1,612	2,486	1,328	1,064	38,885	39,949	9,029	74,108	75,172
	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	WESTERN	WESTERN	DOM	PJM RTO	PJM RTO
Jan 2015	13,564	5,056	6,500	9,625	1,690	2,582	1,366	1,125	40,383	41,508	9,622	77,382	78,507
Feb 2015	11,912	4,452	5,816	8,536	1,492	2,263	1,213	960	35,684	36,644	8,364	68,166	69,126
Mar 2015	12,001	4,434	6,005	8,881	1,516	2,268	1,274	878	36,379	37,257	8,092	68,837	69,715
Apr 2015	10,795	3,913	5,628	8,365	1,420	2,131	1,200	732	33,452	34,184	7,302	63,103	63,835
May 2015	11,097	3,970	5,819	8,703	1,474	2,236	1,264	749	34,563	35,312	7,682	65,466	66,215
Jun 2015	11,687	4,145	6,012	9,456	1,606	2,575	1,362	857	36,843	37,700	9,046	72,005	72,862
Jul 2015	12,855	4,568	6,669	11,094	1,810	2,898	1,536	955	41,430	42,385	10,170	81,700	82,655
Aug 2015	12,722	4,510	6,567	10,667	1,777	2,835	1,500	946	40,578	41,524	9,886	79,633	80,579
Sep 2015	11,079	3,950	5,771	8,865	1,489	2,299	1,269	766	34,722	35,488	8,238	67,151	67,917
Oct 2015	11,297	4,045	5,918	8,932	1,511	2,257	1,269	750	35,229	35,979	7,699	66,497	67,247
Nov 2015	11,443	4,184	5,821	8,778	1,490	2,232	1,243	850	35,191	36,041	7,843	66,505	67,355
Dec 2015	13,233	4,915	6,423	9,764	1,676	2,541	1,362	1,079	39,914	40,993	9,313	76,069	77,148

Table E-3

MONTHLY NET ENERGY FORECAST (GWh) FOR FE-EAST AND PLGRP

	FE_EAST	PLGRP
Jan 2013	5,378	4,203
Feb 2013	4,735	3,683
Mar 2013	4,840	3,674
Apr 2013	4,458	3,274
May 2013	4,623	3,327
Jun 2013	4,970	3,427
Jul 2013	5,709	3,832
Aug 2013	5,583	3,780
Sep 2013	4,679	3,317
Oct 2013	4,734	3,409
Nov 2013	4,668	3,474
Dec 2013	5,216	4,015

	FE_EAST	PLGRP
Jan 2014	5,489	4,265
Feb 2014	4,837	3,740
Mar 2014	4,957	3,743
Apr 2014	4,576	3,332
May 2014	4,744	3,386
Jun 2014	5,110	3,503
Jul 2014	5,879	3,923
Aug 2014	5,706	3,836
Sep 2014	4,833	3,401
Oct 2014	4,882	3,485
Nov 2014	4,799	3,537
Dec 2014	5,424	4,131

	FE_EAST	PLGRP
Jan 2015	5,632	4,339
Feb 2015	4,983	3,822
Mar 2015	5,126	3,841
Apr 2015	4,728	3,412
May 2015	4,894	3,459
Jun 2015	5,280	3,599
Jul 2015	6,039	4,007
Aug 2015	5,868	3,919
Sep 2015	4,979	3,476
Oct 2015	5,021	3,551
Nov 2015	4,961	3,632
Dec 2015	5,612	4,239

Note: FE_EAST contains JCPL, METED and PENLC zones. PLGRP contains PL and UGI zones.

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Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

SUMMER

YEAR	NORMALIZED BASE	NORMALIZED COOLING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
1998				131,726	Tuesday, July 21, 1998	17:00
1999	88,933			139,685	Friday, July 30, 1999	17:00
2000	90,958			130,098	Wednesday, August 9, 2000	17:00
2001	92,064			149,294	Thursday, August 9, 2001	16:00
2002	92,661			149,009	Thursday, August 1, 2002	17:00
2003	93,576			143,563	Thursday, August 21, 2003	17:00
2004	95,001			137,592	Tuesday, August 3, 2004	17:00
2005	95,677	54,703	150,380	153,384	Tuesday, July 26, 2005	16:00
2006	95,236	57,174	152,410	165,103	Wednesday, August 2, 2006	17:00
2007	96,631	57,479	154,110	160,065	Wednesday, August 8, 2007	16:00
2008	96,918	57,852	154,770	148,803	Monday, June 9, 2008	17:00
2009	94,450	56,550	151,000	143,324	Monday, August 10, 2009	16:00
2010	93,006	58,744	151,750	155,371	Wednesday, July 7, 2010	17:00
2011	93,277	58,523	151,800	163,721	Thursday, July 21, 2011	17:00
2012	92,858	59,547	152,405	156,319	Tuesday, July 17, 2012	17:00

WINTER

YEAR	NORMALIZED BASE	NORMALIZED HEATING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
97/98				102,595	Monday, December 8, 1997	19:00
98/99	88,312			114,330	Tuesday, January 5, 1999	19:00
99/00	89,281			116,717	Thursday, January 27, 2000	20:00
00/01	91,279			116,296	Wednesday, December 20, 2000	19:00
01/02	92,316			110,444	Wednesday, January 2, 2002	19:00
02/03	92,533			127,692	Thursday, January 23, 2003	19:00
03/04	93,704			120,784	Monday, January 26, 2004	19:00
04/05	94,384			129,211	Monday, December 20, 2004	19:00
05/06	94,708	30,262	124,970	125,041	Wednesday, December 14, 2005	19:00
06/07	96,196	29,424	125,620	134,551	Monday, February 5, 2007	20:00
07/08	97,259	30,341	127,600	126,293	Thursday, January 3, 2008	19:00
08/09	96,393	32,147	128,540	131,847	Friday, January 16, 2009	19:00
09/10	93,530	33,140	126,670	123,249	Monday, January 4, 2010	19:00
10/11	91,872	35,128	127,000	130,131	Tuesday, December 14, 2010	19:00
11/12	92,260	35,760	128,020	122,566	Tuesday, January 3, 2012	19:00

Notes:
Normalized values for 2005 - 2012 are calculated by PJM staff using a methodology consistent with the PJM Load Forecast Model.
Normalized base values are calculated by PJM staff using a two-period average of peak loads on non-heating/non-coolong days.
All times are shown in hour ending Eastern Prevailing Time.
All historic peak values reflect the membership of the PJM RTO as January 1, 2012.

Table F-2

PJM RTO HISTORICAL NET ENERGY
(GWH)

YEAR	ENERGY	GROWTH RATE
1998	710,095	1.3%
1999	730,986	2.9%
2000	746,574	2.1%
2001	744,672	-0.3%
2002	771,810	3.6%
2003	770,248	-0.2%
2004	786,656	2.1%
2005	812,839	3.3%
2006	792,659	-2.5%
2007	822,589	3.8%
2008	811,192	-1.4%
2009	770,653	-5.0%
2010	808,853	5.0%
2011	795,160	-1.7%

Note: All historic net energy values reflect the membership of the PJM RTO as January 1, 2012.

Table G-1

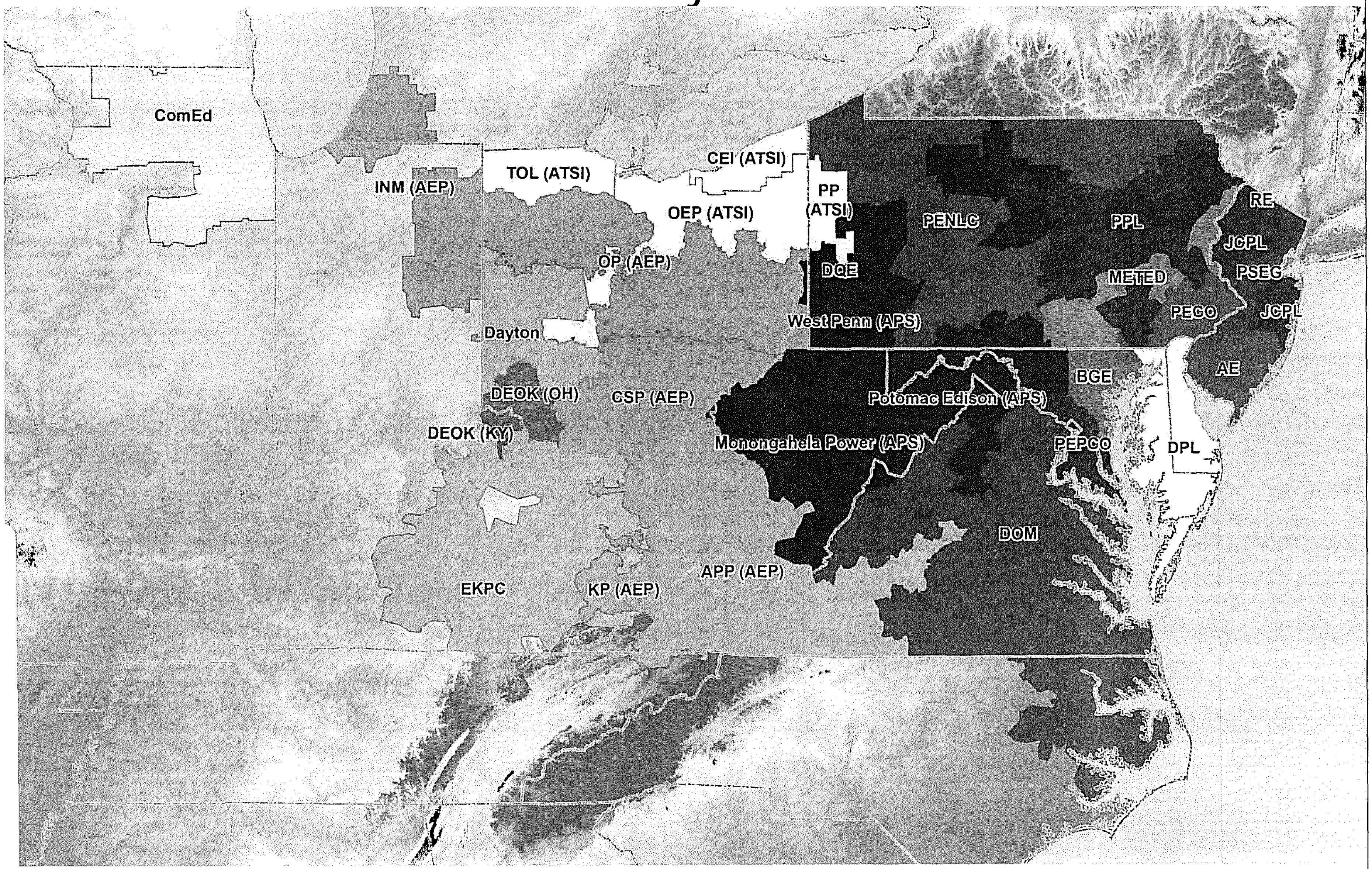
ANNUALIZED AVERAGE GROWTH OF INDEXED ECONOMIC VARIABLE
FOR EACH PJM ZONE AND RTO

	5-Year (2013-18)	10-Year (2013-23)	15-Year (2013-28)
AE	1.8%	1.3%	1.1%
BGE	2.1%	1.7%	1.5%
DPL	2.5%	2.0%	1.8%
JCPL	1.9%	1.4%	1.3%
METED	2.2%	1.8%	1.6%
PECO	2.2%	1.8%	1.6%
PENLC	2.1%	1.7%	1.5%
PEPCO	2.1%	1.7%	1.5%
PL	2.1%	1.7%	1.5%
PS	1.9%	1.5%	1.3%
RECO	1.7%	1.2%	1.1%
UGI	1.4%	1.1%	1.0%
AEP	2.2%	1.7%	1.5%
APS	2.2%	1.8%	1.6%
ATSI	2.1%	1.6%	1.5%
COMED	2.3%	1.8%	1.5%
DAYTON	1.9%	1.4%	1.3%
DEOK	2.1%	1.7%	1.5%
DLCO	2.1%	1.6%	1.4%
EKPC	2.1%	1.7%	1.5%
DOM	2.0%	1.7%	1.5%
PJM RTO	2.1%	1.7%	1.5%

Source: Moody's Analytics, November, 2012

Notes:
Values presented are annualized compound average growth rates.
Indexed economic variable is a combination of U.S. Gross Domestic Product, Gross Metropolitan Product, Real Personal Income, Population, Households, and Non-Manufacturing Employment.

PJM Load Forecast Report
January 2014



Prepared by PJM Resource Adequacy Planning Department

SC - EXHIBIT 17

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TERMS AND ABBREVIATIONS USED IN THIS REPORT

AE	Atlantic Electric zone (part of Pepco Holdings, Inc)
AEP	American Electric Power zone (incorporated 10/1/2004)
APP	Appalachian Power, sub-zone of AEP
APS	Allegheny Power zone (incorporated 4/1/2002)
ATSI	American Transmission Systems, Inc. zone (incorporated 6/1/2011)
Base Load	Average peak load on non-holiday weekdays with no heating or cooling load. Base load is insensitive to weather.
BGE	Baltimore Gas & Electric zone
CEI	Cleveland Electric Illuminating, sub-zone of ATSI
COMED	Commonwealth Edison zone (incorporated 5/1/2004)
Contractually Interruptible	Load Management from customers responding to direction from a control center
Cooling Load	The weather-sensitive portion of summer peak load
CSP	Columbus Southern Power, sub-zone of AEP
Direct Control	Load Management achieved directly by a signal from a control center
DAY	Dayton Power & Light zone (incorporated 10/1/2004)
DEOK	Duke Energy Ohio/Kentucky zone (incorporated 1/1/2012)
DLCO	Duquesne Lighting Company zone (incorporated 1/1/2005)
DOM	Dominion Virginia Power zone (incorporated 5/1/2005)
DPL	Delmarva Power & Light zone (part of Pepco Holdings, Inc)
EKPC	East Kentucky Power Cooperative (incorporated on 6/1/2013)
FE-East	The combination of FirstEnergy's Jersey Central Power & Light, Metropolitan Edison, and Pennsylvania Electric zones (formerly GPU)
Heating Load	The weather-sensitive portion of winter peak load
INM	Indiana Michigan Power, sub-zone of AEP
JCPL	Jersey Central Power & Light zone
KP	Kentucky Power, sub-zone of AEP

METED	Metropolitan Edison zone
MP	Monongahela Power, sub-zone of APS
NERC	North American Electric Reliability Corporation
Net Energy	Net Energy for Load, measured as net generation of main generating units plus energy receipts minus energy deliveries
OEP	Ohio Edison, sub-zone of ATSI
OP	Ohio Power, sub-zone of AEP
PECO	PECO Energy zone
PED	Potomac Edison, sub-zone of APS
PEPCO	Potomac Electric Power zone (part of Pepco Holdings, Inc)
PL	PPL Electric Utilities, sub-zone of PLGroup
PLGroup/PLGRP	Pennsylvania Power & Light zone
PENLC	Pennsylvania Electric zone
PP	Pennsylvania Power, sub-zone of ATSI
PS	Public Service Electric & Gas zone
RECO	Rockland Electric (East) zone (incorporated 3/1/2002)
TOL	Toledo Edison, sub-zone of ATSI
UGI	UGI Utilities, sub-zone of PLGroup
Unrestricted Peak	Peak load prior to any reduction for load management, accelerated energy efficiency or voltage reduction.
WP	West Penn Power, sub-zone of APS
Zone	Areas within the PJM Control Area, as defined in the PJM Reliability Assurance Agreement

2014 PJM LOAD FORECAST REPORT

EXECUTIVE SUMMARY

- This report presents an independent load forecast prepared by PJM staff.

- The report includes long-term forecasts of peak loads, net energy, load management and energy efficiency for each PJM zone, region, locational deliverability area, and the total RTO.

- Included in the report is a second set of E-Tables (net energy), representing an alternate derivation of the forecast using trended RTO monthly load factors.

- All load models were estimated with historical data from January 1998 through August 2013. The models were simulated with weather data from years 1974 through 2012, generating 507 scenarios. The economic forecast used was Moody's Analytics' November 2013 release.

- Revisions to historical economic data and the addition of another year of load experience to the model resulted in generally lower peak and energy forecasts in this year's report, compared to the same year in last year's report. See the Moody's Analytics summary report on economic assumptions on Page 4 for more detail on the economic data revisions and outlook.

- The forecasts of the following zones have been adjusted to account for large, unanticipated load changes (see Table B-9 for details):
    - AEP: the loss of an aluminum smelter decreases the summer peak by 370 MW in all years;
    - APS: rapid expansion of load to serve hydraulic fracturing facilities adds 80-120 MW to the summer peak;
    - BGE: an undisclosed project currently under construction adds 120-315 MW to the summer peak;
    - DOM: substantial on-going growth in data center construction adds 288-896 MW to the summer peak.

- The PJM RTO weather normalized summer peak for 2013 was 155,185 MW. The projection for the 2014 PJM RTO summer peak is 157,399 MW, an increase of 2,214 MW, or 1.4%, from the 2013 normalized peak.

- Summer peak load growth for the PJM RTO is projected to average 1.0% per year over the next 10 years, and 0.9% over the next 15 years. The PJM RTO summer peak is forecasted to be 173,852 MW in 2024, a 10-year increase of 16,453 MW, and reaches 180,137 MW in 2029, a 15-year increase of 22,738 MW. Annualized 10-year growth rates for individual zones range from 0.4% to 1.8%.

- Winter peak load growth for PJM RTO is projected to average 0.9% per year over the next 10-year period, and 0.8% over the next 15-years. The PJM RTO winter peak load in 2023/24 is forecasted to be 144,496 MW, a 10-year increase of 12,777 MW, and reaches 148,423 MW in 2028/29, a 15-year increase of 16,704 MW. Annualized 10-year growth rates for individual zones range from 0.3% to 1.7%.

- Compared to the 2013 Load Report, the 2014 PJM RTO summer peak forecast shows the following changes for three years of interest:
  - The next delivery year – 2014 -1,318 MW (-0.8%)
  - The next RPM auction year – 2017 -2,777 MW (-1.7%)
  - The next RTEP study year – 2019 -3,457 MW (-2.0%)

- Assumptions for future Load Management (LM) have decreased from the 2013 Load Report (from approximately 14,600 MW to 12,400 MW). Energy Efficiency (EE) impacts have decreased from approximately 1,100 MW to 900MW. Assumptions for both LM and EE are based on Reliability Pricing Model (RPM) auction results.

NOTE:
Unless noted otherwise, all peak and energy values are non-coincident, unrestricted peaks, which represent the peak load or net energy prior to reductions for load management or energy efficiency impacts.
All compound growth rates are calculated from the first year of the forecast.

Summary Table

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR PJM RTO AND SELECTED GEOGRAPHIC REGIONS

	METERED 2013	UNRESTRICTED 2013	NORMAL 2013		THIS YEAR 2014	RPM YEAR 2017	RTEP YEAR 2019
PJM RTO	157,141	159,369	155,185		157,399	164,434	167,064
				Growth Rate	1.4%		
Demand Resources + Energy Efficiency					-14,964	-13,320	-13,320
PJM RTO - Restricted					142,435	151,114	153,744
PJM MID-ATLANTIC	59,119	59,580	59,505		60,451	62,875	63,821
				Growth Rate	1.6%		
Demand Resources + Energy Efficiency					-7,187	-5,378	-5,378
MID-ATL - Restricted					53,264	57,497	58,443
EASTERN MID-ATLANTIC	32,519	32,581	32,550		32,941	34,165	34,599
				Growth Rate	1.2%		
Demand Resources + Energy Efficiency					-2,837	-1,968	-1,968
EMAAC - Restricted					30,104	32,197	32,631
SOUTHERN MID-ATLANTIC	13,343	13,571	13,990		14,228	14,772	14,927
				Growth Rate	1.7%		
Demand Resources + Energy Efficiency					-2,256	-1,699	-1,699
SWMAAC - Restricted					11,972	13,073	13,228

Note:
Normal 2013 and all forecast values are non-coincident as estimated by PJM staff.
Except as noted, all values reflect the membership of the PJM RTO as of June 1, 2013.

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December 2013

Bradley Turner, 610-235-5235

Summary of the November 2013 U.S. Macro Forecast

The November U.S. macro forecast was completed as the economy demonstrated resilience to unprecedented fiscal drag. Real GDP growth was tracking at a 1.9% annualized rate in the third quarter, the same as this time last year. The economy was slowing then, but is accelerating now: Output gains averaged just 1.5% through the third quarter in 2013, not including the second revision to third-quarter GDP in December. Job growth also points to an improving labor market, with payroll increases accelerating to an average of 191,000 jobs in the 12 months through November from 183,000 in 2012. As a result, the unemployment rate steadily declined to 7% in November. Slack in the labor market, including high unemployment and low participation, are still suppressing wage increases, however. Weak spending growth in 2012 is accelerating along with the labor market; the 2.1% year-over-year gain in real spending in October was the best reading of the year. The upward trajectory of the economy led the Federal Reserve to announce that it will begin to reduce bond-buying in January.

The pace of growth is solid given that the year has been characterized by the most intense fiscal austerity since the U.S. demobilized after World War II. The economic drag from fiscal policy clipped 1.5 percentage points off GDP in 2013. The year started in the wake of a divisive budget and policy negotiation that raised taxes and failed to avert sequestration, the more than $1.2 trillion in across-the-board spending cuts over 10 years, or raise the nearing debt ceiling. Tax hikes included higher marginal rates on taxpayers making more than $450,000 annually on a joint basis; limits on tax deductions and credits taken by taxpayers making more than $250,000; the expiration of the payroll tax holiday; and somewhat higher capital gains, dividend income, and estate taxes. Higher taxes improved the medium-term budget outlook, but weighed on consumer spending in the first quarter, when GDP grew just 1.3%.

The first phase of budget sequestration went into effect in March, leading the federal government to lay off more workers: Federal employment contracted an average 2.6% per month between March and November, after falling an average 1.5% per month in the previous 12 months. This occurred even though federal agencies were able to mitigate the impact with one-off adjustments to their budgets such as temporary furloughs or zeroing-out unobligated funds that were authorized but not spent. The Defense Department and other federal agencies furloughed civilian employees for six days in July and August, less than initially expected, but still depleting income growth in the third quarter.

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Strife over the Treasury debt ceiling also created economic drag. Congress failed to act on the debt ceiling in January, after the Treasury had already begun extraordinary measures to finance the government. The president suspended the ceiling through May, when a second wave of brinkmanship came to a head in October's 15-day government shutdown. The shutdown idled 400,000 federal employees, plus contractors, and disrupted trade, investment and housing. In mid-October, Congress refunded the government but delayed dealing with the budget and debt ceiling. A two-year budget accord was reached in December, but the debt ceiling will have to be raised in early 2014. Therefore, the perceived threat of government default will loom over consumers and businesses for longer. Budget and policy battles dominated the media for much of the year, continually hurting consumer and business confidence.

The psychological damage created by brinkmanship in Washington impedes risk-taking and expansion. Businesses are more reluctant to invest and hire, and entrepreneurs less likely to attempt startups. Financial institutions are cautious about lending and households are more restrained in spending. These factors contributed to lackluster consumer spending growth, which fell to 1.9% in the first three quarters of 2013 from 2.2% in 2012.

Fiscal drag affected private sector job and income growth less than expected in 2013, however, leading the U.S. economy to exceed expectations on those measures. Final numbers for 2013 are not yet available, but real GDP for the year will come in around 1.8%, according to the November forecast, down slightly from the expected 2% in the December 2012 forecast. Employment gains will finish the year at 1.65%, ahead of expectations for a 1.3% rate of growth. Manufacturing employment, up 0.4%, and nonmanufacturing employment, up 1.4%, beat expectations. Real personal income growth will finish the year at a modest 1.7%, beating expectations of 1.2% growth.

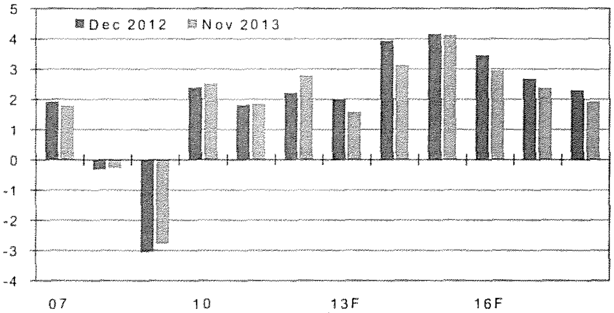
The economy is poised for a promising start to 2014. After a year of gridlock, the government's budget accord in December sets spending levels for fiscal years 2014 and 2015 and replaces $65 billion in spending cuts with $85 billion in other savings spread out over the next 10 years. It also extends planned sequestration cuts by two years through 2023, reducing austerity in exchange for more austerity later. The compromise legislation thus essentially eliminates the drag from sequestration on the U.S. economy for two years, bringing the total drag on GDP growth down to 0.4 percentage point in 2014. In addition, because the deal forms the basis of a budget resolution for this fiscal year and next, it reduces the likelihood of another disruptive government shutdown for the foreseeable future.

Consumers responded positively to the news. While lower-income households remained more cautious, rising stock and house prices buoyed wealth and confidence in higher-income households. Investors are especially upbeat, with stock prices continuing to hit record highs. Businesses are also getting their confidence back, according to the Moody's Analytics weekly survey, which recorded a higher ratio of positive to negative responses than at any time since early 2005.

The principal weight on growth next year will be the expiration of the emergency unemployment insurance program, which will slow GDP growth by 0.15 percentage point. Still, if confidence is sustained and the private sector economy keeps doing what it did in 2013, GDP will rise nearly 3% in 2014 and 4% in 2015.

Political Uncertainty Weighs on Growth in 2013

U.S. real GDP growth, % change



Sources: BEA, Moody's Analytics

Near-Term Outlook and Changes to the Forecast

Between August and December, Moody's Analytics made several changes to the near- and long-term forecasts. In August, new population projections from the Census Bureau were adopted, and then adapted to reflect the Moody's Analytics assumptions about the trajectory of the economic growth in the baseline forecast. The new projections assume weaker international migration and as a result, a slower rate of natural increase in the population. Because population is a fundamental driver of growth, the changes affect many variables in the model. Specifically, the forecast now calls for average population growth of 0.81% between 2013 and 2028, while the December 2012 forecast expected average population gains of 0.94%. This results in about 3 million fewer U.S. residents by 2018, 5 million fewer by 2023, and 7.6 million fewer by 2028. Compared with the late 2012 forecast, the nation is expected to have 1 million fewer households in 2019 and about 2 million fewer in 2028.

In August, comprehensive U.S. National Income and Product Accounts revisions from the Bureau of Economic Analysis were also adopted. These redefine and reclass the accounts to keep them in line with changes in the economy and international reporting conventions. Nominal GDP was raised by 3.6%, or $560 billion, in 2012. This was mainly a result of definitional changes, such as redefining R&D and artistic production as investment. In the past, these were not classified as investments because of concerns about measurement issues. Similarly, some real estate ownership transfer costs were shifted to investment and pension income is now counted as earned by workers as they work rather than when their

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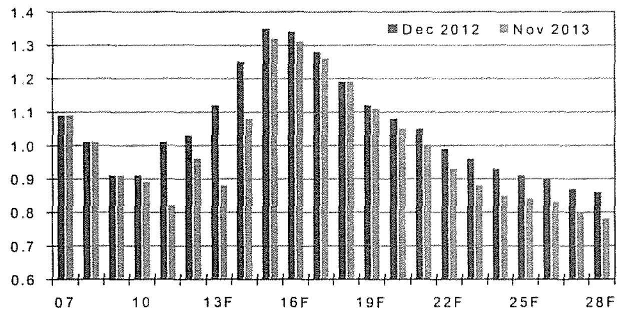
employer puts money in the pension account. This effectively raised income and GDP by the unfunded pension liability of employers. Definitional changes boosted GDP but had little impact on the forecast or patterns of growth, as they are fairly stable over time as a percentage of GDP.

In late September, the BEA released state-level personal income for the second quarter and revised history to incorporate the comprehensive benchmark revisions. History from 2000 onward was revised, and this shifted the near-term forecast as a result. The revisions show that real personal income held up better during the recession and recovered more robustly in the last three years. Over the near term, the income forecast is marginally weaker, especially in nonwage components of income, while in the out years it is significantly weaker. This is largely owing to the new, more subdued population projections, however.

Household Formation to Accelerate Strongly

U.S. household growth, % change



Sources: Census Bureau, Moody's Analytics

Basically unchanged from last year, household formation and home-related economic activity will accelerate over the near term. As the recovery matures and migration into the U.S. and between regions rebounds, household formation will return to a pace consistent with long-run demographics. In particular, the young who delayed forming households because of the weak labor market will do so. Moreover, the young-adult population will expand as more of the echo-boom generation enters adulthood. Finally, the recession put a damper on net immigration, but growth in the foreign-born population is still expected to pick up as the U.S. economy improves relative to others. Rising interest rates dampened housing activity in late 2013 but have not affected the outlook. As fundamentals solidify in 2014, housing construction and price appreciation will also reaccelerate.

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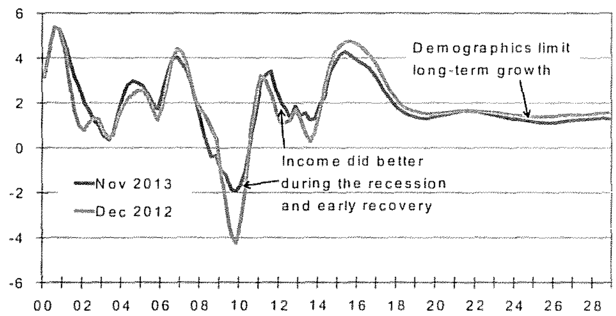
Income Beat Expectations in Early Recovery

Real personal income by forecast, % change yr ago, 3-mo MA



Sources: BEA, Moody's Analytics

Summary of the Forecast for PJM Service Territories

The PJM service territory covers all or parts of 13 states and the District of Columbia, accounting for more than 52 million people, or about a sixth of the U.S. population. The regional economies of the service territory include metro areas in the Midwest, South and Northeast and run the gamut from highly diversified, large economies such as Chicago, to small economies that depend heavily on one industry, such as Elkhart IN.

Overall, the dominant industry in the service territory is education/healthcare. In addition to employing the largest share of the region's workers, about 17%, it was also one of the few industries to add jobs during the recession. Healthcare hiring has held up well in PJM's service territory, despite growing pains associated with the Affordable Care Act, a trend toward consolidation, and cuts to Medicare and Medicaid reimbursements as part of sequestration. Over the longer term, increasing demand from the expanding elderly population will support job gains. Consistent with the historical trend, education- and healthcare-related services will provide the lion's share of new jobs in the forecast period.

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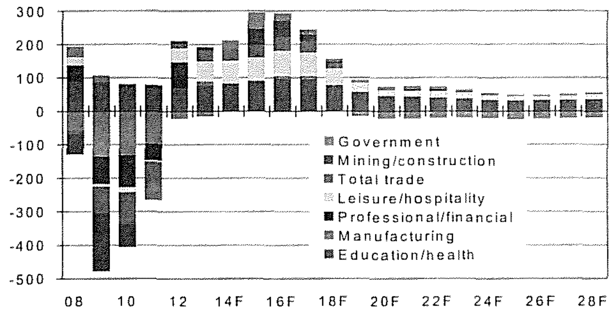
Education/Health Will Drive Job Gains

Employment, difference, ths



Sources: BLS, Moody's Analytics

On average, the concentration of manufacturing in the service territory is roughly in line with the national average, but more than half of the metro areas' economies, mainly smaller old-line manufacturing localities in the Northeast and Midwest, rely more heavily on industrial production for growth. While the public sector has a slightly smaller presence in the service territory than it does nationally, the federal government accounts for a larger share of employment. The public sector is a pillar of the Mid-Atlantic and many southern metro areas in the service territory, including many state capitals, college towns and military-reliant areas. The budget deal struck by Congress in December, which effectively nullifies budget sequestration for two years, improves the outlook but is not included in the November forecast.

Resource and mining represent a small portion of the service territory's economy, but provide significant upside risk, especially in eastern Ohio and western Pennsylvania. The potential for extraction of significant quantities of untapped natural resources offers the possibility of boosting long-term growth in several related industries, including construction, transportation and manufacturing.

Recent Performance

The November 2013 regional forecast was generated in the context of the U.S. macro forecast described above, with fiscal drag and political uncertainty weighing on business investment and hiring. Still, the current estimate is that output growth exceeded expectations in 2013, coming in at 1.9%, compared with a forecast in December 2012 of 1.4%. Total employment growth of 1.1% doubled expectations, with manufacturing contracting less than expected and nonmanufacturing employment growing more strongly. Likewise, real income will rise about 1.1%, compared with expectations last year of 0.6%.

Manufacturing was a net drag on employment in 2013 and added less to output than in 2012. Manufacturing employment contracted modestly between June and October, from a year ago. Manufacturing is an important driver, particularly in many of the territory's Midwest metal-production and auto-related metro areas.

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Overall, the sector benefited from robust growth in auto demand and transportation equipment manufacturing, which added jobs and increased production in 2013. However, some economies suffered job losses this year as tepid demand from abroad weighed on exports and businesses delayed investment spending because of policy uncertainty. The service territory is more exposed to Europe than the rest of the U.S.

The service territory added fewer jobs in percent terms than the nation partly because federal budget cuts pose more of a threat. In PJM's service territory, federal employment did not contract more steeply, but it accounts for 3% of total employment, compared with 2% in the rest of the U.S. The concentration is, of course, much higher in the District of Columbia, Maryland, and Virginia. Moreover, federal workers earn more in the Mid-Atlantic than elsewhere in the country. In Maryland, for example, federal workers earn about $92,000 annually on average, compared with about $73,000 in the rest of the U.S. Therefore, federal layoffs do more damage to incomes.

Pennsylvania and Ohio account for a substantial portion of PJM's customers, and saw employment gains slow this year. In Ohio, manufacturing cooled off after outperforming through late 2012 and early 2013. Steel production has hit a soft patch and auto assemblers have cut back on hiring plans. The secular uptrend in healthcare employment has also been stymied as local hospitals adjust to lower expected reimbursement rates. Ohio and Pennsylvania metro areas make up 20% to 25% of the territory's payroll employment. Natural gas prices have rebounded, encouraging investment in shale drilling in the two states.

Near-Term Outlook and Changes to the Forecast

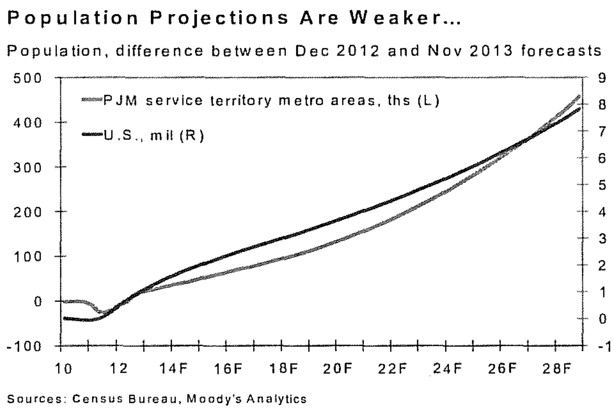
Changes to the near-term outlook for the PJM service territory are similar to those in the U.S. macro forecast. Removing the drags of fiscal policy uncertainty on private business investment and consumer spending will lead to stronger growth in the first half of 2014.

The rebound in manufacturing will be more subdued as businesses deal with slow final demand and concerns over frothy inventories. Manufacturing employment is estimated to fall 0.15% in 2013, beating expectations of a 0.4% fall. Manufacturing will contract slightly in 2014 and enjoy a temporary rebound in 2015 and 2016 before returning to secular decline over the long term. Real GDP in the service territory is forecast to rise 2.3% in 2014 and 3.8% in 2015. Last year, output was projected to grow 3.4% in 2014 and 3.6% in 2015. The forecast calls for employment in the service territory to increase 1.2% in 2014 and 2.3% in 2015, down from the previous forecast of 1.9% in 2014 and 2.5% in 2015.

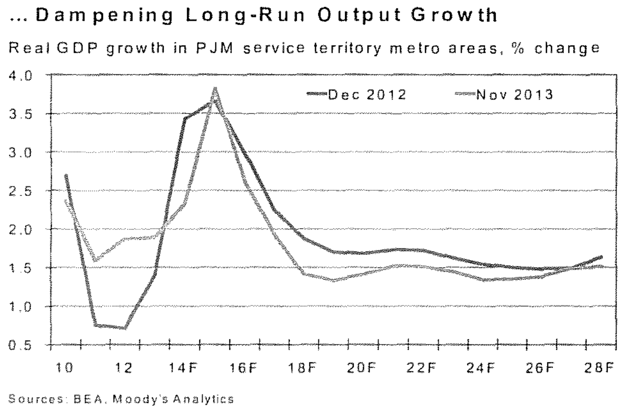
Expectations of weaker short-term growth have to do with federal agencies' response to the first round of budget sequestration cuts this year. Agencies found one-off savings and furloughed employees whenever possible, to avoid more permanent actions, such as layoffs. Having picked the low-hanging fruit, agencies were expected to cut jobs and output more in 2014, when budget cuts were set to escalate. Thus, job and income growth beat expectations in 2013 but was revised down in 2014, reflecting the delayed impact of cuts. After 2015, the impact of this shift disappears. In addition, the November forecast does not take into account the December budget deal, which improves the near-term outlook.

Long-Term Outlook

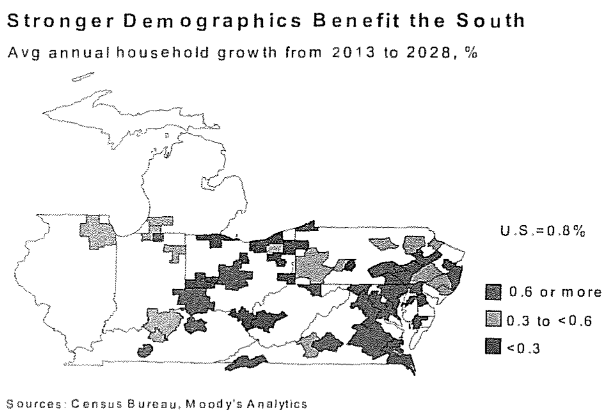
The November 2013 forecast is for weaker long-term growth in metro areas in the PJM service territory than the forecast from December 2012. Growth in key variables—output, employment and households—is somewhat more subdued because of weaker population gains.



For the metro areas in the service territory, the November 2013 forecast is for population to expand 0.4% between 2013 and 2028, down from 0.5% in the December 2012 forecast. This will result in 100,000 fewer residents in 2018, 200,000 fewer in 2022, and 440,000 fewer in 2028. As a result, real GDP growth will average 1.8% in the region out to 2028, compared with the 2% expected last year. Likewise, average annual job growth is forecast at 0.6%, versus 0.8% last year.



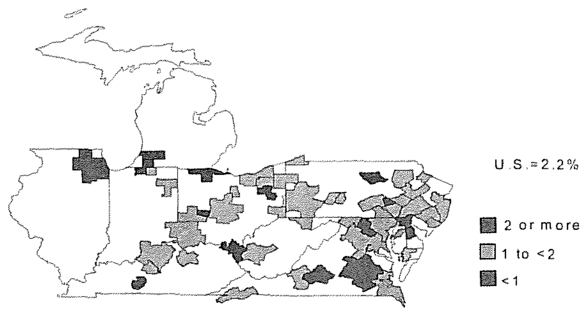
The southernmost metro areas are expected to be among the fastest-growing in the PJM service territory. The biggest comparative advantage for these areas is their favorable demographic trends, which will help boost overall final demand. Despite the weaker long-term forecast, in-migration and household formation will rebound further in 2014 and will drive growth in consumer-based services such as education/healthcare and leisure/hospitality. Virginia metro areas, including Lynchburg and Richmond, as well as Bowling Green KY, are expected to lead with average annual real GDP growth of 2% or more. Relatively low costs will buoy growth in these metro areas. Large metro areas including Chicago and Baltimore and metro areas in the Mid-Atlantic, including Washington DC and those in Delaware, will also outperform the rest of the service area. Aside from favorable demographics, these metro areas will be driven by highly educated labor forces and productivity growth.



Metro areas in Ohio, West Virginia and parts of Pennsylvania will expand more slowly. Expansion in those states will be more restrained as regions transition away from manufacturing toward more service-oriented economies. With lower-value-added services accounting for a larger part of the regional economies, income gains are expected to be more restrained. Weaker demographics will also undermine long-term growth, as workers and their families are expected to seek opportunities in stronger labor markets outside of the slow-growth metro areas in the Midwest and Northeast. Of the 10 areas with the weakest increases in the number of households, seven are in Ohio and three are in West Virginia. The number of households will decline in just three areas, all in Ohio: Youngstown, Cleveland and Mansfield.

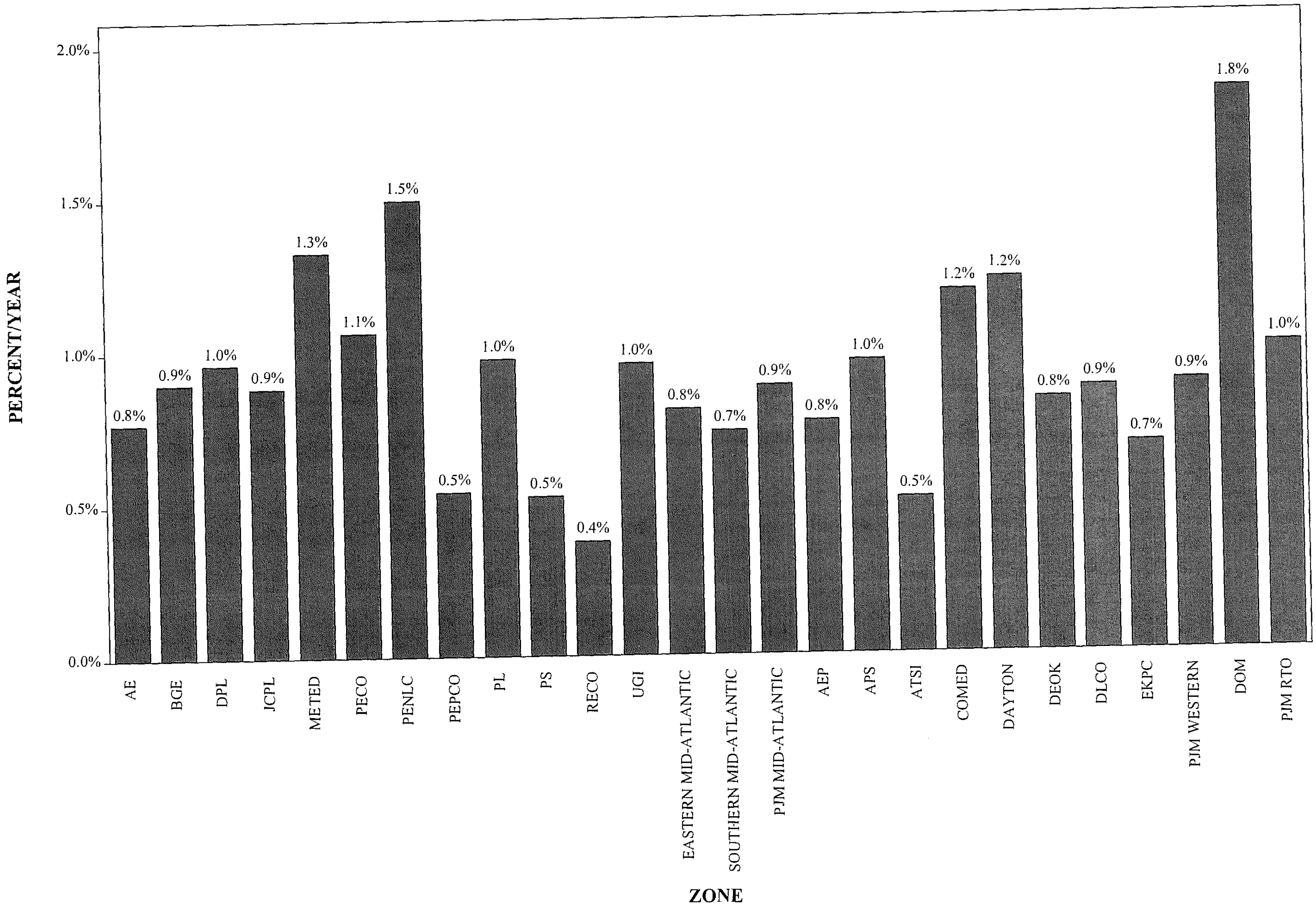
The Service Territory Will Underperform the U.S.

Avg real GDP growth from 2013 to 2028, %

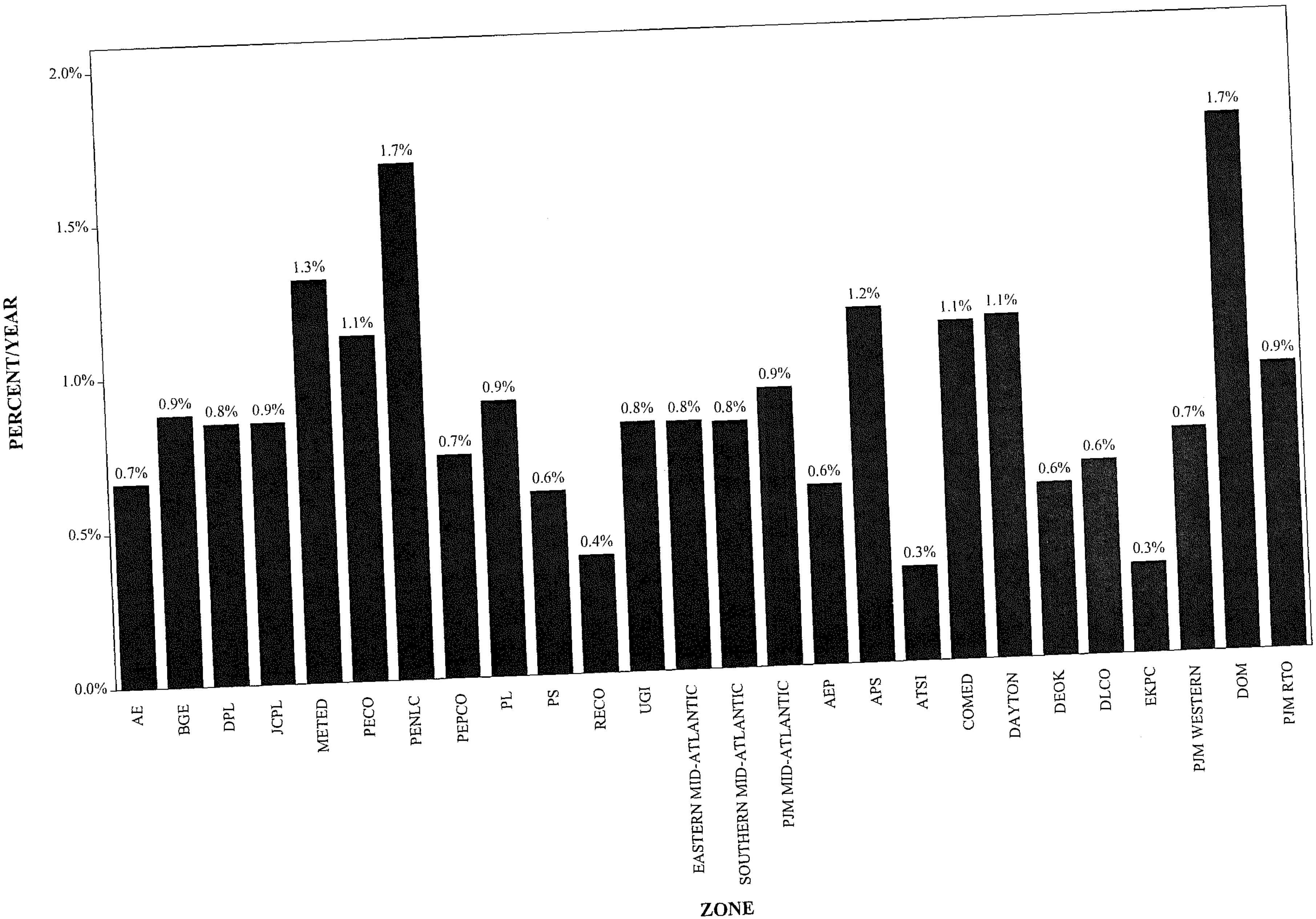


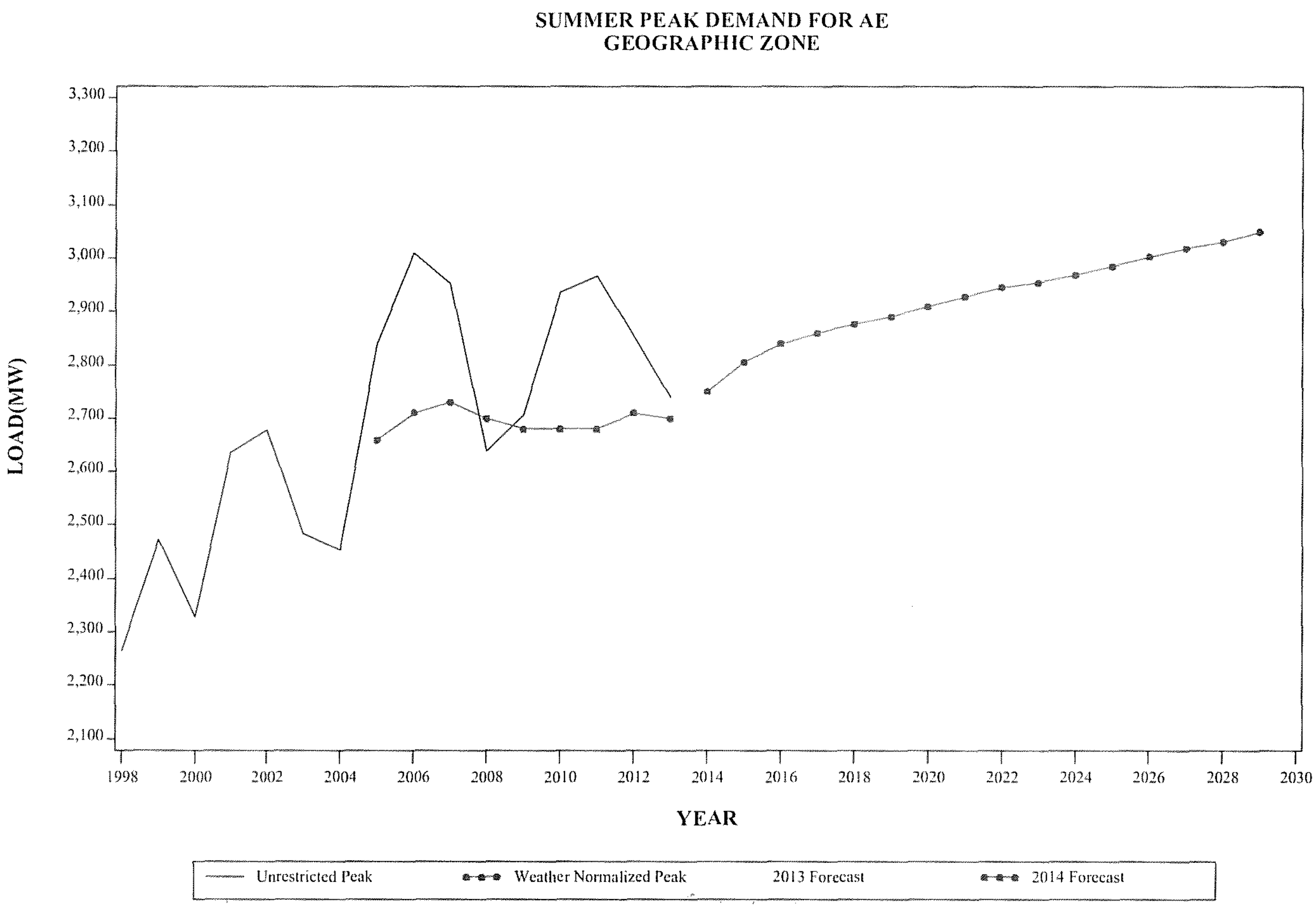
Sources: Census Bureau, Moody's Analytics

PJM SUMMER PEAK LOAD GROWTH RATE
2014 - 2024

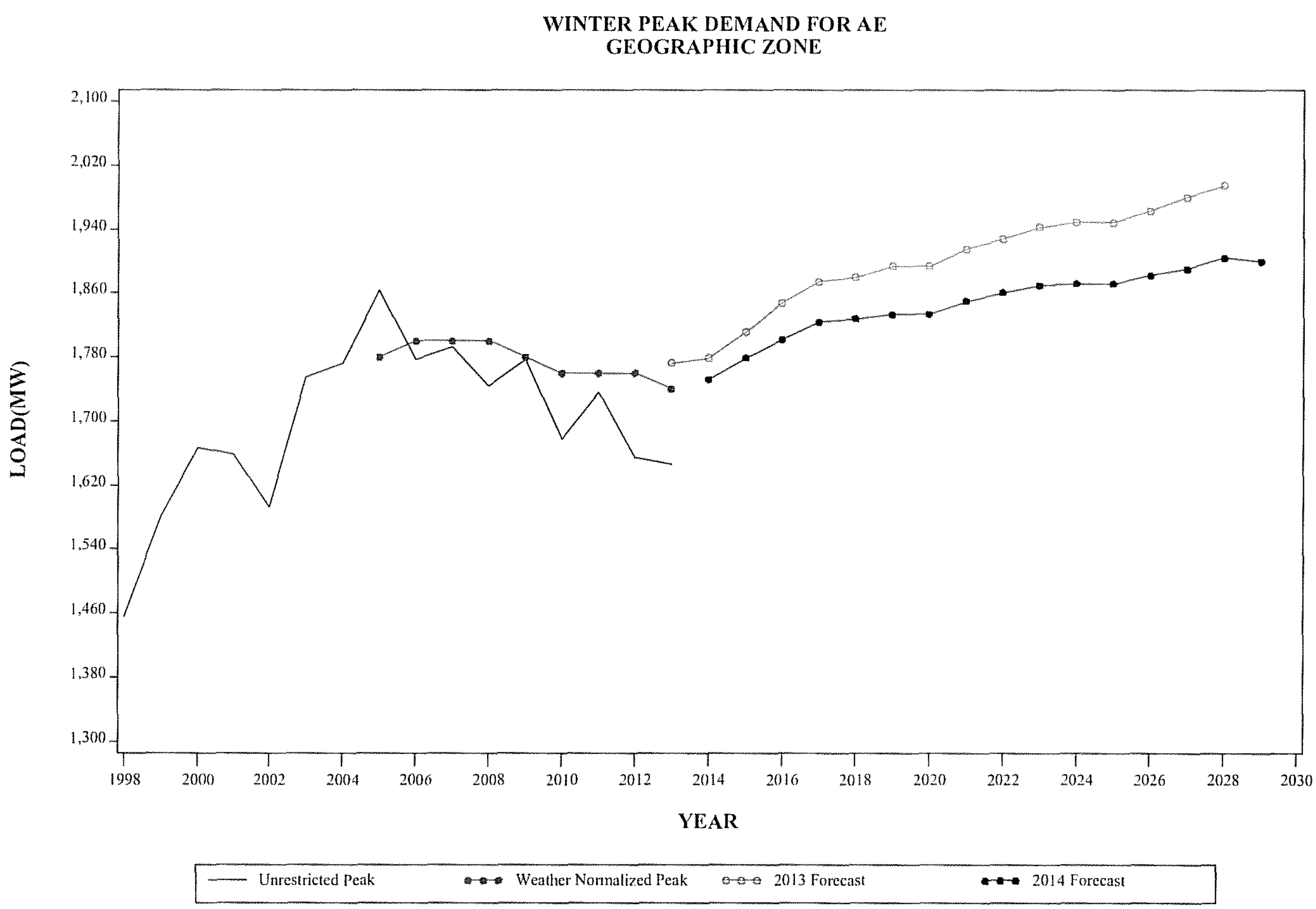


PJM WINTER PEAK LOAD GROWTH RATE
2014 - 2024



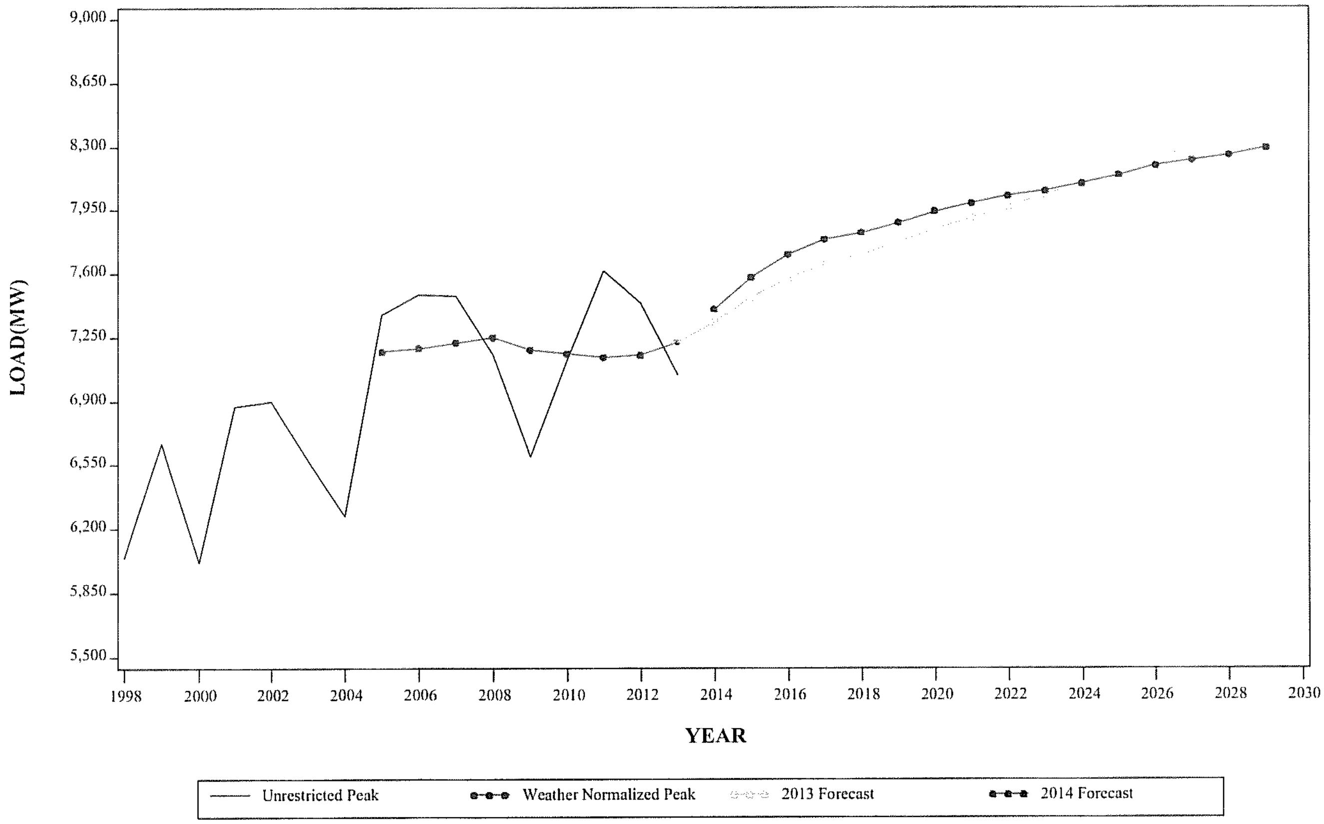


SUMMER PEAK DEMAND FOR AE
GEOGRAPHIC ZONE
LOAD(MW)
3,300
3,200
3,100
3,000
2,900
2,800
2,700
2,600
2,500
2,400
2,300
2,200
2,100
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
YEAR
Unrestricted Peak
Weather Normalized Peak
2013 Forecast
2014 Forecast

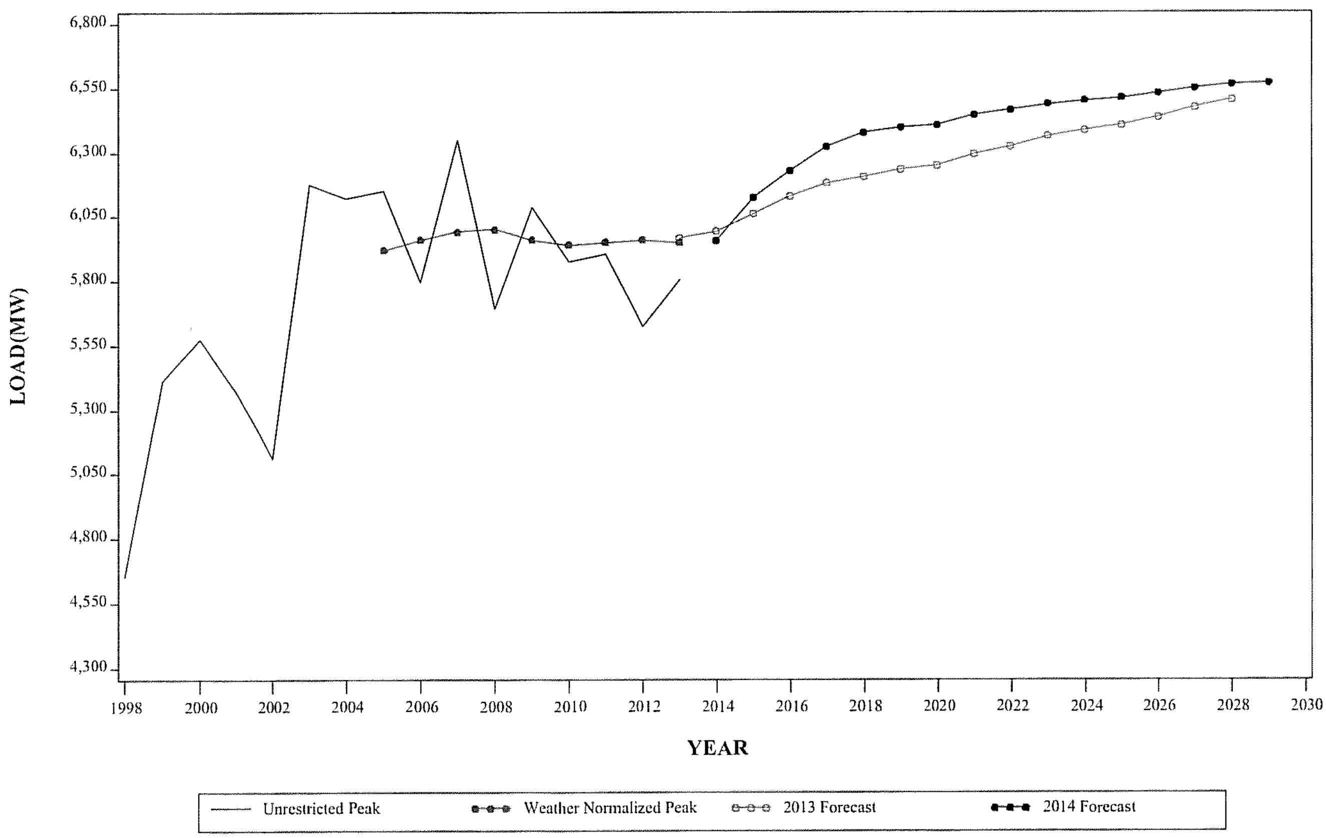


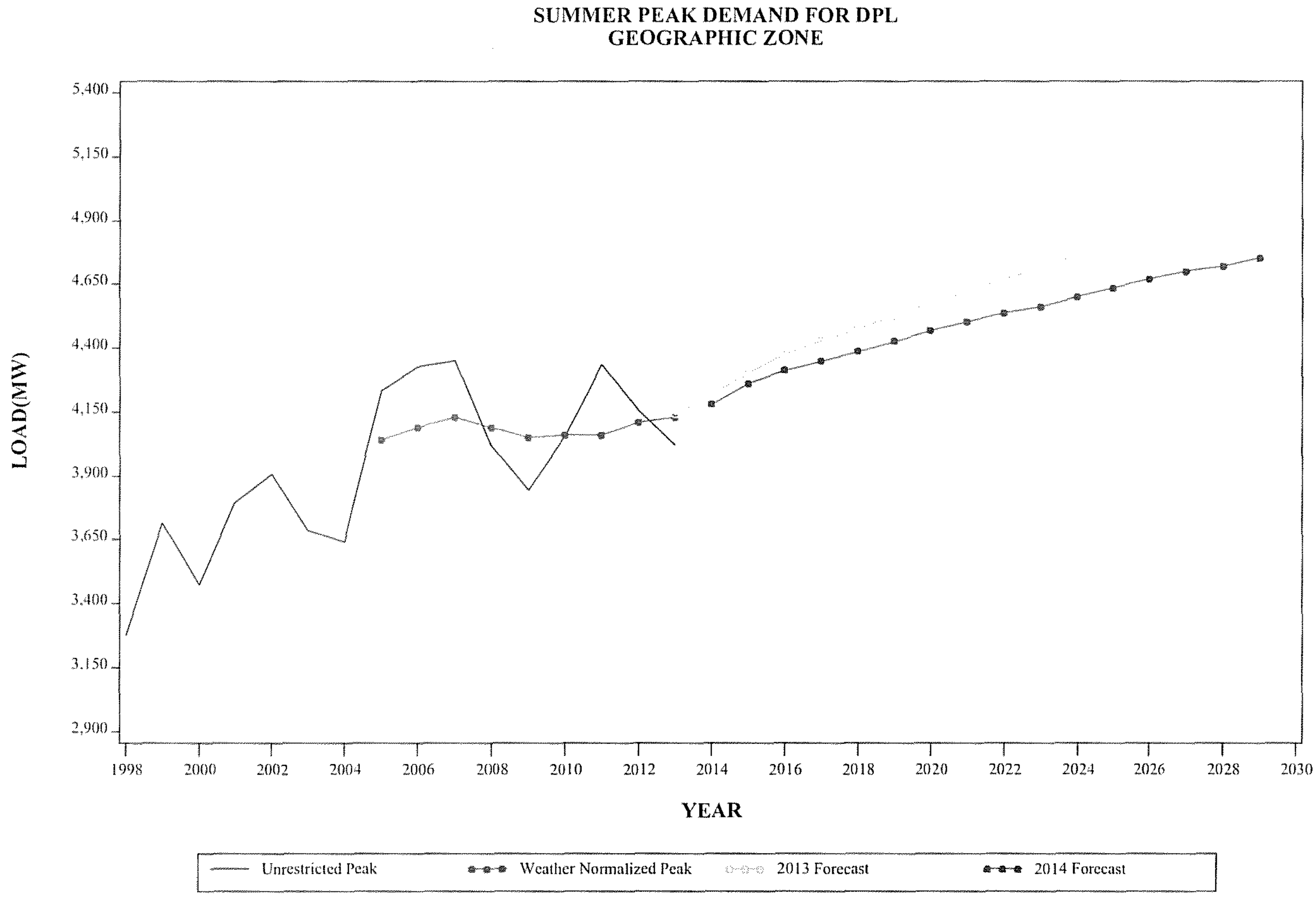
WINTER PEAK DEMAND FOR AE
GEOGRAPHIC ZONE
LOAD(MW)
2,100
2,020
1,940
1,860
1,780
1,700
1,620
1,540
1,460
1,380
1,300
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
YEAR
Unrestricted Peak
Weather Normalized Peak
2013 Forecast
2014 Forecast

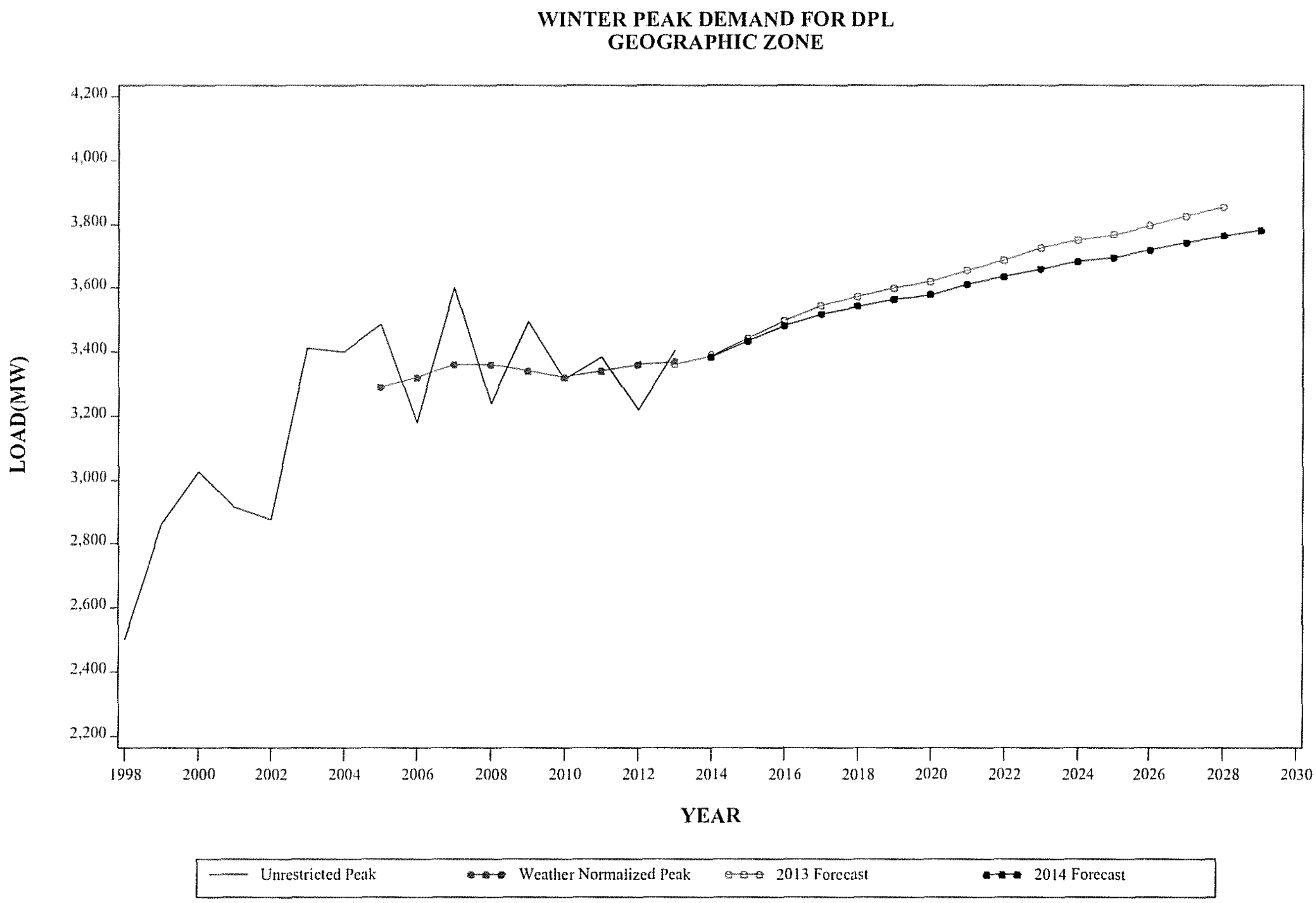
SUMMER PEAK DEMAND FOR BGE GEOGRAPHIC ZONE



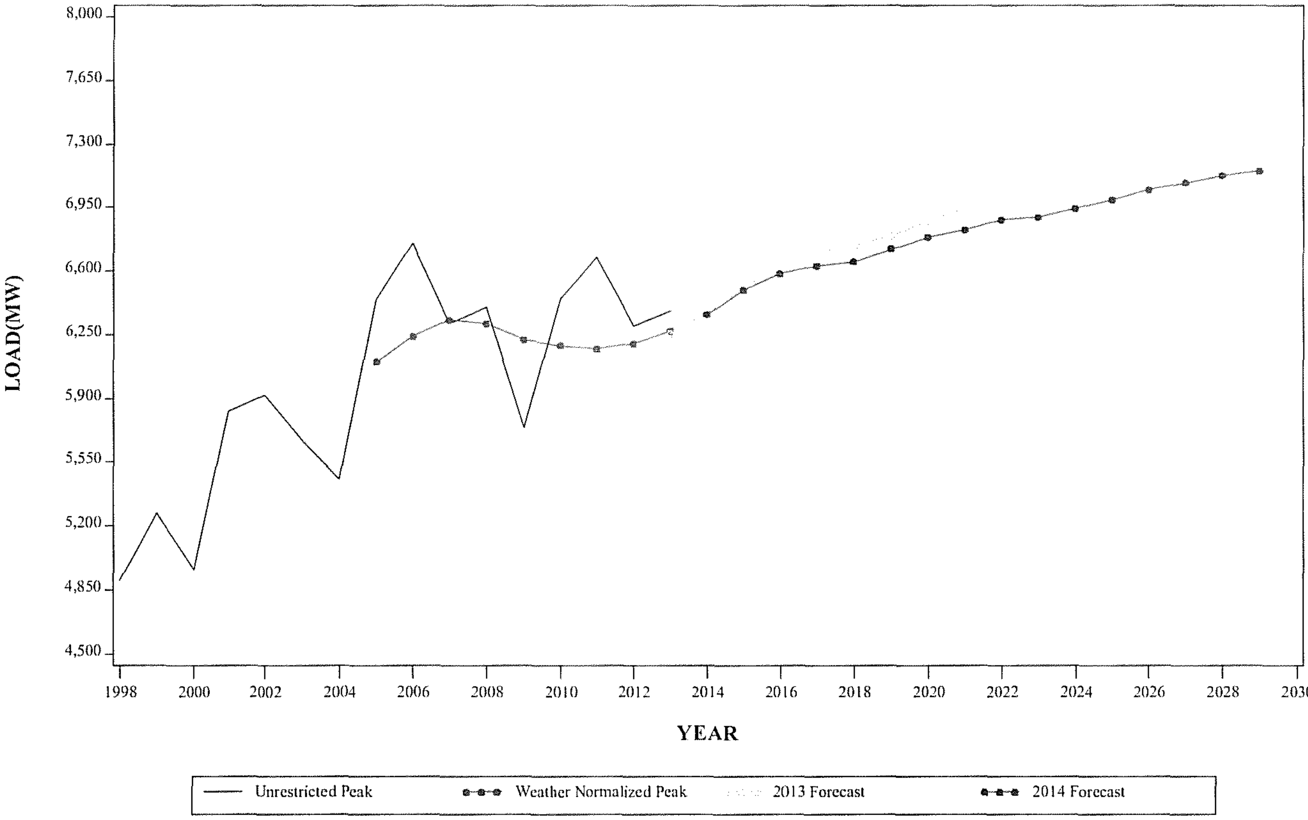
WINTER PEAK DEMAND FOR BGE GEOGRAPHIC ZONE



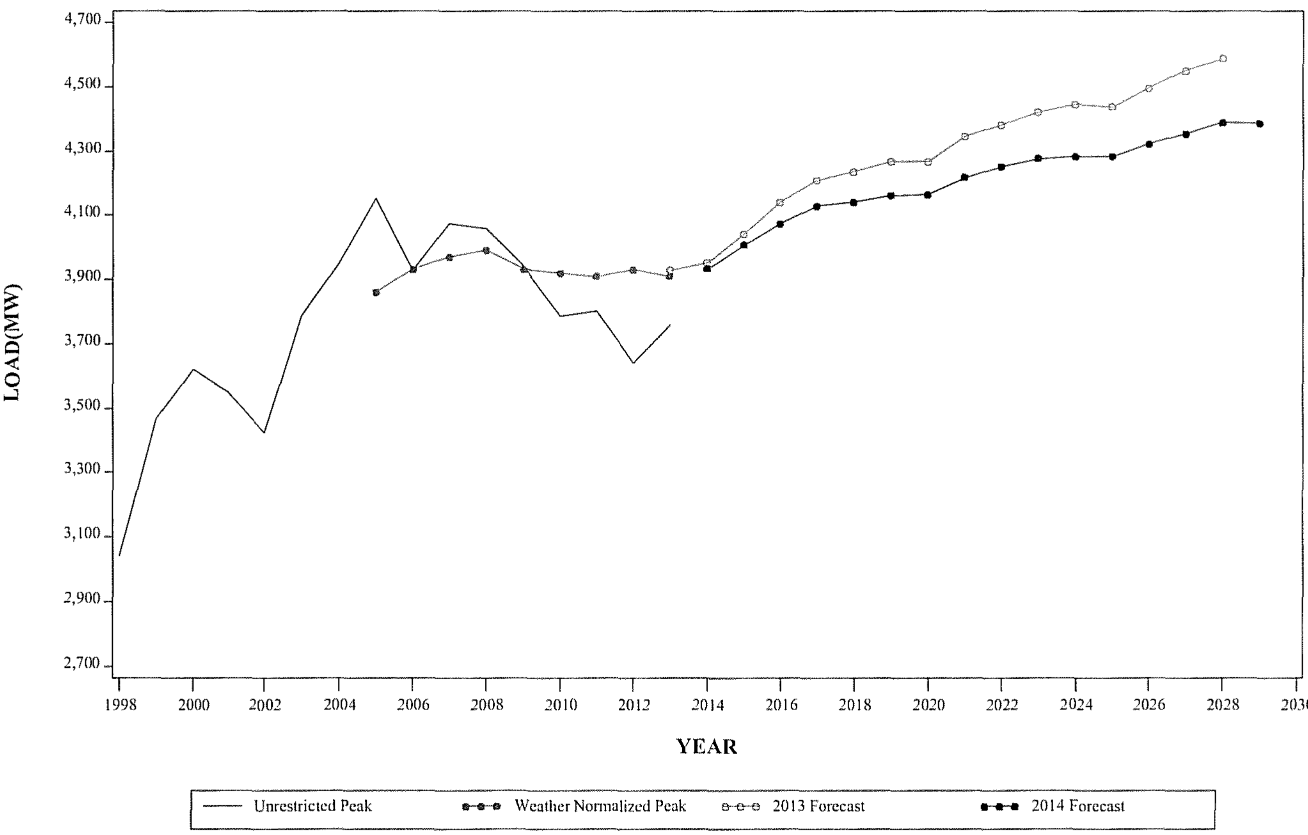

SUMMER PEAK DEMAND FOR DPL
GEOGRAPHIC ZONE
LOAD(MW)
5,400
5,150
4,900
4,650
4,400
4,150
3,900
3,650
3,400
3,150
2,900
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
YEAR
Unrestricted Peak
Weather Normalized Peak
2013 Forecast
2014 Forecast


WINTER PEAK DEMAND FOR DPL
GEOGRAPHIC ZONE
LOAD(MW)
4,200
4,000
3,800
3,600
3,400
3,200
3,000
2,800
2,600
2,400
2,200
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
YEAR
Unrestricted Peak
Weather Normalized Peak
2013 Forecast
2014 Forecast

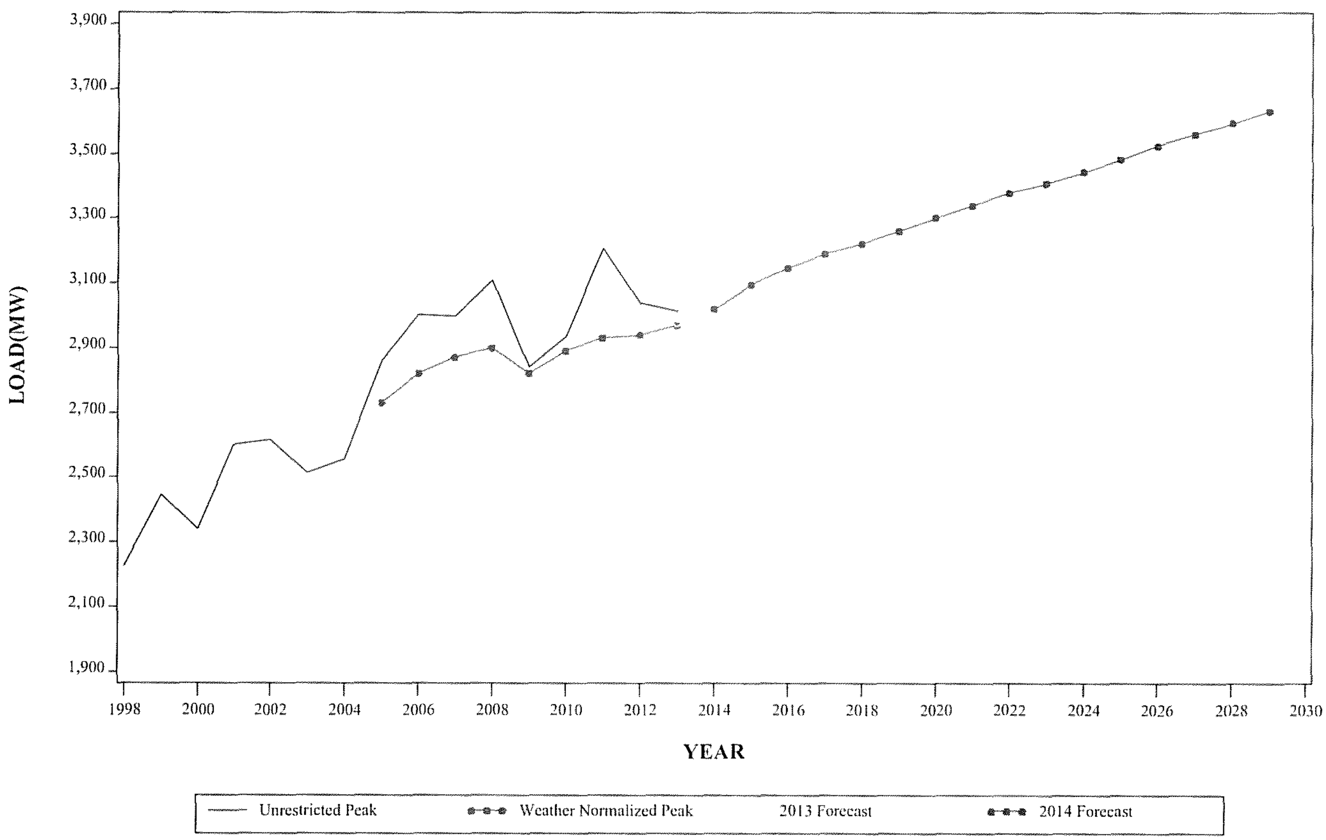
SUMMER PEAK DEMAND FOR JCPL GEOGRAPHIC ZONE



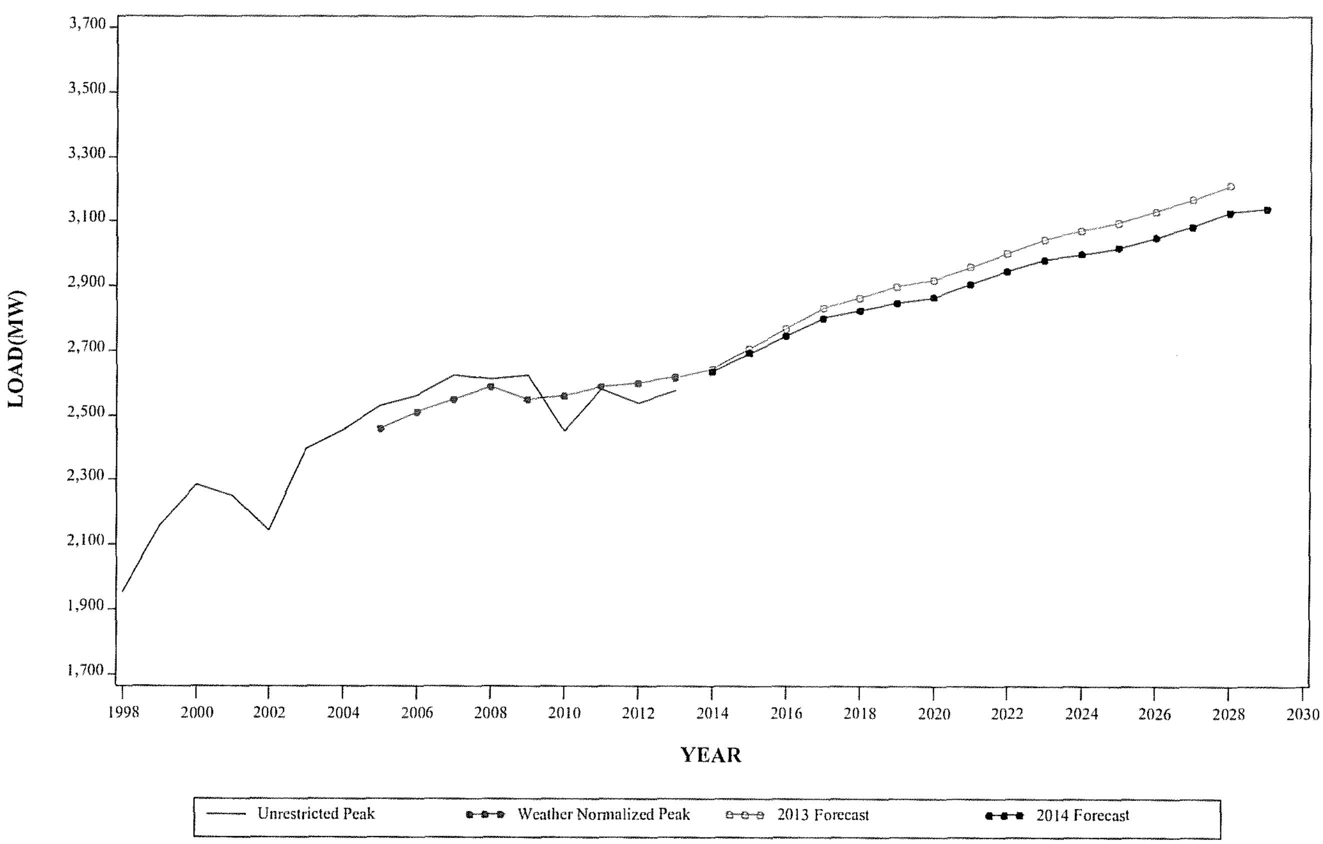
WINTER PEAK DEMAND FOR JCPL GEOGRAPHIC ZONE



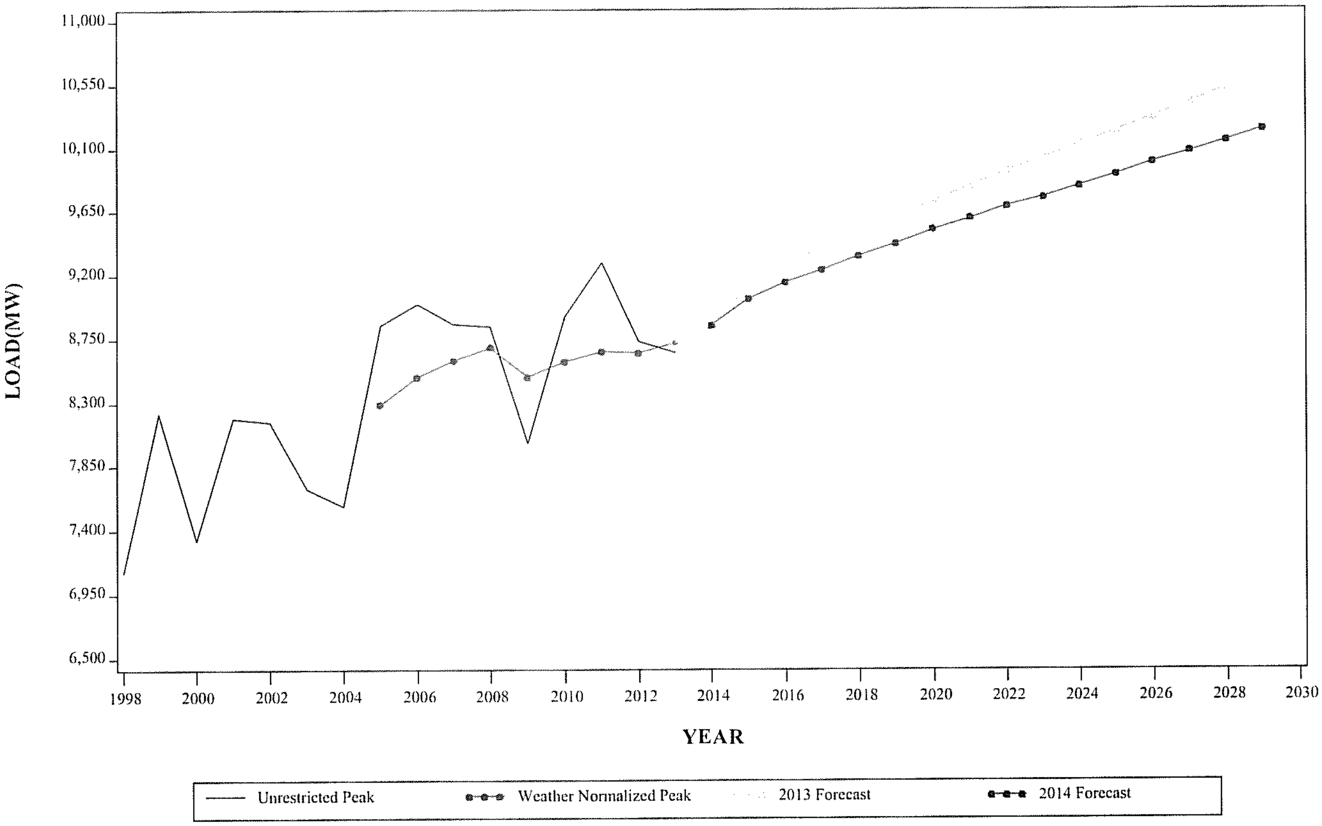
SUMMER PEAK DEMAND FOR METED GEOGRAPHIC ZONE



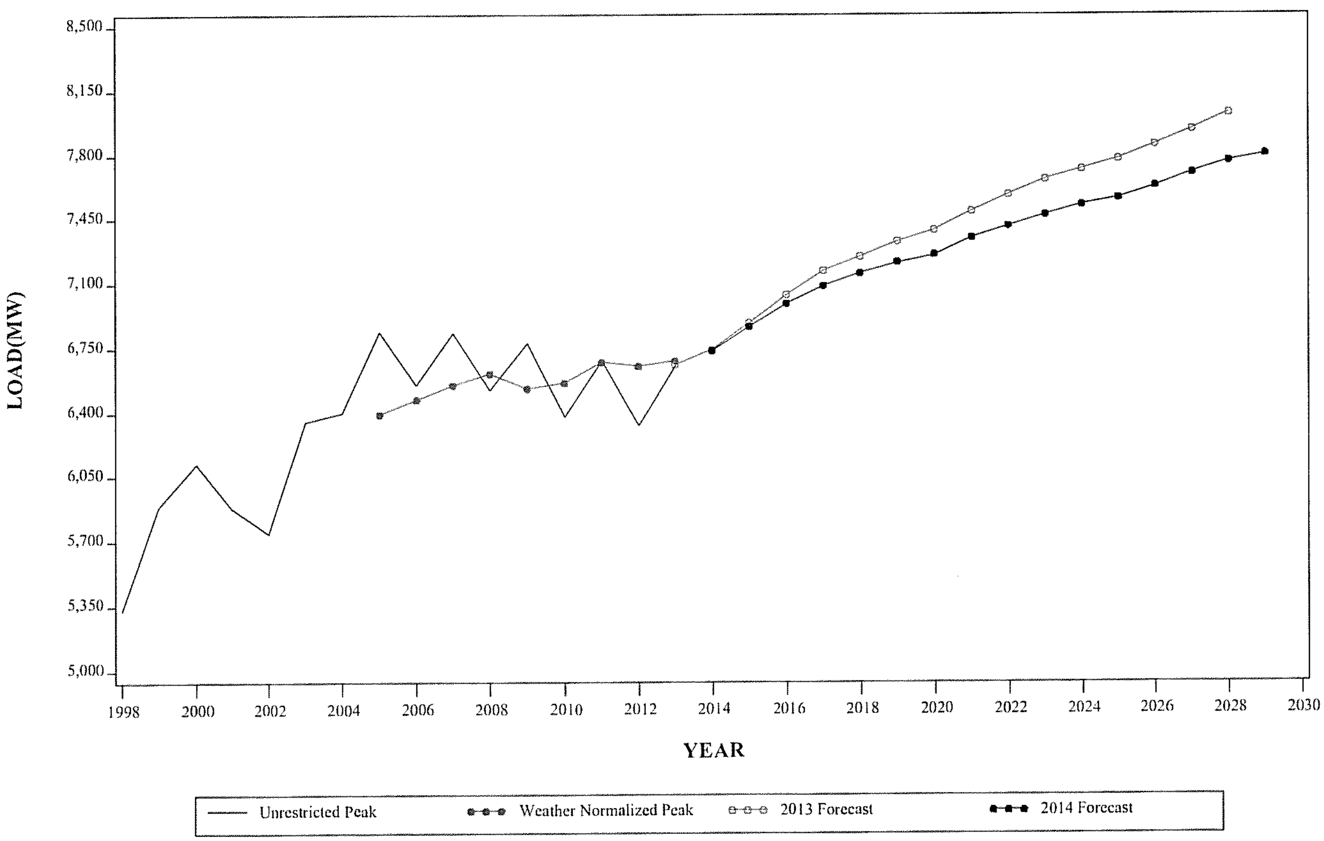
WINTER PEAK DEMAND FOR METED GEOGRAPHIC ZONE



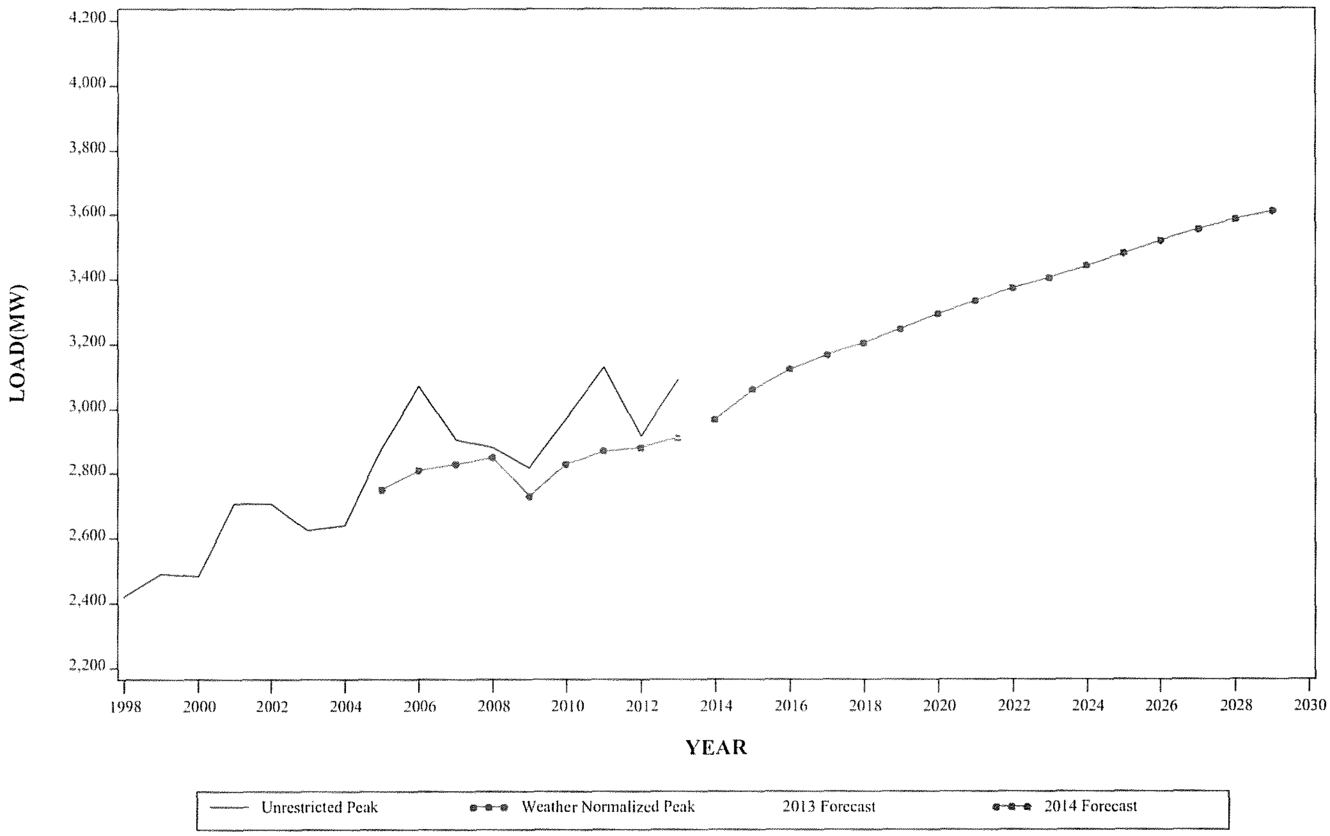
SUMMER PEAK DEMAND FOR PECO
GEOGRAPHIC ZONE



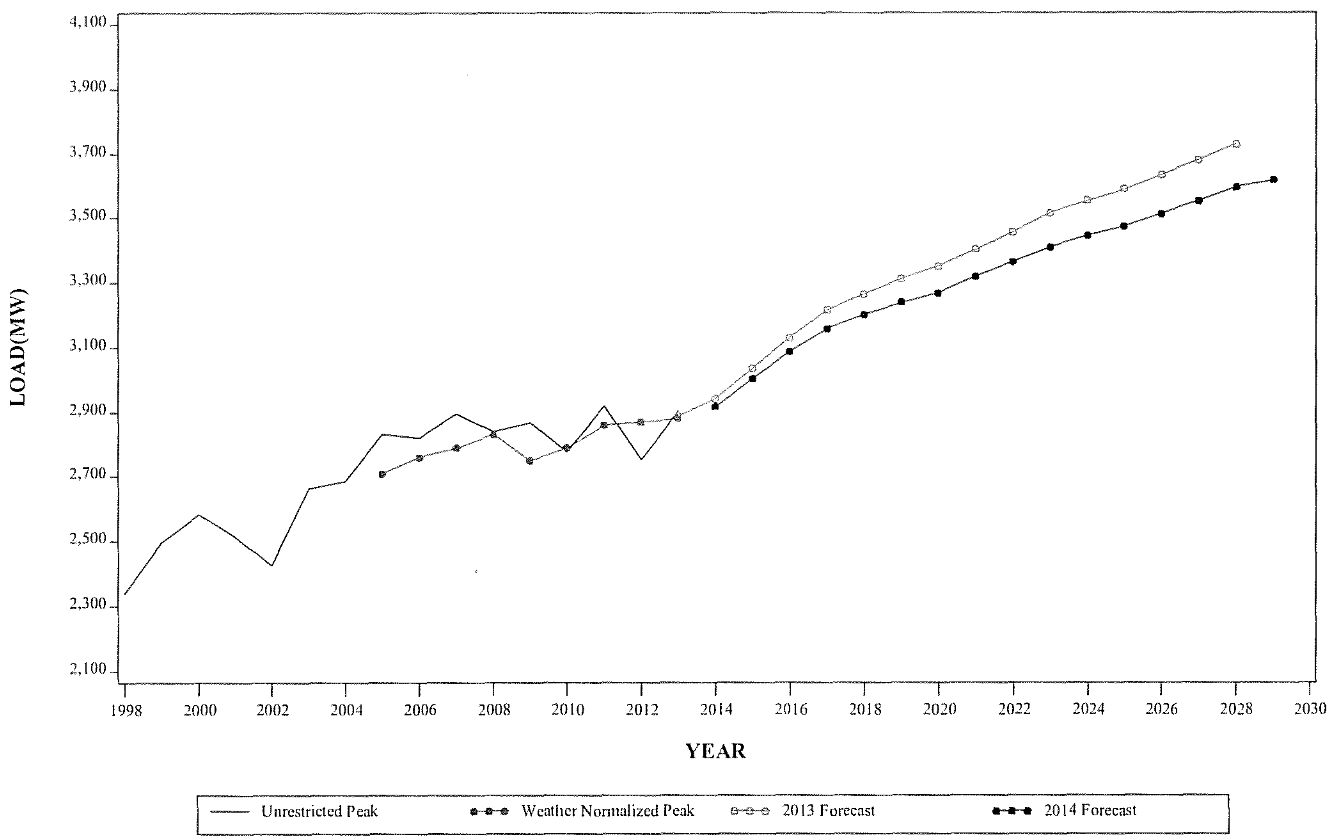
WINTER PEAK DEMAND FOR PECO
GEOGRAPHIC ZONE



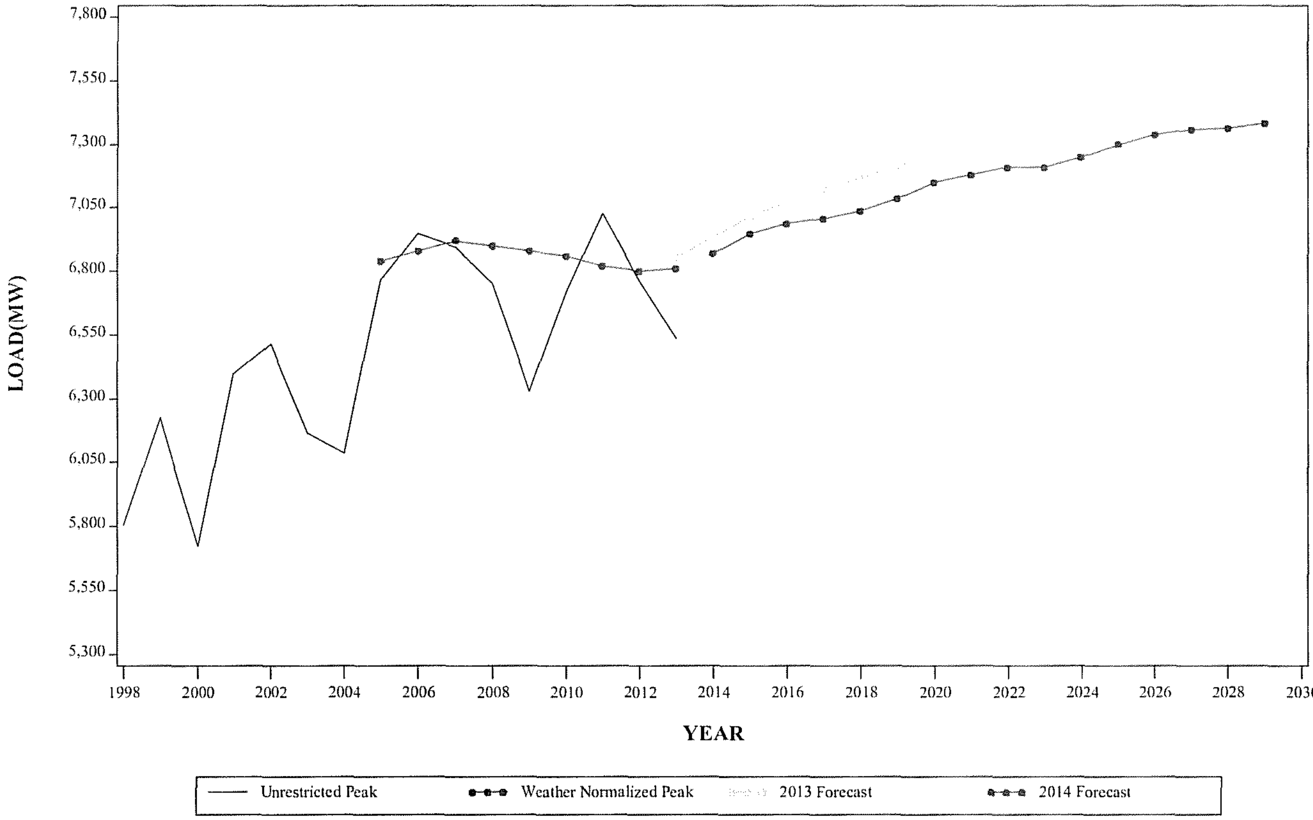
SUMMER PEAK DEMAND FOR PENLC GEOGRAPHIC ZONE



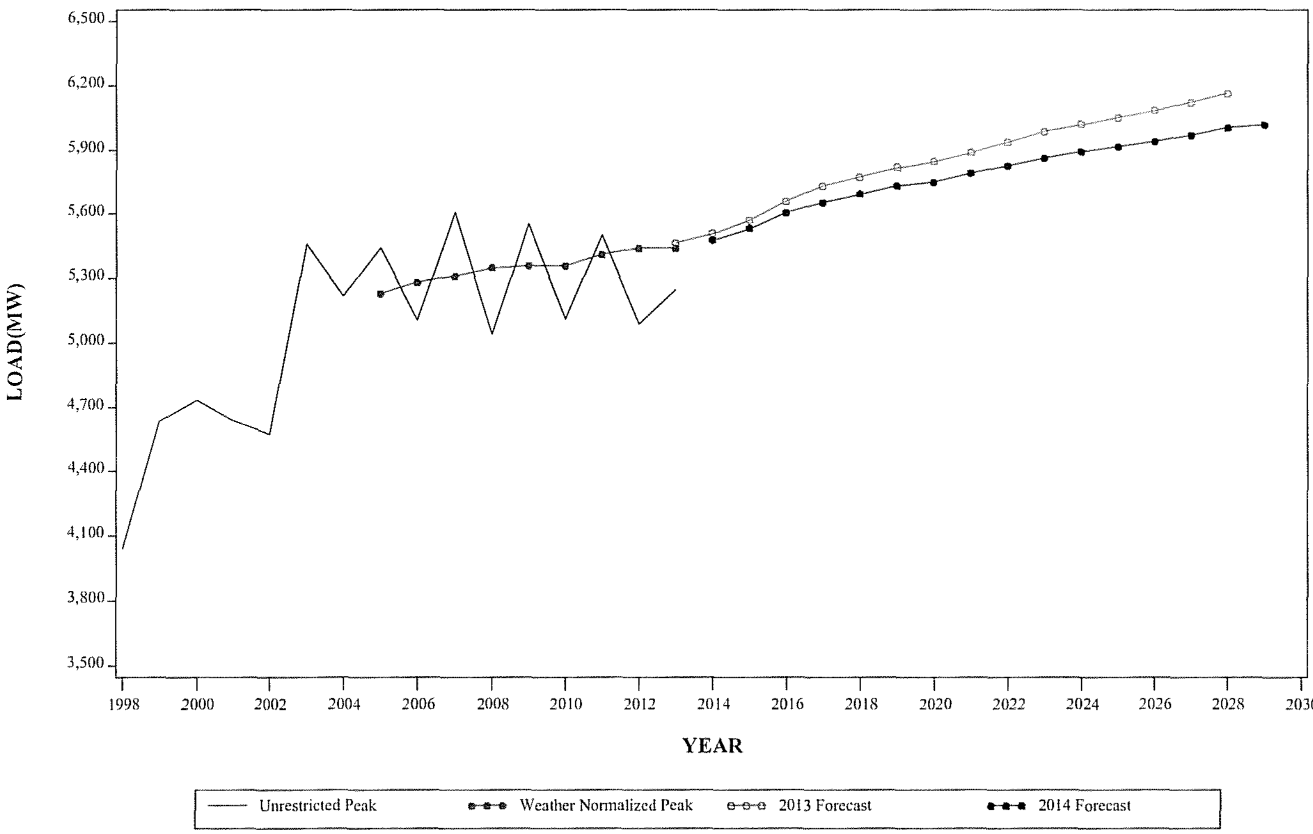
WINTER PEAK DEMAND FOR PENLC GEOGRAPHIC ZONE



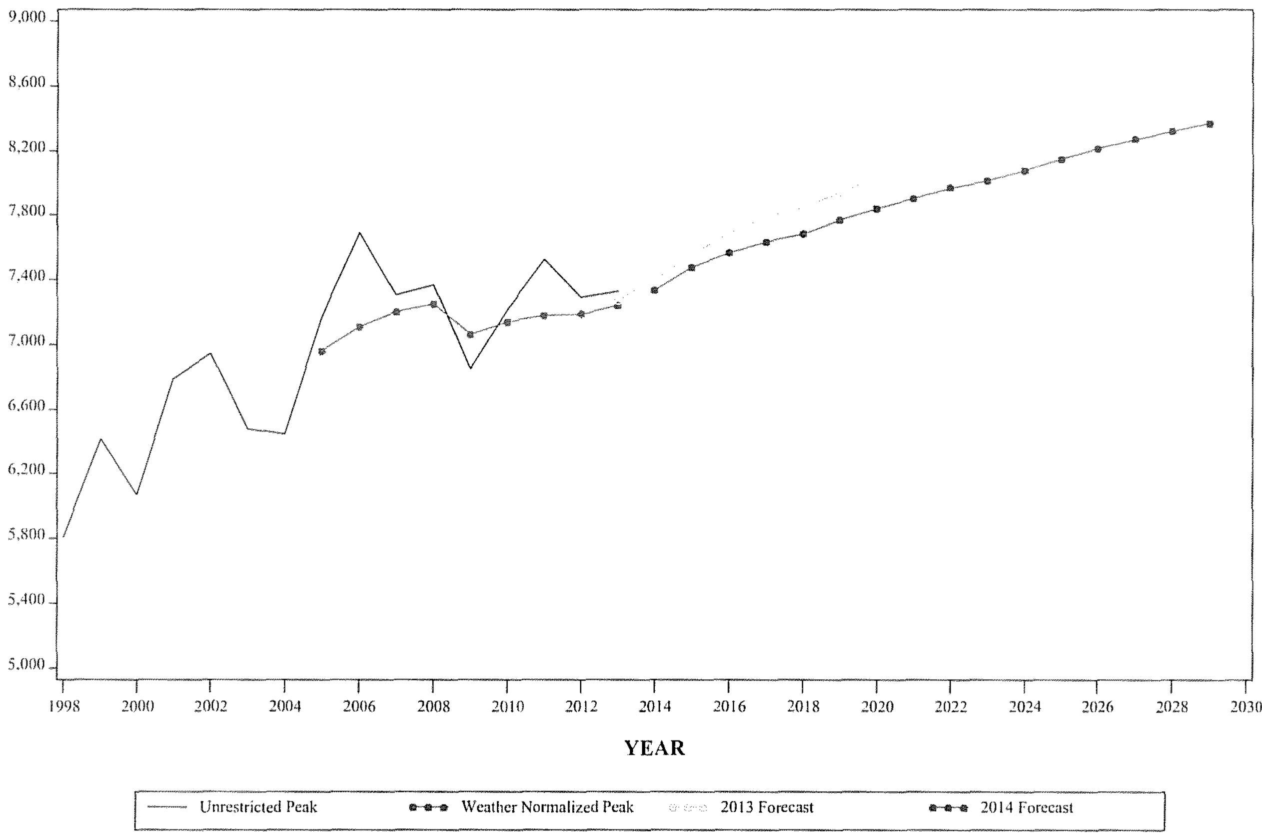
SUMMER PEAK DEMAND FOR PEPCO GEOGRAPHIC ZONE



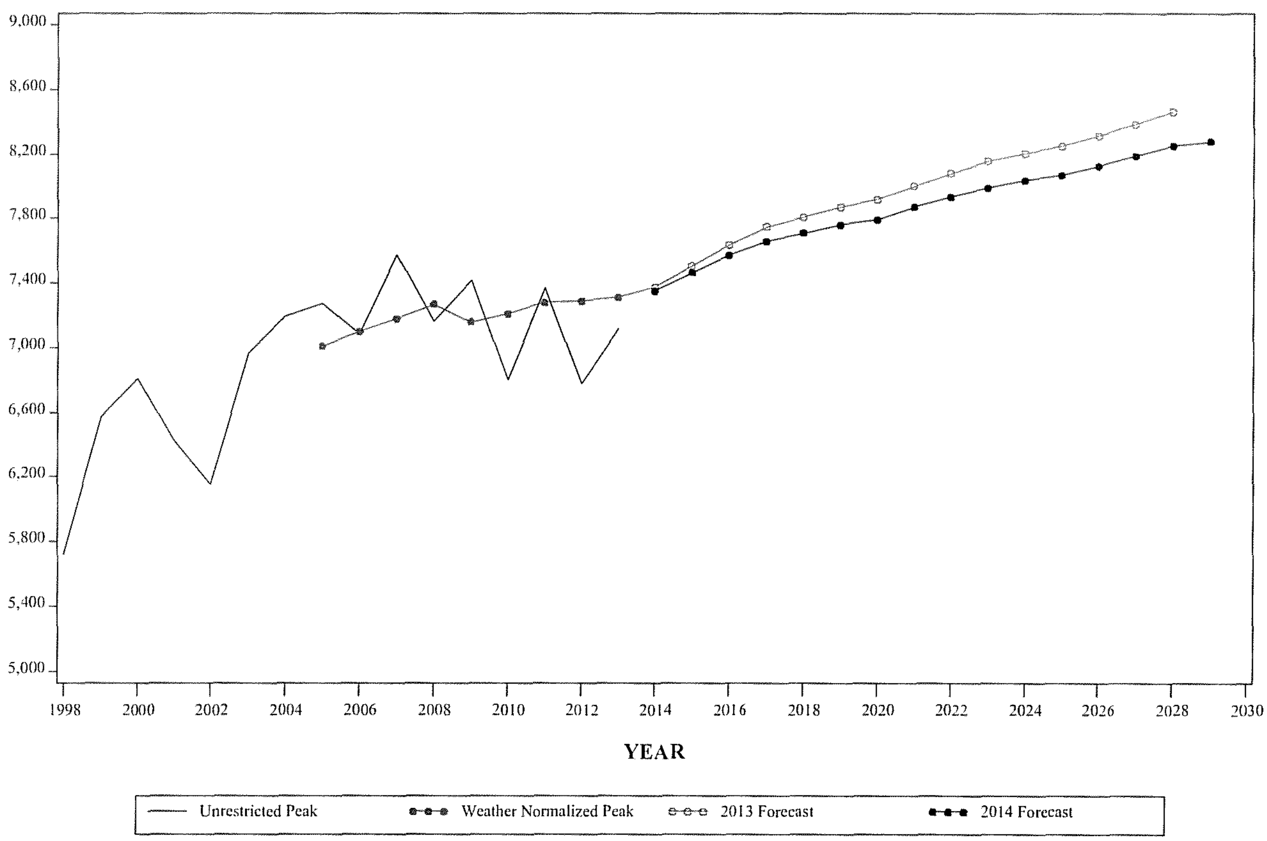
WINTER PEAK DEMAND FOR PEPCO GEOGRAPHIC ZONE



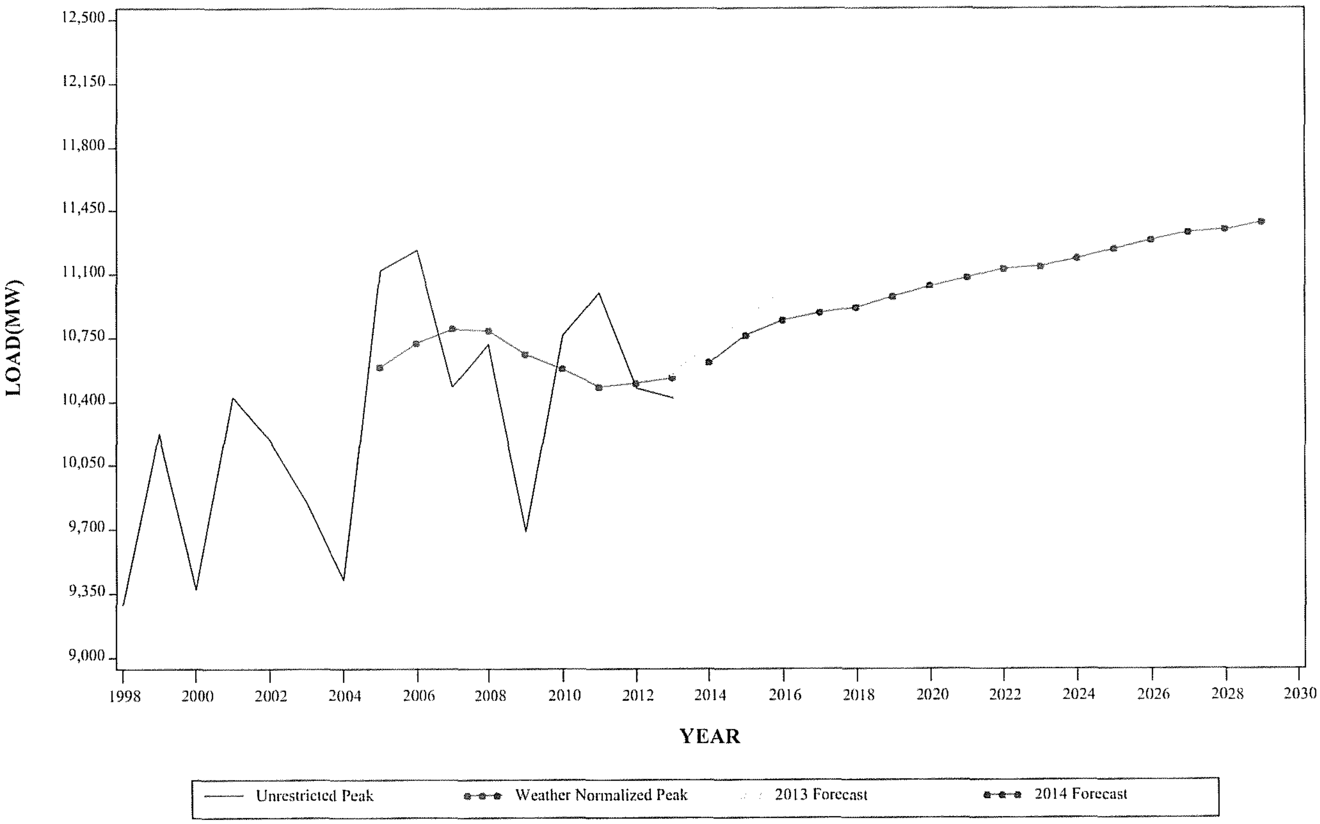
SUMMER PEAK DEMAND FOR PL GEOGRAPHIC ZONE



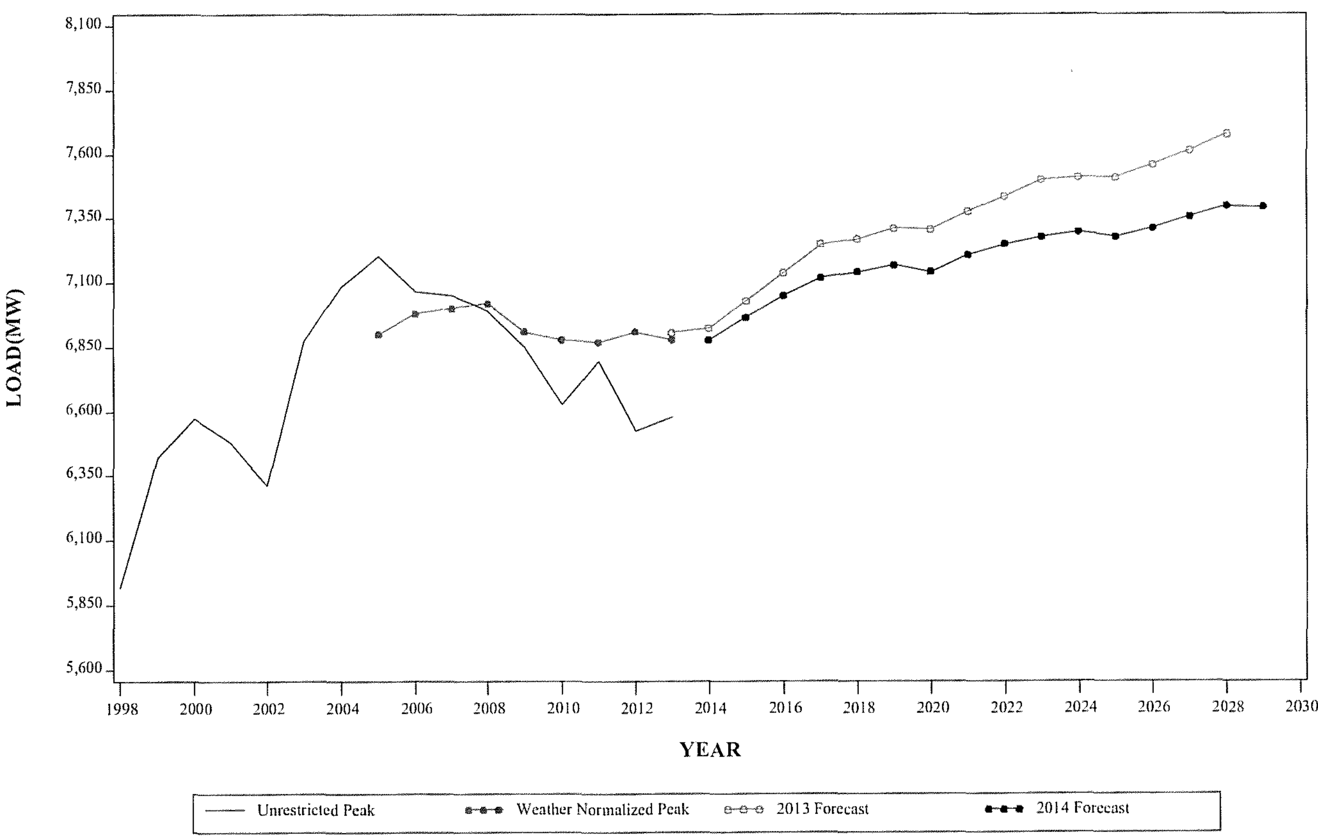
WINTER PEAK DEMAND FOR PL GEOGRAPHIC ZONE



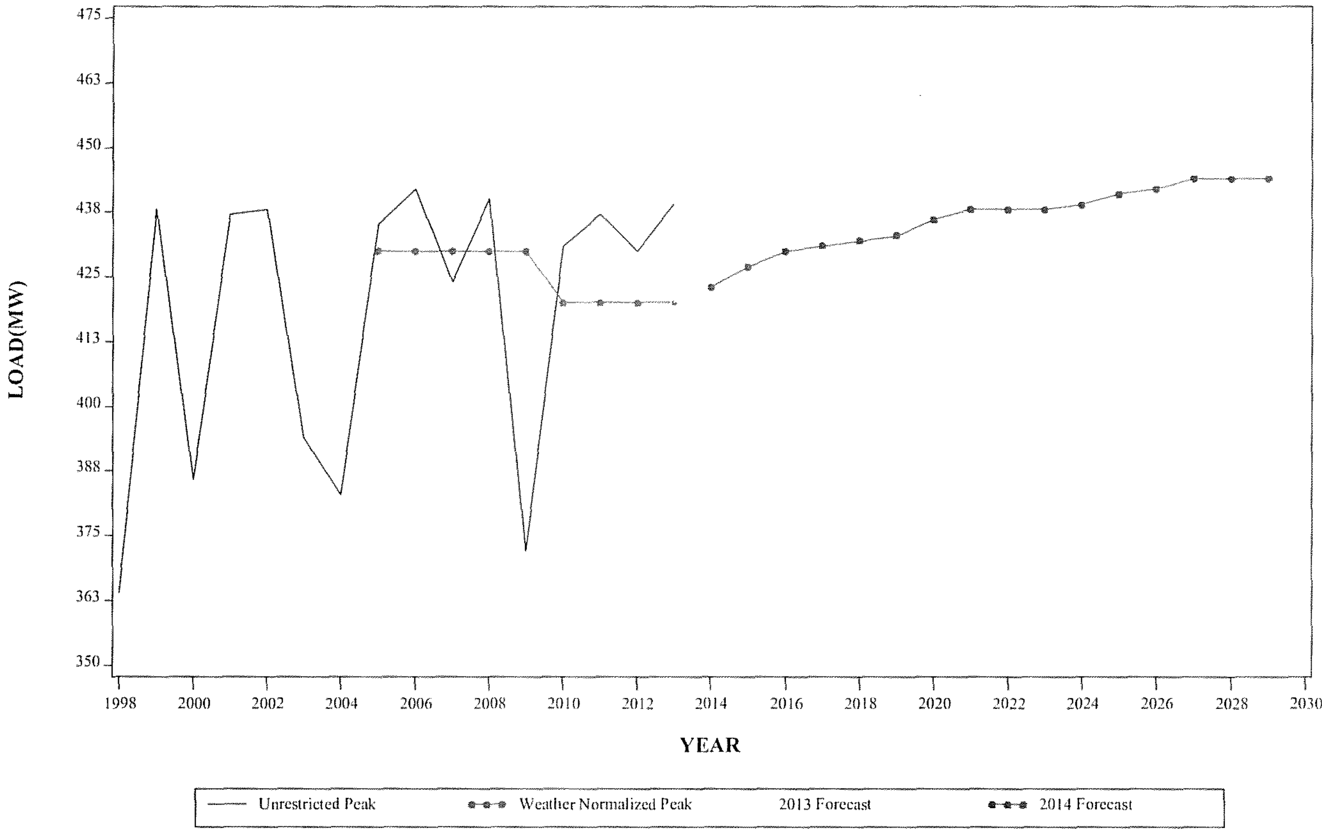
SUMMER PEAK DEMAND FOR PS
GEOGRAPHIC ZONE



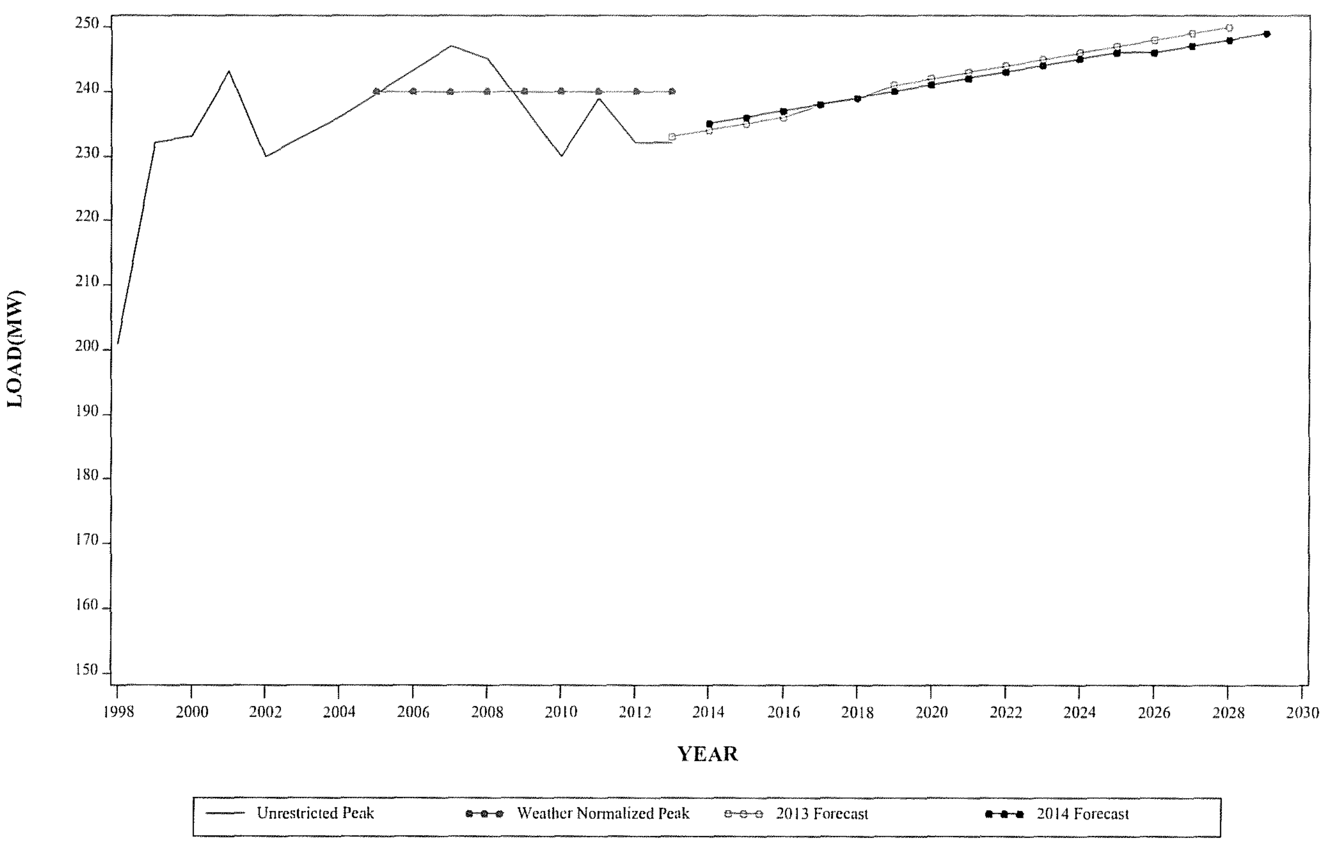
WINTER PEAK DEMAND FOR PS
GEOGRAPHIC ZONE



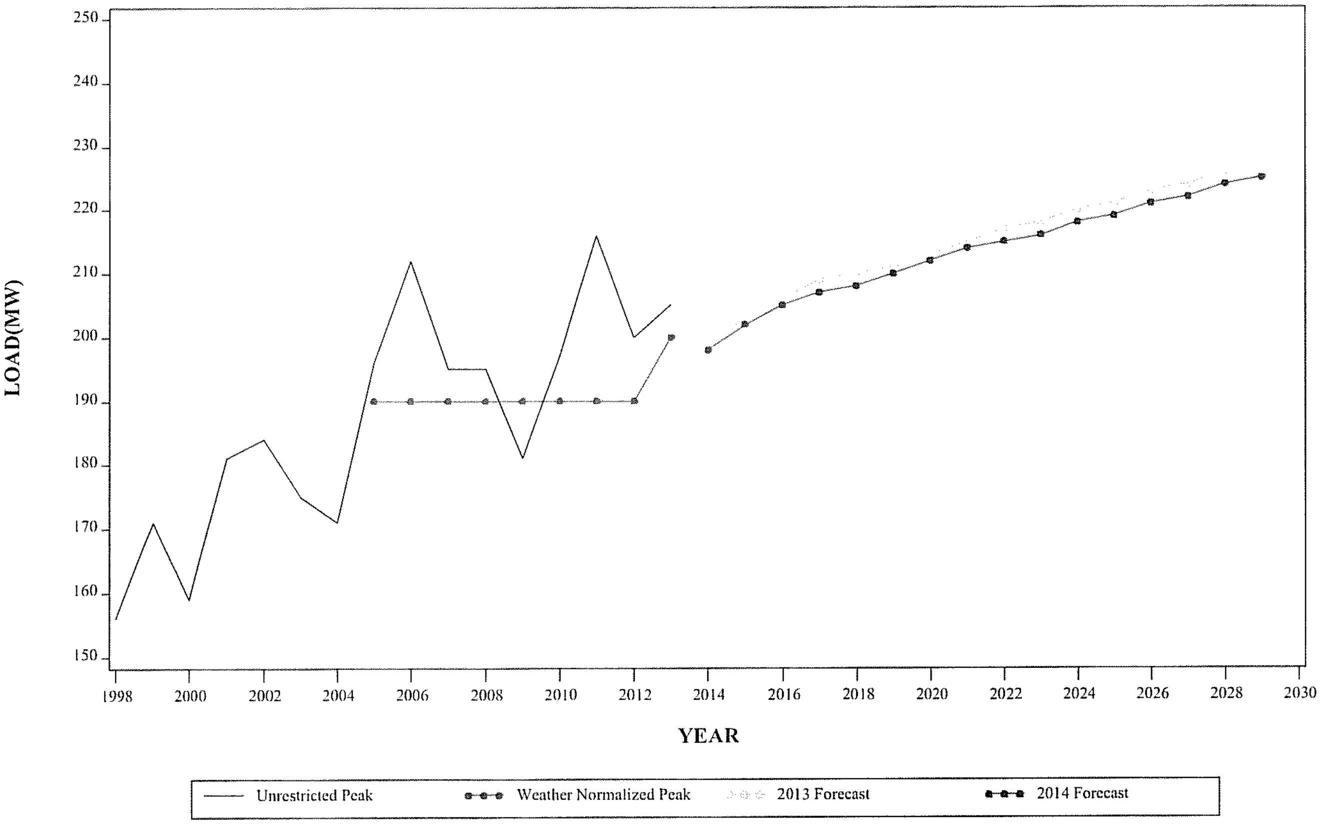
SUMMER PEAK DEMAND FOR RECO GEOGRAPHIC ZONE



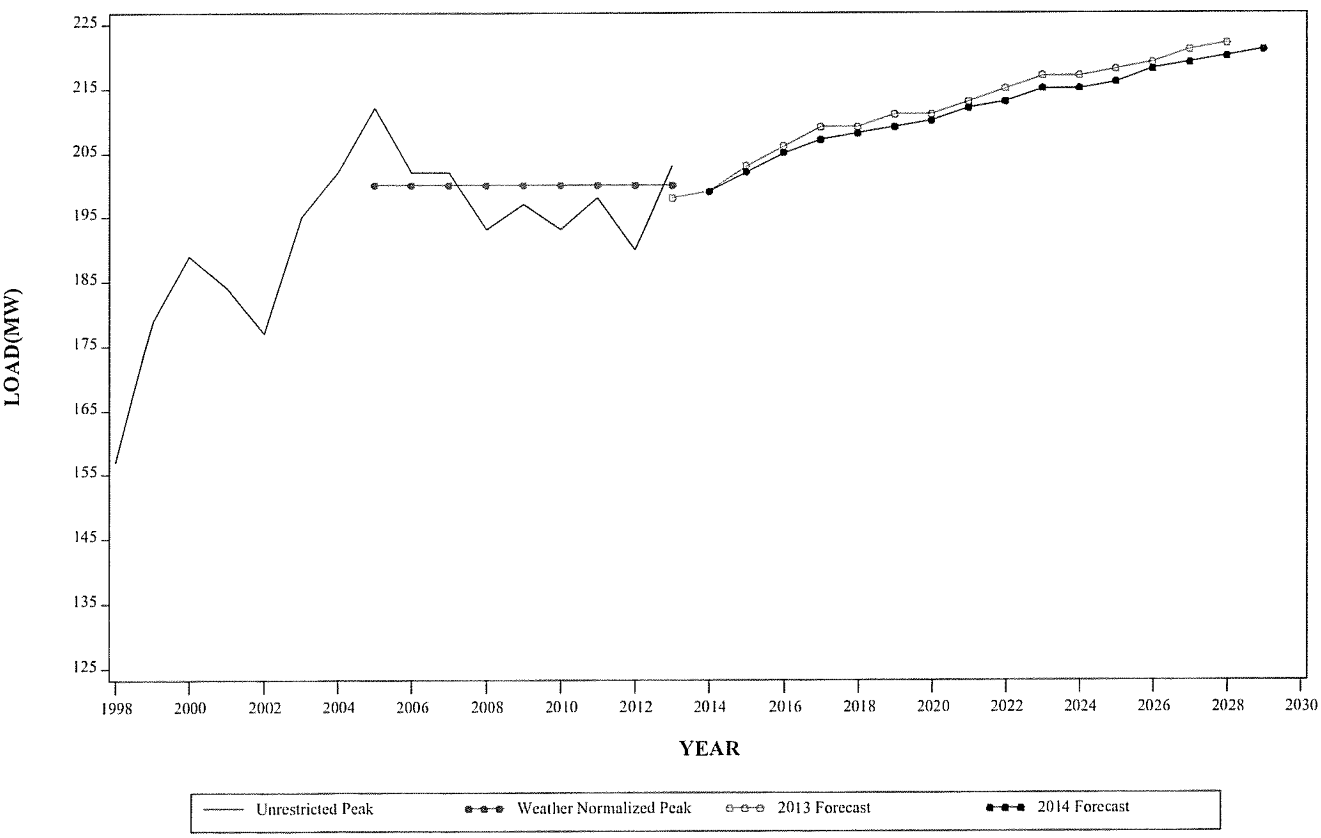
WINTER PEAK DEMAND FOR RECO GEOGRAPHIC ZONE



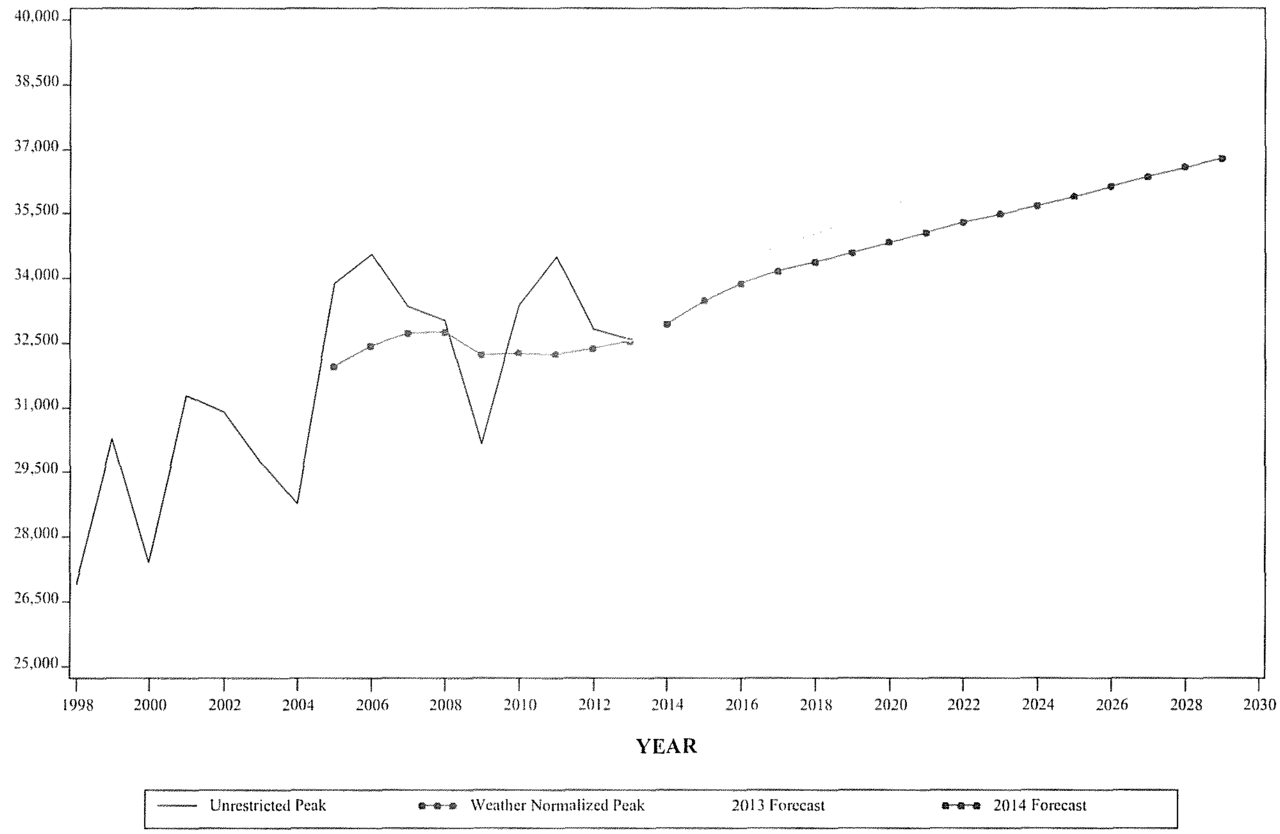
SUMMER PEAK DEMAND FOR UGI GEOGRAPHIC ZONE



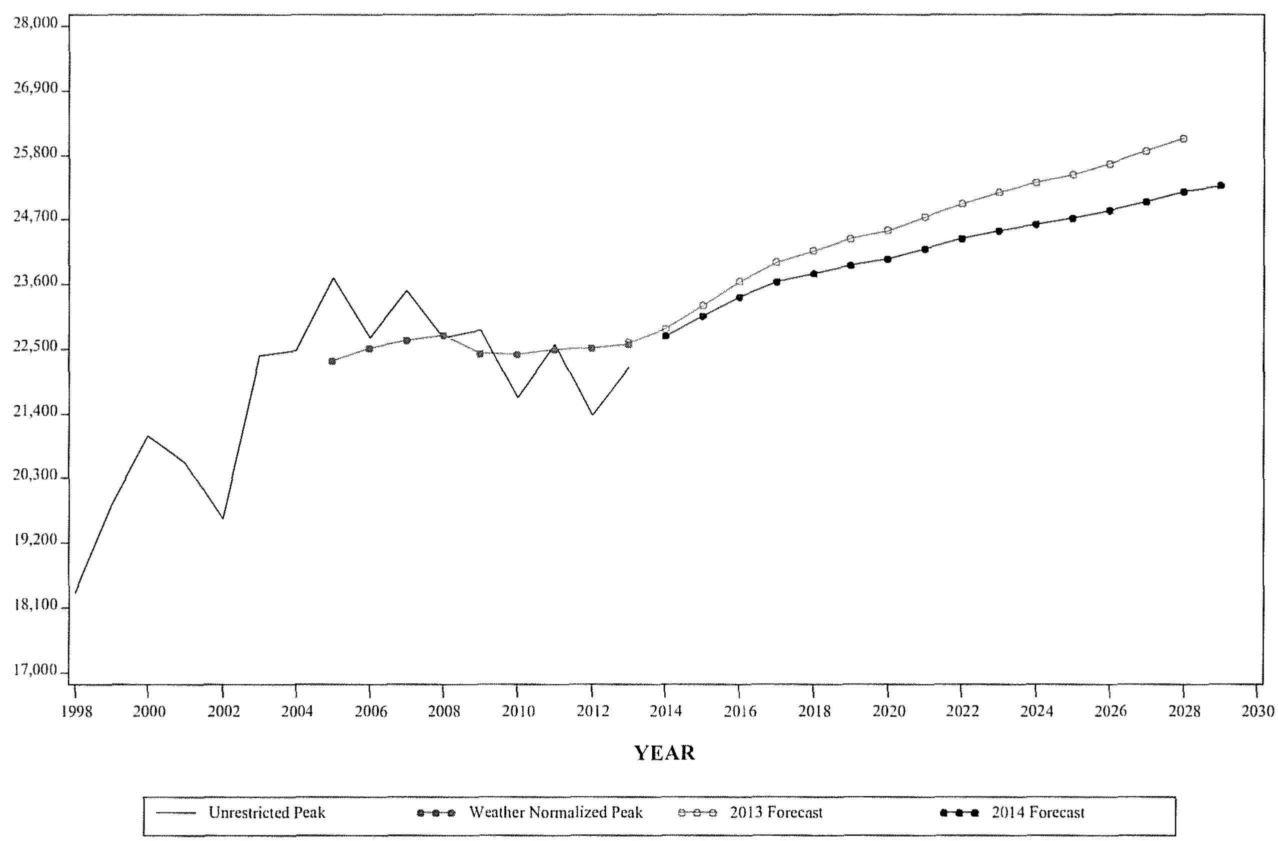
WINTER PEAK DEMAND FOR UGI GEOGRAPHIC ZONE



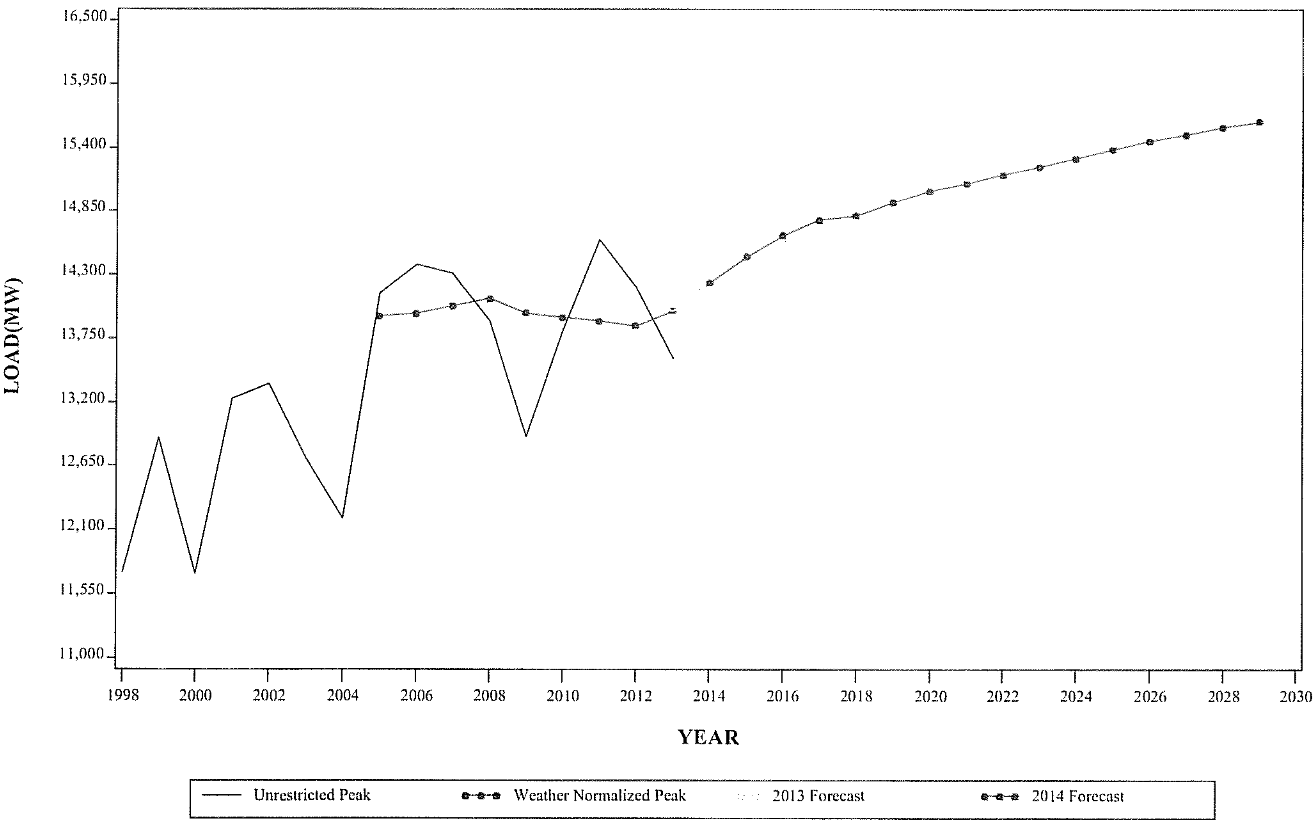
SUMMER PEAK DEMAND FOR EASTERN MID-ATLANTIC GEOGRAPHIC ZONE



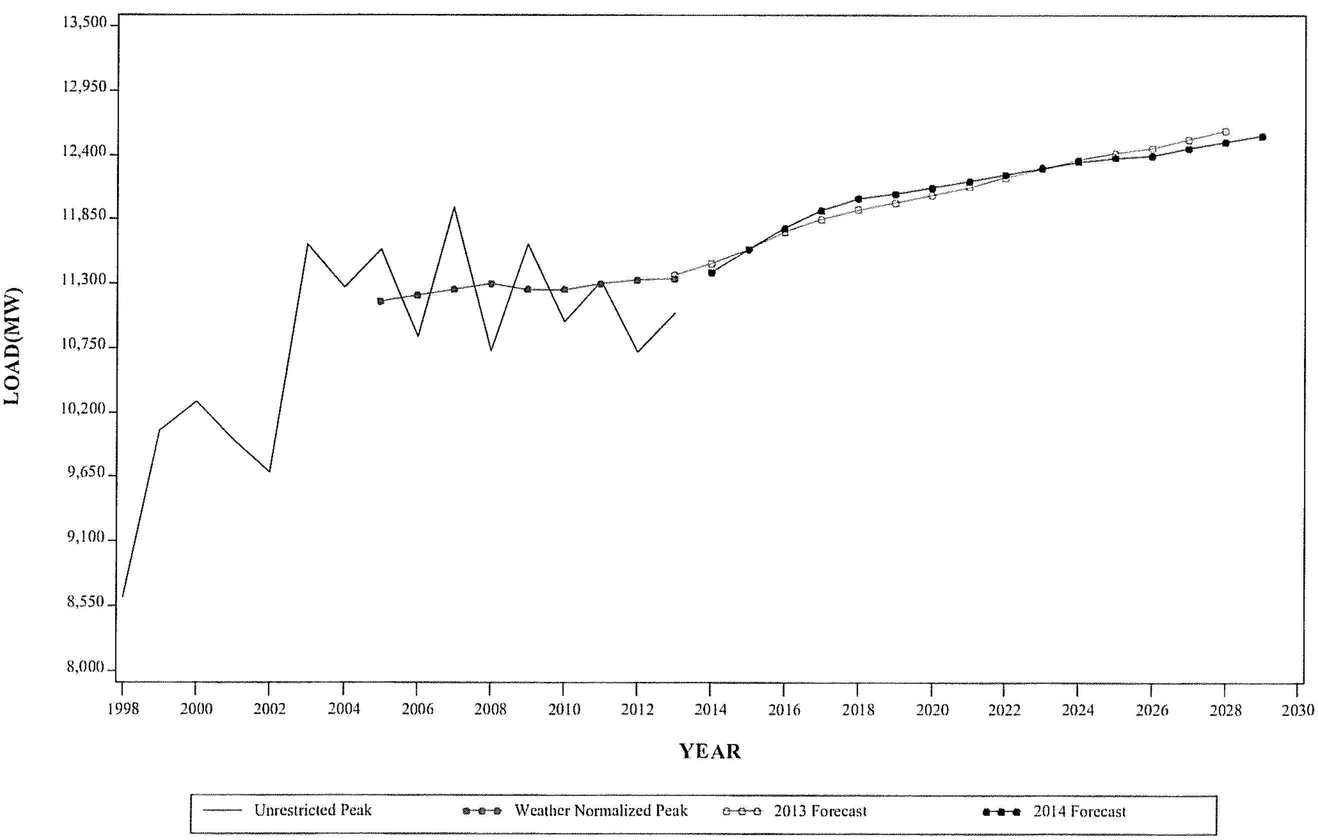
WINTER PEAK DEMAND FOR EASTERN MID-ATLANTIC GEOGRAPHIC ZONE



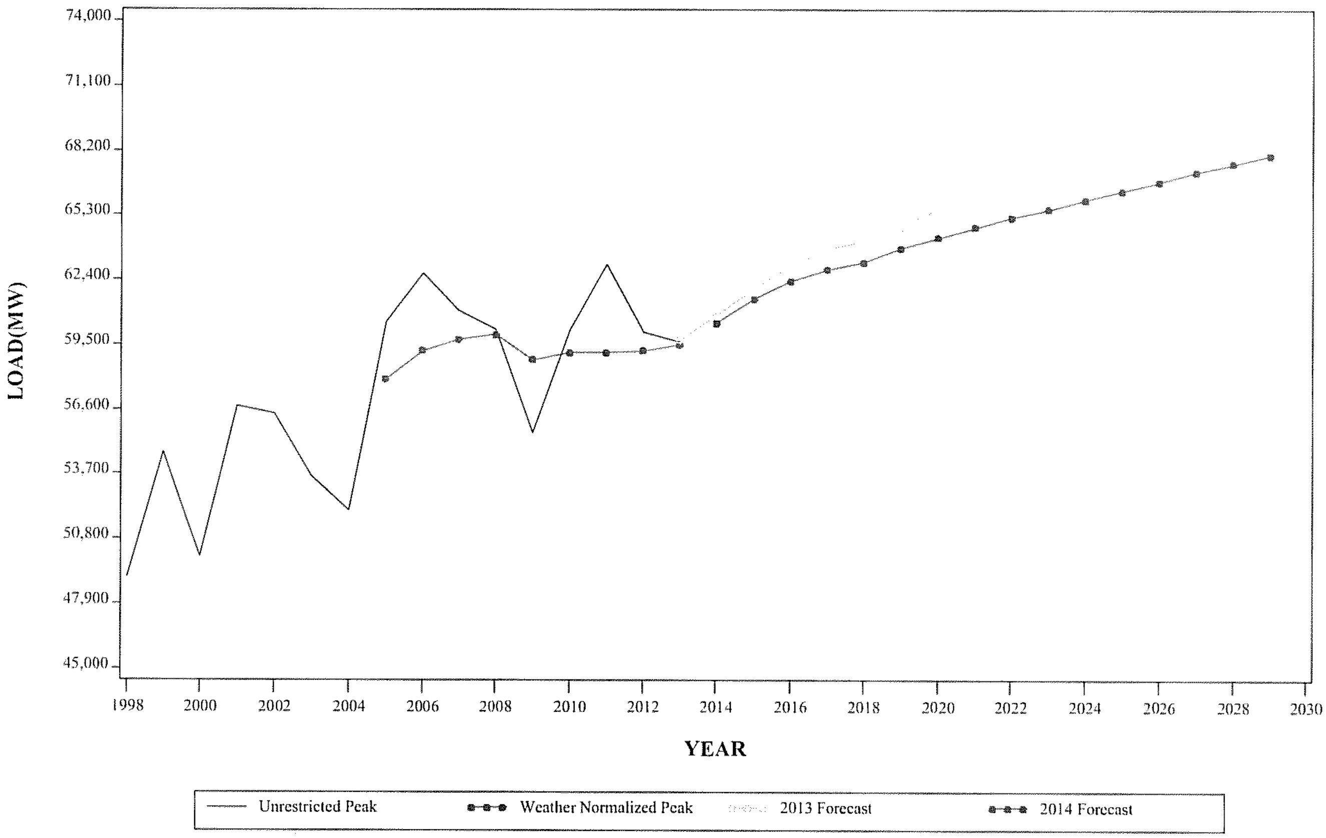
SUMMER PEAK DEMAND FOR SOUTHERN MID-ATLANTIC GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR SOUTHERN MID-ATLANTIC GEOGRAPHIC ZONE



SUMMER PEAK DEMAND FOR PJM MID-ATLANTIC GEOGRAPHIC ZONE



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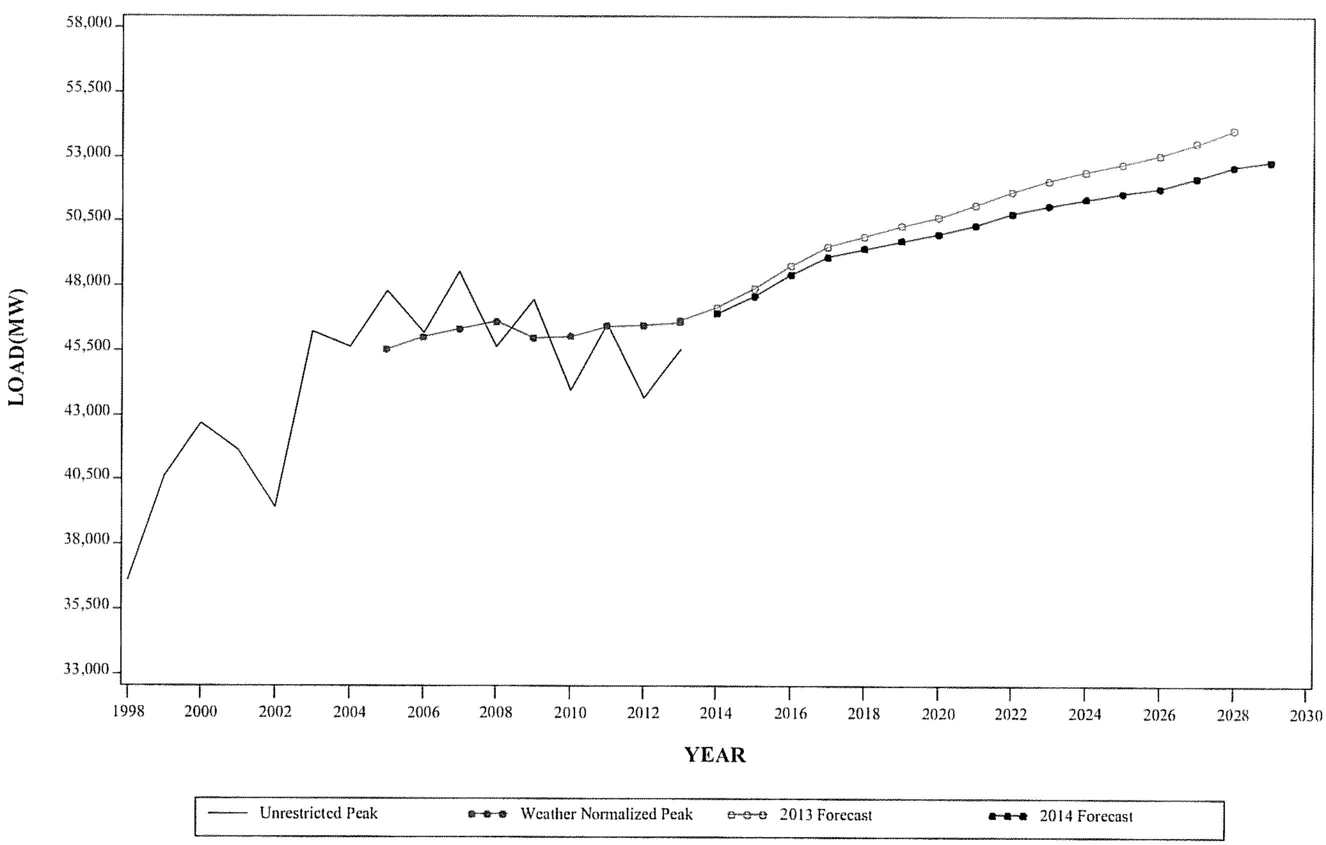
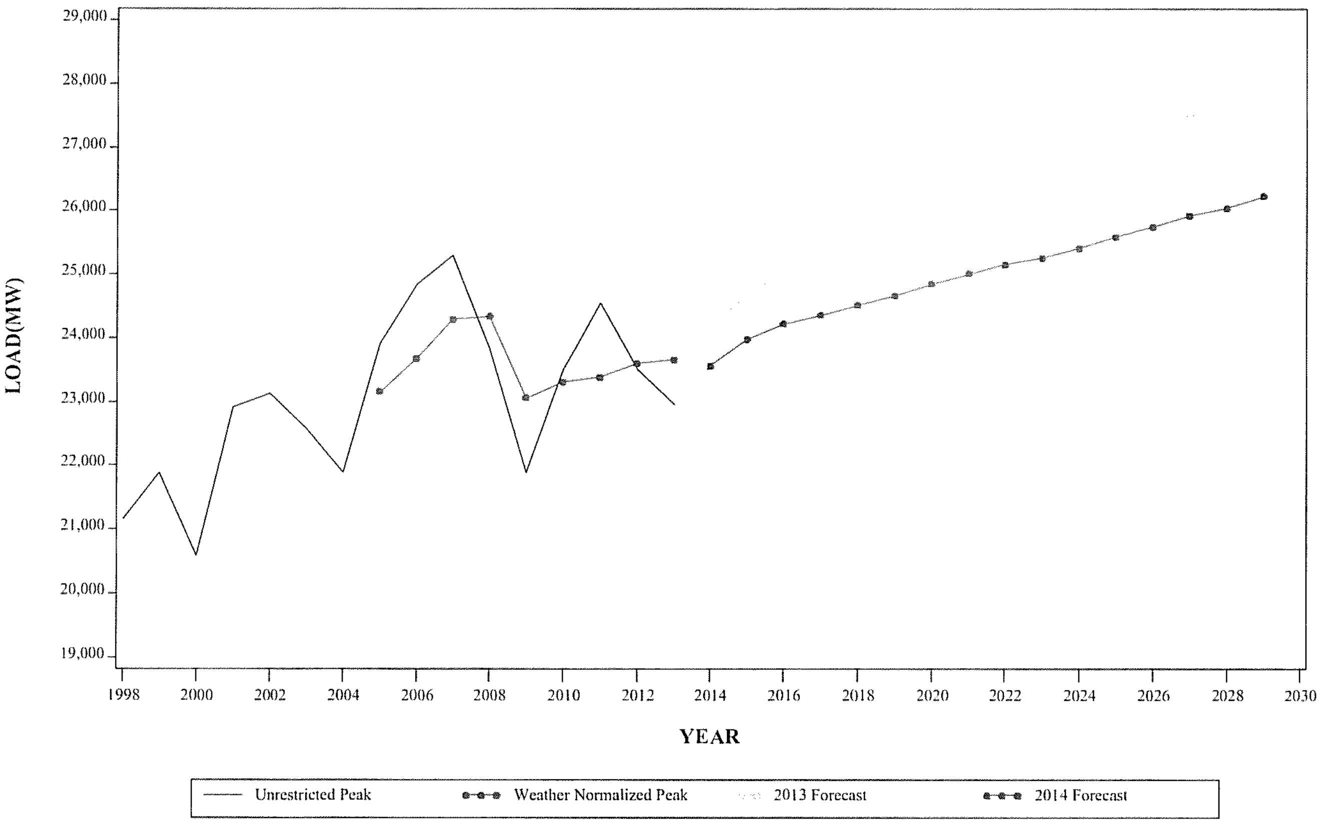
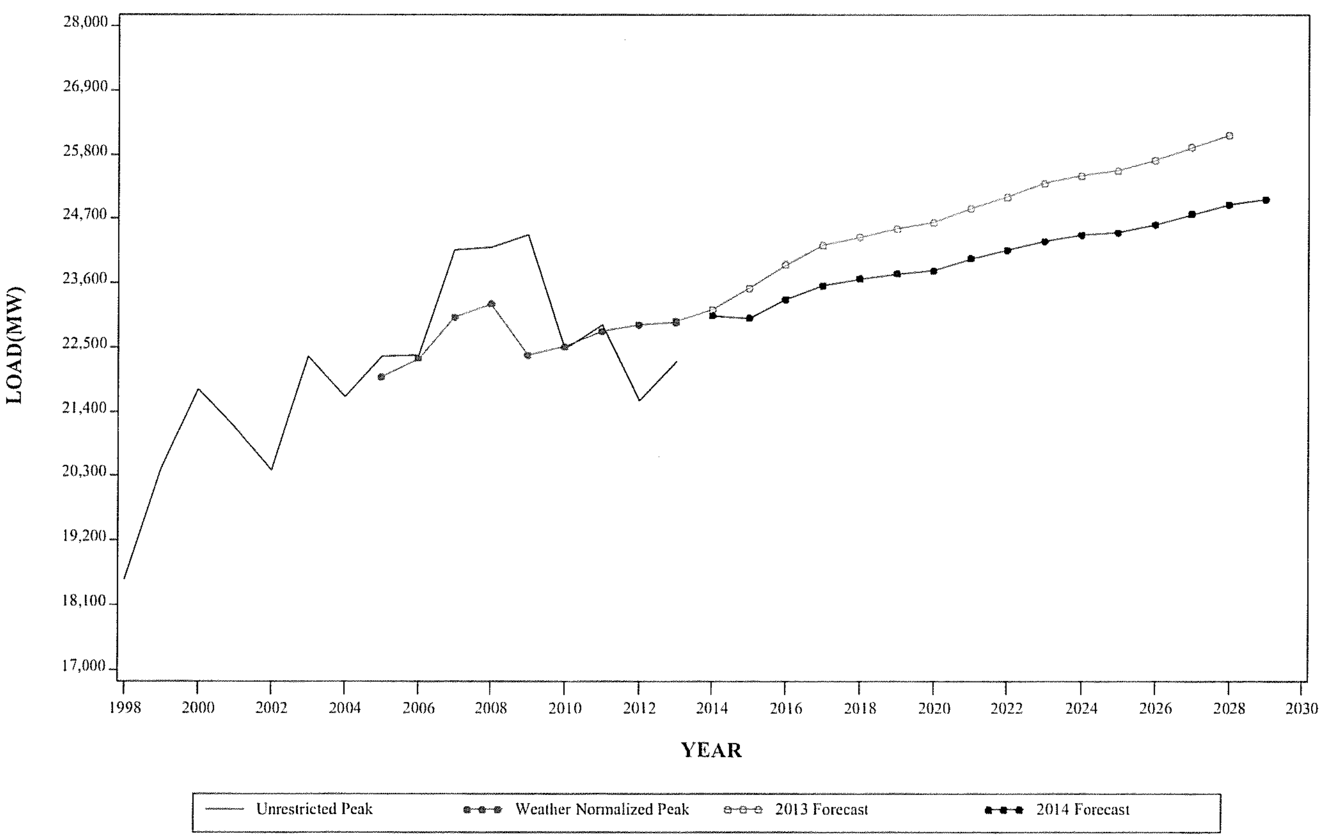


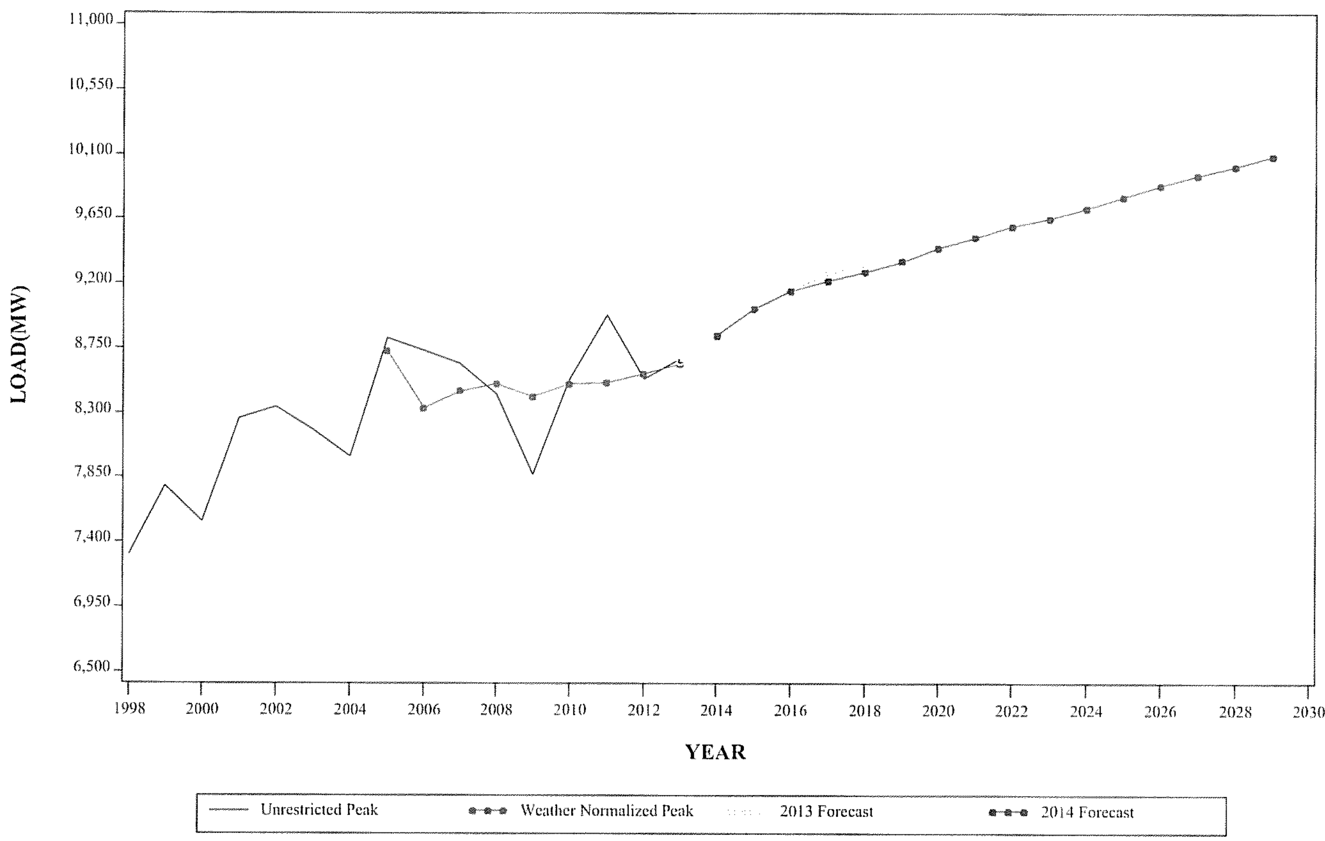
SUMMER PEAK DEMAND FOR AEP GEOGRAPHIC ZONE



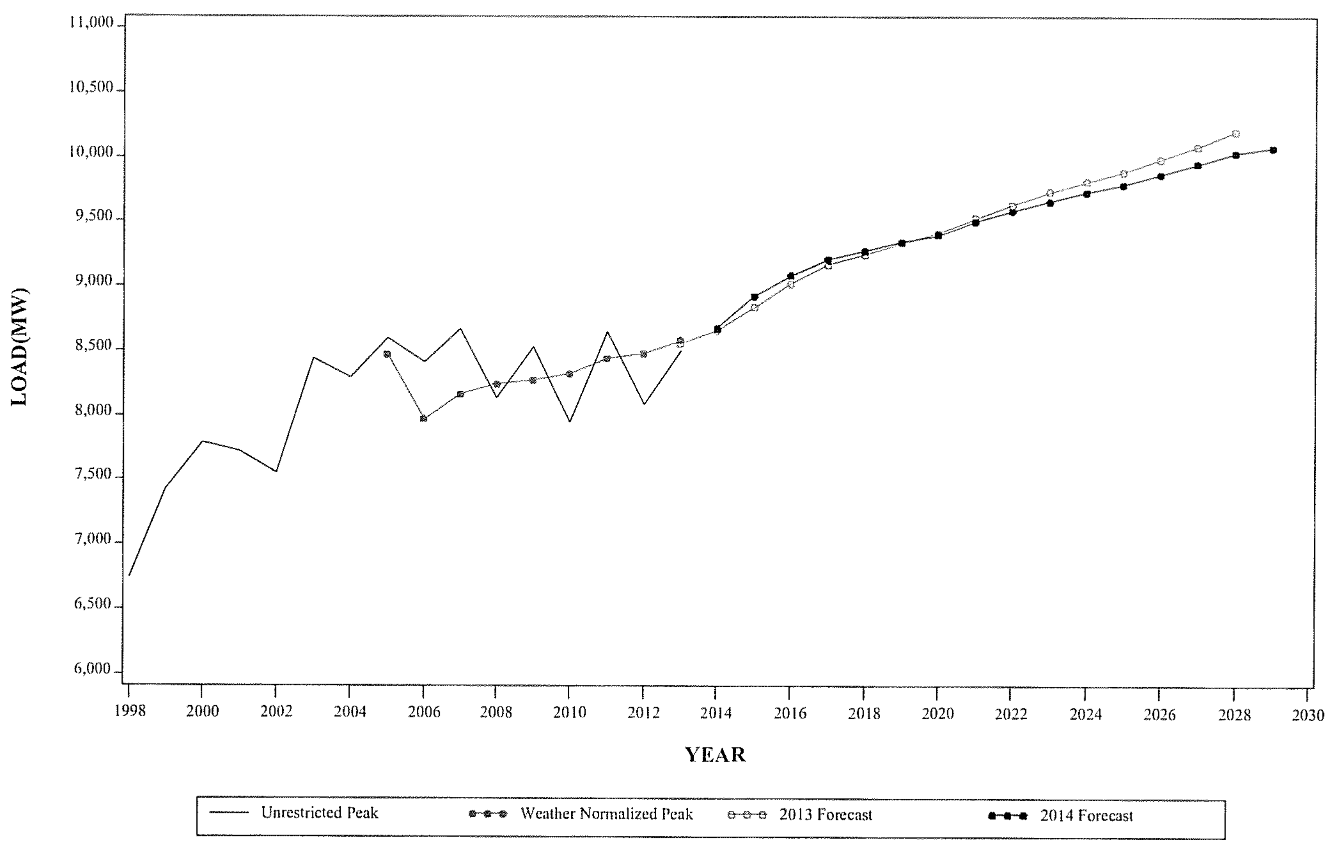
WINTER PEAK DEMAND FOR AEP GEOGRAPHIC ZONE



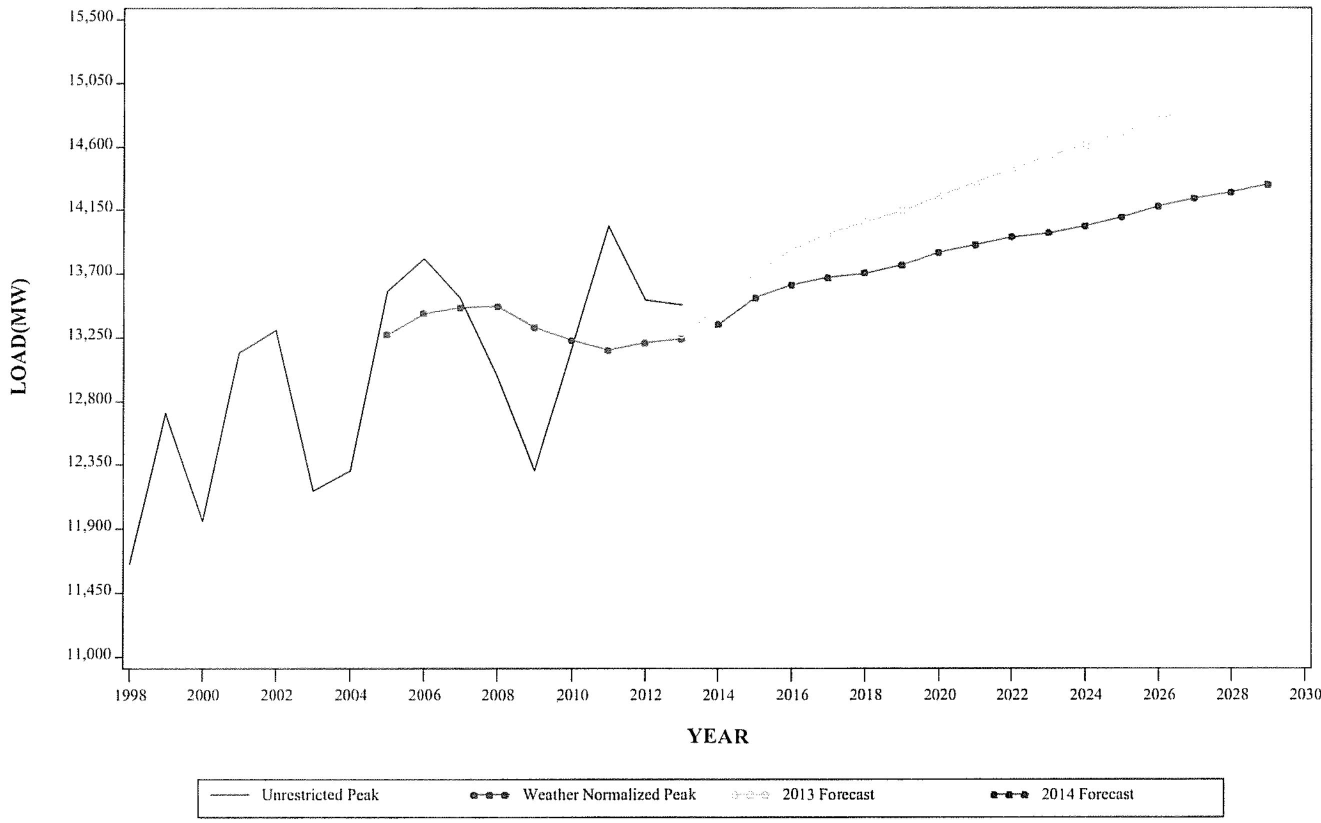
SUMMER PEAK DEMAND FOR APS GEOGRAPHIC ZONE



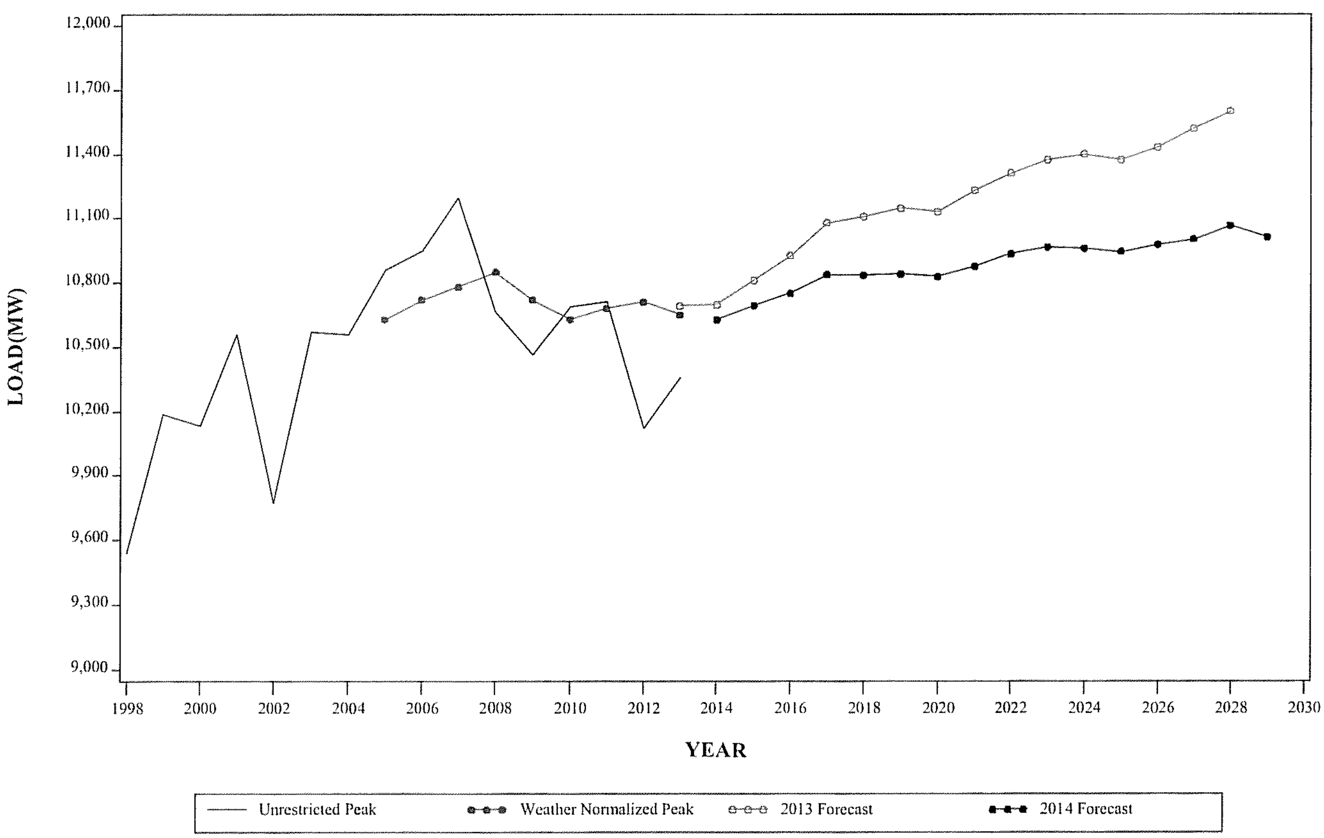
WINTER PEAK DEMAND FOR APS GEOGRAPHIC ZONE



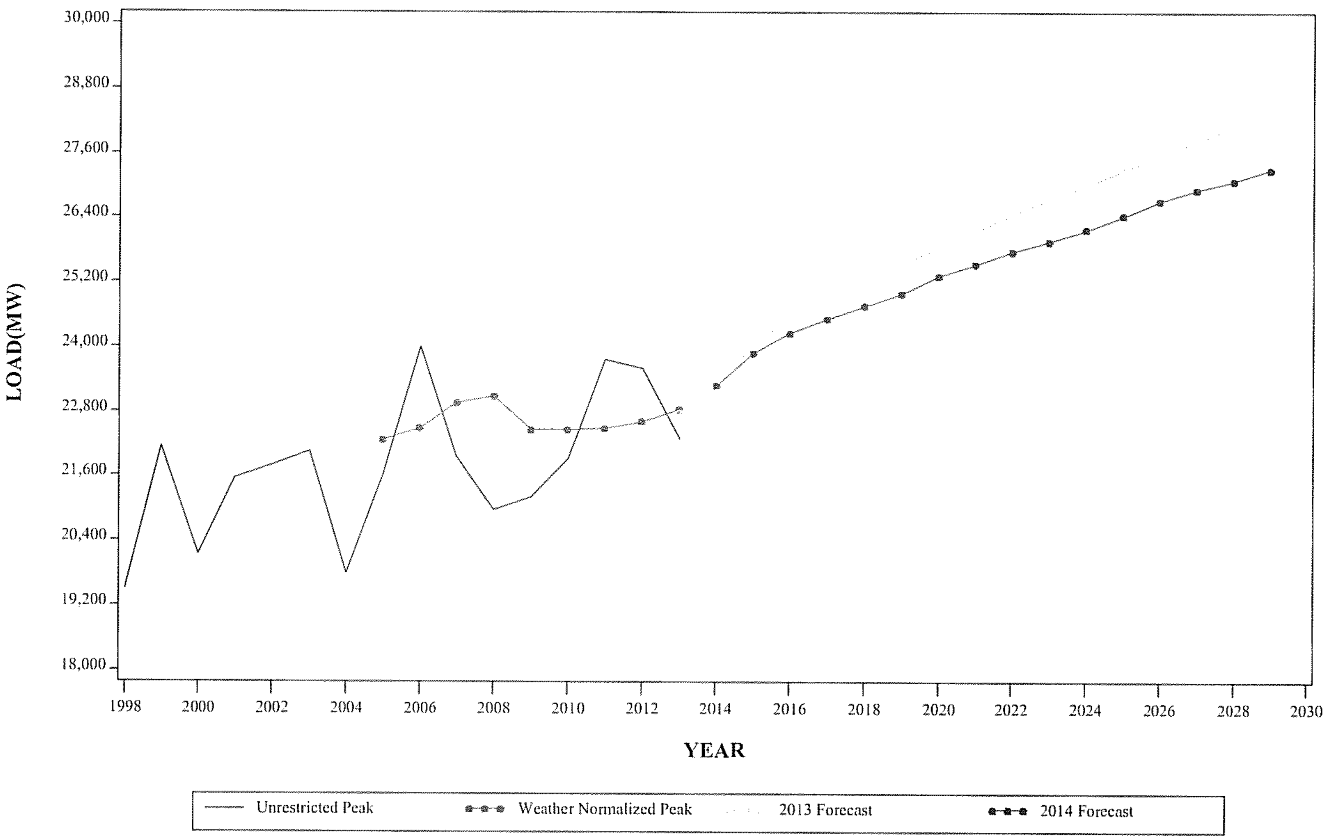
SUMMER PEAK DEMAND FOR ATSI GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR ATSI GEOGRAPHIC ZONE



SUMMER PEAK DEMAND FOR COMED GEOGRAPHIC ZONE



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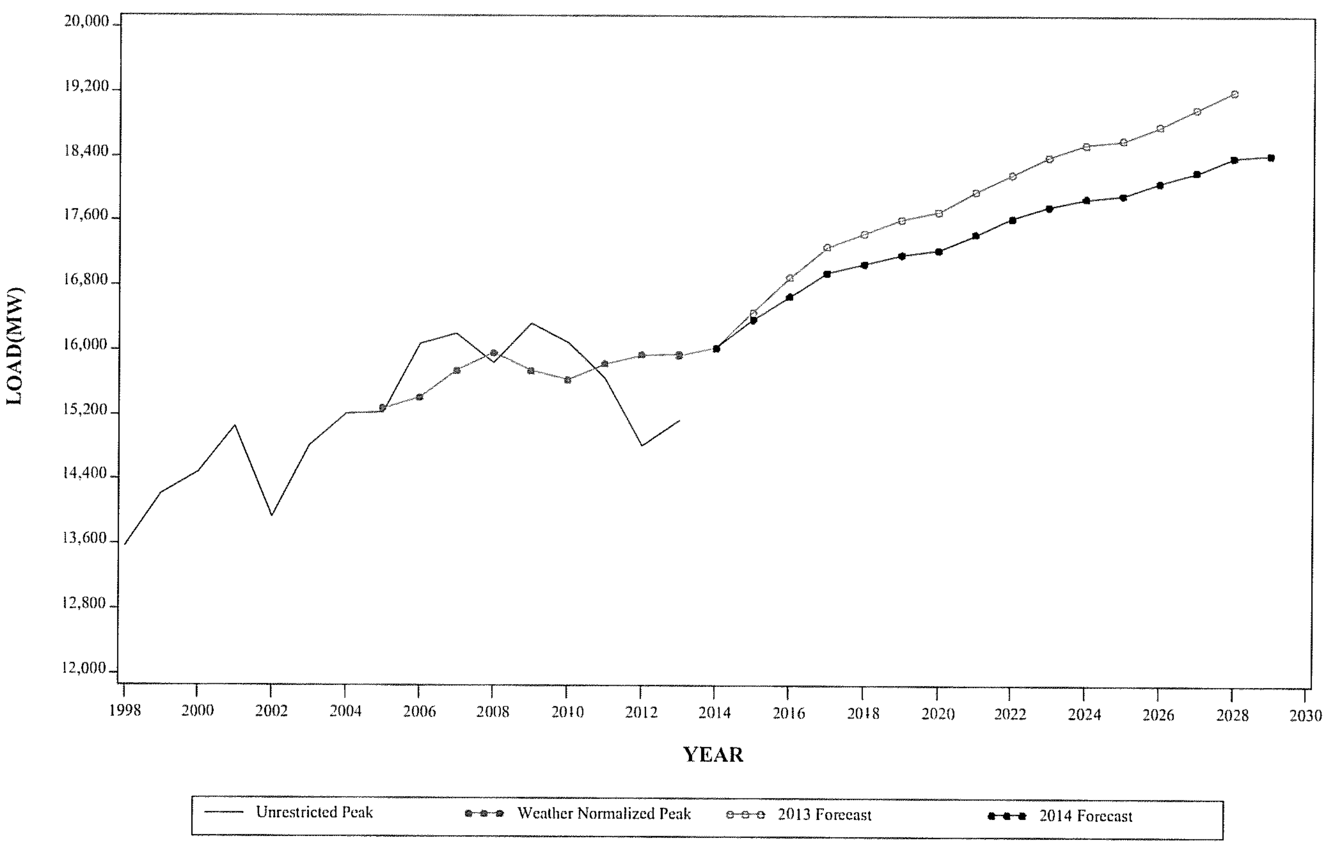
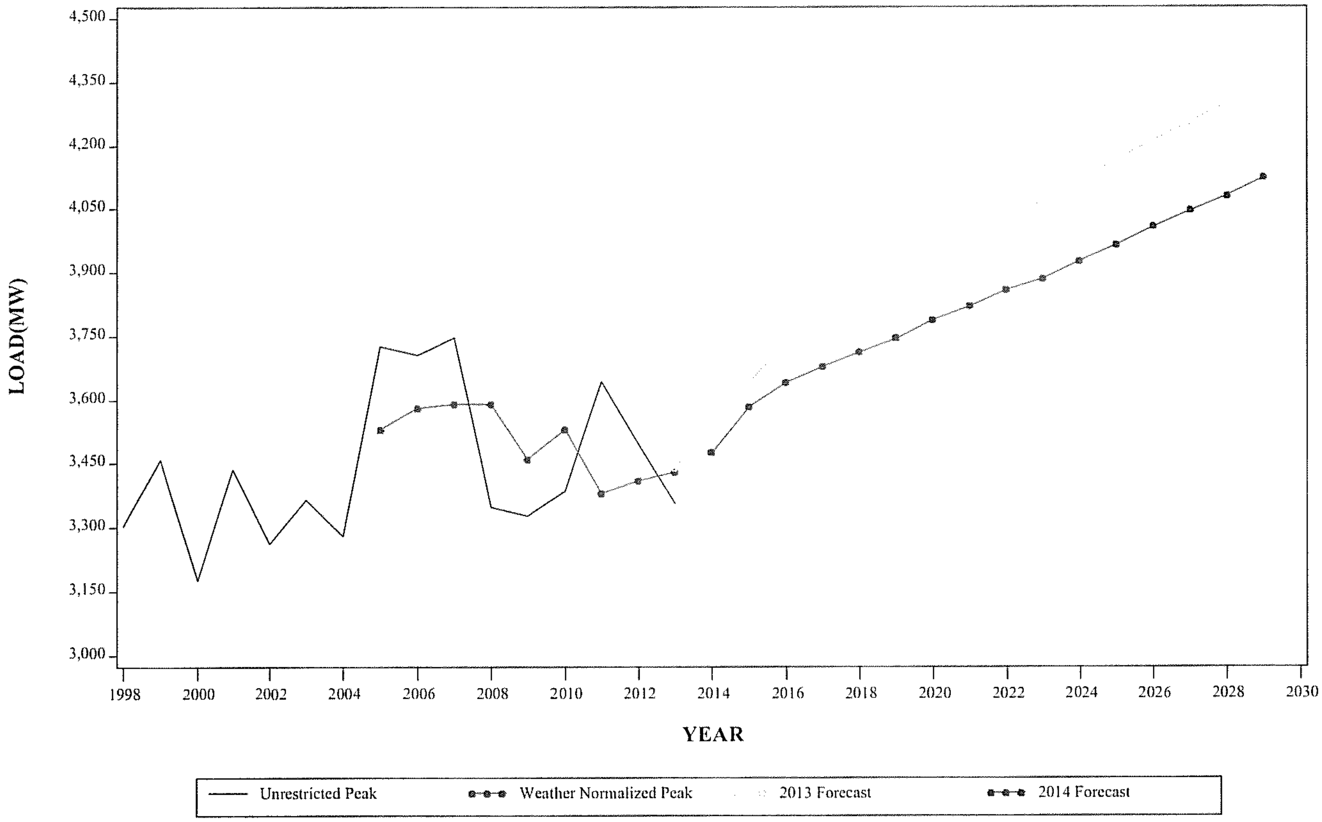
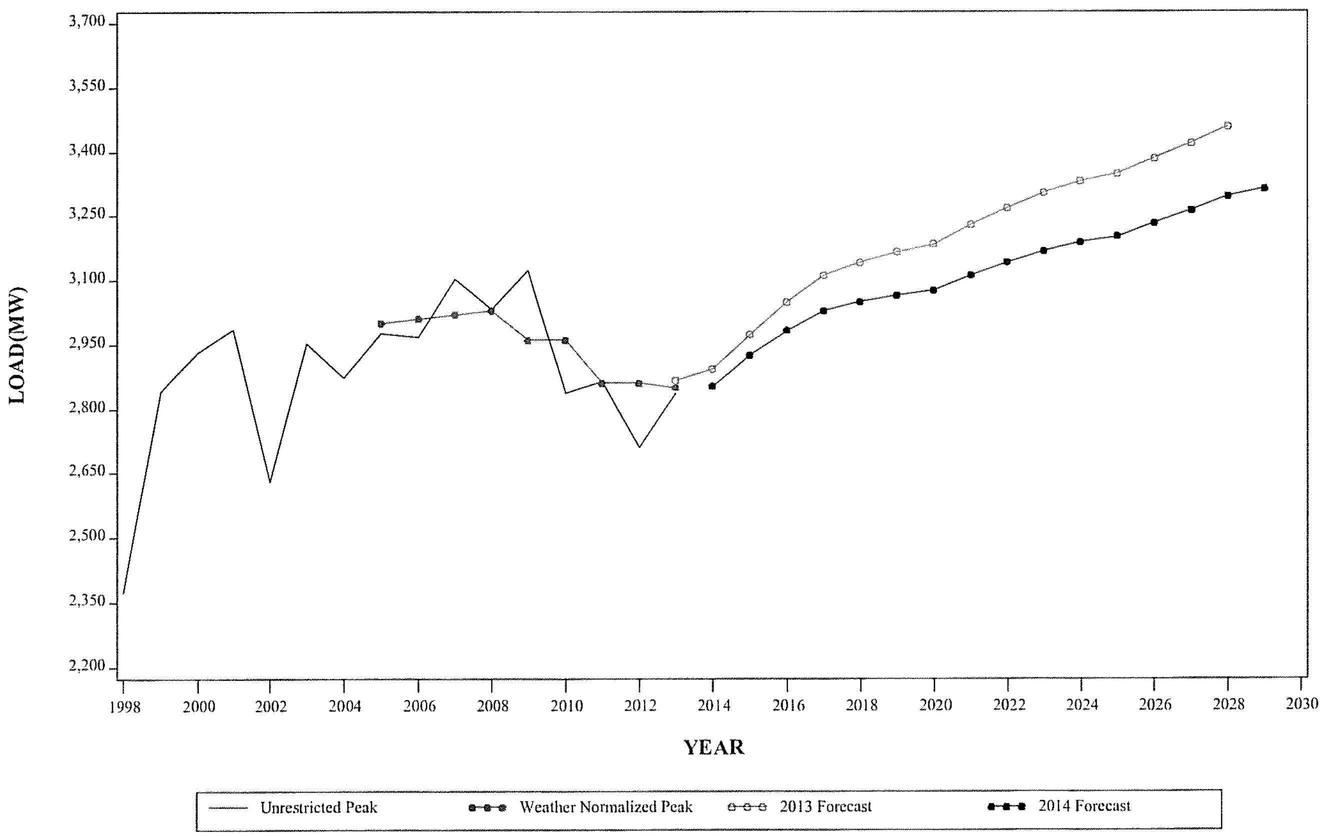


SUMMER PEAK DEMAND FOR DAYTON
GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR DAYTON
GEOGRAPHIC ZONE



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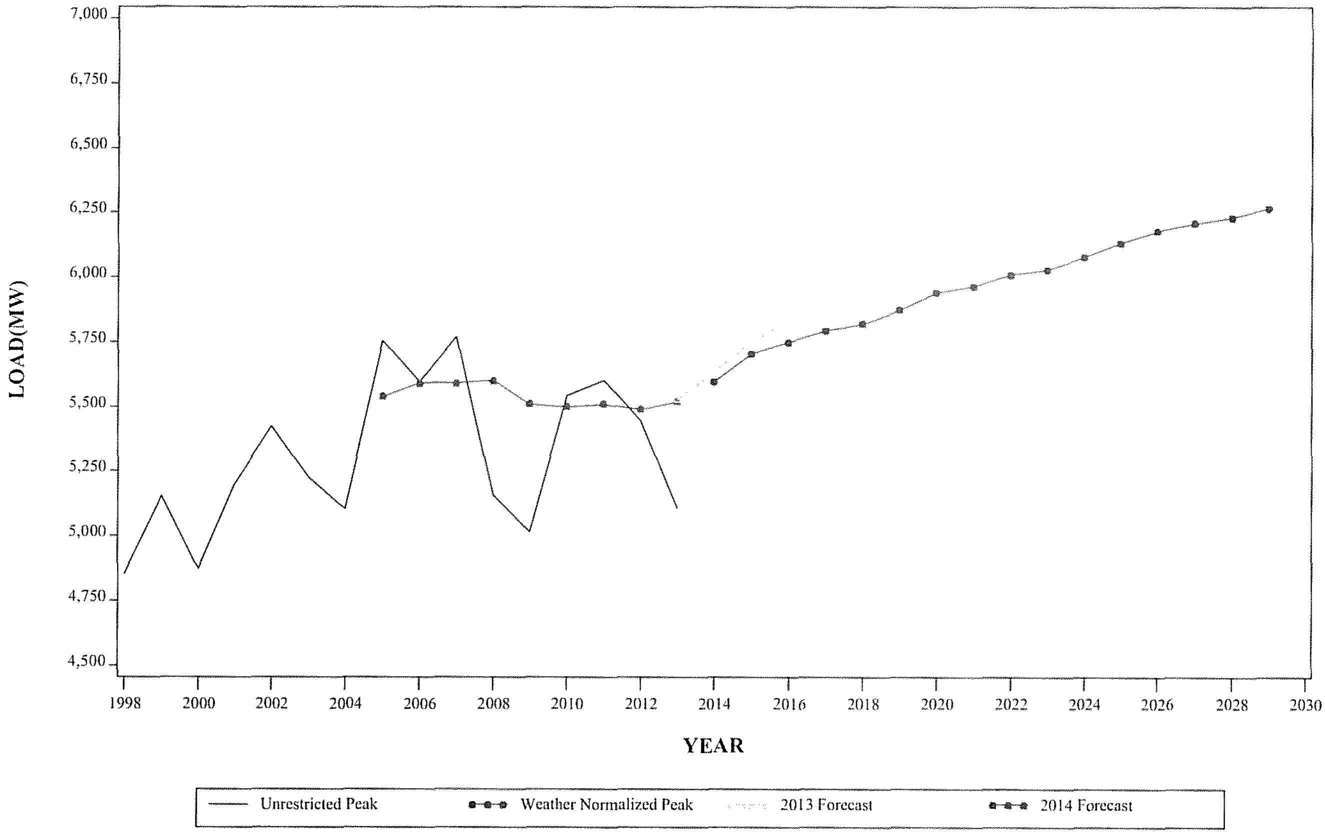

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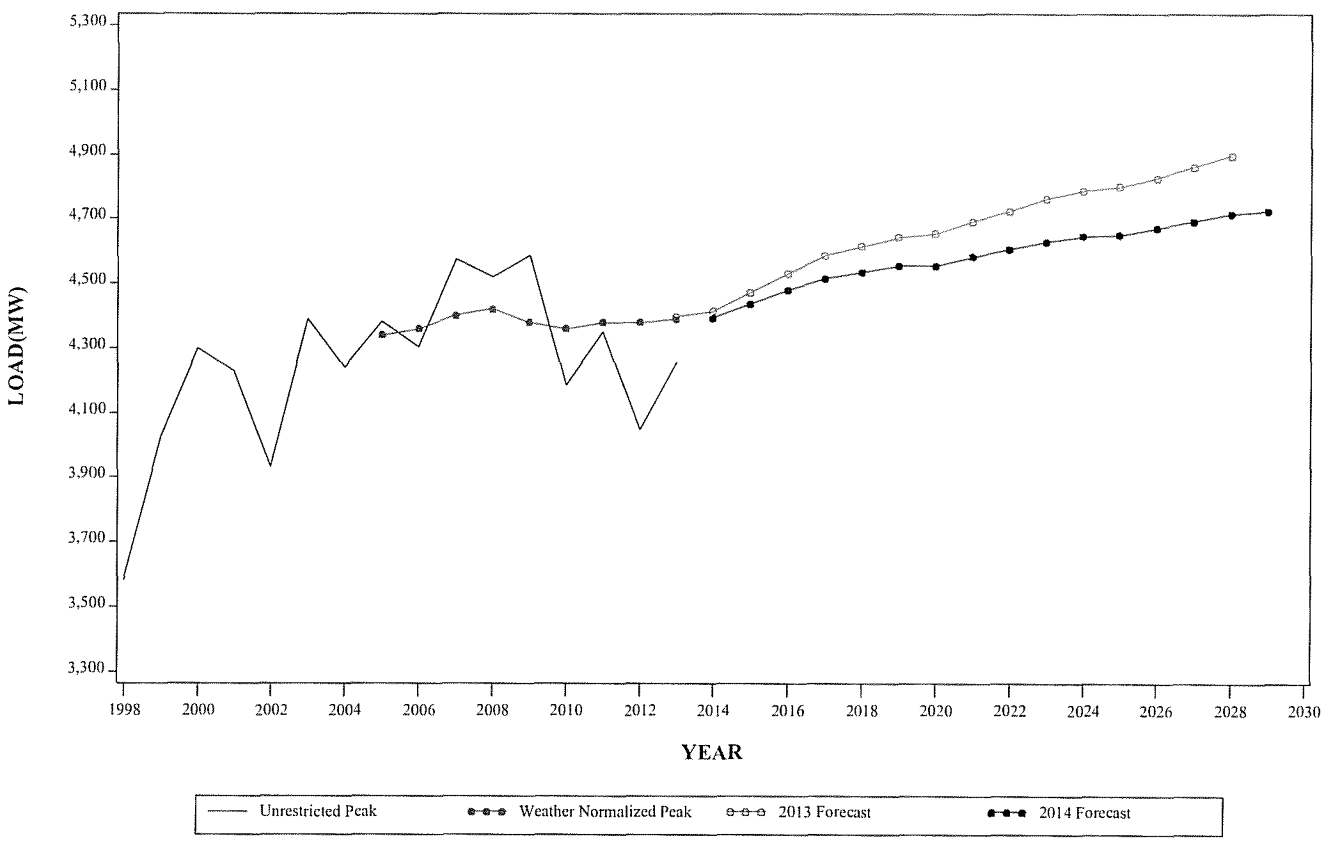
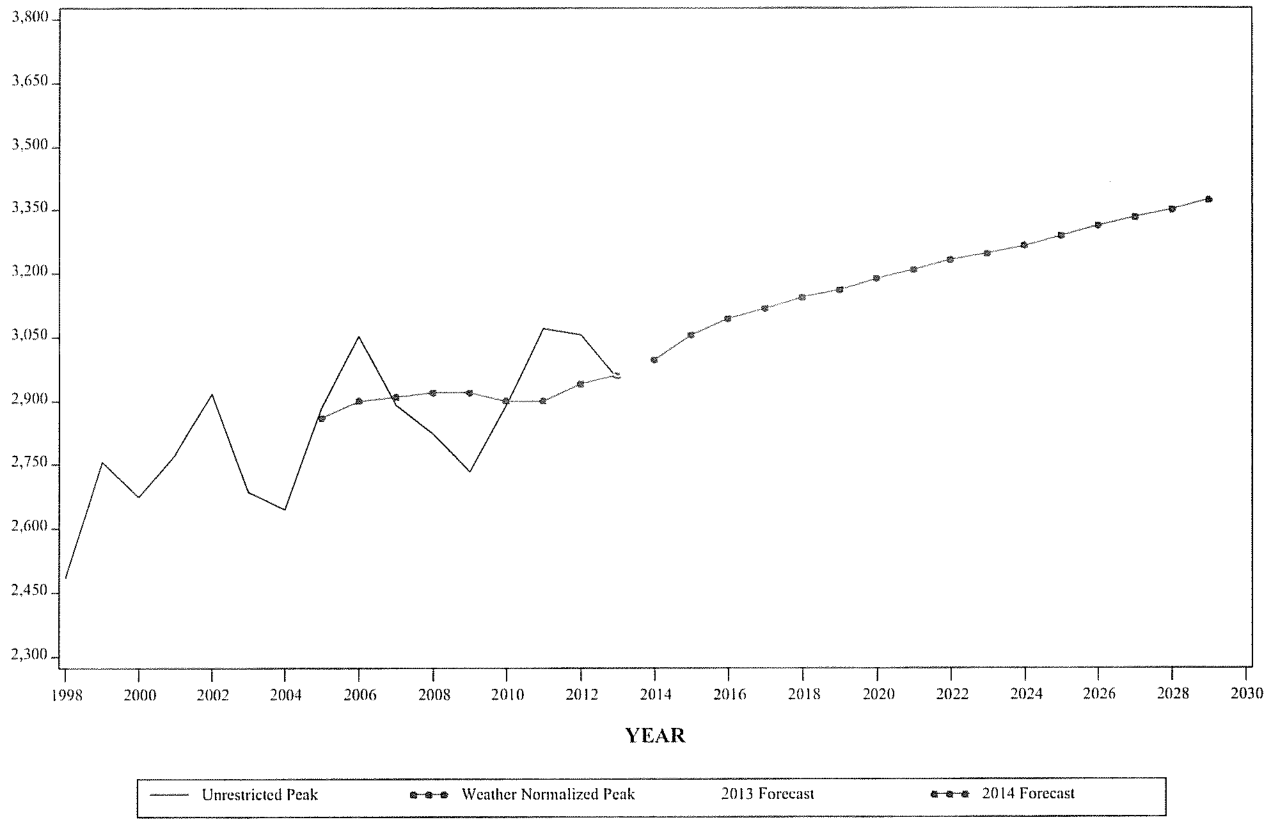
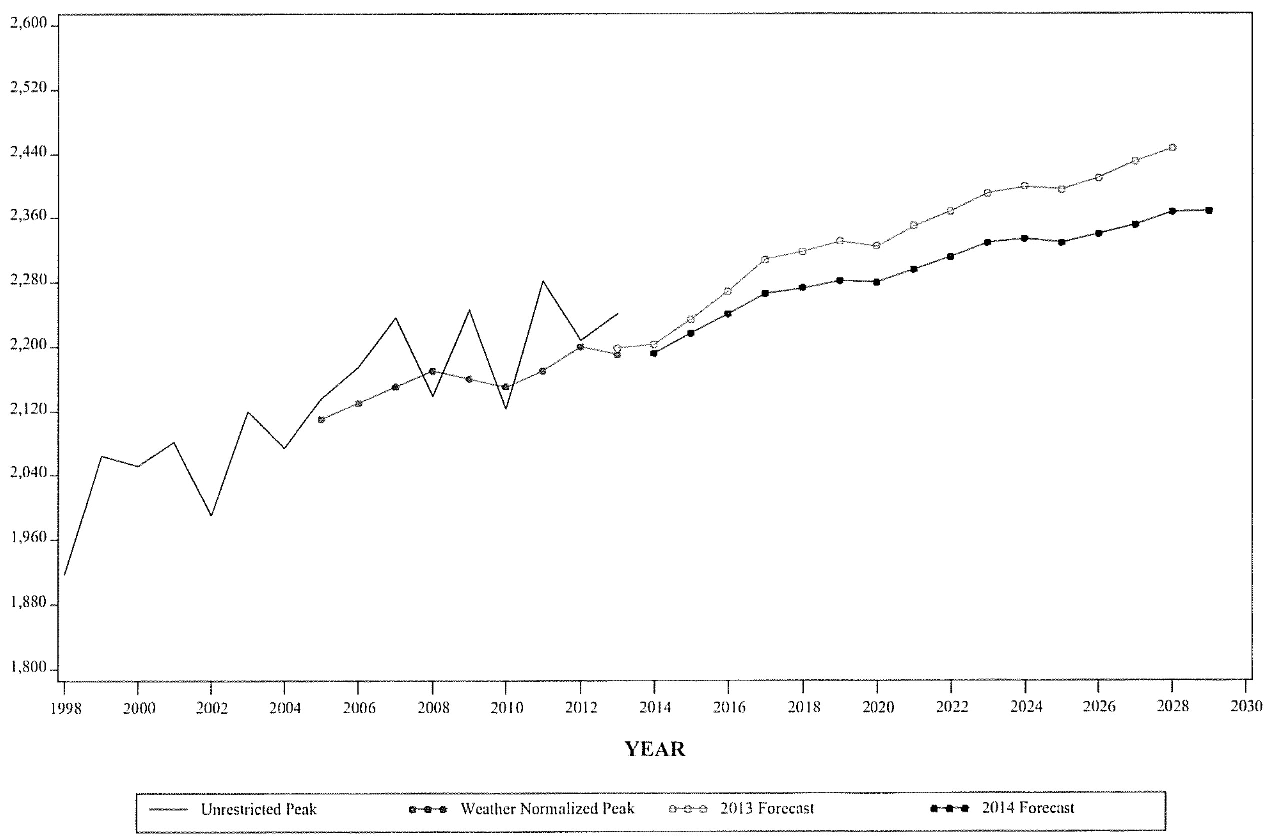


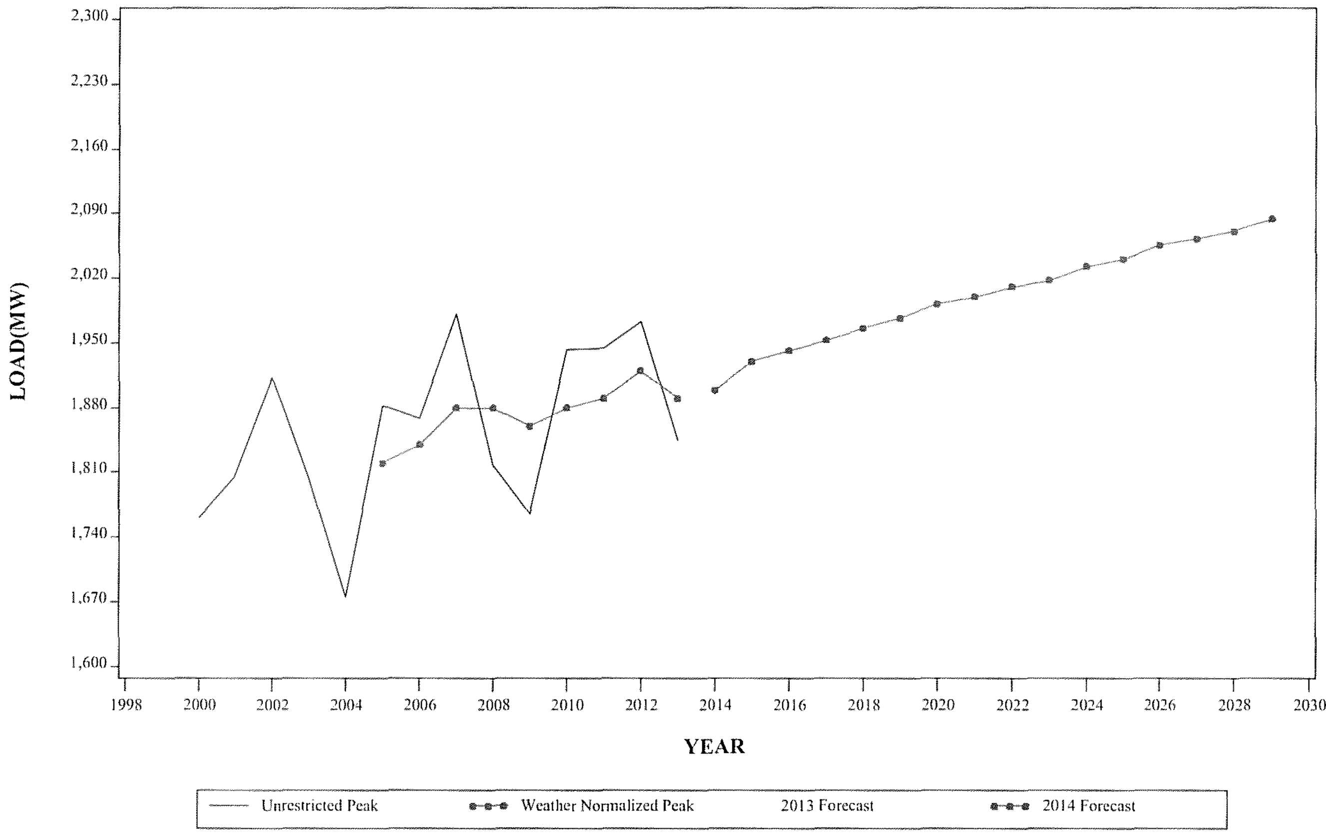
SUMMER PEAK DEMAND FOR DLCO
GEOGRAPHIC ZONE



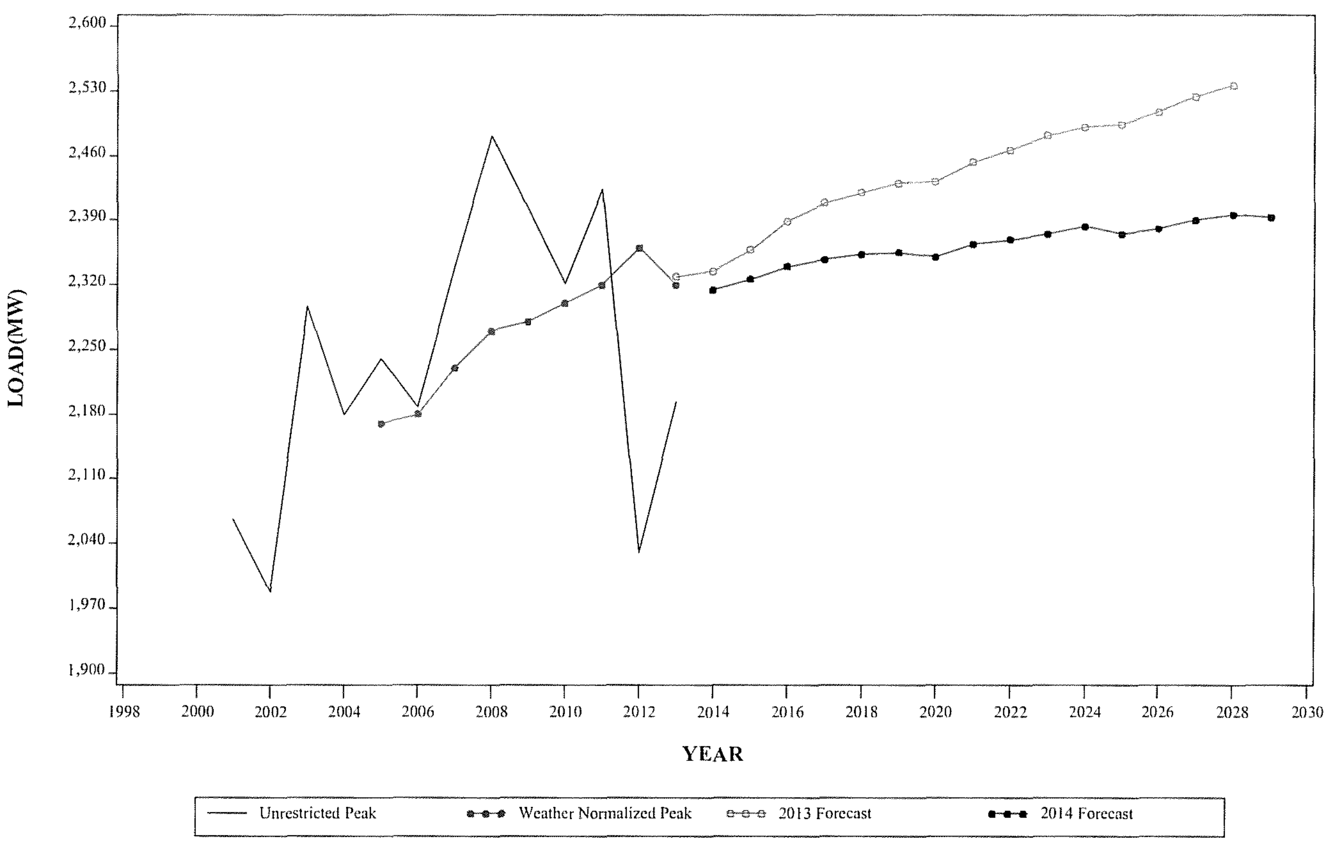
WINTER PEAK DEMAND FOR DLCO
GEOGRAPHIC ZONE



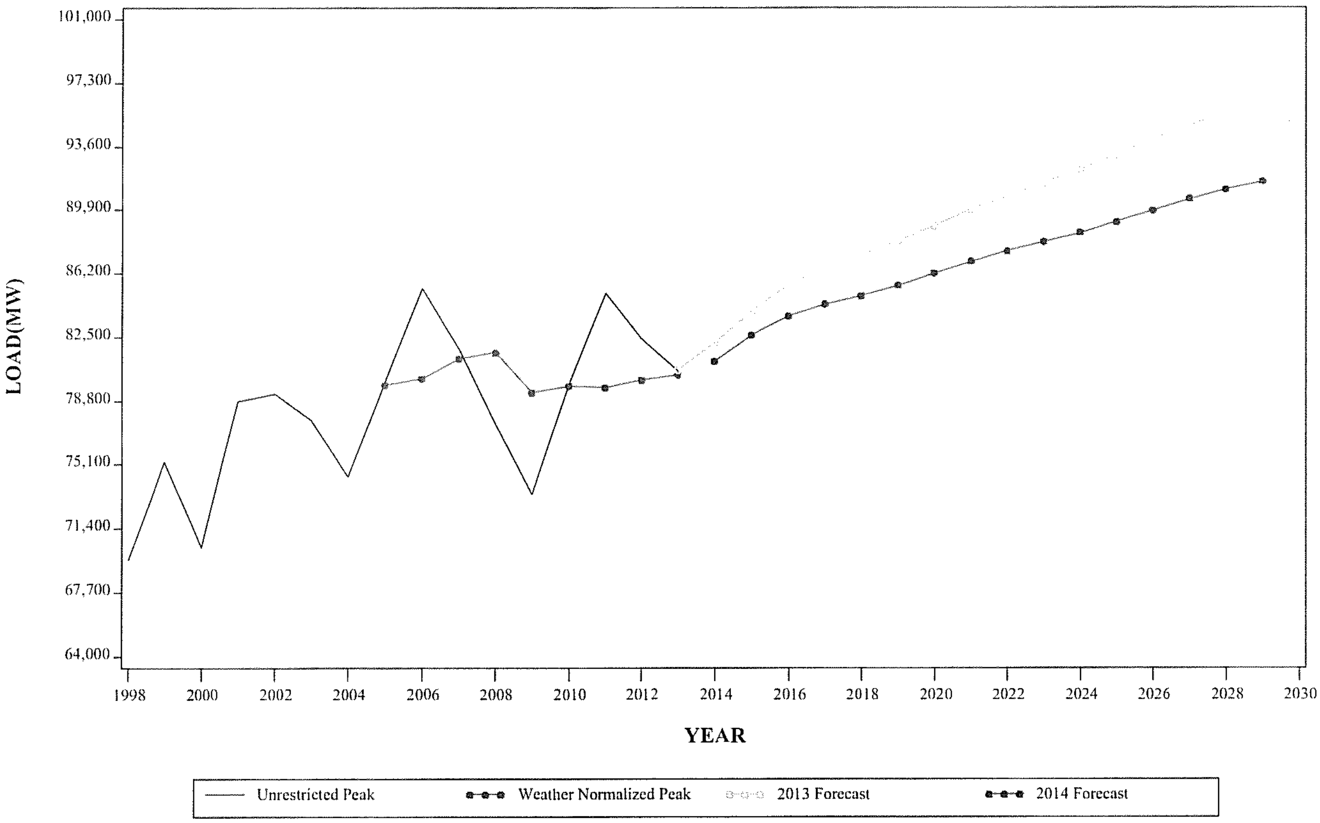
SUMMER PEAK DEMAND FOR EKPC GEOGRAPHIC ZONE



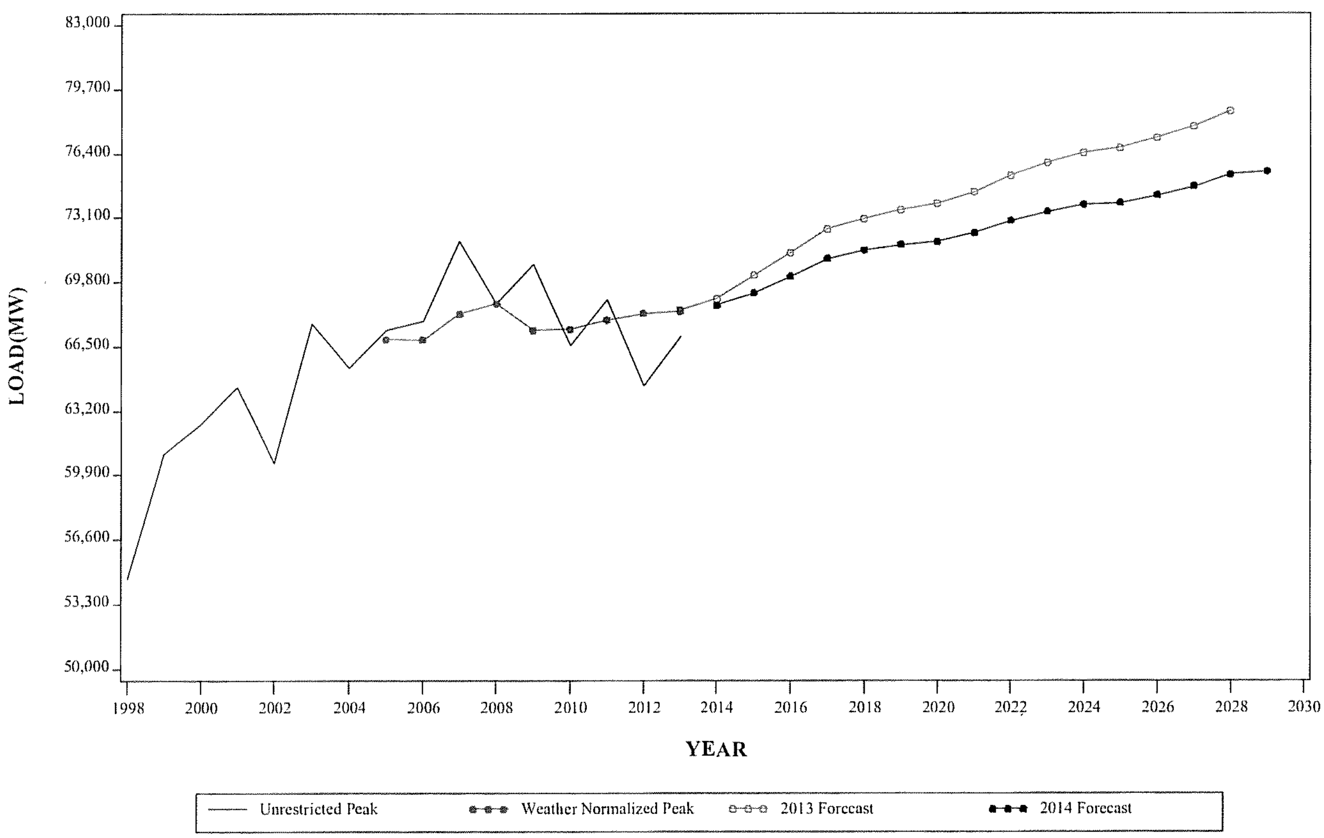
WINTER PEAK DEMAND FOR EKPC GEOGRAPHIC ZONE



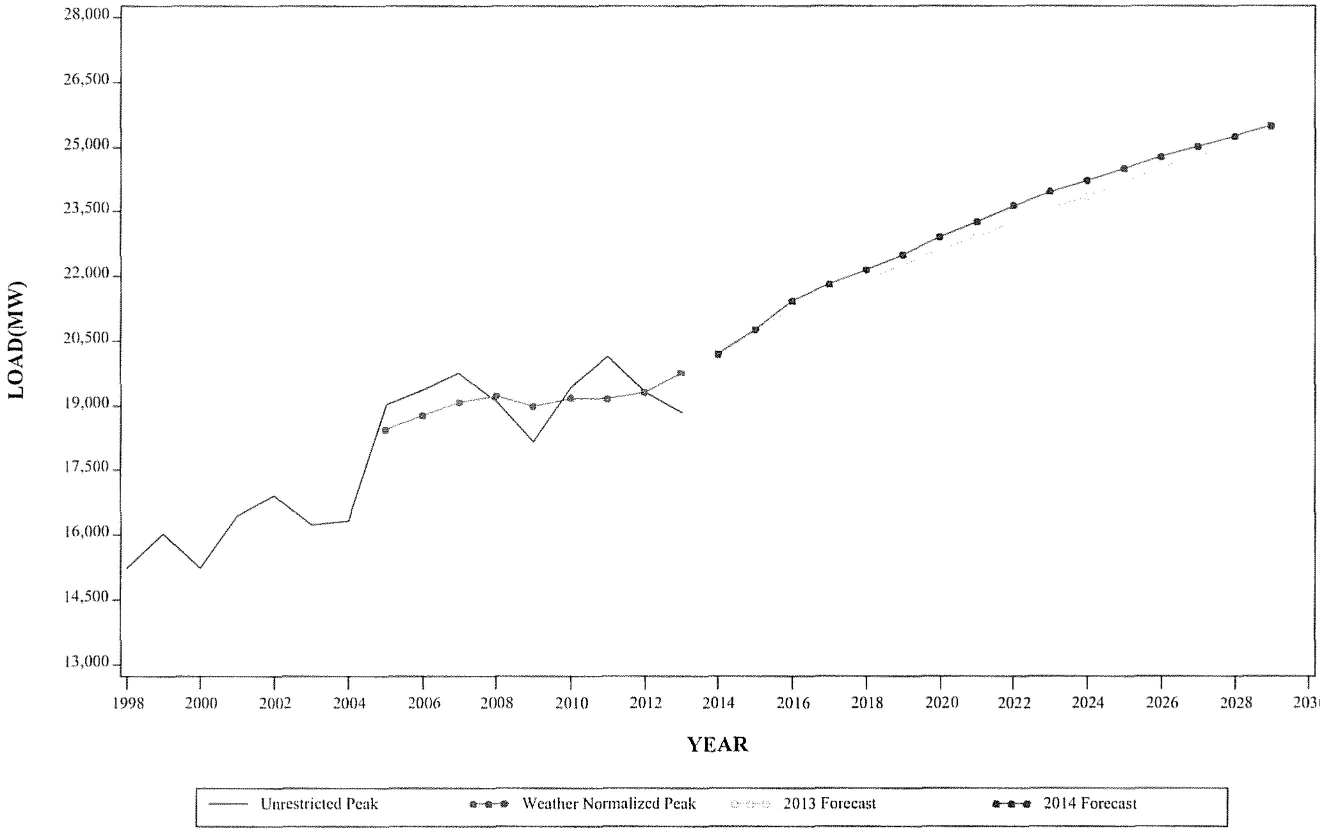
SUMMER PEAK DEMAND FOR PJM WESTERN GEOGRAPHIC ZONE



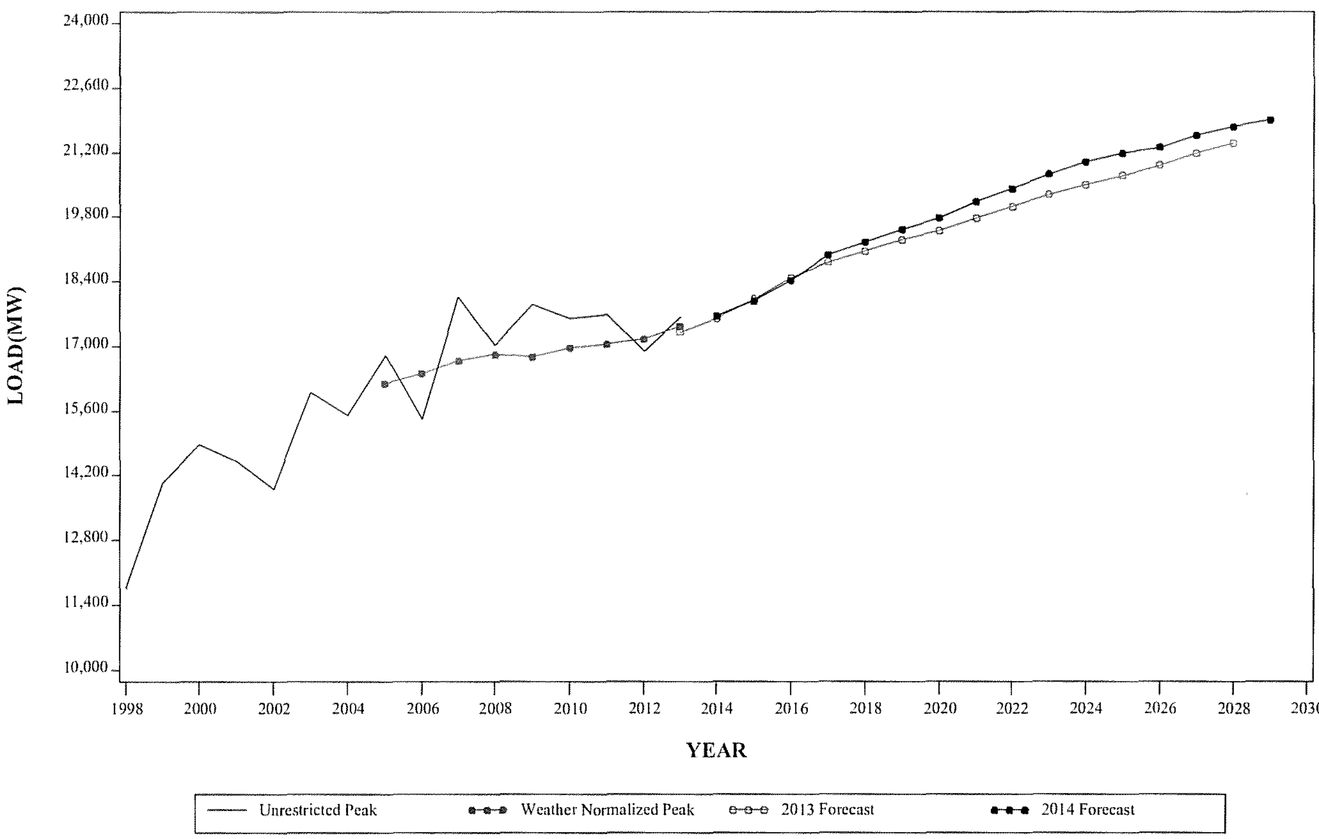
WINTER PEAK DEMAND FOR PJM WESTERN GEOGRAPHIC ZONE



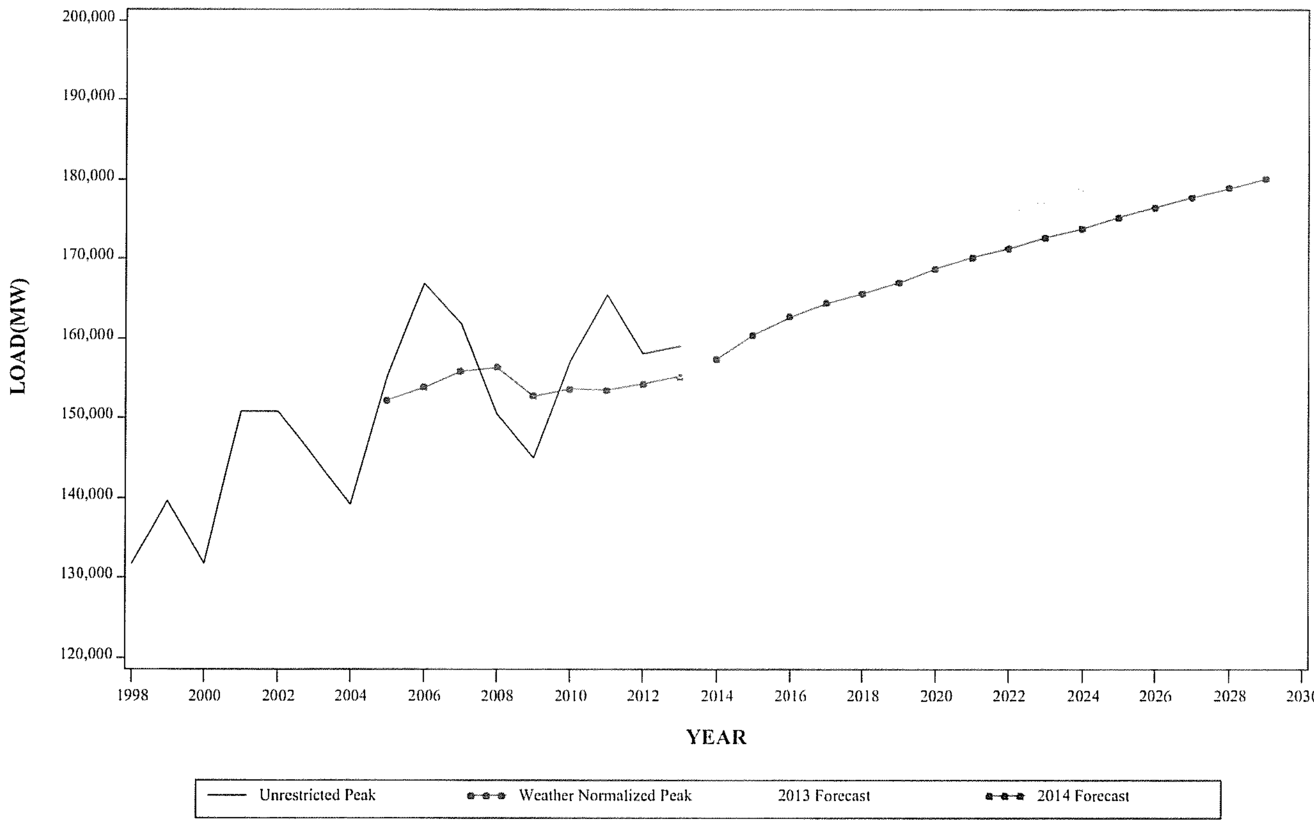
SUMMER PEAK DEMAND FOR DOM
GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR DOM
GEOGRAPHIC ZONE



SUMMER PEAK DEMAND FOR PJM RTO
GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR PJM RTO
GEOGRAPHIC ZONE

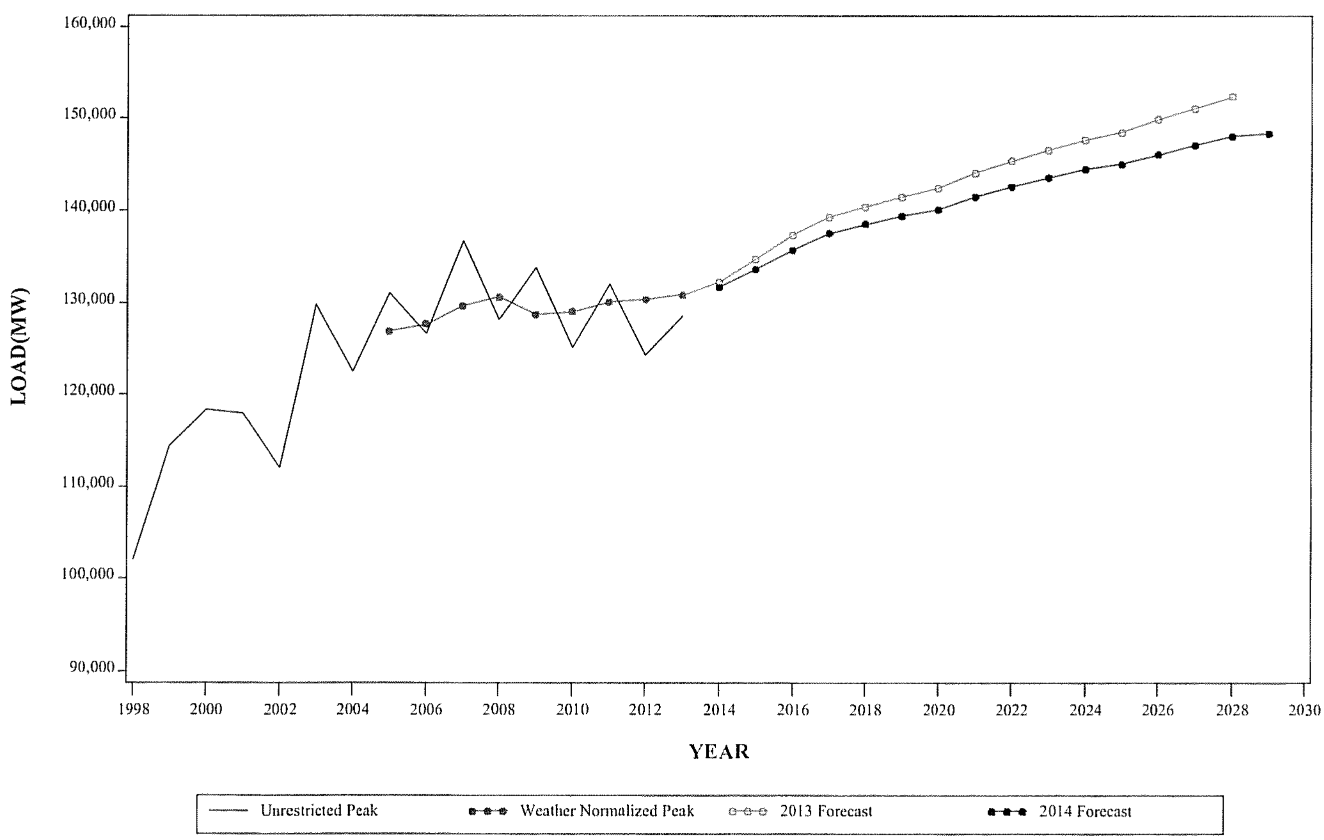


Table A-1

PJM MID-ATLANTIC REGION
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2013 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2014		2019		2024	
	MW	%	MW	%	MW	%
AE	(34)	-1.2%	(74)	-2.5%	(102)	-3.3%
BGE	70	1.0%	108	1.4%	3	0.0%
DPL	(37)	-0.9%	(100)	-2.2%	(164)	-3.4%
JCPL	(11)	-0.2%	(74)	-1.1%	(149)	-2.1%
METED	(28)	-0.9%	(68)	-2.0%	(105)	-3.0%
PECO	(58)	-0.7%	(191)	-2.0%	(298)	-2.9%
PENLC	(36)	-1.2%	(92)	-2.8%	(135)	-3.8%
PEPCO	(65)	-0.9%	(129)	-1.8%	(181)	-2.4%
PL	(69)	-0.9%	(175)	-2.2%	(258)	-3.1%
PS	(84)	-0.8%	(234)	-2.1%	(342)	-3.0%
RECO	(2)	-0.5%	(6)	-1.4%	(9)	-2.0%
UGI	(1)	-0.5%	(1)	-0.5%	(2)	-0.9%
PJM MID-ATLANTIC	(327)	-0.5%	(965)	-1.5%	(1,732)	-2.6%
FE-EAST	(84)	-0.7%	(283)	-2.1%	(444)	-3.2%
PLGRP	(69)	-0.9%	(183)	-2.3%	(265)	-3.1%

Table A-1

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2013 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2014		2019		2024	
	MW	%	MW	%	MW	%
AEP	(634)	-2.6%	(1,045)	-4.1%	(1,406)	-5.2%
APS	14	0.2%	(78)	-0.8%	(184)	-1.9%
ATSI	(118)	-0.9%	(388)	-2.7%	(570)	-3.9%
COMED	(68)	-0.3%	(538)	-2.1%	(817)	-3.0%
DAYTON	(58)	-1.6%	(135)	-3.5%	(192)	-4.7%
DEOK	(37)	-0.7%	(139)	-2.3%	(215)	-3.4%
DLCO	(24)	-0.8%	(58)	-1.8%	(85)	-2.5%
EKPC	(39)	-2.0%	(76)	-3.7%	(108)	-5.0%
PJM WESTERN	(1,071)	-1.3%	(2,575)	-2.9%	(3,670)	-4.0%
DOM	43	0.2%	239	1.1%	368	1.5%
PJM RTO	(1,318)	-0.8%	(3,457)	-2.0%	(5,190)	-2.9%

Table A-2

PJM MID-ATLANTIC REGION
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2013 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	13/14		18/19		23/24	
	MW	%	MW	%	MW	%
AE	(27)	-1.5%	(61)	-3.2%	(77)	-4.0%
BGE	(38)	-0.6%	163	2.6%	116	1.8%
DPL	(7)	-0.2%	(34)	-0.9%	(69)	-1.8%
JCPL	(19)	-0.5%	(104)	-2.4%	(162)	-3.6%
METED	(10)	-0.4%	(50)	-1.7%	(73)	-2.4%
PECO	(8)	-0.1%	(115)	-1.6%	(192)	-2.5%
PENLC	(24)	-0.8%	(74)	-2.2%	(109)	-3.1%
PEPCO	(31)	-0.6%	(88)	-1.5%	(128)	-2.1%
PL	(24)	-0.3%	(111)	-1.4%	(169)	-2.1%
PS	(47)	-0.7%	(142)	-1.9%	(212)	-2.8%
RECO	1	0.4%	(1)	-0.4%	(1)	-0.4%
UGI	0	0.0%	(2)	-0.9%	(2)	-0.9%
PJM MID-ATLANTIC	(206)	-0.4%	(586)	-1.2%	(1,056)	-2.0%
FE-EAST	(49)	-0.5%	(216)	-2.1%	(334)	-3.0%
PLGRP	(27)	-0.4%	(117)	-1.5%	(174)	-2.1%

Table A-2

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2013 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	13/14		18/19		23/24	
	MW	%	MW	%	MW	%
AEP	(96)	-0.4%	(765)	-3.1%	(1,006)	-4.0%
APS	15	0.2%	6	0.1%	(84)	-0.9%
ATSI	(70)	-0.7%	(306)	-2.7%	(440)	-3.9%
COMED	(10)	-0.1%	(436)	-2.5%	(666)	-3.6%
DAYTON	(41)	-1.4%	(101)	-3.2%	(143)	-4.3%
DEOK	(23)	-0.5%	(90)	-1.9%	(140)	-2.9%
DLCO	(11)	-0.5%	(49)	-2.1%	(65)	-2.7%
EKPC	(21)	-0.9%	(75)	-3.1%	(108)	-4.3%
PJM WESTERN	(329)	-0.5%	(1,785)	-2.4%	(2,639)	-3.5%
DOM	51	0.3%	237	1.2%	498	2.4%
PJM RTO	(510)	-0.4%	(2,074)	-1.5%	(3,234)	-2.2%

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2014 - 2024

	METERED 2013	UNRESTRICTED 2013	NORMAL 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Annual Growth Rate (10 yr)
AE	2,740	2,740	2,700	2,750	2,806	2,840	2,860	2,877	2,891	2,910	2,928	2,946	2,954	2,969	0.8%
				1.9%	2.0%	1.2%	0.7%	0.6%	0.5%	0.7%	0.6%	0.6%	0.3%	0.5%	
BGE	6,831	7,039	7,220	7,403	7,579	7,705	7,788	7,823	7,878	7,941	7,985	8,026	8,053	8,094	0.9%
				2.5%	2.4%	1.7%	1.1%	0.4%	0.7%	0.8%	0.6%	0.5%	0.3%	0.5%	
DPL	4,019	4,019	4,130	4,181	4,261	4,314	4,351	4,388	4,427	4,470	4,504	4,538	4,562	4,600	1.0%
				1.2%	1.9%	1.2%	0.9%	0.9%	0.9%	1.0%	0.8%	0.8%	0.5%	0.8%	
JCPL	6,379	6,379	6,270	6,361	6,494	6,584	6,629	6,651	6,721	6,788	6,828	6,882	6,897	6,944	0.9%
				1.5%	2.1%	1.4%	0.7%	0.3%	1.1%	1.0%	0.6%	0.8%	0.2%	0.7%	
METED	3,013	3,013	2,970	3,019	3,096	3,147	3,189	3,222	3,260	3,303	3,339	3,378	3,408	3,444	1.3%
				1.6%	2.6%	1.6%	1.3%	1.0%	1.2%	1.3%	1.1%	1.2%	0.9%	1.1%	
PECO	8,619	8,655	8,720	8,843	9,032	9,147	9,237	9,330	9,421	9,522	9,602	9,684	9,746	9,827	1.1%
				1.4%	2.1%	1.3%	1.0%	1.0%	1.0%	1.1%	0.8%	0.9%	0.6%	0.8%	
PENLC	3,088	3,088	2,910	2,966	3,059	3,122	3,168	3,203	3,246	3,292	3,332	3,372	3,404	3,441	1.5%
				1.9%	3.1%	2.1%	1.5%	1.1%	1.3%	1.4%	1.2%	1.2%	0.9%	1.1%	
PEPCO	6,534	6,534	6,810	6,870	6,948	6,985	7,005	7,037	7,086	7,150	7,177	7,208	7,207	7,249	0.5%
				0.9%	1.1%	0.5%	0.3%	0.5%	0.7%	0.9%	0.4%	0.4%	-0.0%	0.6%	
PL	7,190	7,328	7,240	7,334	7,477	7,568	7,635	7,686	7,767	7,842	7,901	7,970	8,013	8,079	1.0%
				1.3%	1.9%	1.2%	0.9%	0.7%	1.1%	1.0%	0.8%	0.9%	0.5%	0.8%	
PS	10,415	10,415	10,530	10,614	10,760	10,845	10,888	10,915	10,974	11,034	11,080	11,127	11,139	11,185	0.5%
				0.8%	1.4%	0.8%	0.4%	0.2%	0.5%	0.5%	0.4%	0.4%	0.1%	0.4%	
RECO	439	439	420	423	427	430	431	432	433	436	438	438	438	439	0.4%
				0.7%	0.9%	0.7%	0.2%	0.2%	0.2%	0.7%	0.5%	0.0%	0.0%	0.2%	
UGI	205	205	200	198	202	205	207	208	210	212	214	215	216	218	1.0%
				-1.0%	2.0%	1.5%	1.0%	0.5%	1.0%	1.0%	0.9%	0.5%	0.5%	0.9%	
DIVERSITY - MID-ATLANTIC(-)				511	597	547	513	591	493	593	559	574	465	507	
PJM MID-ATLANTIC	59,119	59,580	59,505	60,451	61,544	62,345	62,875	63,181	63,821	64,307	64,769	65,210	65,572	65,982	0.9%
				1.6%	1.8%	1.3%	0.9%	0.5%	1.0%	0.8%	0.7%	0.7%	0.6%	0.6%	
FE-EAST	12,402	12,402	11,960	12,174	12,434	12,638	12,778	12,887	13,016	13,143	13,266	13,392	13,490	13,612	1.1%
				1.8%	2.1%	1.6%	1.1%	0.9%	1.0%	1.0%	0.9%	0.9%	0.7%	0.9%	
PLGRP	7,393	7,532	7,410	7,507	7,639	7,742	7,822	7,873	7,950	8,015	8,083	8,150	8,210	8,274	1.0%
				1.3%	1.8%	1.3%	1.0%	0.7%	1.0%	0.8%	0.8%	0.8%	0.7%	0.8%	

Notes:
Normal 2013 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2013 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Table B-1 (Continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2025 - 2029

	2025	2026	2027	2028	2029	Annual Growth Rate (15 yr)
AE	2,985	3,003	3,019	3,031	3,050	0.7%
	0.5%	0.6%	0.5%	0.4%	0.6%	
BGE	8,140	8,192	8,222	8,250	8,288	0.8%
	0.6%	0.6%	0.4%	0.3%	0.5%	
DPL	4,635	4,671	4,701	4,721	4,753	0.9%
	0.8%	0.8%	0.6%	0.4%	0.7%	
JCPL	6,992	7,048	7,086	7,126	7,149	0.8%
	0.7%	0.8%	0.5%	0.6%	0.3%	
METED	3,483	3,524	3,560	3,594	3,632	1.2%
	1.1%	1.2%	1.0%	1.0%	1.1%	
PECO	9,910	9,996	10,073	10,145	10,227	1.0%
	0.8%	0.9%	0.8%	0.7%	0.8%	
PENLC	3,480	3,519	3,554	3,584	3,610	1.3%
	1.1%	1.1%	1.0%	0.8%	0.7%	
PEPCO	7,299	7,337	7,357	7,362	7,381	0.5%
	0.7%	0.5%	0.3%	0.1%	0.3%	
PL	8,146	8,211	8,270	8,319	8,368	0.9%
	0.8%	0.8%	0.7%	0.6%	0.6%	
PS	11,235	11,285	11,327	11,343	11,383	0.5%
	0.4%	0.4%	0.4%	0.1%	0.4%	
RECO	441	442	444	444	444	0.3%
	0.5%	0.2%	0.5%	0.0%	0.0%	
UGI	219	221	222	224	225	0.9%
	0.5%	0.9%	0.5%	0.9%	0.4%	
DIVERSITY - MID-ATLANTIC(-)	585	640	594	522	520	
PJM MID-ATLANTIC	66,380	66,809	67,241	67,621	67,990	0.8%
	0.6%	0.6%	0.6%	0.6%	0.5%	
FE-EAST	13,726	13,835	13,956	14,070	14,186	1.0%
	0.8%	0.8%	0.9%	0.8%	0.8%	
PLGRP	8,338	8,398	8,463	8,520	8,574	0.9%
	0.8%	0.7%	0.8%	0.7%	0.6%	

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2014 - 2024

	METERED 2013	UNRESTRICTED 2013	NORMAL 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Annual Growth Rate (10 yr)
AEP	22,859	22,947	23,660	23,556	23,982	24,220	24,358	24,516	24,667	24,850	25,011	25,153	25,255	25,414	0.8%
				-0.4%	1.8%	1.0%	0.6%	0.6%	0.6%	0.7%	0.6%	0.6%	0.4%	0.6%	
APS	8,678	8,682	8,640	8,837	9,024	9,147	9,217	9,282	9,355	9,448	9,521	9,597	9,651	9,722	1.0%
				2.3%	2.1%	1.4%	0.8%	0.7%	0.8%	1.0%	0.8%	0.8%	0.6%	0.7%	
ATSI	13,142	13,480	13,240	13,341	13,530	13,620	13,670	13,705	13,760	13,850	13,905	13,960	13,987	14,038	0.5%
				0.8%	1.4%	0.7%	0.4%	0.3%	0.4%	0.7%	0.4%	0.4%	0.2%	0.4%	
COMED	22,270	22,290	22,830	23,275	23,879	24,246	24,521	24,759	24,991	25,311	25,536	25,768	25,954	26,182	1.2%
				1.9%	2.6%	1.5%	1.1%	1.0%	0.9%	1.3%	0.9%	0.9%	0.7%	0.9%	
DAYTON	3,358	3,358	3,430	3,476	3,583	3,641	3,678	3,712	3,745	3,788	3,821	3,859	3,884	3,926	1.2%
				1.3%	3.1%	1.6%	1.0%	0.9%	0.9%	1.1%	0.9%	1.0%	0.6%	1.1%	
DEOK	5,109	5,109	5,520	5,597	5,704	5,747	5,794	5,820	5,874	5,942	5,966	6,009	6,030	6,079	0.8%
				1.4%	1.9%	0.8%	0.8%	0.4%	0.9%	1.2%	0.4%	0.7%	0.3%	0.8%	
DLCO	2,952	2,952	2,960	2,997	3,056	3,094	3,118	3,143	3,162	3,189	3,209	3,232	3,246	3,266	0.9%
				1.3%	2.0%	1.2%	0.8%	0.8%	0.6%	0.9%	0.6%	0.7%	0.4%	0.6%	
EKPC	1,845	1,845	1,890	1,899	1,930	1,942	1,953	1,966	1,977	1,992	2,000	2,011	2,018	2,033	0.7%
				0.5%	1.6%	0.6%	0.6%	0.7%	0.6%	0.8%	0.4%	0.6%	0.3%	0.7%	
DIVERSITY - WESTERN(-)				1,876	2,088	1,947	1,905	2,022	2,031	2,150	2,081	2,099	1,981	2,095	
PJM WESTERN	79,811	80,536	80,320	81,102	82,600	83,710	84,404	84,881	85,500	86,220	86,888	87,490	88,044	88,565	0.9%
				1.0%	1.8%	1.3%	0.8%	0.6%	0.7%	0.8%	0.8%	0.7%	0.6%	0.6%	
DOM	18,763	18,839	19,760	20,197	20,765	21,433	21,812	22,156	22,501	22,914	23,262	23,641	23,966	24,224	1.8%
				2.2%	2.8%	3.2%	1.8%	1.6%	1.6%	1.8%	1.5%	1.6%	1.4%	1.1%	
DIVERSITY - INTERREGIONAL(-)				4,351	4,470	4,768	4,657	4,543	4,758	4,698	4,743	4,984	4,903	4,919	
PJM RTO	157,141	158,954	155,185	157,399	160,439	162,720	164,434	165,675	167,064	168,743	170,176	171,357	172,679	173,852	1.0%
				1.4%	1.9%	1.4%	1.1%	0.8%	0.8%	1.0%	0.8%	0.7%	0.8%	0.7%	

Notes:
Normal 2013 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2013 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Table B-1 (Continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2025 - 2029

	2025	2026	2027	2028	2029	Annual Growth Rate (15 yr)
AEP	25,590	25,749	25,929	26,038	26,232	0.7%
	0.7%	0.6%	0.7%	0.4%	0.7%	
APS	9,799	9,882	9,953	10,013	10,085	0.9%
	0.8%	0.8%	0.7%	0.6%	0.7%	
ATSI	14,101	14,175	14,234	14,273	14,329	0.5%
	0.4%	0.5%	0.4%	0.3%	0.4%	
COMED	26,439	26,716	26,927	27,090	27,293	1.1%
	1.0%	1.0%	0.8%	0.6%	0.7%	
DAYTON	3,965	4,008	4,046	4,079	4,123	1.1%
	1.0%	1.1%	0.9%	0.8%	1.1%	
DEOK	6,133	6,179	6,209	6,231	6,267	0.8%
	0.9%	0.8%	0.5%	0.4%	0.6%	
DLCO	3,289	3,313	3,333	3,351	3,373	0.8%
	0.7%	0.7%	0.6%	0.5%	0.7%	
EKPC	2,041	2,056	2,063	2,071	2,084	0.6%
	0.4%	0.7%	0.3%	0.4%	0.6%	
DIVERSITY - WESTERN(-)	2,190	2,221	2,157	2,069	2,244	
PJM WESTERN	89,167	89,857	90,537	91,077	91,542	0.8%
	0.7%	0.8%	0.8%	0.6%	0.5%	
DOM	24,494	24,764	25,011	25,243	25,481	1.6%
	1.1%	1.1%	1.0%	0.9%	0.9%	
DIVERSITY - INTERREGIONAL(-)	4,839	4,928	4,987	4,986	4,876	
PJM RTO	175,202	176,502	177,802	178,955	180,137	0.9%
	0.8%	0.7%	0.7%	0.6%	0.7%	

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2013/14 - 2023/24

	METERED 12/13	UNRESTRICTED 12/13	NORMAL 12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	Annual Growth Rate (10 yr)
AE	1,647	1,647	1,740	1,752	1,779	1,802	1,824	1,828	1,833	1,834	1,850	1,861	1,870	1,872	0.7%
				0.7%	1.5%	1.3%	1.2%	0.2%	0.3%	0.1%	0.9%	0.6%	0.5%	0.1%	
BGE	5,805	5,805	5,950	5,956	6,123	6,227	6,320	6,376	6,397	6,405	6,444	6,463	6,487	6,501	0.9%
				0.1%	2.8%	1.7%	1.5%	0.9%	0.3%	0.1%	0.6%	0.3%	0.4%	0.2%	
DPL	3,406	3,406	3,370	3,383	3,435	3,482	3,519	3,544	3,566	3,579	3,613	3,635	3,661	3,682	0.9%
				0.4%	1.5%	1.4%	1.1%	0.7%	0.6%	0.4%	0.9%	0.6%	0.7%	0.6%	
JCPL	3,760	3,760	3,910	3,933	4,008	4,073	4,128	4,139	4,161	4,163	4,217	4,251	4,276	4,281	0.9%
				0.6%	1.9%	1.6%	1.4%	0.3%	0.5%	0.0%	1.3%	0.8%	0.6%	0.1%	
METED	2,579	2,579	2,620	2,635	2,693	2,747	2,800	2,826	2,849	2,866	2,907	2,947	2,982	3,000	1.3%
				0.6%	2.2%	2.0%	1.9%	0.9%	0.8%	0.6%	1.4%	1.4%	1.2%	0.6%	
PECO	6,652	6,652	6,680	6,732	6,864	6,991	7,087	7,154	7,214	7,255	7,348	7,412	7,472	7,526	1.1%
				0.8%	2.0%	1.9%	1.4%	0.9%	0.8%	0.6%	1.3%	0.9%	0.8%	0.7%	
PENLC	2,904	2,904	2,880	2,916	3,003	3,087	3,157	3,200	3,239	3,267	3,319	3,364	3,409	3,445	1.7%
				1.3%	3.0%	2.8%	2.3%	1.4%	1.2%	0.9%	1.6%	1.4%	1.3%	1.1%	
PEPCO	5,246	5,246	5,440	5,479	5,533	5,605	5,654	5,692	5,729	5,749	5,791	5,825	5,859	5,890	0.7%
				0.7%	1.0%	1.3%	0.9%	0.7%	0.7%	0.3%	0.7%	0.6%	0.6%	0.5%	
PL	7,114	7,114	7,310	7,352	7,466	7,573	7,658	7,711	7,763	7,794	7,872	7,934	7,988	8,036	0.9%
				0.6%	1.6%	1.4%	1.1%	0.7%	0.7%	0.4%	1.0%	0.8%	0.7%	0.6%	
PS	6,579	6,579	6,880	6,877	6,965	7,050	7,118	7,142	7,168	7,142	7,207	7,250	7,278	7,298	0.6%
				-0.0%	1.3%	1.2%	1.0%	0.3%	0.4%	-0.4%	0.9%	0.6%	0.4%	0.3%	
RECO	232	232	240	235	236	237	238	239	240	241	242	243	244	245	0.4%
				-2.1%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	
UGI	203	203	200	199	202	205	207	208	209	210	212	213	215	215	0.8%
				-0.5%	1.5%	1.5%	1.0%	0.5%	0.5%	0.5%	1.0%	0.5%	0.9%	0.0%	
DIVERSITY - MID-ATLANTIC(-)				508	703	639	596	609	623	485	661	600	624	626	
PJM MID-ATLANTIC	45,529	45,529	46,600	46,941	47,604	48,440	49,114	49,450	49,745	50,020	50,361	50,798	51,117	51,365	0.9%
				0.7%	1.4%	1.8%	1.4%	0.7%	0.6%	0.6%	0.7%	0.9%	0.6%	0.5%	
FE-EAST	9,177	9,177	9,350	9,429	9,641	9,844	10,004	10,100	10,181	10,242	10,375	10,480	10,578	10,652	1.2%
				0.8%	2.2%	2.1%	1.6%	1.0%	0.8%	0.6%	1.3%	1.0%	0.9%	0.7%	
PLGRP	7,305	7,305	7,480	7,535	7,643	7,748	7,833	7,892	7,938	7,990	8,051	8,117	8,170	8,219	0.9%
				0.7%	1.4%	1.4%	1.1%	0.8%	0.6%	0.7%	0.8%	0.8%	0.7%	0.6%	

Notes:
Normal 12/13 and all forecast values are non-coincident as estimated by PJM staff.
Normal 12/13 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Table B-2 (Continued)

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2024/25 - 2028/29

	24/25	25/26	26/27	27/28	28/29	Annual Growth Rate (15 yr)
AE	1,872	1,882	1,890	1,904	1,900	0.5%
	0.0%	0.5%	0.4%	0.7%	-0.2%	
BGE	6,511	6,530	6,549	6,564	6,569	0.7%
	0.2%	0.3%	0.3%	0.2%	0.1%	
DPL	3,696	3,719	3,743	3,764	3,781	0.7%
	0.4%	0.6%	0.6%	0.6%	0.5%	
JCPL	4,283	4,320	4,353	4,387	4,385	0.7%
	0.0%	0.9%	0.8%	0.8%	-0.0%	
METED	3,019	3,051	3,085	3,128	3,140	1.2%
	0.6%	1.1%	1.1%	1.4%	0.4%	
PECO	7,563	7,627	7,698	7,763	7,799	1.0%
	0.5%	0.8%	0.9%	0.8%	0.5%	
PENLC	3,473	3,512	3,552	3,594	3,617	1.4%
	0.8%	1.1%	1.1%	1.2%	0.6%	
PEPCO	5,914	5,938	5,967	6,001	6,016	0.6%
	0.4%	0.4%	0.5%	0.6%	0.2%	
PL	8,070	8,127	8,189	8,250	8,278	0.8%
	0.4%	0.7%	0.8%	0.7%	0.3%	
PS	7,278	7,312	7,356	7,397	7,393	0.5%
	-0.3%	0.5%	0.6%	0.6%	-0.1%	
RECO	246	246	247	248	249	0.4%
	0.4%	0.0%	0.4%	0.4%	0.4%	
UGI	216	218	219	220	221	0.7%
	0.5%	0.9%	0.5%	0.5%	0.5%	
DIVERSITY - MID-ATLANTIC(-)	545	687	658	610	523	
PJM MID-ATLANTIC	51,596	51,795	52,190	52,610	52,825	0.8%
	0.4%	0.4%	0.8%	0.8%	0.4%	
FE-EAST	10,708	10,817	10,920	11,023	11,082	1.1%
	0.5%	1.0%	1.0%	0.9%	0.5%	
PLGRP	8,261	8,313	8,373	8,436	8,476	0.8%
	0.5%	0.6%	0.7%	0.8%	0.5%	

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2013/14 - 2023/24

	METERED 12/13	UNRESTRICTED 12/13	NORMAL 12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	Annual Growth Rate (10 yr)
AEP	22,254	22,254	22,930	23,046	23,005	23,324	23,555	23,676	23,761	23,810	24,022	24,167	24,316	24,428	0.6%
				0.5%	-0.2%	1.4%	1.0%	0.5%	0.4%	0.2%	0.9%	0.6%	0.6%	0.5%	
APS	8,496	8,496	8,580	8,673	8,920	9,084	9,208	9,273	9,345	9,399	9,500	9,583	9,657	9,727	1.2%
				1.1%	2.8%	1.8%	1.4%	0.7%	0.8%	0.6%	1.1%	0.9%	0.8%	0.7%	
ATSI	10,360	10,360	10,650	10,628	10,693	10,751	10,838	10,835	10,841	10,828	10,877	10,934	10,966	10,960	0.3%
				-0.2%	0.6%	0.5%	0.8%	-0.0%	0.1%	-0.1%	0.5%	0.5%	0.3%	-0.1%	
COMED	15,139	15,139	15,950	16,023	16,379	16,665	16,956	17,071	17,183	17,239	17,436	17,632	17,776	17,877	1.1%
				0.5%	2.2%	1.7%	1.7%	0.7%	0.7%	0.3%	1.1%	1.1%	0.8%	0.6%	
DAYTON	2,836	2,836	2,850	2,853	2,925	2,983	3,028	3,049	3,065	3,076	3,112	3,142	3,168	3,188	1.1%
				0.1%	2.5%	2.0%	1.5%	0.7%	0.5%	0.4%	1.2%	1.0%	0.8%	0.6%	
DEOK	4,257	4,257	4,390	4,392	4,437	4,480	4,515	4,536	4,554	4,554	4,584	4,607	4,629	4,647	0.6%
				0.0%	1.0%	1.0%	0.8%	0.5%	0.4%	0.0%	0.7%	0.5%	0.5%	0.4%	
DLCO	2,241	2,241	2,190	2,192	2,217	2,241	2,266	2,273	2,282	2,280	2,296	2,311	2,329	2,334	0.6%
				0.1%	1.1%	1.1%	1.1%	0.3%	0.4%	-0.1%	0.7%	0.7%	0.8%	0.2%	
EKPC	2,193	2,193	2,320	2,314	2,326	2,340	2,347	2,353	2,355	2,350	2,364	2,369	2,375	2,383	0.3%
				-0.3%	0.5%	0.6%	0.3%	0.3%	0.1%	-0.2%	0.6%	0.2%	0.3%	0.3%	
DIVERSITY - WESTERN(-)				1,515	1,662	1,777	1,714	1,627	1,671	1,665	1,874	1,803	1,805	1,760	
PJM WESTERN	67,006	67,006	68,310	68,606	69,240	70,091	70,999	71,439	71,715	71,871	72,317	72,942	73,411	73,784	0.7%
				0.4%	0.9%	1.2%	1.3%	0.6%	0.4%	0.2%	0.6%	0.9%	0.6%	0.5%	
DOM	17,623	17,623	17,440	17,657	17,976	18,432	18,984	19,258	19,536	19,784	20,126	20,408	20,727	20,997	1.7%
				1.2%	1.8%	2.5%	3.0%	1.4%	1.4%	1.3%	1.7%	1.4%	1.6%	1.3%	
DIVERSITY - INTERREGIONAL(-)				1,485	1,191	1,257	1,539	1,594	1,587	1,536	1,285	1,510	1,634	1,650	
PJM RTO	128,593	128,593	130,840	131,719	133,629	135,706	137,558	138,553	139,409	140,139	141,519	142,638	143,621	144,496	0.9%
				0.7%	1.5%	1.6%	1.4%	0.7%	0.6%	0.5%	1.0%	0.8%	0.7%	0.6%	

Notes:
Normal 12/13 and all forecast values are non-coincident as estimated by PJM staff.
Normal 12/13 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Table B-2 (Continued)

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2024/25 - 2028/29

	24/25	25/26	26/27	27/28	28/29	Annual Growth Rate (15 yr)
AEP	24,468	24,603	24,779	24,947	25,033	0.6%
	0.2%	0.6%	0.7%	0.7%	0.3%	
APS	9,786	9,867	9,949	10,034	10,075	1.0%
	0.6%	0.8%	0.8%	0.9%	0.4%	
ATSI	10,945	10,979	11,003	11,067	11,012	0.2%
	-0.1%	0.3%	0.2%	0.6%	-0.5%	
COMED	17,923	18,075	18,209	18,393	18,421	0.9%
	0.3%	0.8%	0.7%	1.0%	0.2%	
DAYTON	3,202	3,233	3,262	3,295	3,312	1.0%
	0.4%	1.0%	0.9%	1.0%	0.5%	
DEOK	4,651	4,672	4,693	4,717	4,725	0.5%
	0.1%	0.5%	0.4%	0.5%	0.2%	
DLCO	2,329	2,340	2,351	2,367	2,368	0.5%
	-0.2%	0.5%	0.5%	0.7%	0.0%	
EKPC	2,375	2,381	2,390	2,396	2,393	0.2%
	-0.3%	0.3%	0.4%	0.3%	-0.1%	
DIVERSITY - WESTERN(-)	1,820	1,899	1,930	1,909	1,866	
PJM WESTERN	73,859	74,251	74,706	75,307	75,473	0.6%
	0.1%	0.5%	0.6%	0.8%	0.2%	
DOM	21,174	21,308	21,567	21,754	21,901	1.4%
	0.8%	0.6%	1.2%	0.9%	0.7%	
DIVERSITY - INTERREGIONAL(-)	1,593	1,222	1,349	1,571	1,776	
PJM RTO	145,036	146,132	147,114	148,100	148,423	0.8%
	0.4%	0.8%	0.7%	0.7%	0.2%	

Table B-3

**SPRING (APRIL) PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2014 - 2029**

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AE	1,503	1,533	1,560	1,578	1,592	1,599	1,609	1,645	1,640	1,638	1,683	1,688	1,696	1,701	1,687	1,693
BGE	4,970	5,116	5,201	5,243	5,297	5,306	5,367	5,449	5,422	5,409	5,478	5,501	5,553	5,595	5,548	5,578
DPL	2,665	2,724	2,756	2,775	2,801	2,821	2,861	2,906	2,904	2,906	2,957	2,976	3,008	3,037	3,019	3,018
JCPL	3,371	3,460	3,477	3,495	3,558	3,584	3,648	3,780	3,717	3,647	3,823	3,851	3,910	3,939	3,801	3,838
METED	2,296	2,361	2,401	2,419	2,456	2,474	2,523	2,584	2,585	2,585	2,632	2,678	2,716	2,748	2,727	2,752
PECO	5,737	5,915	5,979	6,017	6,117	6,167	6,305	6,421	6,387	6,376	6,539	6,597	6,696	6,770	6,667	6,739
PENLC	2,555	2,658	2,713	2,765	2,808	2,844	2,900	2,948	2,964	2,994	3,036	3,069	3,125	3,166	3,179	3,204
PEPCO	4,488	4,552	4,574	4,584	4,633	4,651	4,705	4,758	4,746	4,718	4,779	4,800	4,853	4,890	4,831	4,879
PL	5,890	6,010	6,081	6,120	6,203	6,246	6,331	6,389	6,397	6,410	6,516	6,552	6,635	6,705	6,671	6,733
PS	6,223	6,336	6,368	6,350	6,433	6,439	6,521	6,618	6,543	6,516	6,687	6,671	6,702	6,761	6,645	6,711
RECO	219	220	220	220	220	221	221	221	221	222	222	222	223	223	223	223
UGI	155	159	161	162	164	165	167	170	169	170	174	175	177	178	176	177
DIVERSITY - MID-ATLANTIC(-)	1,674	1,954	1,881	1,711	2,066	2,017	2,002	2,346	1,854	1,693	1,917	1,553	1,975	2,244	1,869	2,024
PJM MID-ATLANTIC	38,398	39,090	39,610	40,017	40,216	40,500	41,156	41,543	41,841	41,898	42,609	43,227	43,319	43,469	43,305	43,521
FE-EAST	7,876	8,103	8,224	8,342	8,462	8,558	8,679	8,838	8,848	8,897	9,121	9,195	9,315	9,394	9,329	9,458
PLGRP	5,896	5,990	6,064	6,116	6,199	6,261	6,304	6,344	6,383	6,416	6,535	6,575	6,606	6,666	6,669	6,753

Table B-3

SPRING (APRIL) PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2014 - 2029

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AEP	18,500	18,841	19,050	19,192	19,336	19,368	19,536	19,701	19,759	19,777	19,927	19,991	20,180	20,350	20,405	20,542
APS	7,097	7,264	7,373	7,431	7,503	7,556	7,639	7,746	7,742	7,756	7,870	7,914	8,017	8,094	8,072	8,127
ATSI	9,479	9,617	9,655	9,681	9,731	9,711	9,821	10,021	9,847	9,824	9,952	9,958	10,048	10,193	9,973	10,022
COMED	14,147	14,633	14,880	15,010	15,306	15,413	15,737	16,062	15,988	16,045	16,452	16,569	16,882	17,124	16,904	17,243
DAYTON	2,385	2,477	2,523	2,557	2,586	2,600	2,643	2,687	2,690	2,706	2,749	2,775	2,818	2,853	2,854	2,888
DEOK	3,756	3,843	3,843	3,867	3,916	3,923	3,989	4,044	4,002	4,010	4,082	4,101	4,160	4,190	4,133	4,179
DLCO	2,036	2,095	2,104	2,094	2,142	2,156	2,191	2,212	2,198	2,181	2,242	2,244	2,276	2,301	2,255	2,300
EKPC	1,534	1,551	1,554	1,555	1,562	1,564	1,576	1,587	1,580	1,578	1,594	1,591	1,605	1,610	1,601	1,602
DIVERSITY - WESTERN(-)	2,370	2,749	3,346	3,283	3,361	3,132	3,219	3,431	3,574	3,406	3,380	2,802	3,483	3,657	3,726	3,834
PJM WESTERN	56,564	57,572	57,636	58,104	58,721	59,159	59,913	60,629	60,232	60,471	61,488	62,341	62,503	63,058	62,471	63,069
DOM	14,026	14,520	14,994	15,259	15,634	15,893	16,267	16,667	16,766	16,999	17,399	17,504	17,780	18,012	17,985	18,212
DIVERSITY - INTERREGIONAL(-)	2,617	1,926	1,916	2,114	2,066	1,969	2,017	1,693	1,780	2,076	1,658	2,507	1,760	2,076	2,389	1,943
PJM RTO	106,371	109,256	110,324	111,266	112,505	113,583	115,319	117,146	117,059	117,292	119,838	120,565	121,842	122,463	121,372	122,859

Table B-4

FALL (OCTOBER) PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2014 - 2029

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AE	1,559	1,584	1,605	1,626	1,640	1,652	1,658	1,660	1,679	1,693	1,708	1,717	1,727	1,724	1,749	1,765
BGE	4,793	4,891	4,970	5,069	5,101	5,131	5,134	5,139	5,205	5,258	5,313	5,335	5,341	5,276	5,373	5,421
DPL	2,638	2,673	2,694	2,742	2,776	2,802	2,815	2,816	2,863	2,894	2,927	2,946	2,960	2,949	2,997	3,033
JCPL	3,484	3,538	3,566	3,624	3,713	3,711	3,726	3,715	3,755	3,812	3,884	3,893	3,912	3,884	3,954	4,036
METED	2,197	2,239	2,282	2,313	2,343	2,372	2,392	2,409	2,459	2,490	2,523	2,548	2,572	2,576	2,631	2,664
PECO	5,743	5,825	5,909	6,008	6,109	6,172	6,188	6,223	6,319	6,399	6,479	6,528	6,579	6,569	6,684	6,761
PENLC	2,556	2,625	2,705	2,752	2,792	2,829	2,845	2,878	2,943	2,980	3,021	3,036	3,065	3,090	3,152	3,185
PEPCO	4,560	4,591	4,586	4,643	4,688	4,716	4,733	4,719	4,738	4,794	4,846	4,855	4,865	4,840	4,895	4,944
PL	5,718	5,805	5,896	5,949	5,993	6,043	6,088	6,110	6,213	6,255	6,323	6,365	6,408	6,396	6,488	6,551
PS	6,625	6,646	6,635	6,728	6,811	6,849	6,828	6,789	6,816	6,889	6,982	7,003	6,987	6,943	7,022	7,114
RECO	244	244	242	245	249	248	247	245	245	249	252	251	250	247	250	254
UGI	155	157	160	162	163	164	165	165	169	170	171	172	173	172	176	177
DIVERSITY - MID-ATLANTIC(-)	1,358	1,309	1,322	1,284	1,376	1,414	1,442	1,303	1,262	1,219	1,356	1,334	1,368	1,337	1,284	1,391
PJM MID-ATLANTIC	38,914	39,509	39,928	40,577	41,002	41,275	41,377	41,565	42,142	42,664	43,073	43,315	43,471	43,329	44,087	44,514
FE-EAST	8,027	8,203	8,337	8,464	8,581	8,666	8,721	8,797	8,965	9,098	9,218	9,286	9,356	9,318	9,532	9,657
PLGRP	5,843	5,931	6,026	6,093	6,141	6,176	6,211	6,257	6,351	6,404	6,463	6,497	6,539	6,552	6,642	6,703

Table B-4

FALL (OCTOBER) PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2014 - 2029

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AEP	17,857	18,034	18,222	18,418	18,538	18,612	18,616	18,639	18,858	19,027	19,111	19,185	19,231	19,259	19,538	19,796
APS	6,791	6,904	7,028	7,083	7,136	7,208	7,255	7,287	7,402	7,464	7,542	7,578	7,638	7,633	7,763	7,842
ATSI	9,146	9,189	9,255	9,295	9,321	9,366	9,359	9,349	9,480	9,534	9,572	9,588	9,603	9,506	9,688	9,711
COMED	14,259	14,603	14,833	15,074	15,296	15,462	15,619	15,743	15,955	16,142	16,472	16,620	16,710	16,750	16,969	17,230
DAYTON	2,379	2,437	2,482	2,518	2,546	2,573	2,589	2,600	2,647	2,685	2,727	2,751	2,774	2,773	2,835	2,877
DEOK	3,754	3,795	3,831	3,868	3,914	3,933	3,937	3,948	3,990	4,029	4,066	4,075	4,090	4,091	4,150	4,197
DLCO	1,969	1,995	2,008	2,036	2,054	2,071	2,080	2,077	2,102	2,120	2,144	2,154	2,161	2,155	2,187	2,208
EKPC	1,539	1,539	1,551	1,553	1,561	1,564	1,563	1,563	1,580	1,586	1,584	1,585	1,590	1,579	1,599	1,605
DIVERSITY - WESTERN(-)	1,781	1,904	1,978	1,915	2,011	2,057	2,106	2,079	2,106	2,109	2,199	2,234	2,215	2,266	2,245	2,473
PJM WESTERN	55,913	56,592	57,232	57,930	58,355	58,732	58,912	59,127	59,908	60,478	61,019	61,302	61,582	61,480	62,484	62,993
DOM	14,036	14,358	14,934	15,233	15,566	15,833	16,086	16,339	16,682	16,976	17,202	17,367	17,526	17,656	17,907	18,191
DIVERSITY - INTERREGIONAL(-)	1,811	1,727	1,664	1,846	1,977	1,985	1,806	2,181	1,950	2,130	1,994	2,041	2,145	2,360	2,242	2,195
PJM RTO	107,052	108,732	110,430	111,894	112,946	113,855	114,569	114,850	116,782	117,988	119,300	119,943	120,434	120,105	122,236	123,503

Table B-5

MONTHLY PEAK FORECAST (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC DIVERSITY	PJM MID-ATLANTIC
Jan 2014	1,752	5,956	3,383	3,933	2,635	6,732	2,916	5,479	7,352	6,877	229	199	502	46,941
Feb 2014	1,674	5,716	3,255	3,747	2,557	6,475	2,842	5,261	7,056	6,606	216	189	725	44,869
Mar 2014	1,545	5,193	2,877	3,479	2,429	5,943	2,682	4,575	6,405	6,191	208	171	1,240	40,458
Apr 2014	1,503	4,970	2,665	3,371	2,296	5,737	2,555	4,488	5,890	6,223	219	155	1,674	38,398
May 2014	1,853	5,754	3,099	4,458	2,456	6,774	2,486	5,454	5,941	8,091	321	151	1,743	45,095
Jun 2014	2,393	6,783	3,766	5,695	2,829	8,196	2,833	6,392	6,888	9,754	386	182	566	55,531
Jul 2014	2,750	7,403	4,181	6,361	3,019	8,843	2,966	6,870	7,334	10,614	423	198	511	60,451
Aug 2014	2,619	7,069	3,944	5,785	2,892	8,449	2,889	6,568	7,062	9,774	382	187	457	57,163
Sep 2014	2,164	6,298	3,407	4,947	2,567	7,350	2,693	5,876	6,384	8,743	337	170	659	50,277
Oct 2014	1,559	4,793	2,638	3,484	2,197	5,743	2,556	4,560	5,718	6,625	244	155	1,358	38,914
Nov 2014	1,517	4,871	2,702	3,462	2,291	5,880	2,670	4,440	6,159	6,271	214	169	456	40,190
Dec 2014	1,770	5,791	3,236	3,997	2,604	6,691	2,933	5,229	7,098	6,919	236	199	582	46,121

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2015	1,779	6,123	3,435	4,008	2,693	6,864	3,003	5,533	7,466	6,965	230	202	697	47,604
Feb 2015	1,704	5,892	3,313	3,826	2,625	6,622	2,930	5,318	7,190	6,703	217	193	764	45,769
Mar 2015	1,570	5,336	2,938	3,567	2,496	6,113	2,780	4,657	6,546	6,299	211	175	1,450	41,238
Apr 2015	1,533	5,116	2,724	3,460	2,361	5,915	2,658	4,552	6,010	6,336	220	159	1,954	39,090
May 2015	1,880	5,880	3,150	4,538	2,508	6,911	2,561	5,484	6,036	8,171	323	154	1,931	45,665
Jun 2015	2,448	6,962	3,849	5,845	2,911	8,390	2,929	6,478	7,043	9,918	390	186	587	56,762
Jul 2015	2,806	7,579	4,261	6,494	3,096	9,032	3,059	6,948	7,477	10,760	427	202	597	61,544
Aug 2015	2,669	7,224	4,001	5,897	2,965	8,621	2,976	6,625	7,187	9,883	385	191	490	58,134
Sep 2015	2,222	6,468	3,488	5,073	2,649	7,554	2,793	5,962	6,548	8,883	342	175	891	51,266
Oct 2015	1,584	4,891	2,673	3,538	2,239	5,825	2,625	4,591	5,805	6,646	244	157	1,309	39,509
Nov 2015	1,550	5,017	2,773	3,552	2,363	6,045	2,761	4,514	6,322	6,371	216	175	508	41,151
Dec 2015	1,800	5,912	3,292	4,073	2,667	6,840	3,024	5,322	7,231	7,020	237	202	503	47,117

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2016	1,802	6,227	3,482	4,069	2,747	6,991	3,087	5,605	7,573	7,050	231	205	629	48,440
Feb 2016	1,734	6,020	3,363	3,887	2,682	6,762	3,014	5,403	7,329	6,791	218	196	571	46,828
Mar 2016	1,617	5,464	3,009	3,660	2,551	6,217	2,851	4,741	6,640	6,398	211	178	1,234	42,303
Apr 2016	1,560	5,201	2,756	3,477	2,401	5,979	2,713	4,574	6,081	6,368	220	161	1,881	39,610
May 2016	1,924	6,021	3,203	4,627	2,568	7,020	2,635	5,543	6,135	8,260	325	157	1,695	46,723
Jun 2016	2,492	7,112	3,923	5,980	2,984	8,522	3,002	6,563	7,159	10,093	399	190	655	57,764
Jul 2016	2,840	7,705	4,314	6,584	3,147	9,147	3,122	6,985	7,568	10,845	430	205	547	62,345
Aug 2016	2,710	7,387	4,089	6,027	3,039	8,772	3,053	6,716	7,323	10,062	391	195	508	59,256
Sep 2016	2,240	6,581	3,521	5,114	2,677	7,609	2,850	5,988	6,604	8,897	341	177	788	51,811
Oct 2016	1,605	4,970	2,694	3,566	2,282	5,909	2,705	4,586	5,896	6,635	242	160	1,322	39,928
Nov 2016	1,570	5,119	2,812	3,613	2,409	6,131	2,845	4,549	6,429	6,421	217	177	444	41,848
Dec 2016	1,824	6,006	3,333	4,128	2,729	6,935	3,110	5,356	7,334	7,109	238	205	404	47,903

Table B-5

MONTHLY PEAK FORECAST (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	WESTERN DIVERSITY	PJM WESTERN	DOM	INTER REGION DIVERSITY	PJM RTO
Jan 2014	23,046	8,673	10,628	16,023	2,853	4,392	2,192	2,314	1,515	68,606	17,657	1,485	131,719
Feb 2014	22,236	8,345	10,379	15,497	2,754	4,222	2,117	2,200	1,489	66,261	16,915	1,694	126,351
Mar 2014	20,011	7,636	9,830	14,232	2,502	3,816	2,006	1,805	1,447	60,391	14,897	1,792	113,954
Apr 2014	18,500	7,097	9,479	14,147	2,385	3,756	2,036	1,534	2,370	56,564	14,026	2,617	106,371
May 2014	19,336	7,083	10,203	16,860	2,703	4,414	2,360	1,480	2,435	62,004	16,053	3,803	119,349
Jun 2014	22,423	8,385	12,696	21,392	3,238	5,307	2,835	1,786	2,273	75,789	18,741	3,439	146,622
Jul 2014	23,556	8,837	13,341	23,275	3,476	5,597	2,997	1,899	1,876	81,102	20,197	4,351	157,399
Aug 2014	22,966	8,546	12,815	22,246	3,360	5,461	2,878	1,872	1,821	78,323	19,505	4,678	150,313
Sep 2014	20,787	7,778	11,271	19,270	3,027	4,947	2,607	1,754	1,889	69,552	17,230	3,917	133,142
Oct 2014	17,857	6,791	9,146	14,259	2,379	3,754	1,969	1,539	1,781	55,913	14,036	1,811	107,052
Nov 2014	19,002	7,292	9,524	14,421	2,470	3,770	1,993	1,771	1,189	59,054	14,037	888	112,393
Dec 2014	21,798	8,479	10,614	16,379	2,803	4,297	2,202	2,141	1,316	67,397	16,785	1,568	128,735
	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2015	23,005	8,920	10,693	16,286	2,925	4,437	2,217	2,326	1,569	69,240	17,976	1,191	133,629
Feb 2015	22,206	8,614	10,450	15,789	2,827	4,267	2,146	2,218	1,512	67,005	17,237	1,563	128,448
Mar 2015	20,403	7,836	9,938	14,628	2,584	3,881	2,047	1,829	1,651	61,495	15,398	1,143	116,988
Apr 2015	18,841	7,264	9,617	14,633	2,477	3,843	2,095	1,551	2,749	57,572	14,520	1,926	109,256
May 2015	19,574	7,176	10,301	17,212	2,791	4,479	2,398	1,494	2,477	62,948	16,450	3,558	121,505
Jun 2015	22,872	8,581	12,874	22,030	3,361	5,413	2,897	1,821	2,427	77,422	19,313	3,789	149,708
Jul 2015	23,982	9,024	13,530	23,879	3,583	5,704	3,056	1,930	2,088	82,600	20,765	4,470	160,439
Aug 2015	23,359	8,684	12,904	22,809	3,462	5,560	2,925	1,907	1,992	79,618	20,036	4,854	152,934
Sep 2015	21,310	7,987	11,518	19,828	3,142	5,050	2,665	1,781	2,112	71,169	17,823	3,579	136,679
Oct 2015	18,034	6,904	9,189	14,603	2,437	3,795	1,995	1,539	1,904	56,592	14,358	1,727	108,732
Nov 2015	19,365	7,473	9,635	14,799	2,552	3,841	2,025	1,791	1,165	60,316	14,588	895	115,160
Dec 2015	22,188	8,656	10,685	16,665	2,869	4,349	2,230	2,163	1,449	68,356	17,270	1,569	131,174
	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2016	23,324	9,084	10,751	16,535	2,983	4,480	2,241	2,340	1,647	70,091	18,432	1,257	135,706
Feb 2016	22,537	8,782	10,514	16,055	2,886	4,309	2,169	2,242	1,487	68,007	17,743	1,818	130,760
Mar 2016	20,647	7,985	10,022	14,988	2,646	3,919	2,068	1,830	2,257	61,848	15,968	1,302	118,817
Apr 2016	19,050	7,373	9,655	14,880	2,523	3,843	2,104	1,554	3,346	57,636	14,994	1,916	110,324
May 2016	19,950	7,389	10,428	17,777	2,871	4,552	2,436	1,507	2,655	64,255	17,114	3,951	124,141
Jun 2016	23,357	8,764	13,054	22,492	3,451	5,488	2,950	1,840	2,597	78,799	20,039	4,235	152,367
Jul 2016	24,220	9,147	13,620	24,246	3,641	5,747	3,094	1,942	1,947	83,710	21,433	4,768	162,720
Aug 2016	23,814	8,884	13,170	23,348	3,549	5,656	2,987	1,930	2,336	81,002	20,763	5,002	156,019
Sep 2016	21,379	8,043	11,490	20,095	3,178	5,084	2,688	1,788	1,882	71,863	18,385	4,141	137,918
Oct 2016	18,222	7,028	9,255	14,833	2,482	3,831	2,008	1,551	1,978	57,232	14,934	1,664	110,430
Nov 2016	19,574	7,618	9,707	15,083	2,609	3,881	2,052	1,803	1,083	61,244	15,168	1,032	117,228
Dec 2016	22,484	8,809	10,838	16,956	2,936	4,408	2,266	2,169	1,472	69,394	17,893	1,926	133,264

Table B-6

MONTHLY PEAK FORECAST (MW) FOR FE-EAST AND PLGRP

	FE_EAST	PLGRP
Jan 2014	9,429	7,535
Feb 2014	9,051	7,235
Mar 2014	8,344	6,464
Apr 2014	7,876	5,896
May 2014	9,060	5,976
Jun 2014	11,154	7,061
Jul 2014	12,174	7,507
Aug 2014	11,385	7,248
Sep 2014	10,038	6,555
Oct 2014	8,027	5,843
Nov 2014	8,356	6,318
Dec 2014	9,486	7,266

	FE_EAST	PLGRP
Jan 2015	9,641	7,643
Feb 2015	9,291	7,359
Mar 2015	8,590	6,580
Apr 2015	8,103	5,990
May 2015	9,253	6,064
Jun 2015	11,427	7,210
Jul 2015	12,434	7,639
Aug 2015	11,646	7,378
Sep 2015	10,291	6,700
Oct 2015	8,203	5,931
Nov 2015	8,594	6,472
Dec 2015	9,730	7,404

	FE_EAST	PLGRP
Jan 2016	9,844	7,748
Feb 2016	9,527	7,502
Mar 2016	8,775	6,694
Apr 2016	8,224	6,064
May 2016	9,487	6,182
Jun 2016	11,696	7,334
Jul 2016	12,638	7,742
Aug 2016	11,919	7,517
Sep 2016	10,449	6,779
Oct 2016	8,337	6,026
Nov 2016	8,780	6,601
Dec 2016	9,915	7,495

Note: FE_EAST contains JCPL, METED and PENLC zones. PLGRP contains PL and UGI zones.

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Table B-7

PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AE																
CONTRACTUALLY INTERRUPTIBLE	165	158	124	124	124	124	124	124	124	124	124	124	124	124	124	124
DIRECT CONTROL	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
TOTAL LOAD MANAGEMENT	207	200	166	166	166	166	166	166	166	166	166	166	166	166	166	166
BGE																
CONTRACTUALLY INTERRUPTIBLE	854	664	465	465	465	465	465	465	465	465	465	465	465	465	465	465
DIRECT CONTROL	435	435	435	435	435	435	435	435	435	435	435	435	435	435	435	435
TOTAL LOAD MANAGEMENT	1,289	1,099	900	900	900	900	900	900	900	900	900	900	900	900	900	900
DPL																
CONTRACTUALLY INTERRUPTIBLE	376	397	392	392	392	392	392	392	392	392	392	392	392	392	392	392
DIRECT CONTROL	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
TOTAL LOAD MANAGEMENT	406	427	422	422	422	422	422	422	422	422	422	422	422	422	422	422
JCPL																
CONTRACTUALLY INTERRUPTIBLE	427	342	214	214	214	214	214	214	214	214	214	214	214	214	214	214
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	427	342	214	214	214	214	214	214	214	214	214	214	214	214	214	214
METED																
CONTRACTUALLY INTERRUPTIBLE	386	337	301	301	301	301	301	301	301	301	301	301	301	301	301	301
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	386	337	301	301	301	301	301	301	301	301	301	301	301	301	301	301
PECO																
CONTRACTUALLY INTERRUPTIBLE	801	775	510	510	510	510	510	510	510	510	510	510	510	510	510	510
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	801	775	510	510	510	510	510	510	510	510	510	510	510	510	510	510
PENLC																
CONTRACTUALLY INTERRUPTIBLE	415	516	408	408	408	408	408	408	408	408	408	408	408	408	408	408
DIRECT CONTROL	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
TOTAL LOAD MANAGEMENT	422	523	415	415	415	415	415	415	415	415	415	415	415	415	415	415

Notes:
Forecast represents the amount of Demand Resources cleared in RPM auctions.
Winter load management is equal to Contractually Interruptible.

Table B-7 (Continued)

PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PEPCO																
CONTRACTUALLY INTERRUPTIBLE	841	799	603	603	603	603	603	603	603	603	603	603	603	603	603	603
DIRECT CONTROL	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
TOTAL LOAD MANAGEMENT	876	834	638	638	638	638	638	638	638	638	638	638	638	638	638	638
PL																
CONTRACTUALLY INTERRUPTIBLE	1,256	1,114	959	959	959	959	959	959	959	959	959	959	959	959	959	959
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	1,256	1,114	959	959	959	959	959	959	959	959	959	959	959	959	959	959
PS																
CONTRACTUALLY INTERRUPTIBLE	866	683	522	522	522	522	522	522	522	522	522	522	522	522	522	522
DIRECT CONTROL	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
TOTAL LOAD MANAGEMENT	950	767	606	606	606	606	606	606	606	606	606	606	606	606	606	606
RECO																
CONTRACTUALLY INTERRUPTIBLE	30	20	10	10	10	10	10	10	10	10	10	10	10	10	10	10
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	30	20	10	10	10	10	10	10	10	10	10	10	10	10	10	10
UGI																
CONTRACTUALLY INTERRUPTIBLE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM MID-ATLANTIC																
CONTRACTUALLY INTERRUPTIBLE	6,417	5,805	4,508	4,508	4,508	4,508	4,508	4,508	4,508	4,508	4,508	4,508	4,508	4,508	4,508	4,508
DIRECT CONTROL	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633
TOTAL LOAD MANAGEMENT	7,050	6,438	5,141	5,141	5,141	5,141	5,141	5,141	5,141	5,141	5,141	5,141	5,141	5,141	5,141	5,141

Table B-7

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AEP																
CONTRACTUALLY INTERRUPTIBLE	2,013	1,897	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738
DIRECT CONTROL	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
TOTAL LOAD MANAGEMENT	2,037	1,921	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762
APS																
CONTRACTUALLY INTERRUPTIBLE	864	923	657	657	657	657	657	657	657	657	657	657	657	657	657	657
DIRECT CONTROL	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
TOTAL LOAD MANAGEMENT	865	924	658	658	658	658	658	658	658	658	658	658	658	658	658	658
ATSI																
CONTRACTUALLY INTERRUPTIBLE	1,054	1,693	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736
DIRECT CONTROL	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
TOTAL LOAD MANAGEMENT	1,058	1,697	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740
COMED																
CONTRACTUALLY INTERRUPTIBLE	1,440	1,602	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150
DIRECT CONTROL	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
TOTAL LOAD MANAGEMENT	1,477	1,639	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187
DAYTON																
CONTRACTUALLY INTERRUPTIBLE	220	186	234	234	234	234	234	234	234	234	234	234	234	234	234	234
DIRECT CONTROL	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
TOTAL LOAD MANAGEMENT	223	189	237	237	237	237	237	237	237	237	237	237	237	237	237	237
DEOK																
CONTRACTUALLY INTERRUPTIBLE	29	253	276	276	276	276	276	276	276	276	276	276	276	276	276	276
DIRECT CONTROL	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
TOTAL LOAD MANAGEMENT	88	312	335	335	335	335	335	335	335	335	335	335	335	335	335	335
DLCO																
CONTRACTUALLY INTERRUPTIBLE	214	236	137	137	137	137	137	137	137	137	137	137	137	137	137	137
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	214	236	137	137	137	137	137	137	137	137	137	137	137	137	137	137
EKPC																
CONTRACTUALLY INTERRUPTIBLE	119	122	124	124	124	124	124	124	124	124	124	124	124	124	124	124
DIRECT CONTROL	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
TOTAL LOAD MANAGEMENT	123	126	128	128	128	128	128	128	128	128	128	128	128	128	128	128

otes:
precast represents the amount of Demand Resources cleared in RPM auctions.
'inter load management is equal to Contractually Interruptible.

Table B-7 (Continued)

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PJM WESTERN																
CONTRACTUALLY INTERRUPTIBLE	5,953	6,912	6,052	6,052	6,052	6,052	6,052	6,052	6,052	6,052	6,052	6,052	6,052	6,052	6,052	6,052
DIRECT CONTROL	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
TOTAL LOAD MANAGEMENT	6,085	7,044	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184
DOM																
CONTRACTUALLY INTERRUPTIBLE	1,220	1,243	990	990	990	990	990	990	990	990	990	990	990	990	990	990
DIRECT CONTROL	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87
TOTAL LOAD MANAGEMENT	1,307	1,330	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077
PJM RTO																
CONTRACTUALLY INTERRUPTIBLE	13,590	13,960	11,550	11,550	11,550	11,550	11,550	11,550	11,550	11,550	11,550	11,550	11,550	11,550	11,550	11,550
DIRECT CONTROL	852	852	852	852	852	852	852	852	852	852	852	852	852	852	852	852
TOTAL LOAD MANAGEMENT	14,442	14,812	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402

Table B-8

PJM MID-ATLANTIC REGION ENERGY EFFICIENCY PROGRAMS AND SUM OF ENERGY EFFICIENCY AND LOAD MANAGEMENT - SUMMER (MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AE																
ENERGY EFFICIENCY	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
LOAD MANAGEMENT	207	200	166	166	166	166	166	166	166	166	166	166	166	166	166	166
TOTAL	207	201	167	167	167	167	167	167	167	167	167	167	167	167	167	167
BGE																
ENERGY EFFICIENCY	62	65	93	93	93	93	93	93	93	93	93	93	93	93	93	93
LOAD MANAGEMENT	1,289	1,099	900	900	900	900	900	900	900	900	900	900	900	900	900	900
TOTAL	1,351	1,164	993	993	993	993	993	993	993	993	993	993	993	993	993	993
DPL																
ENERGY EFFICIENCY	5	12	17	17	17	17	17	17	17	17	17	17	17	17	17	17
LOAD MANAGEMENT	406	427	422	422	422	422	422	422	422	422	422	422	422	422	422	422
TOTAL	411	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439
JCPL																
ENERGY EFFICIENCY	1	0	3	3	3	3	3	3	3	3	3	3	3	3	3	3
LOAD MANAGEMENT	427	342	214	214	214	214	214	214	214	214	214	214	214	214	214	214
TOTAL	428	342	217	217	217	217	217	217	217	217	217	217	217	217	217	217
METED																
ENERGY EFFICIENCY	12	6	7	7	7	7	7	7	7	7	7	7	7	7	7	7
LOAD MANAGEMENT	386	337	301	301	301	301	301	301	301	301	301	301	301	301	301	301
TOTAL	398	343	308	308	308	308	308	308	308	308	308	308	308	308	308	308
PECO																
ENERGY EFFICIENCY	3	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
LOAD MANAGEMENT	801	775	510	510	510	510	510	510	510	510	510	510	510	510	510	510
TOTAL	804	785	520	520	520	520	520	520	520	520	520	520	520	520	520	520
PENLC																
ENERGY EFFICIENCY	11	6	7	7	7	7	7	7	7	7	7	7	7	7	7	7
LOAD MANAGEMENT	422	523	415	415	415	415	415	415	415	415	415	415	415	415	415	415
TOTAL	433	529	422	422	422	422	422	422	422	422	422	422	422	422	422	422

otes:
nergy Efficiency values are impacts approved for use in PJM Reliability Pricing Model.
oad Management details appear in Table B-7.

Table B-8 (Continued)

PJM MID-ATLANTIC REGION ENERGY EFFICIENCY PROGRAMS
AND SUM OF ENERGY EFFICIENCY AND LOAD MANAGEMENT - SUMMER (MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PEPCO																
ENERGY EFFICIENCY	29	44	68	68	68	68	68	68	68	68	68	68	68	68	68	68
LOAD MANAGEMENT	876	834	638	638	638	638	638	638	638	638	638	638	638	638	638	638
TOTAL	905	878	706	706	706	706	706	706	706	706	706	706	706	706	706	706
PL																
ENERGY EFFICIENCY	7	9	22	22	22	22	22	22	22	22	22	22	22	22	22	22
LOAD MANAGEMENT	1,256	1,114	959	959	959	959	959	959	959	959	959	959	959	959	959	959
TOTAL	1,263	1,123	981	981	981	981	981	981	981	981	981	981	981	981	981	981
PS																
ENERGY EFFICIENCY	7	6	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LOAD MANAGEMENT	950	767	606	606	606	606	606	606	606	606	606	606	606	606	606	606
TOTAL	957	773	615	615	615	615	615	615	615	615	615	615	615	615	615	615
RECO																
ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LOAD MANAGEMENT	30	20	10	10	10	10	10	10	10	10	10	10	10	10	10	10
TOTAL	30	20	10	10	10	10	10	10	10	10	10	10	10	10	10	10
UGI																
ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LOAD MANAGEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM MID-ATLANTIC																
ENERGY EFFICIENCY	137	159	237	237	237	237	237	237	237	237	237	237	237	237	237	237
LOAD MANAGEMENT	7,050	6,438	5,141	5,141	5,141	5,141	5,141	5,141	5,141	5,141	5,141	5,141	5,141	5,141	5,141	5,141
TOTAL	7,187	6,597	5,378	5,378	5,378	5,378	5,378	5,378	5,378	5,378	5,378	5,378	5,378	5,378	5,378	5,378

Table B-8

PJM WESTERN REGION AND PJM SOUTHERN REGION ENERGY EFFICIENCY PROGRAMS
AND SUM OF ENERGY EFFICIENCY AND LOAD MANAGEMENT - SUMMER (MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AEP																
ENERGY EFFICIENCY	6	156	95	95	95	95	95	95	95	95	95	95	95	95	95	95
LOAD MANAGEMENT	2,037	1,921	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762
TOTAL	2,043	2,077	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857
APS																
ENERGY EFFICIENCY	21	13	8	8	8	8	8	8	8	8	8	8	8	8	8	8
LOAD MANAGEMENT	865	924	658	658	658	658	658	658	658	658	658	658	658	658	658	658
TOTAL	886	937	666	666	666	666	666	666	666	666	666	666	666	666	666	666
ATSI																
ENERGY EFFICIENCY	25	46	177	177	177	177	177	177	177	177	177	177	177	177	177	177
LOAD MANAGEMENT	1,058	1,697	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740	1,740
TOTAL	1,083	1,743	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917
COMED																
ENERGY EFFICIENCY	299	301	362	362	362	362	362	362	362	362	362	362	362	362	362	362
LOAD MANAGEMENT	1,477	1,639	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187	1,187
TOTAL	1,776	1,940	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549	1,549
DAYTON																
ENERGY EFFICIENCY	2	1	7	7	7	7	7	7	7	7	7	7	7	7	7	7
LOAD MANAGEMENT	223	189	237	237	237	237	237	237	237	237	237	237	237	237	237	237
TOTAL	225	190	244	244	244	244	244	244	244	244	244	244	244	244	244	244
DEOK																
ENERGY EFFICIENCY	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
LOAD MANAGEMENT	88	312	335	335	335	335	335	335	335	335	335	335	335	335	335	335
TOTAL	89	315	338	338	338	338	338	338	338	338	338	338	338	338	338	338
DLCO																
ENERGY EFFICIENCY	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
LOAD MANAGEMENT	214	236	137	137	137	137	137	137	137	137	137	137	137	137	137	137
TOTAL	216	239	140	140	140	140	140	140	140	140	140	140	140	140	140	140
EKPC																
ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LOAD MANAGEMENT	123	126	128	128	128	128	128	128	128	128	128	128	128	128	128	128
TOTAL	123	126	128	128	128	128	128	128	128	128	128	128	128	128	128	128

Jotes:
:nergy Efficiency values are impacts approved for use in PJM Reliability Pricing Model.
.oad Management details appear in Table B-7.

Table B-8 (Continued)

PJM WESTERN REGION AND PJM SOUTHERN REGION ENERGY EFFICIENCY PROGRAMS
AND SUM OF ENERGY EFFICIENCY AND LOAD MANAGEMENT - SUMMER (MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PJM WESTERN																
ENERGY EFFICIENCY	356	523	655	655	655	655	655	655	655	655	655	655	655	655	655	655
LOAD MANAGEMENT	6,085	7,044	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184
TOTAL	6,441	7,567	6,839	6,839	6,839	6,839	6,839	6,839	6,839	6,839	6,839	6,839	6,839	6,839	6,839	6,839
DOM																
ENERGY EFFICIENCY	29	3	26	26	26	26	26	26	26	26	26	26	26	26	26	26
LOAD MANAGEMENT	1,307	1,330	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077
TOTAL	1,336	1,333	1,103	1,103	1,103	1,103	1,103	1,103	1,103	1,103	1,103	1,103	1,103	1,103	1,103	1,103
PJM RTO																
ENERGY EFFICIENCY	522	685	918	918	918	918	918	918	918	918	918	918	918	918	918	918
LOAD MANAGEMENT	14,442	14,812	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402
TOTAL	14,964	15,497	13,320	13,320	13,320	13,320	13,320	13,320	13,320	13,320	13,320	13,320	13,320	13,320	13,320	13,320

Table B-9

ADJUSTMENTS TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO 2014 - 2029

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BGE	120	180	250	290	295	300	305	310	315	315	315	315	315	315	315	315
DPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JCPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
METED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PENLC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PEPCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UGI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AEP	-370	-370	-370	-370	-370	-370	-370	-370	-370	-370	-370	-370	-370	-370	-370	-370
APS	80	100	120	120	120	120	120	120	120	120	120	120	120	120	120	120
ATSI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DAYTON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEOK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DLCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EKPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	0	0	288	361	438	521	608	699	796	896	896	896	896	896	896	896
PJM RTO	-215	-150	218	361	478	566	658	754	856	961	961	961	961	961	961	961

Notes:
Adjustment values presented here are reflected in Tables B-1 through B-6 and Tables B-10, B-11 and B12.
Adjustments are large, unanticipated load changes deemed by PJM to not be captured in the forecast model.

Table B-10

SUMMER COINCIDENT PEAK LOAD (MW) FOR
EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO
2014 - 2029

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AE	2,644	2,694	2,728	2,750	2,765	2,777	2,796	2,815	2,828	2,840	2,853	2,868	2,882	2,901	2,918	2,933
BGE	7,109	7,269	7,401	7,491	7,529	7,578	7,633	7,684	7,716	7,760	7,797	7,838	7,879	7,918	7,955	7,991
DPL	4,021	4,090	4,141	4,184	4,219	4,255	4,295	4,330	4,357	4,388	4,424	4,455	4,488	4,518	4,545	4,576
JCPL	6,111	6,236	6,316	6,369	6,393	6,456	6,510	6,554	6,597	6,636	6,672	6,716	6,763	6,804	6,849	6,872
METED	2,895	2,965	3,015	3,061	3,091	3,127	3,168	3,205	3,240	3,277	3,310	3,346	3,384	3,423	3,460	3,493
PECO	8,493	8,663	8,773	8,881	8,973	9,053	9,140	9,225	9,297	9,377	9,447	9,522	9,599	9,681	9,762	9,843
PENLC	2,830	2,914	2,976	3,025	3,060	3,100	3,143	3,185	3,221	3,259	3,292	3,329	3,366	3,403	3,436	3,465
PEPCO	6,602	6,666	6,705	6,729	6,755	6,793	6,861	6,894	6,915	6,926	6,951	7,010	7,041	7,067	7,070	7,093
PL	7,034	7,154	7,242	7,319	7,371	7,439	7,507	7,571	7,628	7,688	7,743	7,806	7,866	7,928	7,987	8,041
PS	10,216	10,334	10,416	10,470	10,500	10,549	10,604	10,649	10,683	10,723	10,754	10,794	10,837	10,884	10,921	10,959
RECO	406	409	412	413	413	415	417	418	419	420	420	421	422	424	425	425
UGI	190	193	196	198	200	201	203	205	206	208	209	210	212	214	215	216
AEP	22,567	22,926	23,148	23,323	23,467	23,597	23,752	23,920	24,024	24,158	24,318	24,460	24,602	24,779	24,901	25,099
APS	8,476	8,641	8,758	8,841	8,903	8,965	9,049	9,126	9,187	9,261	9,323	9,391	9,465	9,537	9,608	9,682
ATSI	12,791	12,937	13,013	13,083	13,116	13,172	13,253	13,310	13,339	13,393	13,429	13,506	13,567	13,634	13,671	13,718
COMED	22,272	22,833	23,156	23,447	23,646	23,878	24,197	24,415	24,606	24,805	25,011	25,261	25,491	25,708	25,888	26,046
DAYTON	3,309	3,404	3,460	3,503	3,532	3,564	3,600	3,636	3,667	3,701	3,737	3,774	3,813	3,854	3,890	3,931
DEOK	5,340	5,432	5,484	5,533	5,563	5,604	5,659	5,695	5,727	5,764	5,801	5,845	5,884	5,926	5,963	5,986
DLCO	2,861	2,913	2,948	2,976	2,998	3,016	3,041	3,061	3,079	3,100	3,118	3,138	3,162	3,182	3,203	3,226
EKPC	1,803	1,830	1,846	1,860	1,874	1,882	1,899	1,908	1,920	1,930	1,944	1,957	1,969	1,975	1,987	2,003
DOM	19,431	19,936	20,584	20,978	21,308	21,642	22,015	22,369	22,700	23,064	23,298	23,552	23,811	24,044	24,301	24,538
PJM RTO	157,401	160,439	162,718	164,434	165,676	167,063	168,742	170,175	171,356	172,678	173,851	175,199	176,503	177,804	178,955	180,136
PJM MID-ATLANTIC	58,551	59,587	60,321	60,890	61,269	61,743	62,277	62,735	63,107	63,502	63,872	64,315	64,739	65,165	65,543	65,907
EASTERN MID-ATLANTIC	31,891	32,426	32,786	33,067	33,263	33,505	33,762	33,991	34,181	34,384	34,570	34,776	34,991	35,212	35,420	35,608
SOUTHERN MID-ATLANTIC	13,711	13,935	14,106	14,220	14,284	14,371	14,494	14,578	14,631	14,686	14,748	14,848	14,920	14,985	15,025	15,084
MID-ATLANTIC and APS	67,027	68,228	69,079	69,731	70,172	70,708	71,326	71,861	72,294	72,763	73,195	73,706	74,204	74,702	75,151	75,589

Notes:
Load values for Zones and Locational Deliverability Areas are coincident with the PJM RTO peak.
This table will be used for the Reliability Pricing Model.

Table B-11

PJM CONTROL AREA - JANUARY 2014
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2014 - 2024

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST	135,303	137,744	139,345	140,669	141,553	142,586	143,837	144,914	145,705	146,695	147,595	0.9%
		1.8%	1.2%	1.0%	0.6%	0.7%	0.9%	0.7%	0.5%	0.7%	0.6%	
PJM - SERC	22,096	22,695	23,375	23,765	24,122	24,478	24,906	25,262	25,652	25,984	26,257	1.7%
		2.7%	3.0%	1.7%	1.5%	1.5%	1.7%	1.4%	1.5%	1.3%	1.1%	
PJM RTO	157,399	160,439	162,720	164,434	165,675	167,064	168,743	170,176	171,357	172,679	173,852	1.0%
		1.9%	1.4%	1.1%	0.8%	0.8%	1.0%	0.8%	0.7%	0.8%	0.7%	

Notes:
Projected PJM seasonal peak load at normal peak weather conditions in the absense of any load reductions due to load management, voltage reductions or voluntary curtailments.
The above forecasts incorporate all load in the PJM Control Area, including members and non-members.
All growth rates are caculated from the first year of the forecast.

Table B-11 (Continued)

PJM CONTROL AREA - JANUARY 2014
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2025 - 2029

	2025	2026	2027	2028	2029	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST	148,667	149,682	150,728	151,641	152,572	0.8%
	0.7%	0.7%	0.7%	0.6%	0.6%	
PJM - SERC	26,535	26,820	27,074	27,314	27,565	1.5%
	1.1%	1.1%	0.9%	0.9%	0.9%	
PJM RTO	175,202	176,502	177,802	178,955	180,137	0.9%
	0.8%	0.7%	0.7%	0.6%	0.7%	

Table B-12

PJM CONTROL AREA - JANUARY 2014
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2013/14 - 2023/24

	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST	111,748	113,327	114,934	116,227	116,942	117,518	118,005	119,029	119,861	120,519	121,116	0.8%
		1.4%	1.4%	1.1%	0.6%	0.5%	0.4%	0.9%	0.7%	0.5%	0.5%	
PJM - SERC	19,971	20,302	20,772	21,331	21,611	21,891	22,134	22,490	22,777	23,102	23,380	1.6%
		1.7%	2.3%	2.7%	1.3%	1.3%	1.1%	1.6%	1.3%	1.4%	1.2%	
PJM RTO	131,719	133,629	135,706	137,558	138,553	139,409	140,139	141,519	142,638	143,621	144,496	0.9%
		1.5%	1.6%	1.4%	0.7%	0.6%	0.5%	1.0%	0.8%	0.7%	0.6%	

Notes:
Projected PJM seasonal peak load at normal peak weather conditions in the absense of any load reductions due to load management, voltage reductions or voluntary curtailments.
The above forecasts incorporate all load in the PJM Control Area, including members and non-members.
All growth rates are caculated from the first year of the forecast.

Table B-12 (Continued)

PJM CONTROL AREA - JANUARY 2014
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2024/25 - 2028/29

	24/25	25/26	26/27	27/28	28/29	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST	121,487	122,443	123,157	123,950	124,129	0.7%
	0.3%	0.8%	0.6%	0.6%	0.1%	
PJM - SERC	23,549	23,689	23,957	24,150	24,294	1.3%
	0.7%	0.6%	1.1%	0.8%	0.6%	
PJM RTO	145,036	146,132	147,114	148,100	148,423	0.8%
	0.4%	0.8%	0.7%	0.7%	0.2%	

Table C-1

PJM LOCATIONAL DELIVERABILITY AREAS
CENTRAL MID-ATLANTIC: BGE, METED, PEPCO, PL and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2014	17,207	24,547	16,845	21,506
2015	17,605	25,017	17,113	21,889
2016	17,775	25,369	17,357	22,215
2017	17,887	25,630	17,564	22,487
2018	18,015	25,735	17,760	22,669
2019	18,163	25,992	17,878	22,778
2020	18,462	26,187	17,920	22,911
2021	18,701	26,372	18,019	23,083
2022	18,632	26,562	18,206	23,237
2023	18,637	26,725	18,473	23,379
2024	18,956	26,909	18,630	23,485
2025	19,136	27,077	18,712	23,582
2026	19,273	27,250	18,737	23,709
2027	19,416	27,421	18,721	23,864
2028	19,239	27,575	19,045	24,016
2029	19,368	27,738	19,213	24,100

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2014	18,836	25,893	18,623	22,677
2015	19,206	26,337	18,942	23,134
2016	19,568	26,713	19,149	23,439
2017	19,660	26,997	19,381	23,730
2018	19,884	27,138	19,587	23,921
2019	20,017	27,378	19,730	24,049
2020	20,196	27,575	19,835	24,133
2021	20,416	27,777	19,941	24,330
2022	20,505	27,971	20,106	24,486
2023	20,570	28,163	20,259	24,631
2024	20,801	28,342	20,478	24,761
2025	20,941	28,516	20,594	24,828
2026	21,061	28,692	20,689	25,004
2027	21,283	28,880	20,736	25,140
2028	21,264	29,067	20,907	25,282
2029	21,480	29,184	21,151	25,411

Table C-2

PJM LOCATIONAL DELIVERABILITY AREAS
WESTERN MID-ATLANTIC: METED, PENLC, PL and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2014	10,561	13,383	10,508	13,044
2015	10,775	13,671	10,744	13,290
2016	10,947	13,904	10,913	13,529
2017	11,109	14,068	11,041	13,743
2018	11,256	14,188	11,161	13,867
2019	11,395	14,342	11,246	13,981
2020	11,499	14,489	11,399	14,091
2021	11,641	14,634	11,475	14,230
2022	11,722	14,797	11,643	14,381
2023	11,817	14,927	11,757	14,509
2024	12,022	15,050	11,882	14,619
2025	12,111	15,197	11,991	14,721
2026	12,211	15,335	12,115	14,831
2027	12,336	15,475	12,150	14,968
2028	12,387	15,613	12,293	15,109
2029	12,523	15,713	12,469	15,198

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2014	10,915	14,092	10,603	13,651
2015	11,162	14,397	10,815	13,965
2016	11,407	14,621	11,013	14,216
2017	11,528	14,761	11,132	14,486
2018	11,667	14,885	11,277	14,619
2019	11,796	15,084	11,396	14,691
2020	11,903	15,250	11,469	14,722
2021	12,065	15,398	11,550	14,930
2022	12,212	15,537	11,754	15,127
2023	12,284	15,647	11,877	15,275
2024	12,426	15,817	12,039	15,387
2025	12,540	15,977	12,138	15,356
2026	12,652	16,106	12,214	15,549
2027	12,817	16,250	12,241	15,679
2028	12,900	16,356	12,440	15,877
2029	13,044	16,470	12,613	15,903

Table C-3

PJM LOCATIONAL DELIVERABILITY AREAS
EASTERN MID-ATLANTIC: AE, DPL, JCPL, PECO, PS and RECO
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2014	18,852	32,941	20,134	22,720
2015	19,239	33,484	20,288	23,064
2016	19,445	33,880	20,322	23,386
2017	19,560	34,165	20,734	23,642
2018	19,772	34,374	21,180	23,781
2019	19,925	34,599	21,313	23,920
2020	20,134	34,839	21,188	24,034
2021	20,601	35,069	21,197	24,206
2022	20,416	35,307	21,276	24,377
2023	20,468	35,493	21,640	24,511
2024	21,257	35,688	22,066	24,622
2025	21,371	35,901	22,156	24,724
2026	21,434	36,133	22,049	24,863
2027	21,508	36,353	22,051	25,006
2028	21,151	36,586	22,370	25,181
2029	21,298	36,780	22,841	25,280

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2014	22,731	35,173	23,108	23,732
2015	23,290	35,767	23,481	24,111
2016	23,388	36,212	23,685	24,413
2017	23,469	36,487	24,001	24,696
2018	23,859	36,553	24,349	24,871
2019	24,097	36,943	24,509	24,967
2020	24,379	37,258	24,503	25,054
2021	24,652	37,505	24,742	25,251
2022	24,578	37,754	24,763	25,407
2023	24,570	37,912	25,033	25,592
2024	24,998	38,116	25,364	25,724
2025	25,205	38,395	25,362	25,749
2026	25,427	38,591	25,493	25,927
2027	25,656	38,829	25,728	26,069
2028	25,413	39,056	25,877	26,226
2029	25,801	39,134	26,264	26,314

Table C-4

PJM LOCATIONAL DELIVERABILITY AREAS
SOUTHERN MID-ATLANTIC: BGE and PEPCO
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2014	9,074	14,228	9,229	11,396
2015	9,313	14,456	9,364	11,593
2016	9,400	14,641	9,423	11,774
2017	9,477	14,772	9,609	11,924
2018	9,596	14,813	9,719	12,029
2019	9,668	14,927	9,757	12,067
2020	9,753	15,022	9,764	12,121
2021	9,833	15,092	9,753	12,174
2022	9,805	15,164	9,815	12,234
2023	9,783	15,234	9,969	12,291
2024	9,980	15,307	10,039	12,345
2025	9,985	15,386	10,073	12,376
2026	10,072	15,456	10,108	12,393
2027	10,127	15,511	10,027	12,459
2028	10,017	15,575	10,201	12,510
2029	10,150	15,627	10,267	12,563

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2014	10,420	14,961	10,526	12,024
2015	10,624	15,195	10,707	12,330
2016	10,836	15,410	10,786	12,487
2017	10,899	15,542	10,930	12,637
2018	10,958	15,601	11,031	12,734
2019	11,012	15,704	11,095	12,770
2020	11,101	15,806	11,157	12,769
2021	11,207	15,896	11,219	12,905
2022	11,284	15,986	11,231	12,959
2023	11,292	16,040	11,286	13,017
2024	11,341	16,112	11,384	13,063
2025	11,399	16,202	11,433	13,033
2026	11,437	16,262	11,478	13,154
2027	11,541	16,335	11,532	13,200
2028	11,568	16,409	11,540	13,242
2029	11,607	16,453	11,650	13,224

Table C-5

PJM LOCATIONAL DELIVERABILITY AREAS
MID-ATLANTIC and APS: AE, APS, BGE, DPL, JCPL, METED, PECO, PENLC, PEPCO, PL, PS, RECO and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2014	44,989	69,064	45,276	55,337
2015	46,079	70,289	46,021	56,362
2016	46,489	71,252	46,571	57,269
2017	46,836	71,932	47,185	58,110
2018	47,417	72,419	47,748	58,490
2019	47,787	72,928	47,985	58,878
2020	48,520	73,450	48,171	59,108
2021	49,014	73,983	48,397	59,606
2022	49,087	74,502	49,125	60,126
2023	49,028	74,976	49,741	60,543
2024	50,153	75,442	50,347	60,831
2025	50,285	75,894	50,589	61,043
2026	50,855	76,376	50,769	61,399
2027	51,181	76,885	50,405	61,837
2028	50,783	77,407	51,439	62,356
2029	51,399	77,906	52,010	62,610

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2014	50,688	72,974	51,065	58,036
2015	51,737	74,257	51,953	59,270
2016	52,364	75,115	52,570	60,108
2017	52,728	75,841	53,172	61,261
2018	53,464	76,312	53,829	61,701
2019	53,870	77,037	54,232	61,970
2020	54,466	77,650	54,410	62,063
2021	54,919	78,183	54,859	62,494
2022	55,163	78,622	55,099	63,325
2023	55,545	79,135	55,701	63,790
2024	56,141	79,762	56,374	64,109
2025	56,536	80,337	56,568	64,047
2026	56,927	80,823	56,865	64,419
2027	57,329	81,324	57,189	64,807
2028	57,354	81,737	57,653	65,631
2029	58,057	82,077	58,411	65,617

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Table D-1

SUMMER EXTREME WEATHER (90/10) PEAK LOAD FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2014 - 2029

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AE	2,908	2,963	3,002	3,026	3,043	3,056	3,077	3,096	3,114	3,127	3,140	3,158	3,172	3,191	3,210	3,231
BGE	7,762	7,922	8,074	8,167	8,196	8,250	8,306	8,359	8,410	8,444	8,480	8,528	8,563	8,606	8,651	8,687
DPL	4,357	4,436	4,502	4,540	4,567	4,612	4,659	4,699	4,739	4,761	4,794	4,836	4,866	4,901	4,932	4,961
JCPL	6,836	6,960	7,058	7,105	7,106	7,198	7,260	7,310	7,362	7,385	7,429	7,487	7,526	7,574	7,615	7,625
METED	3,155	3,228	3,280	3,324	3,358	3,399	3,446	3,485	3,520	3,554	3,594	3,641	3,677	3,717	3,751	3,786
PECO	9,364	9,554	9,694	9,798	9,880	9,969	10,086	10,172	10,258	10,326	10,402	10,496	10,576	10,661	10,746	10,817
PENLC	3,072	3,162	3,225	3,272	3,302	3,351	3,400	3,441	3,478	3,510	3,548	3,594	3,630	3,663	3,691	3,720
PEPCO	7,200	7,273	7,336	7,375	7,405	7,454	7,500	7,538	7,576	7,596	7,632	7,674	7,699	7,729	7,758	7,790
PL	7,657	7,795	7,901	7,948	8,007	8,113	8,194	8,267	8,326	8,356	8,447	8,529	8,587	8,658	8,680	8,729
PS	11,250	11,391	11,492	11,550	11,495	11,638	11,703	11,755	11,807	11,837	11,874	11,938	11,971	12,021	12,071	12,024
RECO	458	463	465	468	462	470	473	474	475	476	477	480	480	481	482	476
UGI	208	212	215	217	218	221	222	224	226	227	228	230	232	233	235	235
DIVERSITY - MID-ATLANTIC(-)	332	332	400	302	138	271	341	336	363	329	239	292	259	256	322	192
PJM MID-ATLANTIC	63,895	65,027	65,844	66,488	66,901	67,460	67,985	68,484	68,928	69,270	69,806	70,299	70,720	71,179	71,500	71,889
FE-EAST	13,063	13,350	13,563	13,701	13,766	13,948	14,106	14,236	14,359	14,449	14,571	14,722	14,833	14,954	15,056	15,131
PLGRP	7,865	8,007	8,116	8,165	8,225	8,333	8,416	8,491	8,551	8,583	8,675	8,759	8,819	8,891	8,914	8,964

Table D-1

SUMMER EXTREME WEATHER (90/10) PEAK LOAD FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2014 - 2029

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AEP	24,707	25,117	25,441	25,600	25,731	25,892	26,066	26,241	26,451	26,559	26,701	26,881	27,021	27,197	27,413	27,588
APS	9,273	9,453	9,582	9,683	9,743	9,816	9,903	9,981	10,055	10,140	10,204	10,284	10,351	10,426	10,519	10,594
ATSI	13,957	14,118	14,194	14,263	14,305	14,416	14,478	14,528	14,566	14,605	14,701	14,763	14,811	14,870	14,908	14,979
COMED	25,053	25,603	26,055	26,358	26,566	26,869	27,122	27,376	27,650	27,855	28,124	28,371	28,586	28,824	29,067	29,266
DAYTON	3,626	3,730	3,802	3,848	3,879	3,906	3,945	3,986	4,028	4,059	4,093	4,133	4,171	4,216	4,262	4,308
DEOK	5,837	5,938	6,061	6,081	6,116	6,150	6,200	6,248	6,328	6,330	6,358	6,405	6,453	6,500	6,550	6,594
DLCO	3,184	3,243	3,287	3,340	3,339	3,360	3,385	3,409	3,433	3,475	3,471	3,494	3,514	3,540	3,585	3,587
EKPC	2,044	2,070	2,089	2,103	2,116	2,127	2,142	2,156	2,171	2,180	2,192	2,207	2,218	2,230	2,244	2,261
DIVERSITY - WESTERN(-)	754	930	963	921	860	813	972	970	1,054	939	830	865	955	937	991	970
PJM WESTERN	86,927	88,342	89,548	90,355	90,935	91,723	92,269	92,955	93,628	94,264	95,014	95,673	96,170	96,866	97,557	98,207
DOM	20,790	21,332	22,052	22,437	22,788	23,130	23,521	23,907	24,295	24,640	24,887	25,165	25,404	25,675	25,957	26,236
DIVERSITY - INTERREGIONAL(-)	2,287	2,113	2,425	3,188	3,169	3,308	2,398	2,455	2,585	3,271	3,511	2,792	2,621	2,682	3,475	3,459
PJM RTO	169,325	172,588	175,019	176,092	177,455	179,005	181,377	182,891	184,266	184,903	186,196	188,345	189,673	191,038	191,539	192,873

Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2013/14 - 2028/29

	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
AE	1,830	1,864	1,887	1,907	1,909	1,911	1,911	1,928	1,938	1,950	1,950	1,943	1,959	1,970	1,977	1,966
BGE	6,245	6,449	6,549	6,663	6,704	6,706	6,694	6,765	6,799	6,823	6,824	6,789	6,851	6,868	6,894	6,846
DPL	3,610	3,703	3,751	3,788	3,808	3,817	3,829	3,885	3,911	3,932	3,948	3,944	3,992	4,018	4,042	4,038
JCPL	4,071	4,174	4,219	4,263	4,282	4,293	4,309	4,354	4,383	4,403	4,419	4,422	4,462	4,488	4,512	4,512
METED	2,742	2,820	2,866	2,918	2,942	2,965	2,981	3,032	3,072	3,102	3,123	3,134	3,188	3,216	3,257	3,261
PECO	6,970	7,147	7,267	7,406	7,463	7,491	7,508	7,631	7,709	7,800	7,843	7,815	7,922	7,989	8,065	8,075
PENLC	2,999	3,101	3,187	3,266	3,309	3,341	3,359	3,423	3,478	3,523	3,557	3,561	3,619	3,661	3,708	3,713
PEPCO	5,780	5,882	5,949	6,012	6,044	6,064	6,076	6,155	6,200	6,230	6,254	6,244	6,311	6,346	6,385	6,378
PL	7,703	7,893	8,009	8,108	8,159	8,166	8,163	8,314	8,392	8,445	8,488	8,435	8,577	8,635	8,711	8,699
PS	7,056	7,187	7,257	7,310	7,336	7,342	7,333	7,417	7,446	7,472	7,493	7,464	7,540	7,569	7,600	7,581
RECO	241	242	243	244	245	246	246	247	248	249	250	251	252	253	253	254
UGI	208	213	215	218	219	219	220	222	224	226	226	226	228	229	231	230
DIVERSITY - MID-ATLANTIC(-)	442	652	676	636	585	411	387	691	631	627	570	388	669	694	595	358
PJM MID-ATLANTIC	49,013	50,023	50,723	51,467	51,835	52,150	52,242	52,682	53,169	53,528	53,805	53,840	54,232	54,548	55,040	55,195
FE-EAST	9,802	10,025	10,213	10,398	10,509	10,587	10,635	10,745	10,884	10,983	11,074	11,102	11,210	11,307	11,424	11,483
PLGRP	7,911	8,105	8,221	8,321	8,377	8,385	8,383	8,531	8,600	8,668	8,712	8,661	8,802	8,858	8,930	8,929

Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2013/14 - 2028/29

	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
AEP	24,496	24,735	25,091	25,215	25,322	25,384	25,388	25,861	25,921	26,019	26,125	26,080	26,489	26,680	26,727	26,677
APS	9,182	9,503	9,664	9,813	9,880	9,921	9,969	10,120	10,236	10,304	10,373	10,377	10,527	10,606	10,721	10,723
ATSI	11,006	11,124	11,177	11,222	11,228	11,225	11,201	11,293	11,326	11,344	11,347	11,300	11,390	11,416	11,445	11,383
COMED	16,599	16,992	17,276	17,473	17,589	17,699	17,695	17,972	18,113	18,262	18,362	18,277	18,551	18,682	18,841	18,799
DAYTON	3,025	3,117	3,168	3,201	3,218	3,230	3,238	3,295	3,310	3,334	3,352	3,357	3,413	3,441	3,459	3,457
DEOK	4,689	4,788	4,821	4,844	4,859	4,863	4,851	4,923	4,939	4,954	4,965	4,941	5,014	5,030	5,043	5,019
DLCO	2,267	2,310	2,329	2,344	2,352	2,349	2,349	2,379	2,389	2,392	2,397	2,394	2,418	2,426	2,436	2,431
EKPC	2,623	2,652	2,662	2,668	2,670	2,668	2,664	2,687	2,693	2,697	2,699	2,688	2,709	2,714	2,720	2,708
DIVERSITY - WESTERN(-)	999	1,165	1,274	1,485	1,415	1,274	1,194	1,370	1,465	1,572	1,500	1,221	1,367	1,419	1,503	1,320
PJM WESTERN	72,888	74,056	74,914	75,295	75,703	76,065	76,161	77,160	77,462	77,734	78,120	78,193	79,144	79,576	79,889	79,877
DOM	18,944	19,467	19,841	20,538	20,812	20,998	21,139	21,578	21,953	22,339	22,590	22,536	22,859	23,069	23,331	23,400
DIVERSITY - INTERREGIONAL(-)	1,746	880	696	753	1,226	1,981	1,871	715	813	843	1,290	1,907	834	799	891	1,909
PJM RTO	139,099	142,666	144,782	146,547	147,124	147,232	147,671	150,705	151,771	152,758	153,225	152,662	155,401	156,394	157,369	156,563

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2014 - 2024

	ESTIMATED 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Annual Growth Rate (10 yr)
AE	11,200	11,329	11,510	11,682	11,740	11,799	11,840	11,934	12,000	12,059	12,114	12,199	0.7%
		1.2%	1.6%	1.5%	0.5%	0.5%	0.3%	0.8%	0.6%	0.5%	0.5%	0.7%	
BGE	34,364	35,142	35,772	36,477	36,754	36,913	37,049	37,336	37,478	37,669	37,814	38,053	0.8%
		2.3%	1.8%	2.0%	0.8%	0.4%	0.4%	0.8%	0.4%	0.5%	0.4%	0.6%	
DPL	19,380	19,580	19,871	20,171	20,304	20,453	20,576	20,789	20,928	21,071	21,205	21,393	0.9%
		1.0%	1.5%	1.5%	0.7%	0.7%	0.6%	1.0%	0.7%	0.7%	0.6%	0.9%	
JCPL	24,249	24,621	25,112	25,578	25,780	25,967	26,117	26,392	26,600	26,799	26,974	27,191	1.0%
		1.5%	2.0%	1.9%	0.8%	0.7%	0.6%	1.1%	0.8%	0.7%	0.7%	0.8%	
METED	16,226	16,517	16,918	17,298	17,506	17,714	17,881	18,167	18,353	18,580	18,780	19,022	1.4%
		1.8%	2.4%	2.2%	1.2%	1.2%	0.9%	1.6%	1.0%	1.2%	1.1%	1.3%	
PECO	42,229	42,891	43,836	44,714	45,219	45,714	46,137	46,761	47,133	47,603	48,027	48,552	1.2%
		1.6%	2.2%	2.0%	1.1%	1.1%	0.9%	1.4%	0.8%	1.0%	0.9%	1.1%	
PENLC	18,689	19,174	19,879	20,507	20,874	21,207	21,488	21,903	22,191	22,525	22,828	23,174	1.9%
		2.6%	3.7%	3.2%	1.8%	1.6%	1.3%	1.9%	1.3%	1.5%	1.3%	1.5%	
PEPCO	32,541	32,791	33,124	33,519	33,665	33,857	34,019	34,300	34,434	34,615	34,771	35,024	0.7%
		0.8%	1.0%	1.2%	0.4%	0.6%	0.5%	0.8%	0.4%	0.5%	0.5%	0.7%	
PL	42,068	42,645	43,467	44,262	44,646	45,064	45,380	45,965	46,284	46,703	47,076	47,554	1.1%
		1.4%	1.9%	1.8%	0.9%	0.9%	0.7%	1.3%	0.7%	0.9%	0.8%	1.0%	
PS	46,814	47,276	47,885	48,497	48,679	48,869	49,015	49,418	49,613	49,861	50,033	50,291	0.6%
		1.0%	1.3%	1.3%	0.4%	0.4%	0.3%	0.8%	0.4%	0.5%	0.3%	0.5%	
RECO	1,558	1,568	1,582	1,594	1,597	1,599	1,604	1,613	1,613	1,619	1,623	1,628	0.4%
		0.6%	0.9%	0.8%	0.2%	0.1%	0.3%	0.6%	0.0%	0.4%	0.2%	0.3%	
UGI	1,071	1,088	1,109	1,132	1,142	1,154	1,163	1,177	1,183	1,194	1,204	1,216	1.1%
		1.6%	1.9%	2.1%	0.9%	1.1%	0.8%	1.2%	0.5%	0.9%	0.8%	1.0%	
PJM MID-ATLANTIC	290,389	294,622	300,065	305,431	307,906	310,310	312,269	315,755	317,810	320,298	322,449	325,297	1.0%
		1.5%	1.8%	1.8%	0.8%	0.8%	0.6%	1.1%	0.7%	0.8%	0.7%	0.9%	
FE-EAST	59,164	60,312	61,909	63,383	64,160	64,888	65,486	66,462	67,144	67,904	68,582	69,387	1.4%
		1.9%	2.6%	2.4%	1.2%	1.1%	0.9%	1.5%	1.0%	1.1%	1.0%	1.2%	
PLGRP	43,139	43,733	44,576	45,394	45,788	46,218	46,543	47,142	47,467	47,897	48,280	48,770	1.1%
		1.4%	1.9%	1.8%	0.9%	0.9%	0.7%	1.3%	0.7%	0.9%	0.8%	1.0%	

Notes:

All average growth rates are calculated from the first year of the forecast.

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2025 - 2029

	2025	2026	2027	2028	2029	Annual Growth Rate (15 yr)
AE	12,216	12,268	12,326	12,420	12,453	0.6%
	0.1%	0.4%	0.5%	0.8%	0.3%	
BGE	38,091	38,227	38,367	38,630	38,671	0.6%
	0.1%	0.4%	0.4%	0.7%	0.1%	
DPL	21,469	21,592	21,718	21,912	21,981	0.8%
	0.4%	0.6%	0.6%	0.9%	0.3%	
JCPL	27,296	27,477	27,666	27,942	28,077	0.9%
	0.4%	0.7%	0.7%	1.0%	0.5%	
METED	19,180	19,402	19,631	19,901	20,066	1.3%
	0.8%	1.2%	1.2%	1.4%	0.8%	
PECO	48,847	49,277	49,716	50,318	50,632	1.1%
	0.6%	0.9%	0.9%	1.2%	0.6%	
PENLC	23,402	23,704	24,015	24,365	24,571	1.7%
	1.0%	1.3%	1.3%	1.5%	0.8%	
PEPCO	35,085	35,230	35,371	35,627	35,696	0.6%
	0.2%	0.4%	0.4%	0.7%	0.2%	
PL	47,799	48,192	48,596	49,122	49,370	1.0%
	0.5%	0.8%	0.8%	1.1%	0.5%	
PS	50,378	50,585	50,799	51,167	51,241	0.5%
	0.2%	0.4%	0.4%	0.7%	0.1%	
RECO	1,629	1,630	1,633	1,641	1,641	0.3%
	0.1%	0.1%	0.2%	0.5%	0.0%	
UGI	1,220	1,230	1,240	1,254	1,261	1.0%
	0.3%	0.8%	0.8%	1.1%	0.6%	
PJM MID-ATLANTIC	326,612	328,814	331,078	334,299	335,660	0.9%
	0.4%	0.7%	0.7%	1.0%	0.4%	
FE-EAST	69,878	70,583	71,312	72,208	72,714	1.3%
	0.7%	1.0%	1.0%	1.3%	0.7%	
PLGRP	49,019	49,422	49,836	50,376	50,631	1.0%
	0.5%	0.8%	0.8%	1.1%	0.5%	

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2014 - 2024

	ESTIMATED 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Annual Growth Rate (10 yr)
AEP	137,712	137,450	139,332	141,104	141,656	142,364	142,834	144,133	144,528	145,335	145,990	147,001	0.7%
		-0.2%	1.4%	1.3%	0.4%	0.5%	0.3%	0.9%	0.3%	0.6%	0.5%	0.7%	
APS	49,892	50,933	51,869	52,773	53,096	53,484	53,804	54,438	54,766	55,203	55,594	56,115	1.0%
		2.1%	1.8%	1.7%	0.6%	0.7%	0.6%	1.2%	0.6%	0.8%	0.7%	0.9%	
ATSI	70,302	70,831	71,558	72,265	72,369	72,598	72,681	73,281	73,466	73,751	73,918	74,253	0.5%
		0.8%	1.0%	1.0%	0.1%	0.3%	0.1%	0.8%	0.3%	0.4%	0.2%	0.5%	
COMED	105,300	107,405	110,231	112,829	114,151	115,388	116,424	118,110	119,192	120,474	121,628	123,003	1.4%
		2.0%	2.6%	2.4%	1.2%	1.1%	0.9%	1.4%	0.9%	1.1%	1.0%	1.1%	
DAYTON	17,572	17,892	18,478	18,939	19,176	19,356	19,484	19,777	19,966	20,193	20,387	20,611	1.4%
		1.8%	3.3%	2.5%	1.3%	0.9%	0.7%	1.5%	1.0%	1.1%	1.0%	1.1%	
DEOK	27,917	28,180	28,582	28,970	29,124	29,284	29,407	29,681	29,826	30,009	30,163	30,375	0.8%
		0.9%	1.4%	1.4%	0.5%	0.5%	0.4%	0.9%	0.5%	0.6%	0.5%	0.7%	
DLCO	15,102	15,315	15,598	15,869	15,990	16,107	16,191	16,366	16,450	16,571	16,674	16,804	0.9%
		1.4%	1.8%	1.7%	0.8%	0.7%	0.5%	1.1%	0.5%	0.7%	0.6%	0.8%	
EKPC	10,209	10,262	10,322	10,407	10,414	10,449	10,466	10,536	10,546	10,583	10,610	10,667	0.4%
		0.5%	0.6%	0.8%	0.1%	0.3%	0.2%	0.7%	0.1%	0.4%	0.3%	0.5%	
PJM WESTERN	434,006	438,268	445,970	453,156	455,976	459,030	461,291	466,322	468,740	472,119	474,964	478,829	0.9%
		1.0%	1.8%	1.6%	0.6%	0.7%	0.5%	1.1%	0.5%	0.7%	0.6%	0.8%	
DOM	97,822	99,880	102,496	106,273	108,014	109,728	111,347	113,479	115,115	116,965	118,749	120,332	1.9%
		2.1%	2.6%	3.7%	1.6%	1.6%	1.5%	1.9%	1.4%	1.6%	1.5%	1.3%	
PJM RTO	822,217	832,770	848,531	864,860	871,896	879,068	884,907	895,556	901,665	909,382	916,162	924,458	1.0%
		1.3%	1.9%	1.9%	0.8%	0.8%	0.7%	1.2%	0.7%	0.9%	0.7%	0.9%	

Notes:

All average growth rates are calculated from the first year of the forecast.

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2025 - 2029

	2025	2026	2027	2028	2029	Annual Growth Rate (15 yr)
AEP	147,319	148,096	148,938	150,164	150,651	0.6%
	0.2%	0.5%	0.6%	0.8%	0.3%	
APS	56,358	56,762	57,179	57,763	58,043	0.9%
	0.4%	0.7%	0.7%	1.0%	0.5%	
ATSI	74,351	74,654	74,960	75,383	75,480	0.4%
	0.1%	0.4%	0.4%	0.6%	0.1%	
COMED	123,858	125,077	126,288	127,754	128,588	1.2%
	0.7%	1.0%	1.0%	1.2%	0.7%	
DAYTON	20,779	21,019	21,273	21,574	21,771	1.3%
	0.8%	1.2%	1.2%	1.4%	0.9%	
DEOK	30,462	30,636	30,813	31,076	31,173	0.7%
	0.3%	0.6%	0.6%	0.9%	0.3%	
DLCO	16,870	16,986	17,104	17,266	17,337	0.8%
	0.4%	0.7%	0.7%	0.9%	0.4%	
EKPC	10,669	10,698	10,724	10,788	10,796	0.3%
	0.0%	0.3%	0.2%	0.6%	0.1%	
PJM WESTERN	480,666	483,928	487,279	491,768	493,839	0.8%
	0.4%	0.7%	0.7%	0.9%	0.4%	
DOM	121,281	122,524	123,841	125,565	126,575	1.6%
	0.8%	1.0%	1.1%	1.4%	0.8%	
PJM RTO	928,559	935,266	942,198	951,632	956,074	0.9%
	0.4%	0.7%	0.7%	1.0%	0.5%	

Table E-2

MONTHLY NET ENERGY FORECAST (GWh) FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	PJM MID-ATLANTIC
Jan 2014	965	3,282	1,820	2,143	1,526	3,838	1,766	2,981	4,125	4,014	129	109	26,698
Feb 2014	846	2,845	1,588	1,870	1,347	3,363	1,564	2,591	3,611	3,536	112	95	23,368
Mar 2014	852	2,798	1,542	1,899	1,368	3,423	1,628	2,548	3,614	3,666	119	94	23,551
Apr 2014	792	2,493	1,377	1,764	1,245	3,150	1,493	2,329	3,204	3,478	113	81	21,519
May 2014	843	2,602	1,439	1,858	1,281	3,262	1,520	2,459	3,254	3,659	122	80	22,379
Jun 2014	995	3,051	1,690	2,163	1,354	3,666	1,509	2,923	3,373	4,194	143	83	25,144
Jul 2014	1,263	3,537	1,995	2,635	1,524	4,280	1,644	3,370	3,780	4,930	170	95	29,223
Aug 2014	1,224	3,424	1,923	2,500	1,485	4,126	1,631	3,231	3,692	4,724	160	92	28,212
Sep 2014	918	2,773	1,555	1,953	1,282	3,394	1,519	2,660	3,268	3,841	130	80	23,373
Oct 2014	850	2,598	1,452	1,877	1,316	3,337	1,590	2,433	3,342	3,699	124	84	22,702
Nov 2014	833	2,631	1,470	1,844	1,301	3,299	1,565	2,428	3,402	3,591	118	89	22,571
Dec 2014	948	3,108	1,729	2,115	1,488	3,753	1,745	2,838	3,980	3,944	128	106	25,882

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2015	976	3,324	1,842	2,178	1,555	3,907	1,820	3,004	4,182	4,047	130	110	27,075
Feb 2015	858	2,893	1,614	1,907	1,379	3,437	1,621	2,621	3,677	3,583	113	96	23,799
Mar 2015	865	2,851	1,568	1,940	1,406	3,509	1,695	2,579	3,694	3,726	120	96	24,049
Apr 2015	807	2,544	1,401	1,805	1,276	3,226	1,550	2,355	3,269	3,526	113	83	21,955
May 2015	858	2,651	1,459	1,897	1,310	3,336	1,575	2,478	3,311	3,703	123	82	22,783
Jun 2015	1,014	3,115	1,717	2,211	1,392	3,757	1,570	2,959	3,454	4,264	145	85	25,683
Jul 2015	1,282	3,596	2,021	2,681	1,558	4,365	1,701	3,396	3,849	4,983	171	97	29,700
Aug 2015	1,243	3,483	1,949	2,547	1,519	4,212	1,688	3,258	3,758	4,780	162	94	28,693
Sep 2015	934	2,820	1,575	1,991	1,312	3,463	1,576	2,679	3,328	3,881	131	82	23,772
Oct 2015	863	2,643	1,470	1,911	1,341	3,402	1,640	2,453	3,392	3,738	125	85	23,063
Nov 2015	847	2,685	1,495	1,884	1,337	3,378	1,626	2,462	3,481	3,641	119	91	23,046
Dec 2015	963	3,167	1,760	2,160	1,533	3,844	1,817	2,880	4,072	4,013	130	108	26,447

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2016	986	3,371	1,863	2,208	1,585	3,974	1,875	3,032	4,243	4,084	130	112	27,463
Feb 2016	900	3,047	1,694	2,009	1,459	3,631	1,734	2,747	3,873	3,756	118	102	25,070
Mar 2016	885	2,917	1,600	1,990	1,443	3,590	1,755	2,621	3,772	3,792	121	98	24,584
Apr 2016	818	2,588	1,418	1,835	1,299	3,280	1,594	2,373	3,314	3,560	114	84	22,277
May 2016	871	2,704	1,481	1,931	1,339	3,402	1,626	2,507	3,371	3,746	123	84	23,185
Jun 2016	1,028	3,172	1,740	2,250	1,421	3,826	1,617	2,984	3,512	4,315	146	87	26,098
Jul 2016	1,293	3,629	2,030	2,702	1,569	4,396	1,726	3,392	3,862	4,985	170	98	29,852
Aug 2016	1,259	3,555	1,978	2,599	1,563	4,303	1,750	3,303	3,849	4,865	165	96	29,285
Sep 2016	945	2,867	1,592	2,020	1,335	3,517	1,616	2,699	3,371	3,913	131	83	24,089
Oct 2016	872	2,685	1,484	1,936	1,362	3,453	1,678	2,471	3,432	3,766	126	87	23,352
Nov 2016	852	2,728	1,509	1,905	1,365	3,439	1,676	2,485	3,541	3,662	119	92	23,373
Dec 2016	973	3,214	1,782	2,193	1,558	3,903	1,860	2,905	4,122	4,053	131	109	26,803

Table E-2

MONTHLY NET ENERGY FORECAST (GWh) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	PJM WESTERN	DOM	PJM RTO
Jan 2014	13,108	4,976	6,373	9,351	1,620	2,525	1,332	1,094	40,379	9,384	76,461
Feb 2014	11,424	4,356	5,669	8,243	1,419	2,199	1,176	927	35,413	8,108	66,889
Mar 2014	11,490	4,334	5,854	8,552	1,433	2,206	1,233	849	35,951	7,848	67,350
Apr 2014	10,291	3,815	5,465	8,031	1,334	2,054	1,155	701	32,846	7,026	61,391
May 2014	10,605	3,884	5,647	8,356	1,388	2,164	1,219	722	33,985	7,413	63,777
Jun 2014	11,132	4,033	5,810	9,062	1,506	2,484	1,311	824	36,162	8,724	70,030
Jul 2014	12,348	4,472	6,505	10,732	1,718	2,815	1,489	924	41,003	9,879	80,105
Aug 2014	12,152	4,398	6,372	10,256	1,676	2,739	1,446	910	39,949	9,564	77,725
Sep 2014	10,577	3,851	5,586	8,507	1,401	2,218	1,223	740	34,103	7,960	65,436
Oct 2014	10,796	3,952	5,737	8,569	1,424	2,178	1,224	718	34,598	7,418	64,718
Nov 2014	10,912	4,078	5,620	8,397	1,398	2,148	1,196	816	34,565	7,562	64,698
Dec 2014	12,615	4,784	6,193	9,349	1,575	2,450	1,311	1,037	39,314	8,994	74,190

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	WESTERN	DOM	PJM RTO
Jan 2015	13,243	5,055	6,402	9,541	1,658	2,548	1,349	1,099	40,895	9,595	77,565
Feb 2015	11,596	4,443	5,721	8,446	1,461	2,228	1,196	933	36,024	8,323	68,146
Mar 2015	11,691	4,427	5,934	8,807	1,487	2,242	1,259	856	36,703	8,075	68,827
Apr 2015	10,436	3,891	5,517	8,254	1,383	2,085	1,178	705	33,449	7,238	62,642
May 2015	10,720	3,943	5,695	8,580	1,436	2,192	1,241	724	34,531	7,613	64,927
Jun 2015	11,313	4,116	5,895	9,346	1,566	2,529	1,340	830	36,935	8,963	71,581
Jul 2015	12,494	4,543	6,567	10,988	1,769	2,855	1,515	929	41,660	10,115	81,475
Aug 2015	12,302	4,469	6,430	10,511	1,729	2,780	1,472	916	40,609	9,800	79,102
Sep 2015	10,698	3,915	5,638	8,728	1,447	2,244	1,245	742	34,657	8,156	66,585
Oct 2015	10,899	4,009	5,773	8,775	1,465	2,202	1,243	720	35,086	7,602	65,751
Nov 2015	11,081	4,163	5,693	8,633	1,446	2,182	1,220	822	35,240	7,778	66,064
Dec 2015	12,859	4,895	6,293	9,622	1,631	2,495	1,340	1,046	40,181	9,238	75,866

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	WESTERN	DOM	PJM RTO
Jan 2016	13,380	5,132	6,443	9,732	1,694	2,573	1,367	1,104	41,425	9,901	78,789
Feb 2016	12,168	4,682	5,979	8,949	1,551	2,335	1,260	971	37,895	8,920	71,885
Mar 2016	11,854	4,518	6,005	9,042	1,533	2,281	1,283	862	37,378	8,421	70,383
Apr 2016	10,516	3,938	5,549	8,438	1,412	2,104	1,195	707	33,859	7,504	63,640
May 2016	10,843	4,011	5,749	8,788	1,475	2,221	1,262	730	35,079	7,917	66,181
Jun 2016	11,425	4,178	5,945	9,566	1,602	2,559	1,361	834	37,470	9,261	72,829
Jul 2016	12,480	4,560	6,536	11,102	1,782	2,862	1,524	930	41,776	10,356	81,984
Aug 2016	12,510	4,558	6,541	10,791	1,782	2,829	1,501	924	41,436	10,150	80,871
Sep 2016	10,781	3,962	5,669	8,902	1,477	2,267	1,261	745	35,064	8,424	67,577
Oct 2016	10,965	4,051	5,800	8,933	1,493	2,220	1,259	722	35,443	7,858	66,653
Nov 2016	11,230	4,227	5,730	8,804	1,481	2,204	1,239	826	35,741	8,036	67,150
Dec 2016	12,952	4,956	6,319	9,782	1,657	2,515	1,357	1,052	40,590	9,525	76,918

Table E-3

MONTHLY NET ENERGY FORECAST (GWh) FOR
FE-EAST AND PLGRP

	FE_EAST	PLGRP
Jan 2014	5,435	4,234
Feb 2014	4,781	3,706
Mar 2014	4,895	3,708
Apr 2014	4,502	3,285
May 2014	4,659	3,334
Jun 2014	5,026	3,456
Jul 2014	5,803	3,875
Aug 2014	5,616	3,784
Sep 2014	4,754	3,348
Oct 2014	4,783	3,426
Nov 2014	4,710	3,491
Dec 2014	5,348	4,086

	FE_EAST	PLGRP
Jan 2015	5,553	4,292
Feb 2015	4,907	3,773
Mar 2015	5,041	3,790
Apr 2015	4,631	3,352
May 2015	4,782	3,393
Jun 2015	5,173	3,539
Jul 2015	5,940	3,946
Aug 2015	5,754	3,852
Sep 2015	4,879	3,410
Oct 2015	4,892	3,477
Nov 2015	4,847	3,572
Dec 2015	5,510	4,180

	FE_EAST	PLGRP
Jan 2016	5,668	4,355
Feb 2016	5,202	3,975
Mar 2016	5,188	3,870
Apr 2016	4,728	3,398
May 2016	4,896	3,455
Jun 2016	5,288	3,599
Jul 2016	5,997	3,960
Aug 2016	5,912	3,945
Sep 2016	4,971	3,454
Oct 2016	4,976	3,519
Nov 2016	4,946	3,633
Dec 2016	5,611	4,231

Note: FE_EAST contains JCPL, METED and PENLC zones. PLGRP contains PL and UGI zones.

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Table E-1a

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2014-2024

	ESTIMATED 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Annual Growth Rate (10 yr)
AE	11,080	11,184	11,356	11,509	11,534	11,540	11,543	11,605	11,651	11,662	11,669	11,710	0.5%
%		0.9%	1.5%	1.3%	0.2%	0.1%	0.0%	0.5%	0.4%	0.1%	0.1%	0.4%	
BGE	34,364	35,182	36,026	36,727	36,984	37,121	37,204	37,547	37,680	37,762	37,819	37,993	0.8%
%		2.4%	2.4%	1.9%	0.7%	0.4%	0.2%	0.9%	0.4%	0.2%	0.1%	0.5%	
DPL	19,070	19,189	19,466	19,698	19,726	19,772	19,821	19,986	20,048	20,092	20,116	20,209	0.5%
%		0.6%	1.4%	1.2%	0.1%	0.2%	0.3%	0.8%	0.3%	0.2%	0.1%	0.5%	
JCPL	24,018	24,317	24,796	25,172	25,254	25,360	25,443	25,742	25,903	25,982	26,013	26,215	0.8%
%		1.2%	2.0%	1.5%	0.3%	0.4%	0.3%	1.2%	0.6%	0.3%	0.1%	0.8%	
METED	15,785	16,017	16,398	16,722	16,848	16,961	17,065	17,344	17,525	17,679	17,779	17,927	1.1%
%		1.5%	2.4%	2.0%	0.8%	0.7%	0.6%	1.6%	1.0%	0.9%	0.6%	0.8%	
PECO	42,091	42,753	43,746	44,470	44,831	45,278	45,643	46,416	46,856	47,182	47,482	47,966	1.2%
%		1.6%	2.3%	1.7%	0.8%	1.0%	0.8%	1.7%	0.9%	0.7%	0.6%	1.0%	
PENLC	18,151	18,520	19,122	19,653	19,946	20,185	20,418	20,768	21,009	21,296	21,542	21,808	1.6%
%		2.0%	3.2%	2.8%	1.5%	1.2%	1.2%	1.7%	1.2%	1.4%	1.2%	1.2%	
PEPCO	32,476	32,726	33,092	33,418	33,473	33,619	33,740	34,094	34,201	34,307	34,371	34,564	0.5%
%		0.8%	1.1%	1.0%	0.2%	0.4%	0.4%	1.0%	0.3%	0.3%	0.2%	0.6%	
PL	41,653	42,137	42,968	43,682	43,944	44,200	44,485	45,116	45,372	45,767	46,037	46,409	1.0%
%		1.2%	2.0%	1.7%	0.6%	0.6%	0.6%	1.4%	0.6%	0.9%	0.6%	0.8%	
PS	46,327	46,711	47,351	47,907	48,018	48,157	48,290	48,737	48,979	49,115	49,259	49,551	0.6%
%		0.8%	1.4%	1.2%	0.2%	0.3%	0.3%	0.9%	0.5%	0.3%	0.3%	0.6%	
RECO	1,532	1,542	1,557	1,568	1,571	1,574	1,573	1,587	1,592	1,594	1,597	1,601	0.4%
%		0.7%	1.0%	0.7%	0.1%	0.2%	-0.1%	0.9%	0.3%	0.1%	0.2%	0.2%	
UGI	1,062	1,073	1,094	1,112	1,117	1,122	1,126	1,139	1,146	1,153	1,157	1,164	0.8%
%		1.0%	2.0%	1.6%	0.5%	0.4%	0.4%	1.2%	0.6%	0.6%	0.4%	0.6%	
PJM MID-ATLANTIC	287,608	291,352	296,974	301,637	303,246	304,890	306,351	310,082	311,963	313,591	314,843	317,118	0.9%
%		1.3%	1.9%	1.6%	0.5%	0.5%	0.5%	1.2%	0.6%	0.5%	0.4%	0.7%	
FE/GPU	57,954	58,855	60,316	61,546	62,048	62,506	62,926	63,854	64,437	64,957	65,334	65,950	1.1%
%		1.6%	2.5%	2.0%	0.8%	0.7%	0.7%	1.5%	0.9%	0.8%	0.6%	0.9%	
PLGRP	42,715	43,210	44,063	44,794	45,061	45,322	45,611	46,255	46,519	46,920	47,195	47,573	1.0%
%		1.2%	2.0%	1.7%	0.6%	0.6%	0.6%	1.4%	0.6%	0.9%	0.6%	0.8%	

Note: All forecast values derived from trended RTO load factors.
All average growth rates are calculated from the first year of the forecast.

Table E-1a (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2025-2029

		2025	2026	2027	2028	2029	Annual Growth Rate (15 yr)
AE		11,696	11,719	11,722	11,758	11,742	0.3%
	%	-0.1%	0.2%	0.0%	0.3%	-0.1%	
BGE		38,003	38,187	38,203	38,340	38,340	0.6%
	%	0.0%	0.5%	0.0%	0.4%	0.0%	
DPL		20,195	20,283	20,294	20,345	20,298	0.4%
	%	-0.1%	0.4%	0.1%	0.3%	-0.2%	
JCPL		26,277	26,478	26,547	26,645	26,621	0.6%
	%	0.2%	0.8%	0.3%	0.4%	-0.1%	
METED		18,048	18,255	18,398	18,551	18,639	1.0%
	%	0.7%	1.1%	0.8%	0.8%	0.5%	
PECO		48,281	48,840	49,216	49,589	49,858	1.0%
	%	0.7%	1.2%	0.8%	0.8%	0.5%	
PENLC		21,957	22,240	22,465	22,769	22,914	1.4%
	%	0.7%	1.3%	1.0%	1.4%	0.6%	
PEPCO		34,632	34,834	34,888	35,030	35,033	0.5%
	%	0.2%	0.6%	0.2%	0.4%	0.0%	
PL		46,570	47,056	47,347	47,784	47,940	0.9%
	%	0.3%	1.0%	0.6%	0.9%	0.3%	
PS		49,578	49,857	50,019	50,229	50,329	0.5%
	%	0.1%	0.6%	0.3%	0.4%	0.2%	
RECO		1,602	1,610	1,613	1,617	1,620	0.3%
	%	0.0%	0.5%	0.2%	0.3%	0.2%	
UGI		1,165	1,175	1,179	1,189	1,189	0.7%
	%	0.1%	0.9%	0.3%	0.9%	0.0%	
PJM MID-ATLANTIC		318,003	320,534	321,890	323,845	324,523	0.7%
	%	0.3%	0.8%	0.4%	0.6%	0.2%	
FE/GPU		66,281	66,973	67,410	67,966	68,174	1.0%
	%	0.5%	1.0%	0.7%	0.8%	0.3%	
PLGRP		47,735	48,231	48,525	48,972	49,129	0.9%
	%	0.3%	1.0%	0.6%	0.9%	0.3%	

Note: All forecast values derived from trended RTO load factors.

Table E-1a

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2014-2024

		ESTIMATED 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Annual Growth Rate (10 yr)
AEP		135,933	135,058	136,674	138,402	138,752	139,008	139,028	140,165	140,426	141,163	141,561	141,903	0.5%
	%		-0.6%	1.2%	1.3%	0.3%	0.2%	0.0%	0.8%	0.2%	0.5%	0.3%	0.2%	
APS		48,632	49,545	50,431	51,184	51,170	51,200	51,271	51,727	51,869	52,019	52,054	52,199	0.5%
	%		1.9%	1.8%	1.5%	0.0%	0.1%	0.1%	0.9%	0.3%	0.3%	0.1%	0.3%	
ATSI		68,253	68,501	69,063	69,616	69,452	69,343	69,235	69,736	69,933	69,898	69,839	69,883	0.2%
	%		0.4%	0.8%	0.8%	-0.2%	-0.2%	-0.2%	0.7%	0.3%	0.0%	-0.1%	0.1%	
COMED		104,058	106,023	108,614	110,839	111,990	113,044	113,780	115,563	116,650	117,616	118,666	119,919	1.2%
	%		1.9%	2.4%	2.0%	1.0%	0.9%	0.7%	1.6%	0.9%	0.8%	0.9%	1.1%	
DAYTON		17,266	17,487	17,996	18,374	18,511	18,595	18,682	18,930	19,066	19,231	19,349	19,501	1.1%
	%		1.3%	2.9%	2.1%	0.7%	0.5%	0.5%	1.3%	0.7%	0.9%	0.6%	0.8%	
DEOK		27,679	27,923	28,339	28,637	28,734	28,803	28,911	29,219	29,320	29,438	29,529	29,685	0.6%
	%		0.9%	1.5%	1.1%	0.3%	0.2%	0.4%	1.1%	0.3%	0.4%	0.3%	0.5%	
DLCO		14,795	14,957	15,211	15,414	15,474	15,564	15,619	15,789	15,857	15,934	15,992	16,111	0.7%
	%		1.1%	1.7%	1.3%	0.4%	0.6%	0.4%	1.1%	0.4%	0.5%	0.4%	0.7%	
EKPC		10,074	10,091	10,154	10,186	10,124	10,090	10,052	10,110	10,084	10,059	10,028	9,997	-0.1%
	%		0.2%	0.6%	0.3%	-0.6%	-0.3%	-0.4%	0.6%	-0.3%	-0.3%	-0.3%	-0.3%	
PJM WESTERN		426,691	429,586	436,482	442,653	444,206	445,646	446,579	451,240	453,206	455,359	457,017	459,198	0.7%
	%		0.7%	1.6%	1.4%	0.4%	0.3%	0.2%	1.0%	0.4%	0.5%	0.4%	0.5%	
DOM		96,569	98,103	100,543	103,832	105,295	106,635	107,812	109,940	111,345	112,621	113,882	114,937	1.6%
	%		1.6%	2.5%	3.3%	1.4%	1.3%	1.1%	2.0%	1.3%	1.1%	1.1%	0.9%	
PJM RTO		810,868	819,040	833,999	848,123	852,747	857,171	860,742	871,262	876,513	881,570	885,742	891,253	0.8%
	%		1.0%	1.8%	1.7%	0.5%	0.5%	0.4%	1.2%	0.6%	0.6%	0.5%	0.6%	

Note: All forecast values derived from trended RTO load factors.
All average growth rates are calculated from the first year of the forecast.

Table E-1a (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2025-2029

		2025	2026	2027	2028	2029	Annual Growth Rate (15 yr)
AEP		141,859	142,595	143,064	144,102	144,359	0.4%
	%	0.0%	0.5%	0.3%	0.7%	0.2%	
APS		52,176	52,416	52,525	52,711	52,646	0.4%
	%	0.0%	0.5%	0.2%	0.4%	-0.1%	
ATSI		69,822	69,980	70,086	70,171	69,953	0.1%
	%	-0.1%	0.2%	0.2%	0.1%	-0.3%	
COMED		120,707	121,896	122,838	123,987	124,877	1.1%
	%	0.7%	1.0%	0.8%	0.9%	0.7%	
DAY		19,592	19,793	19,929	20,142	20,256	1.0%
	%	0.5%	1.0%	0.7%	1.1%	0.6%	
DEOK		29,753	29,942	30,029	30,165	30,220	0.5%
	%	0.2%	0.6%	0.3%	0.5%	0.2%	
DLCO		16,139	16,246	16,315	16,408	16,486	0.7%
	%	0.2%	0.7%	0.4%	0.6%	0.5%	
EKPC		9,945	9,967	9,933	9,919	9,848	-0.2%
	%	-0.5%	0.2%	-0.3%	-0.1%	-0.7%	
PJM WESTERN		459,994	462,835	464,719	467,605	468,646	0.6%
	%	0.2%	0.6%	0.4%	0.6%	0.2%	
DOM		115,378	116,439	117,231	118,016	118,531	1.3%
	%	0.4%	0.9%	0.7%	0.7%	0.4%	
PJM RTO		893,374	899,807	903,839	909,467	911,699	0.7%
	%	0.2%	0.7%	0.4%	0.6%	0.2%	

Note: All forecast values derived from trended RTO load factors.

Table E-2a

MONTHLY NET ENERGY FORECAST (GWh) FOR EACH
PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	PJM MID-ATLANTIC
Jan 2014	975	3,198	1,770	2,157	1,501	3,856	1,766	2,994	4,168	4,018	126	108	26,638
Feb 2014	862	2,836	1,576	1,926	1,371	3,447	1,582	2,641	3,749	3,556	111	99	23,755
Mar 2014	853	2,809	1,511	1,894	1,368	3,381	1,576	2,497	3,547	3,622	116	93	23,267
Apr 2014	754	2,436	1,345	1,664	1,217	2,999	1,440	2,122	3,192	3,193	103	76	20,543
May 2014	749	2,442	1,310	1,626	1,095	2,899	1,297	2,303	2,789	3,248	113	66	19,937
Jun 2014	989	3,059	1,639	2,178	1,312	3,771	1,445	2,940	3,310	4,229	144	81	25,098
Jun 2014	1,267	3,557	2,007	2,655	1,484	4,319	1,557	3,410	3,699	4,993	170	94	29,212
Jul 2014	1,182	3,403	1,832	2,420	1,408	4,159	1,546	3,202	3,578	4,657	157	89	27,633
Sep 2014	916	2,881	1,546	2,058	1,221	3,516	1,431	2,701	3,178	3,989	137	82	23,656
Oct 2014	817	2,583	1,416	1,716	1,228	3,230	1,540	2,466	3,300	3,636	127	83	22,143
Nov 2014	842	2,773	1,476	1,843	1,322	3,360	1,592	2,521	3,570	3,569	113	91	23,071
Dec 2014	978	3,204	1,760	2,180	1,489	3,817	1,749	2,929	4,056	4,002	126	109	26,399

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2015	988	3,280	1,788	2,200	1,533	3,932	1,820	3,018	4,236	4,075	127	110	27,107
Feb 2015	877	2,926	1,600	1,972	1,411	3,536	1,634	2,671	3,834	3,616	112	102	24,291
Mar 2015	869	2,898	1,543	1,949	1,410	3,494	1,640	2,549	3,639	3,706	119	95	23,912
Apr 2015	765	2,494	1,369	1,709	1,252	3,090	1,502	2,138	3,266	3,253	105	78	21,022
May 2015	747	2,471	1,311	1,628	1,104	2,924	1,329	2,296	2,806	3,238	112	66	20,031
Jun 2015	1,007	3,134	1,665	2,227	1,342	3,860	1,486	2,978	3,372	4,294	145	82	25,594
Jun 2015	1,288	3,628	2,035	2,698	1,513	4,401	1,597	3,442	3,757	5,055	171	96	29,680
Jul 2015	1,198	3,471	1,847	2,459	1,435	4,242	1,587	3,224	3,629	4,707	158	90	28,047
Sep 2015	933	2,953	1,577	2,106	1,254	3,616	1,480	2,738	3,251	4,053	139	85	24,184
Oct 2015	828	2,635	1,431	1,732	1,248	3,280	1,583	2,489	3,354	3,652	127	84	22,444
Nov 2015	861	2,867	1,513	1,892	1,369	3,464	1,654	2,569	3,683	3,635	114	95	23,717
Dec 2015	995	3,270	1,786	2,225	1,526	3,908	1,808	2,979	4,141	4,068	128	111	26,945

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2016	998	3,325	1,802	2,234	1,561	4,004	1,873	3,048	4,296	4,127	127	111	27,508
Feb 2016	924	3,098	1,676	2,080	1,497	3,748	1,745	2,811	4,060	3,802	117	107	25,665
Mar 2016	891	2,960	1,570	1,993	1,436	3,546	1,677	2,586	3,680	3,760	119	97	24,316
Apr 2016	770	2,509	1,370	1,709	1,267	3,104	1,530	2,122	3,295	3,255	104	79	21,115
May 2016	749	2,498	1,309	1,628	1,114	2,928	1,356	2,295	2,816	3,221	112	66	20,091
Jun 2016	1,019	3,192	1,686	2,268	1,366	3,916	1,514	3,012	3,411	4,360	148	83	25,976
Jun 2016	1,300	3,681	2,054	2,728	1,531	4,454	1,624	3,460	3,795	5,096	171	97	29,990
Jul 2016	1,211	3,540	1,874	2,503	1,461	4,312	1,623	3,261	3,683	4,787	161	92	28,506
Sep 2016	932	2,994	1,584	2,116	1,259	3,640	1,504	2,743	3,266	4,054	138	85	24,313
Oct 2016	836	2,677	1,437	1,734	1,268	3,331	1,633	2,492	3,410	3,650	127	86	22,681
Nov 2016	873	2,936	1,533	1,926	1,401	3,526	1,713	2,598	3,767	3,674	115	96	24,158
Dec 2016	1,006	3,317	1,801	2,253	1,561	3,961	1,862	2,991	4,203	4,120	129	113	27,318

Note: All forecast values derived from trended RTO load factors.

Table E-2a

MONTHLY NET ENERGY FORECAST (GWh) FOR EACH
PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	PJM WESTERN	DOM	PJM RTO
Jan 2014	13,429	4,910	6,418	9,560	1,664	2,572	1,312	1,105	40,971	9,048	76,657
Feb 2014	11,645	4,333	5,724	8,384	1,434	2,193	1,178	921	35,812	7,912	67,479
Mar 2014	11,226	4,188	5,777	8,295	1,412	2,142	1,212	806	35,059	7,577	65,903
Apr 2014	10,145	3,767	5,435	8,258	1,306	2,062	1,125	660	32,758	6,633	59,934
May 2014	9,681	3,308	4,775	7,817	1,254	2,004	1,075	647	30,562	6,916	57,415
Jun 2014	11,293	3,954	5,772	9,199	1,457	2,488	1,309	809	36,281	8,637	70,016
Jun 2014	12,215	4,330	6,329	10,865	1,681	2,824	1,460	907	40,611	10,047	79,870
Jul 2014	11,902	4,281	6,166	9,914	1,610	2,697	1,413	889	38,873	9,520	76,025
Sep 2014	10,179	3,652	5,112	8,098	1,326	2,178	1,195	750	32,489	7,961	64,106
Oct 2014	9,842	3,768	5,354	7,933	1,334	2,112	1,182	738	32,264	7,387	61,793
Nov 2014	10,908	4,216	5,455	8,041	1,406	2,172	1,195	844	34,239	7,558	64,867
Dec 2014	12,593	4,836	6,185	9,657	1,602	2,480	1,301	1,014	39,668	8,908	74,975

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	WESTERN	DOM	PJM RTO
Jan 2015	13,405	5,031	6,465	9,738	1,708	2,602	1,328	1,109	41,386	9,184	77,676
Feb 2015	11,610	4,465	5,770	8,552	1,471	2,214	1,197	921	36,200	8,042	68,532
Mar 2015	11,461	4,296	5,857	8,558	1,465	2,182	1,243	815	35,878	7,836	67,626
Apr 2015	10,319	3,843	5,530	8,596	1,358	2,111	1,159	662	33,578	6,807	61,407
May 2015	9,732	3,305	4,770	7,954	1,289	2,021	1,084	646	30,799	7,011	57,840
Jun 2015	11,485	4,012	5,817	9,436	1,502	2,527	1,333	819	36,931	8,868	71,393
Jun 2015	12,387	4,378	6,371	11,107	1,723	2,870	1,479	917	41,231	10,294	81,204
Jul 2015	12,066	4,320	6,176	10,116	1,649	2,738	1,431	902	39,397	9,740	77,184
Sep 2015	10,382	3,712	5,173	8,292	1,363	2,207	1,215	755	33,099	8,217	65,500
Oct 2015	9,898	3,811	5,375	8,128	1,366	2,137	1,204	735	32,654	7,550	62,648
Nov 2015	11,131	4,327	5,528	8,271	1,459	2,219	1,219	855	35,010	7,859	66,586
Dec 2015	12,799	4,932	6,232	9,867	1,642	2,511	1,319	1,018	40,320	9,137	76,402

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	WESTERN	DOM	PJM RTO
Jan 2016	13,583	5,100	6,503	9,904	1,743	2,630	1,342	1,113	41,917	9,382	78,807
Feb 2016	12,179	4,704	6,018	9,014	1,553	2,311	1,255	956	37,990	8,548	72,203
Mar 2016	11,535	4,346	5,884	8,744	1,497	2,194	1,254	808	36,261	8,076	68,653
Apr 2016	10,364	3,866	5,537	8,749	1,378	2,101	1,160	654	33,810	6,931	61,856
May 2016	9,824	3,346	4,764	8,167	1,315	2,036	1,090	643	31,186	7,196	58,473
Jun 2016	11,683	4,058	5,858	9,586	1,529	2,549	1,352	822	37,436	9,158	72,571
Jun 2016	12,480	4,401	6,376	11,255	1,745	2,888	1,490	919	41,554	10,605	82,149
Jul 2016	12,252	4,385	6,268	10,299	1,680	2,774	1,455	910	40,024	10,047	78,577
Sep 2016	10,347	3,694	5,101	8,350	1,364	2,202	1,217	750	33,026	8,444	65,783
Oct 2016	9,956	3,858	5,410	8,257	1,391	2,160	1,217	737	32,987	7,844	63,511
Nov 2016	11,270	4,420	5,580	8,451	1,499	2,250	1,241	862	35,573	8,177	67,908
Dec 2016	12,929	5,006	6,316	10,063	1,680	2,544	1,340	1,013	40,890	9,422	77,630

Note: All forecast values derived from trended RTO load factors.

Table E-3a

MONTHLY NET ENERGY FORECAST (GWh)
FOR FE-EAST AND PLGRP

	FE-EAST	PLGRP
Jan 2014	5,424	4,277
Feb 2014	4,878	3,849
Mar 2014	4,839	3,640
Apr 2014	4,322	3,268
May 2014	4,017	2,855
Jun 2014	4,935	3,391
Jun 2014	5,696	3,794
Jul 2014	5,374	3,667
Sep 2014	4,710	3,260
Oct 2014	4,483	3,383
Nov 2014	4,757	3,661
Dec 2014	5,418	4,166
	FE-EAST	**PLGRP**
Jan 2015	5,553	4,346
Feb 2015	5,017	3,936
Mar 2015	4,999	3,734
Apr 2015	4,464	3,344
May 2015	4,061	2,871
Jun 2015	5,056	3,454
Jun 2015	5,808	3,853
Jul 2015	5,481	3,719
Sep 2015	4,839	3,336
Oct 2015	4,562	3,439
Nov 2015	4,915	3,778
Dec 2015	5,559	4,253
	FE-EAST	**PLGRP**
Jan 2016	5,667	4,408
Feb 2016	5,321	4,167
Mar 2016	5,106	3,777
Apr 2016	4,507	3,374
May 2016	4,098	2,882
Jun 2016	5,149	3,494
Jun 2016	5,884	3,891
Jul 2016	5,587	3,774
Sep 2016	4,878	3,351
Oct 2016	4,634	3,496
Nov 2016	5,040	3,863
Dec 2016	5,676	4,316

Note: FE-EAST contains JCPL, METED, and PENLC zones; PLGRP contains PL and UGI zones.
All forecast values derived from trended RTO load factors.

Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

SUMMER

YEAR	NORMALIZED BASE	NORMALIZED COOLING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
1998				133,100	Tuesday, July 21, 1998	17:00
1999	88,016			141,300	Friday, July 30, 1999	17:00
2000	90,958			131,766	Wednesday, August 9, 2000	17:00
2001	92,064			150,911	Thursday, August 9, 2001	16:00
2002	92,661			150,782	Thursday, August 1, 2002	17:00
2003	93,576			145,191	Thursday, August 21, 2003	17:00
2004	94,997			139,178	Tuesday, August 3, 2004	17:00
2005	95,670	56,590	152,260	155,174	Tuesday, July 26, 2005	16:00
2006	95,223	58,657	153,880	166,850	Wednesday, August 2, 2006	17:00
2007	96,612	59,308	155,920	161,943	Wednesday, August 8, 2007	16:00
2008	96,898	59,532	156,430	150,509	Monday, June 9, 2008	17:00
2009	94,430	58,360	152,790	145,001	Monday, August 10, 2009	16:00
2010	92,985	60,675	153,660	157,128	Wednesday, July 7, 2010	17:00
2011	93,261	60,259	153,520	165,473	Thursday, July 21, 2011	17:00
2012	92,958	61,277	154,235	158,116	Tuesday, July 17, 2012	18:00
2013	92,264	62,921	155,185	158,954	Thursday, July 18, 2013	17:00

WINTER

YEAR	NORMALIZED BASE	NORMALIZED HEATING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
97/98				102,084	Wednesday, January 14, 1998	19:00
98/99	86,625			115,867	Tuesday, January 5, 1999	19:00
99/00	89,294			118,385	Friday, January 28, 2000	8:00
00/01	91,279			117,960	Wednesday, December 20, 2000	19:00
01/02	92,270			112,082	Wednesday, January 2, 2002	19:00
02/03	92,491			129,787	Thursday, January 23, 2003	19:00
03/04	93,706			122,449	Friday, January 23, 2004	9:00
04/05	94,378			131,046	Monday, December 20, 2004	19:00
05/06	94,696	32,194	126,890	126,655	Wednesday, December 14, 2005	19:00
06/07	96,178	31,472	127,650	136,675	Monday, February 5, 2007	20:00
07/08	97,239	32,411	129,650	128,180	Wednesday, January 2, 2008	19:00
08/09	96,373	34,197	130,570	133,845	Friday, January 16, 2009	19:00
09/10	93,518	35,192	128,710	125,143	Monday, January 4, 2010	19:00
10/11	91,862	37,178	129,040	132,074	Tuesday, December 14, 2010	19:00
11/12	92,247	37,833	130,080	124,274	Tuesday, January 3, 2012	19:00
12/13	92,036	38,344	130,380	128,593	Tuesday, January 22, 2013	19:00

Notes:
Normalized values for 2005 - 2013 are calculated by PJM staff using a methodology consistent with the PJM Load Forecast Model.
Normalized base values are calculated by PJM staff using a two-period average of peak loads on non-heating/non-coolong days.
All times are shown in hour ending Eastern Prevailing Time.
All historic peak values reflect the current membership of the PJM RTO.

Table F-2

PJM RTO HISTORICAL NET ENERGY
(GWH)

YEAR	ENERGY	GROWTH RATE
1998	710,096	0.0%
1999	739,723	4.2%
2000	756,238	2.2%
2001	754,541	-0.2%
2002	782,301	3.7%
2003	780,693	-0.2%
2004	796,257	2.0%
2005	822,841	3.3%
2006	802,444	-2.5%
2007	832,999	3.8%
2008	821,635	-1.4%
2009	780,617	-5.0%
2010	819,492	5.0%
2011	805,356	-1.7%
2012	791,220	-1.8%

Note: All historic net energy values reflect the current membership of the PJM RTO.

Table G-1

ANNUALIZED AVERAGE GROWTH OF INDEXED ECONOMIC VARIABLE
FOR EACH PJM ZONE AND RTO

	5-Year (2014-19)	10-Year (2014-24)	15-Year (2014-29)
AE	1.3%	1.0%	0.9%
BGE	1.5%	1.2%	1.1%
DPL	1.9%	1.6%	1.4%
JCPL	1.4%	1.1%	1.0%
METED	1.9%	1.6%	1.5%
PECO	1.9%	1.6%	1.4%
PENLC	1.8%	1.5%	1.3%
PEPCO	1.7%	1.4%	1.2%
PL	1.8%	1.5%	1.3%
PS	1.5%	1.1%	1.0%
RECO	1.2%	0.9%	0.8%
UGI	1.3%	1.1%	1.0%
AEP	1.6%	1.3%	1.2%
APS	1.7%	1.5%	1.4%
ATSI	1.6%	1.3%	1.2%
COMED	1.8%	1.5%	1.3%
DAYTON	1.4%	1.1%	1.0%
DEOK	1.7%	1.4%	1.3%
DLCO	1.7%	1.4%	1.2%
EKPC	1.6%	1.4%	1.3%
DOM	1.7%	1.4%	1.3%
PJM RTO	1.7%	1.4%	1.3%

Source: Moody's Analytics, November, 2013

Notes:
Values presented are annualized compound average growth rates.
Indexed economic variable is a combination of U.S. Gross Domestic Product, Gross Metropolitan Product, Real Personal Income, Population, Households, and Non-Manufacturing Employment.

SC – EXHIBIT 18

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Or

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SC – EXHIBIT 19

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Or

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SC – EXHIBIT 21

(CONFIDENTIAL)

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Or

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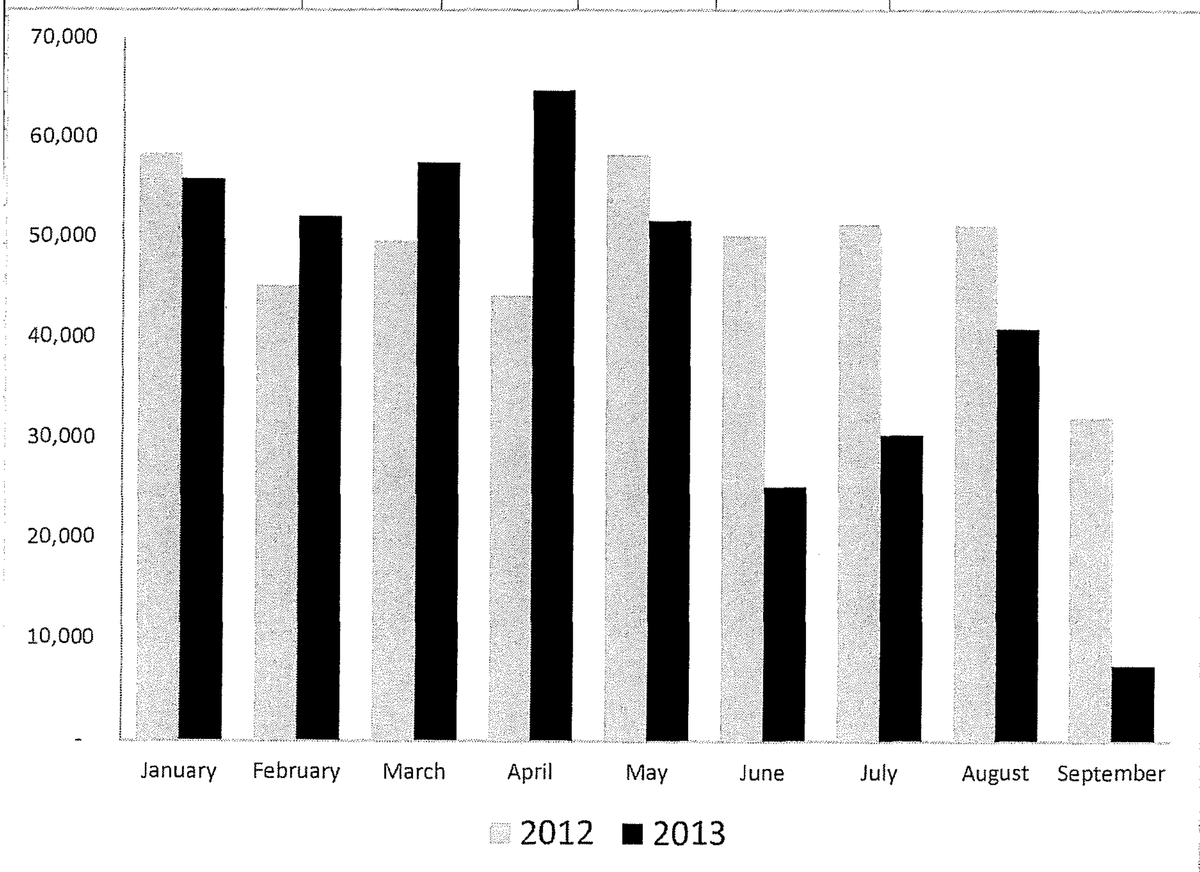
Facility Name	Unit ID	Year	Month	Gross Load (MW-h)
John S. Cooper	1	2012	1	58,333
John S. Cooper	1	2012	2	45,073
John S. Cooper	1	2012	3	49,551
John S. Cooper	1	2012	4	44,041
John S. Cooper	1	2012	5	58,238
John S. Cooper	1	2012	6	50,110
John S. Cooper	1	2012	7	51,306
John S. Cooper	1	2012	8	51,217
John S. Cooper	1	2012	9	32,025
John S. Cooper	1	2012	10	68,427
John S. Cooper	1	2012	11	66,188
John S. Cooper	1	2012	12	59,868
John S. Cooper	1	2013	1	55,813
John S. Cooper	1	2013	2	52,052
John S. Cooper	1	2013	3	57,444
John S. Cooper	1	2013	4	64,755
John S. Cooper	1	2013	5	51,652
John S. Cooper	1	2013	6	25,154
John S. Cooper	1	2013	7	30,348
John S. Cooper	1	2013	8	40,840
John S. Cooper	1	2013	9	7,384



SC - EXHIBIT 22
DENIED ADMITTANCE

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2013-00259
RESPONSE TO INFORMATION REQUEST

INTERVENORS' INITIAL REQUEST FOR INFORMATION DATED 10/04/13
REQUEST 58
RESPONSIBLE PARTY: Julia J. Tucker

Request 58. Refer to Exhibit JJT-1.

Request 58a Please confirm that EKPC stated in the RFP that it would not accept any proposals for demand response resources.

Responses 58a. Yes, EKPC stated in the RFP that it would not accept any proposals for demand response resources.

Request 58b. Please explain why EKPC limited the RFP to supply-side resources and did not accept proposals for demand-side resources.

Responses 58b. EKPC was evaluating the loss of large, central station supply.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2013-00259
RESPONSE TO INFORMATION REQUEST

COMMISSION STAFF'S INITIAL REQUEST FOR INFORMATION DATED 10/04/13
REQUEST 14
RESPONSIBLE PARTY: Julia J. Tucker

Request 14. Refer to page 9 of the Tucker Testimony.

Request 14a. Refer to lines 5 through 6, which state that splitting the 300 MW of capacity would decrease the risks associated developing new capacity by spreading the technology and operational risks. Explain what is meant by this statement.

Response 14a. If EKPC purchased 300 MW of capacity from one new / existing project, then the entire amount of capacity would be dependent on that one project. If the project incurred a "fatal flaw" such as not obtaining permits, equipment, financing, etc., then EKPC would not have obtained any of its capacity in the expected time frame, resulting in a 100% failure during the delay period. By splitting the 300 MW into multiple projects, then the risk of incurring a "fatal flaw" has less impact from a total capacity basis.

Request 14b. Refer to lines 14 and 15, where it is stated that the RFP process should be completed by the end of the third quarter of 2013. Provide the RFP results when they are completed.

Response 14b. EKPC has not finalized its RFP negotiations. Once it does, the final results can be provided.

SC – EXHIBIT 25

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EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2013-00259
RESPONSE TO INFORMATION REQUEST

INTERVENORS' INITIAL REQUEST FOR INFORMATION DATED 10/04/13
REQUEST 16
RESPONSIBLE PARTY: James Read

Request 16. Refer to Exhibit 1a, page 9 of 14, referring to intermittent resources: "When evaluating proposals for the Short List, the value of the forecast energy from wind and solar resources was not discounted to reflect its intermittent quality. Therefore, the NPVs for the intermittent proposals overstate their value added to EKPC in relation to the NPVs of proposals for conventional resources."

Request 16a. Please explain how wind and solar energy should be "discounted" compared to conventional sources and provide any supporting analyses and workpapers (in electronic, machine-readable format with formulas intact) to support this statement.

Response 16a. The "discounting" would reflect costs attributable to the intermittent quality of energy produced by wind and solar generation resources. We did not perform any analysis to estimate these costs.

Request 16b. Please estimate the extent to which the NPV for wind and solar resources "overstate their value" and provide any supporting analyses and workpapers (in electronic, machine-readable format with formulas intact) to support this statement.

Response 16b. We did not perform any analysis to estimate the extent to which the NPVs for wind or solar resources overstate value.

SC 28

Excerpt from "loads and resources final supplemental.xlsx," produced with Loiter supplemental testimony, revising response to EKPC Request No. 49.

7.5%			$343	average $/MWh
	Commercial Lighting		12.0	average measure life
	10	average measure life	$44	levelized $/MWh
	3,402	kWh per participant	9,449	
	0.36	kW per participant		
	$136	cost to generate savings	$0.024	average levelized cost
	$14	levelized cost	$24.22	
	$0.004	levelized cost/kWh		
	$38	levelized cost/kW		
	$40	$/annual MWh		
	Efficient Cooling			
	15	average measure life		
	1,456	kWh per participant	5,993	
	0.24	kW per paricipant		
	$283	cost to generate savings		
	$19	levelized cost		
	$0.013	levelized cost/kWh		
	$78	levelized cost/kW		
	$194	$/annual MWh		
	Small C&I Audit			
	10	average measure life		
	3,708	kWh per participant	3,895	
	0.952	kW per paricipant		
	$2,067	cost to generate savings		
	$207	levelized cost		
	$0.056	levelized cost/kWh		
	$217	levelized cost/kW		
	$557	$/annual MWh		
	low income weatherization			
	15	average measure life		
	3,000	kWh per participant	1,282	
	2.34	kW per paricipant		
	$2,527	cost to generate savings		
	$168	levelized cost		
	$0.056	levelized cost/kWh		
	$72	levelized cost/kW		
	$842	$/annual MWh		
	industrial process			
	10	average measure life		
	2,398,420	kWh per participant	3,454	
	694.45	kW per paricipant		
	$198,000	cost to generate savings		
	$19,800	levelized cost		
	$0.008	levelized cost/kWh		
	$29	levelized cost/kW		
	$83	$/annual MWh		

SC - EXHIBIT 28

SC29

2012 REPORT ON THE IMPLEMENTATION OF P.A. 295 UTILITY ENERGY OPTIMIZATION PROGRAMS

John D. Quackenbush, Chairman
Orjiakor N. Isiogu, Commissioner
Greg R. White, Commissioner

MICHIGAN PUBLIC SERVICE COMMISSION
DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS

November 30, 2012

LARA
LICENSING AND REGULATORY AFFAIRS
CUSTOMER DRIVEN. BUSINESS MINDED.

SC - EXHIBIT 29

Table of Contents

Executive Summary

Michigan's Energy Optimization (EO) standard, created under Public Act 295 of 2008 (PA 295 or the Act), requires all gas and electric utilities in the state to implement programs to reduce overall energy usage by specified targets, in order to reduce the future costs of gas and electric service to customers. This report complies with Section 95(2)(e) of the Act; summaries of the report's major findings are below:

Energy Savings

For 2011, in aggregate Michigan utility companies successfully complied with the energy savings targets laid out in PA 295. Providers met a combined average of 125 percent of their energy savings targets – 0.75 percent of retail sales for electric companies, and 0.50 percent of retail sales for gas companies. EO programs across the state accounted for electric savings totaling over one million megawatt hours (MWh) and gas savings totaling over 3.8 million Mcf for program year 2011. The electric savings amount to the energy required to power 1.5 million homes for a year; gas savings equal enough heat for 40,000 homes for a year.

2011 Cost of EO Programs and Lifecycle Benefits

Energy Optimization program expenditures of $205 million by all combined gas and electric utilities in the state resulted in lifecycle savings to customers of at least $709 million.[1] This means that for every dollar spent on EO programs in 2011, customers should realize benefits of $3.55. The EO program benefits will reduce future costs of service to all customers of gas and electric utilities, whether those customers made energy efficiency improvements through a utility EO program or not.

Emissions Reductions

EO programs also reduce emissions of environmental pollutants from existing generation sources. Michigan relies heavily upon coal-fired generation. EO programs reducing electricity usage in program year 2011 can be credited with emission reductions equal to over 2.2 billion pounds of carbon dioxide, 13 million pounds of sulfur dioxide and 6 million pounds of nitrogen oxide.[2]

[1] This data was provided by DTE Energy (Detroit Edison and MichCon), Consumers Energy Gas and Electric and Efficiency United, which represents over 90 percent of utility customers in Michigan.
[2] Data calculated using emissions data found on http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html.

Next Steps: Ideas for Innovation and Moving Beyond the First Years

Utilities are working closely with their implementation contractors to incorporate new and innovative programs to guarantee the success of the EO programs for future years. There may be areas where programs could be improved to take advantage of greater energy savings. For example, Michigan's large commercial and industrial customers want to take advantage of investments in bigger projects which may require multiple years to realize savings. Additionally, there may be opportunities in the area of "geo-targeting," i.e., targeting EO programs at areas with outage prone circuits in an attempt to maximize reliability and reduce outages. The Commission has also taken steps to make compliance with the EO standard less burdensome for smaller municipal and cooperative providers and will continue to work with all providers to ensure that program goals are met with minimal administrative burden and maximum flexibility.

The Commission is pleased with the savings afforded and successes achieved by Energy Optimization so far, and looks forward to even greater customer savings and satisfaction in years to come. As always, the Commission stands ready to work with the Legislature and other parties to ensure the viability of the program going forward.

Introduction

In October 2008, Public Act 295 of 2008 was signed into law. Section 95(2)(e) of the Act requires that by November 30, 2009, and each year thereafter, the Michigan Public Service Commission (MPSC or Commission) is to submit to the standing committees of the Senate and House of Representatives with primary responsibility for energy and environmental issues, a report on the Commission's effort to implement energy conservation and energy efficiency programs or measures. The report may include any recommendations of the MPSC for energy conservation legislation.

Subpart B of PA 295 requires providers of electric or natural gas service to establish EO programs for their customers.[3] Annual energy savings targets for providers are specified in the Act, ramping up to one percent of annual retail sales for electric providers and 0.75 percent of annual retail sales for natural gas providers in 2012. Providers are required to file plans with the Commission detailing the programs they will utilize to meet their annual energy savings goals. Regulated providers are allowed to fund their programs through Commission-approved EO surcharges, but must demonstrate that the program costs are reasonable and prudent and that they are cost-effective according to a standardized cost-benefit analysis specified in the Act.

In compliance with PA 295, on December 4, 2008, the Commission issued a temporary order in MPSC Case No. U-15800 to implement the provisions of the Act. The temporary order provided EO plan filing guidelines and resolved implementation issues for EO and renewable energy plans. EO plan submittals were required from all gas and electric utilities in Michigan. In 2011 and 2012, there were 14 independently operated utilities (IOUs), 10 electric cooperatives, and 41 municipal electric utilities that filed EO plans, for a total of 65 Energy Optimization Plans. A listing of case numbers, company names, and current plan status can be found in ***Appendix A-1***.

For the 2012 through 2015 plan years, 53 of the 65 utilities in Michigan are formally coordinating the design and implementation of their EO programs in order to reduce administrative costs, create consistency among programs, and improve customer and contractor understanding of program offerings and administrative procedures. The remaining 12 utilities are independently administering their own programs. A chart delineating these EO joint coordination groups, and their respective utility partners, can be found in ***Appendix A-2***.

[3] Energy providers subject to the provisions of the Act exclude alternative electric suppliers and natural gas marketers, since retail choice customers may participate in their local distribution utility programs.

Program Offerings

Beginning November 30, 2009, all natural gas and electric utility customers in Michigan were able to participate in specific energy efficiency programs offered by their local utility. New programs became available in 2010 and in 2011 as utilities continued to phase in the implementation of additional programs and expand existing programs. In general, individual programs are divided into two broad categories: residential and commercial/industrial. Residential programs consist of five major categories: lighting; heating, ventilating and air conditioning (HVAC); weatherization; energy education; and pilot programs. Commercial/industrial programs consist of prescriptive and custom incentive programs, energy education, and pilot programs. Prescriptive programs provide rebates for specific equipment replacement such as lighting, boilers, pumps, compressors, etc. Custom programs generally provide a rebate per kilowatt hour (kWh) of electricity savings or per Mcf of natural gas savings for a comprehensive system or industrial process improvement.

Specific program offerings for years 2009-2011 and implementation dates listed by utility can be found in ***Appendix B***.

Energy Savings Targets

Section 77 of PA 295 provides annual energy savings targets that electric and natural gas utilities are required to meet. The minimum savings targets are based upon a percentage of calendar-year retail sales for each utility. These energy savings targets progressively increase over a four-year period from 2009-2012 at which time they continue at one percent for electric utilities and 0.75 percent for gas utilities.

In 2011, EO program savings achieved for electric utilities were 116 percent of the target of 0.75 percent of retail sales. In 2011, the electric IOUs achieved 118 percent of their savings targets, while the municipal electric utilities reached 116 percent of their savings targets and the electric cooperatives met 62 percent of their targets. Ninety-three percent of the total statewide electric savings targets were achieved by regulated IOUs, while two percent of the total was met by electric cooperatives and the remaining five percent by municipal electric utilities. For 2012, the statewide PA 295 electric target of one percent of sales is projected to be 999,531 MWh. ***Figure 1*** shows target and actual electric savings for 2009 – 2011 and the target for 2012 and ***Figure 2*** shows the retail-sales multiplier for determining yearly electric savings.

Figure 1:
State of Michigan
Electric EO Targets By Year (MWh)

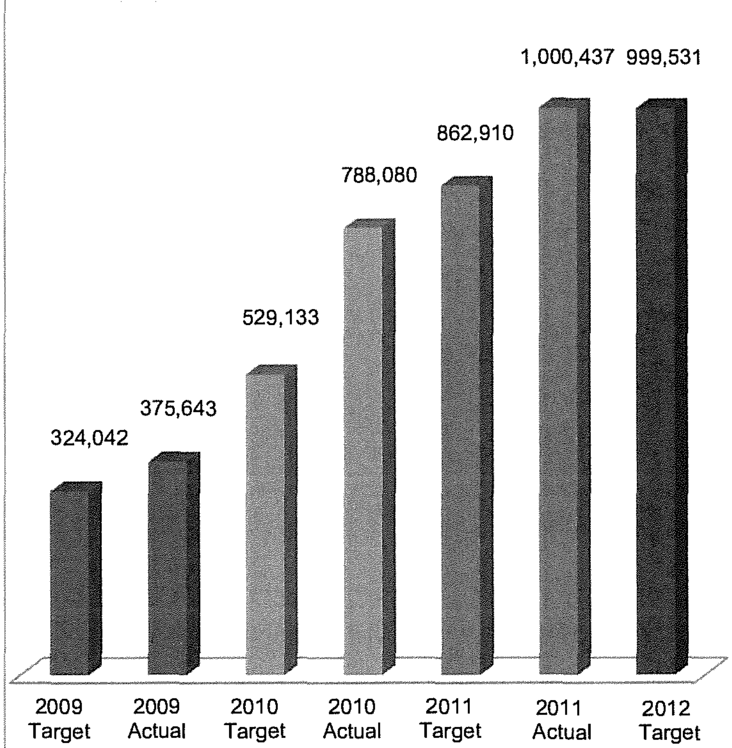
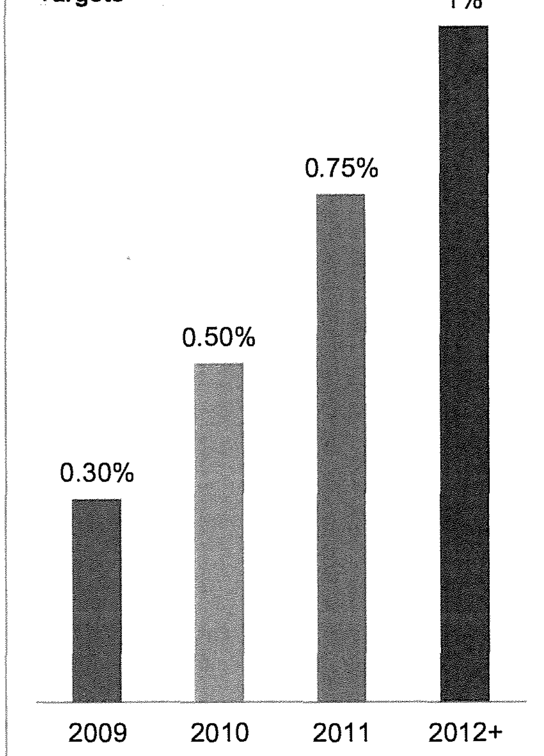


Figure 2:
State of Michigan
PA 295 Electric Energy Savings Targets*



*Note: Electric energy savings targets in Figure 1 for each year are calculated by multiplying the prior year sales by the percentage in Figure 2 for that year.

The 2011 EO program savings achieved for natural gas utilities were 134 percent of the target of 0.50 percent of retail sales. Consumers Energy's Gas Division achieved 161 percent of its savings target and Michigan Consolidated Gas Company (MichCon) achieved 117 percent of its savings target. The remaining gas companies achieved 98 percent of their savings target. For 2009-2011, gas companies cumulatively achieved 138 percent of their targets statewide. For 2012, the statewide PA 295 gas target of 0.75 percent of sales is projected to be 3,436,871 Mcf. ***Figure 3*** shows target and actual gas savings for 2009 – 2011 and the 2012 target and ***Figure 4*** shows the retail sales multiplier for determining yearly gas savings targets.

Figure 3:
State of Michigan
EO Gas Targets By Year (Mcf)

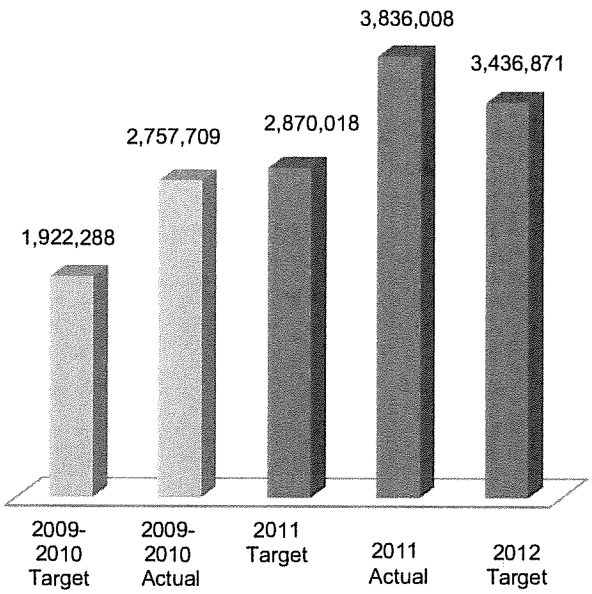
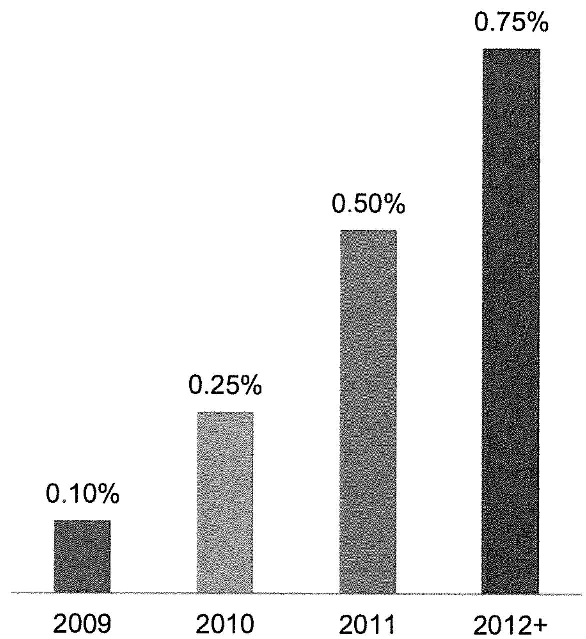


Figure 4:
State of Michigan
PA 295 Gas Energy Savings Targets*



*Note: Gas energy savings targets in Figure 3 for each year are calculated by multiplying the prior year retail sales by the percentage in Figure 4 for that year.

For a detailed spreadsheet of energy savings target information by utility, *see **Appendices C-1 and C-2**.*

EO Surcharges and Program Funding

Section 71 of PA 295 requires utilities to specify necessary funding levels for the activities being proposed. Commission-regulated utilities are able to recover their EO program expenses through a customer surcharge approved by the Commission. Under Section 89 of PA 295, surcharges adopted by the Commission are assessed on an energy usage basis for natural gas and residential electric customers. Commercial and industrial electric customers are assessed a fixed monthly charge.

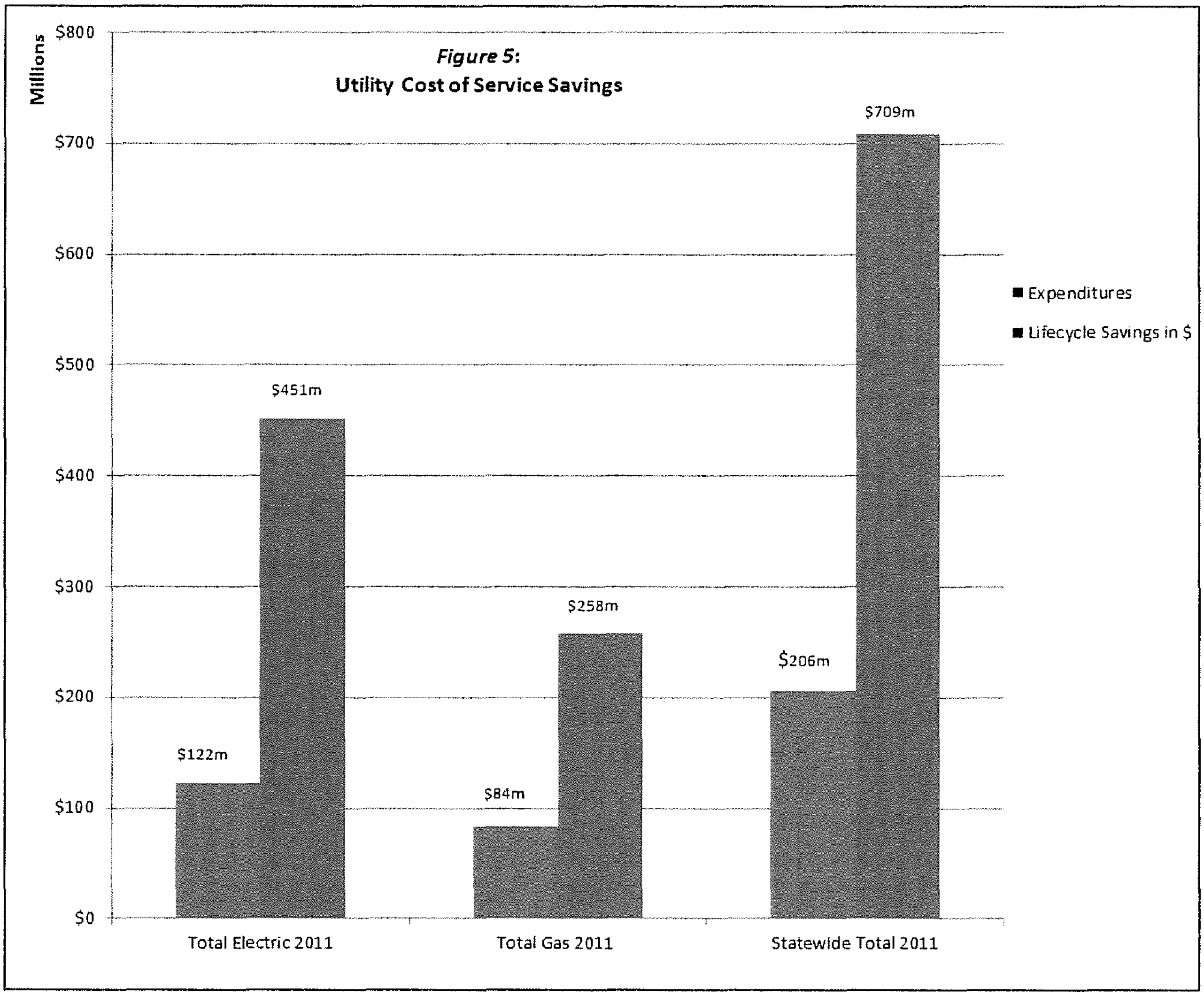
Section 73 of PA 295 requires the Commission to ensure that costs being recovered through surcharges are reasonable and prudent, and that the programs are cost-effective as demonstrated by a Utility System Resource Cost Test (USRCT) which is defined in Section 13 of the Act. For additional detail on surcharges for all customer classes and estimates of typical residential surcharges, *see **Appendix D-1 and D-2***. For detailed spending information by utility, *see **Appendix D-3.***

Program Benefits

In 2011, EO program expenditures of $205 million by all combined gas and electric utilities in the state resulted in lifecycle savings to customers of $709 million.[4] This means that for every dollar spent on EO programs in 2011 customers should realize benefits of $3.55. Data provided to the Commission in EO provider annual reports indicates that EO resources were obtained at a statewide average levelized cost of $20/MWh, significantly cheaper than supply side options such as new natural gas combined cycle generation at $66/MWh, or new coal generation at $111/MWh.[5]

The benefits will flow through to customers over the mean lifecycle of all efficiency projects implemented by customers during the program year. The direct benefits are in the form of reduced utility cost of service for production or purchase of electricity, or purchase of natural gas, which would otherwise be recovered in utility rates. Over the five-year period from 2011-2015, the cumulative benefits to customers are expected to be in excess of $2.5 billion. Over the long-run the cumulative reduction in customer demand for electricity will result in the deferral or reduction in the need to build new electric generation plants. ***Figure 5*** shows the utility cost of service savings for EO investments state-wide.

[4] This data was provided by DTE Energy (Detroit Edison and MichCon) and Consumers Energy gas and electric, which represents over 90 percent of utility customers in Michigan.
[5] EIA 2012 Annual Energy Outlook, http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.



Energy Optimization programs not only delay the need for building new generation, they also reduce emissions of environmental pollutants from existing generation. Coal-fired generation plants in particular emit carbon dioxide, sulfur dioxide and nitrogen oxides. The Midwest Independent Transmission System Operator's (MISO) Spring 2012 Market Monitor Report indicates that coal accounted for 63 percent of generation in its footprint. In Michigan, electricity not generated due to EO programs throughout program year 2011 can be credited with emission reductions equal to over 2.2 billion pounds of carbon dioxide, 13 million pounds of sulfur dioxide, and 6 million pounds of nitrogen oxide.[6]

The EO program also results in the retention of hundreds of millions of dollars in fuel costs that would have been exported to other states in order to import energy to Michigan. Other

[6] Data calculated using emissions data found on http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html.

economic impacts realized by EO programs include: additional spending by participating households and businesses for efficient equipment and services, increased demand for equipment and installations from local businesses, increased spending within the economy due to utility bill savings from reduced energy consumption, and increased production from participating businesses.[7] In addition, the benefits flowing to Michigan utility customers via the EO program should help minimize the debt burden of consumers, reduce utility uncollectible expenses, and strengthen the competitive position of Michigan businesses.

State Administrator: Efficiency United

Section 91 of PA 295 created an option for electric and natural gas providers to offer energy optimization services through a program administrator selected by the Commission. Section 91(6) requires the administrator to be a "qualified nonprofit organization" selected through a competitive bid process. To fund the program, which has been named Efficiency United, the administrator is paid directly by the participating providers using funds collected from customers.

The Michigan Community Action Agency Association (MCAAA) was awarded the Efficiency United contract on August 10, 2009, following the required bid process. MCAAA is a membership organization of 30 local community action agencies covering the entire state of Michigan and has extensive experience in the provision of energy efficiency services. The contract period is through December 31, 2011, with up to four optional, one-year extensions. The Commission exercised one option to extend the contract for 2012 and plans to extend again for the 2013 program year. In 2011, eight additional municipal electric providers elected to join EU for 2012 and 2013 program years. There are now 19 utility providers within the Efficiency United umbrella.

Efficiency United (EU) energy optimization programs were launched for customers of participating providers in December 2009. Services and offerings are similar to, and coordinated with, those of other providers. Although EU program services are specifically exempted from meeting the PA 295 energy savings targets, equivalent contractual targets were imposed by the Commission. Target energy savings for 2011 were 59,171 MWh of electricity and 442,455 Mcf of natural gas, and EU achieved 63,644 MWh and 432,399 Mcf. Overall, the total three year savings achievements of EU are 106 percent and 108 percent of the electric and natural gas

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[7] Optimal Energy, October 2011, Economic Impacts of PA 295 Energy Optimization Investments in Michigan

statutory targets, respectively. Detailed information on participating utilities, funding, and energy savings targets can be found in ***Appendices E-1 and E-2***.

Because EU has to offer programs to customers of many utilities all over the state, it cannot take advantage of the economic and operational advantages that are available to utilities that are implementing their own programs. However, EU has worked to substantially reduce the costs of implementation and has now achieved similar operational efficiencies to Michigan's largest utilities. This is no minor achievement, given that the program serves a geographically diverse set of small utilities. During 2011, the administrative overhead was two percent of the budget, with eight percent reserved for evaluation. The remaining 90 percent of the program budget was split 50 percent for program implementation (which includes advertising, website development and processing rebates) and 50 percent for incentives. For 2012, the split between program implementation and incentives will be 45 percent and 55 percent respectively. For 2013, the split has been fixed at 40 percent for implementation and 60 percent for incentives. The 2013 program will be operating at the same performance level as seen in the best-run programs both in Michigan and nationally.

The competitive bid process will begin again in 2013 for the program year 2014 to ensure the utilities enrolled in the program will continue to see success in meeting savings targets. The MPSC believes this bid process is essential for improving the competiveness of Michigan businesses and the financial standing of its residents. Allowing for a new slate of candidates to propose ideas will also stimulate the creation of new program concepts such as advanced metering, load management options, and consideration of the whole structure which insures energy savings for residential, commercial and industrial customers.

Programs for Low Income Customers

Sections 71, 89, and 93 of PA 295 require utilities to offer EO programs for each customer class, including low-income residential. Each rate class must contribute proportionally to low-income program costs based on its allocation of the utility's total EO budget. Low-income EO programs are excluded from the requirement to meet the cost-benefit test. Over 22,000 low income customers received EO program services during 2011 from Michigan's two largest utilities. ***Figure 6*** and ***Table 1*** below show the contribution to low-income program costs by Michigan utilities in 2009-11.

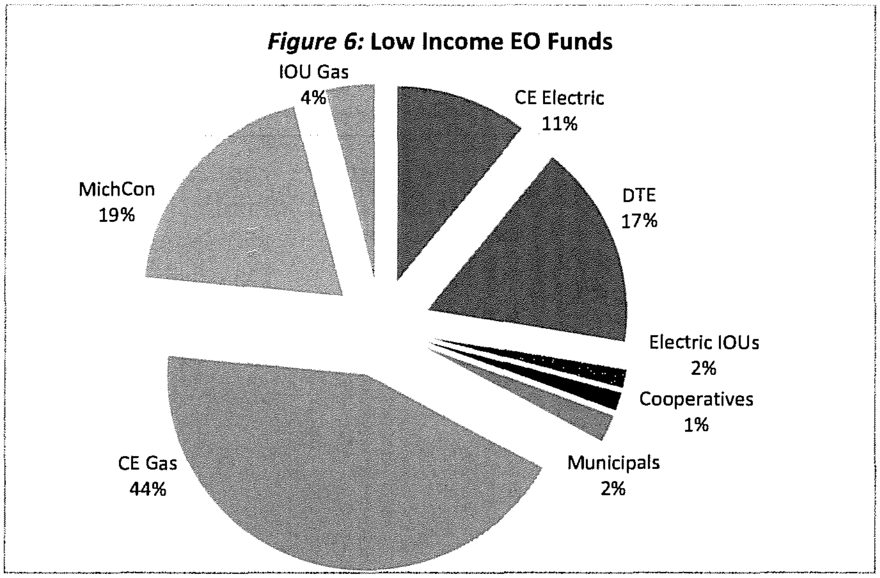

Table 1: Low Income ($000s)	
CE Electric	$5,968
DTE	$9,435
Electric IOUs	$871
Cooperatives	$841
Municipals	1,269
CE Gas	24,365
MichCon	$10,892
IOU Gas	2,228
Total	$55,872

Self-Directed EO Program

Under Section 93 of PA 295, electric customers that meet certain eligibility requirements may create and implement a customized EO plan and thus be exempt from paying an EO surcharge to their utility providers. Electric customer eligibility to participate in the self-directed EO plans is determined by the customer's annual peak demand. For 2012, the Act allows customers with 1 MW annual peak demand in the preceding year, or 5 MW aggregate at all of the customer's sites within a service provider's territory, to participate. These are the same thresholds as 2011, but lower than the 2010 thresholds of 2 MW annual peak demand or 10 MW in aggregate. The number of customers enrolled to self-direct their own EO program has dropped from 77 in 2009 to 47 in 2011. This reflects the flexibility and comprehensive program options that are being offered under utility programs.

Reported and projected energy savings for these large commercial and industrial customers are summarized in ***Table 2***.

Table 2: **Projected Energy Savings for Large Commercial and Industrial Customers**

Provider	2009 Customers	2010 Customers	2011 Customers	2009 reported load reduction (MWh)	2010 reported load reduction (MWh)	2011 reported load reduction (MWh)
Detroit Edison	26	26	13	12,486	18,488	7,835
Consumers	30	30	16	8,515	12,343	7,404
Efficiency United	9	11	10	5,196	14,568	20,808
Cooperative	3	3	4	899	1,498	1,442
Municipal	9	9	4	2,006	3,343	606
Total	**77**	**79**	**47**	**29,102**	**50,240**	**38,095**

Per PA 295, self-directed customers with less than 2 MW annual peak demand per site or 10 MW in aggregate must utilize an approved energy optimization service company (EOSC) to design and implement their EO programs. Following a public hearing in 2010, the Commission enacted an approval process, as required by PA 295, for EOSCs. The approval process and application can be found on the Commission's website.[8]

Financial Incentive Mechanism

Section 75 of PA 295 allows Commission-regulated utilities to request a financial incentive mechanism for exceeding the energy savings targets in a given year. On September 29, 2009, the Commission authorized a financial incentive mechanism for Detroit Edison (U-15806), MichCon (U-15890) and Consumers Energy (U-15805 & U-15889) that encourages utilities to pursue cost effective energy efficiency programs that significantly exceed the statutory minimum targets and the USRCT benefit-cost test. The maximum incentive is capped at 15 percent of program spending. For 2009, Consumers Energy, Detroit Edison, and MichCon were all approved to receive financial incentive payments which were collected, with no interest included, over a 12 month period. For 2010, Consumers Energy, Detroit Edison and MichCon

[8] http://www.michigan.gov/mpsc/0,4639,7-159-52495_54478---,00.html.

have requested an incentive amount for exceeding their minimum targets and exceeding the USRCT.

In the Detroit Edison Case No. U-16671, the Commission found that the financial incentive mechanism should be reevaluated. The Commission therefore directed the EO Evaluation Collaborative to assess the current financial incentive mechanism and consider incorporating additional factors. Detroit Edison and Michigan Consolidated Gas Company filed amended EO plans which considered financial incentive mechanisms and included factors to not only motivate the companies to exceed the legislated energy savings targets, but to also encourage the companies to incorporate specific program design elements focused on deep energy savings. Consumers Energy also filed an amended EO plan requesting approval of a financial incentive mechanism that includes factors to widen the range of opportunities for comprehensive energy savings.

Michigan Saves

Michigan Saves is a non-profit entity that provides energy efficiency financing programs to residential and commercial customers throughout Michigan. Initially funded in part by a grant from the Low-Income and Energy Efficiency Fund formerly administered by the MPSC, Michigan Saves is now a fully independent organization governed by a 15-member board of directors. The grant funds were utilized to create a loan loss reserve which could be used by credit unions and other financial institutions to support the loans. Since its inception, the program has attracted $35 million in federal grants and encouraged the investment of more than $261 million in public and private funds. By the end of the grant period, Michigan Saves made the Home Energy Loan Programs available to residential customers throughout the state, with loans of up to $20,000, and up to $150,000 for commercial customers.

Michigan Saves provides additional incentives through grants and partnerships with the private sector. It is part of a team implementing BetterBuildings for Michigan,[9] a federally funded program that conducts intensive energy efficiency drives in specific neighborhoods around the state. BetterBuildings for Michigan provided incentives, financing, and targeted outreach to improve the energy efficiency of homes and businesses in a total of 27 neighborhoods located across the state and specifically supported a commercial loan program in the city of Detroit. More than 5,500 homes and 20 commercial buildings

[9] BetterBuildings for Michigan, http://www.betterbuildingsformichigan.org/.

received energy efficiency improvements. This results in over $5 million of savings on customer energy bills.

Although the grant period has expired, Michigan Saves, Inc. continues to be a successful, ongoing, sustainable entity. ***Table 3*** shows the positive benefits Michigan residents and businesses are reaping from energy efficiency upgrades.

Table 3: **Michigan Saves**

Loans Approved	2,016
Loan Approval Rate	58 %
Loans Closed	1,783
Average Loan Size Approved	$7,999
Average Credit Score Approved	741
Authorized Contractors State-wide	295
Total Loan Value Issues	$14,262,953

Activity reported through September 30, 2012

Michigan Energy Measures Database

Measurement and verification is an essential tool in improving Energy Optimization programming. In 2009, Michigan began using a database of projected energy savings that was exclusively derived from other states' experience. The database is called the Michigan Energy Measures Database (MEMD).

The initial objective of the MEMD was to provide users with accurate information on energy savings associated with technologies or measures that could be used in energy efficiency programs. The MEMD is also used to prioritize the allocation of funding toward these possible measures. For this critical function, the Commission acknowledges the high importance of including Michigan-specific data in the MEMD. Thus, under the direction of Staff, stakeholders are participating in monthly collaborative meetings to update this database. The collaborative has developed an annual process for selecting the highest priority measures to update with Michigan-specific data. For the selected measures, field studies are undertaken in customer homes and businesses using light loggers, sub metering, and engineering analysis to obtain reliable measurement of the actual energy consumption. The collaborative is also focused on recommendations for improving energy optimization plans for all providers, providing program evaluation and support, and developing any needed re-design and improvements to energy efficiency programs.

MPSC Energy Optimization Collaborative

In Case Nos. U-15805 and U-15806, the Commission directed the Commission Staff to establish a statewide energy optimization collaborative which requires the participation of all gas and electric providers and offers the opportunity for a variety of additional stakeholders to participate. The structure and goals of the EO collaborative were outlined in the Commission's 2009 report to the Legislature. A key goal reached by the collaborative was the reduction of the extent and cost of the formal contested hearing process through stakeholder consensus and industry peer review of standards and procedures. Program Design and Implementation and Program Evaluation workgroups continued to meet throughout 2012 and created the MEMD Technical Sub-Committee to specifically focus on issues arising with the MEMD. The Low-Income Workgroup has continued to be combined with the Coalition to Keep Michigan Warm.

The collaborative is overseen by the Steering Committee that includes representatives from gas and electric providers, interveners in EO plan cases, energy efficiency advocates, and others. In early 2011, the Steering Committee decided to meet on an as needed basis when unresolved issues arose from the workgroups.

Revenue Decoupling

PA 295 requires the Commission to establish revenue decoupling mechanisms (RDMs) upon request by those natural gas utilities which have implemented an Energy Optimization program. The Act also requires the Commission to study the rate impacts on all classes of customers if the electric providers whose rates are regulated by the Commission decouple rates (Sec. 97(4) of PA 295).

Natural Gas

Section 89(6) of PA 295 requires the Commission to establish RDMs for regulated gas utilities that implement an Energy Optimization program and that request such a mechanism. A gas utility must file a request for an RDM, although the Commission may authorize an alternative mechanism that it deems to be in the public interest. On and after May 17, 2010, the Commission approved revenue decoupling mechanisms for three gas utilities: Consumers

Energy, Michigan Consolidated Gas, and Michigan Gas Utilities. All RDMs were approved on a pilot basis.

Electric

The Commission approved various RDMs for several electric utilities, including Detroit Edison, Consumers Energy, and Upper Peninsula Power Company. On April 10, 2012, the Michigan Court of Appeals issued a decision which determined that the Commission had no explicit statutory authority to implement RDMs for electric providers. In light of the Court's determination, the Commission dismissed all pending cases involving electric revenue decoupling, including those RDM reconciliation cases without a settlement order. In the case of Detroit Edison, the company had a $127 million over-collection due to the RDM with pending reconciliations for years 2010 and 2011 at the time the cases were dismissed. Detroit Edison has indicated it intends to use this revenue to postpone the need to apply to the Commission for a revenue increase until 2015. Consumers Energy, however, had an under-collection of approximately $59.6 million due to the RDM with pending reconciliations for years 2010 and 2011 at the time the cases were dismissed.

Conclusion

Energy Optimization programs have seen many successes since first being implemented due to continued strong efforts by utilities and their EO providers and implementation allies. This year, Michigan was ranked among the most improved states in the nation with regard to energy efficiency. The successful implementation of the Energy Optimization program was the largest factor in the ranking by the American Council for an Energy-Efficient Economy (ACEEE).[10] The Commission has taken steps to improve the program over the past year and will continue to do so in years to come.

The Commission continually explores ways to modify programs to get the most energy savings at the lowest costs. For example, this past summer the MPSC, in partnership with the Michigan Economic Development Corporation (MEDC), sponsored a symposium focusing on ways to capture deep energy savings at Michigan industrial facilities so as to improve their global competitiveness. Both DTE Energy and Consumers Energy announced new industrial programs incentivizing major industrial energy retrofits and multi-measure initiatives. The new programs were met with strong support by Michigan-based manufacturers.

[10] The 2011 State Energy Efficiency Scorecard, ACEEE, October 2011, Report No. E115.

The MPSC recently completed an energy efficiency baseline for all segments of the state economy, including residential, commercial and industrial energy users. The report found a wide range of energy efficiency opportunities for existing homes and businesses in the State. The baseline has provided utilities with the type of information they need to continue the evolution of EO programming design and implementation.

Small utilities, including municipal electric utilities and rural electric cooperatives, have unique challenges implementing energy optimization programs. The MPSC has worked hard alongside the smaller utilities to insure they see positive accomplishments within their communities and can overcome their unique challenges. Over the past year, the MPSC has issued several orders approving special flexibility for small utilities implementing Energy Optimization programs. Although the data in this report shows that there is a palpable difference between the program results of some of the small utilities and those of our largest investor owned utilities, the Commission's recent orders should improve the future performance of such small utilities.

In addition, the MPSC is working hard to make Efficiency United the best option for small utilities that do not have the resources to administer their own EO programs. Efficiency United allows many small utilities to join together and benefit from the services offered by one provider, and has been progressively adding new utilities to its membership every year.

Going forward, as a means to add more value to Energy Optimization programs, the MPSC is encouraging utilities to target energy optimization programming into specific geographic areas of their service territory. Geo-targeting energy efficiency can defer more costly upgrades to electric distribution and transmission systems by reducing peak loads in the immediate area of the constrained electric delivery systems. The Commission is also working with utilities to assist large commercial and industrial customers to find ways to include investments in larger projects which will allow for long-term savings over multiple program years.

The Commission is proud of the successes and savings achieved by the Energy Optimization program to date, and looks forward to even greater successes and deeper savings in upcoming years. We stand ready to work with the Legislature and other parties to ensure the continued viability of Energy Optimization efforts.

SC 30

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2012-00149
SUPPLEMENTAL REQUEST FOR INFORMATION RESPONSE

MOVANTS' SUPPLEMENTAL REQUESTS FOR INFORMATION DATED 08/03/12

REQUEST 1
RESPONSIBLE PERSON: **Scott Drake**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 1. Refer to your response to Intervenors' Initial Request 9d.

Request 1a. State whether the 27,848 MWh of energy savings identified therein is the cumulative savings over five years or annual savings.

Response 1a. The 27,848 MWh is an annual savings for the year 2017, the 5th year of our 5 year, 50 MW goal.

Request 1b. Explain how the 27,848 MWh of energy savings figure is consistent with the levels of DSM impacts on energy requirements identified on page 15 of the IRP.

Response 1b. The cumulative energy savings for the 5 years is 109,008 MWh. It is a forecasted practical impact savings. The amount shown on page 15 of the IRP is a theoretical savings based on the possible programs for the portfolio at a mature participation level.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2013-00259
RESPONSE TO INFORMATION REQUEST

INTERVENORS' INITIAL REQUEST FOR INFORMATION DATED 10/04/13
REQUEST 12
RESPONSIBLE PARTY: Julia J. Tucker

Request 12. Please provide the following information for the years 2008-2013:

Request 12a. A list of all wind energy projects built by EKPC

i. For each such wind energy project, identify the size, capital cost, fixed and variable operating cost, levelized cost of energy, and tax revenue for each year of operation.

Response 12a. EKPC has not built any wind projects.

Request 12b. A list of all wind energy power purchase agreements entered into by EKPC

i. For each such wind energy project, identify the size, capital cost, fixed and variable operating cost, and the price at which EKPC purchases power from the project for each year of the contract.

Response 12b. EKPC has not entered into any wind energy projects.

Request 12c. A list of all wind energy projects or power purchase agreements that EKPC considered but rejected participation in.

i. For each such wind energy project, identify the size, capital cost, fixed and variable operating cost, and the LCOE or power purchase price for the project.

ii. For each such wind energy project, explain why EKPC decided not to participate in it.

Response 12c. The wind energy projects received in the 2012 RFP are listed in EKPC's response to the Staff's Initial Request, Response 5. As reported in Case No. 2009-00106, EKPC's 2009 Integrated Resource Plan, Section 8, pages 8-12 and 8-13, EKPC received proposals for eight wind projects, one of which was in Kentucky. Please see http://psc.ky.gov/PSCSCF/2009%20cases/2009-00106/20090422_EKPCs_2009_IRP_and_Petition_for_Confidentiality.PDF. None of those projects proved to be viable. EKPC continuously works with National Renewables Cooperative to review any viable wind projects. EKPC has not contracted with any wind project to date.

Department for Energy Development and Independence

Stimulating Energy Efficiency in Kentucky

KENTUCKY'S ACTION PLAN FOR ENERGY EFFICIENCY

Prepared by:

THE KENTUCKY DEPARTMENT FOR ENERGY DEVELOPMENT AND INDEPENDENCE
THE MIDWEST ENERGY EFFICIENCY ALLIANCE

May 15, 2013

SC - EXHIBIT 32

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TABLE OF CONTENTS

FOREWORD

Kentucky's Action Plan for Energy Efficiency (Action Plan or Plan) was prepared by the Midwest Energy Efficiency Alliance (MEEA) with the Kentucky Energy and Environment Cabinet's (EEC) Department for Energy Development and Independence (DEDI). This Action Plan is a key deliverable in the three-year *Stimulating Energy Efficiency in Kentucky* (SEE KY) process and fulfills the "Phase One" requirements under DEDI's cooperative agreement with the United States Department of Energy (U.S. DOE), Award No. DE-EE0004440.

MEEA and DEDI would like to thank all of the individuals, organizations, corporations and governmental entities (referred to generally as the "stakeholders") that provided feedback throughout the SEE KY process on the many opportunities for expanding Kentucky's energy efficiency efforts. Without this dedicated group of stakeholders, the Action Plan would not have been possible.

ABOUT THE AUTHORS AND PROJECT TEAM

DEDI's mission is to improve the quality and security of life for all Kentuckians by creating efficient, sustainable energy solutions and strategies; by protecting the environment; and by creating a base for strong economic growth. DEDI is a department of the EEC.

MEEA is a non-profit membership organization whose mission is to promote energy efficiency policy and practices through research and analysis and by engaging a cross-section of entities who are interested in energy efficiency. MEEA's members include utilities, manufacturers, academic research institutions, State and local governments and advocates in 13 Midwestern states. MEEA is DEDI's contractor, tasked with managing the SEE KY stakeholder process and developing the Action Plan.

Smith Management Group (SMG) is a Kentucky consulting firm with extensive experience in energy production, regulatory requirements and utility rates and consumption issues. SMG is MEEA's subcontractor, providing local technical expertise during the stakeholder process as well as facilitation of the collaborative meeting series.

The American Council for an Energy-Efficient Economy (ACEEE) is a nonprofit organization that provides technical analysis, advising and collaboration to advance energy efficiency. ACEEE provided research and analyses of Kentucky's energy efficiency landscape via additional technical assistance funding received directly from U.S. DOE.

SUMMARY OF FINDINGS

This Action Plan is the resulting document from "Phase One" of DEDI's three-year SEE KY grant through the U.S. DOE.

In October 2010, DEDI embarked on the SEE KY project to develop recommendations for Kentuckians to further energy efficiency efforts already underway in the Commonwealth and to spur more significant investment in efficiency. *The ultimate goal of the project is to achieve one percent annual electric savings in Kentucky through energy efficiency.* Per DEDI's cooperative agreement with U.S. DOE, this goal will be measured via savings in the electricity sector only; savings realized from natural gas energy efficiency programs will be complimentary and additional to the annual electric savings goal. Otherwise, DEDI was given discretion to work with stakeholders on how progress towards the one percent savings goal will be calculated.[1]

This Action Plan sets out specific measures (referred to as "*action items*") that were recommended by stakeholders as essential to carrying out the SEE KY one percent annual savings goal. Action items are the result of a comprehensive series of meetings with stakeholders in Kentucky over the last two years. The action items are framed in planning terms, e.g. persons/organizations responsible for implementation, resource requirements, potential allies, potential roadblocks, etc. Identifying funding sources for many action items will be challenging, and will be dependent on Kentucky's economy moving forward, the legislative climate, and annual budget allocations. In addition, given that each action item has its own unique challenges, a subset of items function as a call for work groups to address a specific issue. Additional study and stakeholder collaboration is needed to identify concrete solutions and timelines for implementation, which will then replace these initial action items.

It should be noted that the actions discussed in this Plan are voluntary and/or may require legislative action; the stakeholders, for the most part, had little appetite for mandatory measures. Throughout the SEE KY process, stakeholders also stressed the importance of incorporating only those action items that have significant economic potential and are the most likely to capture Kentucky's capacity for energy savings. Further, because the action items were devised collaboratively, they reflect recommendations from the very individuals that are most affected by energy efficiency programs and policies in Kentucky – and thus have the most at stake.

As with any process involving multiple stakeholders, a variety of opinions and views were brought to the discussions. This plan attempts to capture the key themes that developed during the SEE KY process but the reader should be aware that not all participants agreed with each recommendation in this plan. Thus, mention of specific individuals or organizations should not be construed to mean that those individuals or organizations endorsed every action listed in this plan.

The following section summarizes how the action items are organized in this plan.

[1] The agreed-upon approach to measuring Kentucky's progress toward the one percent goal is described in action item A.1.

ACTION ITEMS OVERVIEW

Note: Short-term = Less than 1 year; Near-term = 1-3 years; Long-term = 3-4 years

ALL SECTORS

Short-term

A.1. *Measure statewide energy efficiency targets using electric utility data reported voluntarily to DEDI*

A.2. *Create a peer exchange mechanism specifically for gas and electric utilities to share information, experiences and best practices*

A.3. *Condition State funding on minimum energy efficiency outcomes taking into account life cycle costs*

Near-term

A.4. *Focus on robust education and training programs tailored to each consumer sector*

A.5. *Convene a work group to evaluate effects of utility rate design on energy efficiency incentives*

Long-term

A.6. *Assist Kentucky's governmental and municipal utilities to develop a voluntary suite of energy efficiency programs*

RESIDENTIAL SECTOR

Short-term

R.1. *Support Kentucky Home Performance to increase market penetration*

Near-term

R.2. *Improve residential housing stock via utility and community-sponsored weatherization*

Long-term

R.3. *Improve the energy efficiency of residential buildings through consistent implementation of residential building energy codes*

R.4. *Increase innovative energy efficiency financing options, such as on-bill financing*

R.5. *Provide incentives for energy efficiency retrofits in residential rental property*

R.6. *Develop an advisory group to address options for replacing inefficient manufactured homes*

Legislative Recommendations

R.7. *Expand existing State-provided energy efficiency incentives*

COMMERCIAL SECTOR

Near-term

C.1. *Expand access to low-cost financing for private commercial entities*

C.2. *Recapitalize the Kentucky Green Bank for public buildings*

C.3. *Promote energy efficiency via a "lead by example" approach to State-owned facilities*

Long-term

C.4. *Improve the energy efficiency of commercial buildings through consistent implementation of commercial building energy codes*

C.5. *Devise creative incentives for commercial rental property*

Legislative Recommendation

C.6. *Expand State energy efficiency incentives*

INDUSTRIAL SECTOR

Near-term

I.1. *Establish a revolving loan fund for industrial energy efficiency improvements*

I.2. *Convene a work group to discuss the application of the DSM Statute's opt-out provision*

Long-term

I.3. *Encourage Kentucky's industries to voluntarily share energy efficiency performance data and best practices*

Legislative Recommendation

I.4. *Modify existing State-level incentives to encourage investment in energy efficiency*

FEDERAL ACTION ITEMS

F.1. *USDOE should work with US DHS to evaluate how FEMA funds are provided for home rebuilding or replacement in the wake of natural disasters, and consider requiring that new structures be built better than code (e.g. ENERGY STAR).*

F.2. *US DOE should take a lead role in working with US DHHS to enhance the delivery of energy efficiency and conservation solutions to citizens served by LIHEAP and Weatherization programs.*

F.3. *US DOE needs to assume a lead role in working with other federal agencies (USDA, HUD, EPA) that offer federal infrastructure programs and grants for cities and states to set energy efficiency standards as a condition of awards.*

F.4. *US DOE should coordinate with HUD to improve energy efficiency standards for manufactured homes that are appropriate for various climate zones.*

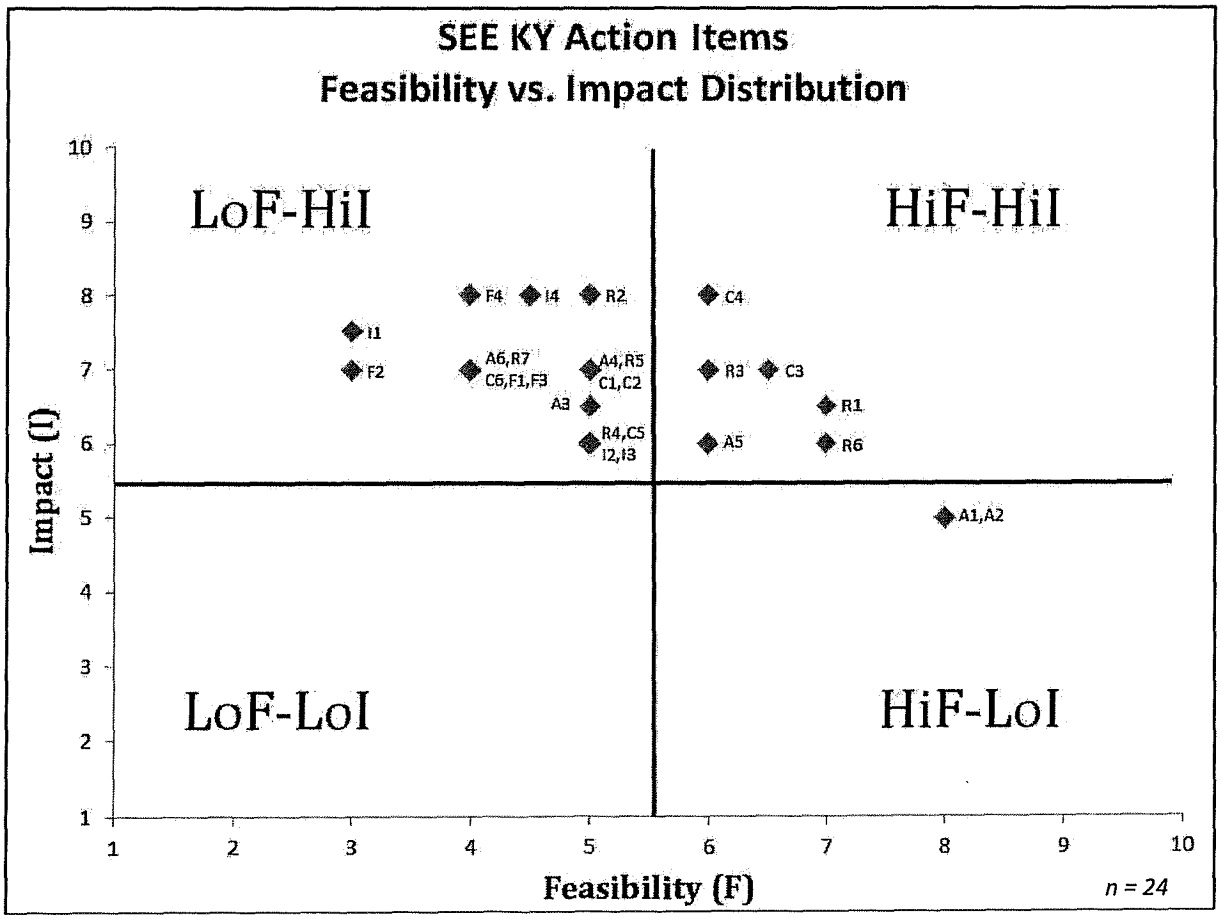
IMPACT & FEASIBILITY CHART

As a part of the development of this Action Plan, approximately 80 stakeholders that participated in SEE KY were given the opportunity to comment on the plan itself and provide a ranking on each of the individual action items. Stakeholders were asked to rank each action item based on two criteria, as defined below:

- **Feasibility** – Score indicates the extent of resources (money and/or people) that would be required to carry out a particular action item and/or the degree to which political considerations may impede its implementation.
- **Impact** – Score indicates the potential for energy savings (either short-term or long-term) with a particular action item.

Once all the action items were ranked by individuals, the median was determined. The following chart is a graphical representation of the median of 24 rankings for all action items presented in this plan. Action items fall into one of four quadrants, indicating their combined feasibility and impact. The following categories are intended help guide implementation and planning:

- High feasibility/High impact (HiF-HiI)
- Low feasibility/High impact (LoF-HiI)
- High feasibility/Low impact (HiF-LoI)
- Low feasibility/Low impact (LoF-LoI)



The chart shows that the median rankings from all stakeholders placed all but two action items above the mid-point for potential impact on energy savings. This is an encouraging sign indicating that, taken as a whole, stakeholders believe that the nearly all of action items proposed in this plan are of value to pursue. Not surprisingly, the Federal Action Items scored lower on the Feasibility scale, while A.1 (voluntary utility data reporting) and A.2 (utility DSM peer exchange forum) were determined to be highly feasible, but with less of an impact on energy savings overall than other action items.

INTRODUCTION

THE ROLE OF KENTUCKY'S ACTION PLAN FOR ENERGY EFFICIENCY

This Action Plan sets out specific action items intended to further energy efficiency efforts that have been underway in the Commonwealth of Kentucky for at least two decades. During that time, a host of entities and initiatives have championed energy efficiency in Kentucky, including the following:

- Governor Steve Beshear, in his 2008 plan entitled *Intelligent Energy Choices for Kentucky's Future: Kentucky's 7-Point Strategy for Energy Independence* (Governor's Energy Strategy) which identified energy efficiency as the leading strategy;
- The Kentucky General Assembly through its passage of the 1994 Demand Side Management Statute (DSM Statute);[2] the 2007 Incentives for Energy Independence Act (also known as House Bill 1) and House Bill 2, 2008 Session;[3]
- Several of Kentucky's electric utilities who have offered demand side management programs as a service to their customers – in some cases for over 20 years – despite the absence of a statutory directive requiring them to do so;[4]
- The Kentucky Public Service Commission (PSC) in its 2008 report to the General Assembly concerning the ways in which efficiency programs are administered in Kentucky;[5]
- DEDI and U.S. DOE through the three-year grant that made SEE KY possible, and the numerous stakeholders in the SEE KY process who have participated in extensive one-on-one meetings, collaborative sessions and work groups;
- DEDI's history with American Recovery and Reinvestment Act (Recovery Act) funds and (to a lesser extent) Federal State Energy Program formula dollars; and
- EEC's 2011 *Climate Action Plan*, addressing Kentucky's strategy to minimize climate change while becoming more efficient, more energy independent and spurring economic growth.[6]

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[2] *See* KRS 278.285. The DSM Statute allows utilities to recover energy efficiency and demand side management (DSM) program costs through a customer surcharge mechanism, as long they meet certain cost-effectiveness requirements. The Statute does not, however, expressly authorize the PSC to direct utilities to implement particular programs.
[3] *See* KRS 154.27-010 to 154.27-090 (House Bill 1) and KRS 141.435 to 141.437 (House Bill 2). These bills created, among other things, an array of tax credits for energy efficiency investments in residential and commercial property.
[4] Over the last two decades Kentucky's utilities have increased their demand side management program budgets exponentially. Compare, for example, Kentucky's total program budget of $2.2 million reported in 2008, which increased to over $48 million in 2011. *See*, http://www.cee1.org/ee-pe/2008/us_electric.php; *see also*, http://www.cee1.org/files/CEE%20AIR%20Data%20Tables%202011.pdf (citing data at p. 11). Kentucky's utilities have also recently made significant commitments to efficiency programming and targets. *See, e.g.*, Duke Energy Kentucky's 2011 Integrated Resource Plan (IRP), pp. 22-23 (listing DSM programs and articulating a goal of reducing total peak energy consumption by 22 MW across all programs by 2017), available at: http://psc.ky.gov/PSCSCF/2011%20cases/201100235/20110701_Duke%20Energy_Application%20and%20Petition.pdf; East Kentucky Power Cooperative's 2012 IRP, pp. 4-6, 73-110 (discussing DSM programs and a complimentary peak energy consumption reduction goal of approximately 50 MW over a 5 year period), available at: http://psc.ky.gov/pscscf/2012%20cases/2012-00149/20120420_EKPC_Integrated%20Resource%20Plan.pdf; Big Rivers Electric Corporation's 2010 IRP, pp. ii and Section 8 (citing plan to launch $1M in DSM programming, with expected savings of a cumulative 14 MW reduction in winter peak demand and a 10 MW reduction in summer peak demand by 2025), available at: http://psc.ky.gov/pscscf/2010%20cases/2010-00443/20101115_Big%20Rivers_IRP.pdf.
[5] *See* 2007 2d Extra. Sess. Ky. Acts ch. 1, sec. 50. As part of House Bill 1, the General Assembly directed the PSC to consider the ways in which efficiency programs are administered in Kentucky. The resulting report identified a number of high priority energy efficiency issues for Kentucky to address – from consumer education to alternative rate structures – many of which are parallel with feedback received during the SEE KY process. Notations are made where recommendations in that report parallel SEE KY action items. The report is available at: http://psc.ky.gov/agencies/psc/industry/electric/hb1report.pdf.
[6] *See* http://www.kyclimatechange.us/.

This Action Plan has been developed during the SEE KY process through stakeholder engagement over a period of two years and builds on decades of Kentucky's energy efficiency efforts. The actions described herein are those which were judged by stakeholders to have: the greatest potential of succeeding; positive impacts on Kentucky's economic outlook; and the highest feasibility for capturing the State's significant energy savings potential. Though several of the action items are still in flux and will require additional stakeholder engagement to define their paths forward, to the extent possible an implementation plan is identified for each recommendation in this Plan.

This Action Plan is a living document which will evolve as actions are completed and new actions are identified as useful, compelling and necessary to achieving Kentucky's efficiency goals. As new opportunities appear, they will be added to the Plan. DEDI will periodically review action items, revise them as necessary and will release an updated Action Plan as progress occurs.

It is also important to recognize that the Action Plan is not merely a roadmap for governmental efforts; rather it describes a continuing collaborative effort that will include feedback and commitments by stakeholders from across the Commonwealth and across businesses, government, advocacy groups and utilities. As noted previously, this collaborative effort will involve work groups to identify concrete solutions for specific issues, which will then replace these initial action items.

The action items that follow are divided into four major sections that address each of Kentucky's energy-consuming rate classes: (1) *all sectors*; (2) *residential*; (3) *commercial*; and (4) *industrial*. Actions are then further organized by the expected timeframe for completion: those that have the potential to be accomplished in the *short-term* (less than one year); in the *near-term* (between one and three years); and in the *long-term* (between three and four years). Some actions items may be addressed legislatively. In addition, the plan includes recommendations that concern energy efficiency activities at the federal level and thus have ramifications for all states.

Key actions recommended in this Plan include:

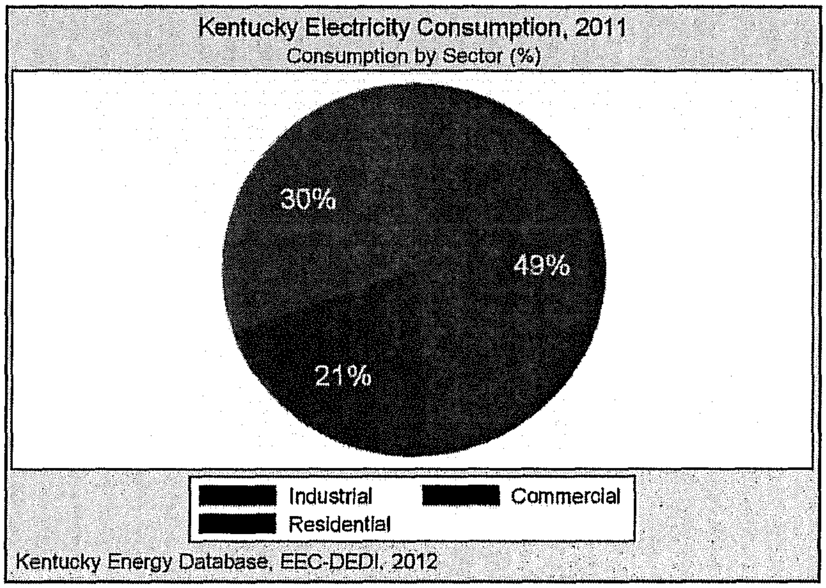
- A simple mechanism to track energy gains from utility-run efficiency programs;
- Creation of a peer exchange for utilities to share information and experiences;
- Providing forums for robust education and training to all rate classes;
- Expanding current State-run programs, such as Kentucky Home Performance;
- Increasing State-level energy efficiency incentives for industrial, commercial and residential sectors;
- Addressing the stock of energy inefficient manufactured homes in Kentucky; and
- Uniform compliance with residential and commercial building energy codes.

The description of each action item also includes the genesis of the idea and how it was shaped by stakeholder input, likely champions for the effort and a list of tasks, resources and a proposed timeline for completion.

THE GOVERNOR'S ENERGY STRATEGY AND THE SEE KY PROCESS

This Action Plan is the main document resulting from the SEE KY process and is the primary means of achieving both the goals of that process and the energy efficiency goals articulated five years ago in the Governor's Energy Strategy.

The Governor's Energy Strategy articulated seven key ways to ensure Kentucky's energy security, create jobs and maintain low-cost, reliable energy into the future.[7] It identified energy efficiency as the first and foremost vehicle to accomplish this objective.[8] In the long-term, the Governor set out a goal to offset a cumulative 18 percent of Kentucky's projected 2025 total energy demand through efficiency, 16 percent of which should come from reductions in natural gas and electric utility use.[9] The Energy Strategy described energy efficiency as the fastest, cleanest, most cost-effective and most secure way to meet Kentucky's growing energy demands.[10] Investing in efficiency is particularly vital as energy rates rise. Even though Kentucky enjoys the fourth lowest electricity rates in the nation,[11] in the last decade residential prices rose by 57 percent; commercial prices by 53 percent; and industrial prices by 68 percent; at the same time, Kentucky's energy intensity, per capita, is among the highest in the nation.[12] This high usage, combined with rising rates, make it even more vital that Kentucky ramp up its energy efficiency efforts in the coming years. Another driving factor in Kentucky is the high proportion of industrial electricity consumption, representing 49 percent of the State's total electricity usage.



One of the key objectives of the SEE KY process is to develop recommendations for Kentuckians to use efficiency to mitigate rising energy costs. Moreover, SEE KY is complimentary to and is a means to advance the energy efficiency recommendations in the Governor's Energy Strategy.[13] For

[7] The complete Governor's Energy Strategy is available: http://energy.ky.gov/resources/Pages/EnergyPlan.aspx.
[8] *See* Strategy #1 of the Governor's Energy Strategy: Improve the Energy Efficiency of Kentucky's Homes, Buildings, Industries and Transportation Fleet, available at: http://energy.ky.gov/Energy%20Plan/Strategy%201%20Improve%20the%20energy%20efficiency%20of%20Kentucky%27s%20homes,%20buildings,%20industries%20and%20transportation%20fleet.pdf.
[9] The remaining 2% will come from transportation energy efficiency programs and vehicle fuel economy initiatives, which are not discussed in this Action Plan. *Id.*, p. 23.
[10] *See id.*, p. 13.
[11] In 2011, at $0.071 per kWh, Kentucky had the 4th lowest electricity prices in the United States after the coal and hydroelectric states of Idaho, Wyoming, and Washington. Source: Kentucky Energy Database, EEC-DEDI, 2012 (derived from 2011 U.S. Energy Information Administration [EIA] data).
[12] Kentucky Energy Profile 2012. Source: Kentucky Energy Database, EEC-DEDI, 2012 (derived from 2011 U.S. Energy Information Administration [EIA] data).
[13] The Governor's Energy Strategy identified ways Kentucky could achieve the 16% savings goal by 2025, several of which SEE KY has incorporated in some fashion into this Action Plan. For example, the Strategy recommended aggressive education, outreach and marketing to support all of Kentucky's energy efficiency activities. *Supra*, n. 8,

example, the SEE KY process's one percent annual electric savings goal paves the way for achieving the Governor's 16 percent energy efficiency goal (the mechanism for realizing these dual goals is set out in *Appendix D*). It is important to note that while the energy efficiency goal in the Governor's Energy Strategy includes both gas and electric savings, the SEE KY goal contemplates electric savings only; savings realized in the natural gas sector will be additional to the one percent savings goal. As a result, all mention of utilities in this Action Plan refers to electric, unless stated otherwise.

The SEE KY process consists of two phases:

- In **Phase One**, the primary tasks were to gather stakeholder feedback on both the opportunities and barriers to expanded efficiency in Kentucky and to generate an implementation plan to reach statewide energy savings goals. This Action Plan is the resulting implementation document from Phase One.
- In **Phase Two**, the main goal will be to carry out action items that are ripe for implementation and to continue to work with stakeholders on items still in process.

DEDI contracted MEEA in February 2011 to manage the stakeholder process and develop the Action Plan to accomplish the project goals. MEEA thereafter sub-contracted with SMG for local technical expertise and meeting facilitation.[14] The project team also coordinated their work with ACEEE, which provided research and analyses of Kentucky's energy efficiency landscape.

The stakeholder engagement process in Phase One was vital in shaping each action item set out in this Action Plan. A complete list of stakeholder participants is attached as *Appendix A* and a summary of key milestones in the process are attached as *Appendix B*. A list of ACEEE's reports referenced in the stakeholder process is provided in *Appendix C*. *Appendix D* provides a description of the methodology that will be used to measure and track progress on the one percent goal.

PROFILE OF ENERGY SERVICE IN KENTUCKY

Electricity in Kentucky is provided to customers by one of the following types of entities: (1) retail electric suppliers that are regulated by the PSC; (2) un-regulated municipally owned utilities; or (3) the Tennessee Valley Authority (TVA) (also un-regulated) and its associated distributors within the Commonwealth. Furthermore, each electric supplier has the exclusive right to serve the customers within its territory.

Electric suppliers that are regulated by the PSC fall into two categories: The first includes investor-owned utilities and rural electric cooperatives. There are three investor-owned utilities in Kentucky: Duke Energy Kentucky (Duke), American Electric Power/Kentucky Power (AEP), and Louisville Gas & Electric/Kentucky Utilities (LG&E). Each of these companies generates or purchases the power required to meet its respective customers' electricity demands. There are 19 rural electric cooperatives that are regulated by the PSC. Sixteen of these jointly own and purchase power from East Kentucky Power Cooperative (EKPC). The remaining three jointly own and purchase power from Big Rivers Electric Corporation (Big Rivers). A "distribution" cooperative typically receives power from its respective "generation and transmission" cooperative at a substation in the distributor's service territory.

There are five rural electric cooperatives and 10 municipal utilities that purchase all of their electricity from TVA. These cooperatives and municipalities then resell and distribute electricity to

Strategy #1 of Governor's Energy Strategy, pp. 21-23, 26. This was one of the leading stakeholder recommendations in SEE KY, and as a result is applied broadly to each energy-consuming sector (*see* action item A.4 herein).

[14] MEEA and SMG's involvement in the project will conclude in September of 2013, at which point DEDI will continue to work with stakeholders across Kentucky to implement the remaining action items.

customers within their service territories. Separately, TVA also directly serves several large industrial customers within Kentucky.

Additionally, there are 18 municipal electric suppliers that do not receive electricity from TVA. These municipal utilities either self-generate electricity—by owning and/or operating generating facilities—or purchase power from various sources. In the case of purchased power, a municipality may negotiate a guaranteed delivery of electricity from an investor owned utility or independent power producer, or purchase electricity on the market for distribution within its service area.

ACTION ITEMS

This Action Plan is the key document by which Kentucky will implement recommendations made throughout the SEE KY process. Stakeholder feedback confirms that there is significant untapped potential in Kentucky to capture greater energy savings through efficiency. The Action Plan serves as a means to capitalize on that potential.

The actions discussed in this Plan are voluntary; the stakeholders, for the most part, had little appetite for mandatory measures. Because this was a collaborative process involving the many diverse opinions of stakeholders representing, at times, conflicting interests, it was essential to find common ground and focus on action items that are the most economically and politically viable for Kentucky. While the Action Plan incorporates feedback from non-jurisdictional utilities, the resulting action items apply primarily to jurisdictional utilities, particularly regarding regulatory and statutory issues. Notations are made where that is not the case.

A. ACTION ITEMS FOR ALL SECTORS

Of the many recommendations MEEA and DEDI received throughout the stakeholder process, several applied broadly to Kentucky as a whole, regardless of rate class. This section includes the following recommendations which apply to all sectors:

Short-term
A.1. *Measure statewide energy efficiency targets using electric utility data reported voluntarily to DEDI*
A.2. *Create a peer exchange mechanism specifically for gas and electric utilities to share information, experiences and best practices*
A.3. *Condition State funding on minimum energy efficiency outcomes taking into account life cycle costs*
Near-term
A.4. *Focus on robust education and training programs tailored to each consumer sector*
A.5. *Convene a work group to evaluate effects of utility rate design on energy efficiency incentives*
Long-term
A.6. *Assist Kentucky's governmental and municipal utilities to develop a voluntary suite of energy efficiency programs*

Short Term Recommendations (Less Than 1 Year)

A.1. *Measure statewide energy efficiency targets using electric utility data reported voluntarily to DEDI*

<u>Background and Stakeholder Observations</u>

Regular tracking of the performance of energy efficiency programs across Kentucky is essential to evaluate progress towards the State's energy efficiency goals. As discussed above, this Action Plan complements the Governor's 16 percent efficiency goal as a voluntary statewide target to reduce energy consumption by one percent annually through energy efficiency.[15] Stakeholders throughout the SEE KY process have expressed support for this goal as a pragmatic means of moving

[15] As mentioned previously, the Governor's Energy Strategy articulates an 18 percent cumulative energy savings goal by 2025 for Kentucky, 16 percent of which will be attributed to reductions in energy consumption in the electric and natural gas sectors, with the remaining 2 percent coming from transportation energy efficiency programs. *Supra*, n. 8, Strategy #1 of Governor's Energy Strategy, p. 23. This 2 percent will not be discussed in the Action Plan.

Kentucky's energy efficiency efforts forward. Rigorously documenting and evaluating the impacts of energy efficiency programs in Kentucky is also imperative if utilities, regulatory staff and other stakeholders are to understand program performance.[16] This action item provides a two-part process to accomplish these goals that will include data collection and analysis.

Kentucky's DSM statute (KRS 278.285) does not require any particular reporting of yearly energy savings data from ratepayer-funded programs, other than what is minimally necessary to establish cost-effectiveness when a program is first proposed. In addition, many of the programs provided by Kentucky's electric cooperatives have not been developed under the DSM Statute.[17] As a result, stakeholders expressed concern that there is no consistent method to determine how well utility-run programs are performing, or how to measure progress towards statewide goals.

The project team discussed this issue with stakeholders at several points during the collaborative meeting series and an agreement was developed with many of Kentucky's utilities to voluntarily report energy efficiency program performance data to the State on an annual basis.

<u>Implementation Plan</u>

The project team's plan for implementing this action item is two-fold:

1. Participating utilities will annually report to DEDI a set of performance metrics for their energy efficiency and demand side management program suites.
2. DEDI will use these metrics to calculate progress on an annual basis towards Kentucky's energy efficiency goals.

The implementation plan for the data *collection* component of this action item is as follows:

1. ***WHO/WHAT*** – Participating utilities currently include LG&E, AEP, Duke, EKPC, Big Rivers and TVA.
    a) DEDI will act as the organizer and repository of the data, as well as the database manager.
    b) The participating utilities will be responsible for reporting annual data to DEDI in an agreed-upon format. A summary table of each utility's current level of commitment to voluntarily submit data, including rate classes and reporting due dates, is attached to this Action Plan as *Appendix D.*
    c) While the PSC has no defined role in data collection in this area, PSC staff has been highly supportive of this effort.

2. ***ACTION STATUS*** – There is agreement among the participating utilities to report program data. The utilities will report data concurrent with their annual DSM reporting obligations to the PSC. EKPC and TVA, who do not provide DSM reports to the PSC, will report data at or near the time they typically report to EIA. The only tasks left to be accomplished are:

[16] This action item parallels Recommendation No. 3 in the PSC's 2008 report, which suggested that Kentucky consider adopting recognized measurement and verification guidelines. *See* PSC Report, p. 26, available at: http://psc.ky.gov/agencies/psc/industry/electric/hb1report.pdf.

[17] Rather than participate in the DSM Statute's cost recovery mechanism, Kentucky's electric cooperatives file their programs through the PSC's tariff procedure and incorporate any associated costs into their base electric rates instead of through a customer surcharge.

a) Running a pilot phase with a sample set of data submitted prior to official launch; Two utilities have made attempts to pull the data and use the template and will provide feedback to DEDI;
b) Final discussions on definitions for each reporting metric and other wrap-up issues will be addressed in early 2013;
c) Ensuring that data are entered fully and accurately each year.

The project team does not expect this action item to require additional budget allocations. DEDI expects to use internal staff it already employs to manage the database and to troubleshoot any reporting issues.

The implementation plan for the data *analysis* component of this action item is as follows:

1. ***WHO*** – DEDI will use data to calculate progress toward annual goals and summarize findings.
2. ***WHAT*** – The data will be reviewed and analyzed as follows on an annual basis (a detailed summary of the data analysis approach is attached as *Appendix D*):
    a) The SEE KY goal incrementally ramps up initially in 2012-2014, to an annual one percent goal from 2015 through 2025.
    b) Percent savings will be calculated by taking the annual cumulative electric energy use reduced as a result of energy efficiency programs, compared to the preceding three year average total electricity consumption.[18] Percent savings will be measured in MWh for electric savings; MW of demand reduction will also be tracked.
    c) While specific natural gas targets will not be set, annual savings will nonetheless be tracked (Mcf) as with electric savings.
    d) In communicating progress toward annual goals, DEDI will generate four separate energy savings values each year:
        i. Residential energy savings, as compared with total residential consumption (average preceding 3 years);
        ii. Commercial energy savings, as compared with total commercial consumption (average preceding 3 years);
        iii. Industrial energy savings (where available), as compared with total industrial consumption (average preceding 3 years); and
        iv. Total energy savings, as compared with total energy consumption (average preceding 3 years).

3. ***ACTION STATUS*** – In process; data compilation will began in early 2013, using 2012 data; analysis will follow collection each year.

It is important to note that performance data from industrial programs will be limited, as EKPC, Duke and TVA are the only participating utilities who offer programs for that sector. EKPC and TVA build all energy efficiency program costs into their base rates. In contrast, the investor-owned utilities use the DSM Statute as a means to recover energy efficiency program costs through each rate class. The DSM Statute allows industrial customers with energy intensive processes to opt out entirely from participating in DSM programs, which every industrial customer in these utilities' service territories has taken advantage of.[19] Consequently, industrial customers do not pay a DSM surcharge on their energy bills and in turn their utility does not offer them efficiency programs.

[18] This approach is similar to energy savings goal calculation methods used in several neighboring states, including Indiana (*see* IURC Cause No. 42693, Phase II), and Ohio (*see* Ohio Revised Code 4928.66 *et seq.*; S.B. 221).
[19] *See* KRS 278.285(3).

Industries and manufacturers who participate in the stakeholder process have shown little interest in changing this opt-out provision.

Thus, the database will be unable to capture enough data to provide a clear, accurate picture of efficiency-related energy savings across the industrial sector. DEDI plans to work with individual manufacturers to gather data on a voluntary basis (action item I.3), but in the absence of statewide participation, it will unfortunately not be representative of all industrial efficiency activities. Rather, these data will serve the limited purpose of providing anecdotal evidence of worthy industrial self-direct accomplishments.

A.2.	***Create a peer exchange mechanism specifically for gas and electric utilities to share information, experiences and best practices***

Background and Stakeholder Observations

This action item encourages transparency through sharing of best practices and educational opportunities *among* utilities in a structured setting. One of the most effective ways of improving utility-run energy efficiency programs is an open exchange of information. Most of Kentucky's large utilities currently participate in a quarterly group called the *Utility Energy Efficiency Working Group* that is open to a variety of stakeholders, including advocates and energy consumers. During the SEE KY process stakeholders suggested that because the *Utility Energy Efficiency Working Group* includes participants from a wide variety of backgrounds and experiences, it may prevent utilities from digging deep into program design and implementation and thus improving the way they run their programs. One solution could be to augment or replace this group with a *utility-specific* peer exchange.

Implementation Plan

1. ***WHO*** – Successful implementation of this action item will require a dedicated work group consisting of jurisdictional electric and gas utilities, as well as the non-jurisdictional municipal utilities to evaluate and design the on-going peer exchange.
    a) The work group may request that the PSC participate, as well as have an occasional role in the peer exchange once implemented.
    b) DEDI will facilitate the work group as needed.

2. ***WHAT*** –
    a) In tailoring a peer exchange that is the most effective for Kentucky's utilities and energy landscape, the work group will review models in other states, such as Missouri, Iowa and Illinois, where each peer meeting spans one or more days and participants dig deep into the details of program selection, design, cost-effectiveness, implementation, data analysis and ratepayer participation.
    b) The work group will determine which elements of model approaches are applicable for Kentucky, if any, and will develop specific parameters, goals, funding structure and a meeting schedule for the resulting peer exchange.
    c) In the event a peer exchange is initiated, some means of sharing information among participants will be implemented.
    d) The work group will also evaluate funding options for any resulting peer exchange.

3. ***ACTION STATUS*** – In process; self-selection of work group participants and review of models will begin in early 2013. The work group's main goal will be to provide a proposal

for a Kentucky-specific peer exchange and the launch of the peer exchange within six months after development.

A.3. *Condition State funding on minimum energy efficiency outcomes taking into account life cycle costs*

Background and Stakeholder Observations

The Commonwealth is the administrator to a number of grant and loan funds scattered among numerous State agencies designed to help fund infrastructure, achieve environmental compliance, provide for safe and affordable housing, among other things. Many of these funds have potential long-term energy cost implications that can, and do, impact taxpayers. Stakeholders have shared anecdotes of State funds being used to build or remodel a public facility, for example, only to turn around and have to do another retrofit on the facility very shortly thereafter because of the high energy costs. There have even been instances of public facilities being built, then left unused because the budget could not support operational costs, primarily for energy. Kentucky already requires State government to consider life cycle costs when making purchases. However, for many grant or loan programs, there are no similar requirements.

Implementation Plan

1. ***WHO, WHAT*** – A work group consisting of key representatives from State agencies that administer grant and loan funds will be convened to look into attaching minimum energy efficiency outcomes for State funding opportunities and make recommendations to the Governor's Office for consideration. This action item will require an inventory of all grant and loan fund programs that have potential energy and energy cost implications.

2. **ACTION STATUS** – Action item not yet in process.

Near Term Recommendations (1 - 3 Years)

A.4. *Focus on robust education and training programs tailored to each consumer sector*

Background and Stakeholder Observations

Stakeholders throughout the SEE KY process stressed that the backbone of any effective energy efficiency program suite is a robust, coordinated outreach and marketing campaign. Similarly, the Governor's Energy Strategy identified public information campaigns as vital to achieving Kentucky's energy efficiency goals.[20] Outreach and education are critical on two levels: 1) to help Kentuckians learn about the benefits of energy efficiency; and 2) to provide information on the array of products and services available to help them reduce their energy consumption. This sentiment was also echoed in the PSC's 2008 report to the General Assembly.[21]

[20] *Supra*, n.8, Strategy #1 of Governor's Energy Strategy, pp. 21 and 26.
[21] The report recommended that greater efforts be made to make ratepayers aware of energy conservation and DSM programs, and suggested that utilities leverage relationships with educational institutions, nongovernmental organizations and community organizations to accomplish this. *Supra*, n. 16, PSC Report, p. 30 (Recommendation #7).

While there appears to be consensus that education is one of the most important aspects of an effective statewide energy efficiency approach, many stakeholders indicate that it can also be the most vexing. Part of the challenge in developing an effective outreach and education campaign is that each rate class consumes information in a different way. Within the rate classes, further divisions occur, such as low and middle income in the residential sector, small and large business owners in the commercial sector and small, medium and heavy manufacturers in the industrial sector. Stakeholders indicate that a custom education approach should be tailored to the needs and habits of each of these distinct classes-within-classes. To complicate matters further, ratepayer-funded energy efficiency education programs are often controversial in Kentucky; energy savings can be difficult to attribute to these programs, thus posing cost-effectiveness challenges.

The challenge for Kentucky, therefore, is to work on a multi-faceted and wide-ranging approach for each consumer sector. The ultimate goal will be to increase energy consumers' knowledge of basic energy efficiency principles and help them make educated decisions about their energy consumption.

Implementation Plan

In the Governor's Energy Strategy, the State committed to conducting a vigorous and ongoing public energy efficiency awareness and education program that will support its energy efficiency goals.[22] This action item is an extension of that original commitment. At the same time, it is important to note that the success of this action item is dependent on ongoing partnerships and collaboration with Kentucky's State agencies (in addition to DEDI), energy service providers, utilities, community organizations, advocates and universities and technical colleges. More than any other recommendation in this Action Plan, education and outreach will require the participation of stakeholders.

1. ***WHO/ WHAT*** –
   a) Many of the stakeholders involved in the SEE KY process already participate in forums (either public or in an invitation-only format) that are ripe for dissemination of energy efficiency-related information across Kentucky. These forums include annual and semi-annual statewide and local conferences, media events, forums hosted by State agencies or private entities, as well as the current *Utility Energy Efficiency Working Group*, each utility's energy efficiency collaborative and the proposed utility-specific Peer Exchange (*see* action item A.2). Existing educational opportunities will also be leveraged, including the industrial peer exchange, and utilizing the Kentucky Manufacturing Assistance Center and the Kentucky Industrial Assessment Center housed at the University Of Kentucky College Of Engineering.[23]
   b) Stakeholders will use these existing processes and forums as a means to share and widely disseminate information on energy efficiency, including both basic principles and State and utility program offerings and the potential for models, best practices and program innovation moving forward.
   c) The goal of this approach will be to provide a coordinated marketing and education campaign, using existing channels and trusted entities who already deliver this kind of information. As necessary, information will be tailored to the distinct needs and habits of the targeted ratepayers/audience.

[22] *Supra*, n. 8, Strategy #1 of Governor's Energy Strategy, p. 26.
[23] In February 2012, the U.S. Department of Energy began funding an Industrial Assessment Center for Kentucky, housed at the University of Kentucky at its Power and Energy Institute of Kentucky, part of the College of Engineering. *See* http://www.engr.uky.edu/power/kiac/. The DOE's IAC program trains university engineering students to conduct energy audits at industrial sites. *See* http://www1.eere.energy.gov/manufacturing/tech_deployment/iacs.html.

d) Successful implementation of this action item will require the participation of a diverse cross-section of stakeholders to add substance to the marketing and outreach approach and improve the quality and breadth of efficiency education in Kentucky. DEDI will participate in and provide support and facilitation, as needed. Participants should include:
   i. Utilities (investor-owned, electric cooperatives and municipal utilities) and utility advocacy groups;
   ii. Representatives of and advocates for Kentucky's residential energy consumers (the Community Action Agencies, low-income housing advocates, home builders, housing retailers and housing associations);
   iii. Representatives of and advocates for Kentucky's commercial energy consumers (trade associations, trade publications, State and local business chambers, etc.);
   iv. Representatives of and advocates for Kentucky's industrial energy consumers (Kentucky Pollution Prevention Center, State and local business chambers, Kentucky Association of Manufacturers and other trade associations and technical consultants);
   v. Contractors, installers, technical consultants and other individuals that deliver energy efficiency services;
   vi. The university system, including local community and technical colleges;
   vii. The PSC;
   viii. The Attorney General's Office.

ACTION STATUS – In process. Parameters, timeline, agenda and goals for the forums will be developed in collaboration with participants following the release of this Action Plan.

A.5. *Convene a work group to evaluate effects of utility rate design on energy efficiency incentives*

Background and Stakeholder Observations

In the Governor's Energy Strategy, the DEDI committed to collaborate with the PSC to evaluate energy rate design and ratemaking alternatives to enhance the impact of cost-effective energy efficiency programs in Kentucky. [24] Similarly, during the SEE KY process, stakeholders – primarily electric cooperatives and their distribution members – made clear that rate design is one of the most important issues determining the degree to which they can invest in efficiency. The PSC has started hearing and ruling on these issues in Kentucky. In early 2012, the PSC approved a request by Owen Electric Cooperative to gradually alter its rate structure, aimed at maintaining financial stability while stepping up efforts to encourage its customers to reduce energy usage.[25] Other stakeholders vigorously oppose this approach to rate design, indicating that there is no quantifiable data that it will create an incentive for energy efficiency and the effects may be disproportionately borne by low income and elderly ratepayer.

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[24] *Supra*, n. 8, Strategy #1 of Governor's Energy Strategy, p. 28.
[25] *See* Case No. 2011-00037, PSC Order available at: http://psc.ky.gov/pscscf/2011%20cases/2011-00037/20120229_PSC_ORDER.pdf.

Implementation Plan

Given conflicting stakeholder feedback on rate design and its capacity to create incentives for greater energy efficiency in Kentucky, an open forum on this topic will be held. While feedback on rate design was collected from utility and ratepayer advocates during the SEE KY collaborative process, DEDI has yet to fully engage a diverse range of stakeholders specifically on this topic.

1. ***WHO*** – This action item will be carried out in collaboration with Kentucky's utilities, the PSC, Office of the Attorney General and a diverse selection of stakeholders. As necessary, experts from within and outside Kentucky will be involved to provide technical assistance in the discussion.

2. ***WHAT*** – A work group, or a series of forums, will be created to discuss the pros and cons of employing alternative rate design as a means to deliver cost-effective energy efficiency to Kentuckians.

3. ***ACTION STATUS*** – Action item not yet in process.

Long Term Recommendations (3-4 Years)

A.6. *Assist Kentucky's governmental and municipal utilities to develop a voluntary suite of energy efficiency programs*

Background and Stakeholder Observations

While the investor-owned utilities and electric cooperatives provide energy efficiency services and programs to a large percentage of Kentuckians, a similar coordinated effort by Kentucky's governmental and municipal utilities may have the potential to open similar programs for the remaining ratepayers. There are 27 municipalities in Kentucky that either self-generate or purchase power from various sources, including the ten that TVA serves. Municipal utilities are locally owned and operated utilities that are governed by city officials or independent utility boards appointed by city officials. Thus, these utilities are not regulated by the PSC in Kentucky. Several municipal utilities participate in energy efficiency programs. This action plan offers a voluntary suite for those utilities that may want to begin offering similar programs.

Several municipal representatives have indicated that they may be interested in providing efficiency services to their customers, possibly via a voluntary, comprehensive approach to turnkey efficiency programs across municipal utility service territories. To accomplish this, they have proposed convening a Municipal Utility Energy Efficiency Advisory Group to gain expertise in developing the efficiency suite.

Implementation Plan

DEDI has committed to assist in this effort and to leverage its relationships with jurisdictional utilities to provide technical assistance for interested municipal utilities during the program design process. The development of a utility Peer Exchange (*see* action item A.2) should also be instrumental in supporting this initiative.

1. ***WHO*** – This action item will be carried out by DEDI in voluntary collaboration with interested municipal utilities, as well as with the Kentucky Municipal Utility Association. The members of the Peer Exchange (*see* action item A.2), when and if organized, will also collaborate with the Municipal Utilities to assist in developing programs suitable to those organizations.

2. ***WHAT*** –
   a) The Municipal Utility Energy Efficiency Advisory Group will invite DEDI and other entities to provide expertise and support, as needed. This support may include some or all of the following:
      - ❖ Educational materials (model approaches, best practices) for review by municipal utilities, to support program development, including information on "Quick Start" programs;
      - ❖ Guidelines and best practice approaches in developing clear, consistent evaluation, measurement and verification guidelines for municipal utility-run energy efficiency programs; and
      - ❖ Templates and best practices in data reporting and storage, as essential elements to tracking energy efficiency performance data.

3. ***ACTION STATUS*** – In process. In addition to the Advisory Group described in this action item, interested municipal utilities may voluntarily participate in the utility Peer Exchange, when and if developed under action item A.2.

R. RESIDENTIAL SECTOR RECOMMENDATIONS

Kentucky's residential sector accounts for nearly 30 percent of the State's total electricity consumption (ranking Kentucky 6th nationally in terms of residential electricity consumption per capita) and 25 percent of its total natural gas use.[26] All of the Commonwealth's investor-owned utilities and electric cooperatives, as well as TVA, offer energy efficiency programs with varying incentives and rebates for Kentucky homes. Stakeholder feedback also indicates that some residential efficiency programs offer the biggest bang for a ratepayer's buck and that participation levels are highest among this rate class as well.

While the residential sector overall is well-served with regard to efficiency programs, stakeholders indicate that more could be done to target specific energy uses and increase focus on certain programs within this sector. The following action items lay out the specific areas where Kentucky should increase its efficiency efforts in the coming years:

Short-term
R.1. ***Support Kentucky Home Performance to increase market penetration***
Near-term
R.2. ***Improve the residential housing stock via utility and community-sponsored weatherization***
Long-term
R.3. ***Improve the energy efficiency of residential buildings through consistent implementation of residential building energy codes***
R.4. ***Increase innovative energy efficiency financing options, such as on-bill financing***
R.5. ***Provide incentives for energy efficiency retrofits in residential rental property***
R.6. ***Develop an advisory group to address options for replacing inefficient manufactured homes***
Legislative Recommendations
R.7. ***Expand existing State-provided energy efficiency incentives***

Short Term Recommendations (Less Than 1 Year)

R.1. ***Support Kentucky Home Performance to increase market penetration***

Background and Stakeholder Observations

Kentucky Home Performance (KHP) is a residential efficiency retrofit program that was launched in November 2010 as a new statewide Home Performance with ENERGY STAR program.[27] It uses whole home analysis and a certified professional contractor network to provide a market-based system of incentives and technical support for energy efficiency upgrades to existing single family homes. Over the course of 20 months, KHP retrofitted more than 1,000 homes in Kentucky. On March 15, 2012, the Environmental Protection Agency awarded KHP the national ENERGY STAR Partner of the Year.

Stakeholder feedback during the SEE KY process indicates that KHP is a valuable component of the residential efficiency programs in Kentucky. The program began in 2010 leveraging funds from the Recovery Act. Following the expenditure of 2012 Recovery Act funds, a small amount of carry-

[26] *See* DEDI's Kentucky Energy Profile 2011, available at: http://energy.ky.gov/Documents/Kentucky_Energy_Profile_2011.pdf (electricity consumption is broken down by sector at pages 8-10, 23, 29).
[27] *See* http://www.kyhomeperformance.org.

over dollars were allocated for the establishment of a KHP loan fund and one year of program administration. In December 2012, Kentucky Housing Corporation, the entity that administers KHP, was awarded $3 million by DEDI, as part of TVA's 2011 settlement agreement with the U.S. Environmental Protection Agency.[28] The grant will fund nearly three years of KHP program operations and will focus on owner-occupied, single-family energy efficiency loans ranging from $1,000-$25,000 per home.

Implementation Plan

The Kentucky Housing Corporation will continue to increase market penetration by KHP across Kentucky. Now that funding is secure through 2015, staff can focus on coordinating KHP with existing residential weatherization and retrofit programs in Kentucky to expand its reach and scope.

1. ***WHO/WHAT*** – This action item will be carried out by KHP staff, the Kentucky Housing Corporation, with support from DEDI and other stakeholders as necessary.
    a) The Kentucky Housing Corporation will work to increase KHP's market penetration across the State.
    b) Kentucky Housing Corporation will also coordinate its efforts with utilities to evaluate potential partnerships between KHP and utility residential efficiency retrofit programs.

2. ***ACTION STATUS*** – Administrative program funding is secured through 2015 with program income being generated to keep the loan fund capitalized for some years to come.

Near Term Recommendations (1 - 3 Years)

R.2.	***Improve residential housing stock via utility and community-sponsored weatherization***

Background and Stakeholder Observations

KHP is part of a larger suite of programs aimed at improving the energy efficiency of Kentucky's housing stock. Other programs that focus on making existing homes more efficient are also essential to realizing the significant energy savings potential in the residential sector.

For example, many utility stakeholders indicate that their residential efficiency programs are among their most cost-effective, as well as the most popular in terms of participation. These programs are critical to improving the overall efficiency of a home. Every jurisdictional utility in Kentucky offers some form of weatherization to its residential customers. In addition, Kentucky's Community Action Agencies offer the Kentucky Weatherization Assistance Program (KY WAP), the Commonwealth's primary vehicle of home weatherization for low-income residents serving each of the 120 counties.[29] KY WAP is funded annually by allocations from U.S. DOE; in 2009 efforts were ramped up as a result of a considerable funding supplement via the Recovery Act. As of April 2012, the KY WAP reverted back to lower than pre-Recovery Act funding levels.

[28] *See* press release at: http://kentucky.gov/Pages/Activity-Stream.aspx?viewMode=ViewDetailInNewPage&eventID={267B01B3-0959-4A7A-B0CE-A1B3A773DC6D}&activityType=PressRelease.
[29] *See* https://www.kyhousing.org/page.aspx?id=2327.

Implementation Plan

1. ***WHO***
   a) Community Action Kentucky (CAK) will be the lead in carrying out this action item, with support from DEDI and other stakeholders as necessary.
   b) As with action item A.4, successful implementation of this action item will require the participation of a diverse cross-section of stakeholders. DEDI will participate in and provide support and facilitation, as needed. Additional participants should include:
      i. Utilities, including investor-owned, electric cooperatives and municipal utilities (discussions will focus on potential partnerships and/or coordination with KY WAP and utility residential efficiency retrofit programs);
      ii. Representatives of and advocates for Kentucky's residential energy consumers (the Community Action Agencies and other low-income housing advocates, home builders, housing retailers and housing associations, including: Kentucky Homebuilders Association, Kentucky Housing Corporation, Kentucky Manufactured Housing Institute, Federation of Appalachian Housing Enterprises, Frontier Housing, Kentucky Habitat for Humanity, Bluegrass ASHRAE and the Kentucky Chapter of the US Green Building Council;
      iii. Contractors, installers, technical consultants and other individuals that deliver energy efficiency services, to educate them on proper procedures for installing energy efficiency equipment and thereby maximizing benefits to their clients;
      iv. The university system, including local community and technical colleges;
      v. The PSC; The Attorney General's Office.

2. ***WHAT*** – Stakeholder feedback indicates that Kentucky should strive to support and expand these programs on a parallel track to KHP. The expansion of effective residential programs in Kentucky is also dependent on the dissemination of information on basic energy efficiency, as well as increasing current program offerings.
   a) Thus, this action item will parallel A.4 above and will use currently-existing forums to encourage discussion across a wide range of stakeholders on residential energy efficiency opportunities and possibilities for innovation, as well as review of best practices and models in other jurisdictions. The goal will be to coordinate among all residential efficiency programs and ensure that progress made through Recovery Act funding is maintained into the future.
   b) Participants will also be encouraged to address energy efficiency matters over which the federal government has primary control. This reflects stakeholder feedback related to the Federal Emergency Management Agency's (FEMA) post-disaster rebuilding approach, as well as how funds are apportioned via the Low Income Home Energy Assistance Program (LIHEAP) (*see* action items F.1 and F.2 below).

3. ***ACTION STATUS*** – Action item not yet in process. Parameters, timeline, agenda and goals for the forums will be developed in collaboration with participants following the release of this Action Plan.

Long Term Recommendations (3-4 Years)

R.3. ***Improve the energy efficiency of residential buildings through consistent implementation of residential building energy codes***

Background and Stakeholder Observations

Another vital element of improving Kentucky's housing stock, and thus capitalizing on significant energy savings potential, is ensuring compliance with residential building energy codes statewide. The residential energy codes were updated January 2012 and became effective October 2012.

Adequate resources for residential inspections and compliance are critical to achieving the full savings potential from new building energy codes. The Kentucky Department for Housing, Buildings and Construction (DHBC) is responsible for statewide compliance with energy codes related to all buildings systems, except where there are delegated local jurisdictions. As such, there is a mosaic of State and local jurisdictions performing energy code permitting and inspection of energy code activities. Relative to residential energy code compliance capacity in the State's jurisdiction, DHBC currently performs whole-building energy code inspections on all multi-family residential units, but only has sufficient resources to employ inspectors for heating, ventilation, and air conditioning (HVAC) on single family units, meaning that some home components go un-inspected. This work is being funded via inspection fees. The State's jurisdiction covers roughly half of the geographic area of Kentucky, but represents some of the less populous areas; the remainder by local jurisdictions.

Critically, many counties across the State have no local code inspection of any kind. This is something some stakeholders have advised is needed to protect the health, safety, and financial well-being of consumers across the State. Finding local resources to hire additional inspectors is sorely needed to ensure energy code compliance.

Implementation Plan

DHBC and DEDI will seek funding to increase the State's capacity for compliance activities for all residential building energy code components not currently covered by inspections or permits. DHBC projects that the HVAC inspection fees it now uses to fund HVAC energy code inspection is sufficient to eventually fund additional HVAC inspectors.

1. ***WHO*** –
    a) The lead coordinator for this action item is yet to be determined. DHBC will necessarily need to be involved; DEDI will provide support as requested and needed.
    b) As necessary, the DHBC will seek the feedback and assistance of representatives of and advocates for Kentucky's housing organizations and representatives of home builders and residential energy consumers, including but not limited to: Kentucky Homebuilders Association, Kentucky Housing Corporation, Kentucky Manufactured Housing Institute, Federation of Appalachian Housing Enterprises, Frontier Housing, Kentucky Habitat for Humanity, Bluegrass ASHRAE, Kentucky Association of Counties, and the Kentucky Chapter of the US Green Building Council.
    c) The work group may also seek feedback from utilities, particularly where DHBC and utilities may be able to partner to fund residential building energy code compliance activities and thus enhance energy savings in utility service territories.

2. ***WHAT*** –
   a) The work group will work with housing stakeholders as needed, to identify opportunities to expand statewide energy codes inspection, and to identify additional sources of funding for inspectors.
   b) Avenues to secure code inspectors in non-jurisdiction areas of the State will be pursued.
   c) Supplementary energy code activities will also be evaluated, including: providing ongoing training and/or continuing education credits to inspectors, builders, and contractors; holding regional information sessions on current residential building energy codes and updates; and funding compliance surveys.
   d) The work group will explore potential residential building energy code collaboratives, where stakeholders (utilities, homebuilders, State agencies – including DEDI) come together on a regular basis in a structured forum to explore common interests around energy code adoption and compliance.
   e) The work group will work with utilities via a utility Peer Exchange, when and if formed (action item A.2), to evaluate how utilities can benefit from collaborating on residential building energy code compliance activities.

ACTION STATUS – Action item in process.

R.4. *Increase innovative energy efficiency financing options, such as on-bill financing*

Background and Stakeholder Observations

Access to low-cost upfront financing for energy efficiency improvements is critical to success in the residential sector. Creative financing options are currently being piloted in Kentucky and stakeholders generally indicate support to expand these options in the future. A key initiative is the How$martKY pilot, an on-bill financing program currently managed by the Mountain Association for Community Economic Development (MACED) and offered by four of EKPC's distribution cooperative members.[30] On-bill financing allows a homeowner to have energy-efficient improvements installed in their residence. These measures are paid for by the electric cooperative using capital provided through a line of credit from MACED to the cooperatives. Participating cooperatives recover their investment through a charge added to the monthly bill. The efficiency improvements and monthly charge are structured such that the homeowner has an immediate net positive cash flow – that is, the now-reduced utility bill plus the retrofit payment will not exceed 90 percent of the original utility bill. MACED is currently gathering data on the performance of homes retrofitted through How$martKY. In addition, as part of a DEDI grant program that also provided funding for KHP through 2015, MACED received a grant award of $300,000 to support How$martKY.[31] The funds provided will enable MACED to perform 150 energy efficient retrofits in area residences, saving an estimated 825 MWh/year of electricity, representing more than $90,000 a year of savings on participating customers' utility bills.

Some electric cooperative stakeholders indicate that they would like to pursue this on-bill financing model for Kentucky's energy consumers in the future. In addition, other utilities and some housing

[30] *See* http://www.maced.org/howsmart-overview.htm.
[31] *Supra*, n. 33.

advocates are interested in exploring mechanisms beyond on-bill financing. That said, the success or applicability of this approach will be dependent upon a number of motivating factors among the various utilities and utility types, e.g. IOUs vs. coops.

While this recommendation for on-bill financing is presented for the residential sector, there may be opportunities to utilize this model for commercial or industrial sectors as well.

Implementation Plan

1. ***WHO/WHAT*** – DEDI will provide support, as needed, for MACED as it expands How$martKY in Kentucky. This support will include sharing information on the How$martKY model when opportunities arise, as well as encouraging collaboration with additional utility partners. Additional creative funding models will be explored as appropriate. MACED and DEDI will continue to encourage support for and adoption of the How$martKY program.

2. ***ACTION STATUS*** – Given the Action item is in process, there are aspects of this approach that are both near-term and long-term. There is still a need to market the program to utilities that have yet to adopt this approach and there is an on-going need to raise capital for financing.

R.5. ***Provide incentives for energy efficiency retrofits in residential rental property***

Background and Stakeholder Observations

Rental housing presents a particularly tough challenge to carrying out residential energy efficiency retrofits. Renters are reluctant to pay for improvements to property they do not own and, in turn, owners have little motivation to make efficiency improvements to property when they don't pay the energy bills. As a result, stakeholders – particularly utilities and housing advocates – would like to create a mechanism to incent landlords to make rental units more efficient, while providing the benefit of lower energy bills to renters.

Implementation Plan

1. ***WHO*** – Creative options for addressing inefficient rental property will be explored via a work group made up of interested stakeholders.
    a) DEDI will identify an agency or organization who will organize and facilitate the work group. DEDI will serve as a member of the work group and will provide support as resources allow.
    b) Representatives of and advocates for Kentucky's residential ratepayers, including rental associations, the League of Cities and those representing landlords and tenants will be participants in the work group.
    c) This work group may also be organized as a sub-group of a utility Peer Exchange, when and if created (*see* action item A.2) and/or the existing *Utility Energy Efficiency Working Group*.
    d) This work group's activities will be coordinated with, and informed by, the National Association of State Energy Officials, Southeast Region, initiative entitled "Advancing Multifamily Energy Efficiency Policies and Programs." This initiative proposes to engage stakeholders to address policy and program barriers to improve

energy performance and comfort of the region's multifamily building stock. Successful models from other states will be examined for suitability to Kentucky and the region.

2. ***WHAT*** –
   a) Stakeholders have expressed interest in investigating mechanisms where both landlord and tenants would receive some of the benefits from energy efficiency investments. The work group will review existing programs and models in other states.
   b) Work group participants will be responsible for determining whether models in other states may be applicable to Kentucky, as well as the parameters for any resulting Kentucky-specific approach. Incentive funding options will be reviewed, including allocations from utility-run DSM program budgets, State budgets and federal funding.

3. ***ACTION STATUS*** – Action item not yet in process.

R.6. *Develop an advisory group to address options for replacing inefficient manufactured homes*

Background and Stakeholder Observations

Kentucky's residential sector includes a significant stock of energy inefficient manufactured homes. Housing advocates estimate that manufactured homes account for 13.6% of Kentucky's residential stock. Stakeholders have indicated two classes of concern relative to manufactured housing: (1) use of resistance heat in new units complying with U.S. Department of Housing and Urban Development (HUD) codes; and (2) Kentucky's extensive stock of very energy inefficient and costly pre-1976 manufactured homes. These manufactured homes, of which there are over 85,000 in Kentucky (13,500 in EKPC's territory alone), were built prior to HUD regulations that set minimum standards for energy efficiency. They are so inefficient that it is not cost-effective to retrofit them in a manner that will yield meaningful cost savings. Thus, residents living in pre-1976 manufacture homes would not be good candidates for weatherization programs, such as KHP or KY WAP, thereby leaving them limited resources for making their homes more efficient. Similarly, newer manufactured units with resistance heat are extremely inefficient and costly for their occupants.

Ultimately, stakeholders indicated that there are two main barriers to increasing the efficiency of manufactured housing in Kentucky. The first is the difficulty with moving energy efficient manufactured homes onto the market. There is currently no consumer demand because of a lack of understanding of the long-term energy cost savings; and retailers do not offer them because of lack of demand and concern over customer confusion. The second is lack of access to low-cost financing to retrofit or replace these homes. Energy efficient manufactured homes are currently available in Kentucky, but appropriate financing is not.[32] Many lenders refuse to treat manufactured homes as part of the real estate, even when the home buyer owns the land on which the home is placed. This prevents buyers from qualifying for financing in the mainstream housing finance market. And while some of Kentucky's housing organizations, such as Frontier Housing[33] and (more recently through

[32] *See, e.g.*, homes offered through NextStep, http://www.nextstepus.org/homesoverview.htm.
[33] For a description of Frontier Housing's pre-1976 replacement program, and a case study, visit: http://www.frontierhousing.org/Kelly.htm.

the TVA grant dollars) Next Step,[34] offer subsidies to help defray the cost of replacing these homes with newer, more efficient models, stakeholders report that more needs to be done to address these barriers.

Another parallel concern voiced during the SEE KY process relates to manufactured housing installation. Even where a resident is successful in replacing their manufactured home with a more efficient model, stakeholders indicate that housing installers are not always fully trained on proper installation procedures. Proper installation is critical to achieving the maximum level of energy efficiency performance in a manufactured home, thereby making the occupant's investment worthwhile. In 2010, Kentucky passed a bill requiring 100% inspection of all manufactured homes installed.[35] Stakeholders have suggested supporting DHBC's efforts by seeking additional funding to increase the number of inspectors within the agency. In cooperation with the Manufactured Housing Section of Building Code Enforcement within the DHBC, the Kentucky Manufactured Housing Institute (KMHI) provides training opportunities around the State and online to meet the requirements of becoming a Certified Installer or Certified Manager.[36] Stakeholders have recommended expanding these efforts.

<u>Implementation Plan</u>

Stakeholders suggest convening an advisory group to develop recommendations for creating a more favorable environment in Kentucky to replace these homes on a larger scale, and to provide enhanced training for installers.

1. ***WHO*** – The advisory group will be organized either by DEDI or a third party.
    a) Participants will include utilities that serve low-income communities, representatives of Kentucky's manufactured housing retailers and installers, and representatives of both landlords and tenants of manufactured housing developments.
    b) Other low-income housing advocates and financing institutions will be included, as well as State and Federal legislators.

2. ***WHAT*** –
    a) The advisory group will be responsible for determining whether program models in other states may be applicable to Kentucky, as well as the parameters for any resulting Kentucky-specific approach. Stakeholders have suggested a number of options such as:
        i. A pilot for manufactured home replacements that would build a case for true energy savings potential and stimulate market transformation, and thus spur attractive financing options by lending institutions;
        ii. Increase tax incentives for energy efficient manufactured homes at the manufacturer, retailer, and/or purchaser levels;
        iii. Supporting DHBC in providing more resources for manufactured housing inspection across Kentucky; and
        iv. Additional incentives for contractor training on energy efficiency measures to ensure proper installation, as well as possible penalties following improper installation.

[34] *Supra*, n. 33.
[35] *See* KRS 227.57 (5) ("The installation of a new manufactured home shall be inspected under subsection (3) of this section").
[36] *See* http://dhbc.ky.gov/bce/mmh/Pages/default.aspx.

b) Budget: The advisory group will review, and ideally identify, adequate funding sources for a pilot, incentives, and training options.

ACTION STATUS – Action item not yet in process.

Legislative Recommendations (2013/2014 Sessions)

R.7. *Expand existing State-provided energy efficiency incentives*

Background and Stakeholder Observations

In addition to the residential energy efficiency programs offered by utilities and the State, there are a number of existing State-level tax credits that provide incentives to homebuilders and homeowners to invest in energy efficiency. House Bill 2 was passed in 2008 following the release of the Governor's Energy Strategy and included several tax credit provisions aimed at increasing the uptake of energy efficiency measures in Kentucky homes.[37] For residential homeowners, total tax credits are capped at $500 per taxpayer and cover products such as insulation, windows, doors and various HVAC and water heating measures.[38] Credits of up to $800 are also available for homebuilders that construct a new ENERGY STAR site-built home and $400 for a vendor who sells an ENERGY STAR manufactured home.[39]

While these tax credits have been useful in raising awareness and interest in energy efficiency, they have proven insufficient to significantly stimulate Kentucky's energy efficiency market.[40] As a result, stakeholders in the SEE KY process recommend expanding the current credits.[41] This is consistent with EEC's commitment in the Governor's Energy Strategy to identify new tax incentives that will further enhance energy efficiency in the Commonwealth.[42] EEC estimates that doubling these credits would stimulate demand in the residential housing market for energy assessments and equipment installations and would help homeowners manage their energy bills.

Expanded House Bill 2 credits would also benefit KHP and existing utility-run energy efficiency programs. Because participants have the option of applying these credits to equipment purchased through the KHP or any utility-financed program,[43] doubling the credits would likely increase participation in those programs.

Implementation Plan

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[37] *See* http://energy.ky.gov/Programs/Documents/HB2TaxCreditsTableSummary.pdf (for a summary of the energy efficiency and renewable tax credits). The full bill can be viewed at http://www.lrc.ky.gov/record/08RS/HB2/SCS1.doc

[38] House Bill 2 also sets out parallel credits for commercial efficiency, which are discussed in action item C.6 below.

[39] *See* House Bill 2, 2008 Session, KRS 141.435 to 141.437, Section 13, subsection (2)(b) (manufactured housing incentive).

[40] Memorandum entitled *ENERGY STAR home and ENERGY STAR manufactured home credits claimed for Fiscal Year ending 6/30/11* from Regina Ritchey, Supervisor, Tax Credits Section, Dept. of Revenue, to Robert Sherman, Director of LRC, November 30, 2011 ; *see also* Memorandum entitled *Energy Efficiency Products Credits claimed for Fiscal Year ending 6/30/11* from Regina Ritchey, Supervisor, Tax Credits Section, Dept. of Revenue, to Robert Sherman, Director of LRC, November 30, 2011.

[41] A similar recommendation was made in the PSC's 2008 report to the General Assembly. There, the PSC expressed support for the use of rebate or financing programs, though in the context of utility-run programs. *Supra*, n. 16, PSC Report, p. 31 (Recommendation #8).

[42] *Supra*, n. 7, Strategy #1 of Governor's Energy Strategy, p. 25.

[43] *See* http://www.kyhomeperformance.org/UtilityPartners.aspx.

Kentucky should expand these and other State-level tax incentives to encourage increased energy efficiency in the residential sector.

1. ***WHO/WHAT*** –
   a) This action item will be primarily carried out by DEDI in collaboration with the Kentucky Cabinet for Economic Development, the Office of the State Budget Director and the Department of Revenue.
   b) As necessary, DEDI will seek the feedback and assistance of representatives of and advocates for Kentucky's housing organizations and representatives of home builders and residential energy consumers.
   c) These entities will identify opportunities to expand House Bill 2 credits and other State-level incentives as applicable

2. ***ACTION STATUS*** – Action pending.

C. COMMERCIAL SECTOR RECOMMENDATIONS

Kentucky's commercial sector buildings account for 21 percent of the State's total electricity use and 17 percent of its total natural gas use.[44] As with the residential sector, the commercial sector holds significant energy savings potential for Kentucky. Nearly all of the Commonwealth's jurisdictional utilities, and TVA, offer programs with varying incentives for energy efficiency retrofits to commercial buildings. At the same time, stakeholder feedback indicates that this sector remains underserved with regard to effective efficiency programs and that more could be done to capitalize on untapped savings potential.

In addition to the vital need for education and training in the commercial sector as discussed in action item A.4 above, the following are the highest priority stakeholder recommendations to address this sector:

Near-term
- C.1. *Expand access to low-cost financing for private commercial entities*
- C.2. *Recapitalize the Kentucky Green Bank for public buildings*
- C.3. *Promote energy efficiency via a "lead by example" approach to State-owned facilities*

Long-term
- C.4. *Improve the energy efficiency of commercial buildings through consistent implementation of commercial building energy codes*
- C.5. *Devise creative incentives for commercial rental property*

Legislative Recommendation
- C.6. *Expand State energy efficiency incentives*

Near Term Recommendations (1 - 3 Years)

C.1. *Expand access to low-cost financing for private commercial entities*

Background and Stakeholder Observations

Energy efficiency retrofits for the commercial sector are cash intensive and as a result access to upfront capital is critical for success. The largest end-uses in commercial buildings are heating, cooling and lighting – representing over half of commercial site energy consumption[45] and requiring significant investments to upgrade. While KHP (action item R.1 above) and the Green Bank of Kentucky (action item C.3 below) both have revolving loan programs for, respectively, private homes and State government buildings, there is no such program to provide low-cost loans to owners of private commercial buildings. As a result, stakeholders recommended that Kentucky explore creative sources of funding for these energy users, specifically keyed to energy efficiency improvements and verified savings.

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[44] *See* DEDI's Kentucky Energy Profile 20101 available at: http://energy.ky.gov/Documents/Kentucky_Energy_Profile_2011.pdf (electricity consumption is broken down by sector at pages 8-10, 23, 29).

[45] American Council for an Energy Efficient Economy. March 2012. Technical Assistance Program: Energy Efficiency Cost-Effective Resource Assessment for Kentucky, page 7. Available at: http://energy.ky.gov/Programs/SEE%20KY/March%202012%20Meeting/KY%20Econ%20Potential%20Analysis%20-%20FINAL%20DRAFT.pdf.

Implementation Plan

1. ***WHO*** –The main challenge in implementing this action item will be identifying a funding source to capitalize the revolving loan program. A work group will be convened to address options to provide upfront energy retrofit financing for the commercial sector.
   a) DEDI will identify an agency or organization who will organize and facilitate the work group. DEDI will serve as a member of the work group and will provide support as needed.
   b) Additional work group members will be invited to participate, such as representatives from Kentucky's commercial sector which may include the Kentucky Chamber of Commerce, Commerce Lexington, Louisville Energy Alliance, Building Owners and Managers Association, Northern Kentucky Chamber of Commerce, Greater Louisville Inc. and Bluegrass ASHRAE. Given that this action item has positive implications for economic development in Kentucky, DEDI and representatives from the Cabinet for Economic Development, as well as individual commercial energy consumers where possible, will be included.

2. ***WHAT*** –
   a) Participants will review funding models and evaluate their appropriateness for Kentucky. During SEE KY's breakout and interim work group sessions, stakeholders reviewed a number of innovative approaches – both here in Kentucky and in other states – to address this financing hurdle. These approaches include:
      i. Appropriating an existing $80 million bond authorization that the General Assembly approved in 2008 as part of House Bill 2 to retrofit State and commercial buildings;[46]
      ii. The Greater Cincinnati Energy Alliance's *Building Performance Program* that uses public and private investments to offer market rate financing to upgrade commercial buildings with energy efficiency measures[47]
      iii. Pennsylvania's use of State funds to invest in low-risk energy efficiency loans to homeowners and businesses, with a rate of return for the State retirement system;[48]
      iv. Connecticut's C-PACE (Connecticut Property Assessed Clean Energy) program financing model for energy efficiency in the commercial real estate industry;[49] and
      v. On-bill financing, similar to action item R.4 for the residential sector.
   b) Representatives from Kentucky's commercial sector will determine which elements of model approaches are applicable to Kentucky and will develop specific parameters, a funding structure and data verification procedures for any resulting approach.
   c) The work group may also conduct a survey of this sector through the local business chambers, as well as interviews with utilities and individual commercial entities, to assess interest in a loan model and in energy efficiency programming in the first place.

3. ***ACTION STATUS*** – Action item not yet in process.

[46] *See* http://www.lrc.ky.gov/record/08RS/HB2/SCS1.doc (Sections 27 and 28).
[47] *See* http://www.greatercea.org/commercial; *see also* http://www.building-cincinnati.com/2012/08/energy-alliance-wins-national-award-for.html.
[48] *See* http://www.keystonehelp.com/.
[49] *See* http://www.cleanenergyfinancecenter.org/wp-content/uploads/Whitepaper_CT_PACE_Final_01-15-13.pdf

C.2. *Recapitalize the Kentucky Green Bank for public buildings*

Background and Stakeholder Observations

Access to low-cost financing for energy efficiency improvements is as critical to success in public facilities as it is in private commercial buildings. In 2009, the Kentucky Finance and Administration Cabinet (FAC) established the Green Bank of Kentucky's revolving loan fund to promote energy efficiency in State buildings.[50] The Green Bank was originally capitalized by a $14 million Recovery Act grant from DEDI and has provided low interest loans to fund energy savings performance contracts (ESPC) in State buildings. To date, all loans have been made and the bank has funded nine ESPCs representing over 50 State buildings and in excess of 2,000,000 conditioned square feet. The Green Bank will be replenished as the first set of loans is repaid over the next 10-12 years, with a new slate of funds for ESPC projects as funds accumulate. However, further recapitalization of the Green Bank is necessary to meet demand for these loans in State government.

Implementation Plan

1. ***WHO/WHAT*** – The FAC and DEDI will be responsible for carrying out all tasks necessary to implement this action item. The challenge for Kentucky is to identify ways to further capitalize the Green Bank. DEDI and the FAC will work together to determine viable methods to identify additional capital for the Green Bank.
2. ***ACTION STATUS*** – Action item not yet in process.

C.3. *Promote energy efficiency via a "lead by example" approach to State-owned facilities*

Background and Stakeholder Observations

Kentucky's investment in the Green Bank is part of a greater overall effort to promote energy efficiency via leadership by State Government. In 2008, the Governor's Energy Strategy challenged Kentucky's State agencies to establish a leadership role by focusing on improving the energy efficiency of public buildings.[51] State and local government facilities, such as government offices, schools and hospitals, represent unique opportunities for Kentucky to implement and ramp up energy efficiency practices while also saving taxpayer dollars. Focusing on energy efficiency in public buildings is also a powerful marketing tool to encourage consumers, local governments and the private sector to follow the State's example.

Kentucky State Government has provided this example in a number of ways. In the last few years, Kentucky has disbursed over $68 million in Recovery Act funding for 26 energy efficiency programs statewide.[52] Even in the post-Recovery Act era, Kentucky continues this role. EEC recently

[50] Visit http://finance.ky.gov/initiatives/greenbank/Pages/default.aspx for more information.
[51] *Supra*, n. 8, Strategy #1 of Governor's Energy Strategy, pp. 21-24.
[52] *See generally*:
http://energy.ky.gov/Pages/agri.aspx; http://energy.ky.gov/Pages/industrial.aspx; http://energy.ky.gov/Pages/Residential.aspx; http://energy.ky.gov/Pages/schoolprojects.aspx;

received US DOE funding to launch the Local Government Energy Retrofit Program (LGERP), a self-sustaining, public facilities energy retrofit program that will assist local governments in reducing energy consumption via energy savings performance contracting.[53] In addition to retrofitting existing State- and locally-owned buildings, Kentucky used a $3.65 million energy management grant from Recovery Act funds to develop the Commonwealth Energy Management and Control System, which provides several layers of information to better manage State utility bills and identify energy savings opportunities to help preserve taxpayers' dollars, to date generating about $800,000 energy savings annually.[54]

In December of 2012, several State and local entities also received DEDI grant funding.[55] Among those entities is the Department for Local Government, which was awarded $1.2 million to support continuation of the Energy Efficiency and Conservation Block Grant that provides funding to local governments for programs that reduce energy consumption, greenhouse gas emissions and utility costs for local governments. Kentucky School Boards Association was also awarded $700,000 to support the School Energy Managers Project in school districts in and adjacent to the TVA service counties. In addition, Fayette County Public Schools received an award to complete live energy monitoring at their facilities. These recent awards will provide further opportunities for State and local governments and schools to promote energy leadership for the rest of Kentucky.

Implementation Plan

Kentucky should explore these and other options to continue to provide energy efficiency leadership at the State level.

1. ***WHO*** – DEDI and FAC will be responsible for implementing this action item. DEDI will have the overall lead and other State and local agencies may be involved as necessary.

2. ***WHAT*** –
   a) State Government should aggressively pursue the requirements and goals outlined in legislation and the Governor's Energy Strategy, including improving the energy efficiency of State-supported facilities and the fleet fuel efficiency of State-owned vehicles.[56]
   b) DEDI will be responsible for finding new opportunities that will increase the adoption of energy efficiency into Kentucky's economy, including financing opportunities such as the Green Bank and LGERP.
   c) Successful implementation of this action item may also require State budget appropriation. Thus, the project team may address legislative approaches in upcoming legislative sessions.

3. ***ACTION STATUS*** – Action item in process, ongoing.

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http://energy.ky.gov/StimulusPrograms/Pages/Utilities.aspx;
http://energy.ky.gov/Pages/StateGovernmentBuildings.aspx;
See also, Energy and Environment Cabinet, 2011 Annual Summary, available at:
http://energy.ky.gov/resources/Annual%20Summaries/annual%20summary%20without%20calendar%203-8-12.pdf
(report re Recovery Act projects at page 10).

53 *See* http://migration.kentucky.gov/Newsroom/governor/20120709energyassistancegrant.htm.

54 *See* http://kyenergydashboard.ky.gov/.

55 *Supra*, n. 33.

56 *Supra*, n. 7, Strategy #1 of Governor's Energy Plan, pp. 23-24.

Long Term Recommendations (3-4 Years)

C.4. *Improve the energy efficiency of commercial buildings through consistent implementation of commercial building energy codes*

Background and Stakeholder Observations

Similar to the residential sector, another vital element of improving Kentucky's commercial building stock is ensuring that commercial building energy codes are in compliance statewide. The Commonwealth's commercial building energy codes were last updated in March of 2011, and compliance was effective the following June. The DHBC performs full energy code plan review and on-site inspections for all commercial buildings. However, because of the mosaic of jurisdictions for permitting, plan reviews, and inspections performed at the local level, there are varying levels of compliance activities across the State.

Implementation Plan

The DHBC and DEDI will seek additional resources for statewide inspection of commercial building components.

1. ***WHO*** –
    a) The lead for this action item has yet to be determined, and will be primarily carried out by a work group, with support from DHBC and DEDI.
    b) As necessary, the work group will seek the feedback and assistance of representatives of and advocates for Kentucky's commercial building sector and local code jurisdictions.
    c) The work group will collaborate with the Kentucky Association of Counties, Kentucky League of Cities and utilities to evaluate and quantify how utilities can participate in and benefit from funding commercial building energy code activities in each utility service territory.

2. ***WHAT*** –
    a) The work group, including DEDI, DHBC and commercial building stakeholders, will identify opportunities to expand statewide energy codes compliance capacity, and to identify additional funding sources for inspectors and plan reviews.
    b) Supplementary energy code activities will also be evaluated, including: providing ongoing training and/or continuing education credits to inspectors, builders, and contractors; holding regional information sessions on current codes and updates; funding compliance surveys for new buildings.
    c) DHBC and DEDI will explore potential ongoing commercial building energy code collaboratives.
    d) DEDI will also collaborate with DHBC and utilities to evaluate potential for partnerships to improve energy code compliance capacity.

ACTION STATUS – Action item in process, ongoing.

C.5. *Devise creative incentives for commercial rental property*

Background and Stakeholder Observations

As with Kentucky's residential rental units, incenting commercial energy efficiency retrofits is difficult because commercial owners have little incentive to invest in energy efficiency retrofits where tenants pay the energy bills. As a result, stakeholders would like to create a mechanism to incent landlords to make commercial property more efficient, while providing the benefit of lower energy bills to tenants.

Implementation Plan

1. ***WHO*** – Creative options for addressing inefficient commercial rental property will be explored via a work group.
   a) DEDI will identify an agency or organization who will organize and facilitate the work group. DEDI will serve as a member of the work group and will provide support as needed.
   b) Representatives of and advocates for Kentucky's commercial ratepayers, including those representing landlords and tenants, will be participants in the work group. DEDI will participate and provide support as needed.

2. ***WHAT*** –
   c) Kentucky will explore programs or policies that reduce the split incentive inherent in making commercial rental property more efficient.
   d) Participants will review existing programs and models in other states.
   e) Work group participants will be responsible for determining whether models in other states may be applicable to Kentucky, as well as the parameters for any resulting Kentucky-specific approach. Incentive funding options will be reviewed, including allocations from utility-run DSM program budgets, state budgets and federal funding.

3. ***ACTION STATUS*** – Action item not yet in process.

Legislative Recommendations (2013/2014 Sessions)

C.6. *Expand State energy efficiency incentives*

Background and Stakeholder Observations

In addition to credits aimed at the residential housing sector, House Bill 2 (2008 Regular Session) also provides credits to reduce up-front energy efficiency costs for commercial businesses.[57] Each incentive is capped at $500 and covers equipment such as energy-efficient interior lighting systems, HVAC and hot water mechanical systems. While these current tax credits have been useful, only 16

[57] *See* http://energy.ky.gov/Programs/Documents/HB2TaxCreditsTableSummary.pdf (summary of HB2 energy efficiency and renewable tax credits). The full bill can be viewed at http://www.lrc.ky.gov/record/08RS/HB2/SCS1.doc.

were claimed by Kentucky's commercial entities in fiscal year 2011 – which has not significantly stimulated the commercial energy efficiency market.[58]

Similar to House Bill 2's residential credits, therefore, stakeholders recommend an expansion of commercial credits. This is particularly vital for commercial entities, given stakeholder feedback indicating that the commercial sector is under-served with regard to energy efficiency programs and financing.

Implementation Plan

Kentucky should expand this and other State-level tax incentives to encourage increased energy efficiency in the commercial sector.

1. ***WHO/WHAT*** –
   a) This action item will be primarily carried out by DEDI in collaboration with the Kentucky Cabinet for Economic Development and the Office of the State Budget Director.
   b) DEDI will seek the feedback and assistance of representatives of and advocates for Kentucky's commercial entities, where possible, in identifying opportunities to expand House Bill 2 credits and other State-level incentives.

2. ***ACTION STATUS*** – Action is pending.

[58] Memorandum entitled *Energy Efficiency Products Credits claimed for Fiscal Year ending 6/30/11* from Regina Ritchey, Supervisor, Tax Credits Section, Dept. of Revenue, to Robert Sherman, Director of LRC, November 30, 2011.

I. INDUSTRIAL SECTOR RECOMMENDATIONS

Similar to the commercial sector, stakeholder feedback indicates that Kentucky's industrial community is underserved with respect to energy efficiency programs and services. While the DSM Statute empowers the utilities to use residential and commercial ratepayer dollars to fund efficiency programs, no such dollars exist for the lion's share of industrial customers. As noted above, the DSM Statute allows Kentucky's industries to opt out from contributing to the ratepayer-funded DSM pool.[59] Consequently, there are no dollars to draw from and, as a result, most utilities do not offer programs to this sector. Currently, there is little support among Kentucky's large industries to change the opt-out provisions. EKPC, TVA and Big Rivers offer industrial efficiency programs, because they build the programs into their base rate, with no surcharge. Duke, which has a relatively low industrial load, recently launched a program (approved under the DSM Statute) providing incentives for their small commercial and industrial customers to install high-efficiency equipment.[60]

Given the large percentage of industrial energy usage in Kentucky, the industrial sector offers huge opportunities for energy efficiency programming. Manufacturing is the largest sector in Kentucky's economy, in 2010 accounting for 18 percent of the Gross State Product,[61] nearly half of its electricity use and nearly half of its natural gas use.[62] This sector also faces mounting pressures with increasing energy rates and environmental compliance costs. Energy efficiency is one way to reduce these pressures: it will render Kentucky's manufacturers more competitive; allow them to retain their workforce; increase productivity; and assure that these industries remain in the State and thus continue to contribute to the economy. Thus, while several barriers exist, addressing this sector is critical to reducing overall energy use in Kentucky and realizing statewide goals.

The challenge for Kentucky is to look beyond traditional funding structures to encourage industry to invest in efficiency, while exploring the underlying statutory barriers that prevent comprehensive efficiency programs from becoming a reality. The action items discussed below begin to address this challenge and recommend the following:

Near-term

I.1. ***Establish a revolving loan fund for industrial energy efficiency improvements***

I.2. ***Convene a work group to discuss the application of the DSM Statute's opt-out provision***

Long-term

I.3. ***Encourage Kentucky's industries to voluntarily share energy efficiency performance data and best practices***

Legislative Recommendation

I.4. ***Modify existing State-level incentives to encourage investment in energy efficiency***

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59 *See* KRS 278.285(3).

60 See psc.ky.gov/order_vault/Orders.../201200495_04112013.pdf.

61 Economy.com 2012

62 *See* DEDI's Kentucky Energy Profile 2012 available at: http://energy.ky.gov/Documents/Kentucky_Energy_Profile_2012.pdf (electricity consumption is broken down by sector at pages 8-10, 23, 29). In a national context, the industrial sector's significance in the consumption of electricity is much greater in Kentucky than in most other states. An average national electricity portfolio apportions just 25 percent of total electricity use to the industrial sector, compared with nearly 50 percent in Kentucky.

Near Term Recommendations (1 - 3 Years)

I.1. *Establish a revolving loan fund for industrial energy efficiency improvements*

Background and Stakeholder Observations

Similar to the commercial and residential sectors, access to upfront capitol is one of the key factors crucial for successful energy efficiency investment in Kentucky's industrial sector. Stakeholders have stressed this fact throughout the SEE KY process and indicate that in the absence of utility-run programs, low interest loans will be necessary for industries to make significant strides in energy efficiency.

Implementation Plan

1. ***WHO*** – This action item will be carried out via a work group organized by representatives of and advocates for Kentucky's industries, which could include the Kentucky Association of Manufacturers, Kentucky Chamber of Commerce, Commerce Lexington, Northern Kentucky Chamber of Commerce, Greater Louisville Inc. and the Kentucky Pollution Prevention Center. Given that this action item has positive implications for economic development in Kentucky, representatives of the Cabinet for Economic Development and individual industries will be included, where possible.

2. ***WHAT*** –
   a) The main challenge in implementing this action item will be to identify sources of initial funding for a revolving loan program. During SEE KY's breakout and interim work group sessions, stakeholders reviewed a number of innovative approaches in other states to addressing this financing hurdle, including those described in action item C.1 above. Kentucky should explore these and other options to provide upfront funding for energy efficiency retrofits.
   b) Representatives from Kentucky's industries will determine which elements of model approaches are applicable for Kentucky and will develop specific parameters, funding structure and data verification procedures for any resulting approach.
   c) As necessary, this industrial work group will coordinate with the parallel work group for the commercial sector identified in action item C.1. Similar funding sources and/or approaches may be identified and the work groups may involve some of the same participants.
   d) The work group may also conduct a survey of this sector through the local business chambers, as well as interviews with utilities and individual industries, to assess interest in a revolving loan model and in energy efficiency programming in the first place.
   e) Successful implementation of this action item may require complimentary legislation, or State budget appropriation.

3. ***ACTION STATUS*** – Action item not yet in process.

I.2. *Convene a work group to discuss the application of the DSM Statute's opt-out provision*

Background and Stakeholder Observations

As noted previously, while many stakeholders agree that there is great potential for reducing industrial energy use in Kentucky, the DSM Statute contains an opt-out provision that prevents utilities from establishing comprehensive efficiency programs for this sector. There is little support among Kentucky's large energy-using industries (typically considered "5 MW or above" manufacturers) to change the opt-out provision. Larger manufacturers tend to already have staff and resources available to initiate energy efficiency efforts and thus do not feel they would benefit from utility-run programs. At the same time, stakeholders acknowledge that smaller manufacturers (typically considered below the "5 MW" energy use category) often need additional technical support and would benefit from coordinated programs.

The SEE KY process is not the first time this dichotomy has arisen. Similar observations were made in the PSC's 2008 report to the Kentucky General Assembly.[63] The report suggested that rules governing industrial customer exclusion from the DSM Statute be clarified, standardized and uniformly applied. This recommendation was based in part on feedback received from participating utilities, industrial representatives, the Office of the Attorney General, and environmental advocates, indicating support for a self-certification element to the opt-out provision (i.e., that industrial customers who seek to opt out of the DSM Statute make a showing of their own energy efficiency efforts before they are allowed an exemption).

Implementation Plan

Given the wealth of diverse – and often conflicting – feedback received on this issue during the SEE KY process, a work group composed of a cross section of energy stakeholders will be developed to explore how Kentucky can continue to meet the needs of its industries while providing equitable solutions for all rate classes.

1. ***WHO*** –
   a) This action item will be carried out by a work group organized in collaboration with representatives from the following:
      i. Kentucky's industrial representatives, including the Kentucky Association of Manufacturers, Kentucky Industrial Utility Customers, Kentucky Chamber of Commerce, Commerce Lexington, Northern Kentucky Chamber of Commerce, Greater Louisville Inc. and the Kentucky Pollution Prevention Center. DEDI will also participate to assist and support the work group.
      ii. Individual industries, where possible;
      iii. Jurisdictional utilities that participate in the DSM Statute, including LG&E, AEP and Duke Kentucky;
      iv. Environmental organizations;
      v. The Office of the Attorney General; and
      vi. The PSC.

[63] *Supra*, n. 16, PSC's 2008 report to the General Assembly (Recommendation No. 5).

2. ***WHAT*** –
   a) Work group participants will review the opt-out provision, as well as the PSC's parallel 2008 report, and make recommendations on the provision.
   b) A facilitator from among the participants will be selected by the participants and a schedule and scope of work will be developed through collaboration.

3. ***ACTION STATUS*** – Action item not yet in process.

Long Term Recommendations (3-4 Years)

I.3. *Encourage Kentucky's industries to voluntarily share energy efficiency performance data and best practices*

Background and Stakeholder Observations

As noted previously, tracking energy efficiency gains in each of Kentucky's rate classes is essential to evaluating progress towards the State's energy efficiency goals. This is particularly important for the industrial sector, given that it is the largest consumer of Kentucky's energy resources.[64] This sector is unique among Kentucky's rate classes, however, because little is known statewide about industrial energy efficiency performance. While the utilities collect ample performance data on residential and commercial programs (and will begin voluntarily reporting this data to DEDI in 2013), the industrial sector's ability to opt out from the DSM Statute means that many utilities lack parallel performance data for their industrial customers. Industrial data is collected in a limited manner in conjunction with EKPC and TVA's industrial programs, but not enough to paint an accurate picture statewide. Energy efficiency service entities and universities, such as the Kentucky Pollution Prevention Center, collect performance data on industrial clients, but this is not similarly scalable to the State as a whole.

Stakeholders are concerned that this lack of data leaves most of Kentucky's efficiency efforts unaccounted for. Thus, in measuring progress toward statewide savings goals, DEDI will be unable to accurately estimate energy savings attributable to industry.

Implementation Plan

Given overwhelming stakeholder feedback rejecting mandatory measures, DEDI will work to establish a voluntary reporting mechanism to collect data from industries on energy efficiency performance and best practices. This effort will be complimentary to the utilities' voluntary reporting efforts described in action item A.1.

1. ***WHO*** – This action item will be carried out primarily by DEDI, in collaboration with representatives of industries and entities providing technical support to the industrial sector. Similar to the project team's plan for implementing the utility reporting mechanism, DEDI will act as the organizer and repository of the data.

2. ***WHAT*** – A multi-pronged approach will be developed to collect performance data for this industry. DEDI will:

[64] *Supra*, n. 70.

a) Collect annual data from each participating utility that runs industrial programs, through the voluntary reporting mechanism outlined in action item A.1 above. A summary table of each utility's current level of commitment to voluntarily submit data, including rate classes and reporting due dates, is attached to this Action Plan as *Appendix D*.
b) Work with industry representatives and manufacturers on an individual basis to gather data.
c) Leverage other action items included in this Action Plan, such as the revolving loan fund for industrials recommended in action item I.1 above and the expanded State-level incentives in action item I.4 below, to collect data from industries that participate in those funding opportunities.
d) Request that entities providing grants and technical assistance to Kentucky's industries provide anonymous performance data for participating industries.
e) Use these metrics to estimate progress on an annual basis towards the Governor's energy goal, as it applies to the industrial sector. While this calculation will not be representative of savings across the sector, DEDI anticipates that it will, in time, improve as the pool of participating industry grows. Collection of data adequate to calculate progress will depend on the level of voluntary participation by Kentucky's industries and the other entities outlined above.
f) Assess whether a third party entity is more appropriate to manage industrial data, given confidentiality or trade secret concerns that may be implicated.

3. ***ACTION STATUS*** – Action item not yet in process. Specific timeframes for utility data reporting are set out in *Appendix D*.

Legislative Recommendations (2013/2014 Sessions)

I.4. *Modify existing State-level incentives to encourage investment in energy efficiency*

Background and Stakeholder Observations

As noted above, very few utilities in Kentucky offer energy efficiency programs to their industrial customers and there are even fewer incentives available at the State level. Given that utility-sponsored industrial programs are unlikely to increase in the short term, stakeholders in the SEE KY process suggest that Kentucky focus on expanding current State-level financial incentives. This approach will benefit Kentucky's industries several ways: through reduced energy bills; increased competitiveness at the national and local level; and retention of a highly skilled and paid workforce that often provides the economic backbone for entire communities. There is also great potential for small and medium industries in particular to benefit from State-level incentives, since they tend to have far more limited internal resources to invest in efficiency, coupled with heavy competition for whatever capital dollars do exist. Stakeholders indicate that increasing access to State-level incentives will also mean quicker cost recovery – a factor that often determines whether efficiency projects will be carried out in the first place.

Implementation Plan

The Kentucky Reinvestment Act (KRA) currently provides tax credits and partial reimbursement of investment dollars to Kentucky's manufacturers that incur at least $2.5 million in capital costs and that maintain at least 85 percent employment of their workforce. Stakeholders have suggested carving out a separate and distinct incentive tier in the KRA that lowers this investment threshold, applicable only to energy efficiency investments. This separate tier would be directed at small to medium size industries that were previously ineligible for the KRA because they were unable to meet the original expenditure requirement.

Kentucky should explore this and other options to expand State-level tax incentives to encourage increased energy efficiency in the industrial sector.

1. ***WHO* / WHAT** –
   a) DEDI will primarily carry out this action item in collaboration with the Kentucky Cabinet for Economic Development and the Office of the State Budget Director.
   b) As necessary, DEDI will seek the feedback and assistance of representatives of and advocates for Kentucky's industries to identify opportunities to expand the KRA and other State-level incentives as applicable.

2. ***ACTION STATUS*** – Revisions to the KRA are pending.

F. RECOMMENDATIONS AT THE FEDERAL LEVEL

The remaining action items in this Plan were derived from stakeholder feedback concerning energy efficiency matters over which the federal government has primary control. Thus, none of the stakeholders involved in SEE KY can directly implement actions related to these recommendations. Instead, DEDI requests that U.S. DOE and other appropriate federal agencies consider these action items as essential to furthering energy efficiency efforts in Kentucky. If addressed, they may also benefit efforts in other states to develop comprehensive energy efficiency program and policy suites.

Recommendations

Stakeholders during the SEE KY process provided feedback on energy efficiency issues related to FEMA's post-disaster rebuilding approach, as well as to how funds are apportioned via LIHEAP.

F.1. ***USDOE should work with US DHS to evaluate how FEMA funds are provided for home rebuilding or replacement in the wake of natural disasters, and consider requiring that new structures be built better than code (e.g. ENERGY STAR).***

Several participants in the SEE KY residential working groups and breakout sessions have witnessed post-disaster rebuilding efforts in Kentucky and are concerned that FEMA could do more to use disaster assistance to leverage energy efficiency to the benefit of the disaster victims.

F.2. ***US DOE should take a lead role in working with US DHHS to enhance the delivery of energy efficiency and conservation solutions to citizens served by LIHEAP and Weatherization programs.***

Participants in the residential working groups were also concerned that LIHEAP provides a disincentive for homeowners to invest in energy efficiency upgrades and thus allows inefficient dwellings to perpetuate. The US DOE needs take a fresh look at how these services are provided and consider if the current model is appropriate, ideally with the assistance of the United States Department of Health and Human Services (US DHHS). As currently delivered, at least in some states, the resources are segregated in separate silos, preventing the optimal delivery of services.

F.3. ***US DOE should assume a lead role in working with other federal agencies (USDA, HUD, EPA) that offer federal infrastructure programs and grants for cities and states to set energy efficiency standards as a condition of awards.***

Stakeholders also commented that when any federal funding supports the construction of new or replacement buildings they should be built to a higher energy efficiency standard. Buildings and construction programs supported by the US Department of Agriculture (USDA), HUD and the US Environmental Protection Agency (EPA) would be priority candidates for establishing such standards.

F.4. *US DOE should coordinate with HUD to improve energy efficiency standards for manufactured homes that are appropriate for various climate zones.*

Given the serious energy inefficiency and high utility costs associated with manufactured homes across the nation, as discussed in action item R.6, HUD should review the manufactured housing codes. The problem in rural Kentucky is exacerbated by manufactured housing equipped with resistance heating units. While resistance heating is code-compliant, low income homeowners typically cannot afford the associated high electric bills in cold winters. In fact, several utilities in Kentucky offer incentives to replace these heating systems, to both reduce peak demands and ease the burden of high bills for manufactured housing residents. This issue is ripe for HUD's review. Manufactured housing codes that consider more efficient heating systems, while also accounting for the effects in different climate zones, would be a first step in addressing high energy bills in the low income sector.

APPENDIX A - COMPLETE LIST OF SEE KY STAKEHOLDER PARTICIPANTS

Note: *This list identifies organizations, and their representatives, that participated in one or more phases of the SEE KY project's stakeholder series. It includes participants who provided both formal and informal feedback during one-on-one and/or small group meetings that took place from February through November 2011, as well as attendees at any of the three meetings held in the collaborative series from December 2011 through July 2012.*

UTILITIES AND ASSOCIATIONS	REPRESENTATIVE(S)
Atmos Energy	Len Matheny
Big Rivers Electric Corporation	Roger Hickman, Russ Pogue
Big Sandy Rural Electric Cooperative	David Estepp, Jeff Prater
Blue Grass Energy	Roy Honican, Mike Williams, Barry Drury
Columbia Gas	Herb Miller, Judy Cooper
Duke Energy Kentucky	Trisha Haemmerle, Kevin Bright, Tasha Davis
East Kentucky Power Cooperative	Jeff Hohman, Scott Drake
Farmers Rural Electric Cooperative Corporation	Bill Prather, Chuck Bishop
Frankfort Plant Board	Jim Carter
Jackson Purchase Energy Corp.	Izell White
Kenergy	David Hamilton
Kentucky Association of Electric Cooperatives	Dennis Cannon
Kentucky Municipal Utility Association	Annette Dupont-Ewing
Kentucky Power / American Electric Power	Ranie Wohnhas, E.J. Clayton
Louisville Gas & Electric / Kentucky Utilities	David Huff, Michael Hornung, Rick Lovekamp, Chuck Schram, Lonnie E. Bellar
Meade County Rural Electric Cooperative	Tim Gossett
Owen Electric Cooperative	Mark Stallons, Mike Cobb
Owensboro Municipal Utilities	Sonya Dixon
Tennessee Valley Authority	Carl Seigenthaler, Tim Hughes, Sara Davasher, Frank Rapley, Bryan Moneymaker, Brent Powell

HOUSING ORGANIZATIONS/ASSOCIATIONS	REPRESENTATIVE(S)
Bluegrass ASHRAE	Grant Page
Federation of Appalachian Housing Enterprises	Vonda Pynter
Frontier Housing	Josh Trent, Sherry Farley
Kentucky Habitat for Humanity	Mary Shearer, Ginger Watkins
Kentucky Homebuilders Association	Bob Weiss, Laurent Rawlings
Kentucky Housing Corporation	Rick McQuady, Rick Boggs, Andrew Isaacs
Kentucky Manufactured Housing Institute	Betty Whittaker, Erica Klimchak
Next Step	Stacey Epperson, Kelley Hancock
US Green Building Council, KY Chapter	Grant Page, Paul Kaplan

INDUSTRY, COMMERCIAL ENTITIES, AND ASSOCIATIONS	REPRESENTATIVE(S)
Arkema, Calvert City Plant	Dwight Stoffel
Big Ass Fans	Christian Tabler
Century Aluminum	David Whitmore, Ryan Neel
C.I.Agent Solutions	Tom Downs
Commerce Lexington, Inc.	Tyler Campbell, Gina Greathouse
Distillers' Association	Eric Gregory
Dow Chemical	Jana Zigrye
General Electric	Leanne Monsove, Earl Jones
Greater Louisville, Inc.	Carmen Hickerson, Tim Corrigan
Kentucky Association of Manufacturers	Greg Higdon
Kentucky Chamber	Chad Harpole
Kentucky Corn Growers' Association / Small Grain Growers' Association	Laura Knoth
Kentucky Farm Bureau	Brian Alvey
Kentucky Industrial Utility Customers	David Boehm
Kentucky Retail Federation	Gay Dwyer
KROGER Engineering and Maintenance Services	Bryan Handy
Lexmark	Paul Ackerman
Link-Belt Lexington	Paul Zink, James Bowman, Bob Jones
Logan Aluminum	Russ Hendrick
NACCO Materials Handling Group	Rodney Wilson
National Federation of Independent Business	Tom Underwood
Northern Kentucky Chamber of Commerce	Steve Stevens
Owl Inc.	Martin Slicemaker
Rio Tinto Alcan	Pam Schneider, David Whitmore
SECAT	Denis Ray
SemiCon Associates	Roger Leet
Sustainable Business Ventures	Bobby Clark
Toyota Motor Manufacturing, Kentucky	David Absher
Zeon Chemicals	Tom Herman

ADVOCATES	REPRESENTATIVE(S)
Office of the Attorney General	Jennifer Hans, Dennis Howard, Larry Cook
KY Conservation Committee	Art Williams
Community Action Kentucky	Rob Jones, Michael Moynahan
Goodwill Industries of Kentucky	Roland Blahnik
Greater Cincinnati Energy Alliance	Chris, Jones, Jeremy Faust
Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties	Jack Burch, Charlie Lanter
Kentuckians for the Commonwealth	Steve Wilkins
KY Green Party	Geoff Young
Mountain Association for Community Economic Development	Peter Hille, Kristin Tracz
Sierra Club	Rick Clewett, Wallace McMullen, Susan Lambert

EDUCATIONAL/RESEARCH INSTITUTIONS AND ASSOCIATIONS	REPRESENTATIVE(S)
Kentucky Community & Technical College System	Billie Hardin
Kentucky School Boards Association	Ron Willhite
University of Louisville's Kentucky Pollution Prevention Center	Cam Metcalf, Richard Meisenhelder, Lissa McCracken

STATE AND LOCAL GOVERNMENT AGENCIES/CABINETS/ ASSOCIATIONS	REPRESENTATIVE(S)
Cabinet for Economic Development	Holland Spade, Tim Back
Dept. of Housing, Buildings and Construction	Comm. Ambrose Wilson
Kentucky League of Cities	Joe Ewalt
Kentucky Public Service Commission	Comm. Linda Breathitt, Comm. Jim Gardner, Jeff DeRouen, Aaron Greenwell, John Rogness, Gretchen Gillig, Talina Matthews
Lexington Downtown Development Authority	Jeff Fugate
Lexington-Fayette Urban County Government	Susan Bush, James Bush, Tom Webb
Lieutenant Governor's Office	Madeline Abramson
Louisville Department of Public Works and Assets	Christy Dooley
Louisville Metro Economic Growth & Innovation	Maria Koetter
Pikeville, Economic Development and Energy Projects	Charles Carlton

LEGISLATIVE	REPRESENTATIVE(S)
Legislative Research Council	D. Todd Littlefield, Sarah Kidder
Kentucky House of Representatives	Rep. Rocky Adkins, Chief of Staff Tom Dorman Rep. Leslie Combs Rep. Jim Gooch Rep. Keith Hall
Kentucky State Senate	Senator Brandon Smith

APPENDIX B – OVERVIEW OF THE SEE KY STAKEHOLDER PROCESS

ONE-ON-ONE MEETINGS, FEBRUARY TO OCTOBER 2011

The first part of SEE KY's stakeholder engagement process focused on identifying and building relationships with stakeholders interested in energy efficiency issues across the Commonwealth. Between February and October 2011, DEDI and MEEA held individual meetings across Kentucky to evaluate the efficacy of current efficiency efforts, as well as to determine where the opportunities for improvement lie and what barriers exist. SMG was a vital member of the project team during this phase, as they provided local knowledge of the energy landscape and introductions to stakeholders who were essential to the process.

The early portion of the stakeholder process focused on representatives of utilities, manufacturers and industry, commercial energy consumers, local business chambers and trade organizations, housing associations, agriculture, the advocacy community, the Office of the Attorney General, the PSC and members of the Kentucky General Assembly. A complete list of stakeholder participants is attached to this Action Plan as *Appendix A*. Each individual and organizational stakeholder had their own perspective on energy efficiency, which added great value to the collaborative process. Not everyone agreed on every issue, but there was overwhelming consensus that efficiency has an important role in Kentucky's energy future.

THE COLLABORATIVE MEETING SERIES, DECEMBER 2011 TO JULY 2012

While individual meetings with stakeholders continue intermittently through the present day, by December of 2011 the project team largely wrapped up the one-on-one meeting phase and launched a three-meeting series of collaborative sessions. The goal of this series was to finalize the program and policy recommendations that are now included in this Action Plan. In organizing content and messaging, a list of "key findings" was compiled, consisting of stakeholder feedback gathered over the previous 10 months. During the series, the stakeholders worked through each key finding in a collaborative format, eventually crafting actionable recommendations to propel Kentucky towards achieving its energy efficiency goals. Work groups were also convened between Meetings 1 and 2, to move more complex issues down the road prior to each collaborative session.

A summary of the key issues discussed with stakeholders in the collaborative sessions is provided below, as well as the evolution of these issues throughout the process. Some recommendations initially made during the one-on-one meetings were later rejected in the collaborative sessions, while still others were added and eventually evolved into action items.

Collaborative Meeting 1

The first meeting of the collaborative series (Meeting 1) was held on December 2nd, 2011, during which approximately 70 stakeholders participated. During the morning session, the project team provided context on the energy efficiency regulatory scheme in Kentucky, as well as an overview of current utility and State-run efficiency programs. The project team then presented the list of key findings gathered from the one-on-one meeting phase, followed by a breakout series focusing on residential issues, industrial efficiency and the DSM Statute. The day also included remarks from representatives of Toyota Motor Manufacturing Kentucky, the Arkansas Public Service Commission and the Regulatory Assistance Project's Director of US Programs. Minutes from Meeting 1 and a list of participants are available on the DEDI website at http://energy.ky.gov/Programs/Pages/InterimGroups.aspx.

While stakeholders provided many diverse opinions during this session, there was surprisingly consistent feedback on a number of issues relating to energy efficiency:

- **First**, in regard to the *residential sector*, stakeholders largely agreed that improving Kentucky's housing stock should be a main focus of efficiency efforts moving forward. Barriers to this currently include inconsistent compliance with the housing code, the difficulty in effectively reaching consumers, the challenges in offering incentives to improve rental property where landlords do not pay the energy bill, and the significant stock of energy inefficient manufactured homes in Kentucky.
- **Second**, in regard to *Kentucky's DSM Statute*, the majorities of investor-owned utilities – both gas and electric – believe that the statute, as written, is favorable to their customers and would like to see the current language preserved.
- **Third**, stakeholder feedback revealed that the DSM Statute allows KY's *industrials* to opt out from participating in industrial energy efficiency programs and, as a result, the investor-owned utilities do not offer programs for this sector. At the same time, there is little support in the industrial and manufacturing community to change the opt–out provision.
- **Fourth**, in discussing *energy efficiency savings goals* the majority of participants did not favor a legislated Energy Efficiency Resource Standard. Instead, there was support for statewide voluntary goals, such as those articulated in the Governor's Energy Strategy and the SEE KY initiative's one percent voluntary savings goal, rather than mandated standards.

Work groups were also convened following Meeting 1 (called "Interim Sessions"), to discuss regulatory process improvement (particularly the DSM Statute program approval process), industrial and commercial efficiency issues and opportunities for more effective residential and low income energy efficiency programs. Minutes from the Interim Sessions and a list of participants are available on the DEDI website at http://energy.ky.gov/Programs/Pages/InterimGroups.aspx.

Collaborative Meeting 2

The second meeting of the collaborative series (Meeting 2) was held on March 22, 2012 and involved many of the same stakeholders present at Meeting 1. The main objectives of Meeting 2 were to take the basic concepts introduced at Meeting 1 and incorporate more discussion of best practices from surrounding states. The project team framed these best practices as potential strategies that could be tailored to Kentucky's unique energy landscape. As a result of participant feedback following Meeting 1, the project team also organized Meeting 2 to focus primarily on small breakout sessions, including a set of three sessions in the morning and a complimentary set in the afternoon. The project team also included a mid-afternoon session to provide stakeholders with varying perspectives on the future of energy efficiency in Kentucky, including representatives from the PSC, the Office of the Attorney General and the Kentucky Association of Manufacturers. Minutes from Meeting 2 and a list of participants are available on the DEDI website at http://energy.ky.gov/Programs/Pages/SEE-KY.aspx.

The project team received a wealth of feedback during Meeting 2's breakout-heavy sessions, yet several common themes emerged:

- **First**, in regard to *measuring progress toward the statewide goals* in the Governor's Energy Strategy, the project team had learned over the stakeholder process that the DSM Statute does not dictate any particular requirements for reporting performance data from utility-run energy efficiency programs. Access to basic annualized performance data from each utility in Kentucky is essential for DEDI to measure progress towards both the Governor's and the SEE KY initiative's efficiency goals. This issue was discussed during breakout sessions at Meeting 2, though stakeholders did not initially reach consensus on how it could be resolved. The project team's approach has evolved recently, as several Kentucky utilities have agreed to voluntarily provide performance data to DEDI on an annual basis.

- **Second**, there was general consensus that *large industrial consumers* tend to have enough expertise and capital to implement efficiency on their own, whereas *smaller to medium industries* could benefit from utility-run DSM programs, both from an incentive and technical expertise standpoint.
- **Third**, stakeholders expressed widespread concern that the *commercial sector* is under-served with regard to effective energy efficiency programs. Some of the many suggestions for rectifying this included more robust education and marketing programs for this sector, increasing financial incentives and funding opportunities, improving Kentucky's commercial building stock and consistent implementation of the commercial building code.
- **Fourth**, in the *residential sector* stakeholders agreed that there is vital need for more education and marketing programs, segmented by income levels. In addition, focus was placed on efficiency programs aimed at *improving the residential housing* stock at all income levels. There was also desire among a proportion of stakeholders to further innovative funding programs, such as on-bill financing, in Kentucky's middle and low income communities.

Rather than hold Interim Sessions following up on each of the breakout sessions in Meeting 2, after this meeting the project team took a more pragmatic approach and picked a few distinct issues to delve deeply into before returning for the third and final meeting of the collaborative series. DEDI and MEEA reviewed the findings and stakeholder feedback gathered from Meetings 1 and 2, and prioritized a list of potential action items. The project team then opted to focus their efforts on the data collection issue. Between April and July of 2012, the project team worked with utilities to devise a data reporting system that will enable DEDI to measure progress toward statewide savings goals – which has never before been done in Kentucky.

Collaborative Meeting 3

The final meeting of this collaborative series (Meeting 3) was held on July 31, 2012 and was attended by a record number of stakeholders. Minutes from Meeting 3 and a list of participants are available on the DEDI website at http://energy.ky.gov/Programs/Pages/SEE-KY.aspx. The goal of Meeting 3 was to provide a forum to discuss the action items that resulted from over a year of stakeholder feedback and collaborative meetings. The project team focused on articulating how the action items, and the Action Plan as a whole, were tailored to reflect the issues that stakeholders felt were most feasible to achieve the Governor's energy efficiency goals and to position Kentucky as a leader in energy efficiency in the national arena. Meeting 3 also featured remarks from newly-appointed Commissioner to the Kentucky PSC, Linda Breathitt, and a preview of each main policy and program option included in the Action Plan.

Stakeholders were encouraged to continue to provide feedback on the action items through the fall and to review the Action Plan in detail prior to its official release. Please note that a new version will be released regularly to reflect evolving action items, timelines and approaches. The stakeholders listed in *Appendix A* will be asked to continue to participate in small work groups and provide other feedback throughout implementation and evolution of the Action Plan.

APPENDIX C – REFERENCE DOCUMENTS USED IN THE STAKEHOLDER PROCESS

ACEEE TECHNICAL ASSISTANCE AND ANALYSES

Over the course of its involvement in the SEE KY process, ACEEE produced a series of resource guides for national models and local analyses as a technical accompaniment to the stakeholder process. In collaboration with DEDI, ACEEE released four reports intended to educate stakeholders and provide context on Kentucky's energy landscape, efficiency potential and current savings, and applicable elements of best practice approaches in other states. These reports are posted on the DEDI website for reference at http://energy.ky.gov/Programs/Pages/SEE-KY.aspx. DEDI briefed stakeholders and facilitated questions and answers on the reports during Meeting 2.

Report #1, entitled *Kentucky Electricity and Natural Gas Price and Consumption*,[65] models the expected increase in electricity prices and consumption in the residential, commercial and industrial classes through 2030.

Report #2, entitled *Energy Efficiency Cost-Effective Resource Assessment for Kentucky*,[66] provides the maximum, "best case scenario" energy savings that could be achieved through energy efficiency in each of Kentucky's main rate classes through 2030.

Report #3, entitled *Assessment of Utility Program Portfolios,*[67] surveyed utility-run energy efficiency portfolios in ten states (Arkansas, Georgia, Illinois, Indiana, Iowa, Michigan, North Carolina, Ohio, Pennsylvania and Tennessee) and provided the corresponding energy savings realized where available.

Report #4, entitled *Assessment of Utility Program Portfolios in Kentucky,*[68] analyzed the performance of a select set of Kentucky's existing utility-run energy efficiency programs, evaluated their effectiveness and compared them to other states' programs. The analysis included a review of program savings and costs for programs offered by Duke, AEP, LG&E and TVA in the 2008 - 2010 program years.

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[65] Full document available at: http://energy.ky.gov/Programs/SEE%20KY/Dec%202,%202011%20Meeting/ACEEE%20Price-Consumptin%20Forcast%208_09_11_B.pdf (last visited November 6, 2012). Fact Sheet available at: http://energy.ky.gov/Programs/SEE%20KY/Dec%202,%202011%20Meeting/Summary%20Price%20Consumption%20Forecast_FINAL.pdf (last visited November 6, 2012).

[66] Full document available at: http://energy.ky.gov/Programs/SEE%20KY/March%202012%20Meeting/KY%20Econ%20Potential%20Analysis%20-%20FINAL%20DRAFT.pdf (last visited November 6, 2012). Fact Sheet available at: http://energy.ky.gov/Programs/SEE%20KY/March%202012%20Meeting/03_16_2012_ACEEE%20Economic%20Potential%20fact%20sheet%203.pdf (last visited November 6, 2012).

[67] Full document available at: http://energy.ky.gov/Programs/SEE%20KY/March%202012%20Meeting/ACEEE%20Utiilty-Program%20Analysis%20Report.pdf (last visited November 6, 2012). Fact Sheet available at: http://energy.ky.gov/Programs/SEE%20KY/March%202012%20Meeting/03_16_2012_ACEEE%20State%20comparison%20fact%20sheet%202.pdf (last visited November 6, 2012).

[68] Full document available at: http://energy.ky.gov/Programs/SEE%20KY/July%202012%20Meeting/KY%20Utility%20Program%20Analysis-FINAL_7-2-12.pdf (last visited November 6, 2012). Fact Sheet available at: http://energy.ky.gov/Programs/SEE%20KY/March%202012%20Meeting/03_16_2012_ACEEE%20Ky%20Utility%20Program%20fact%20sheet%204.pdf (last visited November 6, 2012).

APPENDIX D – UTILITY DATA REPORTING COMMITMENTS AND TIMELINES

METHOD FOR MEASURING GOAL

II. Energy Savings Goals

- Requirement of Grant– "Under this Area of Interest, DOE is seeking applications from states and groups of states to achieve an annual minimum target electricity savings of one percent through energy efficiency. Should a state decide to address them, natural gas and transportation fuel savings should be additional to the minimum one percent electricity savings."

- Governor's Goal (7-Point Strategy, 2008) – "Energy efficiency will offset at least 18 percent of Kentucky's projected 2025 energy demand." The Governor's efficiency goal includes all fuels (gas, electricity, etc.) and sectors (residential, commercial, industrial and transportation) so will be tracked in Btu.

III. Mechanism – Statewide electricity efficiency target, via voluntary utility participation and annual reporting of energy cost, use and savings data. Goal will be measured in terms of efficiency programs (MWh) and demand reduction (MW).

IV. Expression of Target – Percentage annual cumulative electric energy use reduction as a result of energy efficiency programs, compared to the preceding three year average total electricity sales.

Notes - Specific natural gas targets will not be set, but annual savings may be tracked (mcf) on the same path as electric savings (MWh) in DEDI's database. Likewise, electricity demand reduction (MW) will be tracked as well.

V. Calculation

Efficiency Savings will be reported as cumulative energy efficiency, as illustrated in the following *example (Note*: The table below is for illustration purposes only and assumes a DSM program that has been in existence since 2007, and all efficiency measures installed have a life of greater than five years.)

Year	Total Sales	DSM Energy Savings
2012	S_{12}	$C_{12} = I_{12} + C_{11}$
2011	S_{11}	$C_{11} = I_{11} + C_{10}$
2010	S_{10}	$C_{10} = I_{10} + C_{09}$
2009	S_{09}	$C_{09} = I_{09} + C_{08}$
2008	S_{08}	$C_{08} = I_{08} + C_{07}$
2007	S_{07}	$C_{07} = I_{07}$

- *Formula example for 2012:* % Energy Savings = $C_{12} / [(S_{11} + S_{10} + S_{09})/3 + C_{12}]$

- *Where:*
  - ***S##** = Total **Sales** of energy (MWh) for a given year*
  - ***I##** = **Incremental** energy savings achieved through DSM programs for a given year as a result of new enrollments or measure installations*
  - ***C##** = **Cumulative** energy savings achieved through DSM programs for a given year as a result of new enrollments or measure installations, plus carry-forward energy savings from previous year's enrollments or measure installations.*

- *Reported Values* – DEDI will generate four separate energy savings values each year:
  1. Residential energy savings, as compared with total residential consumption (average of preceding 3 years).
  2. Commercial energy savings, as compared with total commercial consumption (average of preceding 3 years).
  3. Industrial energy savings, as compared with total industrial consumption (average of preceding 3 years).
  4. Total energy savings, as compared with total energy consumption (average of preceding 3 years).

- *Practical Considerations*
  - i. Some utilities will report on a calendar year (Jan 1 through Dec 31), some on a federal fiscal year (Oct 1 through Sep 30) and others will report on state fiscal year (Jul 1 through Jun 30) (see table below).
  - ii. The first measured year will be 2012.
  - iii. The total energy sales baseline will be expressed as a three year average, based on the preceding three years and will be recalculated on a rolling basis each year. This method will serve to normalize data for a number of factors (e.g., new or lost economic growth, extreme weather changes, etc.). The first baseline period will be 2009-2011.
  - iv. For all utility data reported, energy savings data will be cumulative to the beginning of program operation.
  - v. However, energy savings will be cumulative only as far back as the effective useful life of the program measures installed, e.g. if a CFL program has been in existence for 20 years, but the CFL's have an assumed life of five years, the energy savings will only accumulate back as far as five years.
  - vi. All utilities will be covered in any final summary report of data; absence of data will appear as zero activity.
  - vii. Because each utility has a different history with DSM programs and each has a different database for tracking these data, it is important to note that not all utilities will show a fair representation of energy savings. For example: At least one utility has been running programs for nearly 20 years; however, they only have data going back about five years. Another utility is only just beginning their DSM programs, so has no history of energy savings to accumulate/compound over time. Yet another utility has a fair amount of data going back in time, but because of the way their data tracking has

evolved over the years, they have less confidences in their older data and may chose not to use the older data. All these factors conspire to underscore that comparing energy savings among utilities is not something that can be easily or fairly done. As time goes by, and more consistency of data is compiled, some of the data issues may recede, but there are still other issues making comparisons difficult, such as market and demographic differences in service areas.

viii. In the same vein, some utilities report net energy savings and others report gross energy savings to the Energy Information Administration. So, the entire data set for all utilities will likely be a mix of net vs. gross energy savings data. As such, any data summaries or comparison will require care and clear qualification.

RAMP UP OF ANNUAL TARGETS

Annual targets ramp up in 2012-2014, to an annual one percent goal from 2015 through 2025, according to the following schedule:

Calendar Year	Incremental Electric Consumption Reduction	Cumulative Electric Consumption Reduction
2012	0.2%	0.2%
2013	0.3%	0.5%
2014	0.5%	1%
2015	1%	2%
2016	1%	3%
2017	1%	4%
2018	1%	5%
2019	1%	6%
2020	1%	7%
2021	1%	8%
2022	1%	9%
2023	1%	10%
2024	1%	11%
2025	1%	12%

Note: Natural gas consumption reductions will be added to make up the remainder of 2025 goal.

UTILITY DATA REPORTING COMMITMENTS AND TIMELINES

Utility	Residential Data	Commercial Data	Industrial Data	Reporting Period	Year 1 Report Date	Report Date After Year 1	Net vs. Gross Energy Savings*
LG&E/ KU	✓	✓	N/A	Calendar Year	April 30	April 30	Net
Duke	✓	✓	✓	State Fiscal Year (July 1 to June 30)	April 30	Dec. 31	Net
AEP	✓	✓	N/A	Calendar Year	April 30	April 30	Net*
EKPC	✓	✓	✓	Calendar Year	April 30	April 30	Net*
TVA	✓	✓	✓	Fed. Fiscal Year (Oct. 1 to Sept. 30)	April 30	Dec. 31	Gross
Big Rivers	✓	✓	N/A	Calendar Year	April 30	April 30	Net
Municipal Utilities							

* Indicates net vs. gross energy savings data as reported to the Energy Information Administration. Net energy savings takes into account "free riders" only.

SC – EXHIBIT 33

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

Or

In the Confidential File Materials at PSC