

Mark David Goss Member

859.244.3232 mgoss@fbtlaw.com

November 18, 2010



Mr. Jeffrey Derouen Executive Director Kentucky Public Service Commission 211 Sower Boulevard P. O. Box 615 Frankfort, Kentucky 40602-0615

Re:

PSC Case No. 2010-00238

In the Matter of: An Investigation of East Kentucky Power Cooperative, Inc.'s Need for the Smith 1 Generating Facility

Dear Mr. Derouen:

Please find enclosed for filing with the Commission in the above-referenced case an original and ten redacted copies of certain Exhibits of East Kentucky Power Cooperative, Inc. ("EKPC") in responding to items contained in the Commission's Order dated June 22, 2010, as well as EKPC's Petition for Confidential Treatment of Information ("Petition"). Prepared testimonies of Anthony S. Campbell, Julia J. Tucker, David K. Mitchell, and Gary G. Stansberry are also enclosed. One unredacted copy of the designated confidential portion of the Exhibits, which is the subject of the Petition, is enclosed in a sealed envelope.

Please file same of record in the captioned case.

Sincerely yours,

Mark David Goss

Enclosures

cc:

All Parties of Record

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BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN INVESTIGATION OF EAST KENTUCKY)	CASE NO.
POWER COOPERATIVE INC.'S NEED FOR)	2010-00238
THE SMITH 1 GENERATING FACILITY)	

PETITION FOR CONFIDENTIAL TREATMENT OF INFORMATION

Comes now the petitioner, East Kentucky Power Cooperative, Inc. ("EKPC"), and as grounds for this Petition for Confidential Treatment of Information (the "Petition"), states as follows:

- 1. This Petition is filed in conjunction with the filing of EKPC's Direct Testimony in this case, required by Commission Order dated June 22, 2010, and subsequently amended July 16, 2010, September 7, 2010, September 24, 2010 and November 10, 2010, and relates to confidential information contained in certain exhibits and supporting assumptions that is entitled to protection pursuant to 807 KAR 5:001 Section 7 and KRS §61.878(1)(c)1 and §61.878(1)(c)2c.
- 2. The information designated as confidential in these exhibits and supporting assumptions include fuel, emission, purchased power, and load/financial forecast assumptions that are proprietary in nature. The open disclosure of such information could present an unfair commercial advantage to competitors of EKPC in EKPC's efforts to compete with the power marketers, utilities and other entities that deal in the market for surplus bulk power, and to compete with other utilities in Kentucky for

new industrial customers. As such this information is confidential and not subject to public disclosure pursuant to KRS §61.878(1)(c)1.

- 3. The subject information is also entitled to protection pursuant to KRS §61.878(1)(c)2c, as records generally recognized as confidential or proprietary which are confidentially disclosed to an agency in conjunction with the regulation of a commercial enterprise.
- 4. Along with this Petition, EKPC has enclosed one copy of the subject exhibits with the confidential information identified by highlighting or other designation, and 10 copies of the same exhibits with the confidential information redacted. The identified confidential information is not known outside of EKPC and is distributed within EKPC only to persons with a need to use it for business purposes. It is entitled to confidential treatment pursuant to 807 KAR 5:001 Section 7 and the various sections of KRS 61.878 delineated above.

WHEREFORE, EKPC respectfully requests the Public Service Commission to grant confidential treatment to the identified information and deny public disclosure of said information.

Respectfully submitted,

Mark David Goss

Mark David Goss

Frost Brown Todd LLC

250 West Main Street, Suite 2800

Lexington, KY 40507-1749

(859) 231-000—Telephone

(859) 231-0011—Facsimile

Counsel for East Kentucky Power Cooperative, Inc.

CERTIFICATE OF SERVICE

This is to certify that an original and 10 copies of the foregoing Petition for Confidential Treatment of Information in the above-styled case were hand-delivered to the Office of Jeffrey Derouen, Executive Director of the Kentucky Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40601 on November 18, 2010, and sent by first class mail to: Honorable Michael R. Campbell, Campbell and Rogers, 154 Flemingsburg Drive, Morehead, KY 40351; Honorable Dennis G. Howard II, Esq., Assistant Attorney General, P.O. Box 2000, Frankfort, Kentucky 40602-2000; Honorable Michael L. Kurtz, Attorney at Law, Boehm, Kurtz & Lowry, 36 East Seventh Street, Suite 1510, Cincinnati, OH 45202; and Honorable Robert Ukeiley, 435R Chestnut Street, Suite 1, Berea, KY 40403.

Mark Dair D 655

Counsel for East Kentucky Power Cooperative, Inc.

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

AN INVESTIGATION OF EAST KENTUCKY)	
POWER COOPERATIVE, INC. 'S NEED FOR)	CASE NO. 2010-00238
THE SMITH 1 GENERATING FACILITY)	

RESPONSES TO COMMISSION STAFF'S INVESTIGATION INTO THE NEED FOR SMITH 1 GENERATING FACILITY COMMISSION REQUEST DATED JUNE 22, 2010

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN INVESTIGATION OF EAST KENTUCKY) CASE NO
POWER COOPERATIVE, INC.'S NEED FOR) 2010-00238
THE SMITH 1 GENERATING FACILITY)

TESTIMONY OF ANTHONY S. CAMPBELL PRESIDENT AND CHIEF EXECUTIVE OFFICER EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: November 18, 2010

- 1 Q. Please state your name, business address and occupation.
- 2 A. My name is Anthony S. Campbell and my business address is East Kentucky Power
- Cooperative, Inc. (EKPC), 4775 Lexington Road, Winchester, Kentucky 40391. I am
- 4 President and Chief Executive Officer.
- 5 Q. How long have you been employed by East Kentucky Power Cooperative, Inc.
- 6 ("EKPC")?
- 7 A. I have been employed by EKPC since June 2009.
- 8 Q. Please state your education and professional experience.
- 9 A. I received a Bachelor of Science degree in electrical engineering from the Southern
- 10 Illinois University at Carbondale and a Masters of Business Administration from the
- University of Illinois at Champaign. Prior to joining EKPC, I served as CEO of
- 12 Citizens Electric Corporation, a transmission and distribution company located in
- southeast Missouri.
- 14 Q. Please provide a brief description of your duties at EKPC.
- 15 A. The Board of Directors has given me, as CEO, the responsibility for managing the
- 16 Cooperative's business on a day-to-day basis. I carry out the Board's strategy within
- the guidelines and policies developed by the Board.
- 18 Q. What is the purpose of your testimony?
- 19 A. The purpose of my testimony is to introduce other witnesses providing testimony and
- 20 to provide an overview of the results of EKPC's analysis.
- 21 Q. Please list EKPC's witnesses who will provide detailed testimony regarding the
- investigation of the Smith 1 generating facility.

- 1 (1) Mr. David K. Mitchell, Vice-President of Construction at EKPC, will discuss the A. 2 Smith 1 cost estimate by major component and the operational and financial impacts of a hypothetical delay of the in-service date for Smith 1 of two years and four years. 3 (2) Ms. Julia J. Tucker, Director of Power Supply Planning at EKPC, will discuss 4 5 EKPC's most recent long-term load forecast and EKPC's existing generating 6 capacity, provide information regarding peaks, capacity, sales and reserve requirements, discuss EKPC's efficiency and other demand-side management 7 programs and their impacts, and discuss EKPC's production costing model. 8 9 (3) Gary G. Stansberry, Manager of Performance Measures at EKPC, will discuss the 10 financial results of each alternative scenario compared to Smith 1 as planned, provide 11 revenue requirements of each scenario and the impact on member rates.
- 12 Q. What is the background of the Smith 1 Unit?
- On August 29, 2006, in Case No. 2005-00053, the Commission granted EKPC a 13 A. Certificate of Public Convenience and Necessity ("CPCN") to construct the 278 MW 14 Smith Circulating Fluidized Bed Generating Unit ("Smith 1"). On January 5, 2007, in 15 light of the decision by Warren Rural Electric Cooperative Corporation to terminate a 16 power supply agreement with EKPC, the Commission investigated the continued 17 18 need for Smith 1 (Case No. 2006-00564). After much discovery, on May 11, 2007, the Commission issued an Order allowing EKPC to retain the CPCN for Smith 1, as 19 EKPC submitted evidence during the proceeding that showed: 1) that Smith 1 20 generation was still needed and 2) that Smith 1 was the least cost power supply 21 22 alternative.

1	Q.	Were there portions of the Commission's Order in Case No. 2006-00564 that
2		were particularly compelling?

3 A. Yes. The Commission states on pages 9 and 10 of the Order: "With regard to the 4 Smith No. 1 unit, there are two alternatives to consider. The Commission might order EKPC to purposefully delay the construction of Smith No. 1 to guarantee that its 5 6 native load requirements are sufficient to support the addition of the generating unit. 7 This course of action, however, would result in the levying of significant contractual penalties on EKPC and increase its exposure to escalating costs for labor and 8 9 materials in the future. On the other hand the Commission might allow EKPC to 10 proceed with construction of the Smith No. 1 unit and run the risk that EKPC's native 11 load growth might not grow as quickly as forecasted—potentially resulting in EKPC having excess generation capacity. While neither situation is ideal, the latter position 12 13 is clearly preferred under the specific facts of this case. In the long run, EKPC's 14 ratepayers and the public interest at large will be best served by allowing EKPC to complete the construction of Smith No. 1 and avoid unnecessary penalties and cost 15 escalations associated with a lengthy delay. Any risk of reaching a situation where 16 EKPC has excess generation capacity should be mitigated by EKPC's careful 17 18 development and implementation of a mechanism for making off-system sales. 19 Accordingly, EKPC will be permitted to continue with the construction of the Smith 20 No. 1 unit as originally certificated but should develop and implement an appropriate 21 plan for facilitating off-system sales if the opportunity arises."

Q. Based on this Order, did EKPC continue its construction of Smith 1?

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- 1 A. Yes. EKPC was concerned about the labor and materials escalations referenced in the
- 2 Order and continued with construction.
- 3 Q. Has EKPC prudently incurred costs on Smith 1 to date?
- 4 A. Without question. EKPC's load forecasts in 2006 and 2008 supported the continued
 5 need for Smith 1, and Smith 1 was the least cost option. EKPC believes that all of the
 6 costs for Smith 1 to date were prudently incurred.
- Q. Since the awarding of the certificates in the above-referenced proceedings, has

 EKPC conducted its own analyses relating to Smith 1 prior to the Commission's

 opening of this investigation?
- 10 A. Yes. EKPC has reviewed its assumptions relating to Smith 1 numerous times over
 11 the last few years to ensure Smith 1 was still the least cost option. Until recently,
 12 Smith 1 proved to be the least cost option to supply EKPC's power supply needs.
- O. Could you elaborate on what is meant by "until recently"?
- 14 A. The Commission's Order initiating the investigation into the need and cost of Smith
 15 1 was coincident with EKPC's completion of its 2010 load forecast. As discussed in
 16 greater detail in Ms. Tucker's testimony, the 2010 load forecast showed a diminished
 17 load growth. The forecast indicates that base load generation is not needed until
 18 approximately 2018. As further discussed in the testimony of Mr. Stansberry, Smith
 19 1 is no longer the least cost option compared to other power supply alternatives.
- 20 Q. What is the conclusion reached as a result of your recent analysis?
- A. As stated above, the results of EKPC's load forecast do not support the immediate
 need for base load generation. Additionally, continuing to build Smith 1 will place an

1		undue burden on EKPC from a long-term debt perspective, and will cause EKPC's
2		rates to its members to increase substantially. EKPC's Board of Directors has
3		concluded unanimously that, based upon the results of EKPC's analysis, it must
4		voluntarily relinquish the CPCN for Smith 1.
5	Q.	How are you proposing to treat the costs already incurred on building Smith 1?
6	A.	Through a separate Application filed with the Commission, EKPC is requesting the
7		Commission's approval to establish a regulatory asset. This Application contains the
8		testimony of Mike McNalley, EKPC's Chief Financial Officer, who addresses this
9		matter at length.
10	Q.	Does this conclude your testimony?
11	A.	Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

AN INVESTIGATION OF EAST KENTUCKY)	
POWER COOPERATIVE, INC. 'S NEED FOR)	CASE NO. 2010-00238
THE SMITH 1 GENERATING FACILITY)	

AFFIDAVIT

STATE OF KENTUCKY	
COUNTY OF CLARK	

Anthony S. Campbell, being duly sworn, states that he has read the foregoing prepared testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Subscribed and sworn before me on this / / day o

WY COMMISSION EXPIRES NOVEMBER 30, 2013 NOTARY ID #409352

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BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN INVESTIGATION OF EAST KENTUCKY) PSC CASE NO).
POWER COOPERATIVE, INC.'S NEED FOR) 2010-00238	
THE SMITH 1 GENERATING FACILITY)	

TESTIMONY OF DAVID K. MITCHELL VICE-PRESIDENT OF CONSTRUCTION EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: November 18, 2010

1		COMMONWEALTH OF KENTUCKY
2		BEFORE THE PUBLIC SERVICE COMMISSION
3 4 5		AN INVESTIGATION OF EAST KENTUCKY POWER COOPERATIVE, INC.'S NEED FOR THE SMITH 1 GENERATING FACILITY) PSC CASE NO.) 2010-00238)
6 7 8 9		DIRECT TESTIMONY OF DAVID K. MITCHELL ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.
10	Q.	Please state your name, business address and occupation.
11	A.	My name is David K. Mitchell and my business address is East Kentucky Power
12		Cooperative (EKPC), 4775 Lexington Road, Winchester, Kentucky 40391. I am Vice-
13		President of Construction for EKPC.
14	Q.	Please state your education and professional experience.
15	A.	I hold a Bachelor of Science Degree in Electrical Engineering and a Master Degree in
16		Business Administration both from the University of Kentucky. I have over 25 years of
17		experience in the design, construction, operation and maintenance of fossil fuel based
18		power generating stations. I have worked for Kentucky Utilities Company, Indianapolis
19		Power & Light Company, the Tennessee Valley Authority and now East Kentucky Power
20		Cooperative.
21	Q.	Please provide a brief description of your duties at EKPC.
22	A.	I am responsible for all generation construction activities at East Kentucky Power.
23	Q.	What is the purpose of your testimony?
24	A.	The purpose of my testimony is to discuss the Smith 1 cost estimate by major component.
25		I will also discuss the operational and financial impacts of a hypothetical delay of the in-

- service date for Smith 1 of two years and four years. 1 2 Are you sponsoring any exhibits in this proceeding? Q. 3 A. Yes. I am sponsoring Exhibit DKM-1, Smith 1 Cost Estimate. What is the most recent cost estimate for Smith 1 as currently scheduled? 4 0. Exhibit DKM-1 reflects EKPC's most recent cost estimate, by major component, of 5 A. 6 Smith 1. 7 How much has EKPC spent on this project to date? Q. As of September 30, 2010, EKPC has spent \$153,448,904 on Smith 1. 8 A. How much does this cost increase assuming Smith 1 is delayed for two years and for 9 Q. 10 four years? The current estimated cost for Smith 1 is roughly \$820 million. A two year delay causes 11 A. an increase in the estimated cost to a new total of \$950 million. A four year delay 12 increases the estimated total cost to \$1.021 billion. The primary reasons for these cost 13 14 increases are design changes to address new environmental regulations and assumed 15 escalation in material and labor expenses. Please see Mr. Stansberry's testimony for additional details on the cost impacts of delaying the project. 16 Would you please explain the cost impacts of changing environmental regulation? 17 Q. Changing environmental regulation is expected to require the addition of a tail end SCR 18 A. to Smith 1. The anticipated cost of this device to further reduce NOx emissions is 19 20 \$65 million in 2010 dollars. What impacts would a Smith 1 delay for two years and for five years have on 21 Q.
- 23 A. There are no adverse impacts on EKPC's operations for a delay of Smith 1 for a period of

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EKPC's operations?

1		1-5 years. Please see the testimony of Ms. Tucker for a discussion of EKPC's expansion
2		plan needs.
3	Q.	Assuming that Smith 1 is cancelled, what are the additional contractual obligations?
4	A.	There are 4 suppliers who may be entitled to receive cancellation charges. EKPC will
5		negotiate with those suppliers. However, EKPC anticipates that its obligations may reach
6		\$10 million, which includes contract unwinding costs and asset disposal costs.
7	Q.	Assuming that Smith 1 is cancelled, will EKPC be able to use any of the components
8		purchased for Smith 1 in any of its other circulating fluidized bed units?
9	A.	Yes. EKPC estimates that components valued at approximately \$14 million could be
10		placed in inventory as capital spares.
11	Q.	How likely would another utility/merchant plant owner be interested in the Smith 1
12		equipment purchased?
13	A.	EKPC is in discussions with independent power producers, project developers,
14		international marketers, EKPC contractors and others but, to date, interest in the Smith 1
15		equipment has been minimal.
16	Q.	What is the salvage value for this equipment?
17	A.	EKPC estimates that salvage value could range from that of scrap (5 to 10 cents on the
18		dollar) up to 30% if the project can be sold in whole or in part. EKPC has assumed a \$20
19		million salvage value in making its financial comparisons.
20	Q.	Does this conclude your testimony?
21	A.	Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

AN INVESTIGATION OF EAST KENTUCKY)	
POWER COOPERATIVE, INC. 'S NEED FOR)	CASE NO. 2010-00238
THE SMITH 1 GENERATING FACILITY)	

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

David K. Mitchell, being duly sworn, states that he has read the foregoing prepared testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

MY COMMISSION EXPIRES NOVEMBER 30, 2013 NOTARY ID #409352

REDACTED



SMITH STATION UNIT 1

PRELIMINARY ESTIMATED PROJECT COSTS - SEPTEMBER 2010

DATE OF ESTIMATE: DECEMBER 28, 2009

DATE OF ESTIMATE: DECEMBER 28, 2009				
CONTRACT NUMBER	CONTRACT	UNIT 1 ESTIMATE DEC 2009		
G1	TURBINE GENERATOR			
G3	SITE IMPROVEMENTS	N. C.		
G6	FEEDWATER HEATERS			
G8	DEAERATOR			
G11	CONDENSER			
G16	CIRCULATING WATER PUMPS			
G17	CONDENSATE PUMPS	14 24 25		
G21	BOILER FEED PUMPS			
G36	DISTRIBUTED CONTROL SYSTEM			
G46	FANS	×.		
G71	ASH HANDLING EQUIPMENT	X		
G82	TURBINE BRIDGE CRANE			
G101	ALLOY PIPING			
G131A	LARGE POWER TRANSFORMERS	3		
G131B	MEDIUM POWER TRANSFORMERS	medical explanation of contractions		
G131C	SMALL POWER DISTRIBUTION TRANSFORMERS			
G132	GENERATOR BREAKER & ISOPHASE			
G146	SWITCHGEAR			
G201	BOILER ISLAND			
G204	EMISSIONS MONITORING	*		
G211	COAL/LIMESTONE HANDLING			
G221	CHIMNEY			
G222	COOLING TOWER			

REDACTED



SMITH STATION UNIT 1

PRELIMINARY ESTIMATED PROJECT COSTS - SEPTEMBER 2010

DATE OF ESTIMATE: DECEMBER 28, 2009

DATE OF EST	IMATE: DECEMBER 28, 2009		UNIT 1
CONTRACT NUMBER	CONTRACT		ESTIMATE DEC 2009
G223	CIRCULATING WATER PIPE		
G241	DAM & WATER RESERVOIR /PUMP HOUSE/PI DEVELOPMENT, AND LAND	ERMIT MITIGATION,	*
G261/G262	SUBSTRUCTURE I and II		
G264	ASH SILOS		
G271	TURBINE BUILDING STRUCTURAL STEEL		
G281	BUILDING & MECHANICAL WORK		in . s
G283	ASH HANDLING INSTALLATION		· J
G285	RIVER WATER INTAKE & PUMPHOUSE		** **
G311	ELECTRICAL & INSTRUMENTATION WORK		
G332	PAINTING		
G335	OFFICE AND MAINTENANCE BUILDING		4
G338	PAVING AND ROAD WORK		** # - A
		SUBTOTAL	
	CONTINGENCY (7% of above subtotal)	SUBTOTAL	
	ENGINEERING COST ORIGINAL DESIGN MISC. STUDIES CONSTRUCTION MANAGEMENT ASSISTA MITIGATION PLAN, DESIGN, AND MANAGE US ARMY CORP OF ENGINEERS IN-LIEU F PERMITTING COSTS PERFORMANCE TEST OWNERS COST	EMENT EE	*
		SUBTOTAL	-
		TOTAL IDO PROJECT TOTAL	
	UN	SUBSTATION TRANSMISSION IIT 1 TOTAL PROJECT COST	* * * 819,333,003

^{*}Information provided by EKPC.

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN INVESTIGATION OF EAST KENTUCKY) PSC CASE NO
POWER COOPERATIVE, INC.'S NEED FOR) 2010-00238
THE SMITH 1 GENERATING FACILITY)

TESTIMONY OF JULIA J. TUCKER DIRECTOR OF POWER SUPPLY PLANNING EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: November 18, 2010

	COMMONWEALTH OF KENTUCKY		
	BEFORE THE PUBLIC SERVICE COMMISSION		
	AN INVESTIGATION OF EAST KENTUCKY) PSC CASE NO. POWER COOPERATIVE, INC.'S NEED FOR) 2010-00238 THE SMITH 1 GENERATING FACILITY)		
	DIRECT TESTIMONY OF JULIA J. TUCKER, P.E. ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.		
Q.	Please state your name, business address and occupation.		
A.	My name is Julia J. Tucker and my business address is East Kentucky Power Cooperative		
	(EKPC), 4775 Lexington Road, Winchester, Kentucky 40391. I am Director of Power		
	Supply Planning for EKPC.		
Q.	Please state your education and professional experience.		
A.	I received a Bachelor of Science Degree in Electrical Engineering from the University of		
	Kentucky in 1981. I received my Professional Engineer license from the State of		
	Kentucky (Registration No. 15532) in 1988. I completed 18 hours towards a Masters of		
	Business Administration degree. I have maintained my Continuing Education		
	requirements for my P.E. license. I have been employed in various engineering,		
	planning, and management roles with East Kentucky Power for over 23 years.		
Q.	Please provide a brief description of your duties at EKPC.		
A.	I am responsible for all generation / resource planning functions at East Kentucky Power,		
	including day ahead planning, mid-term planning, long term resource planning, load		
	forecasting, load research and demand side planning.		
O.	What is the purpose of your testimony?		

- 1 A. The purpose of my testimony is to discuss EKPC's most recent long-term load forecast,
- 2 EKPC's existing generating capacity, provide information regarding expected sales and
- 3 reserve requirements, discuss EKPC's demand-side management programs and their
- 4 impacts, and discuss EKPC's power supply options.
- 5 Q. Are you sponsoring any exhibits in this proceeding?
- 6 A. Yes. I am sponsoring five exhibits: Exhibit JJT-1, EKPC's 2010 Long-Term Load
- Forecast; Exhibit JJT-2, EKPC's expected capacity requirements as compared to its
- 8 existing generating capacity; Exhibit JJT-3, Current and Planned Energy Efficiency and
- 9 Demand Side Management ("DSM") Programs; Exhibit JJT-4, Expansion Plans; and,
- Exhibit JJT-5, Production Cost results for each case.
- 11 Q. When was EKPC's 2010 Long-Term Load Forecast completed?
- 12 A. EKPC completed its preliminary 2010 Long-Term Load Forecast in July. The
- preliminary load forecast was presented to EKPC's Board of Directors ("Board") in July
- 14 2010. After much review and discussion, the Board approved the 2010 Long-Term Load
- Forecast in November 2010. The Executive Summary from the EKPC 2010 Load
- Forecast report is included as Exhibit JJT-1. Energy sales and peak demand growth rates
- 17 range from the 1.0 to 1.8%. This reflects the downward trend that EKPC has experienced
- in its load growth. Energy sales grew from 1999 to 2004 by an average annual rate of
- 4.2%; however, from 2004 to 2009, the energy sales grew by an average annual rate of
- 20 1.2%.
- 21 Q. How often does EKPC complete a load forecast?
- 22 A. EKPC completes a load forecast every two years, as required by Rural Utilities Service.
- 23 Q. Are there any significant changes in the 2010 load forecast as compared to the 2008

and 2006 load forecasts?

2 A. Yes. The significant changes include the following:

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EKPC purchases county level projections of economic and demographic variables from IHS Global Insight, a consulting firm with expertise in economic modeling. The 2006 and 2008 economic projections did not project the recession that the US experienced beginning in late 2007. In 2005 when developing the 2006 forecast, the downturn had not yet begun. However, in 2007 when the 2008 forecast was developed, the majority of the member systems had begun to see declines in housing starts and development in their service territory resulting in a more conservative forecast than the 2006 forecast. The 2010 load forecast does have the full impacts of the recession. Most notably, unemployment reached an all time high and is not expected to return to pre-recession levels for nearly 10 years. Related, personal income levels are also projected to be lower than the previous assumptions showed. Therefore, the 20 year projections developed in 2010 for customer growth and energy usage are lower than those in 2008 and 2006. Lastly, the automotive industry experienced sharp declines both in response to the national economic downturn and in Kentucky due to various Toyota recalls which resulted in lower sales and interruptions in automobile manufacturing. EKPC member systems serve many satellite industrial and commercial customers that produce parts for Toyota and, as a result of the aforementioned circumstances, were negatively impacted.

Price

The load forecast incorporates future electricity prices and customers' response to fluctuations in price. The forecast uses the most recent Board approved Twenty-Year

Financial Forecast which is developed in house. The 2010 long term projections are 1 2 significantly higher than the ones used in the 2008 or the 2006 forecast. These increases 3 are due to costs to build a scrubber on Cooper 2, assumptions about future environmental 4 legislation issues such as carbon, and future power supply resources. 5

Efficiency

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EKPC attains future appliance efficiency improvements from the Department of Energy (DOE) Energy Information Administration (EIA). According to the 2009 update, there are more improvements in HVAC and water heating than previously assumed. These efficiency improvements will result in lower sales as consumers change out older less efficient appliances for newer ones. This impact will be a gradual one. In addition, there are new lighting standards to take effect in 2012.

Direct Load Control

The 2008 and 2010 load forecasts incorporate the impacts of a direct load control program that began implementation in 2008. The program is a voluntary program whereby customers agree to have their water heater(s) and/or air conditioner(s) controlled during peak hours. The goal is to save 15 MW off the winter peak and 60 MW off the summer peak.

Was the decline in projected load incorporated into EKPC's analysis of future 0. power supply needs?

- 20 Yes. Seven cases comparing power supply options were developed based on the 2010 A. 21 Load Forecast.
- 22 What is EKPC's existing generating capacity? 0.
- 23 EKPC owns and operates three coal fired generating stations, with a total station normal A.

net capacity of 1,883 MW.Dale Station consists of fou

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Dale Station consists of four pulverized coal units. Each of the first two units has a station normal net capacity of 23 MW. These two units became commercial on December 1, 1954. The third and fourth units have a station normal net capacity of 75 MW each. The third unit went commercial on October 1, 1957 and the fourth unit went commercial on August 9, 1960. Dale Station has a total station normal net capacity of 196 MW. Cooper Station consists of two pulverized coal units. The first unit has a station normal net capacity of 116 MW and went commercial on February 9, 1965. The second unit has a station normal net capacity of 225 MW and went commercial on October 28, 1969. Cooper 2 is currently being retrofitted with pollution control equipment that will become operational in 2012. Cooper Station's total station normal net capacity is 341 MW, which will be reduced by approximately 8 MW when the pollution control equipment becomes operational. Spurlock Station consists of four units, two pulverized coal and two circulating fluidized bed boilers. The first unit has a station normal net capacity of 300 MW and became commercial on September 1, 1977. The second unit has a station normal net capacity of 510 MW and went commercial on March 2, 1981. Both of these units are pulverized coal units and have been retrofitted with pollution control equipment. The third and fourth units are circulating fluidized bed boilers and each has a station normal net capacity of 268 MW. The third unit went commercial on March 1, 2005 and the fourth unit went commercial on April 1, 2009. Smith Station has three 150 MW gas fired ABB combustion turbines with winter ratings of 150 MW each and summer ratings of 110 MW each. These three units went

1		commercial in 1999. There are four 98 MW gas fired GE 7EA combustion turbines with
2		winter ratings of 98 MW each and summer ratings of 74 MW each. Two of these turbines
3		went into commercial operation in November 2001 and the last two became commercial in
4		January 2005. Two new gas fired LMS 100 GE combustion turbines have winter ratings of
5		97 MW each and summer net capacity of 83 MW each. These units went into commercial
6		operation in 2010.
7		Other Generation Resources - In addition, EKPC owns and operates 16.8 MW of
8		landfill gas generating plant capacity.
9		In total, EKPC owns and operates 2,936 MW of generating capacity, based on winter
10		temperature ratings.
11		EKPC purchases 170 MW of hydropower from the Southeastern Power Administration
12		("SEPA") on a long-term basis. The 70 MW at Laurel Dam has continued to be reliable
13		capacity. However, due to various dam repair projects, the 100 MW provided from the
14		Cumberland System has not been dependable capacity during the past few years and is not
15		expected to be considered dependable for another two to three years. Once the dam repairs
16		are completed, the capacity should return to firm dependable status for the long term.
17		EKPC also has a contract with Duke Energy Ohio to purchase the output of the Greenup
18		Hydro facility through 2010. Greenup Hydro is run-of-river generation located on the
19		Ohio River with an average winter capacity of 35 MW. This contract will expire on
20		December 31, 2010.
21	Q.	How does EKPC's existing generation capabilities compare to its expected capacity
22		and energy requirements going forward for the next 20 years?

EKPC has adequate summer capacity for the next several years, until approximately

23

A.

1		2020. However, EKPC is a winter peaking system, and is already lacking sufficient
2		capacity to cover its winter peak load plus reserves. This data is reflected in Exhibit JJT-
3		2. The expected energy requirements will drive the type of capacity that EKPC will need
4		to acquire, such as peaking versus intermediate versus base load. EKPC's average
5		monthly load is a rough indicator of base load capacity needs. Based on this assumption,
6		EKPC does not need additional base load capacity until approximately 2018. The seven
7		cases to be compared for this analysis were developed based on the peak capacity
8		requirements and the expected energy requirements. If a plan has too much or too little
9		cost effective energy resources, it will be reflected in the total cost of the plan.
10	Q.	What are EKPC's existing energy efficiency and demand side management
11		programs and how do they impact EKPC's forecast?
12	A.	For over 20 years, EKPC and its 16 member systems have promoted the cost-effective
13		use of energy by offering conservation and other marketing programs to the retail
14		customer. These programs were designed to meet the needs of the customer, and to delay
15		the need for additional generating capacity.
16		These programs are implemented and administered by the member distribution systems.
17		EKPC supports the member systems with analysis, promotional material, incentives, and
18		other support services. EKPC considers these programs a part of its overall supply
19		portfolio, with the understanding that the programs benefit EKPC indirectly, through its
20		member systems.
21		To incorporate into the 2010 long term load forecast, a demand side management plan
22		was developed to curtail load. The plan includes programs that are currently in existence
23		and offered by EKPC's member systems to its customers as well as new programs.

1		Existing programs include.
2		Electric Thermal Storage Incentive Program
3		Tune-Up HVAC Maintenance Program
4		Button-up Weatherization Program
5		Touchstone Energy Home Program
6		Touchstone Energy Manufactured Home Program
7		Compact Fluorescent Lighting Program
8		Commercial Advanced Lighting
9		Interruptible rates for industrial customers
10		New Programs include:
11		Button-up Weatherization with Air Sealing Program
12		Air Source Heat Pump replacing resistance heat
13		• Dual Fuel
14		Industrial Compressed Air
15		Direct Load Control of Air Conditioners and Water Heaters
16		Estimated demand and energy impacts as well as descriptions of the programs are shown
17		on Exhibit JJT-3. The net total winter peak demand impact grows from 141 MW in 2010
18		to over 220 MW at the end of the 20 year period.
19	Q.	Will you please describe EKPC's production costing model?
20	A.	The primary model used in developing the production costs for each of the evaluated
21		scenarios was RTSim from Simtec, Inc., of Madison, WI. The RTSim production cost
22		model calculates the hour-by-hour operation of the generation system including unit
23		hourly generation, commitment, power purchases and sales, including economy and day

23		delay?
22	Q.	In Case 3, why is EKPC using a four-year delay assumption versus a five-year
21		See Exhibit JJT-4 for the capacity expansion plan for each case.
20		enter into a long term purchase agreement with same entity
19		Case 7: Cancel Smith 1, sell the equipment to an entity constructing a similar plant and
18		cycle generation
17		Case 6: Cancel Smith 1, depend on Purchased Power until 2022 then construct combined
16		increased DSM efforts and renewable generation resources
15		Case 5: Cancel Smith 1, provide all future power supply needs with a combination of
14		Case 4: Cancel Smith 1, build a combined cycle unit in the optimal time frame
13		Case 3: Delay Smith 1 for 4 years (2018 completion)
12		Case 2: Delay Smith 1 for 2 years (2016 completion)
11	A.	Case 1: Smith 1 as planned (2014 completion) - Base Case
10	Q.	Describe each case evaluated/modeled.
9		shown by unit in Exhibit JJT-5 is heat rate and unit availability data.
8		Fuel, emission, variable O & M, purchase and sales costs are listed in Exhibit JJT-5. Also
7		Input assumptions for the load are based on the information described in Exhibit JJT-1.
6		loads using the assumptions.
5		simulating the actual operation of the power system in supplying the projected customer
4		statistical variations of unit forced outages and deratings. The production cost model is
3		startup characteristics. The RTSim model uses a Monte Carlo simulation to capture the
2		expected operating characteristics, Monte Carlo forced outages, unit ramp rates, and unit
1		anead transactions, and daily and monthly options. Generating unit input includes

- 1 A. The optimal time frame to construct a combined cycle unit in Case 4 is 2018. If Smith 1
 2 were delayed five years it would come on line in 2019. The year difference between the
 3 two cases would have reflected potential savings in capital investments in two different
 4 years. Putting the capital investment in the same year gave a more appropriate
 5 comparison between cases, comparing the actual difference in resource costs and not
 6 reflecting a timing differential.
- 7 Q. What was the output of the production costing model?
- A. Exhibit JJT-5 reflects the production data by unit for each case. The exhibit includes the capacity factor, availability factor, average heat rate, fuel cost, variable O&M costs, emission costs and total variable production cost by unit. It also shows expected off-system purchases and sales by case.
- 12 Q. How do the results of the production costing model flow to the financial forecasting model?
- A. As discussed in Mr. Stansberry's testimony, the results of the production cost model are summarized in a spreadsheet format and electronically incorporated into the financial forecasting software.
- 17 Q. Does this conclude your testimony?
- 18 A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

AN INVESTIGATION OF EAST KENTUCKY)	
POWER COOPERATIVE, INC. 'S NEED FOR)	CASE NO. 2010-00238
THE SMITH 1 GENERATING FACILITY)	

AFFIDAVIT

STATE OF KENTUCKY)

Julia J. Tucker, being duly sworn, states that she has read the foregoing prepared testimony and that she would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of her knowledge, information and belief.

Subscribed and sworn before me on this

n ()

MY COMMISSION EXPIRES NOVEMBER 30, 2013 NOTARY ID #409352

SECTION 1.0 EXECUTIVE SUMMARY

Section 1.0 Executive Summary

East Kentucky Power Cooperative Inc. (EKPC) is a generation and transmission electric cooperative located in Winchester, Kentucky. EKPC is owned by 16 member distribution cooperatives who serve approximately 520,000 retail meters. Member distribution cooperatives served by EKPC include:

Big Sandy RECC Jackson Energy Cooperative

Blue Grass Energy Coop. Corp. Licking Valley RECC

Clark Energy Cooperative, Inc. Nolin RECC

Cumberland Valley Electric Owen Electric Cooperative

Farmers RECC Salt River Electric Cooperative

Fleming-Mason Energy Cooperative Shelby Energy Cooperative, Inc.

Grayson RECC South Kentucky RECC

Inter-County Energy Coop. Corp. Taylor County RECC

EKPC's load forecast is prepared every two years in accordance with EKPC's Rural Utilities Service (RUS) approved Work Plan. The Work Plan details the methodology used in preparing the projections. EKPC prepares the load forecast by working jointly with each member system to prepare their load forecast. Member projections are then summed to determine EKPC's forecast for the 20-year period. Member cooperatives use their load forecasts in developing construction work plans, long range work plans, and financial forecasts. EKPC uses the load forecast in such areas as demand-side management analyses, marketing analyses, transmission planning, power supply planning, and financial forecasting.

EKPC's load forecast indicates that total energy requirements are projected to increase by 1.6 percent per year over the 2010 through 2030 period. Net winter peak demand will increase by approximately 1,000 MW, and net summer peak demand will increase by approximately 800 MW. Annual load factor projections are remaining steady at approximately 50 percent. Historical and projected total energy requirements, seasonal peak demands, and annual load factor for the EKPC system are presented in Table 1-1 (page 5). Peak demands are based on coincident hourly-integrated demand intervals. Load Factor is calculated using net peak demand and energy requirements.

Energy projections for the residential, small commercial, and large commercial classifications indicate that during the 2010 through 2030 period, sales to the residential class will increase by 1.4 percent per year, and total commercial and industrial sales will increase by 2.3 percent per year. Class sales are presented in Table 1-5. One member system serves a thin-slab steel mill. This large load is on an interruptible rate and the forecast assumes 360 hours of interruption each year.

Energy Sales a		emands	
Grow	th Rates		
	2010-2015	2010-2020	2010-2030
Total Net Energy Requirements	1.1%	1.4%	1.6%
Residential Sales	0.7%	1.2%	1.4%
Total Commercial and Industrial Sales (Excluding steel mill)	2.7%	2.5%	2.3%
Net Winter Peak Demand	1.9%	1.8%	1.8%
Net Summer Peak Demand	1.0%	1.3%	1.6%

Factors considered in preparing the forecast include national, regional, and local economic performance, population and housing trends, service area industrial development, electric price, household income, appliance saturations and efficiencies, demand-side management programs, and weather. A demand-side impacted load forecast is presented in Table 1-1. Details of the demand-side management plan are provided in Section 8 of this report.

Table 1-1
Peak Demands and Total Requirements
~Historical and Projected~

	Net Winter		Net Summer		Total Net	Load
	Peak Demand		Peak Demand		Requirements	Factor
Season	(MW)	Year	(MW)	Year	(MWh)	(%)
1989 - 90	1,449	1990	1,079	1990	5,489,092	43%
1990 - 91	1,306	1991	1,164	1991	5,958,422	52%
1991 - 92	1,383	1992	1,131	1992	6,099,308	50%
1992 - 93	1,473	1993	1,309	1993	6,860,902	53%
1993 - 94	1,788	1994	1,314	1994	6,917,414	44%
1994 - 95	1,621	1995	1,466	1995	7,761,980	55%
1995 - 96	1,915	1996	1,452	1996	8,505,621	51%
1996 - 97	1,953	1997	1,549	1997	8,850,394	52%
1997 - 98	1,696	1998	1,671	1998	9,073,950	61%
1998 - 99	1,988	1999	1,750	1999	9,825,866	56%
1999 - 00	2,157	2000	1,855	2000	10,521,400	56%
2000 - 01	2,295	2001	1,864	2001	10,750,900	53%
2001 - 02	2,109	2002	2,001	2002	11,456,830	62%
2002 - 03	2,459	2003	1,871	2003	11,568,314	54%
2003 - 04	2,513	2004	1,955	2004	11,865,797	54%
2004 - 05	2,622	2005	2,180	2005	12,527,829	55%
2005 - 06	2,492	2006	2,196	2006	12,331,272	56%
2006 - 07	2,757	2007	2,354	2007	13,080,367	54%
2007 - 08	2,964	2008	2,102	2008	12,948,091	50%
2008 - 09	3,126	2009	2,089	2009	12,380,972	45%
2009 - 10	2,748	2010	2,223	2010	12,781,011	53%
2010 - 11	3,006	2011	2,238	2011	12,855,553	49%
2011 - 12	3,033	2012	2,263	2012	13,024,858	49%
2012 - 13	3,059	2013	2,282	2013	13,124,067	49%
2013 - 14	3,101	2014	2,309	2014	13,318,597	49%
2014 - 15	3,147	2015	2,334	2015	13,516,766	49%
2015- 16	3,189	2016	2,359	2016	13,739,363	49%
2016 - 17	3,245	2017	2,402	2017	13,942,214	49%
2017 - 18		2018	2,449	2018	14,197,087	49%
2018 - 19	1	2019	2,497	2019	14,455,338	49%
2019 - 20	3,414	2020	2,535	2020	14,708,052	49%
2020 - 21	*	2021	2,593	2021	14,985,721	49%
2021 - 22		2022	2,640	2022	15,245,494	49%
2022 - 23	3,613	2023	2,693	2023	15,535,729	49%
2023 - 24	3,666	2024	2,736	2024	15,822,155	49%
2024 - 25	3,737	2025	2,792	2025	16,090,554	49%
2025 - 26	3,801	2026	2,844	2026	16,376,707	49%
2026 - 27	3,862	2027	2,895	2027	16,655,371	49%
2027 - 28	3,906	2028	2,932	2028	16,909,157	49%
2028 - 29	3,973	2029	2,988	2029	17,167,095	49%
2029 - 30	4,053	2030	3,050	2030	17,464,640	49%

Table 1-2
Historical and Projected Winter Peak Demand

ANT DESCRIPTION OF THE PARTY OF	eg a e amingraficio de l'estre de company de l'estre de l'estre de l'estre de l'estre de l'estre de l'estre de	teu willter real	CONTRACTOR AND A CONTRACTOR OF THE PROPERTY OF
	Unadjusted	DSM	Adjusted
	Peak Demand	Impact	Peak Demand
	(MW)	(MW)	(MW)
1989 - 90	1,449	0	1,449
1990 - 91	1,306	0	1,306
1991 - 92	1,383	0	1,383
1992 - 93	1,473	0	1,473
1993 - 94	1,788	0	1,788
1994 - 95	1,621	0	1,621
1995 - 96	1,990	75	1,915
1996 - 97	2,004	51	1,953
1997 - 98	1,789	107	1,682
1998 - 99	2,096	125	1,971
1999 - 00	2,169	29	2,140
2000 - 01	2,322	44	2,278
2001 - 02	2,238	146	2,092
2002 - 03	2,568	133	2,435
2003 - 04	2,610	123	2,487
2004 - 05	2,719	104	2,615
2005 - 06	2,599	122	2,477
2006 - 07	2,840	91	2,749
2007 - 08	3,051	95	2,956
2008 - 09	3,152	49	3,103
2009 - 10	2,868	129	2,739
2010 - 11	3,154	148	3,006
2011 - 12	3,189	155	3,033
2012 - 13	3,223	164	3,059
2013 - 14	3,273	172	3,101
2014 - 15	3,327	180	3,147
2015- 16	3,377	189	3,189
2016 - 17	3,440	195	3,245
2017 - 18	3,505	200	3,305
2018 - 19	3,571	206	3,366
2019-20	3,622	208	3,414
2020-21	3,699	210	3,489
2021-22	3,759	212	3,547
2022-23	3,827	214	3,613
2023-24	3,881	216	3,666
2024-25	3,954	217	3,737
2025-26	4,019	218	3,801
2026-27	4,082	220	3,862
2027-28	4,127	222	3,906
2028-29	4,196	223	3,973
2029-30	4,260	207	4,053
Contract the property of the p	nak province minimization of the following of the followi	Production where it is required to be an interest or the second of the second second of the second o	CONTRACTOR OF THE PROPERTY OF

Impacts from interruptible contracts have been subtracted.

Table 1-3
Historical and Projected Summer Peak Demand

***************************************	Unadjusted Peak	DSM	Adjusted
	Demand	Impact	Peak Demand
	(MW)	(MW)	(MW)
1990	1,079		
1990		0	1,079
1991	1,164	0	1,164
	1,131	0	1,131
1993	1,309	0	1,309
1994	1,314	0	1,314
1995	1,518	52	1,466
1996	1,540	88	1,452
1997	1,650	101	1,549
1998	1,675	21	1,654
1999	1,754	16	1,738
2000	1,941	109	1,832
2001	1,980	139	1,841
2002	2,120	142	1,978
2003	1,996	151	1,845
2004	2,052	104	1,948
2005	2,180	10	2,170
2006	2,332	144	2,188
2007	2,481	135	2,346
2008	2,243	149	2,094
2009	2,195	114	2,081
2010	2,369	146	2,223
2011	2,395	157	2,238
2012	2,430	167	2,263
2013	2,461	179	2,282
2014	2,499	190	2,309
2015	2,535	202	2,334
2016	2,572	213	2,359
2017	2,620	219	2,402
2018	2,670	221	2,449
2019	2,721	224	2,497
2020	2,759	224	2,535
2021	2,818	224	2,593
2022	2,865	225	2,640
2023	2,917	225	2,693
2024	2,961	225	2,736
2025	3,017	224	2,792
2026	3,067	224	2,844
2027	3,119	224	2,895
2028	3,157	224	2,932
2029	3,213	225	2,988
2030	3,264	214	3,050
2030	J,2U4	<i>L</i> 14	2,000

Impacts from interruptible contracts have been subtracted.

Table 1-4 Historical and Projected Total Requirements

		Estimated	
	Unadjusted Energy	DSM Impact	Total Requirements
	(MWh)	(MWh)	(MWh)
1990	5,489,092	0	5,489,092
1991	5,958,422	0	5,958,422
1992	6,099,308	0	6,099,308
1993	6,860,902	0	6,860,902
1994	6,917,414	0	6,917,414
1995	7,796,980	35,000	7,761,980
1996	8,540,621	35,000	8,505,621
1997	8,885,394	35,000	8,850,394
1998	9,108,950	35,000	9,073,950
1999	9,860,866	35,000	9,825,866
2000	10,556,400	35,000	10,521,400
2001	10,785,900	35,000	10,750,900
2002	11,491,830	35,000	11,456,830
2003	11,603,314	35,000	11,568,314
2004	11,900,797	35,000	11,865,797
2005	12,569,829	42,000	12,527,829
2006	12,373,272	42,000	12,331,272
2007	13,122,367	42,000	13,080,367
2008	12,990,091	42,000	12,948,091
2009	12,422,972	42,000	12,380,972
2010	12,838,995	57,984	12,781,011
2011	12,933,784	78,231	12,855,553
2012	13,123,079	98,220	13,024,858
2013	13,248,916	124,850	13,124,067
2014	13,469,609	151,011	13,318,597
2015	13,695,339	178,573	13,516,766
2016	13,945,172	205,809	13,739,363
2017	14,168,260	226,047	13,942,214
2018	14,440,867	243,780	14,197,087
2019	14,717,117	261,779	14,455,338
2020	14,968,552	260,500	14,708,052
2021	15,242,854	257,133	14,985,721
2022	15,499,459	253,965	15,245,494
2023	15,784,559	248,830	15,535,729
2024	16,066,805	244,650	15,822,155
2025	16,329,096	238,542	16,090,554
2026	16,609,551	232,844	16,376,707
2027	16,889,740	234,369	16,655,371
2028	17,144,635	235,477	16,909,157
2029	17,402,612	235,517	17,167,095
2030	17,680,570	215,930	17,464,640

Impacts from interruptible contracts have been subtracted.

Historical energy impacts for DSM and interruptible loads are not directly metered and therefore are estimated.

Table 1-5 Class sales shown are before the impacts of DSM

Г		lass saic		e belote	the impact		
			Small		Large	Public Street And	
	Residential	Seasonal	Comm.	Public	Comm.	Highway Lighting	Total Retail
	Sales	Sales	Sales	Buildings	Sales	Sales	Sales
Year	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
1990	3,497,574	9,094	813,371	9,096	653,502	3,737	4,986,373
1991	3,770,962	9,423	868,031	9,871	725,419	4,029	5,387,735
1992	3,813,577	9,756	913,599	11,586	776,268	4,304	5,529,089
1993	4,230,486	10,144	980,301	13,779	968,345	5,081	6,208,135
1994	4,285,099	10,280	1,014,549	14,240	1,026,927	4,156	6,355,251
1995	4,592,909	11,066	1,097,729	15,889	1,414,196	5,042	7,136,833
1996	4,875,662	12,342	1,138,469	16,785	1,829,516	5,555	7,878,329
1997	4,901,058	11,888	1,163,683	16,272	2,012,108	5,663	8,110,671
1998	5,109,002	11,476	1,230,450	17,315	2,041,910	5,601	8,415,754
1999	5,320,858	11,496	1,336,957	17,765	2,316,814	5,756	9,009,646
2000	5,626,500	12,479	1,446,958	18,280	2,409,695	6,160	9,520,072
2001	5,797,895	12,769	1,505,480	18,865	2,658,579	6,545	10,000,133
2002	6,166,723	14,076	1,577,590	20,453	2,803,844	7,107	10,589,793
2003	6,205,364	13,445	1,550,248	21,754	2,881,780	7,447	10,680,038
2004	6,337,737	13,846	1,598,111	22,974	3,037,246	7,498	11,017,413
2005	6,751,547	14,501	1,733,390	22,530	3,013,699	7,713	11,543,379
2006	6,548,160	13,882	1,777,897	22,196	3,057,184	8,236	11,427,556
2007	6,998,554	14,679	1,861,952	26,427	3,124,043	8,457	12,034,113
2008	7,055,277	14,531	1,872,811	34,074	3,083,589		12,069,760
2009	6,789,142	13,080	1,787,112	35,507	2,831,935	 	11,465,842
2010	6,916,947	13,434	1,820,349	35,741	3,035,175	1	11,830,863
2011	6,919,599	13,419	1,846,959	36,195	3,092,314	1	11,917,991
2012	6,944,934	13,455	1,877,310	36,596	3,210,477		12,092,483
2013	6,957,738	13,333	1,917,456		3,272,546	1	12,208,323
2014	7,055,893	13,570	1,959,197		3,335,403	10,160	12,412,259
2015	7,159,616	13,790	2,001,631	38,752	3,395,326	1	12,619,498
2016	7,281,181	14,097	2,044,932	39,450	3,459,446	· ·	12,849,707
2017	7,391,828	14,359	2,089,551	40,127	3,508,475	10,820	13,055,162
2018	7,523,977	14,682	2,134,733	40,784	3,581,071	11,039	13,306,286
2019	7,661,291	15,007	2,180,098	[3,651,747	1	13,560,843
2020	7,788,470	15,389	2,225,634	1	3,709,435	11,475	13,792,507
2021	7,923,044	15,831	2,271,700		3,780,129	· ·	14,045,165
2022	8,056,599	16,290	2,317,291	43,396	3,836,002	1	14,281,486
2023	8,203,953	16,774	2,362,531	44,026	3,904,812	1	14,544,221
2024	8,351,660	17,235	2,407,717	1	3,970,782		14,804,401
2025	8,482,142	17,589	2,453,143	ı	4,035,146	i .	15,045,903
2026	8,625,165	18,070	2,499,227	1	4,103,086		15,304,309
2027	8,764,282	18,593	2,545,021	46,621	4,174,930	1	15,562,437
2028	8,893,234	18,928	2,590,457	47,232	4,234,283	13,203	15,797,336
2029	9,010,609	19,163	2,635,782	47,870	4,308,104	13,418	16,034,945
2030	9,163,386	19,694	2,681,368	48,548	4,367,000	13,631	16,293,627

Impacts of interruptible contracts have been subtracted.

Table 1-5 continued

Year	Total Retail Sales (MWh)	Office Use		EKPC Sales to			Unadjusted	Additional	Adjusted
	Sales	1		Sales to					
		Use		Sales to	EKPC	Transmission	Total	DSM	Total
-	(MWh)	1	%	Members	Office	Loss	Requirements	Impact	Requirements
1990		(MWh)	Loss	(MWh)	Use (MWh)	(%)	(MWh)	(MWh)	(MWh)
11770	4,986,373	5,087	5.7	5,295,459	6,287	3.5	5,489,092		
1991	5,387,735	5,333	6.3	5,755,588	6,798	3.4	5,958,422		
1992	5,529,089	5,242	6.2	5,903,267	7,559	3.2	6,099,308		
1993	6,208,135	5,552	6.0	6,612,688	8,026	3.6	6,860,902		
1994	6,355,251	5,614	5.5	6,727,959	8,541	2.7	6,917,414		
1995	7,136,833	5,711	5.5	7,558,452	9,197	2.6	7,761,980		
1 1	7,878,329	6,167	5.0	8,301,379	8,856	2.4	8,505,621		
1 1	8,110,671	6,349	5.2	8,559,022	8,505	3.3	8,850,394		
1 1	8,415,754	6,121	4.5	8,821,630	7,236	2.8	9,073,950		
1 1	9,009,646	6,040	4.8	9,468,916	8,157	3.7	9,825,866		
1 1	9,520,072	6,606	5.0	10,027,205	7,862	4.8	10,521,400		
1	10,000,133	6,793	4.0	10,426,995	8,205	3.0	10,750,900	1	
1 1	10,589,793	7,562	4.3	11,071,862	8,818	3.4	11,456,830		
1 1	10,680,038	7,681	4.5	11,190,870	9,123	3.3	11,568,314	i e	
1 1	11,017,413	8,289	4.4	11,537,505	9,106	2.8	11,865,797	I	
1 1	11,543,379	8,617	4.2	12,060,460	8,902	3.8	12,527,829	I	
1 1	11,427,556	8,924	3.8	11,892,304		3.6	12,331,272	l	
1 1	12,034,113	10,291	4.3	12,582,260	7,491	3.9	13,080,367		
1 1	12,069,760		4.5	12,646,146		2.3	12,948,091		
	11,465,842			11,981,909		3.3	12,380,972	 	
1 1	11,830,863	-	4.2	12,365,949		3.3	12,796,531		
	11,917,991	10,225	4.2	12,457,380		3.3	12,891,117	1	i i
1 1	12,092,483	10,225	4.3	12,640,470	į.	3.3	13,080,545	1	l i
1 1	12,208,323		1	12,762,031	8,436	3.3	13,206,274	i	1
1 1	12,412,259			12,975,995	1	3.3	13,427,584		1
1 1	12,619,498			13,193,494	1	3.3	13,652,549	1	
1 1	12,849,707	10,225	4.3	13,435,050		3.3	13,902,392	1	1
1 1	13,055,162	-	l	13,650,646		3.3	14,125,390	E .	1
	13,306,286		1	13,914,159	1	3.3	14,397,940	1	I .
1 1	13,560,843		1	14,181,268	i	3.3	14,674,210	1	1
1 1			4.3	14,424,359		3.3	14,925,642	I	1
1 1	14,045,165		4.3	14,689,483	1	3.3	15,199,858		1
1 1	14,281,486		ı	14,937,462	}	3.3	15,456,345	1	
1 1	14,544,221	10,225	1	15,213,154		3.3	15,741,491		1
1 1	14,804,401	10,225	l .	15,486,159	1	3.3	16,023,858		1
1 1	15,045,903	1	4.3	15,739,582	1	3.3	16,285,976	E	1
1 1	15,304,309		1	16,010,733	1	3.3	16,566,426	1	
i i	15,562,437		1	16,281,592	l .	3.3	16,846,575	l .	1 '
1 1	15,797,336			16,528,072	1	3.3	17,101,514	1	
1 1	16,034,945	1	1	16,777,406	1	3.3	17,359,403	1	
2030	16,293,627	10,225	4.4	17,048,845	9,183	3.3	17,640,153	175,513	17,464,640

Impacts of interruptible contracts have been subtracted.

nergy Requirements
Demand and E

L	-	-	0 201 200	100	Vanitad Capacity	Canacity	Existing Capacity	anacity	Capacity Surplus/(Deficit)	ficit)	Total Energy	Energy Available from	Energy
	Peak Demand	mand	Reserves Reduired	ednired	שבחחום	Capacity			14 th		Dogramonis	Evicting Generation	Surplus/(Deficit)
	Win	Sum	Win	Sum	Win	Sum	Win	wns	Win		vedon ements	LAISUII GENERAMON	יוספל ובפינין
7.	VVLC	7336	379	280	3073	2616	2753	2542	(320)	(74)	12,206,412	8,359,068	(3,847,344)
2000	44/7	7076	373	298	3202	2785	2653	2442	(549)	(343)	13,006,363	8,359,068	(4,647,295)
7007	602	7366	364	270	3397	2524	2653	2442	(744)	(82)	12,957,993	8,359,068	(4,598,925)
2002	3140	7177	378	2,5	3527	2438	2616	2673	(911)	234	12,371,602	9,838,282	(2,533,320)
2003	2007	2270	359	278	3353	2598	3081	2842	(272)	244	12,831,350	9,838,282	(2,993,068)
2010	3006	7335	361	280	3367	2615	3046	2802	(321)	187	13,000,540	9,838,282	(3,162,258)
2017	3000	2333	364	283	3397	2642	3038	2794	(328)	152	13,099,712	9,838,282	(3,261,430)
2012	2059	2378	367	285	3426	2663	3138	2894	(288)	231	13,294,199	9,838,282	(3,455,917)
2017	2101	2005	377	289	3473	2694	3138	2894	(332)	700	13,492,362	9,838,282	(3,654,080)
2014	2107	2403	378	791	3525	2720	3138	2894	(387)	174	13,714,937	9,838,282	(3,876,655)
2012	2100	242	282	294	3572	2747	3138	2894	(434)	147	13,917,699	9,838,282	(4,079,417)
20102	2745	2433	586	566	3634	2794	3138	2894	(496)	100	14,172,526	9,838,282	(4,334,244)
2017	3243	2473	397	305	3702	2848	3138	2894	(564)	46	14,430,752	9,838,282	(4,592,470)
2010	3303	2501	700	211	3770	2902	3138	2894	(632)	(8)	14,683,427	9.838,282	(4,845,145)
2019	2300	7656	7 7	 	3874	2942	3138	2894	(989)	(48)	14,961,045	9,838,282	(5,122,763)
7070	3414	7007	410	322	3008	3007	3138	2894	(770)	(113)	15,220,793	9,838,282	(5,382,511)
707	3489	2003	526	378	3973	3059	3138	2894	(835)	(165)	15,510,989	9,838,282	(5,672,707)
7707	3547	15/7	737	334	4047	3117	3138	2894	(606)	(223)	15,797,369	9,838,282	(2,959,087)
2023	2012	2787	440	330	4106	3165	3138	2894	(896)	(271)	16,065,716	9,838,282	(6,227,434)
2024	3737	7887	448	346	4185	3228	3138	2894	(1,047)	(334)	16,351,807	9,838,282	(6,513,525)
202	3801	2832	456	352	4257	3284	3138	2894	(1,119)	(390)	16,630,476	9,838,282	(6,792,194)
2020	2862	7983	463	358	4325	3341	3138	2894	(1,187)	(447)	16,884,156	9,838,282	(7,045,874)
2020	3905	3020	469	362	4375	3382	3138	2894	(1,237)	(488)	17,142,068	9,838,282	(7,303,786)
2020	3973	3026	477	369	4450	3445	3138	2894	(1,312)	(551)	17,439,558	9,838,282	(7,601,276)
6707	0.00												

Residential/Commercial DSM Plan East Kentucky Power

Estimated demand and energy impacts as well as descriptions of the programs are shown below:

Program Descriptions

<u>Electric Thermal Storage Incentive Program</u>: Provides retail members with a cost-efficient means of using electricity for space heating. A discounted rate for ETS energy encourages retail members to use electricity for heating during off peak hours. This improves the utility's load factor, reduces energy costs for the retail member, and delays the need for new peak load capacity expenses.

<u>Tune-Up HVAC Maintenance Program</u>: This program offers the cleaning of indoor and outdoor heat exchanger coils, checking filters, measuring the temperature differential across the indoor coil to determine proper compressor operation, checking the thermostat to verify operation and proper staging, measuring air flow to ensure proper conditioned air distribution, and sealing the ductwork, either through traditional mastic sealers or with the *Aeroseal* duct-sealing program. Duct losses are to be reduced to 10% or less.

Button-Up Weatherization/Button-Up Weatherization with Air Sealing Program: The program requires the installation of insulation materials or the use of other weatherization techniques to reduce heat loss in the home. Any retail member who resides in a stick-built or manufactured home that is at least two years old and uses electricity as the primary source for space heat is eligible. In addition to the current program, EKPC is adding an option to also seal the envelope of the home.

Touchstone Energy New Construction Program (Heat Pump and Geothermal):

This program builds upon the existing Touchstone Energy Home program by introducing new measures and approaches. If implemented, this program would replace the existing Touchstone Energy Home program. The enhancements include thermal sealing/thermal bypass, and R-38 attic insulation. The program is designed to encourage new homes to be built to higher standards for thermal integrity and equipment efficiency, as well as to choose geothermal or an air source heat pump (SEER 13 HSPF 8.0) rather than less efficient forms of heating. The program is modeled after the ENERGY STAR for New Homes program. Homes built to Touchstone Energy Home Standards typically use 30% less energy than the same home built to typical construction standards.

<u>Touchstone Energy Manufactured Home</u>: The Touchstone Energy Manufactured Home is an allelectric manufactured home that is built to Energy Star® specifications. A manufactured home that is built to these standards typically uses 30% less energy, saving money and reducing greenhouse emissions. The Touchstone Energy Home includes a sealed duct system, energy efficient double-pane windows, added insulation in the roof and wall, and an improved gasket that seals the halves of the home together.

<u>Compact Fluorescent Lighting Program</u>: This program provides compact fluorescent bulbs to retail members at the annual meetings held by the distribution cooperatives every year. Each

registered member receives a two-pack of compact fluorescent bulbs that replace 2 incandescent Page 2 of 3 light bulbs.

Commercial Advanced Lighting including LED Program: This program offers incentives to commercial and industrial customers to install high efficiency lamps and ballasts in their facilities. LED exit signs, T-5 fluorescent fixtures, and advanced controls are examples of eligible technologies. This program is designed as an enhanced version of the existing commercial lighting program and will replace that program when implemented. This advanced lighting program is expected to produce higher levels of savings in each facility.

<u>Interruptible Rates for Industrial Customers</u>: Industrial customers may agree to accept a lesser rate upon agreement to allow EKPC to interrupt load during peak hours.

Air Source Heat Pump Program (Replacing resistance heat -10 years or older):

This program provides incentives for residential customers to install a high efficiency air source heat pump instead of an electric resistance furnace and/or central air conditioner in the home. The existing furnace must be 10 years or older to qualify for incentives.

<u>Dual Fuel</u>: This program will provide incentives for residential customers to replace an existing resistance heat furnace with a combination heat pump/gas heat furnace (Dual Fuel). This program will provided added energy savings while allowing fuel switching to gas at temperatures less than 30 degrees.

<u>Industrial Compressed Air Program</u>: This program is designed to reduce electricity consumption through a comprehensive approach to efficient production and delivery of compressed air in industrial facilities. The program includes (1) training of plant staff; (2) a detailed system assessment of the plant's compressed air system including written findings and recommendations, and (3) incentives for capital-intensive improvements.

<u>Direct Load Control of Residential Air Conditioners and Water Heaters Program</u>: This program is currently being implemented. The objective of the program is to reduce peak demand and energy usage through the installation of load control devices on residential air conditioners and electric water heaters. Peak demand reduction is accomplished by cycling equipment on and off according to a predetermined control strategy. Central air conditioning and heat pump units are cycled on and off, while water heater loads are curtailed. Participating customers receive an annual bill credit incentive.

DSM for 2010 Load Forecast

		EXISTING		***************************************	DLC		NEW					GRAND TOTAL				
		Summer	Winter		Summer	Winter			Summer	Winter			Summer	Winter		
	Annual	Peak	Peak	Annual	Peak	Peak		Annual	Peak	Peak		Annual	Peak	Peak		
	MWh	kW	kW	MWh	kW	kW		MWh	kW	kW		MWh	kW	kW		
2010	51,638	137,146	138,603	158	7,714	1,989		6,164	492	676		57,960	145,352	141,268		
2011	63,147	138,805	141,757	316	15,427	3,978		14,733	1,144	2,331		78,196	155,376	148,066		
2012	74,318	140,465	144,910	475	23,141	5,967		23,303	1,795	3,986		98,096	165,401	154,863		
2013	89,501	142,679	149,115	630	30,856	7,957		34,777	2,669	6,195		124,908	176,204	163,267		
2014	103,963	144,894	153,320	789	38,569	9,946		46,252	3,544	8,403		151,004	187,007	171,669		
2015	119,804	147,108	157,526	946	46,284	11,934		57,728	4,419	10,611		178,478	197,811	180,071		
2016	134,872	149,321	161,730	1,105	53,998	13,923		69,202	5,294	12,820		205,179	208,613	188,473		
2017	146,115	151,096	165,321	1,151	56,371	14,536		78,879	5,971	14,887		226,145	213,438	194,744		
2018	155,853	152,702	168,683	1,151	56,371	14,536		87,085	·	16,836		244,089	215,564	200,055		
2019	165,516	154,309	172,042	1,151	56,371	14,536		95,290	7,012	18,787		261,957	217,692	205,365		
2020	162,298	154,317	173,580	1,151	56,371	14,536		96,227	7,289	19,499		259,676	217,977	207,615		
2021	158,503	154,228	175,046	1,151	56,371	14,536		97,164	7,566	20,210		256,818	218,165	209,792		
2022	154,520	154,071	176,345	1,151	56,371	14,536		98,101	7,842	20,922		253,772	218,284	211,803		
2023	148,846	153,684	177,481	1,151	56,371	14,536		99,038	8,119	21,634		249,035	218,174	213,651		
2024	143,098	153,298	178,617	1,151	56,371	14,536		99,975	8,396	22,345		244,224	218,065	215,498		
2025	137,175	152,775	179,399	1,151	56,371	14,536		100,210	8,465	22,523		238,536	217,611	216,458		
2026	131,086	152,251	180,180	1,151	56,371	14,536		100,444	8,534	22,701		232,681	217,156	217,417		
2027	132,224	152,535	182,088	1,151	56,371	14,536		100,678	8,603	22,879		234,053	217,509			
2028	133,147	152,781	183,896	1,151	56,371	14,536		100,678	8,603	22,879		234,976	217,755	221,311		
2029	134,201	153,028	185,703	1,151	56,371	14,536		100,678	8,603	22,879		236,030		223,118		
2030	123,768	151,685	183,076	995	48,658	12,547		91,665	7,669	21,819		216,428	208,012	217,442		

											Exhibit JJT-4 Page 1 of 1
Sell, InPA		2021	2027	2010 (200) 2011 (100) 2014 (98)		2015 (250)	2024	2010 2011 2012			Base 223 MW
6 PPA, Build		2021 2022	2027	2010 (200) 2011 (100) 2014 (98)	2017 (300)		2024	2010 2011 2012			Base 223 MW
5. Green		2026		2010 (200)			2024	2010 2011 2012	2011 (149) 2019 (99) 2021 (70) 2022 (50)	2025 (56)	Increased 400 MW
4 CC		2017 2021	2028	2010 (200) 2011 (100) 2014 (98)			2024	2010 2011 2012			Base 223 MW
3 4 yr delay	2019	2021	2027	2010 (200) 2011 (100) 2014 (98)			2024	2010 2011 2012			Base 223 MW
2 2 yr delay	2017	2021	2027	2010 (200) 2011 (100) 2014 (98)			2024	2010 2011 2012			Base 223 MW
1 Base	2015	2021	2027 2028	2010 (200) 2011 (100) 2014 (98)			2024	2010 2011 2012			Base 223 MW max
Winter	Smith 1 278 MW	CC 268 MW	CT 98 MW	PPA Peaking	PPA Baseload (5 Years)	PPA CFB	PPA Nuclear 200 MW	Renew. LFG .8 MW	PPA Wind	PPA Biomass	DSM Win Max

							REDACTE	D					Exi Pa
;	2029 258,324 4,120,071 222,299	2029	0.18 0.92 12,416	2029	0.23 0.94 12,189	2029	0.11 0.91 12,533	2029	0.50 0.92 11,612	2029	0.23 0.91 10,446	2029	0.45
	2028 256.984 3,894,950 264,104	2028	0.18 0.92 12,420	2028	0.24 0.94 12,193	2028	0.10 0.91 12,495	2028	0.50 0.92 11,603	2028	0.21 0.91 10,451	2028	0.45 0.92 10.129
	2027 258,256 3.662,646 254,894	2027	0.20 0.92 12,419	2027	0.23 0.94 12,200	2027	0.10 0.91 12,591	2027	0.50 0.92 11,596	2027	0.20 0.91 10.456	2027	0.46 0.92 10.120
	2026 257,362 3,531,051 360,378	2026	0.18 0.92 12,424	2026	0.22 0.94 12,207	2026	0.10 0.91 12,528	2026	0.50 0.92 11,599	2026	0.21 0.91 10,475	2026	0.46
	2025 257,996 3,216,091 472,790	2025	0.19 0.92 12,409	2025	0.22 0.94 12,189	2025	0.11 0.91 12,454	2025	0.51 0.92 11,574	2025	0.22 0.91 10,416	2025	0.47 0.92 10.097
	2024 259,341 3,055,430 502,785	2024	0.17 0.92 12,418	2024	0.20 0.94 12,199	2024	0.10 0.91 12,463	2024	0.51 0.92 11,581	2024	0.19 0.91 10,432	2024	0.47 0.92 10,106
į	2023 257,310 1,966,638 256,425	2023	0.21 0.92 12,416	2023	0.25 0.94 12,198	2023	0.12 0.91 12,479	2023	0.51 0.92 11,562	2023	0.26 0.91 10,448	2023	0.48 0.92 10,079
	2022 256,997 1,709,633 357,617	2022	0.22 0.92 12,410	2022	0.27 0.94 12,190	2022	0.12 0.91 12,417	2022	0.51 0.92 11,552	2022	0.25 0.91 10.420	2022	0.49 0.92 10,069
į	2021 257.765 1,756,850 358,768	2021	0.17 0.92 12.428	2021	0.22 0.94 12,204	2021	0.10 0.91 12,476	2021	0.51 0.92 11,565	2021	0.21 0.91 10.457	2021	0.48 0.92 10,079
	2020 259,443 1,808,132 275,151	2020	0.17 0.92 12,431	2020	0.22 0.94 12,213	2020	0.11 0.91 12,603	2020	0.49 0.92 11,612	2020	0.24 0.91 10,487	2020	0.47 0.92 10,098
;	2019 258.358 1,797.240 264,282	2019	0.15 0.92 12,420	2019	0.18 0.94 12,205	2019	0.10 0.91 12,638	2019	0.49 0.92 11,639	2019	0.22 0.91 10,505	2019	0.46 0.92 10,116
	2018 257,556 1,689,223 288,696	2018	0.14 0.92 12,422	2018	0.17 0.94 12,208	2018	0.09 0.91 12,565	2018	0.49 0.92 11,640	2018	0.22 0.91 10,525	2018	0.45 0.92 10.130
;	257,230 1,526,498 282,344	2017	0.09 0.92 12,432	2017	0.10 0.94 12,216	2017	0.05 0.91 12,731	2017	0.47 0.92 11,688	2017	0.11 0.91 10.624	2017	0.44 0.92 10,143
į	2016 258,354 1,219,434 311,891	2016	0.09 0.92 12,434	2016	0.11 0.94 12,231	2016	0.05 0.91 12,678	2016	0.92 11,677	2016	0.15 0.91 10,578	2016	0.43 0.92 10,167
;	2015 258.012 1,084.877 311,805	2015	0.06 0.92 12,452	2015	0.09 0.94 12,242	2015	0.04 0.91 12,780	2015	0.47 0.92 11,703	2015	0.12 0.91 10,591	2015	0.42 0.92 10.174
i	2014 257,977 1,780,317 124,108	2014	0.13 0.92 12,415	2014	0.17 0.94 12,199	2014	0.08 0.91 12,746	2014	0.48 0.92 11,649	2014	0.22 0.91 10,418	2014	0.43 0.92 10,169
;	2013 263,886 662,018 348,422	2013	0.47 0.92 12,206	2013	0.49 0.94 11,987	2013	0.44 0.91 11,748	2013	0.66 0.92 11,308	2013	0.54 0.91 10,078	2013	0.55 0.92 9,999
	257,510 257,510 720,672 363,582	2012	0.46 0.90 12,188	2012	0.50 0.93 11,957	2012	0,43 0.91 11,765	2012	0.63 0.92 11,355	2012	0.51 0.89 10.105	2012	0.49 0.79 9.986
	2011 255,534 595,862 361,512	2011	0.40 0.91 12,254	2011	0.45 0.93 12,015	2011	0.33 0.91 11,963	2011	0.57 0.92 11,444	2011	0.40 0.91 10,167	2011	0.60 0.88 9.941
;	255.044 744.391 244.988	2010	0.44 0.92 12,210	2010	0.48 0.94 11,995	2010	0.36 0.91 11,848	2010	0.59 0.90 11,376	2010	0.36 0.91 10.173	2010	0.59 0.92 9.972
Case 1 - Base Case	Hydro Generation (MWH) Energy Sudd (MWH) Finergy Sold (MWH) Hydro Total Cost (S) Cost of Purchases (S)	Dale 1	Capacity Factor Availability Factor Average Heat fate (Btu/kWh) Fuel Cost (\$/MM8tu) Variable Poduction Cost (\$/MWh) SQ2 Emission Costs (\$) NOx Emission Costs (\$)	Dale 2	Capacity Factor Availability Factor Average Haes Take (Btu/kWh) Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) Variable Owduction Cost (\$/MWh) 502 Emission Costs (\$) NOx Emission Costs (\$)	Dale 3	Capacity Factor Availability Factor Avariage Hear Bate (BLu/kWh) Fuel Cost (S/MMBtu) Varnable O&M (S/MWth) Varnable Oxottcom Cost (S/MWh) SO2 Emission Costs (S) NOx Emission Costs (S)	Dale 4	Capacity Factor Availability Factor Availability Factor Availability Factor Availability Cost (\$/MMXII) Ful Cost (\$/MMXII) Variable Poduction Cost (\$/MWII) SQ2 Emission Costs (\$) NOx Emission Costs (\$)	Cooper 1	Capacity Factor Availability Factor Availability Factor Avarage Heat Rate (But/kWth) Fuel Cost (\$/AMMBu) Variable Poduction Cost (\$/AWWth) Variable Poduction Cost (\$/AWWth) SOZ Emission Costs (\$) NOx Emission Costs (\$)	Cooper 2	Capacity Factor Availability Factor Availability Factor Avarage Heat Rate (Btu/kwh) Fuel Colly (S/Mwh) Variable O&M (S/Mwh) Variable Production Cost (S/Mwh) SOZ Emission Costs (S) NOx Emission Costs (S)

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Case 1 - Base Case

0.83 0.93 10.194	2010	0.75 0.89 10,054	2010	0.81 0.89 9,779	2010	0.76 0.86 9,815	2010		2010		2010	0.01
Capacity Factor Availability Factor Availability Factor Avarage Heat Rate (Bru/kWh) Fuel Cost (\$/MMRu) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SO2 Emission Costs (\$) NOx Emission Costs (\$)	Spurlock 2	Capacity Factor Availability Factor Average frest false (Bu/kWh) Fuel Cost (\$/MMBtu) Variable O&M (\$/AvWh) Variable Production Cost (\$/MWh) \$02 Emission Costs (\$) NOx Emission Costs (\$)	Gilbert Unit	Capacity Factor Availability Factor Availability Factor Average Heat Rate (Bul/kWh) Fuel Cost (S/MWh) Varrable O&M (S/MWh) Varrable Production Cost (S/MWh) SQ2 Emission Costs (S) NOX Emission Costs (S)	Spurtock 4	Capacity Factor Availability Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Costs (\$/AMMBtu) Variable O&M (\$/AMBtu) Variable Production Cost (\$/AWWh) SO2 Emission Costs (\$) NOx Emission Costs (\$)	Smith 1 (CFB)	Capacity Factor Availability Factor Avarage Heat Rate (Btu/kWh) Fuel Cost (\$/MWh) Variable O&M (\$/Wh) Variable Production Cost (\$/MWh) SOZ Emission Costs (\$) NOX Emission Costs (\$)	Future CC	Capacity Factor Availability Factor Availability Factor Average Heat Rate (But/KWh) Fuel Cost (\$5/MM8tu) Varnable O&M (\$/MWh) Varnable O&M (\$/MWh) Varnable O&M (\$5/MWh)	Smith CT1	Capacity Factor Availability Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (S/MWRbu) Variable O&ku (S/MWh) Variable Production Cost (S/MWh) Variable Fouchton Cost (S/MWh) Variable Fouchton Cost (S/MWh) NOX Emission Costs (S)

						I.											_	Page 2 of 2
2029	0.73 0.90 10.294	2029	0.69 0.89 10,150	2029	0.78 0.89 9,880		2029	0.80 0.89 9.770	200	2029	0.77 0.89 9,680		2029	0.19 0.86 7.601		2029	0.00 0.96 13,795	
2028	0.73 0.90 10,294	2028	0.70 0.89 10.151	2028	0.78 0.89 9,873		2028	0.80 0.89 9.771		2028	0.77 0.89 9,679		2028	0.19 0.86 7.600		2028	0.00 0.96 13.577	
2027	0.74 0.90 10,285	2027	0.70 0.89 10,138	2000	0.78 0.89 9,855	the great and	2027	0.81 0.89 9.754		2027	0.78 0.89 9,659		2027	0.17 0.86 7,612		2027	0.00 0.96 13,268	
2026	0.74 0.90 10.292	2026	0.70 0.89 10,151		0.78 0.89 9,869		2026	0.80 0.89 9.765		2026	0.89 9,689		2026	0.18 0.86 7,599		2026	0.00 0.96 13.741	
2025	0.74 0.90 10.281	2025	0.70 0.89 10,135	1. 1006	0.79 0.89 9,850		2025	0.81 0.89 9,749		2025	0.78 0.89 9.654	:	2025	0.18 0.86 7,600		2025	0.00 0.96 13,781	- -
2024	0.74 0.90 10.279	2024	0.71 0.89 10.128		0.79 0.89 0.847		2024	0.81 0.89 9,748		2024	0.78 0.89 9,652		2024	0.15 0.86 7.608		2024	0.00 0.96 13.523	
2023	0.76 0.90 10.249	2023	0.73 0.89 10,092		0.80		2023	0.82 0.89 9,703		2023	0.80 0.89 9,591		2023	0.21 0.86 7,592		2023	0.00 0.96 13,498	
2022	0.77 0.90 10,245	2022	0.73 0.89 10,089		0.80 0.80 0.89 9.802		2022	0.82 0.89 9.703		2022	0.80 0.89 9,587		2022	0.22 0.86 7,588		2022	0.00 0.96 13,690	
2021	0,75 0,90 10,266	2021	0.71 0.89 10.118		2021 0.79 0.89 9.820		2021	0.82 0.89 9.720		2021	0.79 0.89 9,622	į	2021	0.21 0.86 7,583	. :	2021	0.00 0.96 13,707	
2020	0.74 0.90 10,278	2020	0.70 0.89 10.135		2020 0.79 0.89 9.837		2020	0.81 0.89 9,738		2020	0.78 0.89 9,649		2020	0.03 0.86 7,635		2020	0.00 0.96 13,325	
2019	0.74 0.90 10,289	2019	0.70 0.89 10.146		2019 0.79 0.89		2019	0.81 0.89 9.746		2019	0.78 0.89 9,656		2019			2019	0.00 0.96 13,241	
2018	0.73 0.90 10,297	2018	0.69 0.89 10.159		2018 0.78 0.89		2018	0.81 0.89 9,751		2018	0.77 0.89 9,683		2018			2018	0.00 0.96 13.200	
2017	0.73 0.90 10,295	2017	0.70 0.89 10,146		2017 0.79 0.89		2017	0.81 0.89 9,733		2017	0.78 0.89 9,641		2017			2017	0.00 0.96 13,348	
2016	0.74 0.90 10.276	2016	0.71 0.89 10,117	· .	2016 0.80 0.89	Copic	2016	0.82 0.89 9,703		2016	0.78 0.88 9.610		2016			2016	0.00 0.96 13,371	: :
2015	0.75 0.90 10,270	2015	0.72 0.89 10.108		2015 0.81 0.89	10/16	2015	0.83 0.89 9,687		2015	0.75 0.85 9,635		2015			2015	0.00 0.96 13,138	
2014	0.77 0.90 10,244	2014	0.73 0.89 10,093		2014 0.81 0.89	6//6	2014	0.83 0.89 9,679		2014	0.20 0.83 9,820		2014			2014	0.00 0.96 13,215	
2013	0.85 0.90 10,136	2013	0.78 0.89 10,002		2013	#n/in	2013	0.84 0.89 9.645		2013			2013			2013	0.00 0.96 13.254	,
2012	0.84 0.90 10.148	101	0.78		2012 0.82 0.89	5,733	2012	0.84 0.89 9,640		2012			2012			2012	0.00 0.96 13,197	
2011	0.82 0.90 10.165	2011	0.81 0.95 10,026		2011 0.82 0.89	9,750	2011	0.81 0.89 9.721		2011			2011			2011	0.00 0.96 13.187	
2010	0.83 0.93 10.194		0.75		2010	9,779	2010	0.76 0.86 9,815		2010			2010			2010	0.01 0.96 13,071	
ase		_				(q			æ			#)			/µ)			(h)

2027	0.00 0.96 13,423	2027	0.00 0.96 13,279	2027	0.01 0.97 12,990	2027	0.01 0.97 12,869	2027	0.01 0.97 12,712	2027	0.01 0.97 12,585	2027	0.08 0.96 9,796
2026	0.00 0.96 13,560	2026	0.00 0.96 13,865	2026	0.02 0.97 12,911	2026	0.01 0.97 12,967	2026	0.01 0.97 12,950	2026	0.01	2026	0.09 0.96 9,902
2025	0.00 0.96 13,720	2025	0.00 0.96 13,775	2025	0.02 0.97 12,876	2025	0.01	2025	0.01 0.97 12,850	2025	0.01	2025	0.09 0.96 10,025
2024	0.00 0.96 13,450	2024	0.00 0.96 13,530	2024	0.02 0.97 12,860	2024	0.01 0.97 12,842	2024	0.01 0.97 12,826	2024	0.00 0.97 12,773	2024	0.08 0.96 10,121
2023	0.00 0.96 13,497	2023	0.00 0.96 13,578	2023	0.03	2023	0.02 0.97 12,860	2023	0.01	2023	0.01 0.97 12,815	2023	0.11 0.96 9,771
2022	0.00 0.96 13,681	2022	0.00 0.96 13,793	2022	0.03 0.97 12,849	2022	0.02 0.97 12,872	2022	0.01 0.97 12,859	2022	0.01 0.97 12,862	2022	0.12 0.96 9,785
2021	0.00 0.96 13,653	2021	0.00 0.96 13,757	2021	0.03 0.97 12,863	2021	0.02 0.97 12,916	2021	0.01 0.97 12,917	2021	0.01 0.97 12,882	2021	0.11 0.96 9,774
2020	0.00 0.96 13.551	2020	0.00 0.96 13,258	2020	0.03	2020	0.02 0.97 12,829	2020	0.01 0.97 12,791	2020	0.01 0.97 12,739	2020	0.10 0.96 9,684
2019	0.00 0.96 13,468	2019	0.00 0.96 13,110	2019	0.02 0.97 12,807	2019	0.01 0.97 12,790	2019	0.01 0.97 12,733	2019	0.01 0.97 12,706	2019	0.09 0.96 9,708
2018	0.00 0.96 13,419	2018	0.00 0.96 13,235	2018	0.02 0.97 12,809	2018	0.01 0.97 12,782	2018	0.01 0.97 12,750	2018	0.00 0.97 12,719	2018	0.08 0.96 9,712
2017	0.00 0.96 13,456	2017	0.00 0.96 13,459	2017	0.02 0.97 12,831	2017	0.01 0.97 12,811	2017	0.01 0.97 12,769	2017	0.00 0.97 12,691	2017	0.08 0.96 9.562
2016	0.00	2016	0.00 0.96 13.408	2016	0.01 0.97 12,824	2016	0.01 0.97 12,808	2016	0.00 0.97 12,841	2016	0.00	2016	0.06 0.96 9,608
2015	0.00 0.96 13.257	2015	0.00 0.96 13,142	2015	0.01 0.97 12,792	2015	0.00 0.97 12,760	2015	0.00 0.97 12,734	2015	0.00	2015	0.06 0.96 9,597
2014	0.00 0.96 13,443	2014	0.00 0.96 13,227	2014	0.01 0.97 12,834	2014	0.01 0.97 12,886	2014	0.00 0.97 12,794	2014	0.00 0.97 12,747	2014	0.07 0.96 9,497
2013	0.00 0.96 13,495	2013	0.00 0.96 13,255	2013	0.03 0.97 12.684	2013	0.02 0.97 12,769	2013	0.01 0.97 12,768	2013	0.00 0.97 12,664	2013	0.08 0.96 11,150
2012	0.00 0.96 13,490	2012	0.00 0.96 13,338	2012	0.03 0.99 12,659	2012	0.02 0.99 12,728	2012	0.01 0.99 12,731	2012	0.00 0.95 12,657	2012	0.09 0.98 11,103
2011	0.00 0.96 13,368	2011	0.00 0.96 13,344	2011	0.03 0.93 12,608	2011	0.02 0.99 12,721	2011	0.01 0.95 12.721	2011	0.00 0.99 12,630	2011	0.08 0.92 10.953
2010	0.01 0.96 13,276	2010	0.00 0.94 13.021	2010	0.05 0.97 12,548	2010	0.04 0.99 12,523	2010	0.03	2010	0.02 0.99 12,283	2010	0.10 0.84 10.380
Case 1 - Base Case	Capacity Factor Availability Factor Availability Factor Average Heat Rate (Bru/KWh) Fuel Cost (\$/AWMBu) Variable Oddx (\$/AWWh) Variable Production Cost (\$/AWWh) SO2 Emission Costs (\$) NOX Emission Costs (\$)	Smith CT3	Capacity Factor Availability Factor Availability Factor Average Hear Rate (Bu/KWh) Fuel Cost (\$/MMBtu) Variable Oxdu (\$/MWh) Variable Production Cost (\$/MWh) \$02 Emission Costs (\$) NOX Emission Costs (\$)	Smith CT4	Capacity Factor Availability Factor Avariability Factor Average Hear Rate (Btu/KWh) Fuel Cost (\$/MWMbu) Variable Poduction Cost (\$/MWh) SOZ Emission Costs (\$) NOx Emission Costs (\$)	Smith CTS	Capacity Factor Availability Factor Avarage Hear Rate (Btu/kWh) Fuc Cost (\$/MWMbu) Varrable O&M (\$/MWh) Varrable O&M (\$/MWh) SO Emission Cost (\$/MWh) SO Emission Cost (\$/	Smith CT6	Capacity Factor Availability Factor Availability Factor Average Heat Rate (But/kWh) Fuel Cost (\$/MWh) Varnable O&M (\$/MWh) Varnable Production Cost (\$/MWh) SOZ Emission Costs (\$) NOx Emission Costs (\$)	Smith CT7	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (\$/MMBtu) Varnable O&M (\$/MWh) Varnable Production Cost (\$/MWh) SOZ Emission Costs (\$) NOX Emission Costs (\$)	Smith CT 9	Capacity Factor Availability Factor Availability Factor Average Heat Rate (But/KWh) Fuel Cost (\$/MMB1) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SOZ Emission Costs (\$) NOX Emission Costs (\$)

2029 0.01 0.97 12,847

2028 0.01 0.97 12,805

2029 0.01 0.97 12,867

2028 0.01 0.97 12,841

2029 0.01 0.97 12,890

2028 0.01 0.97 12,882

2029 0.00 0.96 13,565

2028 0.00 0.96 13,529

2029 0.00 0.96 13.762

2028 0.00 0.96 13,609 Exhibit JJT-5 Page 3 of 28

2029 0.10 0.96 9.671

2028 0.09 0.96 9,690

2029 0.01 0.97 12,865

2028 0.01 0.97 12,790

						RED	ACTED
2029	0.15 0.96 9,764	2029	0.94 0.97 11,828	2029	0.03 1.00 12,937	2029	0.02 1.00 12,940
2028	0.14 0.96 9,779	2028	0.94 0.97 11,828	2028	0.03 1.00 12,936	2028	0.02 1.00 12,941
2027	0.12 0.96 9,934	2027	0.94 0.97 11,828	2027	0.02 1.00 13,025	2027	0.00 1.00 12,566
2026	0.12 0.96 9.832	2026	0.94 0.97 11,828	2026	0.00 1.00 12,571	2026	
2025	0.11 0.96 9,845	2025	0.94 0.97 11,828	2025		2025	
2024	0.09 0.96 9,876	2024	0.94 0.97 11,828	2024		2024	
2023	0.15 0.96 9,685	2023	0.94 0.97 11,828	2023		2023	
2022	0.15 0.96 9.611	2022	0.94 0.97 11,828	2022		2022	
2021	0.14 0.96 9,620	2021	0.94 0.97 11,828	2021		2021	
2020	0.14 0.96 9,662	2020	0.94 0.97 11,828	2020		2020	
2019	0.14 0.96 9,674	2019	0.94 0.97 11,828	2019		2019	
2018	0.12 0.96 9,679	2018	0.94 0.97 11,828	2018		2018	
2017	0.13 0.96 9,568	2017	0.94 0.97 11,828	2017		2017	
2016	0.09 0.96 9,522	2016	0.94 0.97 11,828	2016		2016	W
2015	0.09 0.96 9,533	2015	0.94 0.97 11,828	2015		2015	
2014	0.11 0.96 9,474	2014	0.94 0.97 11,828	2014		2014	
2013	0.12 0.96 11,001	2013	0.95 0.97 11,828	2013		2013	
2012	0.13 0.98 10,978	2012	0.95 0.97 11,828	2012		2012	. 1
2011	0.11 0.92 10.799	2011	0.94 0.97 11,842	2011		2011	
2010	0.12 0.84 10,325	2010	0.95 0.97 11,848	2010		2010	
Case 1 - Base Case	Capacity Factor Availability Factor Availability Factor In Capacity (Sydwyla) Fuel Cost (Sydwyla) Variable O&M (Sydwyla) Variable Production Cost (Sydwyla) SOZ Emission Costs (S) NOx Emission Costs (S)	Landfill Gas Projects	Capacity Factor Availability Factor Average Hear Rate (Bru/kWh) Fuel Cost (S/AMMBu) Variable O&M (S/MWh) Variable Production Cost (S/MWh) Variable Production Cost (S/MWh) No Emerson Cost (S/MWh)	Future CT 1	Capacity Factor Availability Factor Average Hear State (Buu/kWh) Fuel Cost (S/MMBul) Variable OB. M (S/MWh) Variable Obduction Cost (S/MWh)	NOX Emission Costs (\$) Future CT 2	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (\$\formalfootnote{NamMah}\) Variable O&M (\$\formalfootnote{NamMah}\) Variable Production Cost (\$\formalfootnote{NamMah}\) SO2 Emission Costs (\$\formalfootnote{NamMah}\) NOx Emission Costs (\$\formalfootnote{NamMah}\)

Case 2 - Delay Sunth Coal for 2 years	th Coal	for 2 ye	ars					i		;			6						900	ococ.	
Hydro Generation (MWH) Energy Purchased (MWH) Energy Sold (MWH) Hydro Total Cost (5) Cost of Purchases (5)	2010 255.044 744,391 244,988	2011 255,534 595,862 361,512	2012 257,510 720,672 363,582	2013 263,886 662,018 348,422	2014 258.177 2,054,068 82,056	2015 258,223 2,092,693 88,050	2016 257,946 1,980,216 147,729	2017 257,174 1,527,498 283,900	2018 257,528 1,694,390 290,579	2019 258,443 1,799,805 264,290	225,425 259,425 1,803,346 275,516	257,765 1,759,426 360,985	256,977 1,710,362 352,401	257,320 1,971,882 255,140	259,133 3,050,531 501,586	258,300 3,223,209 472,319	257,410 3,534,560 364,176	258,063 3,656,901 255,285	257,235 3,894,561 261,027	258,008 4,119,816 222,433	
Dale 1	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
Capacity Factor Availability Factor Average Heat Fatte (BLu/KWh) Fuel Cost (\$/MMBLu) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) NOX Emission Cost (\$) NOX Emission Costs (\$)	0.44 0.92 12,210	0.40 0.91 12.254	0.46 0.90 12.188	0.47 0.92 12,206	0.14 0.92 12,401	0.11 0.92 12,421	0.14 0.92 12,417	0.09 0.92 12,425	0.14 0.92 12,420	0.15 0.92 12.425	0.18 0.92 12,427	0.17 0.92 12,416	0.22 0.92 12,405	0.21 0.92 12,409	0.17 0.92 12,416	0.19 0.92 12,409	0.18 0.92 12,430	0.20 0.92 12,415	0.17 0.92 12,418	0.17 0.92 12,414	
Dale 2	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
Capacity factor Availability Factor Average Heat Rate (Btu/KWh) Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SO2 Emission Costs (\$) NOx Emission Costs (\$)	0.48 0.94 11,995	0.45 0.93 12,015	0.50 0.93 11,957	0.49 0.94 11,987	0.19 0.94 12,193	0.14 0.94 12,207	0.17 0.94 12.199	0.11 0.94 12,217	0.16 0.94 12,200	0.18 0.94 12,200	0.22 0.94 12,218	0.22 0.94 12,203	0.27 0.94 12,192	0.25 0.94 12,196	0.21 0.94 12,195	0,22 0,94 12,187	0.22 0.94 12,212	0.23 0.94 12,198	0.24 0.94 12,192	0.23 0.94 12,191	
Dale 3	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
Capacity Factor Availability Factor Average Heat Rate (BLu/KWh) Tenel Coost (S/MMBLu) Variable O&M (S/MWh) Variable Production Cost (S/MWh) NOZ Emisson Coost (S) MOY Emisson Cost (S)	0.36 0.91 11,848	0.33 0.91 11,963	0.43 0.91 11,765	0.44 0.91 11,748	0.08 0.91 12,709	0.07 0.91 12,727	0.09 0.91 12,519	0.05 0.91 12,712	0.09 0.91 12.570	0.09 0.91 12,634	0.11 0.91 12,591	0.10 0.91 12,470	0.12 0.91 12,409	0.12 0.91 12,476	0.10 0.91 12,470	0.11 0.91 12,446	0.10 0.91 12.525	0.10 0.91 12,556	0.10 0.91 12,496	0.11 0.91 12,531	REDACTE
Dale 4	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	E D
Capacity factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (\$/MMBtu) Variable Production Cost (\$/MWh) SO2 Emission Costs (\$) NOx Emission Costs (\$)	0.59 0.90 11,376	0.57 0.92 11,444	0.63 0.92 11,355	0.66 0.92 11,308	0.49	0.49 0.92 11,640	0.49 0.92 11,644	0.47	0.49 0.92 11,638	0.49	0.49 0.92 11,613	0.51 0.92 11,564	0.52 0.92 11,550	0,51 0.92 11,563	0.51 0.92 11,582	0.51 0.92 11,572	0.50 0.92 11,602	0.50 0.92 11,595	0.50 0.92 11,603	0.50 0.92 11,611	
Cooper 1	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
Capacity Factor Availability Factor	0.36	0.40	0.51 0.89	0.54	0.24	0.21 0.91	0.23 0.91	0.11 0.91	0.22 0.91 10.529	0.22 0.91 10.499	0.24 0.91 10.490	0.21 0.91 10,452	0.25 0.91 10,409	0.26 0.91 10,446	0.19 0.91 10,430	0.22 0.91 10,416	0.21 0.91 10.472	0.20 0.91 10,456	0.21 0.91 10.460	0.23 0.91 10,441	

			Page
10,441	2029	0.45 0.92 10,132	Page :
0.91	2028	0.45 0.92 10.128	
0.91 10,456	2027	0.46 0.92 10,120	
0.91 10,472	2026	0.46 0.92 10,111	
0.91	2025	0.47 0.92 10,097	
0.91 10,430	2024	0.46 0.92 10.106	
0.91 10,446	2023	0.48 0.92 10,080	
10,409	2022	0.49 0.92 10,069	
10,452	2021	0.48 0.92 10,079	
0.91	2020	0.47 0.92 10,098	
10,499	2019	0.46 0.92 10.116	
10,529	2018	0.45 0.92 10,130	
10,616	2017	0.44 0.92 10,142	
0.91 10,518	2016	0.44 0.92 10.140	
0.91 10,519	2015	0.44 0.92 10.140	
0.54 0.91 10.393	2014	0.43 0.92 10,167	
0.91 10,078	2013	0.55 0.92 9.999	
0.89 10,105	2012	0.49 0.79 9.986	
0.40 0.91 10.167	2011	0.60 0.88 9,941	
0.30 0.91 10,173	2010	0.59 0.92 9,972	Constitution of the second
Capacity Pactor Availability Factor Avariage Heat fate (Btu/kWh) Fuel Cast (\$/AMBtu) Variable O&M (\$/AMWh) Variable Production Cast (\$/AWM) SO2 Emission Cast (\$)	NOx Emission Costs (\$) Cooper 2	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Coxt (\$/AMMBtul) Variable O&M (\$/AWWh) Variable Production Cost (\$/AWWh)	SO2 Emission Costs (\$) NOx Emission Costs (\$)

0.00 0.96 13,853

0.00 0.96 13,515

0.00 0.96 13,160

0.00 0.96 13.773

0.00 0.96 13.521

0.00 0.96 13,549

0.00 0.96 13,711

0.00 0.96 13,733

0.00 0.96 13,225

0.00 0.96 13,241

0.00 0.96 13,304

0.00 0.96 13,353

0.00 0.96 13,266

0.00 0.96 13.272

0.00 0.96 13,254

0.00 0.96 13,197

0.00 0.96 13,187

0.01 0.96 13,071

Capacity Factor

Smith CT1

Availability Factor
Average Hast Rate (Bsu/kWh)
Puel Cost (\$/MMStu)
Variable O&M (\$/MWH)
Variable Production Cost (\$/MWh)
NOR Emission Costs (\$/
NOK Emission Costs (\$)

2010

2026

2024

2023

2021

					RI	E D	ACTED						
2029	0.73 0.90 10,294	2029	0.69 0.89 10,150	2029	0.78 0.89 9,878	2029	0.80 0.89 9,770	2029	0.77 0.89 9,680	2029	0.19 0.86 7,600		2029
2028	0.73 0.90 10,295	2028	0.70 0.89 10,151	2028	0.78 0.89 9,871	2028	0.80 0.89 9,770	2028	0.77 0.89 9,676	2028	0.19 0.86 7,599		2028
2027	0.74 0.90 10,284	2027	0.70 0.89 10.138	2027	0.78 0.89 9,856	2027	0.81 0.89 9,753	2027	9,658 9,658	2027	0.17 0.86 7,613		2027
2026	0.74 0.90 10,293	2026	0.70 0.89 10.151	2026	0.78 0.89 9.867	2026	0.80 0.89 9,764	2026	77.0 0.89 9.685	2026	0.18 0.86 7,598		2026
2025	0.74 0.90 10,281	2025	0.70 0.89 10.135	2025	0.79 0.89 9.850	2025	0.81 0.89 9,747	2025	0.78 0.89 9,657	2025	0.18 0.86 7,598		2025
2024	0.74 0.90 10,278	2024	0.71 0.89 10,128	2024	0.79 0.89 9,845	2024	0.81 0.89 9.747	2024	0.78 0.89 9.650	2024	0.15 0.86 7.608		2024
2023	0.76 0.90 10,249	2023	0.73 0.89 10,092	2023	0.80 0.89 9,803	2023	0.82 0.89 9,705	2023	0.80 0.89 9,591	2023	0.21 0.86 7,592		5002
2022	0.77 0.90 10,245	2022	0.73 0.89 10,090	2022	0.80	2022	0.82 0.89 9,702	2022	0.80 0.89 9,592	2022	0.22 0.86 7,587		2002
2021	0.75 0.90 10,266	2021	0.71 0.89 10,118	2021	0.79 0.89 9,820	2021	0.82 0.89 9,720	2021	0.79 0.89 9.620	2021	0.21 0.86 7,584		2021
2020	0.74 0.90 10,278	2020	0.70 0.89 10.135	2020	0.79 0.89 9,838	2020	0.81 0.89 9,738	2020	0.78 0.89 9,644	2020	0.03 0.86 7,637		טבטנ
2019	0.74 0.90 10,289	2019	0.70 0.89 10,146	2019	0.79 0.89 9,845	2019	0.81 0.89 9,747	2019	0.78 0.89 9.658	2019			0000
2018	0.73 0.90 10.297	2018	0.69 0.89 10,159	2018	0.78 0.89 9,856	2018	0.81 0.89 9,751	2018	0.77 0.89 9,683	2018			0,00
2017	0.73 0.90 10.295	2017	0.70 0.89 10,146	2017	0.79 0.89 9,838	2017	0.81 0.89 9.733	2017	0.78 0.89 9.645	2017			1
2016	0.77 0.90 10.233	2016	0.74 0.89 10,075	2016	0.80 0.89 9,781	2016	0.83 0.89 9,685	2016	0.21 0.89 9.712	2016			
2015	0.79 0.90 10,209	2015	0.76 0.89 10,039	2015	0.82 0.89 9.746	2015	0.84 0.89 9,659	2015		2015			
2014	0.78 0.90 10.228	2014	0.74 0.89 10.065	2014	0.81 0.89 9,759	2014	0.83 0.89 9,666	2014		2014			
2013	0.85 0.90 10,136	2013	0.78 0.89 10.002	2013	0.82 0.89 9,734	2013	0.84 0.89 9,645	2013		2013			
ars	0.84 0.90 10,148	2012	0.78 0.89 10.007	2012	0.82 0.89 9,733	2012	0.84 0.89 9,640	2012		2012			
or 2 ye	0.82 0.90 10,165	2011	0.81 0.95 10,026	2011	0.82 0.89 9,750	2011	0.81 0.89 9,721	2011		2011			
h Coal fe	0.83 0.93 10,194	2010	0.75 0.89 10,054	2010	0.81 0.89 9,779	2010	0.76 0.86 9.815	2010		2010			
Case 2 - Delay Sııth Coal for 2 years	Capacity Factor Availability Factor Avarage Heat Hate (Btu/kWh) Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SOZ Emssion Costs (\$) NOx Emssion Costs (\$)	Spurlock 2	Capacity Factor Availability Factor Avariage Heat Rate (Bru/KWh) Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SO2 Emission Costs (\$) NOX Emission Costs (\$)	Gilbert Unit	Capacity Factor Availability Factor Availability Factor Fuel Cost (\$\formalfor{\text{Factor}}{\text{Factor}}\) Variable O&M (\$\formalfor{\text{Factor}}{\text{Factor}}\) Variable Production Cost (\$\formalfor{\text{Factor}}{\text{Factor}}\) NOX Emission Costs (\$\formalfor{\text{Factor}}{\text{Factor}}\)	Spurlock 4	Capacity Factor Availability Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (\$)/MMBtu) Variable O&M (\$/MWh) Variable Production Cost (\$) NOX Emission Costs (\$) NOX Emission Costs (\$)	Smith 1 (CFB)	Capacity Factor Availability Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cookt (\$/MWh) Variable Poduction Cost (\$/MWh) SOZ Emission Costs (\$) NOY Emission Costs (\$)	Future CC	Capacity Factor Availability Factor	Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SO2 Emission Costs (\$)	NOx Emission Costs (\$)

REDACTED	RE	DA	CT	ED
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					R	ED	ACTED						Page 7 of 28
2029	0.00 0.96 13,783	2029	0.00 0.96 13,574	2029	0.01 0.97 12,910	2029	0.01	2029	0.01 0.97 12,874	2029	0.01 0.97 12,896	2029	0.10 0.96 9,664
2028	0.00 0.96 13,572	2028	0.00 0.96 13,478	2028	0.01 0.97 12,871	2028	0.01	2028	0.01 0.97 12,773	2028	0.01 0.97 12,751	2028	0.09 0.96 9.696
2027	0.00 0.96 13.411	2027	0.00	2027	0.01 0.97 13,003	2027	0.01 0.97 12,883	2027	0.01 0.97 12,710	2027	0.01 0.97 12,577	2027	0.08 0.96 9.784
2026	0.00 0.96 13,627	2026	0.00 0.96 13,904	2026	0.02 0.97 12,912	2026	0.01 0.97 12,953	2026	0.01 0.97 12,939	2026	0.01 0.97 12,862	2026	0.09 0.96 9.882
2025	0.00 0.96 13,674	2025	0.00 0.96 13,735	2025	0.02 0.97 12,877	2025	0.01 0.97 12,875	2025	0.01 0.97 12,872	2025	0.01 0.97 12,833	2025	0.09 0.96 10,015
2024	0.00 0.96 13,495	2024	0.00 0.96 13,502	2024	0.02 0.97 12,860	2024	0.01 0.97 12,834	2024	0.01 0.97 12,820	2024	0.00 0.97 12,730	2024	0.08 0.96 10.149
2023	0.00 0.96 13,511	2023	0.00 0.96 13,610	2023	0.03 0.97 12,844	2023	0.02 0.97 12,856	2023	0.01	2023	0.01 0.97 12,807	2023	0.11 0.96 9,770
2022	0,00 0,96 13,716	2022	0.00 0.96 13,789	2022	0.03 0.97 12,855	2022	0.02 0.97 12,878	2022	0.01	2022	0.01 0.97 12,865	2022	0.12 0.96 9,788
2021	0.00 0.96 13,668	2021	0.00 0.96 13.790	2021	0.03 0.97 12,867	2021	0.02 0.97 12,914	2021	0.01 0.97 12,912	2021	0.01 0.97 12,869	2021	0.11 0.96 9,767
2020	0.00 0.96 13,580	2020	0.00 0.96 13,369	2020	0.03 0.97 12,829	2020	0.02 0.97 12,822	2020	0.01 0.97 12,802	2020	0.01 0.97 12,744	2020	0.10 0.96 9,686
2019	0.00 0.96 13,473	2019	0.00 0.96 13,148	2019	0.02 0.97 12,815	2019	0.01 0.97 12,800	2019	0.01	2019	0.00 0.97 12,691	2019	0.09 0.96 9,723
2018	0.00 0.96 13,470	2018	0.00 0.96 13,251	2018	0.02 0.97 12,824	2018	0.01 0.97 12,774	2018	0.01 0.97 12,755	2018	0.00 0.97 12,712	2018	0.08 0.96 9.722
2017	0.00 0.96 13,409	2017	0.00 0.96 13,333	2017	0.02 0.97 12,837	2017	0.01 0.97 12,803	2017	0.01 0.97 12,756	2017	0.00 0.97 12,658	2017	0.08 0.96 9,567
2016	0.00 0.96 13,408	2016	0.00 0.96 13,396	2016	0.02	2016	0.01 0.97 12,844	2016	0.01 0.97 12,826	2016	0.00 0.97 12,750	2016	0.09 0.96 9.426
2015	0.00 0.96 13,387	2015	0.00 0.96 13,215	2015	0.02 0.97 12,821	2015	0.01	2015	0.01 0.97 12,764	2015	0.00 0.97 12,631	2015	0.09 0.96 9.421
2014	0.00 0.96 13,462	2014	0.00 0.96 13,300	2014	0.01 0.97 12,812	2014	0.01 0.97 12,837	2014	0.00 0.97 12,799	2014	0.00 0.97 12,753	2014	0.07 0.96 9.516
2013	0.00 0.96 13,495	2013	0.00	2013	0.03 0.97 12,684	2013	0.02 0.97 12,769	2013	0.01 0.97 12,768	2013	0.00	2013	0.08 0.96 11,150
2012	0.00 0.96 13,490	2012	0.00 0.96 13,338	2012	0.03 0.99 12,659	2012	0.02 0.99 12,728	2012	0.01 0.99 12,731	2012	0.00 0.95 12,657	2012	0.09 0.98 11,103
or 2 ye	0.00 0.96 13,368	2011	0.00 0.96 13,344	2011	0.03 0.93 12,608	2011	0.02 0.99 12,721	2011	0.01 0.95 12,721	2011	0.00 0.99 12,630	2011	0.08 0.92 10.953
h Coal fo	0.01 0.96 13,276	2010	0.00	2010	0.05 0.97 12,548	2010	0.04 0.99 12,523	2010	0.03 0.99 12,449	2010	0.02 0.99 12,283	2010	0.10 0.84 10.380
Case 2 - Delay Snth Coal for 2 years	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (\$/NMMBtu) Vanable O&M (\$/NMWh) Variable Production Cost (\$/MWh) SOZ Emission Costs (\$) NOx Emission Costs (\$)	Smith CT3	Capacity Factor Availability Factor Average Heat Bate (Btu/kWh) Fuel Cost (\$/MMBtu) Variable OSAM (\$/MWh) Variable Production Cost (\$/MWh) SO2 Emission Costs (\$) NOX Emission Costs (\$)	Smith CT4	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (\$/MMBtu) Varnable O&M (\$/MWh) Varnable Production Cost (\$/MWh) SO2 Emission Costs (\$) NOx Emission Costs (\$)	Smith CTS	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (\$/MMBtu) Variable Ost (\$/MWh) Variable Production Cost (\$/MWh) SQ2 Emission Costs (\$) NOx Emission Costs (\$)	Smith CT6	Capacity Factor Availability Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SOZ Emission Costs (\$) NOx Emission Costs (\$)	Smith CT7	Capacity Factor Availability Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (\$/MMBtu) Variable Ost (\$/MWh) Variable Production Cost (\$/MWh) SO2 Emission Costs (\$) NOx Emission Costs (\$)	Smith CT 9	Capacity Factor Availability Factor Availability Factor Average Heat Bate (Btu/KWh) Fuel Cox (\$/AMWh) Variable O&M (\$/AWh) Variable Production Cost (\$/AWh) SO2 Emission Costs (\$) NOx Emission Costs (\$)

]	RED	ACTED
2029	0.15 0.96 9,752	2029	0.94	2029	0.03 1.00 12,958	2029	0.02 1.00 12,960
2028	0.14 0.96 9,774	2028	0.94 0.97 11,828	2028	0.03 1.00 12,930	2028	0.02 1.00 12,926
2027	0.12 0.96 9,926	2027	0.94 0.97 11,828	2027	0.02 1.00 13,029	2027	0.00 1.00 12,547
2026	0.12 0.96 9.839	2026	0.94 0.97 11,828	2026	0.00 1.00 12,586	2026	
2025	0.11 0.96 9,835	2025	0.94 0.97 11,828	2025		2025	
2024	0.09 0.96 9,882	2024	0.94 0.97 11,828	2024		2024	
2023	0.15 0.96 9,688	2023	0.94 0.97 11,828	2023		2023	
2022	0.15 0.96 9,610	2022	0.94 0.97 11,828	2022		2022	
2021	0.14 0.96 9,612	2021	0.94 0.97 11,828	2021		2021	
2020	0.14 0.96 9.662	2020	0.94 0.97 11,828	2020		2020	
2019	0.14 0.96 9.672	2019	0.94 0.97 11,828	2019		2019	
2018	0.12 0.96 9,678	2018	0.94 0.97 11,828	2018		2018	
2017	0.13 0.96 9,567	2017	0.94 0.97 11.828	2017		2017	
2016	0.15 0.96 9.412	2016	0.94 0.97 11,828	2016		2016	
2015	0.16 0.96 9,461	2015	0.95 0.97 11,828	2015		2015	
2014	0.11 0.96 9,488	2014	0.94 0.97 11,828	2014		2014	
2013	0.12 0.96 11,001	2013	0.95 0.97 11.828	2013		2013	
2012	0.13 0.98 10,978	2012	0.95 0.97 11,828	2012		2012	
or 2 ye	0.11 0.92 10.799	2011	0.94 0.97 11,842	2011		2011	
th Coal f	0.12 0.84 10.325	2010	0.95 0.97 11,848	2010		2010	
Case 2 - Delay Sniith Coal for 2 years smith CT 10 2010 2011 201	Capacity Factor Availability Factor Average Heat Rate (Btu/kWn) Fuel Coxt (\$/MMBtu) varnable O&M (\$/MWh) Varnable Production Coxt (\$/MWh) SOZ Emission Coxt (\$) NOx Emission Costs (\$)	Landfill Gas Projects	Capacity Factor Avariability Factor Avariage Heat Rate (Btu/KWh) Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SO2 Emission Costs (\$) NOX Emission Costs (\$)	Future CT 1	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Coxt (\$/AMMBus) Variable O&M (\$/AWh) Variable Production Cost (\$/AWM) SOZ Emission Costs (\$)	NOx Emission Costs (\$) Future CT 2	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Coxt (\$/AMBlau) Variable O&M (\$/AWh) Variable Production Cost (\$/AWh) SOZ Emission Costs (\$) NOX Emission Costs (\$)

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2029	258,045 4,118,706 222,025	2029	0.18 0.92 12,416	2029	0.23 0.94 12,201	2029	0.11 0.91 12,537	2029	0.50 0.92 11,616	2029	0.23		0.45 0.92 10,133
2028	257,139 3,898,244 265,698	2028	0.18 0.92 112,420	2028	0.24 0.94 12,194	2028	0.10 0.91 12,505	2028	0.50 0.92 11,604	2028	0.21 0.91 10.464	2028	0.45 0.92 10,130
2027	258.045 3.663.576 257,782	2027	0.19 0.92 12,417	2027	0,22 0,94 12,202	2027	0.11 0.91 12,546	2027	0.50 0.92 11,594	2027	0.21 0.91 10,454	2027	0.46 0.92 10,121
2026	257,357 3,532,961 361,031	2026	0.19 0.92 12,427	2026	0.21 0.94 12,208	2026	0.10 0.91 12,511	2026	0.50 0.92 11,599	2026	0.21 0.91 10,476	2026	0.46 0.92 10,111
2025	258,398 3,220,452 472,175	2025	0.19 0.92 12,410	2025	0.23 0.94 12,192	2025	0.11 0.91 12,455	2025	0.51 0.92 11,574	2025	0.22 0.91 10,421	2025	0.47 0.92 10,097
2024	259,192 3.053,165 501,706	2024	0.18 0.92 12.413	2024	0.20 0.94 12.197	2024	0.10 0.91 12,472	2024	0.51 0.92 11,581	2024	0.19 0.91 10.431	2024	0.46 0.92 10.107
	257,283 1,966,932 256,888	2023	0.22 0.92 12,413	2023	0.26 0.94 12,196	2023	0.12 0.91 12,468	2023	0.51 0.92 11,562	2023	0.26 0.91 10,445	2023	0.48 0.92 10,079
	256,967 1,710,437 356,330	2022	0.21 0.92 12,406	2022	0.25 0.94 12,187	2022	0.12 0.91 12,412	2022	0.52 0.92 11,548	2022	0.26 0.91 10,413	2022	0.49 0.92 10,069
2021	257,694 1,758,414 361,178	2021	0.17 0.92 12,421	2021	0.22 0.94 12,204	2021	0.10 0.91 12,467	2021	0.51 0.92 11,563	2021	0.22 0.91 10,450	2021	0.48 0.92 10.079
2020		2020	0.17 0.92 12,426	2020	0.22 0.94 12,214	2020	0.10 0.91 12,583	2020	0.50 0.92 11,607	2020	0.24 0.91 10,476	2020	0.47 0.92 10,098
2019	258,508 1,798,209 262,175	2019	0.15 0.92 12,423	2019	0.18 0.94 12,204	2019	0.09 0.91 12,640	2019	0.49 0.92 11,639	2019	0.22 0.91 10,506	2019	0.46 0.92 10.115
2018		2018	0.21 0.92 12,385	2018	0.25 0.94 12,171	2018	0.13 0.91 12,452	2018	0.50 0.92 11,612	2018	0,31 0,91 10,442	2018	0.47 0.92 10,104
2017		2017	0.15 0.92 12,393	2017	0.19 0.94 12,181	2017	0.09 0.91 12,738	2017	0.49 0.92 11,640	2017	0.19 0.91 10,548	2017	0.47 0.92 10,102
2016	259,102 2,296,495 86,330	2016	0.15 0.92 12,409	2016	0.18 0.94 12,200	2016	0.09 0.91 12,693	2016	0.49 0.92 11,617	2016	0.24 0.91 10,500	2016	0.45 0.92 10.134
2015		2015	0.11 0.92 12,421	2015	0.14 0.94 12,207	2015	0.07 0.91 12,727	2015	0.49 0.92 11,640	2015	0.21 0.91 10,519	2015	0.44 0.92 10,140
2014		2014	0.14 0.92 12,401	2014	0.19 0.94 12,193	2014	0.08	2014	0.49 0.92 11,638	2014	0.24 0.91 10,393	2014	0.43 0.92 10.167
2013		2013	0.47 0.92 12,206	2013	0.49 0.94 11,987	2013	0.44 0.91 11,748	2013	0.66 0.92 11,308	2013	0.54 0.91 10.078	2013	0.55 0.92 9,999
2012		2012	0.46 0.90 12,188	2012	0.50 0.93 11,957	2012	0.43 0.91 11,765	2012	0.63 0.92 11,355	2012	0.51 0.89 10,105	2012	0.49 0.79 9,986
years		2011	0.40 0.91 12,254	2011	0.45 0.93 12,015	2011	0.33 0.91 11,963	2011	0.57 0.92 11,444	2011	0.40 0.91 10,167	2011	0.60 0.88 9.941
Coal for 4		2010	0.44 0.92 12.210	2010	0.48 0.94 11,995	2010	0.36 0.91 11,848	2010	0.59 0.90 11,376	2010	0.36 0.91 10,173	2010	0.59 0.92 9,972
Case 3 - Delay Smith Coal for 4 years	Hydro Generation (MWH) Energy Purchased (MWH) Energy Sold (MWH) Hydro Total Cost (\$) Cost of Purchases (\$)	Dale 1	Capacity Factor Availability Factor Availability Factor Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SQ2 Emission Costs (\$) NOX Emission Costs (\$)	Date 2	Capacity Factor Availability Factor Availability Factor Interest (S/MMBtu) Variable O&M (S/MWh) Variable Poduction Cost (S/MWh) SOZ Emission Costs (S) NOX Emission Costs (S)	Dale 3	Capacity Factor Availability Factor Availability Factor Avarage least Rate (Bru/kWh) Fuel Cost (\$/MWBtu) Vanable O&M (\$/MWh) Vanable Production Cost (\$/MWh) SQZ Emission Costs (\$) NOx Emission Costs (\$)	Dale 4	Capacity Factor Availability Factor Availability Factor Avared beat Rate (Bu/kWh) Fuel Cost (\$/Mwittu) Vanable O&M (\$/Mwh) Vanable Production Cost (\$/MWh) SO2 Emission Costs (\$) NOX Emission Costs (\$)	Cooper 1	Capacity Factor Availability Factor Availability Factor (S/MMBtu) Feel Cost (S/MMBtu) Variable O&M (S/MWH) Soz Emission Costs (S) NOx Emission Costs (S)	Cooper 2	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Coxt (S/MMku) Variable O&M (S/MWh) Variable Production Cost (S/MWh) SO2 Emission Costs (S) NOx Emission Costs (S)

						RE.		TATE TO A	y							Page 10 of 28
2029	0.90	2029	0.69 0.89 10,151	2029	0.78	9,877	0.80	9,770	9000	6707	9,676		2029	0.86	2029	0.00 0.96 13,848
2028	10,294	2028	0.70 0.89 10,151	2028	0.78	9,874	0.80	0.89 9,770	0.00	8707	0.89 9,678		2028	0.19 0.86 7,600	2028	0.00 0.96 13.489
7202	10,284	2027	0.70 0.89 10.138	2027	0.78	9,854	777	0.89 9,752		707	0.78 0.89 9,662		2027	0.17 0.86 7,614	2027	0.00 0.96 13.184
	0.74 0.90 10.292	2026	0.69 0.89 10,151	2026	0.78	9,869	0707	0.89 9,766		2026	0.77 0.89 9,685		2026	0.18 0.86 7,598	2026	0.00 0.96 13.696
2025	0.74 0.90 10,281	2025	0.70 0.89 10,135	2025	0.79	9,850	5707	0.81 0.89 9,749		2025	0.78 0.89 9,655		2025	0.18 0.86 7,599	2025	0.00 0.96 13.753
	0.74 0.90 10,278	2024	0.71 0.89 10,128	2024	6.79	0.89	2024	0.81 0.89 9,749		2024	0.78 0.89 9,654		2024	0.15 0.86 7,608	2024	0.00 0.96 13,518
	0.76 0.90 10,249 1	2023	0.73 0.89 10,092	2023	0.80	9,804	2023	0.82 0.89 9,704		2023	0.80 0.89 9,590		2023	0.21 0.86 7,591	2023	0.00 0.96 13,481
	0.77 0.90 10,245 1	2022	0.73 0.89 10.090	202	0.80	9,804	2022	0.82 0.89 9,703		2022	0.80 0.89 9,588		2022	0.22 0.86 7,586	2022	0.00 0.96 13,759
	0.75 0.90 10,266 1	2021	0.71 0.89 10,118	***************************************	0.79	9,819	2021	0.82 0.89 9.720		2021	0.79 0.89 9,621		2021	0.21 0.86 7,584	2021	0.00 0.96 13,731
	0.74 0.90 10,278	2020	0.70 0.89 10.135	900	0.79	9,836	2020	0.81 0.89 9.738		2020	0.78 0.89 9,646		2020	0.03 0.86 7,637	2020	0.00 0.96 13,350
2019	0.74 0.90 10,289	2019	0.70 0.89 10,146		2019	9.845	2019	0.81 0.89 9,747		2019	0.78 0.89 9,660		2019		2019	0.00 0.96 13,257
2018	0.75 0.90 10,265	2018	0.71 0.89 10,125		2018	0.89 9,831	2018	0.81 0.89 9.726		2018	0.21 0.89 9,761		2018		2018	0.00 0.96 13.190
2017	0.76 0.90 10,250	2017	0.73 0.89 10,095		2017	0.89 0.797	2017	0.82 0.89 9,702		2017		-	2017		2017	0.00 0.96 13,225
2016	0.78 0.90 10,222	2016	0.75 0.89 10,056		2016	0.89 9,766	2016	0.83 0.89 9,675		2016			2016		2016	0.00 0.96 13,264
2015	0.79 0.90 10,209	2015	0.76 0.89 10,039		2015	0.82 0.89 9,746	2015	0.84 0.89 9,659	-	2015			2015		2015	0.00 0.96 13,266
2014	0.78 0.90 10,228 10	2014	0.74 0.89 10,065		2014	0.81 0.89 9,759	2014	0.83 0.89 9,666		2014			2014		2014	0.00 0.96 13,272
2013	0.85 0.90 10,136 10	2013	0.78 0.89 10,002		2013	0.82 0.89 9,734	2013	0.84 0.89 9.645		2013			2013		2013	0.00 0.96 13,254
2012	0.84 0.90 10,148 10,	2012	11		2012	0.82 0.89 9.733	2012	0.89 9,640		2012			2012		2017	
/ears	0.82 0.90 10.165 10	2011			2011	0.82 0.89 9,750	2011	0.81 0.89 9,721	:	2011			2011		1100	0.00 0.96 13,187
al for 4 y	0.83 0.93 10,194	2010			2010	0.81 0.89 9,779	2010	0.76 0.86 9,815		2010			2010		0101	0.01 0.95 13,071
Case 3 - Delay Smith Coal for 4 years spuriock 1	Capacity Factor Availability Factor Average Hear Rate (Btu/kWh) Fuel Cost (\$/MMBtu) Variable OSM (\$/MWh) Variable Production Cost (\$/MWh) SO2 Emission Costs (\$)	NOx Emission Costs (\$)	Spuriock 2 Capacity Factor Availability Factor Availability Factor Fuel Cost (\$/MM8tu)	Variable Q&M (\$/MWh) Variable Production Cost (\$/MWh) SO2 Emission Costs (\$) NOx Emission Costs (\$)	Gilbert Unit	Capacity Factor Availability Factor Availability Factor Availability Factor Fuel Cost (\$/MMBtu) Variable Podeuton Cost (\$/MWh) SQ2 Emission Costs (\$) NOx Emission Costs (\$)	Spurlock 4	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (\$/MMBtu)	Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SQ2 Emission Costs (\$) NOX Emission Costs (\$)	Smith 1 (CFB)	Capacity Factor Availability Factor	Average Heat Rate (Btu/kwn) Fuel Cost (\$/MMButh) Variable OBAM (\$/MWh) Variable Production Cost (\$/MWh) SOZ Emission Costs (\$)	NOX Emission Costs (3) Future CC	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (\$/MMBtu) Vanable O&M (\$/MWh) Vanable Powletton Cost (\$/MWh)	NOX Emission Costs (5)	Smith CT1 Capacity Factor Availability Fattor Availability Fattor Average Heat Rate (Bru/kWh) Fuel Cost (\$/MMBtu) Variable Okun (\$/MWh) Variable Production Cost (\$/MWh) SOZ Emission Costs (\$) NOx Emission Costs (\$)

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					IX.								Page 11 of
2029	0.00 0.96 13,804	2029	0.00	2029	0.01 0.97 12,918	2029	0.01 0.97 12.895	2029	0.01	2029	0.01 0.97 12,885	2029	0.10 0.96 9,662
2028	0.00 0.96 13,578	2028	0.00 0.96 13,495	2028	0.01 0.97 12,890	2028	0.01 0.97 12,846	2028	0.01 0.97 12,805	2028	0.01 0.97 12,802	2028	0.09 0.96 9,693
2027	0.00 0.96 13,294	2027	0.00 0.96 13,218	2027	0.01 0.97 12,977	2027	0.01 0.97 12,859	2027	0.01 0.97 12,701	2027	0.01 0.97 12,566	2027	0.08 0.95 9,791
2026	0.00 0.96 13,590	2026	0.00 0.96 13,834	2026	0.02 0.97 12,892	5026	0.01 0.97 12,939	2026	0.01 0.97 12,908	2026	0.01 0.97 12,822	2026	0.09 0.96 9,900
2025	0.00 0.96 13,667	2025	0.00 0.96 13,747	2025	0.02 0.97 12,878	2025	0.01 0.97 12,864	2025	0.01 0.97 12,859	2025	0.01 0.97 12,841	2025	0.09 0.96 10,010
2024	0.00 0.96 13,530 1	2024	0.00 0.96 13.616	2024	0.02 0.97 12,859	2024	0.01 0.97 12,855	2024	0.01 0.97 12,855	2024	0.00 0.97 12,764	2024	0.08 0.96 10,130
2023	0.00 0.96 13,529 13	2023	0.00 0.96 13,580 1	2023	0.03 0.97 12,841 1	2023	0.02 0.97 12,846 1	2023	0.01 0.97 12,819 1	2023	0.01 0.97 12,771	2023	0.11 0.96 9,765
2022	0.00 0.96 13,706 13	2022	0.00 0.96 13.825 1.	2022	0.03 0.97 12,856 1	2022	0.02 0.97 12,878 1	2022	0.01 0.97 12,878	2022	0.01 0.97 12,876	2022	0.12 0.96 9,778
2021	0.00 0.96 13,651 13	2021	0.00 0.96 13,735 1:	2021	0.03 0.97 12,867 1	2021	0.02 0.97 12,914 1	2021	0.01 0.97 12,914 1	2021	0.01 0.97 12.887 1	2021	0.11 0.96 9,781
2020	0.00 0.96 13,520 13	2020	0.00 0.96 13,333 13	2020	0.03 0.97 12,828 11	2020	0.02 0.97 12,838 1.	2020	0.01 0.97 12,809 1	2020	0.01 0.97 12.740 1	2020	0.10 0.96 9.687
2019	0.00 0.96 13,436 13	2019	0.00 0.96 13.225 13	2019	0.02 0.97 12,814 1.7	2019	0.01 0.97 12,795	2019	0.01 0.97 12,747 1	2019	0.01 0.97 12,696 1	2019	0.09 0.96 9,723
2018	0.01 0.96 13,484 13	2018	0.00 0.96 13,255 13	2018	0.04 0.97 12,765 12	2018	0.03 0.97 12,737 15	2018	0.02 0.97 12,716 1:	2018	0.01 0.97 12,689 1	2018	0.12 0.96 9,549
2017	0.00 0.96 13,440 13	2017	0.00 0.96 13,202 13	2017	0.03 0.97 12,767 12	2017	0.02 0.97 12,757 12	2017	0.02 0.97 12,727 13	2017	0.01 0.97 12,609 13	2017	0.13 0.96 9.469
2016		2016		2016		2016		2016		2016	0.01 0.97 12,708 12	2016	0.10 0.96 9.456
	1	2015 21	1	2015	11	2015 2	H	2015	Ħ	2015		2015	
4 2015	0.00 0.96 13,387		0.00		1 0.02 7 0.97 2 12,821		17		7		H		
2014	0.00 0.96 13,462	2014	0.00 0.96 13,300	2014	0.01 0.97 12,812	1 2014	0.01 0.97 12,837	3 2014	0.00 0.97 12,799	3 2014	0.00 0.97 12,753	3 2014	0.07 0.96 9,516
2013	0.00 0.96 13,495	2013	0.00 0.96 13,255	2013	0.03 0.97 12,684	2013	0.02 0.97 12,769	2 2013	0.01 0.97 12,768	2 2013	0.00 0.97	2 2013	0.08 0.96 0.11,150
rs 2012	0.00 0.96 13,490	2012	0.00 0.96 13,338	2012	0.03 0.99 12,659	7017	0.02 0.99 12,728	1 2012	0.01	1 2012	0.00 0.95	1 2012	0.09 0.98 11,103
. 4 year	0.00 0.96 13,368	2011	0.00 0.96 13,344	2011	0.03 0.93 12,608	2011	0.02 0.99 12,721	2011	0.01 0.95 12,721	2011	0.00 0.99 12,630	2011	0.08 0.92 10,953
Coal for	0.01 0.96 13,276	2010	0.00 0.94 13,021	2010	0.05 0.97 12,548	2010	0.04 0.99 12,523	2010	0.03	2010	0.02 0.99 12,283	2010	0.10 0.84 10,380
Case 3 - Delay Smith Coal for 4 years	Capacity Factor Avaiability Factor Avarage Hear Bate (Bru/KWh) Fuel Cost (\$/NMBtu) Variable O&M (\$/MWh) Variable Production Cost (\$/NWh) SOZ Emission Costs (\$) NOX Emission Costs (\$)	Smith CT3	Capacity Factor Availability Factor Availability Factor Average Heat Fate (Btu/AWh) Fuel Cost; (\$\$/AMBUJ Variable O&M (\$/AWh) Variable Production Cost (\$/AWh) Variable Production Cost (\$/MWh) Not Emission Costs (\$) NOX Emission Costs (\$)	Smith CT4	Capacity Factor Availability Factor Availability Factor Average Heat Rate (Bru/kWh) Fuel Cost (\$/MMBtu) Vanable O&M (\$/MWh) SOZ Emission Costs (\$) NOx Emission Costs (\$)	Smith CT5	Capacity Factor Availability Factor Availability Factor Induction (S/MMBtu) Variable O&M (S/MWh) Variable O&M (S/MWh) SOZ Emission Cost (S) NOX Emission Cost (S)	Smith CT6	Capacity Factor Availability Factor Availability Factor Availability Factor Tele Cost (\$/AMBlu) Variable O&M (\$/AWM) Variable Cost (\$/AWM) SOZ Emisson Costs (\$) NOX Emisson Costs (\$)	Smith CT7	Capacity Factor Availability Factor Availability Factor Availability Factor I Avariage deat Rate (Buu/kWh) Fuel Cost (S/MWh) Variable O&M (S/MWh) Variable Production Cost (S/MWh) SO2 Emission Costs (S) NOx Emission Costs (S)	Smith CT 9	Capacity Factor Availability Factor Availability Factor Average Heat Rate (Bru/kWh) Fuel Cost (\$/MMkh) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SQ2 Emission Costs (\$) NOx Emission Costs (\$)

2028 2029	0.14 0.15 0.96 0.96 9,779 9.761	2028 2029	0.94 0.94 0.97 0.97 11,828	2028 2029	0.03 0.03 1.00 1.00 12,934 12,943	2028 2029	0.02 0.02 1.00 1.00 12.941 12,949
	0.12 0.96 9,938	2027	0.94 0.97 11,828	2027	0.02 1.00 12,997	2027	0.00 1.00 12,537
2026	0.12 0.96 9,836	2026	0.94 0.97 11,828	2026	0.00 1.00 12,556	2026	
2025	0.11 0.96 9,827	2025	0.94 0.97 11,828	2025		2025	
2024	0.09 0.96 9,875	2024	0.94 0.97 11,828	2024		2024	
2023	0.15 0.96 9,686	2023	0.94 0.97 11,828	2023		2023	
2022	0.15 0.96 9,617	2022	0.94 0.97 11,828	2022		2022	
2021	0.14 0.95 9,617	2021	0.94 0.97 11,828	2021		2021	
2020	0.15 0.96 9,666	2020	0.94 0.97 11,828	2020		2020	
2019	0.14 0.96 9,677	2019	0.94 0.97 11,828	2019		2019	
2018	0.19 0.96 9,522	2018	0.94 0.97 11,828	2018		2018	
2017	0.21 0.96 9,470	2017	0.94 0.97 11,828	2017		2017	
2016	0.16 0.96 9,465	2016	0.94 0.97 11,828	2016		2016	
2015	0.16 0.96 9,461	2015	0.95 0.97 11,828	2015		2015	
2014	0.11 0.96 9,488	2014	0.94 0.97 11,828	2014		2014	
2013	0.12 0.96 11,001	2013	0.95 0.97 11,828	2013		2013	
2012	0.13 0.98 10,978	2012	0.95 0.97 11,828	2012		2012	
t years	0.11 0.92 10,799	2011	0.94 0.97 11,842	2011		2011	
oal for 4	0.12 0.84 10,325	2010	0.95 0.97 11,848	2010		2010	
Case 3 - Delay Smith Coal for 4 years	Capacity Factor Availability Factor Availability Factor Avarenge Heas Rate (Bru/kwh) Fuel Cost (\$/Mw0tu) Variable Poduction Cost (\$/Mwwh) 502 Emisson Costs (\$) NOx Emisson Costs (\$)	Landfill Gas Projects	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) Variable Poduction Cost (\$/MWh) SOZ Emission Costs (\$/	NOx Emission Costs (5) Future CT 1	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) Variable Poduction Cost (\$/MWh) SOZ Emisson Costs (\$)	NOx Emission Costs (\$) Future CT 2	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Average Hoat Rate (Btu/kWh) Variable O&M (\$/MWh) Variable Poduction Cost (\$/MWh) SOZ Emission Costs (\$) NOx Emission Costs (\$)

029	514	2029	0.21	414	2029	0.26 0.94 12,195	2029	0.13	12,358	6707	0.51 0.92 11,566 0.00 0.00 0.00 0.00 0.00	0.33	10,361	0.46	10,107	5707	0.254
	4,887,614			12		12				e :		3 1					
2028	4,671,737	2028	0.19	12,417	2028	0.26 0.94 12,194	2028		12		0.51 0.92 0.92 0.92 0.92 0.92		10		10		0.00 0.90
2027	4,479,464	2027	0.21	12,417	2027	0.24 0.94 12,189	7505	202	12,387	2027	0.51 0.92 11,555	7707	10,356	202	0.92		0.77 0.50 10,246
2026	4,246,756 189,683	2026	0.19	12,418	2026	0.24 0.94 12,199	9600	2028	12,374	2026	0.52	2026	10,359	9707	10,080	2026	0.76
	3,860,590 256,899	2025	0.22	12,408	2025	0.26 0.94 12,187	i.	5707	0.15 0.91 12,332	2025	0.53	2025	10,323	5072	10,065	2025	0.77 0.90 10,243
	255,627 3,713,259 3, 249,71,1	2024	0.20	12,413	2024	0.22 0.94 12,198		2024	0.12 0.91 12,337	2024	0.53 0.92 11,523	2024	0.31	2024	10,072	2024	0.77 0.90 10,238
	258,534 2 2,669,960 3,7 135,925 2	2023	0.23	0.52 12,415	2023	0.28 0.94 12,192		2023	0.14 0.91 12,326	2023	0.53 0.92 11,517	2023	0.35	2023	0.92 10,046	2023	0.79 0.90 10,212
		2022		0.92 ,406	2022	0.31 0.94 12,182		2022	0.16 0.91 12,331	2022	0.53 0.92 11,505	2022	0.35 0.91 10,338	2022	0.52 0.92 10,034	2022	0.79 0.90 10,206
	115 257,082 194 2,322,348 140 205,630	2021	121	0.92 12,412 12	2021	0.27 0.94 12,199 1.			0.13 0.91 12,355 1	2021					0.51 0.92 10,044	2021	0.78 0.90 10,229
	6 257,815 6 2,390,294 7 195,640			,423 12,4	2020					2020	0.51 0.92 558				0.50 0.92 10,063 1	2020	0.77 0.90 10,240
	258,166 2,546,806 105,527	2020		12		0.25			0.13		11	2019	10			2019	
2019	2,610,292 94,947	2019	0.20	0.92	2019	0.25 0.94 12.195			0.11 0.91 12,477	2019	0.50		0.27		7 0.48 2 0.92 10,082		6 0.76 0 0.90 5 10,248
2018	257.793 2,493.613 105,572	2018	0.18	0.92	2018	0.23		2018	0.11 0.91 12,485	2018	0.50 0.92 11,584	2018	0.27 0.91 10,454	2018	0.47	2018	0.76 0.90 10,255
2017	258,256 2,402,174 98,250	2017	0.11	12,416	2017	0.15	7.5.4.5	2017	0.06	2017	0.49	2017	0.13 0.91 10,585	2017	0.46 0.92 10,113	2017	0.76 0.90 10,247
2016	259,235 2,264,586 86,481	2500	0.14	0,92	2016	0.17	202,21	2016	0.09 0.91 12,550	2016	0.49 0.92 11,623	2016	0.23 0.91 10,492	2016	0.45 0.92 10,135	2016	0.78 0.90 10,222
ne frame		100	207	12,421	2015	0.14	12,207	2015	0.07 0.91 12,727	2015	0.49	2015	0.21 0.91 10,519	2015	0.44 0.92 10,140	2015	0.79 0.90 10.209
timal tir			2014	12,401	2014	0.19	12,193	2014	0.08 0.91 12,709	2014	0.49 0.92 11,638	2014	0.24 0.91 10.393	2014	0.43 0.92 10,167	2014	0.78 0.90 10,228
in the op				12,206	7013	0.49	1,987	2013	0.44 0.91 11,748	2013	0.66 0.92 11,308	2013	0.54 0.91 10.078	2013	0.55 0.92 9,999	2013	0.85 0.90 10,136
cle unit			2012	12,188	2012		11,957	2012	0.43 0.91 11,765	2012	0.63 0.92 11,355	2012	0.51 0.89 10,105	2012	0.49 0.79 9,986	2012	0.84 0.90 10,148
bined cy	257 720 363			0.91 12,254 12,000			12,015 11	2011	0.33 0.91 11,963	2011	0.57 0.92 11,444 1:	2011	0.40 0.91 10.167 1	2011	0.60 0.88 9,941	2011	0.82 0.90 10,165
ld a com	255			0.44 0.92 12,210 12,			11,995 12	2010	0.36 0.91 11,848 11	2010		2010	0.36 0.91 10,173	2010	0.59 0.92 9,972	2010	0.83 0.93 10.194
Coal, bui	2010 # 255,044 # 744,391 # 24,988	122	174	12,			11		11		1		H.				
Case 4 - Cancel Smith Coal, build a combined cycle unit in the optimal time frame	Hydro Generation (MWH) Energy Purchased (MWH) Energy Sold (MWH) Hydro Thal Cost (S)	Cost of Purchases (\$)	Dale 1	Capacity Factor Availability Factor Availability Factor Average Host Raite (Btu/KWh) Fuel Cost (\$/MMBtu) Variable O&M (\$/MBtu) Variable Production Cost (\$/MWh) SOZ Fernison Cost (\$/MWh)	NOx Emission Costs (5)	Dale 2 Capacity Factor Availability Factor	Average Heat Rate (Btu/kWh) Fuel Cost (\$/AMWh) Variable O&M (\$/AWWh) Variable Production Cost (\$/AWWh) SOZ Emission Costs (\$) NOR Emission Costs (\$)	Dale 3	Capacity Factor Availability Factor Availability Factor Fuerage Heat Rate (Btu/KWh) Fuerage Heat Rate (Btu/KWh) Variable C&M (S/MWWh) Variable Powloution Cost (S/MWh) SO2 Emmison Costs (S/ (S/MWh) NOX Finnison Costs (S)	Dale 4	Capacity Factor Availability Factor Availability Factor Availability Factor Availability Factor Availabe (Bulk Milbau) Variable Odduklion (Coxt (S/MWh) Variable Odduklion (Coxt (S/MWh) Nor Emission Coxt (S/MWh) NOR Emission Coxt (S/	Cooper 1	Capadty factor Availability factor Availability factor Fuel Cost (\$/MM8tu) Variable Cost (\$/MM8tu) Variable Production Cost (\$/MWt) Nor Emission Cost (\$/MWt) NOR Emission Cost (\$/MYt)	Cooper 2	Capacity Factor Average Host Rate (BLu/Wh) Fuel Cast (S/MMBtu) Variable CBM (S/MWBtu) Variable Production Cost (S/MWI) SOE Ensisten CCSM (S/MWI)	Spurlock 1	Capadry Factor Availability Factor (Ru/kwh) Fuel Cost (S/MM8tu) Variable Cost (S/MW8tu) Variable Production Cost (S/MWh) SOZ Emission Costs (S) NOx Emission Costs (S)

2015 2013 2014 2015	Spurlock 2 Capacky Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cook (S/MMkh)	Variable Production Cost (\$/MWh) 502 Emission Costs (\$) NOx Emission Costs (\$)	Gilbert Unit	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Periel Cost (S/MMBu)	Variable Count (3/10/Wh) Variable Production Cost (5/MWh) SO2 Emission Costs (5) NOx Emission Costs (5)	Spurlock 4	Capacity Factor Availability Factor Average Heat Rate (Btu/KWh) Fuel Cost (FAMBlu)	Variable Okwi (2/MWh) Variable Production Cost (5/MWh) SO2 Emission Costs (5) NOx Emission Costs (5)	Smith 1 (CFB)	Capacity Factor Availability Factor Availability Factor Availability Factor Variable Poduction (S/MWRtu) Variable Poduction Cost (S/MWR) Variable Poduction Cost (S/MWR)	NOx Emission Costs (\$)	Future CC 1	Availability Factor Average Heat Rate (Bru/kWh) Puel Cost (S/MMBtu) Variable OBM (S/MWh) Variable Production Cost (S/MWh)	SO2 Emission Costs (\$) NOx Emission Costs (\$)	Future CC 2	Capacity Factor Availability Factor Availability Factor Fuel Cost (\$/MMBlul Variable O&M (\$/MWh) SO2 Emission Cost (\$/MWh)	NOx Emission Costs (5)	Smith CT1 Capacity Factor Avarage Heat (BuckWh) Fuel Coxt (S/MM8tul) Variable O&M (S/MWh) Variable O&M (S/MWh) Variable Oxt (S/MWh)	SOZ Emission Costs (5) NOx Emission Costs (5)
Ç	2010 0.75 0.89 10,054		2010	0.81 0.89 9,779		2010	0.76 0.86 9,815		2010		,	2010			2010		0100	0.01 0.01 0.96 13,071	
2011	0,81 0,95 10,026		2011	0.82 0.89 9,750		2011	0.81 0.89 9.721		2011			2011			2011		2011	0.00 0.96 13,187	
2012	0.78 0.89 10.007		2012	0.82 0.89 9.733		2012	0.84 0.89 9,640		2012			2012			2012		2017	0.00 0.96 13,197	
2013	0.78 0.89 10,002		2013	0.82 0.89 9,734		2013	0.84 0.89 9,645	-	2013			2013			2013		2013	0.00 0.96 13,254	
2014	0.74 0.89 10,065		2014	0.81 0.89 9.759		2014	0.83 0.89 9.666		2014		Č	2014			2014		2014	0.00 0.96 13,272	
2015	0.76 0.89 10,039		2015	0.82 0.89 9.746		2015	0.84 0.89 9.659		2015		2015	5102			2015		2015	0.00 0.96 13,266	
2016	0.75 0.89 10,057		2016	0.81 0.89 9,767		2016	0.83 0.89 9.676		2016		2016	0.03	7,680		2016		2016	0.00 0.96 13,238	
2017	0.73 0.89 10,092		2017	0.80 0.89 9.798		2017	0.89 9,703		2017		2017	0.23	7,585		2017		2017	0.00 0.96 13,268	
2018	0.72 0.89 10.108		2018	0.79 0.89 9.821		2018	0.89 9,725		2018		2018	0.23	7,590		7018		2018	0.00 0.96 13,264	
2019	0.73 0.89 10,097		2019	0.80 0.89 9,815	o o	2019	0.89 9.720		507		2019	0.25	7,587	0.00	6107		2019	0.00 0.96 13,319	
2020	0.73 0.89 10,087		7070	0.80 0.89 9,812	deac	0.82	0.89 9,714	500	0707		2020	0.25	7,582	0200	0.06	7,613	2020	0.00 0.96 13,355	
2021	0.74 0.89 10,066	200	1707	0.89 0.89 9.796	1000	0.82	9,704	2021	1		2021	0.25	7,576	2021	0.27	772,7	2021	0.00 0.96 13,684	
2022	0.76 0.89 10,037	2022		0.89 9,779	2022	0.83	9,687	2022			2022	0.27	7.577	2022	0.28	775.7	2022	0.00 0.96 13,719	
2023	0.76 0.89 10,041	2023	180	0.89 9,781	2023	0.83	0.89 9,687	2023			2023	0.26	7,581	2023	0.27	7.581	2023	0,00 0,96 13,483	
	0.74 0.89 10.080	2024	0.80	0.89	2024	0.82	0.89 9,711	2024			2024	0.21	7,600	2024	0.19	7,595	2024	0.00 0.96 13,478	
	0.73 0.89 10,087	2025	0.80	0.89 9,812	2025	0.82	0.89 9,717	2025			2025	0.23	7661	2025	0.22	7,587	2025	0.00 0.96 13,658	
	0.72 0.89 10,102	2026	0.79	0.89 9,832	2026	0.81	0.89 9.736	2026			2026	0.23	777	2026	0.22	7,591	2026	0.00 0.96 13,676	
	0,73 0.89 10,092	2027	67.0	9,825	2027	0.81	9,731	2027			2027	0.21		2027	0.22	7,605	2027	0.00	
	0.72 0.89 10,100	2028	0.79	0.89 9.836	2028	0.81	9,744	2028			2028	0.23		2028	0.24	7,592	5078	0.00 0.95 13.561	
į	0.72 0.89 10,098	2029	0.79	0.89 9,840	2029	0.81	9,745	2029			2029	0.24 0.82 7.596	Sea 2	2029	0.24	565.)	6707	0.00 0.96 13,678	

2029	0.00	13.614	2029	0.00	0.96 13,554	2029	0.01	17,011	2029	0.01	12,807	9000	5707	0.01 0.97 12,778		2029	0.01 0.97 12,834	. 3	2029	0.12 0.96 9,586	
2028	0,00	13,576	2028	0.00	0.96 13,428	2028	0.01	12,837	2028	0.01	12,807	a cor	2028	0.01 0.97 12,763		2028	0.01 0.97 12,776		2028	0.11 0.96 9,595	
2027	0.00	13,311	2027	0.00	0.96 13,321	2027	0.01	12,980	72027	0.01	0.97 12,878		2027	0.01 0.97 12,700		2027	0.01 0.97 12.607		2027	0.10 0.96 9,720	
2026	0.00	13,623	2026	0.00	0.96 13,737	2026	0.03	12,902	2026	0.02	0.97 12,935		2026	0.01 0.97 12,941		2026	0.01 0.97 12,888		2026	0.12 0.96 9,827	
2025	0.00	13,619	2025	0.00	0.96 13,709	2025	0.03	12,858	2025	0.02	0.97 12,874		2025	0.01 0.97 12,854		2025	0.01 0.97 12,782		2025	0.13 0.96 9,897	
2024		0.55 13,473	2024	0.00	13,644	2024	0.03	12,866	2024	0.01	0.97 12,869		2024	0.01 0.97 12,842		2024	0.01		2024	0.11 0.95 10,008	
2023		0.95 13,510	2023	000	13,605	2023	0.04	12,830	2023	0.02	0.97 12,826		2023	0.01 0.97 12,833		2023	0.01		2023	0.16 0.96 9,659	
2022		0.96 13,658	2022		0.04 13,750	2022	0.04	12,834	2022	0.03	0.97 12,844		2022	0.02 0.97 12,835		2022	0.01		2022	0.17 0.96 9.617	
2021		0.96	2021		0.01 0.96 13,750	2021	0.04		2021	0.02	0.97 12,868		2021	0.02 0.97 12,853		2021	0.01	010,71	2021	0.16 0.95 9,649	
2020		0.96 13,427	2020		0.00 0.96 13,477	2020			2020	0.02	0.97		2020	0.01 0.97 12,804		2020	0.01	12,742	2020	0.14 0.96 9,562	
2019		0.96 13,403 1	2019		0.00 0.96 13,402	2019			2019	0.02	0.97 12,789		2019	0.01 0.97 777,21		2019	10.0	12,692	2019	0.13 0.96 9,583	
2018		0.96 13,347 1.	2018		0.00 0.96 13,420 1	7018			2018		0.97 0.97 12,802		2018	0.01 0.97 12,745		2018	0.01	12,671	2018	0.11 0.96 9,626	
2017		13,374	Trac		0.00 0.96 13,417 1	7100		12,839	, tob.		0,01 0,97 12,856		2017	0.01 0.97 12,782		2017			7102	0.10 0.96 9,465	
2016		13,364 13			0.00 0.96 13,325	9101		0.97 12,807 1			0.01 0.97 12,821		2016	0.01 0.97 12,812		3016			2016	0.09	
		0.96 13.387 13		2015	0.00 0.96 13,215			0.97 12,821 1.			0.01 0.97 12,804 1		2015			2035			2015	0.09	
timal time		0.96 13.462 13.		2014	0.00 0.96 13,300 13		2014	0.97		2014	0.01 0.97 12,837 1.		2014						2014	0.07	
in the opti		13		2013	0.00 0.96 13.255 13,		2013	0.97 12,684 12			0.02 0.97 12,769 12		2013				0.00		2013	0.08	OCT 1
ycle unit in		13		2012 2			2012 2	12		2012	0.02 0.99 12,728 12.		. 101	13			2012 0.00 0.95		2012		1 202711
nbined cyc		13		2011 20	13		2011 20	12		2011 2	0.02 0.99 12,721 12,						0.00		2011		10,953
ld a com		13		2010 2	0.00 0.00 0.94 0.96 13,021 13,344		2010 2	12		2010	0.04 0.99 12,523 12				51,445		2010		0100		10,380
Coal, bui	7	0.01 0.96 13,276		1.4	13,		-	12,			12			;				1			
Case 4 - Cancel Smith Coal, build a combined cycle unit in the optimal time frame	Smith CT2	Capacity Factor Availability Factor Availability Factor Fuel Cost (\$/MM8tu) Variable Og&M (\$/MWN) Variable Podeutron (\$/MWN) Variable Podeutron (\$/MWN) Variable Podeutron (\$/MWN)	NOx Emission Costs (5)	Smith CT3	Capacity Factor Availability Factor Average Heat Rate (Bus/KWh) Fuel Cost (\$/MM8tu) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh)	SO2 Emission Costs (3) NOx Emission Costs (5)	Smith CT4	Lupacky ractor Availability Factor Average Heaf Rate (Btu/kWh) Fuel Cost (S/AMMBlu) Variable O&M (S/AWh) Variable Production Cost (S/AWh)	SOZ Emission Costs (5) NOx Emission Costs (5)	Smith CT5	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh)	Fuel Cost (\$/MMbltu) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SOZ Emission Costs (\$) MON Emission Forts (\$)	NOX Emission costs (2)	Smith CT6 Capacity Factor Availability Factor	Average Heat Rate (Btu/kWh) Fuel Cost (\$/MMBtu) Variable O&M (\$/MWH) Variable Production (\$/MWh) COST (\$/MWH)	NOx Emission Costs (\$)	Smith CT7 Capacity Fact <i>or</i>	Availality Factor Average Heat Rate (Btu/kWh) Fuel Cocx (S/MMBtu) Variable O&M (S/MWh) Variable Poduction Cocx (S/MWh) Syriahe Production Cocx (S/MWh) Syriahe Cocx (S/MWh)	NOx Emission Costs (5)	Smith CT 9 Capacity Factor Availability Factor	Average Hast Rate (Bru/kWh) Fuel Cost (\$/MM8tu) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SQ2 Emission Cost (\$) NOx Emission Cost (\$)

ancel Smith Coal, build a combined cycle unit in the optimal time frame 2012 2013 2014 2015 2015 2014 2015 2015 2014 2015	a combine 2011 0.11	od cycle u	unit in the	optimal til	me frame 2015 0.16	2016 0.15 0.96	2017 0.17 0.96	2018 0.16 0.96	2019 0.18 0.96	2020 0.20 0.96	0.20	2022 0.21 0.96	2023 0.20 0.96 9.469	2024 0.12 0.96 9.679	2025 0.15 0.96 9,624	2026 0.16 0.96 9,633	2027 0.16 0.96 9,773	0.18 0.96 9,657	0.19 0.96 9,631
0.84	21	0.98 10,978	0.96	9,488	9,461	9,460	9,445	9,493	9,495	9,450	898	9,594	2,402				Pos	300	9,002
2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	0.94	0.94	0.94
0.95 0.97 11,848	0.94 0.97 11,842	0.95 0.97 11,828	0.95 0.97 11,828	0.94 0.97 11,828	0.95 0.97 11,828	0.94 0.97 11,828	0.94 0.97 11,828	0.94 0.97 11,828	0.94 0.97 11,828	0.94 0.97 11,828	0.94 0.97 11,828	0.97 11,828	0.97	11,828	0.97 11.828	0.97 11,828	0.97 11,828	0.97 11,828	11,828
										02002	2021	2022	2023	2024	2025	2026	2027	2028	2029
2010	2011	2012	2013	2014	2015	2016	2017	2018	5073	2707						0.00 1.00 12,608	0.02 1.00 13.016	0.03 1.00 12,911	0.04 1.00 12,919
									9101	0606	2021	2022	2023	2024	2025	2026	2027	2028	2029
2010	2011	2012	2013	2014	2015	2016	2017	8107	eroz.								0.00 1.00 12,530	0.02 1.00 12,889	0.02 1.00 12,883

2029	0.01 0.96 13,746	2029	0.01 0.96 13,765	2029	0.05	2029	0.03	2029	0.02 0.97 12,782	2029	0.02 0.97 12,730	5029	0.13 0.96 10,265
2028	0.01 0.96 13,730	2028	0.01 0.96 13,850	2028	0.04 0.97 12.825	2028	0.03 0.97 12,842	2028	0.02 0.97 12.837	2028	0.02 0.97 12,797	2028	0.12 0.96 10,320
2027	0.00 0.96 13,628	2027	0.00 0.96 13,771	2027	0.04	2027	0.02 0.97 12,843	2027	0.02 0.97 12,836	2027	0,01 0.97 12,778	2027	0.10 0.96 10,475
2026	0,00 0,96 13,863	2026	0.00 0.96 13,957	2026	0.04	2026	0.02 0.97 12.914	2026	0.02 0.97 12,936	2026	0.01 0.97 12,917	2026	0.10 0.96 10,456
2025	0.01 0.96 13,742	2025	0.00 0.96 13,670	2025	0.05 0.97 12,765	2025	0.04 0.97 12.785	2025	0.03 0.97 12,777	2025	0.02 0.97 12,717	2025	0.12 0.96 10,503
2024	0.01 0.96 13,719	2024	0.00 0.96 13,478	2024	0.05 0.97 12,735	2024	0.04	2024	0.03 0.97 12,744	2024	0.02 0.97 12,680	2024	0.11 0.96 10,517
2023	0.02 0.96 13,596	2023	0.01 0.96 13,403	2023	0.07 0.97 12,663	2023	0.06	2023	0.04 0.97 12,615	2023	0.03 0.97 12,545	2023	0.17 0.96 10,179
urces 2022	0.02 0.96 13,601	2022	0.01 0.96 13,551	2022	0.07 0.97 12,665	2022	0.05 0.97 12,694	2022	0.04 0.97 12,651	2022	0.03 0.97 12,593	2022	0.17 0.96 10,190
ation reso	0.02 0.96 13,601	2021	0.01 0.96 13,476	2021	0.07 0.97 12,658	2021	0.05 0.97 12,675	2021	0.04 0.97 12,639	2021	0.03 0.97 12,578	2021	0.16 0.96 10,145
ble genera	0.01 0.96 13,618	2020	0.00 0.96 13,283	2020	0.06 0.97 12,716	2020	0.04 0.97 12,727	2020	0.03 0.97 12,682	2020	0.02 0.97 12,625	2020	0.14 0.96 10,095
nd renewa 2019	0.01 0.96 13.578	2019	0.00 0.96 13,293	2019	0.05	2019	0.03 0.97 12,722	2019	0.02 0.97 12.679	2019	0.02 0.97 12,633	2019	0.13 0.96 10.138
efforts ar	0.01 0.96 13,566	2018	0.00 0.96 13,236	2018	0.05 0.97 12,706	2018	0.03 0.97 12,716	2018	0.02 0.97 12,679	2018	0.02 0.97 12,614	2018	0.13 0.96 10,112
ased DSM	0.00 0.96 13,524	2017	0.00 0.96 13.236	2017	0.04 0.97 12.745	2017	0.03 0.97 12,760	2017	0.02 0.97 12,763	2017	0.01 0.97 12.739	2017	0.12 0.96 9.977
n of incre	0.00 0.96 13.480	2016	0.00 0.96 13,249	2016	0.03 0.97 12,746	2016	0.02 0.97 12.780	2016	0.01 0.97 12,738	2016	0.01 0.97 12,641	2016	0.10 0.96 10,049
ombinatio 2015	0.00 0.96 13,447	2015	0.00 0.96 13,168	2015	0.03 0.97 12,763	2015	0.02 0.97 12,781	2015	0.01 0.97 12,777	2015	0.00 0.97 12,655	2015	0.10 0.96 9,984
s with a co	0.00 5 0.96 13,455	3 2014	0.00	3 2014	3 0.01 7 0.97 12,827	3 2014	1 0.01 7 0.97 12,877	3 2014	1 0.00 7 0.97 12,825	3 2014	0.00 0.97 12,789	2014	0.06 0.96 9,534
pply needs 2 2013	0 0.00 6 0.96 6 13,505	2 2013	00 0.00 6 0.96 13.371	2 2013	3 0.03 9 0.97 i 12.706	2 2013	2 0.01 9 0.97 i 12,793	2 2013	1 0.01 9 0.97 12.812	2 2013	0.00 5 0.97 217,21	2 2013	3 0.07 3 0.96 11,230
power sup	00 0.00 16 0.96 3 13,516	1 2012	00 0.00 6 0.96 9 13,342	1 2012	3 0.03 3 0.99 7 12,676	1 2012	2 0.02 9 0.99 5 12,776	1 2012	1 0.01 5 0.99 1 12,762	1 2012	0 0.00 9 0.95 8 12,661	1 2012	7 0.08 2 0.98 11,154
all future p	1 0.00 6 0.96 9 13,543	0 2011	0 0,00 4 0,96 13,409	0 2011	5 0.03 7 0.93 8 12,627	0 2011	4 0.02 9 0.99 12,715	0 2011	3 0.01 9 0.95 12,681	0 2011	2 0.00 9 0.99 12,623	0 2011	0 0.07
I, provide a	0.01 0.96 13,269	2010	0.00	2010	0.05 0.97 12,549	2010	0.04 0.99 12,522	2010	0.03 0.99 12,450	2010	0.02 0.99 12.282	2010	0.10 0.84 10.377
Case 5 - Cancel Smith Coal, provide all future power supply needs with a combination of increased DSM efforts and renewable generation resources smith crz 2017 2018 2019 2019 2020 2021 20	Capacity Factor Availability Factor Average Heat Rate (But/kWh) Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SOZ Emission Costs (\$) NOx Emission Costs (\$)	Smith CT3	Capacity Factor Availability Factor Availability Factor Avariage teat Rate (But/kWh) Fuel Cost (\$/MWBtu) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SOZ Emission Costs (\$) NOX Emission Costs (\$)	Smith CT4	Capacity Factor Availability Factor Availability Factor Avarage Heat Rate (Bu/kWh) Fuel Cost (S/MMBtu) Variable D&M (S/MWh) Variable Production Cost (S/MWh) SOZ Emission Costs (S) NOx Emission Costs (S)	Smith CTS	Capacity Factor Availability Factor Average Heat Rate (Buy/kWh) Fuel Cost (\$/MWBtu) Variable O&M (\$/MWBtu) Variable Poduction Cost (\$/MWh) SOZ Emission Costs (\$) NOx Emission Costs (\$)	Smith CT6	Capacity Factor Availability Factor Avarage Heat Rate (Bur/kWh) Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SOZ Emission Costs (\$) NOx Emission Costs (\$)	Smith CT7	Capacity Factor Availability Factor Availability Factor Avarage heat Rate (Btu/kWh) Fuel Cost (\$/NMBtu) Variable O&M (\$/NWh) Variable Production Cost (\$/MWh) SOZ Emission Costs (\$) NOX Emission Costs (\$)	Smith CT 9	Capacity Factor Availability Factor Availability Factor Fuel Cost (\$/MMBtu) Variable C&M (\$/MWh) Variable C&M (\$/MWh) SOE Emission Costs (\$/MWh) SOE Emission Costs (\$) NOx Emission Costs (\$)

Case 5 - Cancel Smith Coal, provide all future power supply needs with a combination of increased DSM efforts and renewable generation resources	orovide all f	uture pow	rer supply	needs wi	ith a com	bination c	of increase	ed DSM ef	forts and	renewabl	e generat	ion resou	I rces 2022	2023	2024	2025	2026	2027	2028	2029
AWH) AWH)	2010 255,032 744,302		-i	. 7		258,139 1,322,595 1		+-	7				257,024 2,528,519 2 304,200	257,133 2,701,768 229,749	259.202 3,883,280 497,054	258,667 4,293,352 554,238	257,024 4,392,930 547,532	258,108 4,380,884 438,079	256.980 4,529,989 455,733	258,056 4,644,078 396,866
Energy Sold (MWH) # Hydro Total Cost (\$) # Cost of Purchases (\$) # #	245,080	446,393	449,932	442,541	104,200	597,555	C++'007								a A					
Dale 1	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor Availability Factor Average Hace flate (Buu/kwh) Fuel Cost (S/MMBu) Varnable O&M (S/MWh) Varnable Production Cost (S/MWh) SOZ Emission Costs (\$)	0.44 0.92 12,209	0.36 0.91 12.268	0.41 0.90 12.211	0.42 0.92 12,231	0.13 0.92 12,423	0.35 0.92 12,340	0.38 0.92 12,327	0.38 0.92 12,328	0.42 0.92 12,305	0.42 0.92 12,306	0.47 0.92 12,293	0.49 0.92 12.280	0.51 0.92 12,266	0.50 0.92 12,268	0.43 0.92 12,284	0.41 0.92 12,291	0.35 0.92 12,324	0.35 0.92 12,326	0.37 0.92 12.317	0.39 0.92 12,315
NOx Emission Costs (\$) Dale 2	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor Availability Factor Availability Factor Avarage Heat Rate (Btu/kWh) Puel Cost (S/AMRbu) Variable O&M (S/AWh) Variable Production Cost (S/AWh) SQ Emission Cost (S) MOX Emission Cost (S)	0.48 0.94 11,995	0.40 0.93 12,035	0.45 0.93 11,990	0.43 0.94 12,015	0.17 0.94 12,205	0.42 0.94 12,100	0.45 0.94 12,085	0.43 0.94 12,107	0.47 0.94 12.069	0.48 0.94 12,071	0.50 0.94 12,062	0.54 0.94 12,039	0.55 0.94 12.029	0.56 0.94 12,026	0.49 0.94 12,051	0.46 0.94 12,067	0.39 0.94 12,107	0.40 0.94 12,106	0.42 0.94 12,101	0.44 0.94 12,098
Dale 3	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor Availability Factor Average Heat flare (BLV/kWh) Fuel Cost (\$5/MMBtu) Variable O&M (\$5/MWh) Variable Production Cost (\$5/MWh) SO2 Emission Cost (\$5) NOX Emission Cost (\$5)	0.36 0.91 11,848	0.29 0.91 12,021	0.39 0.91 11,831	0.39 0.91 11,808	0.07 0.91 12,756	0.26 0.91 12,009	0.30 0.91 12,027	0.30 0.91 12,083	0.33 0.91 12,074	0.33 0.91 12,057	0.36 0.91 12,009	0.38 0.91 11,982	0.39 0.91 11,973	0.40 0.91 11,965	0.35 0.91 12,028	0.32 0.91 12.048	0.27 0.91 12.116	0.29 0.91 12,067	0.31 0.91 12,073	0.33
Dale 4	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor Availability Factor Average Heat Rate (Bru/KWh) Fuel Cost (\$F/AM/Blu) Vanable O&M (\$F/AW/Nh) Variable Production Cost (\$F/MWh) SQ2 Emission Costs (\$) NOX Emission Costs (\$)	0.59 0.90 11,376	0.56 0.92 11,481	0.61 0.92 11,384	0.64 0.92 11,334	0.49 0.92 11,644	0.57 0.92 11,403	0.58 0.92 11,398	0.56 0.92 11,452	0.57 0.92 11,451	0.57 0.92 11,446	0.58 0.92 11,432	0.59 0.92 11,420	0.60 0.92 11,407	0.60 0.92 11,405	0.58 0.92 11,444	0.57 0.92 11,456	0.57 0.92 11,457	0.58 0.92 11,435	0.57 0.92 11,446	0.57 0.92 11,441
Cooper 1	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor Availability Factor Availability Factor Average Heat Rate (Bu/kWh) Fuel Cost (\$/AMMbi) Varnable ORAM (\$/MWh) SQZ Emission Cost (\$/NWh) NOR Emission Cost (\$) NOR Emission Cost (\$)	0.36 0.91 10,174	0.35 0.91 10,201	0.46 0.89 10,116	0.48 0.91 10,104	0.21 0.91 10,408	0.44 0.91 10.169	0.45 0.91 10,155	0.42 0.91 10,216	0.45 0.91 10,205	0.45 0.91 10,202	0.48 0,91 10,188	0.48 0.91 10,190	0.49 0.91 10.177	0.51 0.91 10,171	0.42 0.91 10.195	0.40 0.91 10,215	0.37 0.91 10,245	0.42 0.91 10,190	0.91 0.91 10.185	0.44 0.91 10,197
Cooper 2	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor Availability Factor Avariage Heat Rate (BuyKWh) Fuel Cost (\$/MWBlu1) Variable O&M (\$/MWh) Variable ORM (\$/MWh) SOZ Emission Cost (\$) NOx Emission Costs (\$)	9.972	0.58 0.88 9.959	0.48 0.79 10.000	0.54 0.92 10,012	0.43 0.92 10,173	0.51 0.92 10,039	0.51 0.92 10,038	0.51 0.92 10,044	0.51 0.92 10.043	0.52 0.92 10,037	0.53 0.92 10,026	0.53 0.92 10.025	0.54 0.92 10,020	0.54 0.92 10,019	0.50	0.50 0.92 10.053	0.51 0.92 10,043	0.52 0.92 10,038	10.040	10,039

Case 5 - Cancel Smith Coal, provide all future power supply needs with a combination of increased DSM efforts and renewable generation resources spurlock 1 2017 2018 2019 2020 2021 2021 20	Capacity Factor Availability Factor Availability Factor Availability Factor Availability Factor Variable Code (S/AMMBu) Variable Graduction Cost (S/AMWh) Soz Emission Costs (S) NOx Emission Costs (S)	Spurlock 2	Capacity Factor Availability Factor Availability Factor Availability Factor Availability Factor Variable Code (S/AMMBus) Variable Ordeuricon Cost (S/AMWh) Son Emission Costs (S) NOx Emission Costs (S)	Gilbert Unit	Capacity Factor Availability Factor Availability Factor Fuel Cost (\$\frac{1}{2}\text{AMMbit}\) Variable O&M (\$\frac{5}{2}\text{AMMbit}\) Variable Production Cost (\$\frac{5}{2}\text{AMMi}\) Variable Production Cost (\$\frac{5}{2}\text{AMMi}\) NOR Emission Costs (\$\$)	Spurlock 4	Capacity Factor Availability Factor Availability Factor Gost (S/MMBusu) Varnable C&M (S/MWh)	Smith 1 (CFB)	Capacity Factor Availability Factor Availability Factor Gost (S/MANBus) Fuel Cost (S/MANBus) Variable Poduchino Cost (S/MANR) SOZ Emission Cost (S) NOX Emission Cost (S)	Future CC	Capacity Factor Availability Factor Availability Factor Fuel Cost (S/MMBu) Variable Ordeution Cost (S/MMBu) Variable Production Cost (S/MWh) Nariable Production Cost (S/MWh) Nariable Production Cost (S) NOX Emission Costs (S)	Smith CT1	Capacity Factor Availability Factor Average Heat Rate (Bu/kWh) Puel Cost (S/MRWh) Variable OBM (S/MWh) Variable Production Cost (S/MWh) SO2 Emission Costs (S) NOX Emission Costs (S)
oal, provide all f	0.83 0.93 10,194	2010	0.75 0.89 10,054	2010	0.81 0.89 9.779	2010	0.76 0.86 9.815	2010	i	2010		2010	0.01 0.96 13.073
future pow	0.81 0.90 10,185	2011	0.80 0.95 10,047	2011	0.81 0.89 9.776	2011	0.81 0.89 9,744	2011		2011		2011	0.00 0.96 13,304
ver supply	0.82 0.90 10,165	2012	0.77 0.89 10,026	2012	0.82 0.89 9,746	2012	0.84 0.89 9,652	2012		2012	: : : :	2012	0.00 0.96 13.202
needs witl	0.83 0.90 10,152	2013	0.77 0.89 10.016	2013	0.82 0.89 9,746	2013	0.84 0.89 9,656	2013		2013		2013	0.00
:h a combiı ²⁰¹⁴	0.77 0.90 10,242 1	2014	0.73 0.89 10,079	2014	0.81 0.89 9,771	2014	0.83 0.89 9.677	2014		2014		2014	0.00 0.96 13,180 1
nation of i	0.84 0.90 10,149 11	2015	0.79 0.89 9,989	2015	0.82 0.89 9,732	2015	0.84 0.89 9,647	2015		2015		2015	0.00 0.96 13,278 13
increased	0.84 0.90 10,150 1	2016	0.79 0.89 9.989	2016	0.83 0.89 9.743	2016	0.84 0.89 9.653	2016		2016		2016	0.00 0.96 13,307 15
DSM effor	0.82 0.90 10,165	2017	0.79 0.89 9,994 10	2017	0.82 0.89 9,746	2017	0.84 0.89 9,654 (2017		2017		2017	0.00 0.96 13,301 13
rts and rei	0.82 0.90 10,170 10	2018	0.78 0.89 10,003	2018	0.82 0.89 9,750 9	2018	0.84 0.89 9.659 9	2018		2018		2018	0.00
newable g	0.82 0.90 10.170 10,	2019	0.79 0.89 9,999 9,	2019	0.81 0.89 9,754 9.	2019	0.83 0.89 9.664 9.	2019		2019		2019	0.00 0.96 0.3311 13,
eneration 2020	0.83 0.90 10,164 10,	2020 2	0.79 0.89 9,991 9.9	2020 2	0.82 0.89 9.749 9.7	2020 2	0.84 0.89 9,658 9.1	2020 2		2020 2		2020 2	0.01 0 0.96 0 13.477 13.4
n resources	0.82 0.90 10,165 10.1	2021 2) 08.0 0 68.6 5 68.6 68.6 68.6 68.6 68.6 68.6 68.6 68.6	2021 2	0.82 0.89 0.746 9.746	2021 2	0.84 0.89 9.660 9,6	2021 2		2021 2		2021 20	0.01 0.01 0.96 0.96 13,488 13,535
22	0.83 0.83 0.90 0.90 10.158 10.154	2022 24	0.89 0	2022	0.82 0 0.89 0 9.745 9,7	2022 20	0.84 0.84 0.89 0.89 9,655 9,651	2022 20		2022 20		2022	01 0.01 96 0.96 35 13.466
2023 20	10	2023 20	0.80 0.77 0.89 0.89 9.977 10,021	2023 20	0.82 0.81 0.89 0.89 9,742 9,780	2023 20	6	2023 20		2023 20		2023 2024	11 0.01 96 0.96 56 13,588
2024 20	10	2024 20	77 0,76 89 0,89 11 10,034	2024 20	81 0.80 89 0.89 80 9,795	2024 20	0.83 0.89 0.89 0.89 691 9.706	2024 20		2024 20	0.04 0.90 7,638		11 0.01 66 0.96 88 13,696
2025 20	0.80 0.80 0.90 0.90 0.90 1.199 10.203	2025 20	76 0,76 89 0,89 84 10,034	2025 20		2025 20		2025 20		2025 20		2025 20	11 0.00 66 0.96 66 13.938
2026 20	10	2026 24	.76 0.77 .89 0.89 34 10.017	2026 20	0.80 0.89 9.789 9.7	2026 20	0.82 0 0.89 0 9.698 9.6	2026 20		2026 20		2026 20	11
2027 20	10	2027 20	10	2027 20	0.81 0 0.89 0 0.9776 9,7	2027 20	0.83 0.89 0.896 0.686	2027 20		2027 20		2027 20	# ,
2028	10	2028	10	2028	0.81 0.89 9,772 9.	2028	0.83 0.89 9.684 9.	2028		2028		2028	11
2029	0.81 0.90 10.185	2029	0.78 0.89 10.013	5029	0.81 0.89 9,769	5029	0.83 0.89 9,678	2029		2029	0.24 0.86 7.608	2029	0.01 0.96 13,748 Lagge 13,748

2029	0.16 0.96 10,116	2029	0.94 0.97 11,828
2028	0.15 0.96 10,186	2028	0.94 0.97 11,828
2027	0.13 0.96 10,364	2027	0.94 0.97 11,828
2026	0.13 0.96 10,280	2026	0.94 0.97 11,828
2025	0.15 0.96 10,518	2025	0.94 0.97 11,828
2024	0.15 0.96 10,659	2024	0.94 0.97 11,828
2023	0.22 0.96 10.327	2023	0.94 0.97 11,828
urces 2022	0.22 0.96 10.320	2022	0.95 0.97 11,828
ation reso	0.21 0.96 10,270	2021	0.94 0.97 11,828
ole genera 2020	0.20 0.96 10,234	2020	0.94 0.97 11,828
d renewal	0.18 0.96 10,227	2019	0.94 0.97 11,828
efforts and	0.18 0.96 10,245	2018	0.94 0.97 11,828
sed DSM o	0.17 0.96 10,013	2017	0.94 0.97 11,828
of increa	0.16 0.96 10,177	2016	0.95 0.97 11,828
ıbination 2015	0.15 0.96 9,984	2015	0.95 0.97 11,828
vith a con	0.10 0.96 9,516	2014	0.94 0.97 11,828
ly needs ι	0.10 0.96 11,038	2013	0.95 0.97 11,828
Wer supp	0,11 0.98 11,006	2012	0.95 0.97 11,828
future po	0.09 0.92 10,850	2011	0.94 0.97 11,842
rovide all	0.12 0.84 10,325	2010	0.95 0.97 11,848
Case 5 - Cancel Smith Coal, provide all future power supply needs with a combination of increased DSM efforts and renewable generation resources	Gapacity Factor Availability Factor Availability Factor Avariabe Cate Rate (Btu/Kwh) Fuel Cast (S/Mwlbtu) Variable O&M (S/Mwlh) SOZ Emission Cast (S/Mwh) NOX Emission Cast (S/) NOX Emission Cast (S/)	Landfill Gas Projects	Capacity Factor Availability Factor Availability Factor Eucl Cost (\$/MM8tu) Fuel Cost (\$/MM8tu) Variable Poduction Cost (\$/MWh) SOZ Emisson Costs (\$) NOX Emisson Costs (\$)

epend on Purchased Power until 2022	2015 2015 2015 2015 2015 2016 2016 2015 2015 2016 2015 2015 2015 2016 2016 2016 2016 2016 2016 2016 2016	2010 2011 2012 2013 2014 2015	0,44 0,40 0,46 0,47 0,14 0,11 0,92 0,91 0,90 0,92 0,92 0,92 12,210 12,254 12,188 12,206 12,401 12,421	2010 2011 2012 2013 2014 2015	Capacity Factor 0.48 0.45 0.50 0.49 0.19 0.14 Availability Factor 0.94 0.93 0.93 0.93 0.94 0.94 0.94 Availability Factor 0.94 0.93 0.93 0.93 0.94 0.94 0.94 Fuel Cost (S/MMRIa) 11,995 11,997 11,987 12,193 12,207 Veriable Productors Veriable Productors Veriable Productors Veriable Productors Veriable Productors SOZ Emission Cost (S/MVM) Veriable Productors Veriable Productors Veriable Productors	2010 2011 2012 2013 2014 2015	Capacity Factor 0.36 0.33 0.43 0.44 0.08 0.07 Availability Factor 0.91 0.91 0.91 0.91 0.91 0.91 Availability Factor 0.91 0.91 0.91 0.91 0.91 0.91 Fuel Cost (S/MMRtub 11,363 11,765 11,748 12,709 12,727 Variable Productor Cost (S/MWhh) 202 Emission Costs (S/MWhh) 12,727 12,727 NOX Emission Costs (S) 10,705 12,727 12,727	2010 2011 2012 2013 2014 2015	Capacity Factor 0.59 0.57 0.63 0.66 0.49 0.49 Availability Factor 0.90 0.92 0.92 0.92 0.92 0.92 Availability Factor 0.90 0.92 0.92 0.92 0.92 0.92 Fuel Cost (S/MMRIau) 11,376 11,444 11,355 11,308 11,638 11,640 Vorrable Ordun Cost (S/MWIh) Vorrable (Productor Cost (S/MWIh) NOX Emission Cost (S/MWIh) Available (Productor Cost (S/MWIh) Available (Productor Cost (S/MWIh)	2010 2011 2012 2013 2014 2015	Capacity Factor 0.36 0.40 0.51 0.54 0.24 0.21 Availability Factor 0.91 0.91 0.89 0.91 0.91 0.91 Availability Factor 0.91 0.91 0.89 0.91 0.91 0.91 Puel Cost (S/MMRIA) 10.173 10.167 10.105 10.078 10.393 10.519 Variable Production Cost (S/MWh) 202 Emission Cost (S/MWh) 202 Emission Cost (S/MWh) 203 Emission Cost (S/MWh) 203 Emission Cost (S/MWh)	2010 2011 2012 2013 2014 2015	Capacity Factor 0.59 0.60 0.49 0.55 0.43 0.44 Availability Factor 0.92 0.88 0.79 0.92 0.92 0.92 Availability Factor 0.04 0.97 0.92 0.92 0.92 0.92 Availability Factor 0.04 0.97 0.94 0.99 0.99 0.97 0.92 Availability Factor 0.04 0.97 0.94 0.99 0.99 0.167 10.140 Availability Factor 0.04 0.99 0.999 10.167 10.140 Available Cabil (S/MWH) 0.04 0.994 9.999 10.167 10.140 Available Production Cast (S/MWH) 0.06 0.999 0.999 10.167 10.140 Available Production Cast (S/MWH) 0.06 0.994 9.996 9.999 10.167 10.140 Available Production Cast (S/MWH) 0.06 0.999 0.999 10.167 10.140
onst	259,102 25,896 2,296,495 3,768,060 86,330 443,015	2016 2017	0.15 0.08 0.92 0.92 12.409 12,436	2016 2017	0.18 0.10 0.94 0.94 12,200 12,232	2016 2017	0.09 0.05 0.91 0.91 12,693 12,969	2016 2017	0.49 0.47 0.92 11,617 11,694	2016 2017	0.24 0.10 0.91 0.91 10.500 10,602	2016 2017	0.45 0.44 0.92 10,134 10,153
combined	257,699 258,415 3.885,901 3,971,898 432,930 386,744	2018 2019	0.12 0.13 0.92 0.92 12,433 12,422	2018 2019	0.15 0.16 0.94 0.94 12.213 12,201	2018 2019	0.08 0.09 0.91 0.91 12.689 12,705	2018 2019	0.49 0.49 0.49 0.92 0.92 11,648 11,645	2018 2019	0.20 0.20 0.91 0.91 10.542 10,524	2018 2019	0.44 0.45 0.92 0.92 10,141 10,126
<u> </u>	259,400 3,991,974 3 388,493	2020	0.16 0.92 12,435	2020	0.19 0.94 12,214	2020	0.10 0.91 12,667	2020	0.50 0.92 11,614	2020	0.22 0.91 10,510	2020	0.46 0.92 10,108
,	257,656 258,813 3,973,357 2,323,675 452,848 203,872	2021 2022	0.14 0.27 0.92 0.92 12,427 12,403	2021 2022	0.18 0.30 0.94 0.94 12,204 12,180	2021 2022	0.09 0.16 0.91 0.91 12,432 12,318	2021 2022	0.51 0.53 0.92 0.92 11,578 11,506	2021 2022	0.18 0.35 0.91 0.91 10,462 10,338	2021 2022	0.48 0.52 0.92 10,090 10,094
	258,592 2,671,133 3,7	2023	0.24 0.92 12.417	2023	0.29 0.94 12,194	2023	0.14 0.91 12,339	2023	0.52 0.92 11,518	2023	0.35 0.91 10,369	2023	0.51 0.92 10,046
	256,666 258,723 3,712,481 3,858,926 251,768 258,498	2024 2025	0.20 0.22 0.92 0.92 12.412 12.411	2024 2025	0.23 0.26 0.94 0.94 12,198 12,188	2024 2025	0.13 0.13 0.91 0.91 12,348 12,332	2024 2025	0.53 0.53 0.92 0.92 11,524 11,520	2024 2025	0.31 0.35 0.91 0.91 10,329 10,326	2024 2025	0.49 0.49 0.49 0.92 0.92 10,072 10,065
	257,252 257,898 4,247,242 188,328	5 2026	2 0.19 2 0.92 12,419	5 2026	6 0.24 4 0.94 3 12,200	5 2026	0.12 0.91 0.91 0.12,383	5 2026	3 0.52 2 0.92 0 11,549	5 2026	5 0.31 1 0.91 5 10,362	5 2026	9 0.48 2 0.92 5 10,080
	258,477 258,048 258,477 4,480,273 120,980 141,846	2027 20	0.21 0.18 0.92 0.95 12,414 12,422	2027	0.24 0.25 0.94 0.94 12,191 12,198	2027	0.12 0.13 0.91 0.91 12,396 12,346	2027	0.51 0.51 0.92 0.92 11,559 11,560	2027	0.32 0.31 0.91 0.99 10.356 10,343	2027	0.47 0.47 0.47 0.92 0.92 10.103
	7 258,395 8 4,887,921 6 125,535	2028 2029	0.18 0.20 0.92 0.92 422 12,414	2028 2029	0.25 0.25 0.94 0.94 198 12,195	2028 2029	0.13 0.13 0.91 0.91 0.346 12,367	2028 2029	0.51 0.51 0.92 0.92 560 11,567	2028 2029	0.31 0.33 0.91 0.91 343 10,359	2028 2029	0.47 0.46 0.92 0.92 10.108

Case 6 - Cancel Smith Coal, depend on Purchased Power until 2022 then construct combined cycle generation	Capacity Factor 0.83 0.82 0.84 Availability Factor 0.93 0.90 0.90 Average Heat Fate (Btu/kWh) 10,194 10,165 10,148 Fuel Cost (S/MMku) 10,448 10,165 10,148 Available Cost (S/MWh) 10,165 10,148 10,165 Available Production Cost (S/MWh) 10,165 10,148 10,165 Available Production Cost (S/MWh) 10,165 10,148 10,165 Available Cost (S/MWh) 10,165 10,165 10,148	2010 2011 2012	Capacity Factor 0,75 0,81 0,78 Availability Factor 0,89 0,95 0,89 Average Heat Rate (stu/kWh) 10,054 10,026 10,007 Fuel Cost (\$/MMBU) 10,026 10,007 10,007 Available Production Cost (\$/MWh) 10,002 10,007 10,007 SQE Emission Costs (\$/MWh) 10,002 10,007 10,007	2010 2011 2012	Capacity Factor 0.81 0.82 0.82 Availability Factor 0.69 0.89 0.89 Average Heat Rate (Btu/KWh) 9,779 9,750 9,733 Fuel Cost (S/MMBU) 9,779 9,750 9,733 Avariable Production Cost (S/MWh) 9,779 9,750 9,733 SQE Emission Costs (S/MWh) 9,779 9,750 9,733 Oxo Emission Costs (S) 0,000 0,000 0,000	2010 2011 2012	Capacky Factor 0.76 0.81 0.84 Availability Factor 0.86 0.89 0.89 Average Heat Bate (Btu/kWI) 9,815 9,721 9,640 Fuel Cost (S/MWI) 9,815 9,721 9,640 Available Coduction Cost (S/MWI) 9,815 9,721 9,640 Available Production Cost (S/MWI) 9,815 9,721 9,640 Available Production Cost (S/MWI) 9,815 9,815 9,640 Available Cost (S/MWI) 9,815 9,815 9,640 Available Cost (S/MWI) 9,815 9,815 9,640	2010 2011 2012	Capacity Factor Availability Factor Availability Factor Availability Factor Availability Factor Variabile C&M (\$/MWIN) Variabile C&M (\$/MWIN) Variabile Cate (\$/MWIN) Variabile Cost (\$/MWIN) Variabile Cost (\$/MWIN) Variabile Cost (\$/MWIN) Variabile Cost (\$/MWIN)	2010 2011 2012	Capacity Factor Availability Factor Availability Factor Availability Factor Variable O&M (\$/MWh) Variable O&M (\$/MWh) Variable O&M (\$/MWh) Variable OXE (\$/MWh) NOZE Emission Cost (\$/MWh)	2010 2011 2012	Capacity Factor Availability Factor Avarage Hear Rate (Btu/KWh) Avarage Cad (S/MWh) Variable Cad (S/MWh) SOZ Emission Costs (S) NOX Emission Costs (S) NOX Emission Costs (S)
ased Pow	0.85 0.90 10,136	2013	0.78 0.89 10,002	2013	0.82 0.89 9,734	2013	0.84 0.89 9,645	2013		2013		2013	
er until 2022 2014 2015	0.78 0.79 0.90 0.90 10.228 10,209	2014 2015	0.74 0.76 0.89 0.89 10.065 10.039	2014 20	0.81 0.82 0.89 0.89 9.759 9.746	2014 20	0.83 0.84 0.89 0.89 9,666 9,659	2014 20		2014 20		2014 20	
22 then co	99 0.78 90 0.90 9 10.222	15 2016	76 0.75 39 0.89 9 10,056	2015 2016	82 0.81 89 0.89 6 9,766	2015 2016	84 0.83 89 0.89 89 9,675	2015 2016		2015 2016		2015 2016	
nstruct co	0.73 0.90 10,304	2017	0.69 0.89 10,153	2017	0.78 0.89 9,893	2017	0.79 0.89 9.804	2017		2017		2017	
mbined cyc	0.72 0.73 0.90 0.90 10.306 10.297	2018 2019	0.69 0.69 0.89 0.89 10.163 10,149	2018 2019	0,77 0,78 0,78 0,89 0,89 9,902 9,887	2018 2019	0,79 0,79 0,79 0,89 0,89 0,89 9,812 9,796	2018 2019		2018 2019		2018 2019	
cle genera	0.74 0.90 10,286	2020	0.70 0.89 10,140	\$ 2020	9 0.78 9 0.89 9.874	3 2020	9 0.80 9 0.89 9,779	3 2020		9 2020	0.03 0.90 7,646	9 2020	
ition 2021	0.75 0.90 10,273	2021	0.71 0.89 10,125	2021	0.79 0.89 9.855	2021	0.80 0.89 9,765	2021		2021	0.18 0.86 7,591	2021	0.03 0.90 7,658
2022 2023	0.79 0.79 0.90 0.90 10,206 10,213	2022 20	0.76 0.76 0.89 0.89 10,036 10,041	2022 20	0.81 0.81 0.89 0.89 9,779 9,781	2022 20	0.83 0 0.89 0 9,687 9,6	2022 20		2022	0.28 0. 0.86 0. 7,577 7,5	2022	0.27 0. 0.82 0. 7.577 7;5
23 2024	99 0.77 90 0.90 3 10,238	2023 2024	0.76 0.74 0.89 0.89 0.41 10.079	2023 2024	81 0.80 89 0.89 81 9,804	2023 2024	0.83 0.82 0.89 0.89 9.687 9.711	2023 2024		2023 2024	0.27 0.19 0.86 0.85 7,581 7,596	2023 2024	0.26 0.21 0.82 0.82 7,581 7,601
2025	0,77 0,90 10,243	2025	0.73 0.89 10,087	2025	0.80 0.89 9,812	2025	0.82 0.89 9,718	2025		2025	0.22 0.86 7,586	2025	0.23 0.82 7,592
2026	0.76 0.90 10,255	2026	0.72 0.89 10,102	2026	0.79 0.89 9,832	2026	0.81 0.89 9,736	2026		2026	0.22 0.86 7,591	2026	0.23 0.82 7,594
2027	0.77 0.90 10,246 10	2027	0.73 0.89 10.092 10		0.79 0.89 9,825	2027	0.81 0.89 9,731	2027		2027	0.22 0.86 7,605	2027	0.21 0.82 7.605
2028 203	0.76 0.76 0.90 0.90 10,255 10,254	2028 203	0.72 0.72 0.72 0.85 0.89 10,100 10,098		0.79 0. 0.89 0. 9,836 9.84	2028 20	0.81 0.	2028 20		2028 20	0.24 0. 0.86 0. 7,593 7,5		0.23 0. 0.82 0. 7,594 7,59
2029	0.76	2029	0.72	5029	0.79 0.89 9.840	2029	0.89 0.745	2029	*	2029	0.24 0.86 7,593	202	0.24 0.82 7,595

2029	0.00 0.96 13,670	2029	0.00 0.96 13,575	2029	0.00 0.96 13,449	2029	0.01 0.97 12,802	2029	0.01 0.97 12,787	5029	0.01 0.97 12,754	2029	0.01 0.97 12,825
2028	0.00 0.96 13,547	2028	0.00 0.96 775,E1	2028	0.00 0.96 13,436	2028	0.01 0.97 12,827	2028	0.01 0.97 12,806	2028	0.01 0.97 12,759	2028	0.01 0.97 12,791
2027	0.00 0.96 13,174	2027	0.00 0.96 13,293	2027	0.00 0.96 13.425	2027	0.01 0.97 12,990	2027	0.01 0.97 12,895	2027	0.01 0.97 12,696	2027	0.01 0.97 12,605
2026	0.00 0.96 13,700	2026	0.00 0.96 13,599	2026	0.00 0.96 13,740	2026	0.03 0.97 12,898	2026	0.02 0.97 12,927	2026	0.01 0.97 12,926	2026	0.01 0.97 12,877
2025	0.00 0.96 13,677	2025	0.00 0.96 13,645	2025	0.00 0.96 13,723	2025	0.03 0.97 12,857	2025	0.02 0.97 12,863	2025	0.01 0.97 12,855	2025	0.01 0.97 12,789
2024	0.00 0.96 13,491	2024	0.00 0.96 13,481	2024	0.00 0.96 13,627	2024	0.03 0.97 12,859	2024	0.01 0.97 12,848	2024	0.01 0.97 12,824	2024	0.01 0.97 12,770
2023	0.00 0.96 13,484	2023	0.00	2023	0.00 0.96 13,613	2023	0.04 0.97 12,837	2023	0.02 0.97 12,834	2023	0.01 0.97 12,844	2023	0.01 0.97 12,805
2022	0.00 0.96 13,706	2022	0.00 0.96 13,636	2022	0.01 0.96 13,763	2022	0.04 0.97 12,830	2022	0.03 0.97 12,844	2022	0.02 0.97 12,839	2022	0.01 0.97 12,817
ition 2021	0.00 0.96 13,840	2021	0.00 0.96 13,819	2021	0.00 0.96 13,900	2021	0.02 0.97 12,905	2021	0.01 0.97 12,967	2021	0.01 0.97 12,975	2021	0.01 0.97 12.958
then construct combined cycle generation	0.00 0.96 13,407	2020	0.00 0.96 13.595	2020	0.00 0.96 13,225	2020	0.02 0.97 12,824	2020	0.01 0.97 12,837	2020	0.01 0.97 12,797	2020	0.01 0.97 12,731
ed cycle	0.00 0.96 13,239	2019	0.00 0.96 13,454	2019	0.00 0.96 13,138	2019	0.02 0.97 12.806	2019	0.01 0.97 12.806	2019	0.01 0.97 12,745	2019	0.00 0.97 12,708
combin 2018	0.00 0.96 13,212	2018	0.00 0.96 13,394	2018	0.00 0.96 13,218	2018	0.02 0.97 12,816	2018	0.01 0.97 12,781	2018	0.01 0.97 12,756	2018	0.00 0.97 12.701
nstruct 2017	0.00 0.96 13,279	2017	0.00 0.96 13,378	2017	0.00 0.96 13,281	2017	0.01 0.97 12,853	2017	0.01 0.97 12,821	2017	0.00 0.97 12.748	2017	0.00 0.97 12,643
then co	0.00 0.96 13,264	2016	0.00 0.96 13,381	2016	0.00 0.96 13,245	2016	0.02 0.97 12.796	2016	0.02 0.97 12.781	2016	0.01 0.97 12,773	2016	0.01 0.97 12,708
il 2022	0.00 0.96 13,266	2015	0.00 0.96 13,387	2015	0.00 0.96 13,215	2015	0.02 0.97 12,821	2015	0.01 0.97 12,804	2015	0.01 0.97 12,764	2015	0.00
wer unt	0.00 0.96 13,272	2014	0.00 0.96 13,462	2014	0.00 0.96 13,300	2014	0.01 0.97 12,812	2014	0.01 0.97 12,837	2014	0.00 0.97 12,799	2014	0.00 0.97 12,753
ased Po	0.00 0.96 13,254	2013	0.00 0.96 13,495	2013	0.00 0.96 13,255	2013	0.03 0.97 12,684	2013	0.02 0.97 12,769	2013	0.01 0.97 12,768	2013	0,00
า Purch ₂₀₁₂	0.00 0.95 13,197	2012	0.00 0.96 13,490	2012	0.00 0.96 13,338	2012	0.03 0.99 12,659	2012	0.02 0.99 12,728	2012	0.01 0.99 12,731	2012	0.00 0.95 12,657
h Coal, depend on	0.00 0.96 13,187	2011	0.00 0.96 13,368	2011	0.00 0.96 13,344	2011	0.03 0.93 12,608	2011	0.02 0.99 12.721	2011	0.01 0.95 12,721	2011	0.00 0.99 12,630
	0.01 0.96 13.071	2010	0.00 0.96 13,276	2010	0.00 0.94 13,021	2010	0.05	2010	0.04 0.99 12,523	2010	0.03 0.99 12,449	2010	0.02 0.99 12,283
Case 6 - Cancel Smith Coal, depend on Purchased Power until 2022	Capacity Factor Availability Factor Availability Factor Avariage Heat Rate (BLU/KWh) Fuel Coat (S/MWRBu) Variable Poducton Coat (S/MWh) Variable Producton Coat (S/MWh) SOZ Emission Coats (S) NOX Emission Coats (S)	Smith CT2	Capacity Factor Availability Factor Availability Factor Avarage thest Rate (BrukWh) Fuel Cost (S/MMBus) Variable O&M (S/MWh) Variable Production Cost (S/MWh) SOZ Emission Cost (S) NOx Emission Cost (S)	Smith CT3	Capacity Factor Availability Factor Avariage teat Rate (But/Whi) Fuel Cost (S/MMBsu) Variable OBLM (S/MWh) Variable Production Cost (S/MWh) Variable Production Cost (S/MWh) WOX Emission Costs (S) NOX Emission Costs (S)	Smith CT4	Capacity Factor Availability Factor Avariage that Rate (BLU/KWI) Fuc Cost (S/MWRB tu) Variable Ockew (S/MWN) Variable Poducton Cost (S/MWI) SQZ Emission Costs (S) NOX Emission Costs (S)	Smith CT5	Capacity Factor Availability Factor Availability Factor Evel Cost (\$\frac{5}{4}MM8tu\) Variable Od&M (\$\frac{5}{4}MWh\) Variable Production Cost (\$\frac{5}{4}MWh\) Variable Took (\$\frac{5}{4}MWh\)	Smith CT6	Capacity Factor Availability Factor Availability Factor Avanege that Rate (But/kWh) Fuel Cost (\$/MMBtu) Variable OsBM (\$/MWh) Variable Producton Cost (\$/MWh) Variable Producton Cost (\$/MWh) Variable Producton Cost (\$/MWh)	Smith CT7	Capacity Factor Availability Factor Availability Factor Fuel Cost (\$/MMthu) Variable Cost (\$/MMthu) Variable Production Cost (\$/MWh) SO2 Emission Costs (\$) NOX Emission Costs (\$)

5029	0.17		50						9,629		8 2029	4 0.94	11		1	8 2029		0 1.00 5 12,917	• ;	2029			4 12,873			
7 2028			σ.						999'6		7 2028	94 0.94	11			2028	12 0.03	i0 1.00 .6 12,905		27 2028			36 12,884			
5 2027		0.10	en					6 0.16 6 0.96	9,772		6 2027		7 0.97 3 11,828			7202 5027	0 0.02	H		76 2027		0.00	12,5			
2026			9,828				2026	5 0.16	9,630		5 2026		7 0.97			5 2026	0.00	1.00 12,626.40		3006						
2025	•	0.13	on				2025	0.15	9,627		2025		0.97			2025				2000						
2024			987				2024	0.12			2024		0.97			2024					±707					
2023		0.16	96.0				2023	0.20	9,472		2023	0.94	11.8			2023					2023					
2022		0.17	0.96	270'0			2022	0.21	9,400		2022	0.94	0.97	20,170,174		2022					2022					
ation 2021		0.10	0.96	2,00,0			2021	0.12	9,640		2021	0.94	0.97	77,020.00		1000					2021					
genera		0.09	0.96	3,711			2020	0.12	9,678		2020	0.94	0.97	11,020.00		טנטנ	277				2020					
ed cycle		0.08	96.0	9,749			2019	0.12	9,708		2019	0.94	0.97	11,828.10		9500	6102				2019					
ombino 2018		0.07	96.0	9,762			2018	0.10	9,710		2018	0 94	76.0	11,828.10		6	2018				2018					
struct c		0.07	96'0	9,585			2017	0.11	9,601		2017	0.84		11,828.10			7017				2017					
then construct combined cycle generation		0.10	0.96	9,456			2016	0.16	0.96 9,465		2016	Š		11,827.80			2016				2016					
2022 tl	1	0.09	96'0	9.421			2015	0.16	0.96 9,461		2015			11,827.80			2015				2015					
er until		0.07	96'0	9,516			2014	0.11	0.96 9,488		2014			11,827.80			2014				2014					
ed Pow	5073	900	0.96	11,150			2013	0.12	11,001		2013			11,827.70			2013				2013					
Jurchas	7707	9	0.98	11,103			2012	0.13	0.98		2012	1		11,827.70 1.			2012				2012					
no pu	2011	Š	0.92	10,953			2011	0.11	0.92		2011	100	0.94	11,842.00 1			2011				2011					
al, depe	2010		0.30	10,380			2010	0.12	0.84		3010	2010	0.95				2010				2010					
Case 6 - Cancel Smith Coal, depend on Purchased Power until 2022	Smith CT 9		Capacity Factor	Average Heat Bate (Btu/kWh)	Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh)	Variable Production Cost (3/m/w1) SO2 Emission Costs (5) MOv Emission Costs (5)	Smith CT 10	one of the Control	or man dantes	Variable Production Cost (5/MWh) SO2 Emission Costs (5)	NOx Emission Costs (5)	Landfill Gas Projects	Capacity Factor Availability Factor	(Btu/kWh)	Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) Variable Froduction Cost (\$/MWh)	SQ2 Emission Costs (>) NOx Emission Costs (\$)	Future CT 1	Capacity Factor Availability Factor	Average Heat Rate (NUVKWN) Fuel Cost (\$/MMBtu) Variable O&M (\$/MWN) Variable Production Cost (\$/MWh)	SO2 Emission Costs (\$) NOx Emission Costs (\$)	Future CT 2	Caparity Factor	Availability Factor	Average Heat Rate (Btu/kWh) Fuel Cost (\$/MMBtu)	Variable Production Cost (\$/MWh)	SOZ Emission Costs (3) NOx Emission Casts (5)

2029	0.73	0.90		2029	0.69 0.89 10,152		2029	0.77 0.89 9,895,80	2029	9,802 9,802	2029		2029	7,608	5079	0.00 0.96 13,829
2028	7.0	0.90	00204	2028	0.70 0.89 10.151		2028	0.78 0.89 9,891.70	2028	87.0 803.6 87.0	2028		2028	0.19	2028	0.00 0.96 13,540
2027	0.74	0.90	20777	2027	0.70 0.89 10,134		2027	0.78 0.89 9,876.80	2027	0.80 0.89 9,786	2027		2027	0.17 0.86 7,622	2027	0.00 0.96 13,210
entity	5	0.73	10,233	2026	0.70 0.89 10,149		2026	0.77 0.89 9,901.80	5026	0.79 0.89 9.809	2026		2026	0.18 0.86 7,606	2026	0.00 0.96 13,775
h same	7.0	0.90	10,279	2025	0.71 0.89 10,130		2025	0.78 0.89 9,886.90	2025	0.79 0.89 7.87,	2025		2025	0.18 0.86 7,605	2025	0.00 0.96 13,778
ent wit		0.74	10,276	2024	0.71 0.89 10,121		2024	0.78 0.89 9.888.20	2024	0.79 0.89 9,802	2024		2024	0.16 0.86 7,613	2024	0.00
agreem	7707	0.76	10,249	2023	0.73 0.89 10,089		2023	0.80 0.89 9,815.90	2023	0.82 0.89 9,719	2023		2023	0.21 0.86 7,600	2023	0.00 0.96 13,571
archase	7707	0.90	10.245	2022	0.73 0.89 10,087		2022	0.80 0.89 9,819.50	2022	0.81 0.89 9,725	2022		2022	0.21 0.86 7.594	2022	0.00 0.96 13,779
term pr	1707	0.90	10,266	2021	0.71 0.89 10,115		2021	0.79 0.89 9,835.70	2021	0.81 0.89 9,744	2021		2021	0.20 0.86 7,592	2021	0.00 0.96 13.765
a long	0202	0.74	10,277	2020	0.71 0.89 10,131		2020	0.79 0.89 9,852.30	2020	0.81 0.89 9,755	2020		2020	0.03 0.90 7,643	2020	0.00 0.96 13,376
nter into	5019	0.74	10,288	2019	0.70 0.89 10.141		2019	0.78 0.89 9,861.90	2019	0.80 0.89 9.769	2019		2019		2019	0.00 0.96 13,285
it and ei	2018	0.73	10.297	2018	0.69 0.89 10.154		2018	0.78 0.89 9,877.10	2018	0.80 0.89 9.785	2018		2018		2018	0.00 0.96 13,182
ilar plar	2017	0.73	10,294	2017	0.70 0.89 10,143		2017	0.78 0.89 9,863.10	2017	0.80 0.89 9,773	2017		2017		2017	0.00 0.96 13,311
ng a sim	2016	0.74	10,279	2016	0.71 0.89 10,116		2016	0.79 0.89 9,846.90	2016	0.80 0.89 9.760	2016		2016		2016	0.00 0.96 13.354
ıstructir	2015	0.74	10,278	2015	0.71 0.89 10.113		2015	9,837.70	2015	0.81 0.89 9.754	2015		2015		2015	0,00 0,96 13,321
itity cor	2014	0.78	10,228	2014	0.74 0.89 10,065		2014	0.81 0.89 9.759.30	2014	0.83 0.89 9,666	2014		2014		2014	0.00 0.96 13,272
to an er	2013	0.85	10.136	2013	0.78 0.89 10.002		2013	0.82 0.89 9,734.00	2013	0.84 0.89 9,645	2013		2013		2013	0.00 0.96 13,254
pment	2012	0.84	10,148	2012	0.78		2012	0.82 0.89 9,733.40	2012	0.84 0.89 9,640	2012		2012		2012	0.00 0.96 13,197
sell equi	2011	0.82	10	2011	7		2011	0.82 0.89 9,750.30	2011	0.81 0.89 9,721	2011		0 2011		0 2011	0.00
h Coal, s	2010	0.83	10,194	2010	0.75 0.89 0.89		2010	0.81 0.89 9,779.40	2010	0.76 0.86 9.815	2010		2010	** ** **	2010	0.01 0.96 13.071
Case 7-Cancel Smith Coal, sell equipment to an entity constructing a similar plant and enter into a long term purchase agreement with same entity	Spurfock 1	Capacity Factor	Availatinity 1 actor Availatinity 1 actor Availatinity 1 actor (\$/NMBtul Variable 05M (\$/MWh) Variable Production Cost (\$/MWh) SO2 Emission Costs (\$)	NOx Emission Costs (\$)	Capacity Factor Availability Factor	Average preat near (AVM) Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) SOZ Emission Costs (\$) NOx Emission Costs (\$)	Gilbert Unit	Capacity Factor Availability Factor Avrage Hear Bate (Bur/kWh) Fuel Cost (\$/MMBu) Variable OBM (\$/MWh) Variable Production Cost (\$/MWh) SQ2 Emission Costs (\$/ NOx Emission Costs (\$/ NOx Emission Costs (\$/	Spurlock 4	Capactly Factor Availability Factor Availability Factor Average Heat Rate (BuckWh) Fuel Cost (S/MMBtu) Vanable O&M (S/MMBtu) Vanable Production Cost (S/MWh) Normable Cost (S/MWh) Nor Emission Cost (S) NOx Emission Cost (S)	Smith 1 (CFB)	Capacity Factor Availability Factor Availability Factor Tuel Cost (\$\frac{1}{2}\text{AMM}\$) Variable Or&M (\$\frac{1}{2}\text{AMM}\$) Variable Production cost (\$\frac{1}{2}\text{AMM}\$) NOX Emission Costs (\$\frac{1}{2}\text{AMM}\$)	Future CC	Capacity Factor Availability Factor Availability Factor Avaerage Heat Ret (BLU/AWh) Fuel Cost (S/AMBlu) Variable Ordeu(coost (S/AWWh) Variable Production Cost (S/AWWh) SOZ Emission Costs (S) NOX Emission Costs (S)	Smith CT1	Capacity factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (\$/MMBtu) Variable (\$NWh) Variable Production Cost (\$/MWh) SOZ Emission Costs (\$) NOX Emission Costs (\$)

8 2029	0 0.00 6 0.96 13,819	8 2029	0 0.00 6 0.96 : 13.493	8 2029	1 0.01 7 0.97 5 12,909	8 2029	1 0.01 7 0.97 12,869	8 2029	1 0.01 7 0.97 12,851	8 2029	1 0.01 7 0.97 12,883	3 2029	9 0.10
2028	0.00	2028	0.00 0.95 13,481	2028	0.01 0.97 12,866	2028	0.01 0.97 12,835	2028	0.01 0.97 12,777	2028	0.01 0.97 12,782	2028	0.09 0.96 9,698
2027	0.00 0.96 13,332	2027	0.00 0.96 13.204	2027	0.01 0.97 12,996	2027	0.01 0.97 12,891	2027	0.01 0.97 12,710	2027	0.01 0.97 12,585	2027	0.08 0.96 9,792
entity 2026	0.00 0.96 13,608	2026	0.00 0.96 13.842	2026	0.02 0.97 12,909	2026	0.01 0.97 12,942	2026	0.01 0.97 12.944	2026	0.01 0.97 12,890	2026	0.09 0.96 9,902
same 2025	0.00 0.96 13,706	2025	0.00 0.96 13,804	2025	0.02 0.97 12,884	2025	0.01 0.97 12,894	2025	0.01 0.97 12,876	2025	0.01 0.97 12,843	2025	0.09 0.96 10,026
Similar plant and enter into a long term purchase agreement with same entity	0.00 0.96 13,400	2024	0.00 0.96 13,451	2024	0.02 0.97 12,857	2024	0.01 0.97 12,834	2024	0.01 0.97 12,803	2024	0.00 0.97 12,736	2024	0.08 0.96 10,161
greem6 2023	0.00 0.96 13,544	2023	0.00 0.96 13,637	2023	0.03 0.97 12,846	2023	0.02 0.97 12,851	2023	0.01 0.97 12,842	2023	0.01 0.97 12,804	2023	0.11 0.96 9,796
chase a	0.00 0.96 13,716	2022	0.00 0.96 13,791	2022	0.03 0.97 12.865	2022	0.02 0.97 12,875	2022	0.01 0.97 12.878	2022	0.01 0.97 12,878	2022	0.12 0.96 9.756
rm pur	0.00 0.96 13,703 1	2021	0.00 0.96 13,814 1	2021	0.03 0.97 12,868 1	2021	0.02 0.97 12,934 1	2021	0.01 0.97 12,935 1	2021	0.01 0.97 12,901 1:	2021	0.11 0.96 9.788
long te	0.00 0.96 13,525 13	2020	0.00 0.96 13,280 13	2020	0.03 0.97 12,818 12	2020	0.02 0.97 12,821 12	2020	0.01 0.97 12,780 12	2020	0.01 0.97 12,713 12	2020	0.10 0.96 9.680 9.
er into a	0.00 0.96 13,467 13	2019	13	2019	12	2019	0.01 0.97 12,801 12,	2019	12	2019	12	2019 2	0.09 0.96 9,706 9.4
and enter			13		12				12		12		
lant an	0.00 0.96 13,459	7 2018	0.00 0.96	2018	0.02 0.97 12,818	2018	0.01 0.97 12,778	2018	0.01 0.97 12,761	2018	0.00	2018	0.08 0.96 9,695
milar pl	0.00 0.96 13,371	2017	0.00 0.96 13,283	2017	0.02 0.97 12,830	2017	0.01 0.97 12,818	2017	0.01 0.97 12,765	2017	0.00 0.97 12,660	2017	0.08 0.96 9,536
	0.00 0.96 13,40S	2016	0.00 0.96 13.353	2016	0.01 0.97 12,848	2016	0.01	2016	0.00 0.97 12,810	2016	0.00 0.97 12,795	2016	0.06 0.96 9,610
nstructi 2015	0.00 0.96 13,521	2015	0.00 0.96 13,346	2015	0.01 0.97 12,800	2015	0.00 0.97 12,740	2015	0.00 0.97 12,742	2015	0.00 0.97 12,733	2015	0.05 0.96 9,572
tity cor	0.00 0.95 13,462	2014	0.00 0.96 13,300	2014	0.01 0.97 12,812	2014	0.01 0.97 12,837	2014	0.00 0.97 12,799	2014	0.00 0.97 12,753	2014	0.07 0.96 9,516
o an en	0.00 0.96 13,495	2013	0.00 0.96 13,255	2013	0.03 0.97 12.684	2013	0.02 0.97 12,769	2013	0.01 0.97 12,768	2013	0.00 0.97 12,664	2013	0.08 0.96 11,150
ment t	0.00 0.96 13,490	2012	0.00 0.96 13,338	2012	0.03 0.99 12,659	2012	0.02 0.99 12,728	2012	0.01 0.99 12,731	2012	0.00 0.95 12,657	2012	0.09 0.98 11,103
ll equip	0.00 0.96 13,368	2011	0.00 0.96 13,344	2011	0.03 0.93 12,608	2011	0.02 0.99 12,721	2011	0.01 0.95 12,721	2011	0.00 0.99 12,630	2011	0.08 0.92 10,953
th Coal, sel	0.01 0.96 13,276	2010	0.00 0.94 13,021	2010	0.05 0.97 12,548	2010	0.04 0.99 12,523	2010	0.03 0.99 12,449	2010	0.02 0.99 12,283	2010	0.10 0.84 10,380
Case 7-Cancel Smith Coal, sell equipment to an entity constructing a	Capacity Factor Availability Factor Availability Factor Fuel Cost (\$\times \text{(\$\text{E}\text{E}\text{(\$\text{E}\text{(\$\text{E}\text{E}\text{(\$\text{E}\text{E}\text{(\$\text{E}\text{E}\text{(\$\text{E}\text{E}\text{(\$\text{E}\text{E}\text{(\$\text{E}\text{E}\text{(\$\text{E}\text{E}\text{(\$\text{E}\text{E}\text{(\$\text{E}\text{E}\text{(\$\text{E}\text{E}\text{E}\text{E}\text{E}\text{(\$\text{E}\text{E}\text{E}\text{E}\text{E}\text{E}\text{E}\text{E}\text{(\$\text{E}\text{A}\text{A}\text{A}\text{E}\te	Smith CT3	Capacity Factor Availability Factor Availability Factor Availability Factor Fuel Cost (\$/MM8tu) Variabio C&M (\$/MM8tu) Variabio C&M (\$/MWh) Variabio C&M (\$/MWh) Variabio Cost (\$/MWh) NOV Emission Cost (\$)	Smith CT4	Capacity Factor Availability Factor Availability Factor Avariage Heat Rate (Buy/kWh) Fuel Cost (\$/MMBu) Variable O&M (\$/MMBu) Variable Production Cost (\$/MWh) SOZ Emission Costs (\$) NOX Emission Costs (\$)	Smith CT5	Capacity Factor Availability Factor Availability Factor Fuel Cost (\$\text{S}/\text{MMB} \text{Univ} \text{Viriable} \text{Ogn} \text{(\$\text{S}/\text{MMB} \text{Univ} \text{Viriable} \text{Cost} (\$\text{S}/\text{MW} \text{Ni} \text{Viriable} \text{Viriable} \text{Function} \text{Cost} (\$\text{S}/\text{MW} \text{Viriable} Viria	Smith CT6	Capacity Factor Availability Factor Availability Factor Fuel Cost (\$/MMBtu) Variable O&M (\$/MMBtu) Variable Production Cost (\$/MWh)	Smith CT7	Capacity Factor Availability Factor Availability Factor Euc Cost (S/MMBtu) Variable Ockin (S/MMBtu) Variable Production Cost (S/MWh) Variable Production Cost (S/MWh) Variable Production Cost (S/MWh) Variable Ockinistion Cost (S) NOX Emission Costs (S)	Smith CT 9	Capacity Factor Availability Factor Availability Factor Average Heat Rate (Buz/kWh) Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) Soz Emission Cost (\$/MWh) SOZ Emission Costs (\$) NOx Emission Costs (\$)

	2029	0.15 0.96 9,748		2029	0.94 0.97 11,828		2029	0.03 1.00 12,948		2029	0.02 1.00 12,948
	2028	0.14 0.96 9,777		2028	0.94 0.97 11,828		2028	0.03 1.00 12,946		2028	0.02 1.00 12,936
	2027	0.12 0.96 9,928		2027	0.94 0.97 11,828		2027	0.02 1.00 13,041		2027	0.00 1.00 12,481
entity	2026	0.12 0.96 9,837		2026	0.94 0.97 11,828		2026	0.00 1.00 12,519		2026	
same (2025	0.11 0.96 9,826		2025	0.94 0.97 11,828		2025			2025	
ent with	2024	0.09 0.96 9,872		2024	0.94 0.97 11,828		2024			2024	
greem	2023	0.14 0.96 9,682		2023	0.94 0.97 11,828		2023			2023	
rchase a	2022	0.15 0.96 9,623		2022	0.94 0.97 11,828	•	2022			2022	
erm pu	2021	0.14 0.96 9,617	-	2021	0.94 0.97 11,828		2021			2021	
similar plant and enter into a long term purchase agreement with same entity	2020	0.14 0.96 9,647		2020	0.94 0.97 11,828		2020			2020	
ter into	2019	0.14 0.96 9,679		2019	0.94 0.97 11,828		2019			2019	
and en	2018	0.12 0.96 9,674		2018	0.94 0.97 11,828		2018			2018	
ar plant	2017	0.13 0.96 9,572		2017	0.94 0.97 11,828	-	2017			2017	
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tructing	2015	0.09 0.96 9,576		2015	0.94 0.97 11,828		2015			2015	
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o an ent	2013	0.12 0.96 11,001		2013	0.95 0.97 11,828		2013			2013	
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Case 7-Cancel Smith Coal, sell equipment to an entity constructing a	Smith CT 10	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh) Fuel Cost (\$/MMBtu)	Variable O&M (\$/MWh) Variable Production Cost (\$/MWh) SO2 Emission Costs (\$) NOx Emission Costs (\$)	Landfill Gas Projects	Capacity Factor Availability Factor Average Heat Rate (8tu/kWh)	Fuel Cost (\$/MMBtu) Variable O&M (\$/MWh) Variable Octoberon Cost (\$/MWh) SOZ Emission Costs (\$) NOX Emission Costs (\$)	Future CT 1	Capacity Factor Availability Factor Average Heat Rate (Btu/kWh)	Fuel Cost (\$/MMBtu) Variable O&M (\$/MWI) Variable Production Cost (\$/MWh) SO2 Emission Costs (\$) NOX Emission Costs (\$)	Future CT 2	Capacity Factor Availability Factor Availability Factor Avarage Heat Rate (BLu/KWh) Fuel Cost (\$/AMRu) Variable O&M (\$/NWh) Variable Porduction Cost (\$/MWh) SOZ Emission Costs (\$) NOx Emission Costs (\$)



COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In	tho	Matter	of.
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AN INVESTIGATION OF EAST KENTUCKY)	PSC CASE NO.
POWER COOPERATIVE, INC.'S NEED FOR)	2010-00238
THE SMITH 1 GENERATING FACILITY)	

TESTIMONY OF GARY G. STANSBERRY MANAGER OF PERFORMANCE AND IMPROVEMENT EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: November 18, 2010

	COMMONWEALTH OF KENTUCKY
	BEFORE THE PUBLIC SERVICE COMMISSION
	AN INVESTIGATION OF EAST KENTUCKY POWER COOPERATIVE, INC.'S NEED FOR THE SMITH 1 GENERATING FACILITY PSC CASE NO. 2010-00238)
	DIRECT TESTIMONY OF GARY G. STANSBERRY ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.
Q.	Please state your name, business address and occupation.
A.	My name is Gary G. Stansberry and my business address is East Kentucky Power
	Cooperative (EKPC), 4775 Lexington Road, Winchester, Kentucky 40391. I am
	Manager of Performance and Improvement for EKPC.
Q.	Please state your education and professional experience.
A.	I have a Bachelor of Business Administration Degree in Accounting from Eastern Kentucky
	University, which I received in 1974. I have been employed by East Kentucky Power
	Cooperative since January 1981 in the areas of Accounting, Rates and Pricing, Performance
	and Improvement, and Financial Forecasting.
Q.	Please provide a brief description of your duties at EKPC.
A.	I am currently responsible for financial forecasting and corporate and business unit
	performance measures and targets at EKPC.
Q.	What is the purpose of your testimony?
A.	The purpose of my testimony is to describe the financial forecasting model, to provide
	the financial results of the seven cases described in Ms. Tucker's testimony, and to
	discuss the impact on EKPC's members' rates.

Q. Are you sponsoring any exhibits in this proceeding?

A.

A. Yes. I am sponsoring the following exhibits: Exhibit GGS-1—Net Present Value of
Cost of Each Scenario; Exhibit GGS-2—Comparison PV Total Revenue Requirements
from Members for each case, and Statements of Operations for each case; Exhibit GGS—Annual Revenue Requirements and Percentage of Existing Revenue Requirements Case 1 - Total Dollars and as a Percentage of Existing Revenue; Exhibit GGS-4, Member
Cost Summary and Rate Detail for each case, and Exhibit GGS-5, Financial Assumptions
for the PSC Smith Investigation Study.

O. Can you explain the financial forecasting process?

The long-term financial forecasting process is integrated with the overall planning process. The planning process begins with the load forecast, identifying the generation resources and capital investment necessary to meet peak, energy, and load reserve requirements. These additional resources, commonly referred to as an "expansion plan", along with EKPC's existing resources, are dispatched in an hourly production costing model to determine variable costs (fuel, purchased power, emissions) associated with meeting EKPC's load. These variable costs, along with fixed costs and the investments directly related to the expansion plan, are input into the financial model. The financial model incorporates all the financial parameters and projections of revenue, expenses, margins, assets, etc., which in turn develop the revenue requirements necessary for meeting proper financial objectives. These revenue requirements then translate into rates to our member systems. These rates then become an input into future load forecasts. The planning process with its related financial forecasting process is an interactive and circular process.

- 1 Q. How do the results of the production costing model, described in Ms. Tucker's
 2 testimony, flow to the financial forecasting model?
- A. The output of the production costing model is summarized in spreadsheet form and includes fuel cost, generation levels (MWh), emission levels, power purchases and offsystem sales. This data is entered into the financial model in its appropriate place.
- Q. Can you explain more about the financial forecasting portion of the planningprocess?
- The process incorporates the use of financial statements, including a statement of 8 Α. operations, cash flow, and balance sheet. Actual, budgeted, and forecasted data is used to 9 project future financial positions. For example, an investment in future plant will show 10 the need for increased debt with related interest, depreciation, taxes, insurance, and 11 operation and maintenance (O&M) expense. This future plant example will then set into 12 motion the cash flow aspects of principal payments increasing over time, recovery of 13 depreciation, and the margin effect created by the above expenses. The balance sheet 14 will reflect the increase in assets and corresponding funding by debt and equity. General 15 16 expenses and capital costs are escalated over time based on the assumptions. Please refer to Exhibit GGS-5 "Financial Assumptions for PSC Smith Investigation Study" for 17 18 additional assumptions.

19 Q. How does the need for rates enter into the forecasting process?

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A. The financial situation produced by the forecasted financial statements referred to above, will change from year to year. These changes in financial positions are evaluated in light of creditor standards, company goals, and general business standards to determine the financial viability of the organization in that year. For example, a Times Interest Earned

Ratio (TIER), a Debt Service Coverage (DSC), and Equity to Asset ratio (Equity Ratio) are ratios to help evaluate the current year status. The recognition of revenue shortfall is addressed by the need for additional revenue requirements. These revenue requirements are then translated into future rates in order to recover the proper revenue for financial stability.

A.

Q. How has the financial model been used to address the requirements of this order?

The financial model has been used with all seven cases, as described in Ms. Tucker's testimony, in addressing the requirements of this order. The revenue requirements have been determined in each case on a year by year basis, accumulated on a present value basis, and rates each year from the seven cases have been determined as shown in Exhibit GGS-1, Exhibit GGS-2, and Exhibit GGS-4. These exhibits also show the income statements for 20 years and the detailed rates by rate class for each case. A calculation of percentage increase in revenue requirements from the initial year is also contained in Exhibit GGS-3. These exhibits from the financial model address items 5-8 on pages 9 and 10 of the Commission's Order dated June 22, 2010.

O. What level of TIER was used to determine the revenue requirements?

A. A TIER level of 1.50 was used to determine the revenue requirements. The revenue requirements are determined by the revenue generated from member rates to meet the expenses and margin requirements in a given year, plus any additional revenue needed through rate increases to achieve the financial stability required. This TIER level is consistent with the level used in Case No. 2010-00167.

O. What assumptions are used in the financial model?

A. Assumptions include TIER, discount rate, CO₂ legislation, and residual values. I will

1 expand on each of these assumptions.

Q. What was the basis for determining the rate increases?

A. As mentioned previously, a TIER of 1.50 was used as the basis of the earnings mechanism or margin level in each of the cases. This level reflects EKPC's management philosophy for its equity management and growth position. This value was used as a constant across all years and in all cases for determining the revenue requirements. By using this assumption, EKPC eliminates the timing differences which may occur from working within a bandwidth of minimum and maximum TIER levels. In this way revenue requirements are given equal treatment from the earnings mechanism in each year throughout all cases.

Q. How was possible CO2 legislation handled?

A. One of the assumptions used by EKPC considered the passing of some type of CO2 legislation. This is introduced into the model beginning in 2014 with a cap and trade arrangement. This is modeled after House Bill H.R. 2454: American Clean Energy and Security Act of 2009 presented by Rep. Henry Waxman (D-CA). The total tons of CO2 produced by the generating units are captured from the production costing model. An EKPC tonnage allotment from EPA of approximately 57% of EKPC's usage is assumed beginning in 2014. This initial allotment of 6.8M tons decreases over time resulting in increasing cost for EKPC. The excess tonnage over the allotment amount results in EKPC's responsibility at forecast prices. The emission price forecast is provided by ACES Power Marketing and contained in the assumptions, provided with Ms. Tucker's testimony.

Q. What discount rate was used in the present value calculations?

- 1 A. The rate used was 7.52% and was based on EKPC's cost of capital. This was computed
- from EKPC's current rate case with a 2011 forecasted test year interest expense of 5.01%
- 3 times 1.50 TIER. (Case No. 2010-00167, Application Volume 5, Tab 55).
- 4 Q. Were residual values of related plant investment considered in these cases?
- 5 A. Yes. Residual values of all new plant investment during the twenty year window were
- 6 considered at net book value. These amounts are shown on Exhibit GGS-2 along with
- 7 their related present value amount. This present value amount reduces the net present
- 8 value revenue requirements in each calculation in arriving at the total. This applies to
- 9 only new plant investment during the forecast period in order to give proper recognition
- of asset value at the end of the analysis period.
- 11 Q. Is there anything unique that you would like to explain about the financial model
- used in this analysis?
- 13 A. Yes. Normally, the first two years of this financial model encompass the Two-year
- Budget (2010-2011). In EKPC's current model, the "test year" from EKPC's current rate
- case (Case 2010-00167) has been substituted for the 2011 budget year. For accuracy
- reasons, this should be noted when the reference in the following discussion on
- 17 "procedure and programming" speaks to this 2nd year budget as the 2011 budget year.
- The procedure and programming of the model requires the first two years to be
- hardcoded into the model. Forecasting amounts start thereafter beginning in 2012. The
- 20 new 2010 load forecast has been incorporated into the analysis and affects years 2012 and
- beyond. Due to the timing of this Order, a new budget has not been completed in order to
- 22 synchronize with the 2010 load forecast. Therefore, the first two budget years of the
- forecast are based on the modified 2008 load forecast. We recognize differences due to

- the slower-growth 2010 load forecast for those two years. The revenue downturn has
 been estimated at \$164M with estimated margin reduction of \$29M. The transition from
 2011 budget year to 2012 forecast year therefore may produce results which seem
 disproportionate on the income statement and needs to be understood by this situation.
- 5 O. Will this affect the results of this analysis?

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- A. The comparison results will not be affected. Each case includes the same assumptions relative to the two budget years of 2010-2011, and therefore, the measurement of differences between cases is preserved.
- 9 Q. How were the Cases 1-3 handled in regards to Smith 1?
- 10 A. Cases 1-3 retained Smith 1 in EKPC's portfolio for analysis purposes, yet in two-year

 11 delays to distinguish the cases. Therefore, Case 1 (base case) includes Smith 1 for 2014

 12 and Cases 2 & 3 follow with 2016 and 2018 dates respectively.
- 13 O. How were the cases handled which removed Smith 1 from EKPC's books?
- Cases 4, 5 and 6 incorporated the recovery of a regulatory asset in the amount of the 14 A. Smith 1 net investment. This amount was \$151 million as of 2009. The budgeted 15 amount of Smith 1 through 2011 was \$171 million, and was used as the proxy for the 16 17 total amount of investment, including contract cancellation costs. Salvage was determined at \$20 million, thereby reducing the net amount to \$151 million. Since EKPC 18 19 cannot write off this amount to expense in one year without defaulting on its loan 20 covenants, EKPC assumed that a regulatory asset was established in order to properly account for this situation. This regulatory asset was established assuming a 10 year 21 22 recovery/amortization period.
 - Case 7 involved the sale of Smith 1 at book value to an independent power producer

beginning in 2012. Smith 1 was removed from EKPC's books by reducing Construction
 Work in Progress (CWIP) and reducing the related debt.

Q. Can you explain more of how you handled the regulatory asset?

A. Yes. The regulatory asset was established by transferring the net CWIP balance (\$171M less \$20M salvage) of \$151 million. As noted in the testimony of Mr. Mitchell, the most recent estimate of contract unwinding costs and asset disposal costs is \$10M, which is \$10M less than was used in the forecasting model. This reduction in estimate would not alter the outcome of the analysis. The related CWIP loan amounts were reduced and a new 10 year loan was created in order to finance the regulatory asset. The regulatory asset was amortized on a straight-line basis for 10 years and interest expense from the 10 year loan was charged to the statement of operations.

Q. What were the results from these cases?

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Please refer to Exhibit GGS-1 and GGS-4. Case 1 assumed the initial Smith 1 investment 13 A. 14 to be \$819 million, which is the most recent estimate prepared jointly by Stanley 15 Consultants and EKPC. The Smith 1 investment cost increased 15% for Case 2 (2016) and a total of 24% for Case 3 (2018) over this base amount. Cases 1, 2, 3 ("Smith cases") 16 were shown to be less costly as the in-service time was delayed from 2-years to 4-years. 17 18 The extent of cost savings was \$139M or 1.09%. The savings in member rates can be seen in the early years by the delayed investment, and then followed by slightly higher 19 20 rates once the escalated investment cost was realized in rates. The present value effect 21 valued the early-year savings as greater than the increased cost after in-service.

Q. How did the other cases compare and what were their results?

A. Cases 4 and 6 showed the greatest savings from the base case at \$380M and \$404M

respectively, or 3.17% maximum savings. These cases involved a gas combined cycle 1 2 and additionally a 5 yr purchase agreement for Case 6, instead of the Smith 1 investment. 3 One key factor to these cases is the assumption that \$906/kW (in 2010 dollars) is the combined cycle investment cost, which is one-third of Smith 1. The resulting cost to 4 members starts lower and stays lower than the Smith cases for all 20 years. 5 6 Case 5 involved a portfolio of renewable energy, energy efficiency, and demand-side 7 management (DSM) resources. The amount of DSM was increased in this case from 223 8 MW (base case) to 400 MW, along with known wind and biomass projects to fill the 9 resources. These projects came in the form of purchases including any firm-up charges. Renewable energy credits were applied and transmission charges were included on all of 10 these purchases, as with all purchases in all cases. Case 5 saved \$78M over the base case 11 12 or 0.61%. Case 7 involved a long-term purchase and sale of Smith 1. The sale is a possible 13 alternative to the need for a regulatory asset. This case showed a savings of \$168M or 14 15 1.32%. 16 O. Is there anything else about Case 5 that is unique? 17 Yes, Case 5 required an adjustment to billing units due to its increased DSM and energy A. efficiency. This increased DSM caused a shift in load and therefore recalculation and 18 19 development of new billing units had to occur. This is the only case requiring such 20 treatment.

21 Q. From your analysis, were you able to obtain an overall conclusion?

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A. Yes. Exhibit GGS-1 summarizes the net present value of each case. Based on these results, Smith 1 is no longer the least cost option.

- 1 Q. Does this conclude your testimony?
- 2 A. Yes it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

AN INVESTIGATION OF EAST KENTUCKY)	
POWER COOPERATIVE, INC. 'S NEED FOR)	CASE NO. 2010-00238
THE SMITH 1 GENERATING FACILITY	

AFFIDAVIT

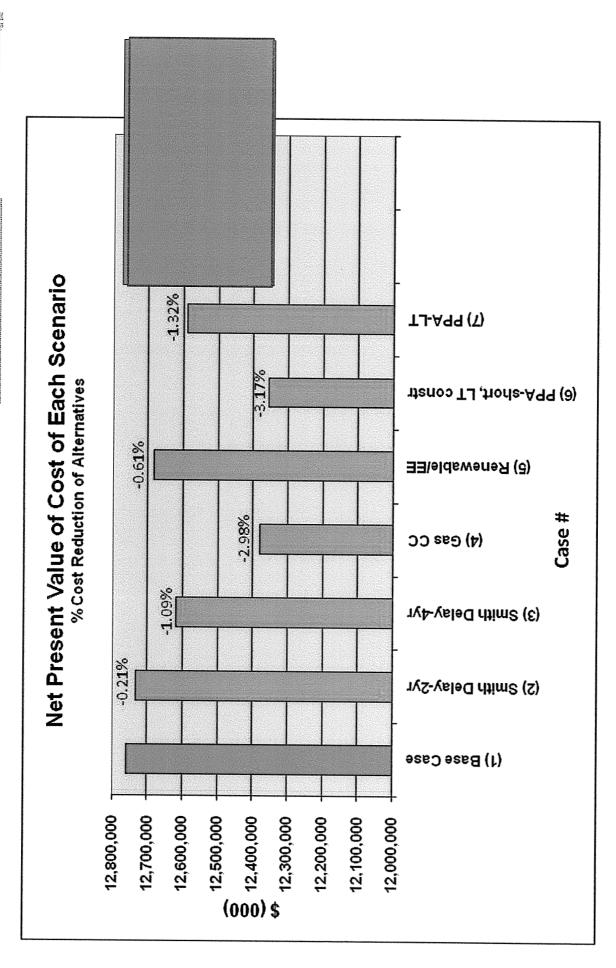
STATE OF KENTUCKY)
COUNTY OF CLARK)

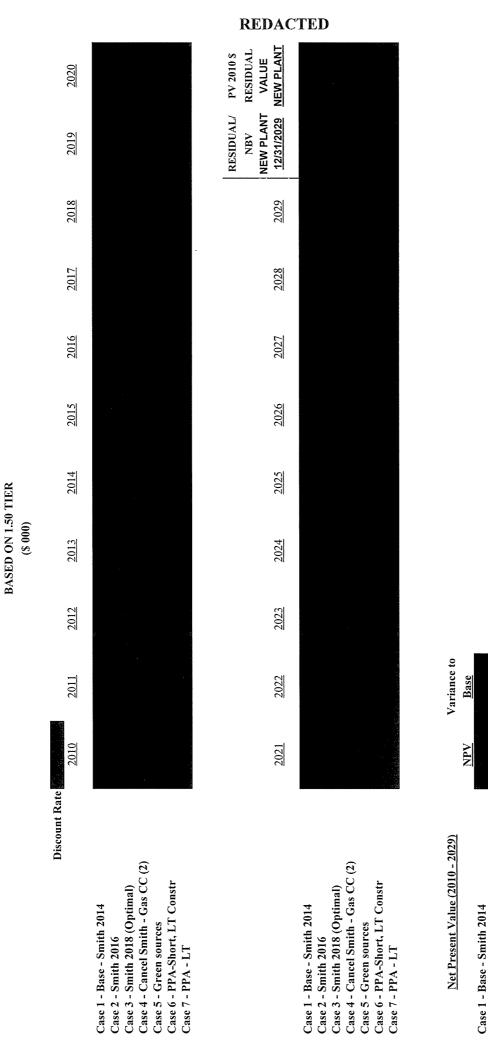
Gary G. Stansberry, being duly sworn, states that he has read the foregoing prepared testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Subscribed and sworn before me on this

_day of <u>Nowerby</u>, 2010

MY COMMISSION EXPIRES NOVEMBER 30, 2013 NOTARY ID #409352





COMPARISON PV TOTAL REVENUE REQUIREMENTS FROM MEMBERS

PSC - SMITH 1 INVESTIGATION - CASE NO. 2010-00238

* NPV Equals Summation of Years 2010 - 2029, Plus Residual Value of New Plant

Case 4 - Cancel Smith - Gas CC (2)

Case 3 - Smith 2018 (Optimal)

Case 2 - Smith 2016

Case 6 - PPA-Short, LT Constr

Case 7 - PPA - LT

Case 5 - Green sources

Case 1 Page 1 of 2

EAST KENTUCKY POWER COOPERATIVE
PSC - SMITH INVESTIGATION STUDY - CASE NO. 2010-00238
CASE 1 - BASE - SMITH 2014 - TIER 1.50

2018				, and the second	06.1
2017				92	06.1
2016				2 1	06:1
2015				, c	1.50
2014				O S	1.50
2013					1.50
2012				C I	1.50
ADJUSTED TEST YEAR 2011				;	1.41
BUDGET 2010			#00 AMP		1.22
ACTUAL 2009					1.27
ACTUAL 2008					1.25
	OPERATING REVENUE MEMBER COOPERATIVES BASE RATES FUEL ADJUSTMENT ENVIRONMENTAL SURCHARGE BASE RATE CHANGE TOTAL FROM MEMBERS OFF SYSTEM SALES TOTAL OPERATING REVENUE	EXPENSES PRODUCTION FUEL O AND M OTHER POWER SUPPLY TRANSMISSION O AND M ADMINISTRATIVE & GENERAL DEPRECIATION TAXES INTEREST ON LONG TERM DEBT INTEREST CHARGED TO CONSTR OTHER DEBT COST TOTAL EXPENSES	OPERATING MARGINS OTHER REVENUE	NET MARGIN	TIMES INTEREST EARNED RATIO

Page 2 of 2 Case 1

EAST KENTUCKY POWER COOPERATIVE
PSC - SMITH INVESTIGATION STUDY - CASE NO. 2010-00238
CASE 1 - BASE - SMITH 2014 - TIER 1.50

STATEMENT OF OPERATIONS (\$000)

2029			1.50
2028			1.50
2027			1.50
2026			1.50
2025			1.50
2024			1.50
2023			1.50
2022			1.50
2021			1.50
2020			1.50
2019			1.50
	OPERATING REVENUE MEMBER COOPERATIVES BASE RATES FUEL ADJUSTMENT ENVIRONMENTAL SURCHARGE BASE RATE CHANGE TOTAL FROM MEMBERS OFF SYSTEM SALES TOTAL OPERATING REVENUE	EXPENSES PRODUCTION FUEL O AND M OTHER POWER SUPPLY TRANSMISSION O AND M ADMINISTRATIVE & GENERAL DEPRECIATION TAXES INTEREST ON LONG TERM DEBT INTEREST CHARGED TO CONSTR OTHER DEBT COST TOTAL EXPENSES OTHER REVENUE NET MARGIN	TIMES INTEREST EARNED RATIO

Case 2 Page 1 of 2

EAST KENTUCKY POWER COOPERATIVE PSC - SMITH INVESTIGATION STUDY - CASE NO. 2010-00238 CASE 2 - SMITH 2016 - TWO-YEAR DELAY - TIER 1.50

ADJUSTED TEST

BUDGET YEAR 2012 2013 2014 2015 2016 2017 2018						1.50 1.50 1.50 1.50 1.50
ACTUAL B						
ACTUAL 2008						
	OPERATING REVENUE MEMBER COOPERATIVES BASE RATES FUEL ADJUSTMENT ENVIRONMENTAL SURCHARGE BASE RATE CHANGE TOTAL FROM MEMBERS OFF SYSTEM SALES TOTAL OPERATING REVENUE	EXPENSES PRODUCTION FUEL O AND M OTHER POWER SUPPLY TRANSMISSION O AND M	ADMINISTRATIVE & GENERAL DEPRECIATION TAXES INTEREST ON LONG TERM DEBT INTEREST CHARGED TO CONSTR OTHER DEBT COST TOTAL EXPENSES	OPERATING MARGINS OTHER REVENUE	NET MARGIN	

1.50

Case 2 Page 2 of 2

EAST KENTUCKY POWER COOPERATIVE
PSC - SMITH INVESTIGATION STUDY - CASE NO. 2010-00238
CASE 2 - SMITH 2016 - TWO-YEAR DELAY - TIER 1.50

2029	Marie Training Training States					1.50
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2027						1.50
2026						1.50
2025						1.50
2024						1.50
2023						1.50
2022						1.50
2021				4	govern and the second	1.50
2020						1.50
2019					100	1.50
	OPERATING REVENUE MEMBER COOPERATIVES BASE RATES FUEL ADJUSTMENT ENVIRONMENTAL SURCHARGE BASE RATE CHANGE TOTAL FROM MEMBERS OFF SYSTEM SALES TOTAL OPERATING REVENUE	EXPENSES PRODUCTION FUEL O AND M OTHER POWER SIPPLY	TRANSMISSION O AND M ADMINISTRATIVE & GENERAL DEPRECIATION TAXES INTEREST ON LONG TERM DEBT INTEREST CHARGED TO CONSTR	OTHER DEBT COST TOTAL EXPENSES OPERATING MARGINS OTHER REVENUE	NET MARGIN	TIMES INTEREST EARNED RATIO

Case 3 Page 1 of 2

EAST KENTUCKY POWER COOPERATIVE
PSC - SMITH INVESTIGATION STUDY - CASE NO. 2010-00238
CASE 3 - SMITH 2018 - FOUR-YEAR DELAY (OPTIMAL) - TIER 1.50

2018			1.50
2017			1.50
2016			1.50
2015			1.50
2014			1.50
2013			1.50
2012			1.50
ADJUSTED TEST YEAR 2011			1,41
BUDGET 2010			1.22
ACTUAL 2009			1.27
ACTUAL 2008			1.25
	OPERATING REVENUE MEMBER COOPERATIVES BASE RATES FUEL ADJUSTMENT ENVIRONMENTAL SURCHARGE BASE RATE CHANGE TOTAL FROM MEMBERS OFF SYSTEM SALES TOTAL OPERATING REVENUE	EXPENSES PRODUCTION FUEL O AND M OTHER POWER SUPPLY TRANSMISSION O AND M ADMINISTRATIVE & GENERAL DEPRECIATION TAXES INTEREST ON LONG TERM DEBT INTEREST CHARGED TO CONSTR OTHER DEBT COST TOTAL EXPENSES OTHER REVENUE NET MARGIN	TIMES INTEREST EARNED RATIO

Case 3 Page 2 of 2

EAST KENTUCKY POWER COOPERATIVE PSC - SMITH INVESTIGATION STUDY - CASE NO. 2010-00238 CASE 3 - SMITH 2018 - FOUR-YEAR DELAY (OPTIMAL) - TIER 1.50

STATEMENT OF OPERATIONS (8000)

2029					1.50
2028					1.50
2027					1.50
2026					1.50
2025					1.50
2024					1.50
2023					1.50
2022					1.50
2021			62 : 18	***	1.50
2020					1.50
2019					1.50
	OPERATING REVENUE MEMBER COOPERATIVES BASE RATES FUEL ADJUSTMENT ENVIRONMENTAL SURCHARGE BASE RATE CHANGE TOTAL FROM MEMBERS OFF SYSTEM SALES TOTAL OPERATING REVENUE	EXPENSES PRODUCTION FUEL O AND M OTHER POWER SUPPLY TRANSMISSION O AND M ADMINISTRATIVE & GENERAL DEPRECIATION TAXES INTEREST ON LONG TERM DEBT INTEREST CHARGED TO CONSTR OTHER DEBT COST TOTAL EXPENSES	OPERATING MARGINS OTHER REVENUE	NET MARGIN	TIMES INTEREST EARNED RATIO

Case 4 Page 1 of 2

EAST KENTUCKY POWER COOPERATIVE PSC - SMITH INVESTIGATION STUDY - CASE NO. 2010-00238 CASE 4 - CANCEL SMITH - GAS (COMBINED CYCLE) - TIER 1.50

2018			1.50
2017			1.50
2016			1.50
2015			1.50
2014			1.50
2013			1.50
2012			1.50
ADJUSTED TEST YEAR 2011			1.41
BUDGET 2010			1.22
ACTUAL 2009			1.27
ACTUAL 2008			1.25
	OPERATING REVENUE MEMBER COOPERATIVES BASE RATES FUEL ADJUSTMENT ENVIRONMENTAL SURCHARGE BASE RATE CHANGE TOTAL FROM MEMBERS OFF SYSTEM SALES TOTAL OPERATING REVENUE	PRODUCTION FUEL O AND M OTHER POWER SUPPLY TRANSMISSION O AND M ADMINISTRATIVE & GENERAL DEPRECIATION TAXES INTEREST CHARGED TO CONSTR OTHER DEBT COST TOTAL EXPENSES OPERATING MARGINS OTHER REVENUE	TIMES INTEREST EARNED RATIO

Case 4 Page 2 of 2

EAST KENTUCKY POWER COOPERATIVE PSC - SMITH INVESTIGATION STUDY - CASE NO. 2010-00238 CASE 4 - CANCEL SMITH - GAS (COMBINED CYCLE) - TIER 1.50

STATEMENT OF OPERATIONS (\$000)

2029					1.50
2028					1.50
2027					1.50
2026					1.50
2025					1.50
2024					1.50
2023					1.50
2022					1.50
2021		es - Au	\$34	gerand.	1.50
2020					1.50
2019				,	1.50
,	OPERATING REVENUE MEMBER COOPERATIVES BASE RATES FUEL ADJUSTMENT ENVIRONMENTAL SURCHARGE BASE RATE CHANGE TOTAL FROM MEMBERS OFF SYSTEM SALES TOTAL OPERATING REVENUE	EXPENSES PRODUCTION FUEL O AND M OTHER POWER SUPPLY TRANSMISSION O AND M ADMINISTRATIVE & GENERAL DEPRECIATION TAXES INTEREST ON LONG TERM DEBT INTEREST CHARGED TO CONSTR OTHER DEBT COST TOTAL EXPENSES	OPERATING MARGINS OTHER REVENUE	NET MARGIN	TIMES INTEREST EARNED RATIO

Case 5 Page 1 of 2

EAST KENTUCKY POWER COOPERATIVE PSC - SMITH INVESTIGATION STUDY - CASE NO. 2010-00238 CASE 5 - CANCEL SMITH - GREEN SOURCES - DSM - TIER 1.50

STATEMENT OF OPERATIONS

ADJUSTED

2018				1.50
2017				1.50
2016				1.50
2015				1.50
2014				1.50
2013				1.50
2012				1.50
TEST YEAR 2011				1.41
BUDGET 2010		£ · · · · · · · · · · · · · · · · · · ·	*	1.22
ACTUAL 2009				1.27
ACTUAL 2008				1.25
	OPERATING REVENUE MEMBER COOPERATIVES BASE RATES FUEL ADJUSTMENT ENVIRONMENTAL SURCHARGE BASE RATE CHANGE TOTAL FROM MEMBERS OFF SYSTEM SALES TOTAL OPERATING REVENUE	EXPENSES PRODUCTION FUEL O AND M OTHER POWER SUPPLY TRANSMISSION O AND M ADMINISTRATIVE & GENERAL DEPRECIATION TAXES INTEREST ON LONG TERM DEBT INTEREST CHARGED TO CONSTR OTHER DEBT COST TOTAL EXPENSES	OPERATING MARGINS OTHER REVENUE	NET MARGIN TIMES INTEREST EARNED RATIO

Case 5 Page 2 of 2

EAST KENTUCKY POWER COOPERATIVE PSC - SMITH INVESTIGATION STUDY - CASE NO. 2010-00238 CASE 5 - CANCEL SMITH - GREEN SOURCES - DSM - TIER 1.50

STATEMENT OF OPERATIONS (8000)

2029			1.50
2028			1.50
2027			1.50
2026			1.50
2025			1.50
2024			1.50
2023			1.50
2022			1.50
2021	dis	д	1.50
2020			1.50
2019			1.50
	OPERATING REVENUE MEMBER COOPERATIVES BASE RATES FUEL ADJUSTMENT ENVIRONMENTAL SURCHARGE BASE RATE CHANGE TOTAL FROM MEMBERS OFF SYSTEM SALES TOTAL OPERATING REVENUE	EXPENSES PRODUCTION FUEL O AND M OTHER POWER SUPPLY TRANSMISSION O AND M ADMINISTRATIVE & GENERAL DEPRECIATION TAXES INTEREST ON LONG TERM DEBT INTEREST CHARGED TO CONSTR OTHER DEBT COST TOTAL EXPENSES OTHER REVENUE NET MARGIN	TIMES INTEREST EARNED RATIO

EAST KENTUCKY POWER COOPERATIVE
PSC - SMITH INVESTIGATION STUDY - CASE NO. 2010-00238
CASE 6 - CANCEL SMITH - SHORT-TERM PPA/LONG-TERM CONSTR W/ CCGT - TIER 1.50

					Page
2018				-	1.50
2017				-	1.50
2016					1.50
2015					1.50
2014					1.50
2013		. :			1.50
2012					1.50
ADJUSTED TEST YEAR 2011					1.41
BUDGET 2010	F 34		й il		1.22
ACTUAL 2009					1.27
ACTUAL 2008					1.25
	OPERATING REVENUE MEMBER COOPERATIVES BASE RATES FUEL ADJUSTMENT ENVIRONMENTAL SURCHARGE BASE RATE CHANGE TOTAL FROM MEMBERS OFF SYSTEM SALES TOTAL OPERATING REVENUE	EXPENSES PRODUCTION FUEL O AND M OTHER POWER SUPPLY TRANSMISSION O AND M ADMINISTRATIVE & GENERAL DEPRECIATION TAXES INTEREST ON LONG TERM DEBT INTEREST CHARGED TO CONSTR OTHER DEBT COST TOTAL EXPENSES	OPERATING MARGINS OTHER REVENUE	NET MARGIN	TIMES INTEREST EARNED RATIO

EAST KENTUCKY POWER COOPERATIVE
PSC - SMITH INVESTIGATION STUDY - CASE NO. 2010-00238
CASE 6 - CANCEL SMITH - SHORT-TERM PPA/LONG-TERM CONSTR W/ CCGT - TIER 1.50

STATEMENT OF OPERATIONS (\$000)

2029					1.50
2028					1.50
2027				7	1.50
2026					1.50
2025					1.50
2024					1.50
2023					1.50
2022					1.50
2021	3 .		\$25 173 8	S. COL	1.50
2020					1.50
2019					1.50
	OPERATING REVENUE MEMBER COOPERATIVES BASE RATES FUEL ADJUSTMENT ENVIRONMENTAL SURCHARGE BASE RATE CHANGE TOTAL FROM MEMBERS OFF SYSTEM SALES TOTAL OPERATING REVENUE	EXPENSES PRODUCTION FUEL O AND M OTHER POWER SUPPLY TRANSMISSION O AND M ADMINISTRATIVE & GENERAL DEPRECIATION TAXES INTEREST ON LONG TERM DEBT INTEREST CHARGED TO CONSTR OTHER DEBT COST TOTAL EXPENSES	OPERATING MARGINS OTHER REVENUE	NET MARGIN	TIMES INTEREST EARNED RATIO

EAST KENTUCKY POWER COOPERATIVE PSC - SMITH INVESTIGATION STUDY - CASE NO. 2010-00238 CASE 7 - CANCEL SMITH - EQUIPMENT SOLD - LONG-TERM PPA - TIER 1.50

				1 46
2018				1.50
2017				1.50
2016				1.50
2015				1.50
2014				1.50
2013				1.50
2012				1.50
ADJUSTED TEST YEAR 2011				1.41
BUDGET 2010	un de	SS scale	d \$500 PA	1.22
ACTUAL 2009				1.27
ACTUAL 2008				1.25
	OPERATING REVENUE MEMBER COOPERATIVES BASE RATES FUEL ADJUSTMENT ENVIRONMENTAL SURCHARGE BASE RATE CHANGE TOTAL FROM MEMBERS OFF SYSTEM SALES TOTAL OPERATING REVENUE	EXPENSES PRODUCTION FUEL O AND M OTHER POWER SUPPLY TRANSMISSION O AND M ADMINISTRATIVE & GENERAL DEPRECIATION TAXES INTEREST ON LONG TERM DEBT INTEREST CHARGED TO CONSTR OTHER DEBT COST TOTAL EXPENSES OTHER DEFVENITE	NET MARGIN	TIMES INTEREST EARNED RATIO

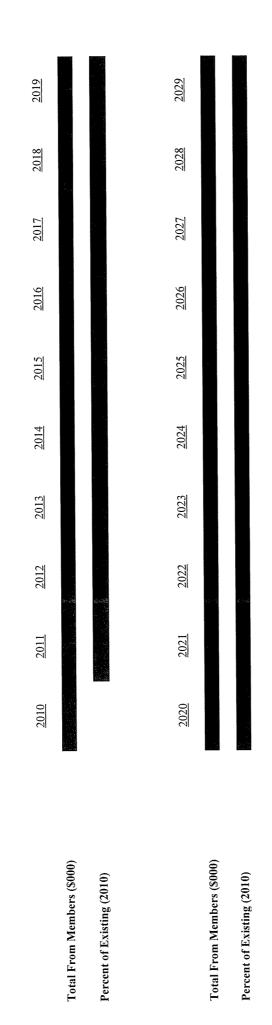
Case 7 Page 2 of 2

EAST KENTUCKY POWER COOPERATIVE PSC - SMITH INVESTIGATION STUDY - CASE NO. 2010-00238 CASE 7 - CANCEL SMITH - EQUIPMENT SOLD - LONG-TERM PPA - TIER 1.50

STATEMENT OF OPERATIONS

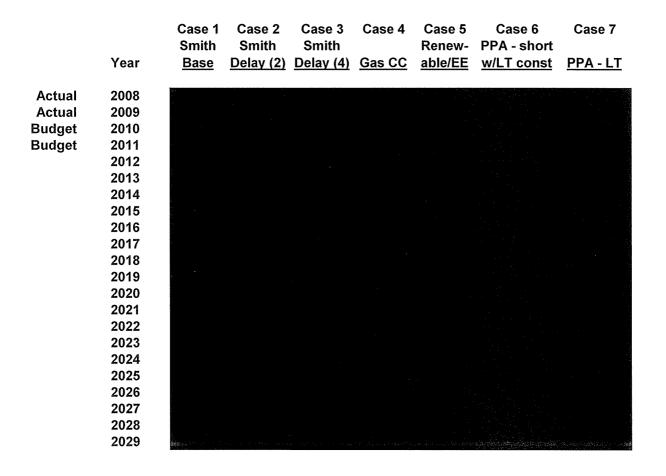
2029					1.50
2028			man in the second se		1.50
2027					1.50
2026					1.50
2025					1.50
2024					1.50
2023					1.50
2022					1.50
2021	der ·		Ant	Art have 1958	1.50
2020					1.50
2019					1.50
	OPERATING REVENUE MEMBER COOPERATIVES BASE RATES FUEL ADJUSTMENT ENVIRONMENTAL SURCHARGE BASE RATE CHANGE TOTAL FROM MEMBERS OFF SYSTEM SALES TOTAL OPERATING REVENUE	EXPENSES PRODUCTION FUEL O AND M OTHER POWER SUPPLY TRANSMISSION O AND M ADMINISTRATIVE & GENERAL DEPRECIATION TAXES INTEREST ON LONG TERM DEBT INTEREST CHARGED TO CONSTR OTHER DEBT COST TOTAL EXPENSES	OPERATING MARGINS OTHER REVENUE	NET MARGIN	TIMES INTEREST EARNED RATIO

ANNUAL REVENUE REQUIREMENTS AND PERCENTAGE OF EXISTING REVENUE REQUIREMENTS - CASE 1 - BASE - SMITH 2014 PSC - SMITH 1 INVESTIGATION - CASE NO. 2010-00238 (\$ 000) & PERCENT



Member Cost Summary

(\$MWH)



PSC - SMITH 1 INVESTIGATIO, JUDY - CASE NO. 2010-00238

CASE 1 - BASE - SMITH 2014 - TIER 1.50 RATE DETAIL

2018 2019		2018 2019	2018 2019	2018 2019	2018 2019	2018 2019	2018 2019	2018 2019	2010 2011 2012 2014 2015 2016 2017 2019 2010 and 2011 On-Peak Energy Rate is Based on Forward Price (Cinergy Hub) Control Plus O & M Plus 3 Mill Adder Adder Amil Adder 2010 and 2011 Off-Peak Energy Rate is Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 Mill Adder Amil Adder
2017		2017	2017	2017	2017	2017	2017	2017	2017 2017 2017
2016		2016	2016	2016	2016	2016	2016	2016	2016 Plus O & M Plu
2015		2015	2015	2015	2015	2015	2015	2015	2015 2015 Hub)
2014		2014	2014	2014	2014	2014	2014	2014	2014 Price (Cinergy
2013		2013	2013	2013	2013	2013	2013	2013	2013 ed on Forward
2012		2012	2012	2012	2012	2012	2012	2012	2011 2012 2013 2014 On-Peak Energy Rate is Based on Forward Price (Cinergy Hub) Off-Peak Energy Rate is Based on EKPC System Avrg Increment
2011		2011	2011	2011	2011	2011	2011	2011	2010 2011 2012 2013 2014 2015 2017 2017 2017 2010 and 2011 On-Peak Energy Rate is Based on Forward Price (Cinergy Hub)
2010		2010	2010	2010	2010	2010	2010	2010	2010 2010 and 2011 2010 and 2011
Schedule E-1	Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	Schedule E-2 Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	Schedule B & C (2) Total Demand Rate (\$/kW) - B & C Total Energy Rate - Schedule B (\$.00/kWh) Total Energy Rate - Schedule C (\$.00/kWh)	Excess Schedule B Total Demand Rate (\$/k\V)	Inland Electric (2) Total Demand Rate (\$/kW) Total Fnerry Rate (\$.00/kWh)	Inland Steam Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	Gallatin Total Firm Demand Rate (\$/kW) Total Interrupt 1 Demand Rate (\$/kW) Total Interrupt 2 Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	AGC Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	TGP (1) Total Demand Rate (\$/kW) Average Energy Rate (\$.00/kWh)

PSC - SMITH 1 INVESTIGATIOL JUDY - CASE NO. 2010-00238

CASE 1 - BASE - SMITH 2014 - TIER 1.50 RATE DETAIL

			KA	KAIE DEIAIL						
Schedule E-1	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)										
Schedule E-2 Total Demand Rate (\$/KW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Beak Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Schedule B & C (2) Total Demand Rate (\$/kW) - B & C Total Energy Rate - Schedule B (\$.00/kWh) Total Energy Rate - Schedule C (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Excess Schedule B Total Demand Rate (SkW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Inland Electric (2) Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Inland Steam Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Gallatin	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Firm Demand Rate (\$/kW) Total Interrupt 1 Demand Rate (\$/kW) Total Interrupt 2 Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)										
AGC Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
TGP (1) Total Demand Rate (\$/kW) Average Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029

PSC - SMITH 1 INVESTIGATIO J. FUDY - CASE NO. 2010-00238

CASE 2 - TWO-YEAR DELAY - SMITH 2016 - TIER 1.50

RATE DETAIL

Schedule E-1 Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Schedule E-2 Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Schedule B & C (2) Total Demand Rate (\$/kW) - B & C Total Energy Rate - Schedule B (\$.00/kWh) Total Energy Rate - Schedule C (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Excess Schedule B Total Demand Rate (\$/kW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Inland Electric (2) Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Inland Steam Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gallatin Total Firm Demand Rate (\$/kW) Total Interrupt 1 Demand Rate (\$/kW) Total Interrupt 2 Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
AGC Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
TGP (1) Total Demand Rate (\$/kW) Average Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	(1) 2010 and 2011		On-Peak Energy Rate is Based on Forward Price (Cinergy Hub) Off Dook Energy Pate is Based on EKPC System Ayra Incremental Cost Plus O.& M Plus 3 Mill Adder	ed on Forward F	Price (Cinergy Faternament)	lub) mental Cost Pli	S M Plus	3 Mill Adder		

2010 and 2011 Off-Peak Energy Rate is Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 Mill Adder 2012 through 2029 On-Peak and Off-Peak Energy Rates are Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 Mill Adder (2) Schedules B, C & Inland Electric - Rate Increase Calculated Proportionally on Total Revenue But Applied to Demand Rate Only Note: All Rate Increases, Except Those Listed in (1) & (2), are Calculated Proportionally on Demand and Energy

PSC - SMITH 1 INVESTIGATIO. JUDY - CASE NO. 2010-00238

CASE 2 - TWO-YEAR DELAY - SMITH 2016 - TIER 1.50 RATE DETAIL

			KAI	KAIE DEIAIL						
Sobodulo E.4	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Schedule E-1 Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)										
Schedule E-2 Total Demand Rate (\$/KVV) Total On-Peak Energy Rate (\$.00/kV/h)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Schedule B & C (2) Total Demand Rate (\$/KW) - B & C Total Energy Rate - Schedule B (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Excess Schedule B Total Demand Rate (S.R.W.)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Inland Electric (2) Total Demand Rate (\$/KW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Inland Steam Total Demand Rate (\$/kW) Total Ferror Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Gallatin Total Firm Demand Rate (\$/kW) Total Interrupt 1 Demand Rate (\$/kW) Total Interrupt 2 Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Off-Peak Energy Rate (\$.00/kWh) AGC Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
TGP (1) Total Demand Rate (\$.NkW) Average Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029

PSC - SMITH 1 INVESTIGATIOL, $_{\circ}$ FUDY - CASE NO. 2010-00238

CASE 3 - FOUR-YEAR DELAY - SMITH 2018 (OPTIMAL) - TIER 1.50 RATE DETAIL

2019	2019	2019	2019	2019	2019	2019	2019	2019	Adder
2018	2018	2018	2018	2018	2018	2018	2018	2018	M Plus 3 Mill. kate Only
2017	2017	2017	2017	2017	2017	2017	2017	2017	s 3 Mill Adder Cost Plus O & I to Demand F
2016	2016	2016	2016	2016	2016	2016	2016	2016	ilus O & M Plu: g Incremental (nue But Applied nand and Ener
2015	2015	2015	2015	2015	2015	2015	2015	2015	Hub) emental Cost F oC System Avr on Total Rever tionally on Den
2014	2014	2014	2014	2014	2014	2014	2014	2014	Price (Cinergy hastem Avrg Increased on EKF Proportionally culated Proport
2013	2013	2013	2013	2013	2013	2013	2013	2013	d on Forward F d on EKPC Sysergy Rates are ase Calculated
2012	2012	2012	2012	2012	2012	2012	2012	2012	ly Rate is Base Iy Rate is Base In Off-Peak En Ic - Rate Increa
2011	2011	2011	2011	2011	2011	2011	2011	2011	On-Peak Energy Rate is Based on Forward Price (Cinergy Hub) Off-Peak Energy Rate is Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 Mill Adder 029 On-Peak and Off-Peak Energy Rates are Based on EKPC System Avrg Incremental Cost Plus O & 28 Inland Electric - Pate Increase Calculated Proportionally on Total Revenue But Applied to Demand Fores Excent Those Listed in (1) & (2), are Calculated Proportionally on Demand and Energy
2010	2010	2010	2010	2010	2010	2010	2010	2010	 (1) 2010 and 2011 On-Peak Energy Rate is Based on Forward Price (Cinergy Hub) 2010 and 2011 Off-Peak Energy Rate is Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 Mill Adder 2012 through 2029 On-Peak and Off-Peak Energy Rates are Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 Mill Adder (2) Schedules B, C& Inland Electric - Rate Increase Calculated Proportionally on Total Revenue But Applied to Demand Rate Only Moder All Details Propert Those I ished in (1) & (2), are Calculated Proportionally on Demand and Energy
Schedule E-1 Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Fnergy Rate (\$.00/kWh)	Schedule E-2 Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	Schedule B & C (2) Total Demand Rate (\$/kW) - B & C Total Energy Rate - Schedule B (\$.00/kWh) Total Energy Rate - Schedule C (\$.00/kWh)		Inland Electric (2) Total Demand Rate (\$/kW) Total Fnerov Rate (\$.00/kWh)	Inland Steam Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	Gallatin Total Firm Demand Rate (\$/kW) Total Interrupt 1 Demand Rate (\$/kW) Total Interrupt 2 Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	AGC Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	TGP (1) Total Demand Rate (\$/kW) Average Energy Rate (\$.00/kWh)	

PSC - SMITH 1 INVESTIGATIO. JUDY - CASE NO. 2010-00238

CASE 3 - FOUR-YEAR DELAY - SMITH 2018 (OPTIMAL) - TIER 1.50 RATE DETAIL

			KAI	KATEDETAIL						
Schedule E-1	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)								A mention of the second		
Schedule E-2 Total Demand Rate (\$/kW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
l otal On-Peak Energy Kate (\$.00/kVvn) Total Off-Peak Energy Rate (\$.00/kVVh)										
Schedule B & C (2) Total Demand Rate (\$/kW) - B & C Total Energy Rate - Schedule B (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Energy Rate - Schedule C (\$.00/kVvn Excess Schedule B	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Intain Defination Rate (why) Intain Electric (2) Total Demand Rate (\$/KW) Total Energy Rate (\$/KW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Inland Steam Total Demand Rate (\$/KW) Total Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Gallatin	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Interrupt 1 Demand Rate (\$/kW) Total Interrupt 2 Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)										
AGC Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
TGP (1) Total Demand Rate (\$/kW) Average Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029

CASE 4 - CANCEL SMITH - GAS (COMBINED CYCLE) - TIER 1.50 RATE DETAIL

Schedule E-1	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)										: : :x3
Schedule E-2 Total Demand Rate (\$/KW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Schedule B & C (2) Total Demand Rate (\$/kW) - B & C Total Energy Rate - Schedule B (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Excess Schedule B Total Demand Rate (\$/kW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Inland Electric (2) Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Inland Steam Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gallatin Total Firm Demand Rate (\$/kW) Total Interrupt 1 Demand Rate (\$/kW) Total Interrupt 2 Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
AGC Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
TGP (1) Total Demand Rate (\$/kW) Average Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	 (1) 2010 and 2011 On-Peak Energy Rate is Based on Forward Price (Cinergy Hub) 2010 and 2011 Off-Peak Energy Rate is Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 2012 through 2029 On-Peak and Off-Peak Energy Rates are Based on EKPC System Avrg Incremental Co (2) Schedules B, C & Inland Electric - Rate Increase Calculated Proportionally on Total Revenue But Applied to Note: All Rate Increases, Except Those Listed in (1) & (2), are Calculated Proportionally on Demand and Energy 	11 On-Peak Ene 1 Off-Peak Ene 2029 On-Peak C & Inland Elec sases, Except T	rgy Rate is Basergy Rate is Baserand Off-Peak Eratric - Rate Increhose Listed in (*)	2010 and 2011 On-Peak Energy Rate is Based on Forward Price (Cinergy Hub) 2010 and 2011 Off-Peak Energy Rate is Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 Mill Adder 2012 through 2029 On-Peak and Off-Peak Energy Rates are Based on EKPC System Avrg Incremental Cost Plus O & Schedules B, C & Inland Electric - Rate Increase Calculated Proportionally on Total Revenue But Applied to Demand F All Rate Increases, Except Those Listed in (1) & (2), are Calculated Proportionally on Demand and Energy	rice (Cinergy Hatem Avrg Incre Based on EKP Proportionally c	ub) mental Cost Pl C System Avrg in Total Reven ionally on Dem	us O & M Plus Incremental C ue But Applied and and Energ	2010 and 2011 On-Peak Energy Rate is Based on Forward Price (Cinergy Hub) 2010 and 2011 Off-Peak Energy Rate is Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 Mill Adder 2012 through 2029 On-Peak and Off-Peak Energy Rates are Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 Mill Adder Schedules B, C & Inland Electric - Rate Increase Calculated Proportionally on Total Revenue But Applied to Demand Rate Only All Rate Increases, Except Those Listed in (1) & (2), are Calculated Proportionally on Demand and Energy	Plus 3 Mill Adde 9 Only	L

PSC - SMITH 1 INVESTIGATIOL, JUDY - CASE NO. 2010-00238

CASE 4 - CANCEL SMITH - GAS (COMBINED CYCLE) - TIER 1.50 PATE DETAIL.

			RAT	RATE DETAIL						
	0000	2024	2022	2023	2024	2025	2026	2027	2028	2029
Schedule E-1 Total Demand Rate (\$/kW)	2020	1707								
Total Off-Peak Energy Nate (\$.00/kWh)					-					
			0000	COOC	7000	2005	2026	2027	2028	2029
Schedule E-2	2020	2021	2022	2023	2024	0707				
Total Demand Rate (\$/KW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)		the state of the s								
										0000
Schedule B & C (2)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Demand Rate (\$/kW) - B & C		S ber								
Total Energy Kate - Schedule B (\$.00/kvvii) Total Energy Rate - Schedule C (\$.00/kWh)					A second of the				The Market States	3
Excess Schedule B	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Demand Rate (\$/kW)	Section (Inc.)									A
									0000	0000
Inland Flactric (2)	2020	2021	2022	2023	2024	2025	2026	2027	2028	8202
Total Demand Rate (\$/kW)										
Total Energy Rate (\$.00/kWh)										
				0000	7000	2008	2026	2027	2028	2029
Inland Steam	2020	2021	2022	2023	2024	2020	0.10			Q good
Total Demand Rate (\$/KW)									The second second second second	± 2 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
וסומו ביופואל זימני (לייסטיניין										
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Firm Demand Rate (\$/kW)	できる 一大大大大大大大大大大大大大大大大大大大大大大大大大大大大大大大大大大大大	7	1 A 1 A 1 A 1 A 1 A 1 A 1 A 1 A 1 A 1 A							arginanya,
Total Interrupt 1 Demand Rate (\$/kW)										
Total Interrupt 2 Demand Rate (\$/kW)										
lotal On-Peak Energy Kate (5.00/kwiii) Total Off-Peak Energy Rate (\$.00/kWh)						7.00	A to the second second			T
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Demand Rate (\$/kW)		2000								
Total Energy Rate (\$.00/kWh)		The state of the s								
									0000	0000
TGP (1)	2020	2021	2022	2023	2024	2025	2026	2027	2028	5073
Total Demand Rate (\$/kW)		X							on the second	
Average Energy Rate (\$.00/kWh)	Actions of the South Control o	***								

PSC - SMITH 1 INVESTIGATIO, \cup FUDY - CASE NO. 2010-00238

CASE 5 - CANCEL SMITH - GREEN SOURCES - TIER 1.50 RATE DETAIL

			arra	arriad						
Schedule E-1	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)										
Schedule E-2 Total Demand Rate (\$/KW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Schedule B & C (2) Total Demand Rate (\$/KW) - B & C Total Energy Rate - Schedule B (\$.00/k/Wh) Total Energy Rate - Schedule C (\$.00/k/Wh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Excess Schedule B Total Demand Rate (\$/kW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Inland Electric (2) Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Injand Steam Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gallatin Total Firm Demand Rate (\$/kW) Total Interrupt 1 Demand Rate (\$/kW) Total Interrupt 2 Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
AGC Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
TGP (1) Total Demand Rate (\$/kW) Average Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	 2010 and 2011 On-Peak Energy Rate is Based on Forward Price (Cinergy Hub) 2010 and 2011 Off-Peak Energy Rate is Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 2012 through 2029 On-Peak and Off-Peak Energy Rates are Based on EKPC System Avrg Incremental Co 2) Schedules B, C & Inland Electric - Rate Increase Calculated Proportionally on Total Revenue But Applied to Note: All Rate Increases, Except Those Listed in (1) & (2), are Calculated Proportionally on Demand and Energy 	11 On-Peak En 11 Off-Peak En 12029 On-Peak , C & Inland Ele eases, Except	2010 and 2011 On-Peak Energy Rate is Based on Forward Price (Cinergy Hub) 2010 and 2011 Off-Peak Energy Rate is Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 Mill Adder 2012 through 2029 On-Peak and Off-Peak Energy Rates are Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 Mill Adder Schedules B, C & Inland Electric - Rate Increase Calculated Proportionally on Total Revenue But Applied to Demand Rate Only All Rate Increases, Except Those Listed in (1) & (2), are Calculated Proportionally on Demand and Energy	ed on Forward F ed on EKPC Sy. nergy Rates are tase Calculated 1) & (2), are Cal	Price (Cinergy F stem Avrg Incre Based on EKF Proportionally of culated Proport	lub) mental Cost P C System Avrg on Total Reven ionally on Dem	tus O & M Plus g Incremental (ue But Applied and and Energ	s 3 Mill Adder Cost Plus O & M I to Demand Ra	l Plus 3 Mill Add te Only	ler

PSC - SMITH 1 INVESTIGATION JUDY - CASE NO. 2010-00238

CASE 5 - CANCEL SMITH - GREEN SOURCES - TIER 1.50

			RATI	RATE DETAIL						
Schedule E-1 Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Schedule E-2 Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Schedule B & C (2) Total Demand Rate (\$/kW) - B & C Total Energy Rate - Schedule B (\$.00/kWh) Total Energy Rate - Schedule C (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Excess Schedule B Total Demand Rate (\$/kW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Inland Electric (2) Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Inland Steam Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Gallatin Total Firm Demand Rate (\$/kW) Total Interrupt 1 Demand Rate (\$/kW) Total Interrupt 2 Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AGC Total Demand Rate (\$.KW) Total Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
TGP (1) Total Demand Rate (\$/kW) Average Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029

PSC - SMITH 1 INVESTIGATIO, JTUDY - CASE NO. 2010-00238

CASE 6 - CANCEL SMITH - SHORT-TERM PPA/LONG-TERM CONSTR W/CCGT - TIER 1.50

RATE DETAIL

									Average Energy Kate (\$.00/kWn)
2018 2019	2017	2016	2015	2014	2013	2012	2011	2010	Total Demand Rate (\$/kW)
									Total Energy Rate (\$.00/kWh)
2018 2019	2017	2016	2015	2014	2013	2012	2011	2010	AGC Total Demand Rate (\$/kW)
									lotal Interrupt z Demano Kare (s/kkv) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)
									Total Firm Demand Rate (\$/kW) Total Interrupt 1 Demand Rate (\$/kW) Total Interrupt 2 Demand Rate (\$/kW)
2018 2019	2017	2016	2015	2014	2013	2012	2011	2010	Gallatin
		. :							Total Demand Rate (\$/k\W) Total Energy Rate (\$.00/k\Wh)
2018 2019	2017	2016	2015	2014	2013	2012	2011	2010	Inland Steam
				·				1	Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)
2018 2019	2017	2016	2015	2014	2013	2012	2011	2010	Inland Electric (2)
2018 2019	2017	2016	2015	2014	2013	2012	2011	2010	Excess Schedule B Total Demand Rate (\$/kW)
							20		Total Demand Rate (\$/kW) - B & C Total Energy Rate - Schedule B (\$.00/kWh) Total Energy Rate - Schedule C (\$.00/kWh)
2018 2019	2017	2016	2015	2014	2013	2012	2011	2010	Schedule B & C (2)
									Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)
2018 2019	2017	2016	2015	2014	2013	2012	2011	2010	Schedule E-2 Total Demand Rate (\$/kW)
									Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)
6102							-	2010	Schedule E-1

²⁰¹⁰ and 2011 Off-Peak Energy Rate is Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 Mill Adder 2012 through 2029 On-Peak and Off-Peak Energy Rates are Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 Mill Adder (2) Schedules B, C & Inland Electric - Rate Increase Calculated Proportionally on Total Revenue But Applied to Demand Rate Only Note: All Rate Increases, Except Those Listed in (1) & (2), are Calculated Proportionally on Demand and Energy

PSC - SMITH 1 INVESTIGATIO1, JTUDY - CASE NO. 2010-00238

CASE 6 - CANCEL SMITH - SHORT-TERM PPA/LONG-TERM CONSTR W/CCGT - TIER 1.50 RATE DETAIL.

			RA	RATE DETAIL						
Schedule E-1 Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Schedule E-2 Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Schedule B & C (2) Total Demand Rate (\$/KW) - B & C Total Energy Rate - Schedule B (\$.00/kWh) Total Energy Rate - Schedule C (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Excess Schedule B Total Demand Rate (\$/kW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Inland Electric (2) Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Inland Steam Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Gallatin Total Firm Demand Rate (\$/kW) Total Interrupt 1 Demand Rate (\$/kW) Total Interrupt 2 Demand Rate (\$/kW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)				CONTRACTOR SERVING AND	SOCIAL ACTION OF THE PROPERTY	OR THE REAL PROPERTY OF THE PR		Soyyi an establish sa		
AGC Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
TGP (1) Total Demand Rate (\$/kW) Average Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029

PSC - SMITH 1 INVESTIGATIO1, JTUDY - CASE NO. 2010-00238

CASE 7 - CANCEL SMITH/EQUIPMENT SOLD - LONG-TERM PPA - TIER 1.50

RATE DETAIL

	0102	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)										
Schedule E-2 Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Schedule B & C (2) Total Demand Rate (\$/KW) - B & C Total Energy Rate - Schedule B (\$.00/kWh) Total Energy Rate - Schedule C (\$.00/kWh)	2010 (h)	2011	2012	2013	2014	2015	2016	2017	2018	2019
Excess Schedule B Total Demand Rate (\$/kW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
inland Electric (2) Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
inland Steam Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gallatin Total Firm Demand Rate (\$/kW) Total Interrupt 1 Demand Rate (\$/kW) Total Interrupt 2 Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
AGC Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
IGE (1) Total Demand Rate (\$/kVV) Average Energy Rate (\$.00kVVh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019

2010 and 2011 Off-Peak Energy Rate is Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 Mill Adder 2012 through 2029 On-Peak and Off-Peak Energy Rates are Based on EKPC System Avrg Incremental Cost Plus O & M Plus 3 Mill Adder (2) Schedules B, C & Inland Electric - Rate Increase Calculated Proportionally on Total Revenue But Applied to Demand Rate Only Note: All Rate Increases, Except Those Listed in (1) & (2), are Calculated Proportionally on Demand and Energy

PSC - SMITH 1 INVESTIGATIO1, JTUDY - CASE NO. 2010-00238

CASE 7 - CANCEL SMITH/EQUIPMENT SOLD - LONG-TERM PPA - TIER 1.50 RATE DETAIL

			KA	KAIE DEIAIL						
Schedule E-1	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Off-Peak Energy Rate (\$.00/kWh)										
Schedule E-2 Total Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
I otal Ott-Peak Energy Kate (\$.00/kvvn) Schedule B & C (2) Total Demand Rate (\$/kw) - B & C Total Energy Rate - Schedule B (\$.00/kwh) Total Energy Rate - Schedule C (\$.00/kwh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Excess Schedule B Total Demand Rate (\$/kW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Inland Electric (2) Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Inland Steam Total Demand Rate (\$/k\V\) Total Energy Rate (\$.00/k\Vh\)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Gallatin Total Firm Demand Rate (\$/kW) Total Interrupt 1 Demand Rate (\$/kW) Total Interrupt 2 Demand Rate (\$/kW) Total On-Peak Energy Rate (\$.00/kWh) Total Of-Peak Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AGC Total Demand Rate (\$/kW) Total Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
TGP (1) Total Demand Rate (\$/kW) Average Energy Rate (\$.00/kWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029

FINANCIAL ASSUMPTIONS for PSC Smith Investigation Study - Redacted

Budget Data Used for 2010 - 2011

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Fixed O & M Rate																		
Dale																		37
Cooper 1							100 100 100 100 100 100 100 100 100 100	17	F		11			100 100 100 100 100				12
Cooper 2 FGD						100												
Spur 1 FGD	1					70		***		2								
Spur 2 FGD																		17
Spur CFB						100												7,
Smith CFB								11	-11 -11 -11		., 1							
Combined Cycle								5								11		
CT's ABB																		11.
CT's EA				77					1,527	Ü	2. V-							71
CT's LMS 100			_															
Landfill Gas																		
			A CONTRACTOR OF THE CONTRACTOR								ORGANICATION OF THE CONTRACT O	AND THE PROPERTY OF THE PROPER						
Variable O & M Rate																		
Dale				1.0	14.3		12				7,	- 1				.,,	1	€ (25)6
Cooper 1			1,1					47				1		H. C.	XX			1
Cooper 2 FGD					1.5		ř									17) 77) 1-1		
Spur 1 FGD				7.	X.					,								
Splir 2 EGD								,				10.00		2.4	0.00	1		
200					,					1								

Dale		The state of the s				100					
Cooper 1	-11			4.7							
Cooper 2 FGD											
Spur 1 FGD			,			11.4	1000				
Spur 2 FGD							10	***			
Spur CFB			,								
Smith CFB					 :: ::					7	-
Combined Cycle						i.					
Landfill Gas							20 20 20				





FAC Base Rate = 36.53 Mills/kWh Combined Cycle Combustion Turbines - GE 7 EA's Circulating Fluidized Bed

General Escalation Rate

Benefits Escalator

0 & M Production

Capital Costs

Escalation Rates

Smith Financing

Short-term Debt Long-term Debt

Interest Rates