COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
MAY 02 2016
PUBLIC SERVICE COMMISSION

IN THE MATTER OF :

A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION CAPACITY AND TRANSMISSION SYSTEM	)	ADMINISTRATIVE CASE NO. 387

****

KENTUCKY POWER COMPANY

ANNUAL FILING

May 2, 2016

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief

Ranie K. Wohnhas

Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY	)	
	)	Administrative Case 387
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Ranie K. Wohnhas, this the 2nd day of May 2016.

Judy K Rosquist 481393

Notary Public

My Commission Expires: January 23, 2017

Kentucky Power Company

REQUEST

Actual and weather-normalized monthly coincident peak demands for the just completed calendar year. Demands should be disaggregated into (a) native load demand (firm and non-firm) and (b) off-system demand (firm and non-firm). Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420).

RESPONSE

Page 1 of Attachment 1 of this response provides actual and weather normalized 2015 monthly peak internal demands for Kentucky Power Company. Kentucky Power Company had one customer with interruptible provisions in its contract in 2015. However, this customer's load was not adequately above its firm load to provide an interruptible resource in PJM's auctions.

Page 2 of Attachment 1 of this response provides actual 2015 monthly system demands for Kentucky. The system demands include internal load and off-system sales. Weather-normalized monthly peak system demands for Kentucky Power Company have not been developed and therefore, are not available.

The AEP Interconnection Agreement terminated on January 1, 2014 and the AEP-East Power Pool no longer exists. As a result, the request for information regarding the AEP-East Power Pool is no longer applicable.

WITNESS: Ranie K Wohnhas

Kentucky Power Company
Actual and Weather Normalized Peak Internal Demand (MW)
2015

	Kentucky Power Company			
Month	Peak	Peak Day	Peak Hour	Normalized Peak
January	1,535	1/8/2015	8	1,471
February	1,666	2/20/2015	8	1,317
March	1,400	3/6/2015	8	1,187
April	905	4/1/2015	8	882
May	988	5/27/2015	16	935
June	1,066	6/23/2015	15	1,077
July	1,097	7/29/2015	16	1,133
August	982	8/19/2015	14	1,095
September	1,019	9/3/2015	16	990
October	894	10/19/2015	8	762
November	1,075	11/23/2015	8	1,073
December	1,022	12/4/2015	8	1,248

Kentucky Power Company
Actual Peak System Demand (MW)
2015

	Kentucky Power Company		
Month	**Peak**	**Peak Day**	**Peak Hour**
January	2,247	1/14/2015	11
February	2,104	2/19/2015	13
March	1,660	3/6/2015	6
April	1,487	4/24/2015	9
May	1,425	5/10/2015	20
June	1,338	6/30/2015	13
July	1,492	7/1/2015	18
August	1,471	8/16/2015	18
September	1,418	9/8/2015	17
October	1,040	10/19/2015	11
November	996	11/18/2015	19
December	950	12/19/2015	22

Kentucky Power Company

REQUEST

Load shape curves that show actual peak demands and weather-normalized peak demands (native load demand and total demand) on a monthly basis for the just competed calendar year. Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420).

RESPONSE

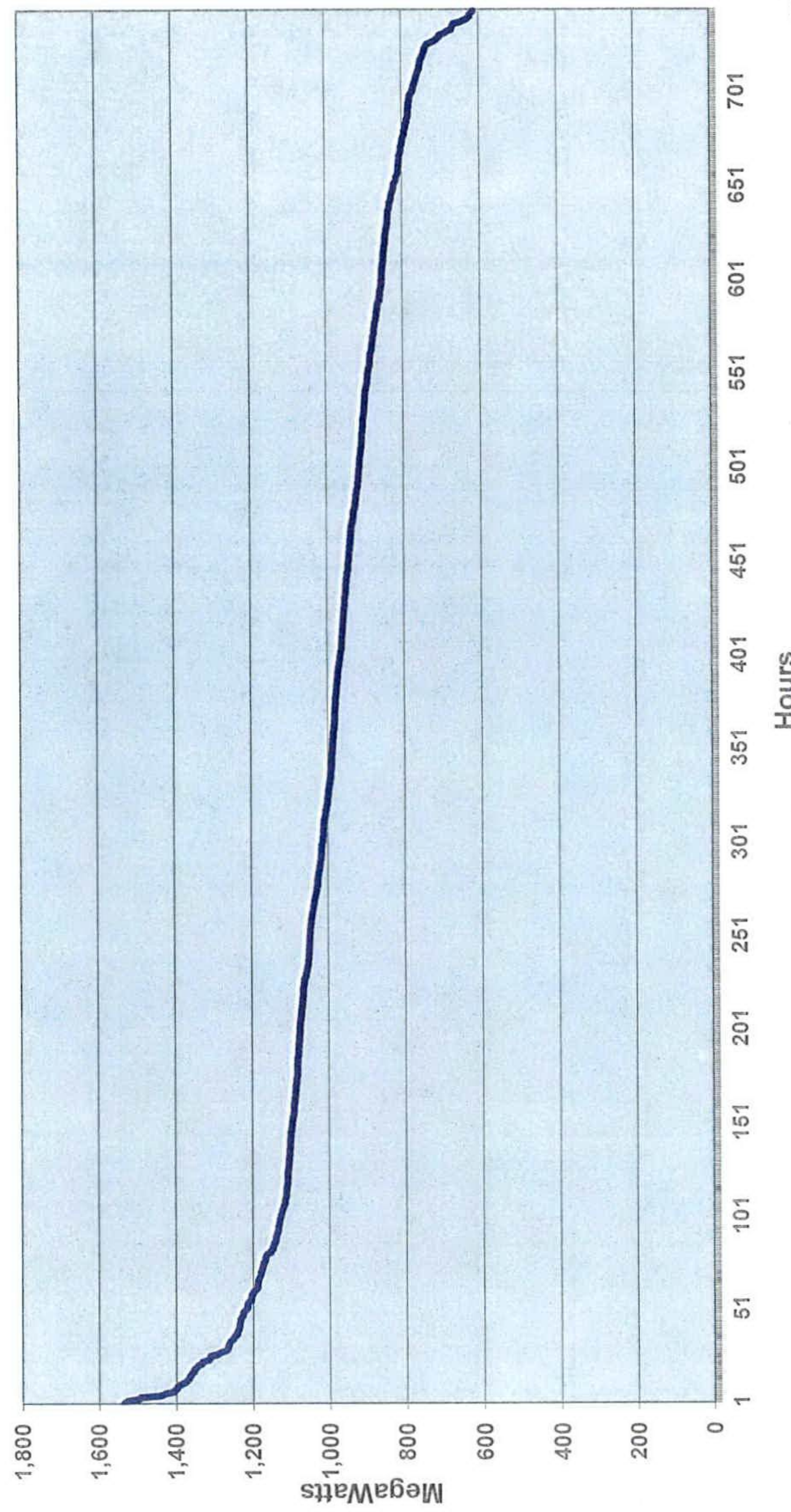
Pages 1 through 12 of Attachment 1 to this response provides 2015 monthly load duration curves for Kentucky Power Company's internal load. Pages 13 through 24 provides 2015 monthly load duration curves for Kentucky Power Company's system load. The system load, for Kentucky Power Company, includes internal load and off-system sales.

Weather-normalized monthly internal peaks for Kentucky Power Company are provided in response to Item No. 1, Page 1 of Attachment 1. Weather normalized system peaks have not been developed and therefore, are not available.

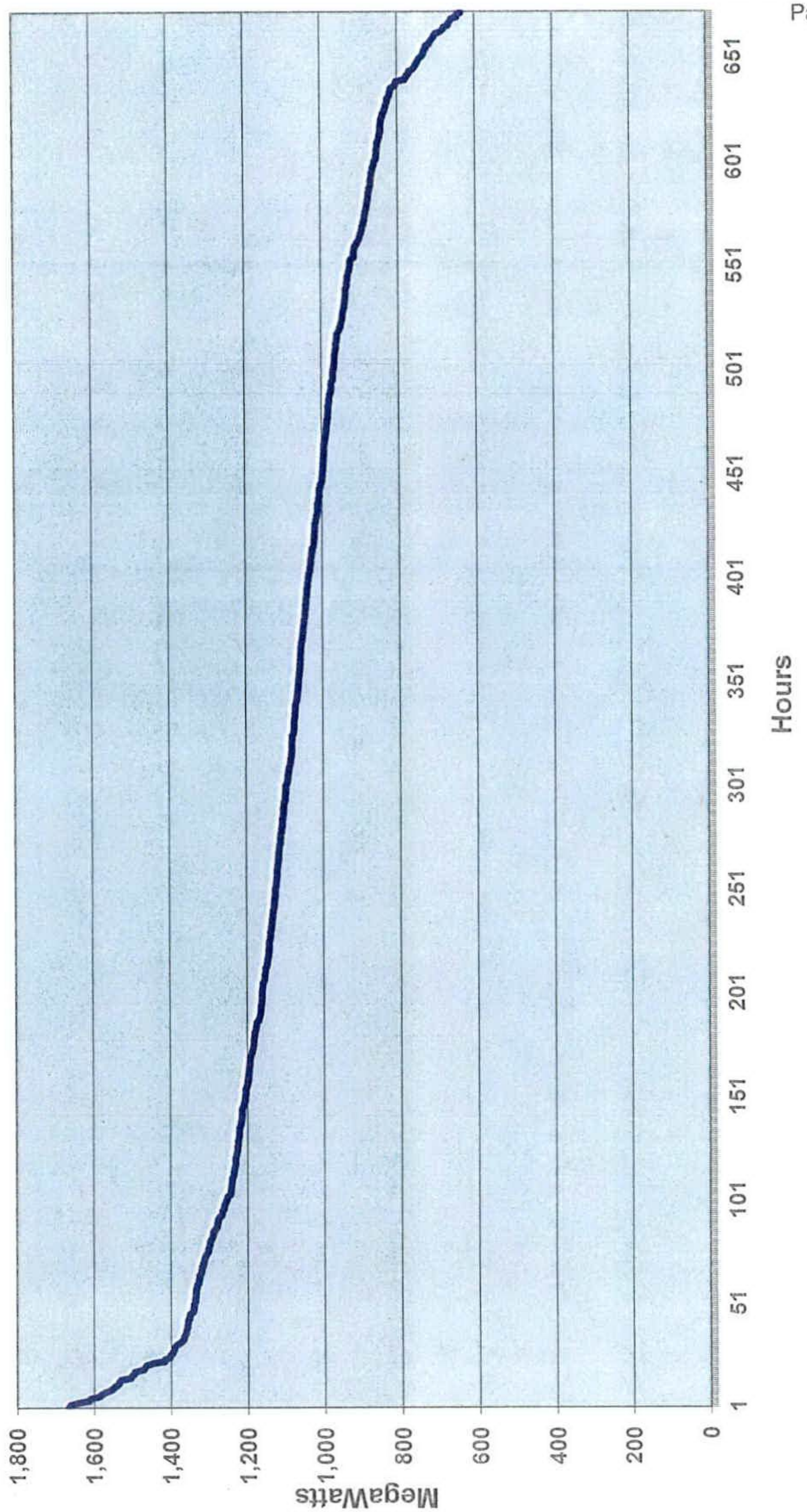
The AEP Interconnection Agreement terminated on January 1, 2014 and the AEP-East Power Pool no longer exists. As a result, the request for information regarding the AEP-East Power Pool is no longer applicable.

WITNESS: Ranie K Wohnhas

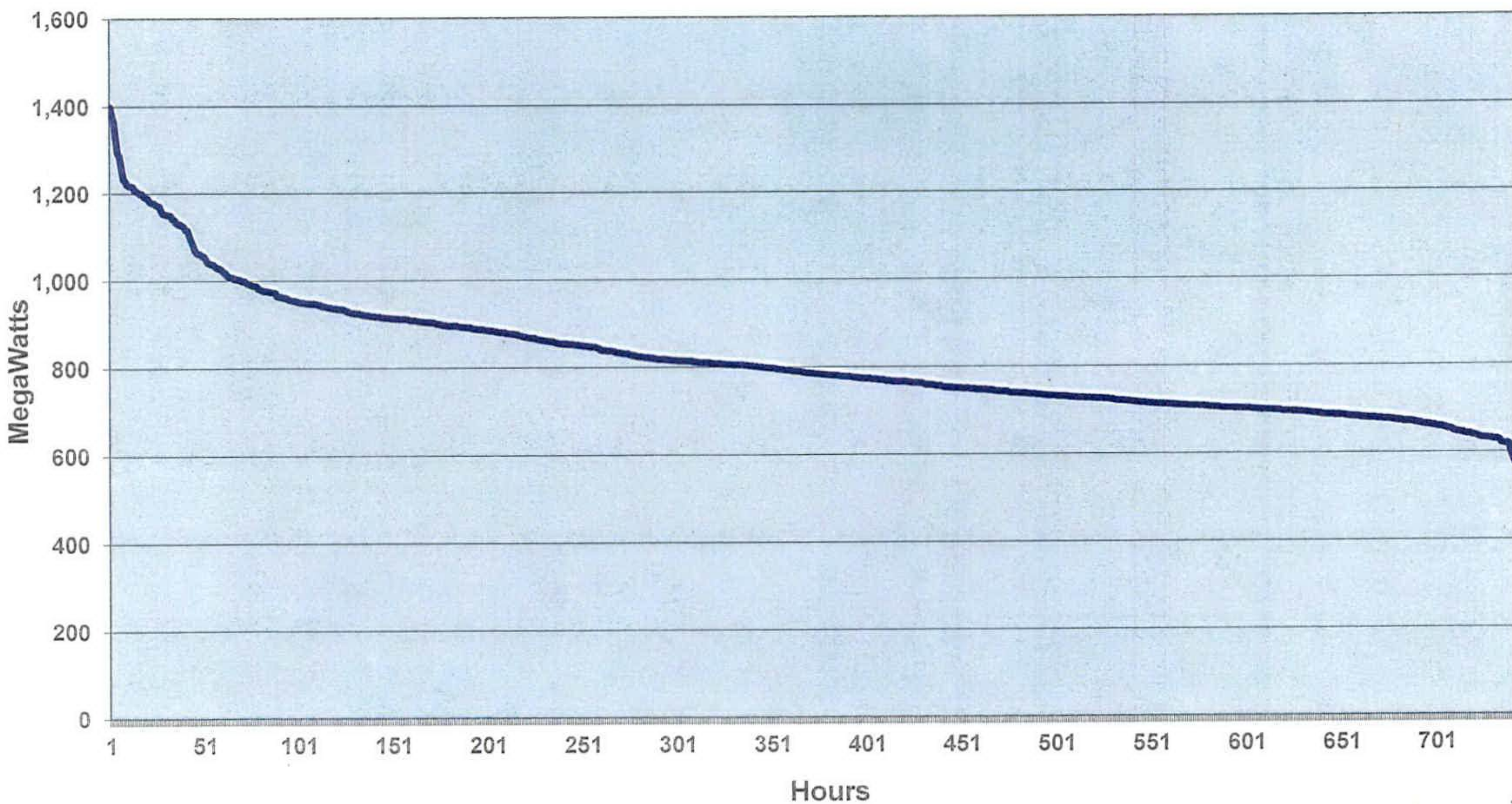
Kentucky Power Company
January 2015 Load Duration Curve
(Internal Load)



Kentucky Power Company
February 2015 Load Duration Curve
(Internal Load)

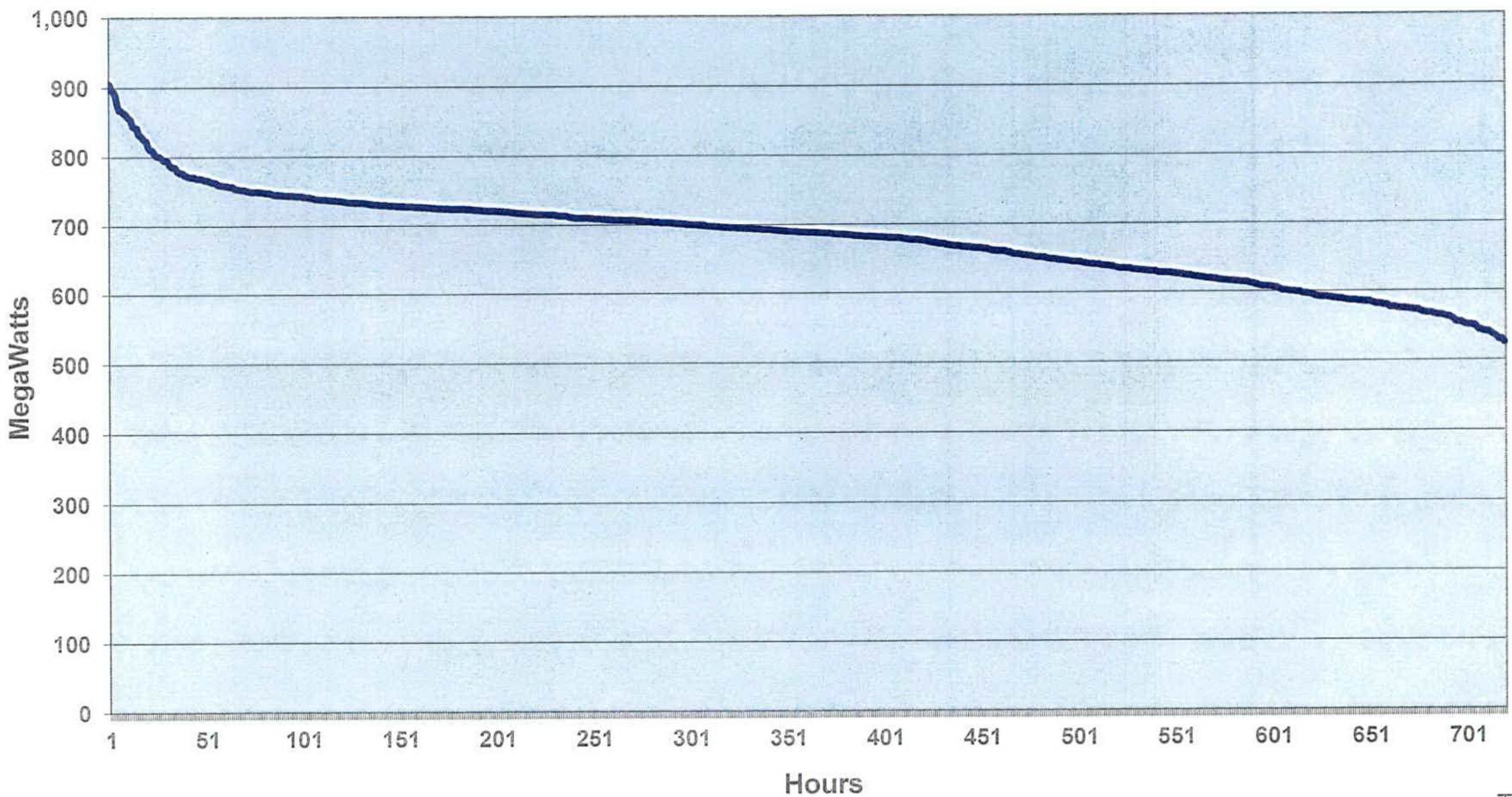


Kentucky Power Company
March 2015 Load Duration Curve
(Internal Load)

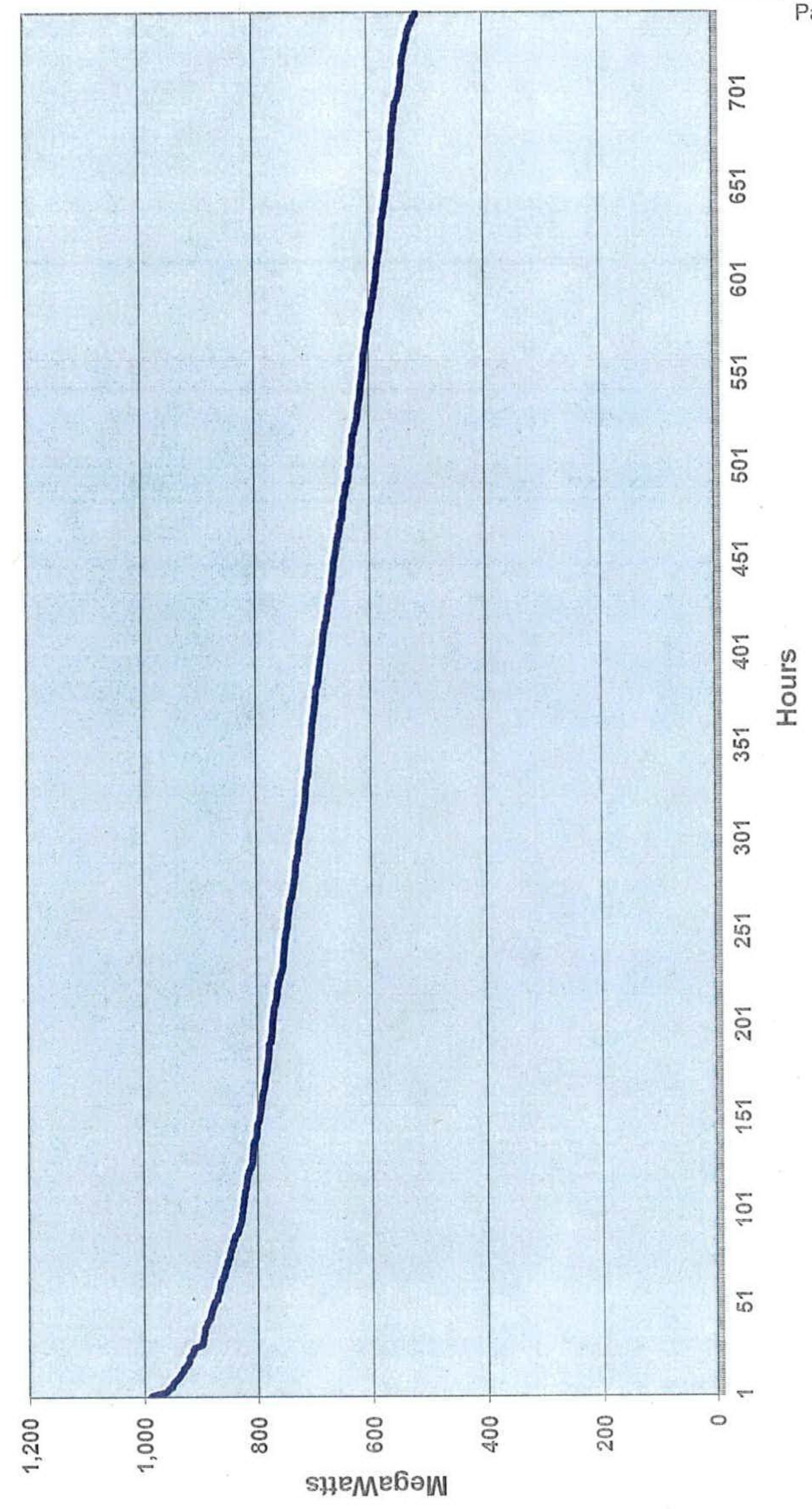


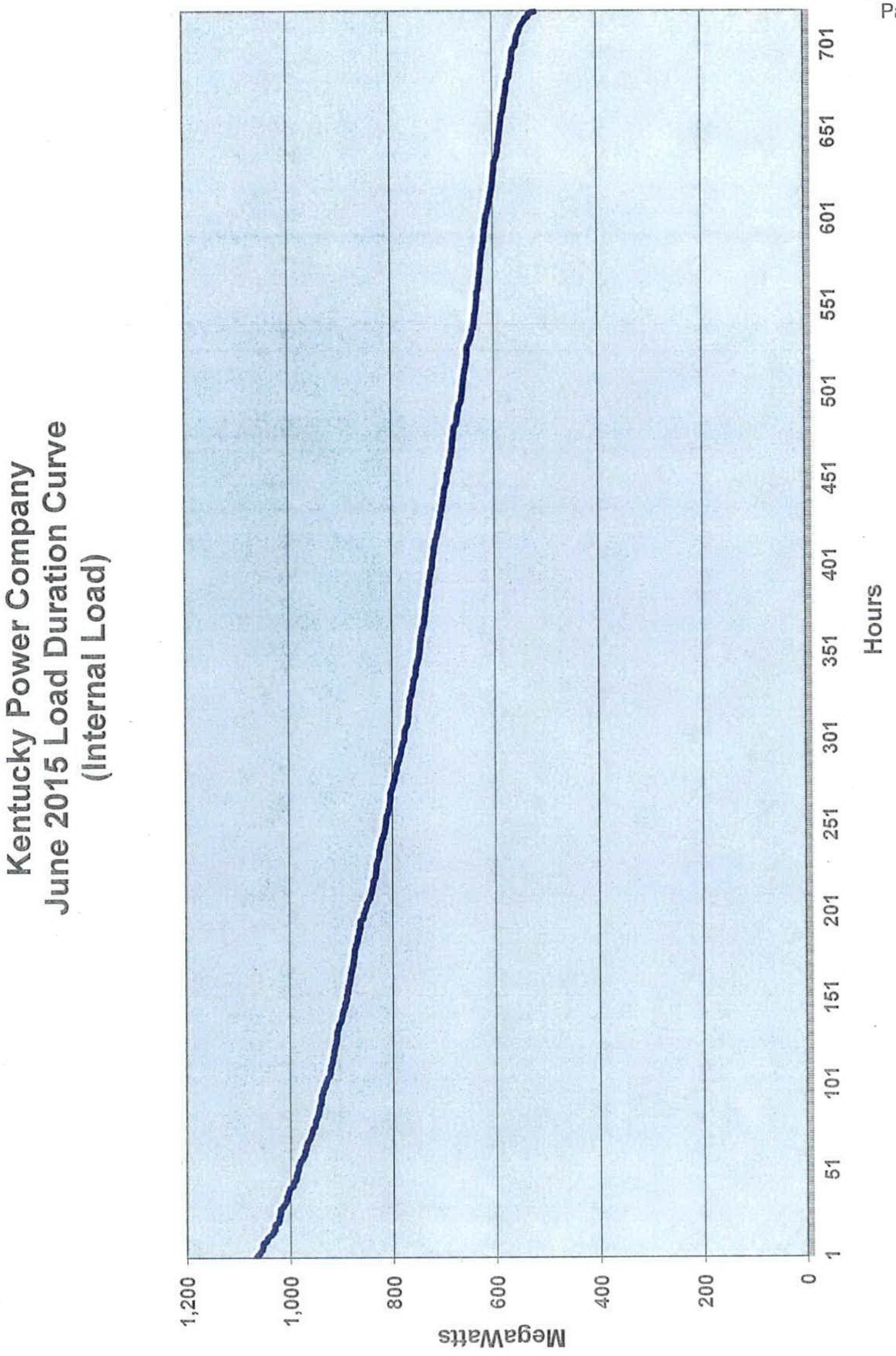
KSPC Administrative No. 387
Order Dated December 20, 2001
Annual Resource Assessment
Calendar Year 2015
Item No. 2, Attachment 1

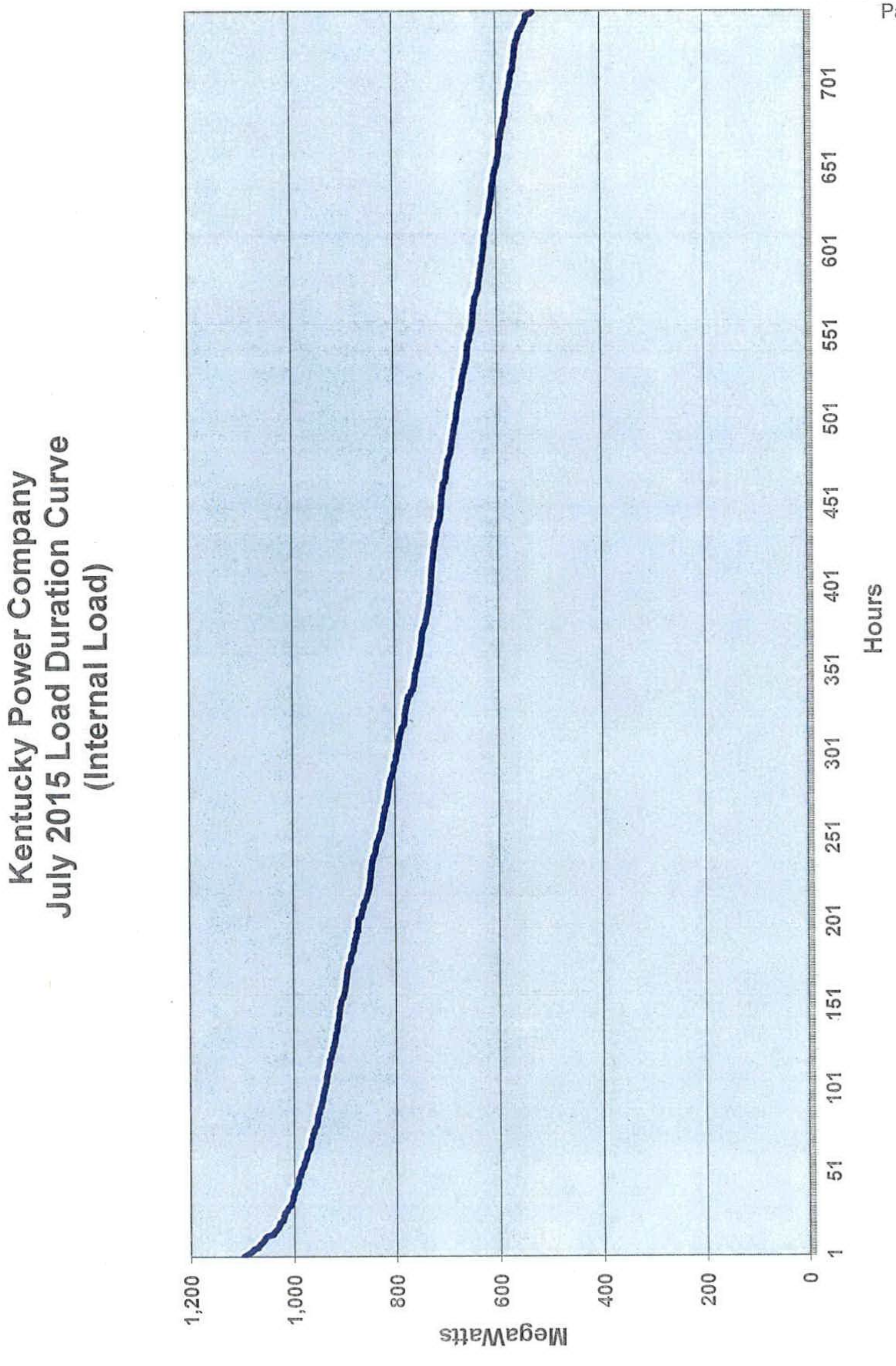
Kentucky Power Company
April 2015 Load Duration Curve
(Internal Load)



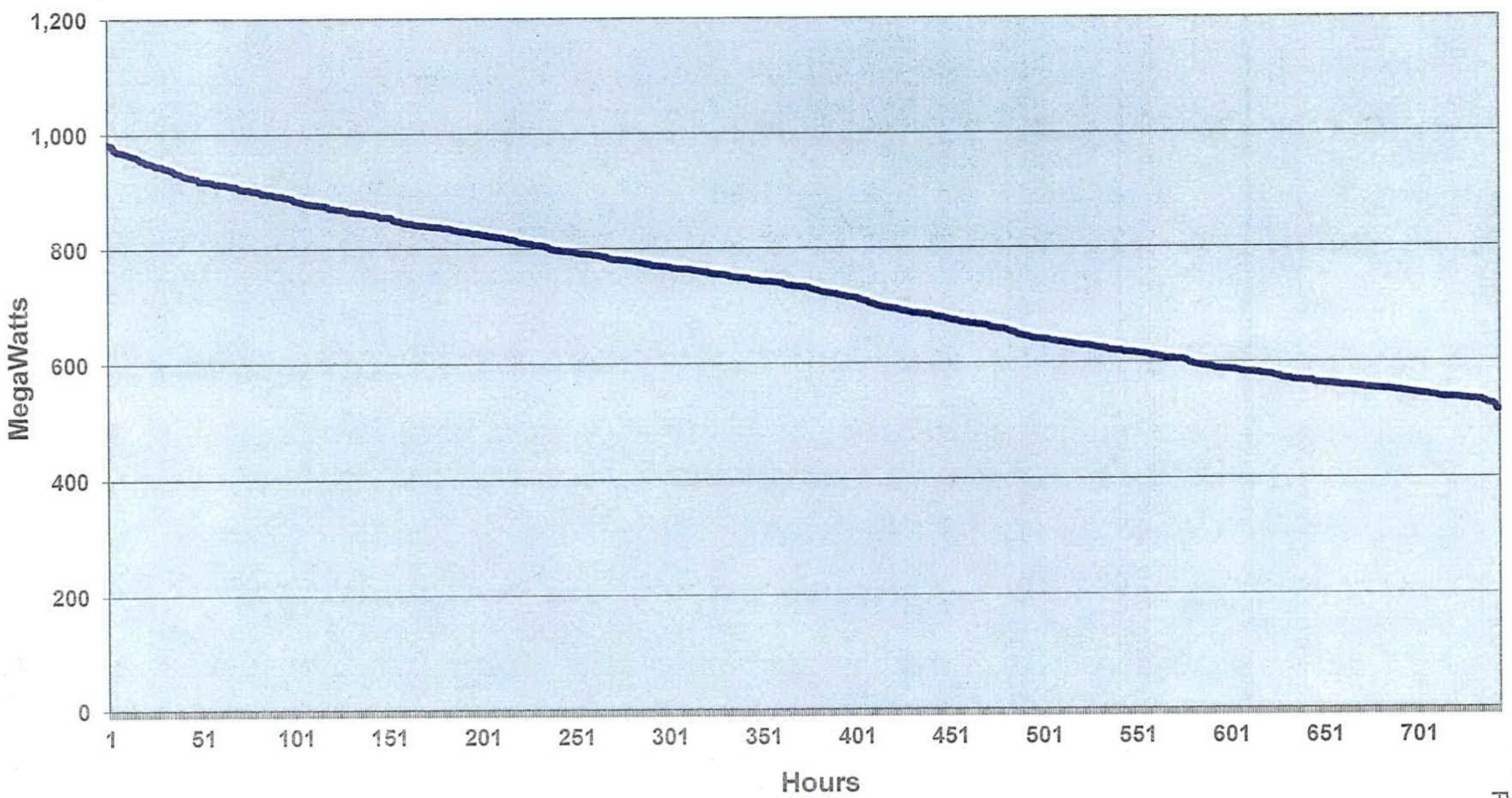
Kentucky Power Company
May 2015 Load Duration Curve
(Internal Load)

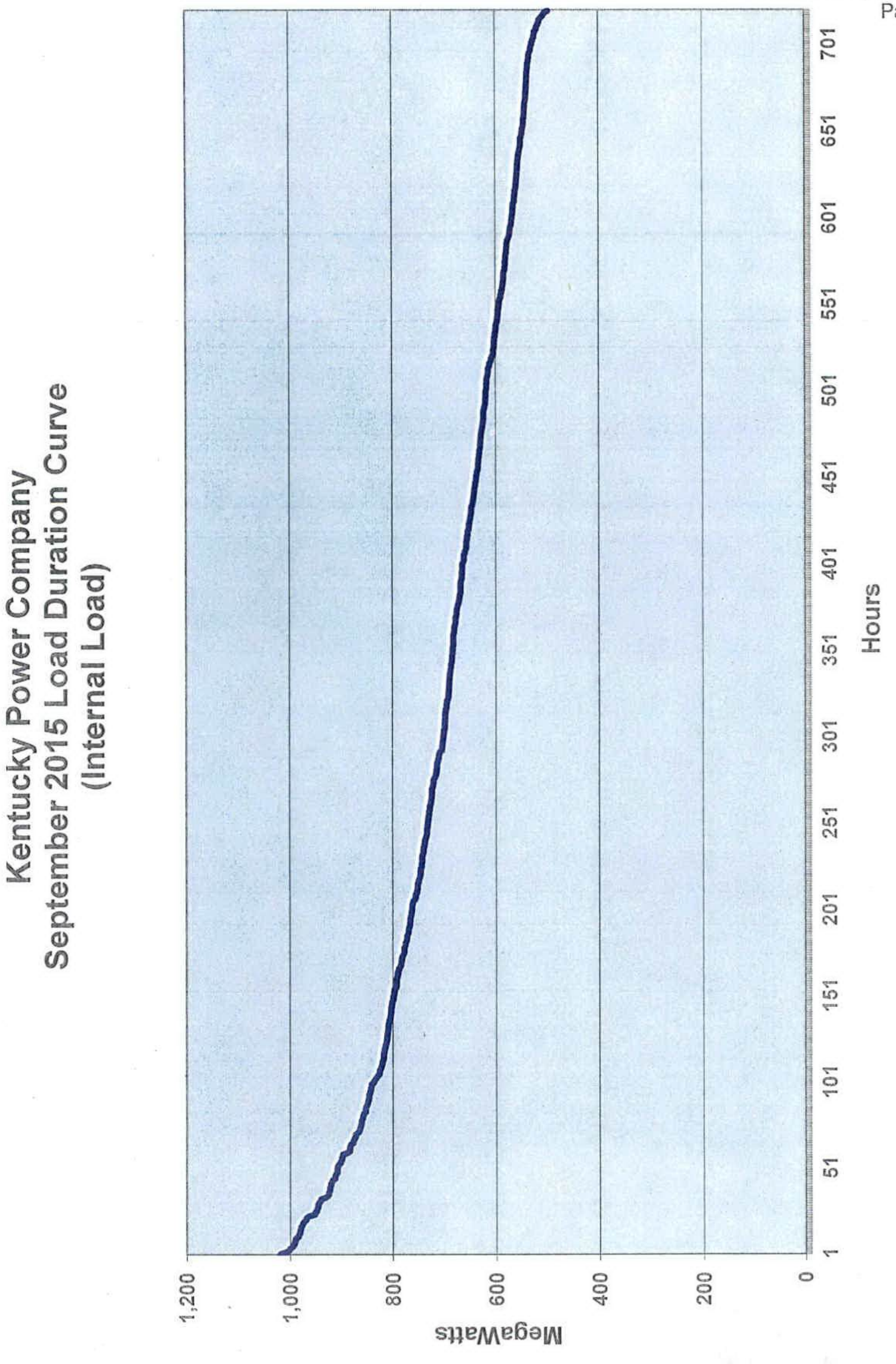



Kentucky Power Company
June 2015 Load Duration Curve
(Internal Load)
MegaWatts
1,200
1,000
800
600
400
200
0
Hours
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701

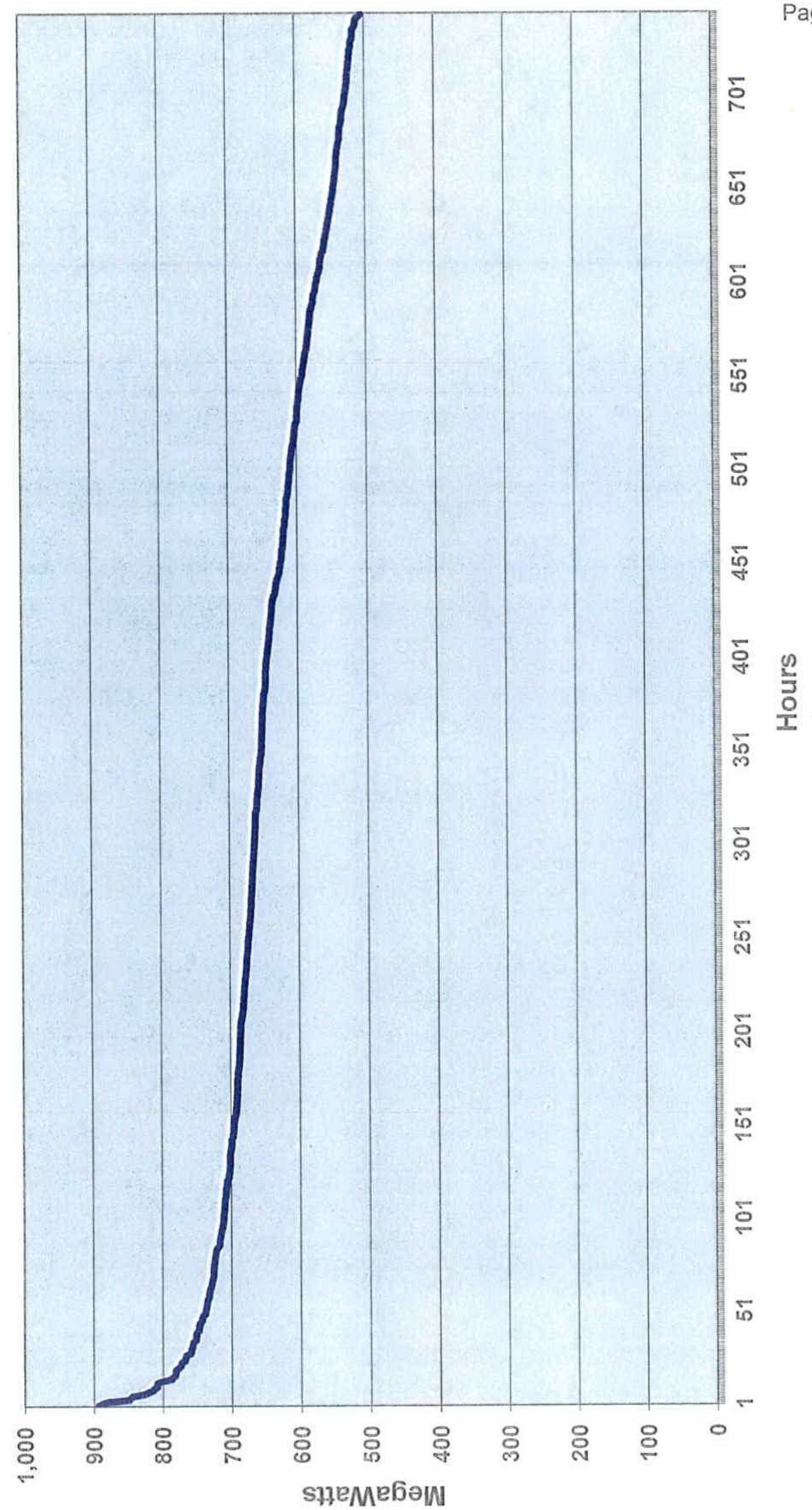

Kentucky Power Company
July 2015 Load Duration Curve
(Internal Load)
MegaWatts
1,200
1,000
800
600
400
200
0
Hours
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701

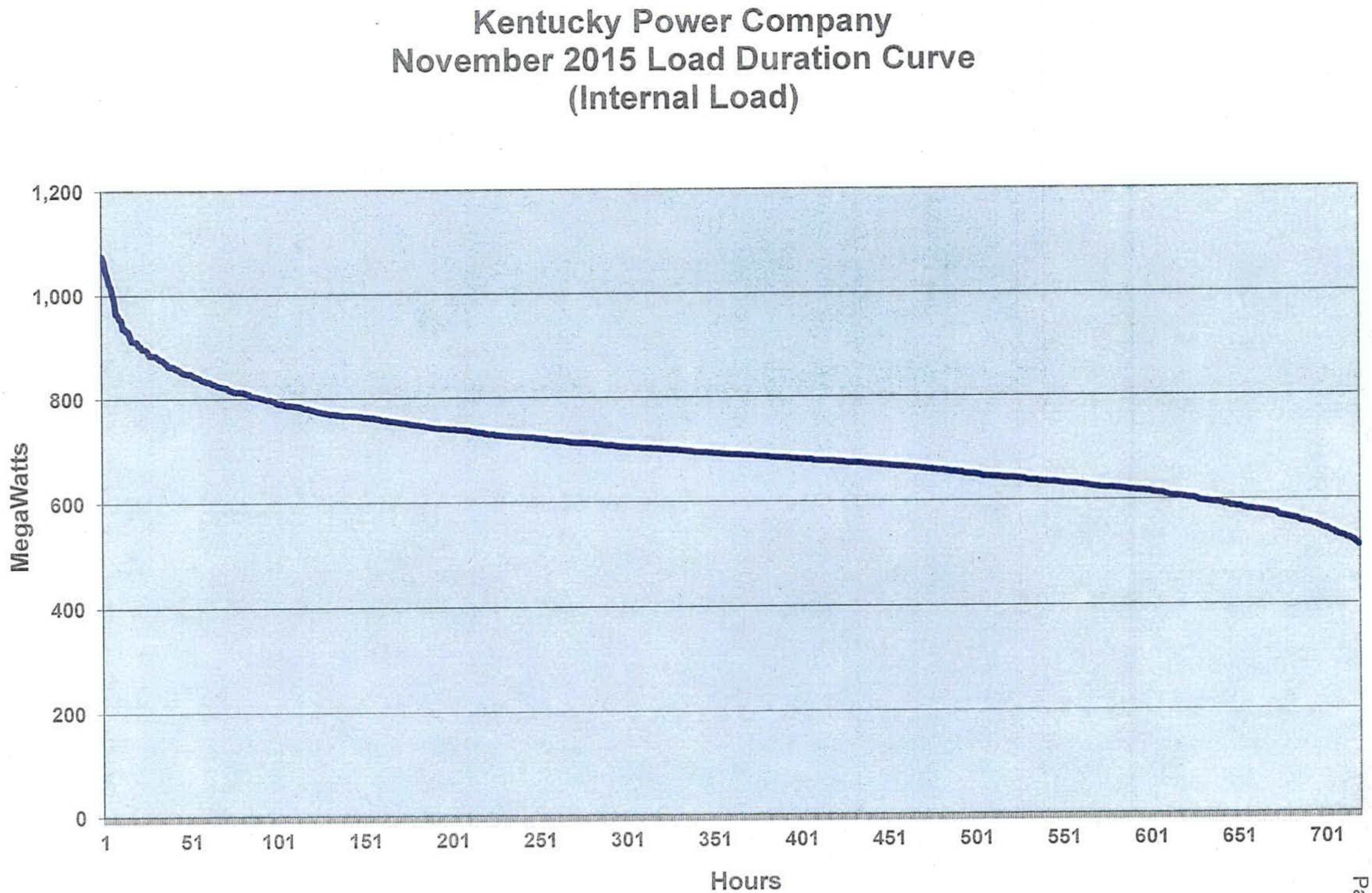
Kentucky Power Company
August 2015 Load Duration Curve
(Internal Load)




Kentucky Power Company
September 2015 Load Duration Curve
(Internal Load)
MegaWatts
1,200
1,000
800
600
400
200
0
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701
Hours

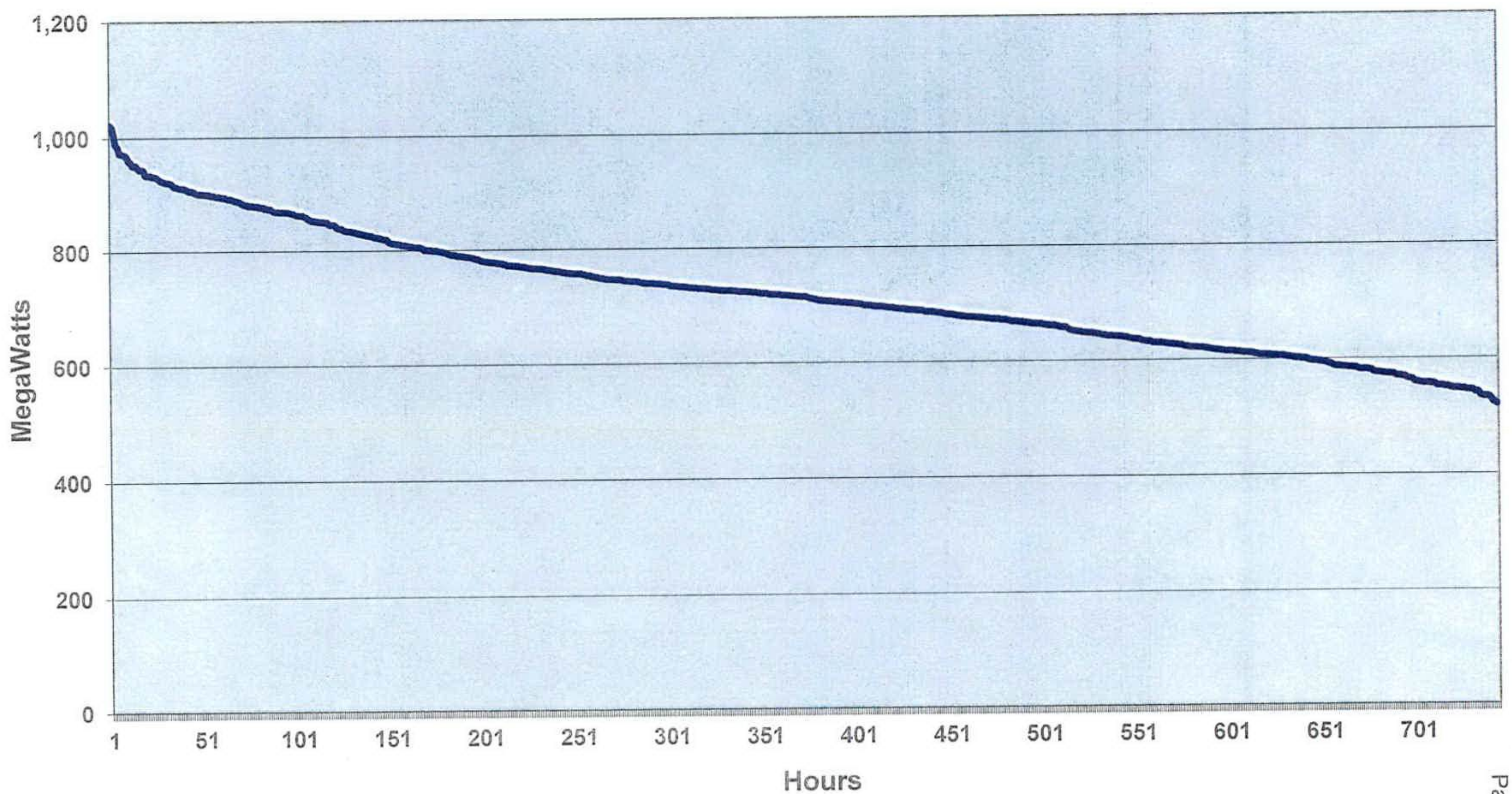
Kentucky Power Company
October 2015 Load Duration Curve
(Internal Load)

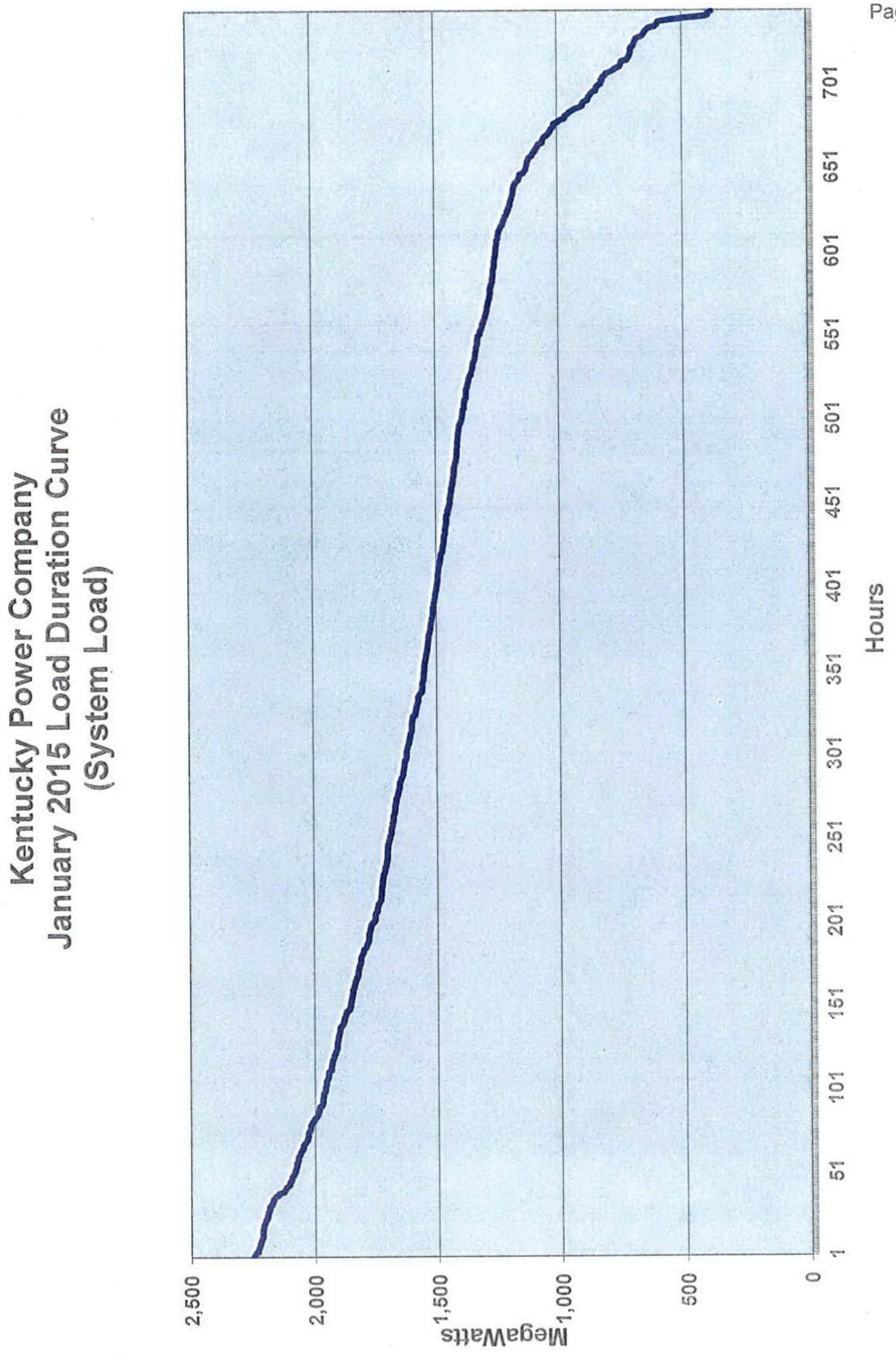




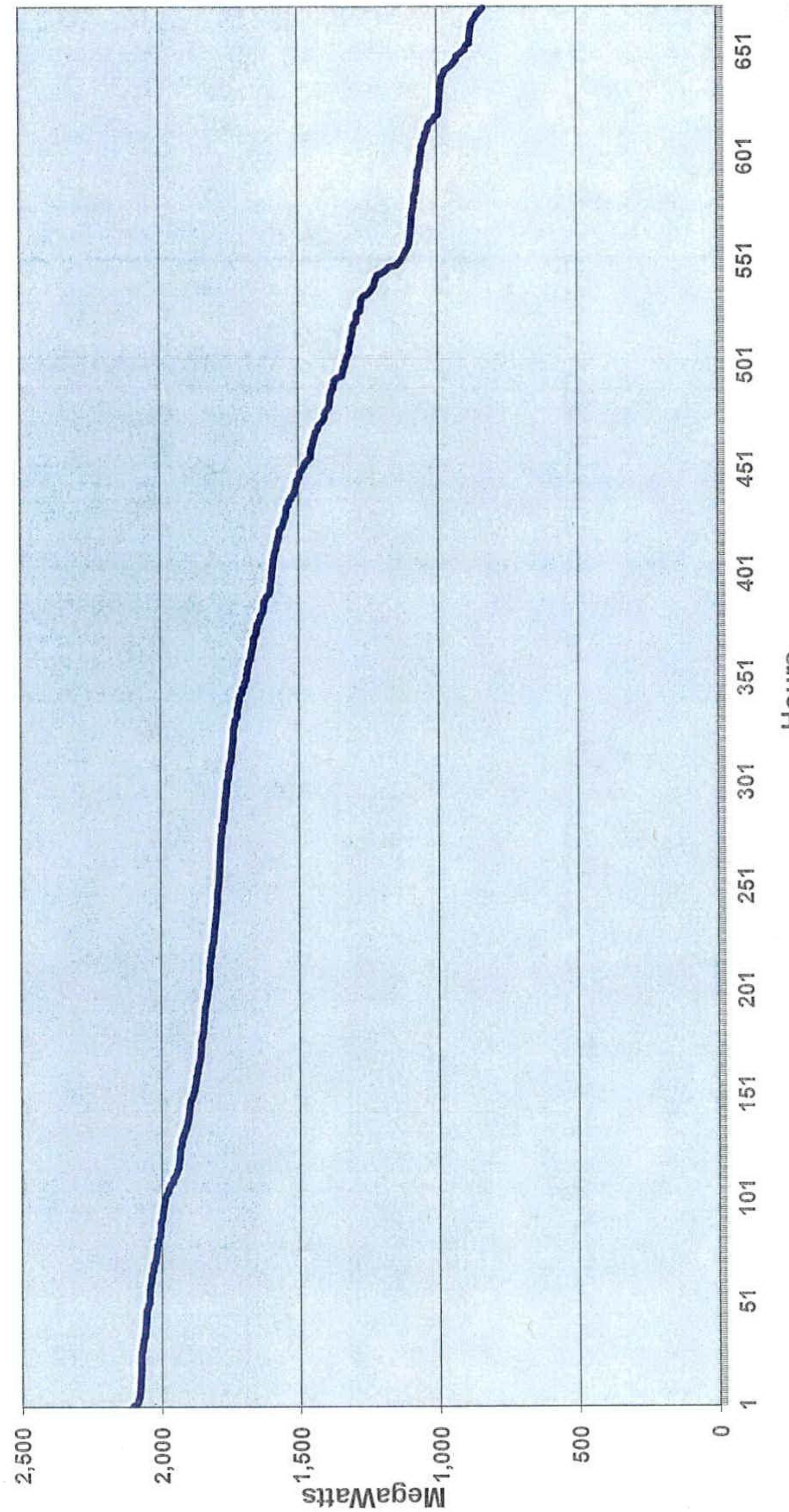
KSPC Adminstrative No. 387
Order Dated December 20, 2001
Annual Resource Assessment
Calendar Year 2015
Item No. 2, Attachment 1

Kentucky Power Company
December 2015 Load Duration Curve
(Internal Load)

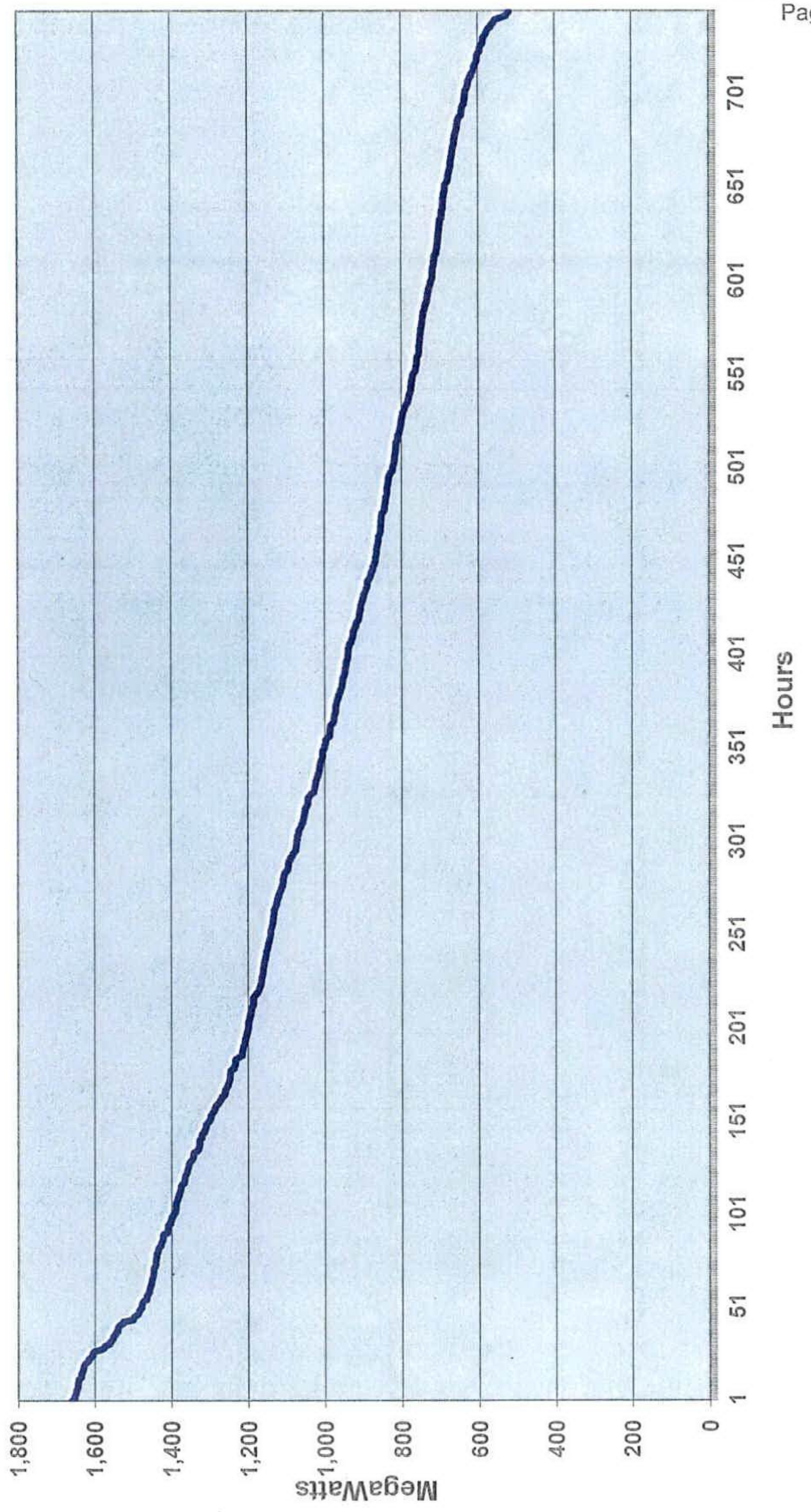


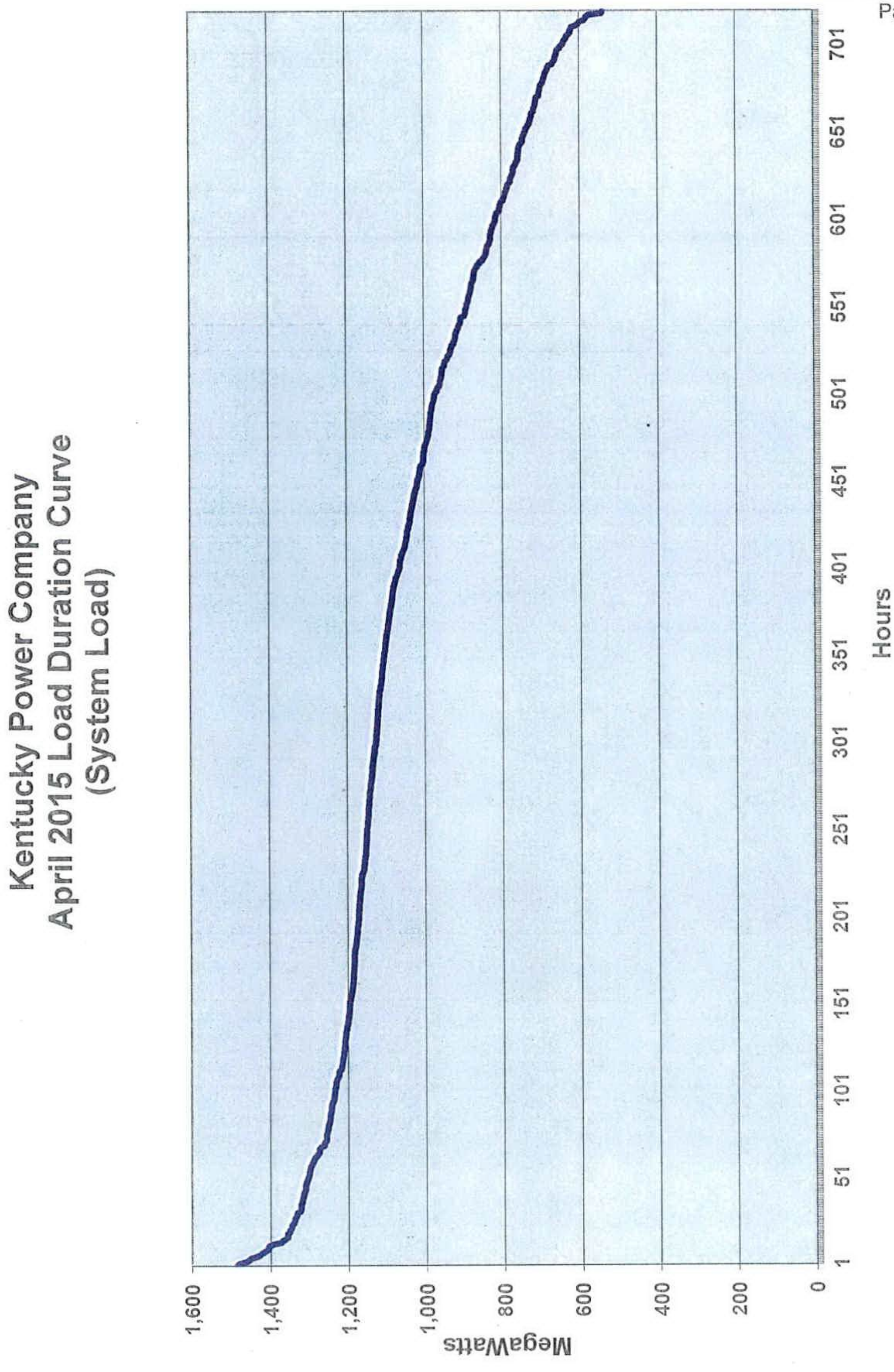

Kentucky Power Company
January 2015 Load Duration Curve
(System Load)
MegaWatts
2,500
2,000
1,500
1,000
500
0
Hours
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701

Kentucky Power Company
February 2015 Load Duration Curve
(System Load)

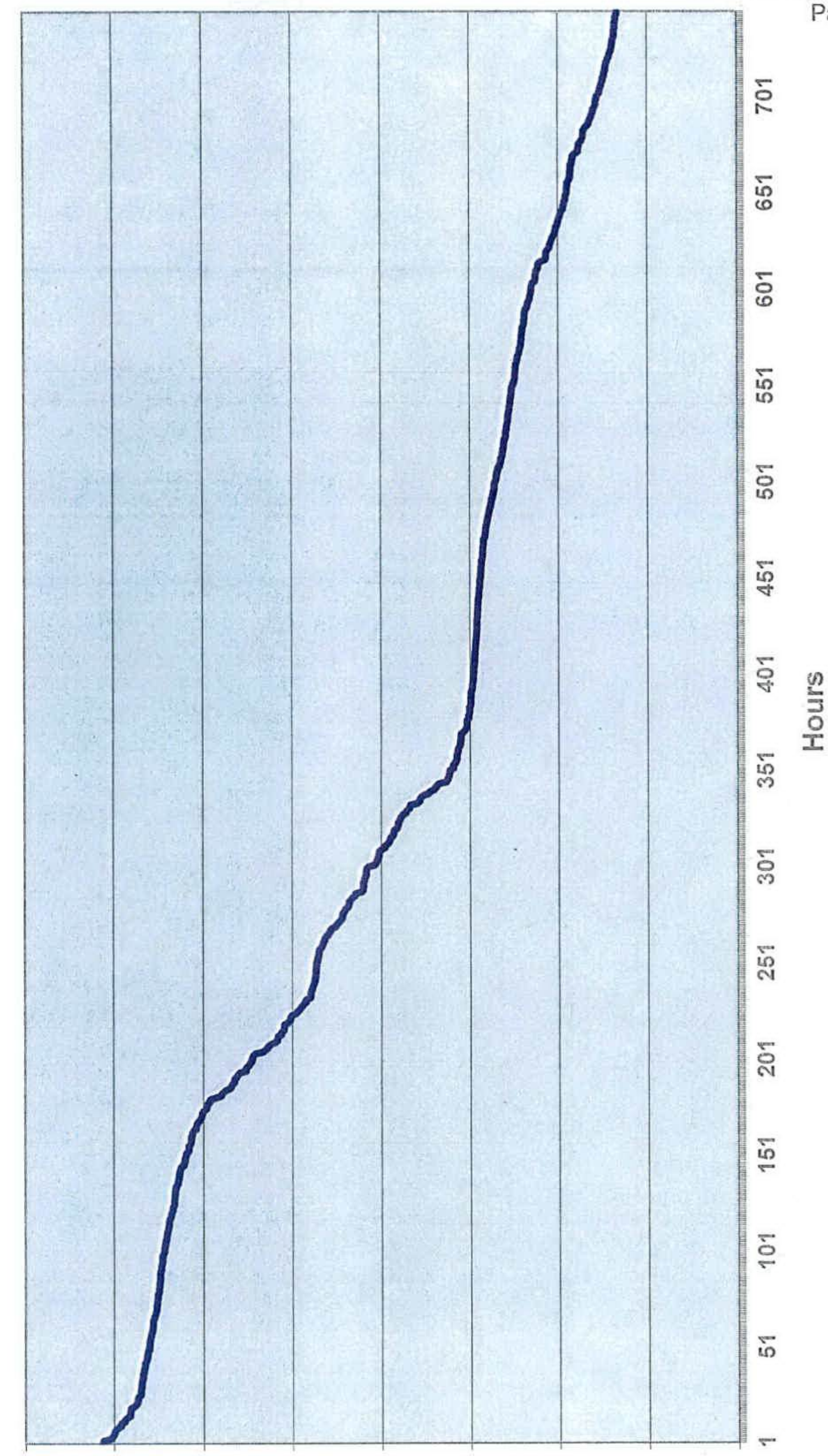


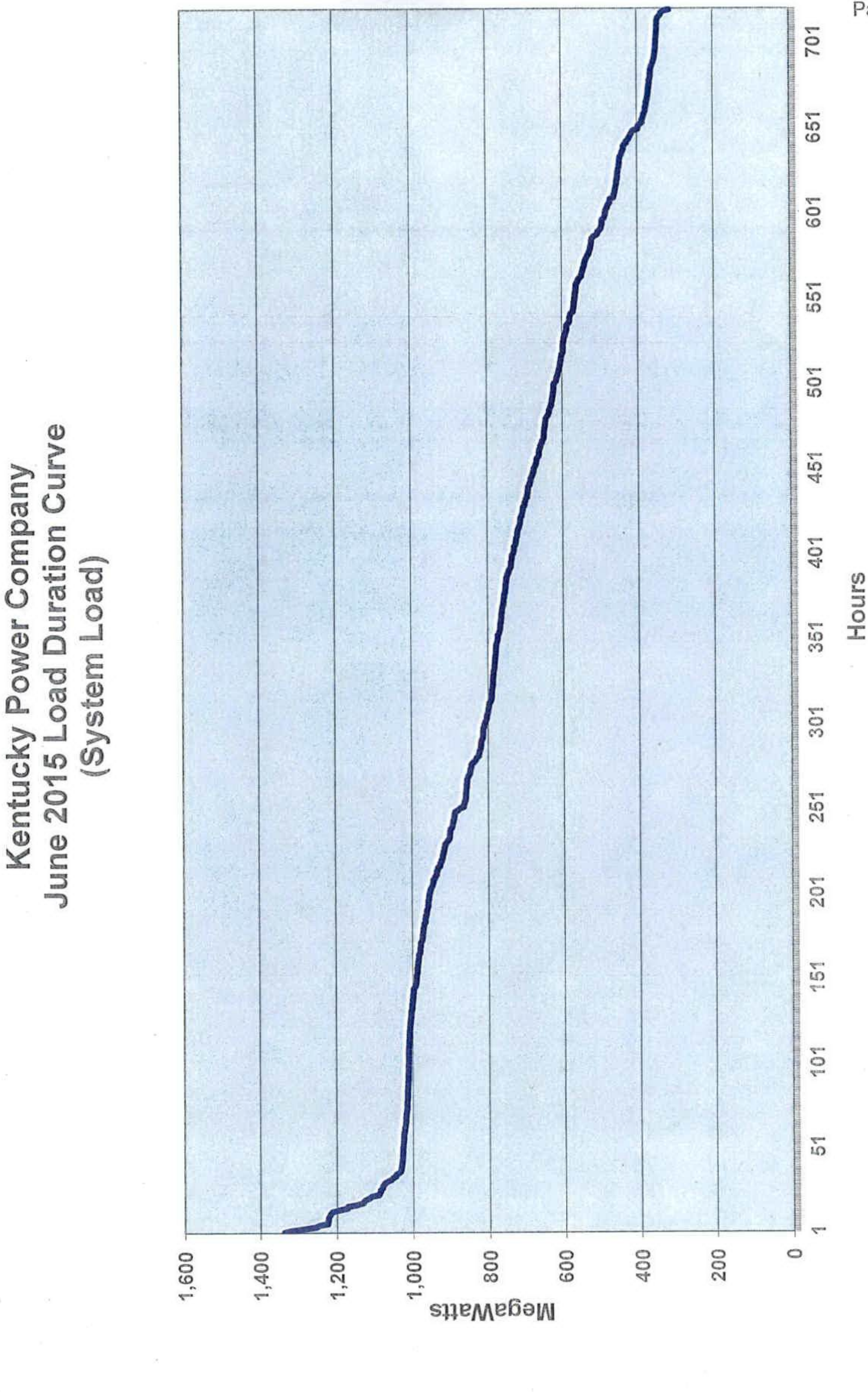
Kentucky Power Company
March 2015 Load Duration Curve
(System Load)

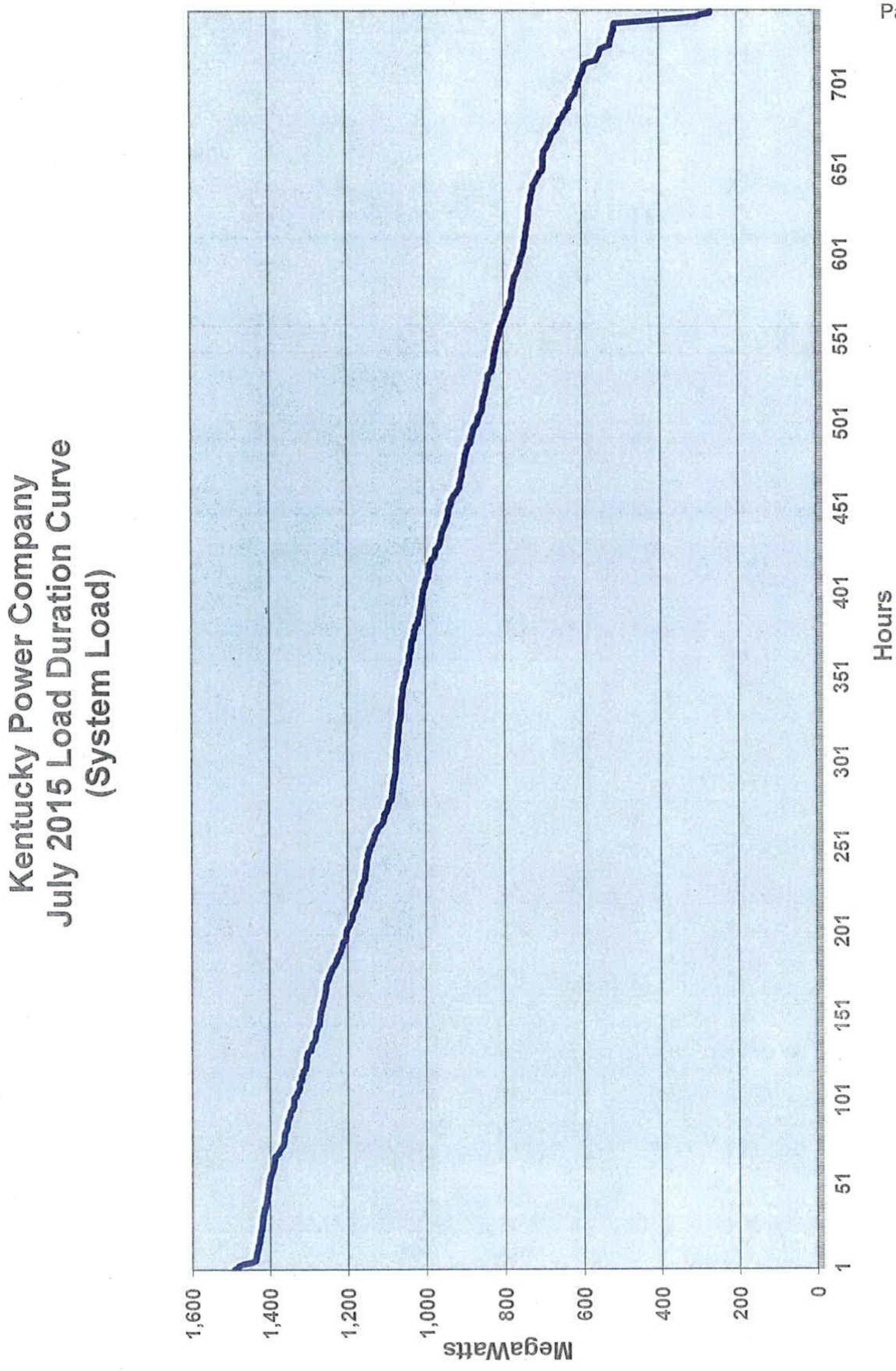



Kentucky Power Company
April 2015 Load Duration Curve
(System Load)
MegaWatts
1,600
1,400
1,200
1,000
800
600
400
200
0
Hours
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701

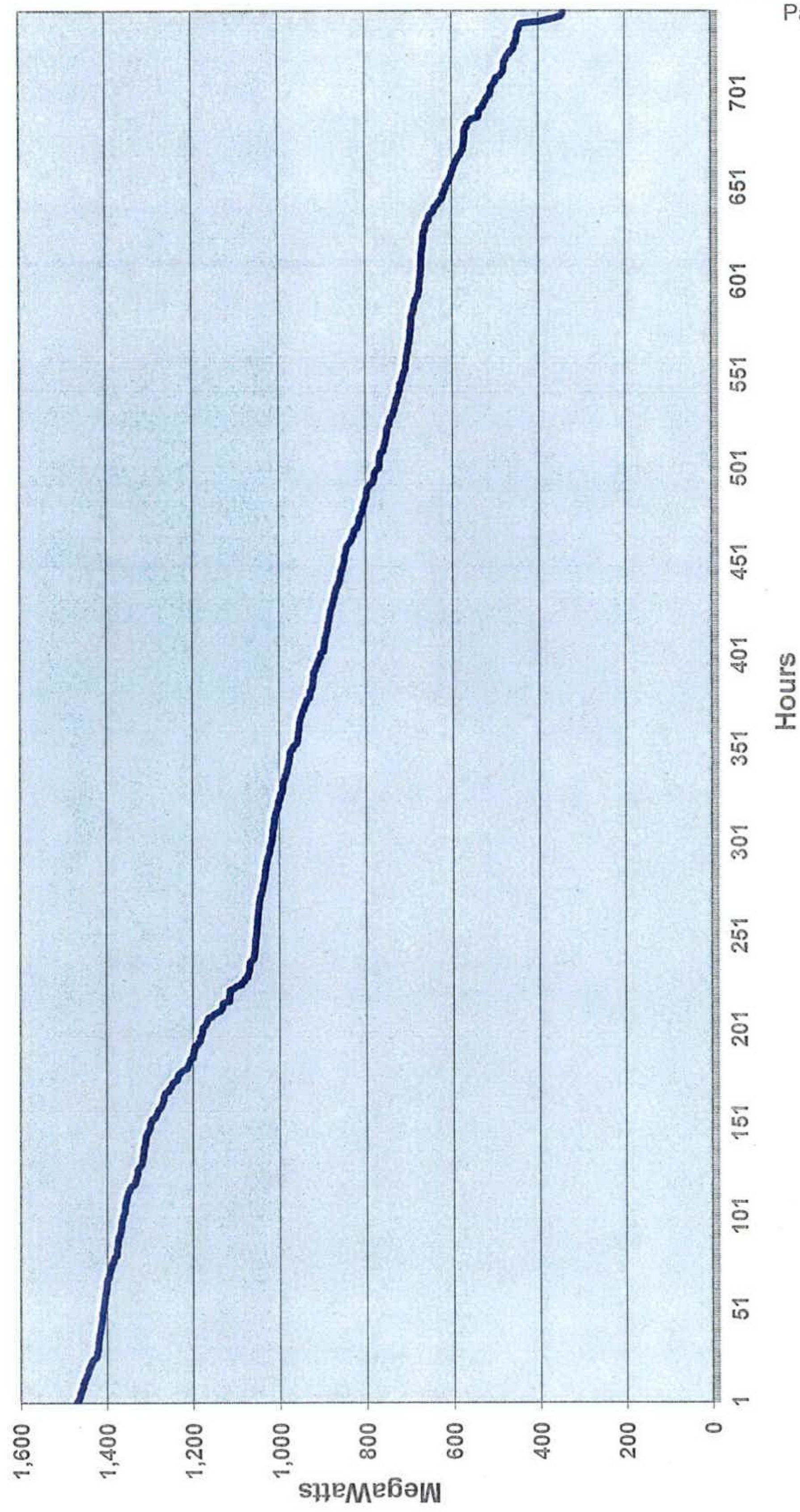
Kentucky Power Company
May 2015 Load Duration Curve
(System Load)

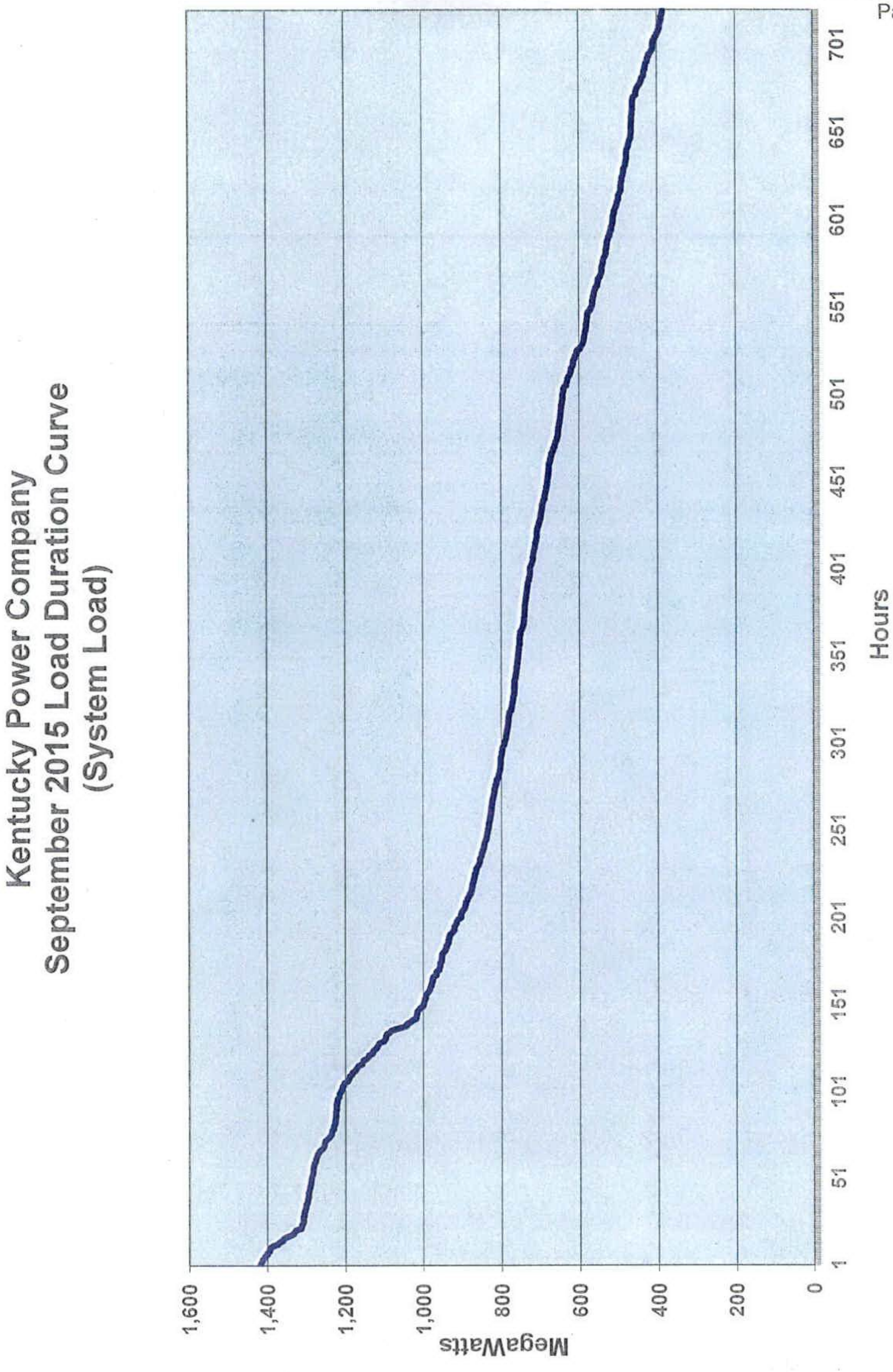



Kentucky Power Company
June 2015 Load Duration Curve
(System Load)
MegaWatts
1,600
1,400
1,200
1,000
800
600
400
200
0
Hours
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701

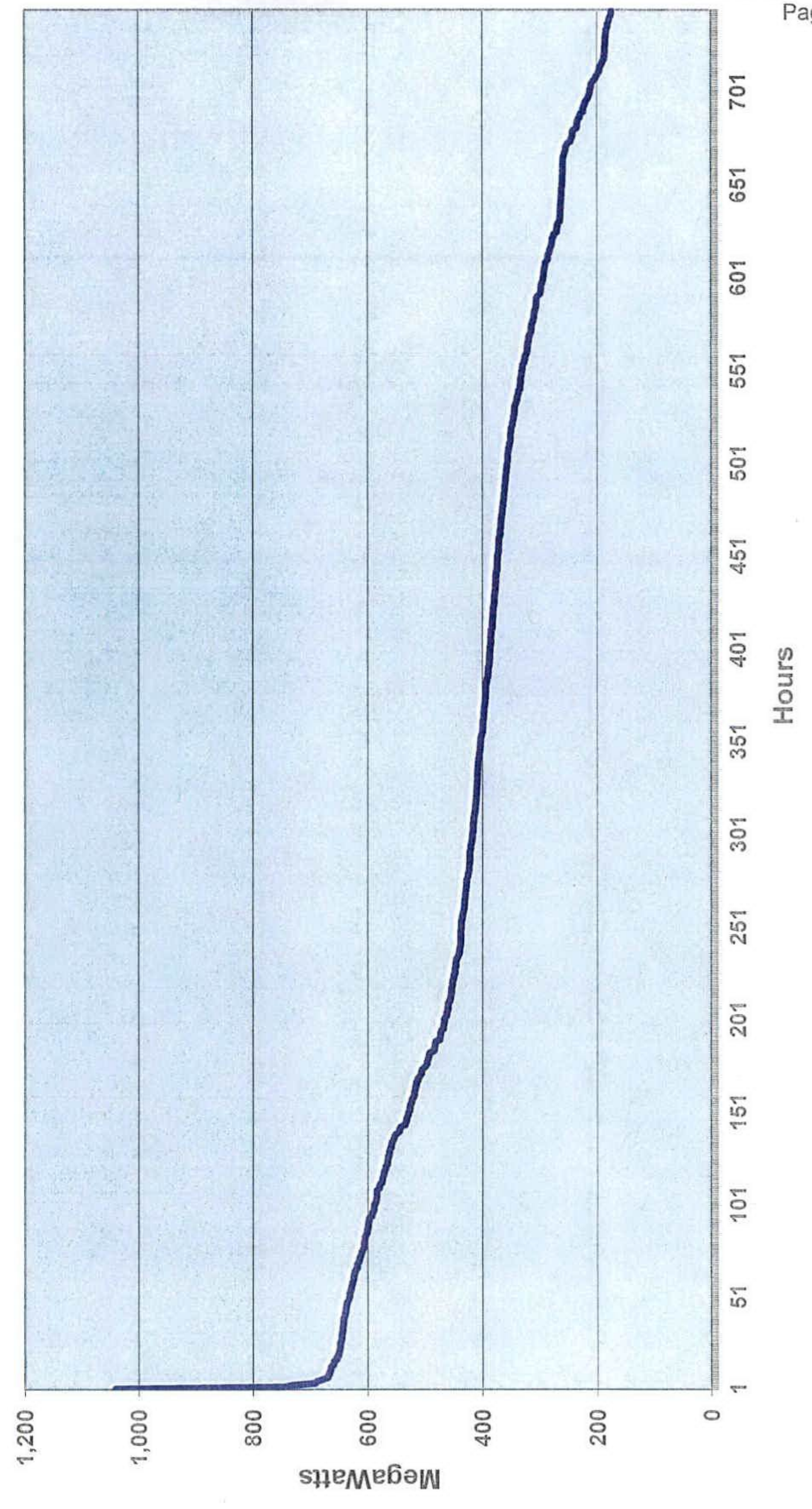

Kentucky Power Company
July 2015 Load Duration Curve
(System Load)
MegaWatts
1,600
1,400
1,200
1,000
800
600
400
200
0
Hours
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701

Kentucky Power Company
August 2015 Load Duration Curve
(System Load)

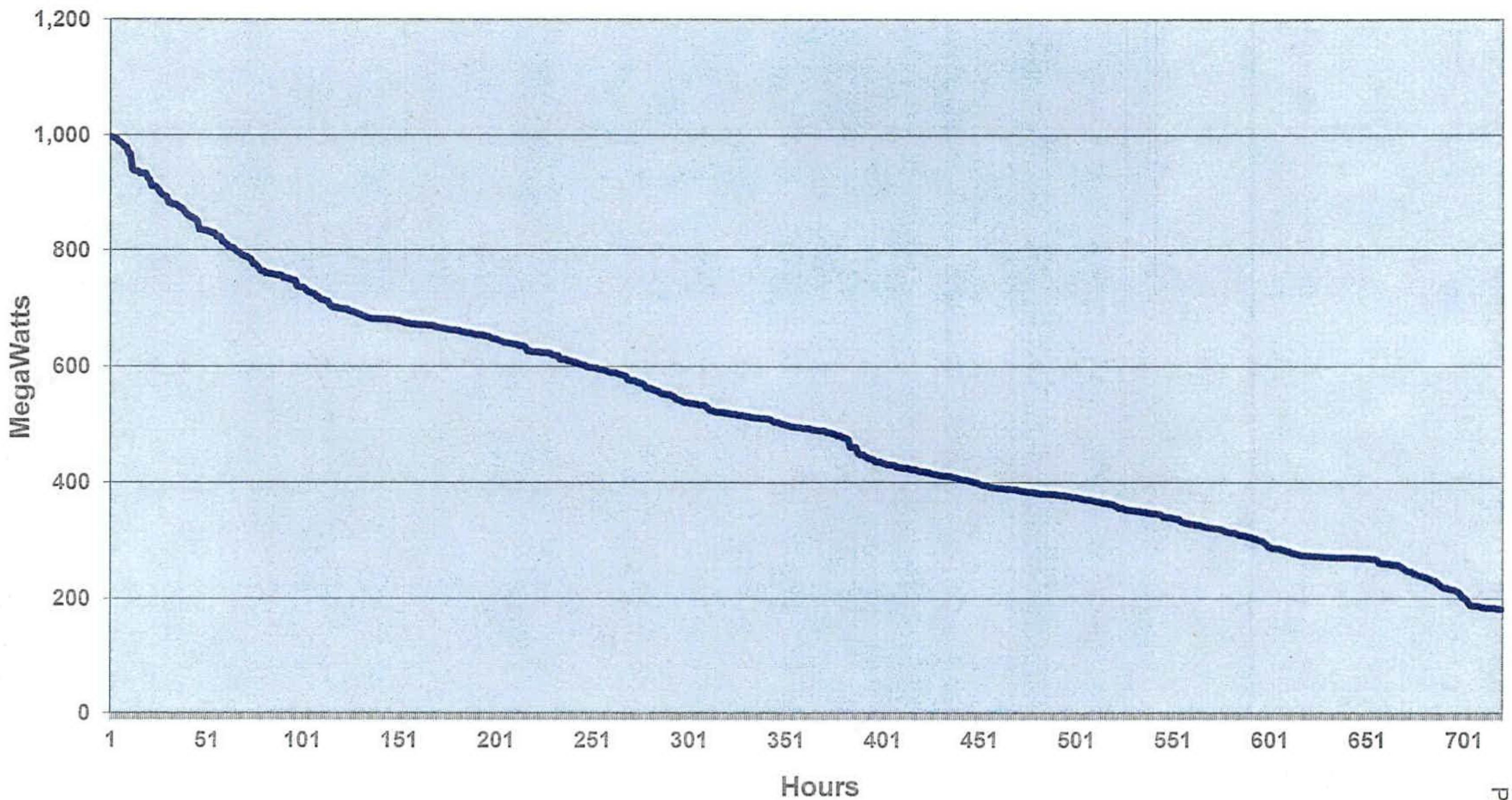



Kentucky Power Company
September 2015 Load Duration Curve
(System Load)
MegaWatts
1,600
1,400
1,200
1,000
800
600
400
200
0
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701
Hours

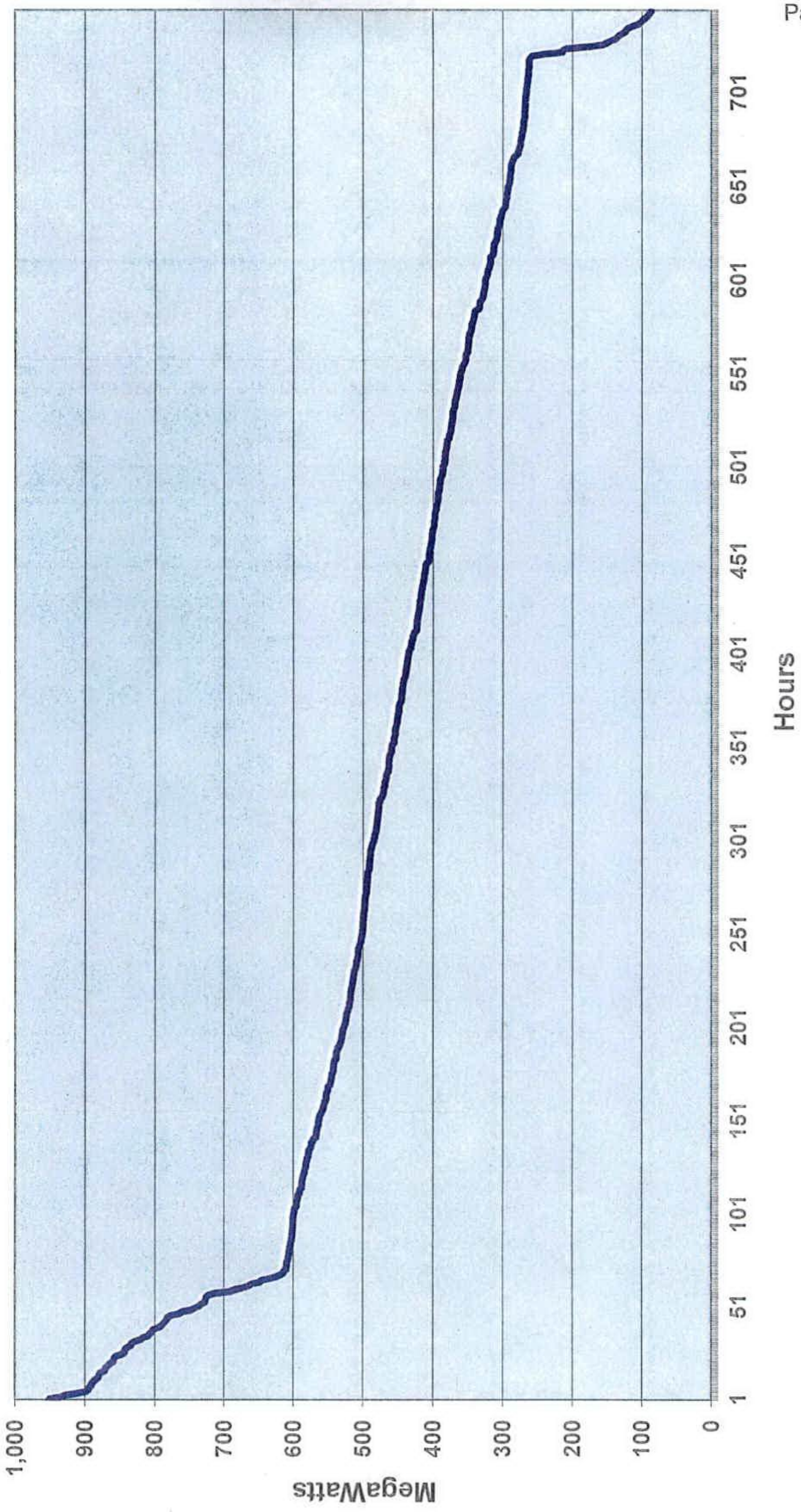
Kentucky Power Company
October 2015 Load Duration Curve
(System Load)



Kentucky Power Company
November 2015 Load Duration Curve
(System Load)



Kentucky Power Company
December 2015 Load Duration Curve
(System Load)



Kentucky Power Company

REQUEST

Based on the most recent demand forecast, the base case demand and energy forecasts and high case demand and energy forecasts for the current year and the following four years. The information should be disaggregated into (a) native load (firm and non-firm demand) and (b) off-system load (both firm and non-firm demand). Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420).

RESPONSE

Page 1 of Attachment 1 to this response provides Kentucky Power Company's forecast of seasonal peak internal demands and annual internal energy requirements. In addition, the associated high forecast for seasonal peak internal demands and internal energy requirements are provided on this page.

The off-system energy sales forecasts for Kentucky Power Company are provided on Page 2 of Attachment 1 to this response. Forecasts of off-system peak demand for Kentucky Power Company have not been developed and therefore, such forecasts are not available. In addition, high forecasts for off-system energy sales and peak demand have not been developed and therefore, such forecasts are not available.

The AEP Interconnection Agreement terminated on January 1, 2014 and the AEP-East Power Pool no longer exists. As a result, the request for information regarding the AEP-East Power Pool is no longer applicable.

WITNESS: Ranie K Wohnhas

Kentucky Power Company
Base and High Forecast
Energy Sales (GWH) and Seasonal Peak Demand (MW)
2016 - 2020

Year	Energy Sales		Summer Peak Demand		Preceding Winter Peak Demand	
	Base	High	Base	High	Base	High
2016	6,821	6,916	1,120	1,136	1,478	1,499
2017	6,818	6,900	1,122	1,136	1,478	1,495
2018	6,803	6,918	1,122	1,141	1,472	1,497
2019	6,795	6,944	1,123	1,147	1,466	1,498
2020	6,794	6,990	1,122	1,154	1,458	1,500

Kentucky Power Company
Forecast Off-System Energy Sales (GWh)
2016 - 2020

Year	KPCo Off-System Sales
2016	2,063
2017	2,541
2018	1,909
2019	1,060
2020	975

Kentucky Power Company

REQUEST

The target reserve margin currently used for planning purposes, stated as a percentage of demand. If changed from what was in use in 2001, include a detailed explanation for the change. Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420).

RESPONSE

Due to the October 1, 2004 integration of AEP's Eastern System into the PJM Interconnection, AEP is now required to comply with the PJM mandated reserve margin.

The installed reserve margin requirement (IRM) is recalculated each year, depending on five-year average generation reliability, PJM load shape, and assistance available from neighboring regions. In addition, KPCo's responsibility to PJM depends on its twelve-month history of generator reliability and its peak demand diversity in relation to the PJM total load. Attachment 1 to this response provides an example of the PJM reserve requirement calculation.

For the 2016/17 delivery period PJM has set the IRM at 16.4%. For the delivery periods 2017/18 through 2020/21, PJM has set the IRM at 16.5%. For planning purposes, KPCo assumed a 16.5% level for future years. The resulting KPCo reserve margin for 2016/17 is 23.1% as shown in Attachment 2 of the response to Item No. 5.

The AEP Interconnection Agreement terminated on January 1, 2014 and the AEP-East Power Pool no longer exists. As a result, the request for information regarding the AEP-East Power Pool is no longer applicable.

WITNESS: Ranie K Wohnhas

PJM Reserve Margin Example For 2016/17 Planning Year

Line			Comment
1	**Factors**		
2	PJM Installed Reserve Margin (IRM) =	16.40%	
3	PJM EFORd =	5.91%	Based on 5-year average PJM EFORd
4	Forecast Pool Requirement (FPR) =	1.095	FPR = (1 + Line 2) * (1 - Line 3)
5			
6	**Obligations**		
7	Total Load Obligation =	1,088	With implied PJM diversity factor
8	UCAP Obligation =	1,192	Line 4 * Line 7
9	UCAP Market Obligations =	0	
10	Total UCAP Obligation =	1,192	Line 8 + Line 9
11			
12	**Resources**		
13	Net ICAP =	1,440	
14	KPCo EFORd =	10.99%	MW-weighted average of Unit EFORds
15	Available UCAP =	1,282	Line 13 * (1- Line 14)
16			
17	**Position**		
18	Net UCAP Position =	90	Line 15 - Line 10
19	Net ICAP Position =	101	Line 18 / (1- Line 14)
20			
21	Reserve Margin Percent =	32.4	Question 5 Attachment 2, Column (16)
22	Reserve Percent Required By PJM =	23.1	Line 21 - (Line 19 / Question 5 Attachment 2, Column (6)) * 100

Kentucky Power Company

REQUEST

Projected reserve margins stated in megawatts and as a percentage of demand for the current year and the following 4 years. Identify projected deficits and current plans for addressing these. For each year identify the level of firm capacity purchases projected to meet native load demand. Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420)

RESPONSE

Attachment 1 to this response provides projected winter peak demands, capabilities, and margins for KPCo for the winter seasons 2015/16/through 2019/20.

Attachment 2 to this response provides projected summer peak demands, capabilities, and margins for KPCo for 2016 through 2020.

The AEP Interconnection Agreement terminated on January 1, 2014 and the AEP-East Power Pool no longer exists. As a result, the request for information regarding the AEP-East Power Pool is no longer applicable.

WITNESS: Ranie K Wohnhas

KENTUCKY POWER COMPANY
Projected Winter Peak Demands, Generating Capabilities, and Margins

	Peak Demand - MW						Capacity - MW						Margin (e)	
							Existing	Sales	Capacity Additions		Purchases			
Winter Season	Internal Demand (a)	DSM (b)	Committed Sales	Total Demand	Interruptible Demand (c)	Total Demand	Capacity & Chngs (d)	Net Sales	Name/ Identifier	MW	Annual Mkt. Purch.	Total Equivalent Capacity	MW	% of Demand
	(1)	(2)	(3)	(4)=(1)-(2+(3)	(5)	(6)=(4)-(5)	(7)	(8)		(9)	(10)	(11)=(7)-(8)+Sum(9)+(10)	(12)=(11)-(6)	(13)=[(12)/(6)]*100
2015/16	1,485	(7)	0	1,478	0	1,478	1,451	0		0	0	1,451	(27)	(1.8)
2016/17	1,488	(10)	0	1,478	0	1,478	1,441	0		0	0	1,441	(37)	(2.5)
2017/18	1,485	(13)	0	1,472	0	1,472	1,446	0		0	0	1,446	(26)	(1.8)
2018/19	1,481	(15)	0	1,466	0	1,466	1,446	0		0	0	1,446	(20)	(1.4)
2019/20	1,475	(17)	0	1,458	0	1,458	1,452	0	ecoPower (Biomass) (f)	58.5	0	1,511	53	3.6

Notes: (a) Based on June 2015 Load Forecast.

(b) Existing plus approved and projected "Passive" EE, and VVO.

(c) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR. KPCo had one customer with interruptible provisions in its contract in 2015. However, this customer's load was not adequately above its firm load to provide an interruptible resource in PJM's auctions. An additional customer contracted for interruptible in 2016 after this analysis was completed.

(d) Reflects KPCo's share of the following winter capability assumptions.
EFFICIENCY IMPROVEMENTS:
2017/18: Rockport 1: 5 MW (turbine)
2019/20: Rockport 2: 6 MW (turbine)
GAS CONVERSION RERATES:
2016/17: Big Sandy 1: (10 MW)

(e) Represents margin relative to KPCo peak demand, not PJM requirement.

(f) Kentucky Power entered into a renewable energy purchase agreement ("REPA") with ecoPower Generation-Hazard LLC to purchase the output of ecoPower's 58.5 MW biomass generation facility to be constructed near Hazard, Kentucky. The Commission's Order approving the REPA has been appealed and is currently before the Kentucky Court of Appeals for review. Representatives from ecoPower have confirmed that it will require approximately 36 months from the final resolution of the appeal before the facility is available for commercial operation. As a result, and assuming a favorable ruling from the Court of Appeals and no further appeal, Kentucky Power estimates that the earliest the ecoPower facility will be available to serve the Company's native load requirements is 2020.

KENTUCKY POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins

Summer Season	Peak Demand - MW						Capacity - MW						Reserve Margin Before Interruptible w/ New Capacity		Reserve Margin After Interruptible w/ New Capacity		PJM ICAP Position After Interruptible w/ New Capacity	
	Internal Demand (a)	Interruptible Demand Response (b)	DSM (c)	Net KPCo Internal Demand	Net Other Committed Sales	Total KPCo Demand	Existing Capacity & Planned Changes (d)	Committed Net Sales	Planned Capacity Additions Name/ Identifier	Planned Capacity Additions MW	Annual Purch.	Total Capacity	MW	% of Demand	MW	% of Demand	Reserve % Required By PJM	Net Position MW
	(1)	(2)	(3)	(4)=sum(1 thru 3)	(5)	(6)=(4)+(5)	(7)	(8)	(9)	(10)	(11)	12)=(7)-(8)+Sum(10)+(11)	(13)=(12)-((6)-(2))	(14)=(13)/((6)-(2))*100	(15)=(12)-(6)	(16)=(15)/(6)*100		
2016	1,088	0	0	1,088	0	1,088	1,440					1,440	352	32.4	352	32.4	23.1	101
2017	1,095	0	0	1,095	0	1,095	1,440					1,440	345	31.5	345	31.5	19.4	133
2018	1,104	0	0	1,104	0	1,104	1,446					1,446	342	31.0	342	31.0	19.4	128
2019	1,118	0	0	1,118	0	1,118	1,446					1,446	328	29.3	328	29.3	19.4	111
2020	1,033	0	(5)	1,028	0	1,028	1,451		ecoPower (Biomass) (e)	58.5		1,510	482	46.9	482	46.9	19.5	282

Notes: (a) Based on (June 2015) Load Forecast (with implied PJM diversity factor)

(b) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR. KPCo had one customer with interruptible provisions in its contract in 2015. However, this customer's load was not adequately above its firm load to provide an interruptible resource in PJM's auctions. An additional customer contracted for interruptible in 2016 after this analysis was completed.

(c) For PJM planning purposes, the ultimate impact of new DSM is 'delayed' about 4 years to represent the ultimate recognition of these amounts through the PJM-originated load forecast process.

(d) Reflects KPCo's share of the following summer capability assumptions:
EFFICIENCY IMPROVEMENTS:
2018: Rockport 1: 6 MW (turbine)
2020: Rockport 2: 5 MW (turbine)

(e) Kentucky Power entered into a renewable energy purchase agreement ("REPA") with ecoPower Generation-Hazard LLC to purchase the output of ecoPower's 58.5 MW biomass generation facility to be constructed near Hazard, Kentucky. The Commission's Order approving the REPA has been appealed and is currently before the Kentucky Court of Appeals for review. Representatives from ecoPower have confirmed that it will require approximately 36 months from the final resolution of the appeal before the facility is available for commercial operation. As a result, and assuming a favorable ruling from the Court of Appeals and no further appeal, Kentucky Power estimates that the earliest the ecoPower facility will be available to serve the Company's native load requirements is 2020.

Kentucky Power Company

REQUEST

A list that identifies scheduled outages or retirements of generating capacity during the current year and the following four years.

RESPONSE

Please refer to Attachment 1 to this response.

WITNESS: Ranie K Wohnhas

Big Sandy Plant

Year	Unit 1	Unit 2
2016	19 weeks	Retired
2017	5 weeks	Retired
2018	10 weeks	Retired
2019	5 weeks	Retired
2020	6 weeks	Retired

Mitchell Plant

Year	Unit 1	Unit 2
2016	No Outage Scheduled	3 weeks
2017	2 weeks	2 weeks
2018	10 weeks	8 weeks
2019	8 weeks	2 weeks
2020	2 weeks	2 weeks

Kentucky Power Company

REQUEST

Identify all planned base load or peaking capacity additions to meet native load requirements over the next 10 years. Show the expected in-service date, size and site for all planned additions. Include additions planned by the utility, as well as those by affiliates, if constructed in Kentucky or intended to meet load in Kentucky. Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420).

RESPONSE

Kentucky Power entered into a renewable energy purchase agreement ("REPA") with ecoPower Generation-Hazard LLC to purchase the output of ecoPower's 58.5 MW biomass generation facility to be constructed near Hazard, Kentucky. The Commission's Order approving the REPA has been appealed and is currently before the Kentucky Court of Appeals for review. Representatives from ecoPower have confirmed that it will require approximately 36 months from the final resolution of the appeal before the facility is available for commercial operation. As a result, and assuming a favorable ruling from the Court of Appeals and no further appeal, Kentucky Power estimates that the earliest the ecoPower facility will be available to serve the Company's native load requirements is 2020.

As a result of the 1/1/2014 AEP Interconnection Agreement ("pool agreement") termination, information regarding AEP-East Power pool capacity expansion plans is no longer available

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

The following transmission energy data for the just completed calendar year and the forecast for the current year and the following four years:

a. Total energy received from all interconnections and generation sources connected to the transmission system.

b. Total energy delivered to all interconnections on the transmission system

RESPONSE

a & b. Please refer to Attachment 1 to this response.

WITNESS: Ranie K Wohnhas

KPSC Adm. Case No. 387
Order Dated December 20, 2001
For Calendar Year 2015
Item No. 8a & 8b

Attachment 1
Page 1 of 1

quantities represent metered values.

Received from (MWh):	2010 (Actual)	2011 (Actual)	2012 (Actual)	2013 (Actual)	2014 (Actual)	2015 (Actual)	2016	
Appalachian Power (1)	5,042,019	4,230,880	4,338,641	4,631,523	5,171,726	4,017,819	(4)	
Ohio Power (1)	11,316,622	11,393,398	10,644,478	10,066,676	9,354,195	9,802,944	(4)	
East Ky Power Coop	412,663	510,543	394,193	386,124	294,361	271,558	(4)	
LGE(Kentucky Utilities)	884,267	780,095	730,063	565,818	623,285	533,642	(4)	
TVA	604,964	654,875	551,305	566,823	460,644	431,204	(4)	
Illinois Power Co. (2)	46,376	59,956	136,798	111,628	84,189	380,121	(5)	
Illinois Power Co. (3)	20,742	26,552	101,471	89,276	67,185	193,480	(5)	
Big Sandy Generating Plant	6,552,258	6,372,925	2,661,344	2,764,447	4,708,473	3,132,143	1,193,300	
Mitchell 1&2 (KPCo Share 50%)				0	4,096,020	2,688,981	4,485,883	(7)
Rockport (KPCo Share 15%)					2,507,564	1,866,891	2,086,778	(7)

8(b) All quantities represent metered values.

Delivered to (MWh) :	2010	2011	2012	2013	2014	2015	2016
Appalachian Power (1)	16,340,364	15,816,607	11,673,720	11,550,084	13,038,290	11,369,584	(4)
Ohio Power (1)	466,832	494,931	526,005	371,910	433,763	440,883	(4)
East Ky Power Coop	154,000	176,721	206,810	136,118	236,884	240,042	(4)
LGE(Kentucky Utilities)	23	1	36	0	0	0	(4)
TVA	0	1	0	0	0	0	(4)
Illinois Power Co. (2)	0	0	0	0	0	0	(5)
Illinois Power Co. (3)	0	0	0	0	0	0	(5)
Vanceburg and Olive Hill	103,058	95,607	95,525	95,502	96,494	90,532	(6)

Notes: (1) An AEP System company.
(2) At the Riverside independent power producing plant (IPP) in Lawrence County, KY.
(3) At the Foothills independent power producing plant (IPP) in Lawrence County, KY.
(4) The Company does not forecast metered interchange; however, the future years' energy flows are not expected to be materially different from the year 2015 actuals.
(5) The Company does not, and can not, forecast energy production output from an IPP.
(6) This is a 3rd Party Firm Load that is served by Kentucky Power
(7) Generation shares from Mitchell Power Plant and Rockport are from Plants not directly connected to the KPCo system

Kentucky Power Company

REQUEST

The following transmission energy data for the just completed calendar year and the forecast for the current year and the following four years.

c. Peak load capacity of the transmission system.

d. Peak demand for summer and winter seasons on the transmission system.

RESPONSE

c. The maximum amount of electric energy that can be transmitted through a transmission network is a function of the level of the load and generation connected to the transmission system as well as the level and direction of transmission service into, out of, and through the network. Therefore, the 'Peak Load Capacity' of the transmission system cannot be quantified as a single value.

The Kentucky Power transmission system capacity is designed to serve the existing and projected load. It is also designed to reliably serve the load for any single contingency outage of a line, transformer or generator. The existing transmission system together with the capacity additions listed in response to Item No. 9 will provide adequate capacity to serve the existing and projected loads shown in the table below.

d. Refer to Attachment 1 to this response for the actual summer and winter peak demands for 2015 and the forecasted summer and winter peak demands for 2016 through 2020.

WITNESS: Ranie K Wohnhas

Kentucky Power Company
Seasonal Peak Demand
Actual 2015 and Forecast 2016-2020

Year	Summer Peak Demand (MW)	Preceding Winter Peak Demand (MW)
2015	1,097*	1,666*
2016	1,120	1,478
2017	1,122	1,478
2018	1,122	1,472
2019	1,123	1,466
2020	1,122	1,458

*Based on Actual Data

Kentucky Power Company

REQUEST

Identify all planned transmission capacity additions for the next 10 years. Include the expected in-service date, size and site for all planned additions and identify the transmission need each addition is intended to address.

RESPONSE

Please refer to Attachment 1 to this response. Confidential treatment is being sought for portions of Attachment 1.

WITNESS: Ranie K Wohnhas

The following projects are planned for the Kentucky Power Company transmission system:

Big Sandy Area Improvements – This project will install a second 765/345 kV transformer at the Baker 765 kV station. This project will provide double contingency reliability to the critical transmission system. The anticipated in-service date would be June 2016.

Cedar Creek Station Upgrades – This project will install two new 138 kV circuit breakers at Cedar Creek Station. This project will provide operational benefits and provide voltage support for single contingency line outages. Current projected in-service date is April 2016.

Bellefonte Transformer Addition – This project will install a 200 MVA 138/69/34.5 kV transformer at Bellefonte station. This project will solve thermal planning criteria violations on the Bellefonte #5 for the loss of the Bellefonte #2 transformer. Current projected in-service date is June 2017.

Ashland Area Improvements – This project will install two new 138 kV circuit breakers and replace two 69 kV circuit breakers at Chadwick station. The project will also replace 69 kV breakers at Leach, England Hill, and Kenova stations while addressing remote end relaying in the area. This project will provide additional reliability to customers, operational flexibility, and voltage support under contingency conditions. Current projected in-service date is May 2017.

[redacted] This is identified as Project A on the accompanying motion for confidential treatment.

Hazard and Vicco Station Improvements – This project will install a new 138 kV circuit breaker at Hazard station. The project will also replace malfunctioning operational switches and aging infastructure at Vicco station. This project will provide additional reliability to customers and operational flexibility under contingency conditions. Current projected in-service date is December 2019.

Johns Creek and Stone Station Upgrades – This project will install new 138 kV circuit breakers at Johns Creek, Stone and Inez stations. This project will provide additional reliability to customers, operational flexibility, and voltage support under contingency conditions. Current projected in-service date is December 2020.

[redacted] This is identified as Project B on the accompanying motion for confidential treatment.

[redacted] This is identified as Project C on the accompanying motion for confidential treatment.

Kentucky Power Company – Electricity Price in Forecast Modeling

In every load forecast, Kentucky Power Company takes electricity price and the effects of it's changes into consideration. This is true for the forecast filed in the 387 Administrative Case. The following provides a discussion of the impacts of prices on electricity sales and how price is accounted for in the load forecast.

An understanding of the relationship between energy prices and energy consumption is fundamental to developing a forecast of electricity consumption. In theory, the effect of a change in the price of a good on the consumption of that good can be disaggregated into two effects, the "income" effect and the "substitution" effect. The income effect refers to the change in consumption of a good attributable to the change in real income incident to the change in the price of that good. For most goods, a decline in real income would induce a decline in consumption. The substitution effect refers to the change in the consumption of a good associated with the change in the price of that good relative to the prices of all other goods. The substitution effect is assumed to be negative in all cases; that is, a rise in the price of a good relative to other, substitute goods would induce a decline in consumption of the original good. Thus, if the price of electricity were to rise, the consumption of electricity would fall, all other things being equal. Part of the decline would be attributable to the income effect; consumers must make decisions on how to allocate their budget to purchase electricity services and other goods and services after the price of electricity rises. Part would be attributable to the substitution effect; consumers would substitute relatively cheaper fuels for electricity once its price had risen.

The magnitude of the effect of price changes on consumption differs over different time horizons. In the short-term, the effect of a rise in the price of electricity is severely constrained by the ability of consumers to substitute other fuels or to incorporate more electricity-efficient technology. (The fact that the Company's short-term energy consumption models do not include price as an explanatory variable is a reflection of the belief that this constraint is severe).

In the long-term, however, the constraints on substitution are lessened for a number of reasons. First, durable equipment stocks begin to reflect changes in relative energy prices by favoring the equipment using the fuel that was expected to be cheaper; second, heightened consumer interest in saving electricity, backed by willingness to pay for more efficiency, spurs development of conservation technology; third, existing technology, too expensive to implement commercially at previous levels of energy prices, becomes feasible at the new, higher energy prices; and fourth, normal turnover of electricity-using equipment contributes to a higher average level of energy efficiency.

For these reasons, energy price changes are expected to have an effect on long-term energy consumption levels. As a reflection of this belief, most of the Company's long-term forecasting models, including the residential, commercial, manufacturing and mine power energy sales models, incorporate the price of electricity as an explanatory variable. The residential Statistically Adjusted End-Use (SAE) Model uses price in development of explanatory variables. There are a variety of short- and long-run elasticities utilized in this analysis. In addition to electricity prices, the residential SAE model utilizes the price of natural gas and associated cross-price elasticities. Likewise, the commercial SAE model incorporates electricity price and an associated price elasticity to develop explanatory variables. Manufacturing and mine power have price as an explanatory variable. In these cases, the coefficient of the price variable provides a quantitative measure of the sensitivity of the forecast value to a change in price.