FINAL DRAFT

2011 INTEGRATED RESOURCE PLAN

B&V PROJECT NO. 174179

PREPARED FOR

Brownsville Public Utilities Board

16 FEBRUARY 2012

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Table of Contents

LIST OF TABLES

LIST OF FIGURES

Acronym List

AEP-TCC	American Electric Power – Texas Central Company
BACT	Best Available Control Technology
BPUB	Brownsville Public Utilities Board
CC	Combined Cycle
CEMS	Continuous Emissions Monitoring System
Cents/kWh	Cents Per Kilowatt Hour
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COD	Commercial Operation Date
CPWC	Cumulative Present Worth Cost
D/F	Dioxins and Furans
DFO	Distillate Fuel Oil
DSIRE	Database of State Incentives For Renewables and Efficiency
DSM	Demand-Side Management
EE	Energy Efficiency
EMP	Energy Market Perspective
EPC	Engineering, Procurement, and Construction
ERCOT	Electric Reliability Council of Texas
GE	General Electric
GSU	Generator Step-Up Transformer
GWh	Gigawatt-Hour
HVAC	Heating, Ventilating and Air Conditioning
IOUs	Investor Owned Utilities
IRP	Integrated Resource Plan
kW	Kilowatt
kWh	Kilowatt-Hour
LBBC	Levelized Bus-Bar Cost
LCOE	Levelized Cost of Energy
LED	Light Emitting Diode
LMP	Locational Marginal Price
LRGV	Lower Rio Grande Valley
MMBtu	Million British Thermal Units

MTP	Market Transformation Programs
MVEC	Magic Valley Electric Cooperative
MW	Megawatts
MWh	Megawatt-Hour
N/A	Not Applicable
NEL	Net Energy for Load
NG	Natural Gas
NO_x	Nitrogen Oxide
NPHR	Net Plant Heat Rate
O&M	Operations and Maintenance
P&ID	Piping and Instrumentation Diagram
PPA	Power Purchase Agreement
PSD	Prevention of Significant Deterioration
PUCT	Public Utility Commission of Texas
PV	Photovoltaic
PWDR	Present Worth Discount Rate
RFP	Request for Proposals
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SOP	Standard Offer Programs
ST	Steam Turbine
TCEQ	Texas Commission on Environmental Quality
Tenaska	Tenaska Marketing Ventures
TGS	Texas Gas Services

1.0 Executive Summary

1.1 STUDY PURPOSE

Black & Veatch was retained by the Brownsville Board of Public Utilities (BPUB) to develop this Integrated Resource Plan (IRP) in order to analyze, evaluate, and recommend power supply alternatives to BPUB's projected future power supply requirements. BPUB provides reliable and economical electric services to approximately 46,000 residential, commercial, industrial, and municipal customers through a combination of solely and jointly owned generating resources and power purchases.

The load forecast utilized in this IRP was developed for BPUB by R.W. Beck, Inc./SAIC in the 2009 timeframe[1]. On the basis of the load forecast and existing generating resources, BPUB is projected to require additional capacity to satisfy its reliability criteria beginning in 2012. However, given the timing of this study and lead times associated with evaluating, permitting, and constructing new generating resources, the earliest operation date for new generating resources assumed for purposes of this IRP is 2014.

The purpose of this IRP was to determine the most economic generation expansion plan for BPUB to satisfy its projected future capacity and energy requirements while considering generating resources that are sized to be consistent with BPUB's project load growth and ability to solely pursue or develop. The need for future resources was determined on the basis of available existing resources and BPUB's projected peak demands through the 2031 planning horizon. The IRP considers both conventional and renewable generating technologies, and expansion of demand-side management and energy efficiency programs. Limitations on the import and export capability of BPUB's current transmission system were also taken into consideration. Evaluation of the expansion plan in this manner allows for a baseline against which BPUB may compare opportunities to jointly participate and/or purchase power from more economical resources, with such opportunities identified through a competitive power supply solicitation, or request for proposals (RFP) process.

Various factors, such as resource availability, cost and performance characteristics, and fuel, carbon dioxide (CO_2) emissions, and power price projections, were considered in the analysis. While the expansion plans considered in this IRP focused on a single set of input assumptions in this regard, consideration should be given to evaluating the potential impact of changes to various input assumptions (such as the load forecast, fuel prices, CO_2 emissions allowance prices, and market power prices).

[1] The R.W. Beck/SAIC load forecast extended through 2028. Load projections beyond 2028 were developed by Black & Veatch based on extrapolations of the R.W. Beck/SAIC forecast.

1.2 OVERVIEW OF BPUB'S GENERATION RESOURCES

BPUB's existing generation system consists of a mix of simple cycle and combined cycle natural gas units, coal-fired capacity, and distributed generation. Figure 1-1 illustrates BPUB's current capacity resource mix, based on summer ambient net capacity ratings. As illustrated in Figure 1-2, power purchases make up a significant portion of the energy utilized to serve BPUB's loads.[2]

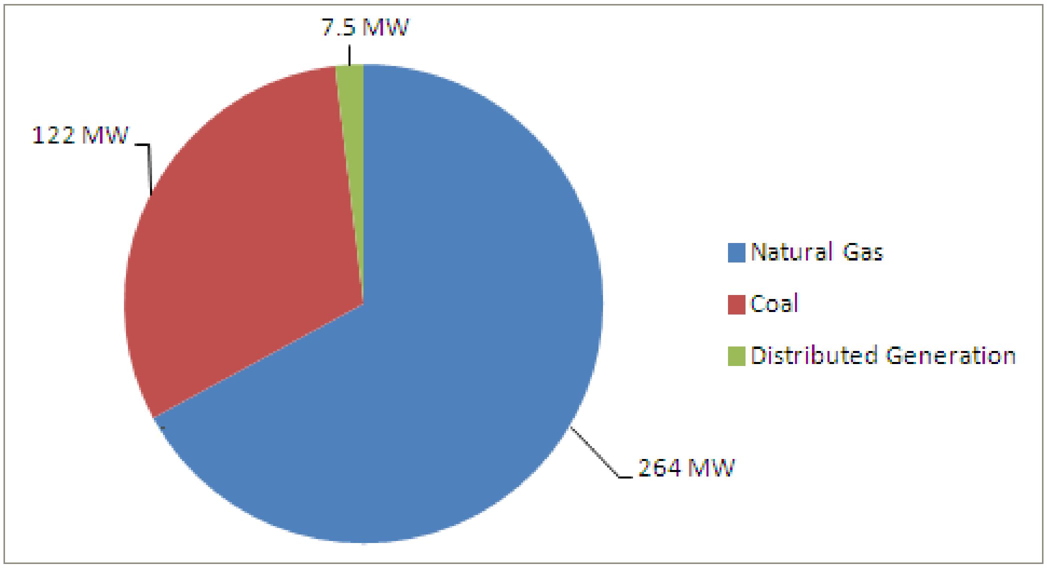
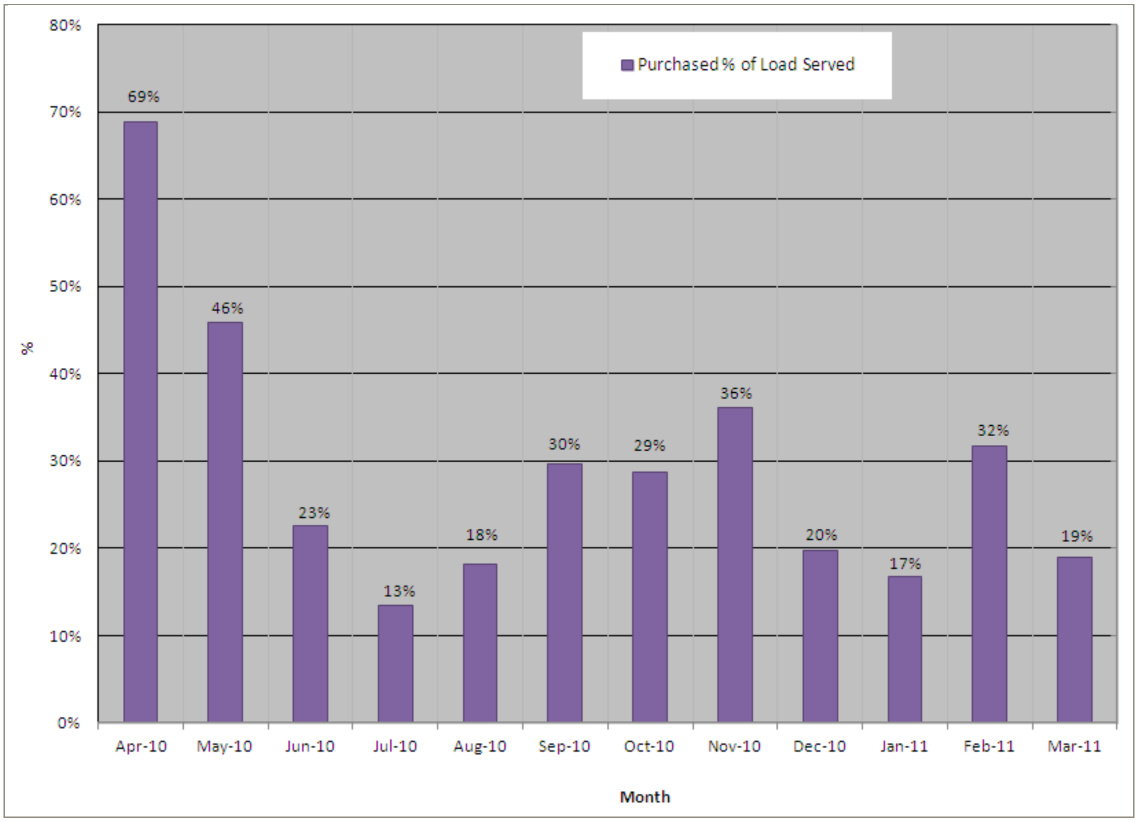


Figure 1-1 Existing BPUB Capacity Mix

[2] Data through March 2011 is the most current data provided by BPUB to Black & Veatch.



(Source: BPUB Marketing Report, March 2011)

Figure 1-2 Proportion of Load Served by Energy Purchases

1.3 STUDY APPROACH

The BPUB IRP approach consisted of several key stages including data collection, data analysis, data modeling, analysis of the findings, and documentation of the study in this report. Black & Veatch utilized data provided by BPUB, supplemented by other sources of information as necessary. Throughout this process, data for non-site specific supply-side alternatives were compiled, reviewed, screened for appropriateness, and modeled using typical power supply study methods and tools. The inputs utilized throughout this IRP are considered reasonable and appropriate for planning purposes, and proper measures were taken by Black & Veatch to maintain internal consistency.

1.3.1 Data Collection

The data collection stage included the compilation and review of both historical and forecast data, based on BPUB's responses to a data request provided by Black & Veatch. In the event that BPUB's was unable to provide requested information, Black & Veatch used reasonable judgment to develop information and assumptions for use in this IRP.

1.3.2 Data Analysis and Modeling

After being collected, the data were analyzed and used as a basis for developing an optimization expansion planning model in Strategist™ to evaluate a variety of alternative expansion scenarios. Strategist™, an optimization expansion planning tool developed and licensed by Ventyx; enables determination of the least-cost plan as well as competing plans within a given set of system parameters and available resources. In developing expansion plans, the model considers the load forecast, existing resources, emissions constraints and allowance prices, fuel prices, cost and performance characteristics of new alternatives, and other factors to estimate the total system cost. The results of the Strategist™ analyses were carried forward to PROMOD™, which allows for development and analysis of more detailed production cost modeling. The PROMOD™ results were used as the basis for the economic analyses presented in Section 8.0 of this IRP. Assumptions regarding the ERCOT market were developed using Black & Veatch's Proprietary Energy Market Perspective ERCOT Spring 2011 data set.

1.4 STUDY FINDINGS

The following conclusions and recommendations can be drawn based on the input parameters, assumptions, and analyses discussed throughout this IRP. A high level summary of the findings is presented first, followed by more detailed conclusions and recommendations.

1.4.1 High Level Summary Findings

- Brownsville is located in a load pocket in the ERCOT grid. As a result of its physical location, at the current time, there is limited available transmission that can be used to bring additional supplies of power into the Brownsville area. As loads grow or resources retire, new generation needs to be located within the Brownsville geographic area unless additional transmission is built into the Brownsville area. While ERCOT is considering building additional transmission into the Brownsville area, to date it has not committed to doing so.
- BPUB's need for new power in the future is small in comparison to the size of the most economical new power plants. Therefore, if new power supplies are to be built in the Brownsville area (i.e., because transmission is not sufficient to bring in power supplies from outside the Brownsville area), then the technology of choice seems to be the Wartsila unit with net capacity of approximately 9.2 MW. These units provide capacity increments that are aligned with the Brownsville need for new power supply. However, smaller units like these are typically more expensive to build and operate than larger units on a per kW and per kWh basis. Alternative, more economical sources of power may be identified through a competitive solicitation (such as a power supply request for proposals, or RFP), as supported by the analysis of the Tenaska Alternative and the Transmission Alternative.

- When BPUB conducts a competitive solicitation for new power supplies, it should require bidders to demonstrate how they plan to deliver the power so that it can be used to serve Brownsville retail loads. Bidders of power from generating units located outside of the Brownsville area will need to discuss transmission needs with ERCOT and/or plan on financing/building the needed transmission themselves and including those costs in their bids.
- Renewable resources (i.e., wind) could be used to help meet BPUB's need for additional power to serve their retail customers. Under an assumption that regulation of emissions of CO_2 will begin adding considerable costs to the burning of fossil fuels in the future, it appears that wind can be added starting in the year 2016 and will be shown to be economic over the life of the wind plant. However, if emissions of CO_2 are not regulated, then the wind may not be economic over its life.
- With respect to impact on Brownsville retail rates in the early years, PROMOD™ analysis indicates that Brownsville could add approximately 33MW (nameplate) of new wind to its portfolio starting in the year 2014 without increasing retail rates by more than 2 percent in that year.

1.4.2 Conclusions

- Expansion of BPUB's demand-side management and energy efficiency program offerings appears to be economic, based on the analysis performed as part of this IRP. Additional study is required to determine optimum program design and implementation strategies for BPUB to consider. Such a study is beyond the scope of this IRP.
- BPUB's existing agreements for natural gas supply appear to provide for adequate and reliable natural gas capacity. However, as additional natural gas fired generating units are added to serve load, BPUB must ensure sufficient natural gas capacity is reserved.
- As demand for natural gas increases through 2035, the Henry Hub natural gas price is projected to double (in real terms). As BPUB's system becomes increasingly reliant on natural gas, the cost of natural gas will have a greater impact on BPUB's cost to serve load.
- The load forecast utilized for purposes of this IRP was developed by R.W. Beck/SAIC in the 2009 timeframe. Coupled with capacity available from BPUB's existing generating resources, BPUB is projected to require approximately an additional 21 MW to maintain target reserve margin requirements in the summer of 2012, increasing to approximately 41 MW in the summer of 2013 and approximately 57 MW in the summer of 2014. By the end of the planning horizon considered in this IRP, BPUB's need for additional capacity to maintain target reserve margin requirements is approximately is approximately 339 MW.

- The results of the economic analyses presented in this IRP indicate that the addition of inlet fogging for Silas Ray Unit 9 is an economic decision.
- The results of the economic analyses presented in this IRP indicate that recommissioning Silas Ray Unit 5 in the 2015 timeframe is an economic decision.
- The economic analyses indicate that the addition of wind energy may be economic for BPUB. However, careful consideration should be given to the impact wind may have on BPUB's transmission system.
- Economies of scale associated with ability to obtain capacity from larger, more economical units than BPUB may be able to pursue/develop without involvement from other utility (or utilities) or developers (i.e. relatively smaller units) are demonstrated by analysis of the Tenaska alternative.
- The Transmission Alternative case indicates that purchasing power from the market to meet system requirements may be more economic than adding generating units sized in proportion to the BPUB system.

1.4.3 Recommendations

- BPUB should continue to monitor program costs and participation levels associated with its GreenLiving program to ensure the program achievements are beneficial to BPUB and its customers.
- BPUB should evaluate the potential benefits of expanding its demand-side management and energy efficiency program offerings through a DSM/energy efficiency potential study.
- BPUB is interested in demonstrating to potential industrial development companies that it has the ability to serve them reliably. Showing the existence of sufficient transmission capacity from the LRGV area to the greater Brownsville area is one way to make this demonstration. If the Public Utility Commission of Texas does not approve the new Cross Valley transmission line, or if ERCOT chooses not to build additional new transmission for speculative loads, BPUB may want to consider building and owning such transmission itself. BPUB may want to study the possibility of building such transmission in advance of the load materializing. If it does so, BPUB may end up owning transmission that is not needed for load. BPUB may have value in owning such a line simply to allow it to import more spot market power and avoid running more expensive generation it owns within its service territory.
- BPUB should continue to monitor ERCOT studies related to transmission capabilities into and out of the Brownsville area, as the ability to import generation from new resources located outside of the Brownsville area is currently limited to approximately 80 MW. Should BPUB pursue power purchase agreements and/or joint ownership opportunities associated with generating resources outside of the Brownsville area, BPUB must ensure that adequate and reliable firm transmission capability is available.

- Increased reliance on natural gas fired generation resources will result in BPUB's cost to serve load becoming more correlated to the cost of natural gas. In recent years and in the near-term, natural gas prices have been and are projected to be at or near historic lows. However, as demand for natural gas increases over the next 20 years, the projected price of natural gas at Henry Hub is projected to double in real terms. In addition, a prolonged disruption in natural gas supplies will have an increasingly adverse impact on BPUB's ability to serve load. As such, BPUB should give consideration to making its resource decisions based in part upon a risk analysis that considers the impact of increasing natural gas prices on its generation expansion planning.
- It is recommended that analysis focus on the availability and cost of contractually or operationally firm pipeline capacity sufficient to provide for the proposed available generation capacity. Supply is abundant and will become even more abundant during the forecast horizon as the Eagle Ford Shale resources are developed. Pipeline capacity development may not keep pace with supply development.
- BPUB should evaluate the possibility of alternative transporters and suppliers of natural gas to the Hidalgo and Silas Ray sites, as outlined in more detail in Section 2.4.7 of this IRP.
- When gas-fired resources are considered in alternative locations, such as at the Port of Brownsville and Site FM511, it is strongly recommended that the availability of favorable pipeline capacity with the ability to accommodate future expansion be considered as a major component in the site ranking and selection.
- The load forecast used in this IRP was developed by R.W. Beck/SAIC in the 2009 timeframe, and resulted in projected summer peak demand growing at an average annual rate of approximately 3.4 percent, and annual energy requirement growing at approximately 3.3 percent. Given the vintage of this load forecast and the current state of the economy, consideration should be given to evaluating resource planning decisions in light of sensitivities to these projected growth rates.
- BPUB has indicated the possibility of a relatively large industrial load being added in the near-term. Such a load addition would represent a significant step increase in both peak demand and annual energy requirements, and would likely affect the determination of the most cost-effective near-term resource additions. BPUB should consider evaluations to gauge the impact of such a potential large load addition on both its generation and transmission planning efforts.
- BPUB should continue to explore recommissioning Silas Ray Unit 5, as doing so appears to be a cost-effective source of reliable capacity. Analysis of details related to the recommissioning process (including permitting requirements) was beyond the scope of this IRP.

- The addition of inlet fogging on Silas Ray Unit 6/9 appears to be an economic source of incremental capacity that may be available to the BPUB system in the near-term, and as such may warrant further consideration.
- As BPUB continues to explore the addition of wind energy, additional study may be appropriate in order to better evaluate the impact that wind may have on operations of BPUB's conventional generating units and on BPUB's transmission system.
- The Reference Case is intended to be illustrative of an expansion plan that economically meets BPUB's projected capacity and energy requirements through the addition of new generation resources that are sized to be consistent with BPUB's project load growth and ability to pursue or develop without involvement from other utility (utilities) or developer (i.e. relatively smaller units). Stated otherwise, larger units that may offer economies of scale, such as a 300 MW 1x1 combined cycle, were not included in the Reference Case analysis as the capital requirements are considered to be in excess of what BPUB could absorb into its system without experiencing significant increase in rates. The opportunity to participate as a joint owner in such a unit, and the opportunity to enter into contracts for firm capacity and energy in the form of a power purchase agreement (PPA), should be pursued through a RFP process subsequent to completion of this IRP. Potential economic advantages of such opportunities have been illustrated in this IRP through the evaluations of the Tenaska Alternative and the Transmission Alternative. The RFP should also allow for proposals involving renewable generating resources. Offers received through the RFP should be evaluated based not only on economics, but reliability and contributions to fuel diversity as well.
- When soliciting and evaluating proposals as part of the RFP process, proper consideration should be given to transmission system constraints to ensure the ability to secure firm delivery of power into the Brownsville system.
- While the Tenaska Case, Modified Tenaska Case, and Transmission Case may be economic compared to the Modified Reference Case, there are other considerations to keep in mind. Since BPUB initially needs about 100 MW of capacity from the unit, this commitment from BPUB will likely not be sufficient to drive development of the proposed Tenaska unit. Therefore, it is recommended that BPUB consider the likelihood of the unit being constructed as proposed. In addition, increasing capacity allocation from single unit (i.e Tenaska) leads to increased reliability risk as outage of the unit would have impact on BPUB's ability to serve customer requirements and the cost to do so. For power generated outside of BPUB's service territory, BPUB needs to ensure firm delivery of power is available to meet BPUB's system requirements.

- In addition to the relative economics discussed previously, there may be advantages realized in the Brownsville community associated with development of a unit such as that proposed by Tenaska. Such benefits may include job creation during construction and operation of the unit, property tax revenue for the portion of the proposed unit owned by taxable entities, stimulus to local economy during construction phase, increased local generation resource that may increase system reliability as compared to relying on imported power. Further, a new, relatively large and efficient source of generation may be viewed as attractive by industries considering locating in the Brownsville area.

1.4.4 Suggested Action Plan

- BPUB should continue to monitor and support development of new transmission projects that will impact BPUB's resource planning efforts.
- BPUB should consider issuing a power supply RFP to further evaluate feasible, cost-effective alternatives to meeting capacity needs.
  - BPUB is projected to require additional capacity to satisfy reserve margin requirements beginning in summer 2012. . New generating units cannot be built in this timeframe, and therefore the RFP should solicit proposals to provide power as quickly as possible.
  - BPUB may consider breaking down the RFP to solicit proposals for near-term (i.e. 2013 through 2015) and subsequent periods.
  - The proposed RFP should allow for conventional and renewable power supply proposals.
  - The proposed RFP should allow for power purchases as well as equity interest proposals
  - As part of the RFP process BPUB should include a criteria in the RFP for bidders to demonstrate ability to deliver power to BPUB service territory
  - BPUB should evaluate bids received in response to RFP and make recommendation for future power supply
  - BPUB should consider factors such as socio-economics, reliability, and other non-price factors while evaluating the RFP
  - BPUB should consider to develop a 2-5 year action plan around RFP evaluation results
- BPUB should consider looking at different futures in an analytical fashion based on "scenario" analysis, using a fundamentally based approach to develop the linkage between variables. Best practices for resource plan include consideration of sensitivities, scenarios, and risks, as appropriate Such an analysis is beyond the current scope of this IRP.

- BPUB should review, analyze, and rank competitive alternatives for gas pipeline capacity, including conducting meetings with competing pipelines to discuss future gas requirements.

2.0 Description of Existing System

BPUB provides reliable and economical electric services to approximately 46,000 residential, commercial, industrial, and municipal customers. BPUB maintains ownership in three power plants fueled by natural gas (Silas Ray and Hidalgo Energy Center) and coal (Oklaunion), as well as distributed generating resources. The BPUB electrical distribution system consists of approximately 1,200 miles of transmission and distribution lines. In addition, BPUB offers its customers the opportunity to participate in various demand-side management (DSM) and energy efficiency (EE) programs.

The remainder of this section provides more detail related to BPUB's existing generating system and DSM/EE programs, and provides an overview of BPUB's existing transmission system and associated reliability considerations. This section also includes discussion of the limitations of natural gas supply and delivery to BPUB's existing natural gas fueled generating resources.

2.1 EXISTING CONVENTIONAL GENERATION RESOURCES

BPUB owns and operates the Silas Ray Power Plant (Silas Ray) in West Brownsville, Texas. Silas Ray consists of two natural gas fired units that are currently operating - a simple cycle unit (Unit 10) and a combined cycle unit (Unit 6/9). Silas Ray Unit 5, a simple cycle steam unit, was taken out of operation in 2005. As part of this IRP, recommissioning of Silas Ray Unit 5 has been evaluated (refer to Section 6.2 for more information on this alternative).

In addition to owning and operating generating resources at Silas Ray, BPUB owns 21 percent of the natural gas fired Hidalgo Energy Center, a 2x1 combined cycle located in Edinburg, Texas and owns 10 percent of the coal fired Oklaunion unit in Wichita Falls, Texas. BPUB also has 7.5 MW of distributed generation capacity. BPUB's total existing summer capacity is approximately 339.5 MW, and the generating resources are summarized in Table 2-1.

Table 2-1 Existing Generating Units

PLANT	UNIT	MAXIMUM CAPACITY (MW)	PRIMARY FUEL	COMMERCIAL ONLINE DATE	FULL LOAD NET PLANT HEAT RATE (MMBTU/ MWH - HHV)	SCHEDULED OUTAGE RATE (HR/YR)	FORCED OUTAGE RATE (%)	SO_2 EMISSIONS RATE (LB/MMBTU)	NO_X EMISSIONS RATE (LB/MMBTU)	CO_2 EMISSIONS RATE (LB/MMBTU)
Silas Ray (Combined Cycle)(1)	6/9	55.0	Natural Gas	1996	9.117	2,945	3.00	0.0006	0.0474	118.9
Silas Ray (Simple Cycle)(2)	9	33.0	Natural Gas	1996	13.096	920	2.00	0.0006	0.0474	118.9
Silas Ray	10	50.0	Natural Gas	2004	9.192	346	3.00	0.0005	0.0214	118.9
Silas Ray	5	21.0	Natural Gas	2014	13.000	336	3.00	0.0005	0.0214	118.9
Hidalgo Energy Center	N/A	105.0	Natural Gas	2000	7.013	336	5.00	0.0006	0.0072	118.0
Oklaunion	1/2	122.0	Coal	1986	10.447	912	12.50	0.2200(3)	0.3385	211.8(4)
Distributed Generation	N/A	7.5	DFO	2001	9.000	420	3.62	0.0407	3.2210	155.0

(1)Units 6 and 9 operated in combined cycle mode.
(2)Unit 9 operated in simple cycle mode.
(3)Changes to 0.014 in 2016.
(4)Changes to 212.4 in 2016.

2.2 EXISTING DSM PROGRAMS[3]

Like many other public utilities in Texas, BPUB has taken steps to promote energy conservation. In October 2011, BPUB introduced the *GreenLiving* program, which is a comprehensive residential and small business rebate program that provides incentives to BPUB's customers for both energy efficiency and water conservation efforts. The energy efficiency measures and corresponding incentives offered as part of the GreenLiving program are summarized in Table 2-2.

Table 2-2 BPUB GreenLiving Program Rebates

MEASURE DESCRIPTION	INCENTIVE SUMMARY	BUDGET (OCT 1, 2011 – SEPT 30, 2012)
HVAC (Heating, Ventilating and Air Conditioning)*	Up to $600 for qualifying units	$50,000
Duct Flow Performance	A rebate of 25% of cost to replace or repair, up to $500	$20,000
Solar Screens and Films	$0.50 per square foot installed	$1,800
ENERGY STAR Windows	30% of invoice, up to $500	$20,000
Radiant Barrier	$0.40 per square foot installed; up to $500	$20,000
ENERGY STAR Water Heaters	Capacity of 50 gallons or less qualify for $100 rebate Capacity over 50 gallons will qualify for $200 rebate	$12,000
WaterSense High Efficiency Toilets	$50 rebate per toilet; limit three toilets per customer	$4,000
Attic/ Ceiling Insulation	Up to $500	$16,000
New Homes Program	$300 per ENERGY STAR Home: Version 2.0** $500 per ENERGY STAR Home: Version 2.5** $150 Additional Premium for Version 3.0 $30 to HERS rater	$50,000
Promotion Related Expenses		$71,200
Total		**$265,000**

*This program has been available since September 2010.
**Home must be completed & certified by 12/31/2011

[3] Information on BPUB's existing DSM and EE programs is also included in Section 7.0 of this IRP to allow for simplified reference.

BPUB's air conditioning rebate program has been offered since September of 2010. The first reported results of this program are presented in Table 2-3.

Table 2-3 BPUB Air Conditioning Rebate Program Results

SEPTEMBER 2010 – DECEMBER 14, 2011	
Total Customer Participation	65
Total Number of EE A/Cs Installed	75
Average Tonnage	3.4
Average SEER	16.2
Total Amount Rebated to Customers	$32,150
Total Amount Paid to Raters	$6,875
Total Amount Given Back to the Community	$39,025

In addition to the incentivized program offerings, BPUB has educational tools available to both its residential and commercial customers - *Home Energy Suite* and *Commercial Energy Suite*. These tools, which can be accessed via the Internet, provide self-help resources on energy conservation. The Energy Suite includes the following:

- Residential:
  - **Interactive Energy Home** is designed to help customers understand where and how energy is used in the home, and how to use it wisely.
  - **The Home Energy Calculator** provides quick estimates of customers' home's current energy-use costs.
  - **Lighting Calculator** calculates how much money can be saved by switching from standard bulbs to compact fluorescent lights.
  - **Appliance Calculator** provides down-to-the-penny energy operating costs for more than 50 different home appliances and electronic devices.
  - **Television Calculator** compares the energy use and cost of LCD, DLP, plasma, and traditional tube televisions.
  - **Home Energy Library** provides information related to home design and construction techniques and the latest in energy-efficiency equipment and appliances.
  - **Kids Korner** provides colorful, interactive energy information and games.
  - **Fundamentals of Electricity** presents the basics of electricity step by step - from power generation and energy delivery to electrical safety.

- Commercial:
  - **The Commercial Energy Calculator** provides quick, detailed estimates of energy use costs for customers' business facilities, and allows for comparison to other businesses. More than 60 different business types modeled.
  - **The Commercial Energy Library** contains thousands of pages of information in a format designed to make the information interesting and easily accessible.
  - **The Understanding Demand** tool assists business customers in understanding the two distinct components to their electric bill: electricity demand and electricity usage.

2.3 BPUB TRANSMISSION SYSTEM OVERVIEW

Brownsville is connected to the rest of the Texas/Electric Reliability Council of Texas (ERCOT) grid by transmission. As detailed in more depth below, ERCOT has adopted plans to improve the transmission connection from north of the Lower Rio Grande Valley (LRGV) by building new transmission to the western edge of the LRGV. However ERCOT has not yet decided to build new transmission from the LRGV into the greater Brownsville area (although they plan to study that possibility). Therefore, BPUB currently should assume that the existing transmission constraints from the LRGV into the greater Brownsville area will be binding for some time period into the future. There is currently about 600 MW of transmission capacity from the LRGV into the greater Brownsville area. However, much of this 600 MW is already required to move certain power including moving power from BPUB's shares of the Oklaunion and Hidalgo power plants into that area. Further, additional amounts of the transmission are needed to serve the firm loads of other load serving entities in the greater Brownsville area. Currently there is about 80 MW of transmission capacity available above current requirements, but as load grows in the Brownsville area, this 80 MW of transmission capacity will be reduced due to the need to purchase energy and capacity from the ERCOT market, unless new generation is built in the greater Brownsville area. Unless ERCOT agrees to increase the transmission capacity from the LRGV into the greater Brownsville area, BPUB has limited ability to access additional power from outside the greater Brownsville footprint. Therefore, this IRP has assumed that BPUB will need to live with the current transmission capacity between LRGV and the greater Brownsville area. The IRP assumption is that BPUB will be able to use 50 MW of the remaining import capacity for spot market purchases, but that any new firm supplies that BPUB will need to acquire to meet its planning reserve targets or renewable targets will need to be located in the greater Brownsville area. When BPUB goes out for bids for new supplies, it is recommended that BPUB indicate to bidders that BPUB will only consider bids from power plants located outside the greater Brownsville area if the bidder can demonstrate the ability to deliver the power on a firm basis.

As a separate matter, if ERCOT does not decide to build new transmission from the LRGV to the greater Brownsville area, BPUB may want to consider building such transmission itself. In that case, Black & Veatch would recommend BPUB perform a separate study to assess the benefits, costs and risks of investing in such transmission.

2.3.1 Existing Transmission System

Brownsville is located at the southernmost tip of Texas. Although there are three (3) electric utilities that have service areas in Brownsville and surrounding areas, the bulk of the electrical service inside the city is supplied by BPUB. The other major electric service providers are:

- American Electric Power – Texas Central Company (AEP-TCC).
- Magic Valley Electric Cooperative (MVEC) of Texas.

BPUB currently distributes power through more than 50 miles of transmission lines, and owns and operates 14 electric substations throughout its service area, plus the substations at the Silas Ray Power Plant. The BPUB transmission system has been upgraded from 69 kV to 138 kV with the exception of one radial circuit serving an industrial substation.

The ERCOT planned and operated transmission grid includes four 138 kV lines that move power from the LRGV to the greater Brownsville area. These lines bring in power to BPUB from their contracted rights to the Oklaunion and Hidalgo power plants. The lines are also used to deliver power to the other two utilities in the greater Brownsville area. In addition, there is generally some reserve capacity to bring in spot market power to the area. The BPUB system is currently interconnected with ERCOT operated transmission lines (American Electric Power –AEP owned lines) in the greater Brownsville area at two locations, both of which are rated at 138 kV, and has two substations connected directly to an AEP transmission line. BPUB's interconnection capacity with AEP is 400 MVA and the two substations have a capacity of 45 MVA. AEP has constructed a 138 kV transmission line around the north side of the City to interconnect the two 138 kV ties which AEP has with the BPUB. This 138 kV line improves the overall reliability of BPUB's transmission interconnections to the ERCOT grid by providing an alternative feed to each of BPUB's 138 kV interconnection points. While the transmission system currently meets ERCOT transmission reliability criteria, BPUB may be, and has been, subjected to curtailments.

Presently whenever BPUB's local generation is out of service, either scheduled or forced, there are limited generation re-dispatch options available to ERCOT and an increased potential for load shedding in preparation for the next transmission contingency. Weather and non-weather events have left the system extremely vulnerable to a Brownsville city-wide blackout for several hours while relying on electric power deliveries from Silas Ray generation and minimal remaining useful transmission infrastructure.

The ERCOT planned and operated transmission grid needed to provide reliable service to the Brownsville area can be viewed in two steps. The first step is the ability of ERCOT to reliably provide power from its main Texas grid to the four counties making up the LRGV. The LRGV area is located at the southernmost portion of the ERCOT region of Texas along the international border with Mexico and includes the cities of Edinburg, McAllen, Harlingen, and Brownsville. The area has experienced high population and economic growth and consequently high electric load growth rates. Currently, the load is primarily served by local natural gas generation and power imports from the rest of the ERCOT system. The local generation consists of three combined cycle natural gas plants (approximately 1,592 MW total capacity) located on the west side of the LRGV, the Silas Ray plant (approximately 116 MW total capacity) located on the east side of the LRGV in Brownsville, and the Falcon hydro-electric plant (approximately 36 MW total capacity) located west of the LRGV area. Additionally, there is a 150 MW direct current tie with the Mexico CFE system located at the Railroad substation on the west side of the LRGV. The LRGV area is able to import power via three 138 kV lines and two 345 kV lines. The two 345 kV lines are the Lon Hill-Nelson Sharpe-Ajo-Rio Hondo 345 kV line and the Lon Hill-North Edinburg 345 kV line.

2.3.2 Recent Studies of Transmission Reliability

ERCOT has recently completed a study of its ability to get power to the LRGV[4]. In conducting that study, ERCOT examined whether a plan to build a line all the way to Brownsville would be the preferred alternative. As a preliminary determination, ERCOT concluded that a plan to first build new transmission to the western edge of the LRGV would be an appropriate first step, and then a later study would be done to see if/when additional transmission from the LRGV into the Brownsville area should be built. ERCOT has made a decision to build a new 345 kV line into the western edge of the LRGV.

The recent ERCOT approved LRGV reinforcement project provides another 345 kV transmission line into the four county area of Southern Texas, but does not solve a potential problem getting all the way to Brownsville. Sharyland and BPUB performed their own study to analyze the ability to deliver power into and out of Brownsville[5]. That study suggested additional 345 kV transmission should be built from Harlingen to Brownsville and from the Edinburg/ Frontera area (to the east of Brownsville) to Brownsville. Both of these new 345 kV lines would terminate at a new Loma Alta 345 kV bus in the Brownsville area.

A key assumption in the Sharyland/BPUB transmission study was an assumption that a new 250 MW load would appear in Brownsville (modeled as connected to the new 345 kV Loma Alta bus). Also, the Sharyland/BPUB study apparently assumed that the entire Silas Ray project (Units 5, 6, 9 and 10) were out of service and that there was a transmission line out of service. With this potential new load and the Silas project out of service entirely and a 138 kV line out of service, all the load in the Brownsville area cannot be served. Sharyland and BPUB have proposed that ERCOT build the two new 345 kV lines to Brownsville.

[4] The *ERCOT Independent Review of the AEPSC Valley Import Project (Laredo to Lower Rio Grande Valley 345 kV Project) Version 1.1*, revision dated September 9, 2011.
[5] The *Cross Valley Brownsville Loop* study, dated April 11, 2011.

When ERCOT performed its study of the need to reinforce the LRGV (the study that resulted in a decision to move forward with the new 345 kV line to the western edge of the LRGV), the new 250 MW load in Brownsville (assumed in the Sharyland/BPUB study) was not included. As recently as August of 2011, ERCOT members did not come to a consensus about the assumption to include the 250 MW load addition at Brownsville (Loma Alta). Also, for the ERCOT study above, Silas Ray Unit 5 (10 MW) was turned off in the model for the extent of the analysis because it was decided to not count on the availability of this unit to solve the local reliability constraints for the timeframe of this study due to its age (approximately 60 years) and technology (small gas steam, non-reheat). However, Silas Ray Unit 6 (22 MW), Unit 9 (33 MW) and Unit 10 (50 MW) were all apparently turned on.

ERCOT will soon be taking up a formal review of the Sharyland/BPUB study. ERCOT will further consider the 250 MW new load assumption while performing the independent review of the Sharyland and BPUB Cross Valley 345 kV Project.[6]

It appears that no one has studied the ability of the ERCOT controlled transmission grid to serve Brownsville if the 250 MW load is not included. Inclusion of that 250 MW load in transmission studies at this point is somewhat controversial. Further, no one appears to have studied the ability of ERCOT to serve Brownsville with some of the Silas Ray units turned on. ERCOT will investigate these matters when ERCOT reviews the Sharyland/BPUB study.

2.3.3 IRP Modeling of Transmission Constraints

For purposes of the IRP analysis, it has been assumed that the new 345 kV line into the LRGV is completed. That will allow showing an ERCOT buy/sell spot market in the LRGV area since the new line will essentially eliminate any material congestion in getting from Southern ERCOT zone to LRGV. In addition, the IRP analysis will assume that no new line is built from LRGV to the greater Brownsville area. As a result, the IRP modeling topology will assume that only 50 MW of spot market import capacity is available to BPUB.[7]

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[6] Discussion between Black & Veatch and ERCOT transmission planning personnel indicated this study was underway at the time this IRP was prepared.

[7] The actual physical location of the Oklaunion and Hidalgo power plants is outside the Brownsville area and uses the existing 138 kV line capacity from LRGV to Brownsville for delivering the power to BPUB retail loads. For purposes of modeling, appropriate modeling results can be developed by modeling the Hidalgo and Oklaunion plants as if they were located in the Brownsville zone and reducing the 400 MW of import capacity from LRGV by the nameplate capacity of these plants. In addition, the 400 MW import capacity is further reduced in the modeling to reflect the rights of other utilities in the greater Brownsville area to import power over those lines. These lines can also be used for export purposes. For purposes of the modeling, it has been assumed that the maximum amount of export (i.e., spot market sales) is limited to 200 MW. The 200 MW limitation reflects both limits of existing transmission lines and limits on the depth of the market at the prices assumed for the power.

The IRP analysis will assume that there are no wheeling or losses charges related to bringing Oklaunion or Hidalgo or spot market power into the Brownsville area. This assumption is being made for two reasons. First, the ERCOT transmission grid usage charge is based on an locational marginal price (LMP) market, where the difference in LMPs between two nodes reflects the congestion charge and losses charge to move power between those two points. As such, the wheeling and losses charge is constantly changing. It would be possible to research historical LMPs at appropriate points to see what historical congestion and losses charges have been, but that effort is outside the scope of the IRP engagement. Further, with the building of the new 345 kV line into the LRGV area, the historical LMPs are likely not to be indicative of future LMPs. Future congestion and losses should be lower with the new line.

For purposes of dispatching the Oklaunion and Hidalgo projects, the IRP analysis will assume these resources are dispatched at their incremental cost. The spot market price assumption used in the IRP analysis will be the forecast spot market price for the Southern ERCOT zone. This assumption is a reasonable approximation of how Oklaunion and Hidalgo will actually be bid into the ERCOT market.

2.3.4 Additional IRP Analysis Based on Recent Development

On January 17, 2012, BPUB and Sharyland Utilities jointly announced that ERCOT's Board of Directors had unanimously voted to endorse the Cross Valley 345kV Line Project; the project still requires approval by the PUCT) before construction can begin. If approved by the PUCT, and constructed as scheduled, the Cross Valley project will increase reliable import capability for BPUB

BPUB is interested in demonstrating to potential industrial development companies that it has the ability to serve them reliably. Showing the existence of sufficient transmission capacity from the LRGV area to the greater Brownsville area is one way to make this demonstration.

To provide an indication of how increased import capability may influence BPUB's generation resource planning decisions, Black & Veatch evaluated the economics of an expansion plan in which BPUB was able to purchase power from the market based on the assumption that transmission would be in place such that import capability is increased by 100 MW.

If the Cross Valley project does not get the required approval from the PUCT, then BPUB may want to consider building and owning such transmission itself. BPUB may want to study the possibility of building such transmission in advance of the load materializing. If it does so, BPUB may end up owning transmission that is not needed for load. BPUB may have value in owning such a line simply to allow it to import more spot market power and avoid running more expensive generation it owns within its service territory. BPUB may want to consider analyzing this possible future in this IRP via an expanded scope.

2.4 ANALYZE NATURAL GAS SUPPLY LIMITATIONS

2.4.1 Overview of Natural Gas Supply and Delivery Capacity

This section addresses the limitations of natural gas supply and delivery capacity to BPUB's existing natural gas-fueled resources, and the potential impacts on integrated resource planning. The section includes a summary of the hourly and daily rates of natural gas consumption required to operate the plants at full capacity; review of the gas supply and delivery contracts to establish BPUB's rights to purchase and deliver gas to the plants; projected natural gas supply and demand, including new gas sources of supply such as the Eagle Ford shale; identification of potential limits on the potential planning alternatives based on natural gas issues; and identification of fuel supply and delivery alternatives recommended for further study.

Figure 2-1 and Figure 2-2 show the intrastate and interstate pipelines of South Texas, along with the BPUB natural gas-fired resources (Silas Ray in Cameron County and Hidalgo Energy Center in Hidalgo County). Also shown are the general locations of some of the significant market pricing points for this region. Figures 2-3 and 2-4 show natural gas pipelines in Cameron County and Hidalgo County, respectively. Additional information related to pipelines for each county is presented in Appendices A through C of this report.

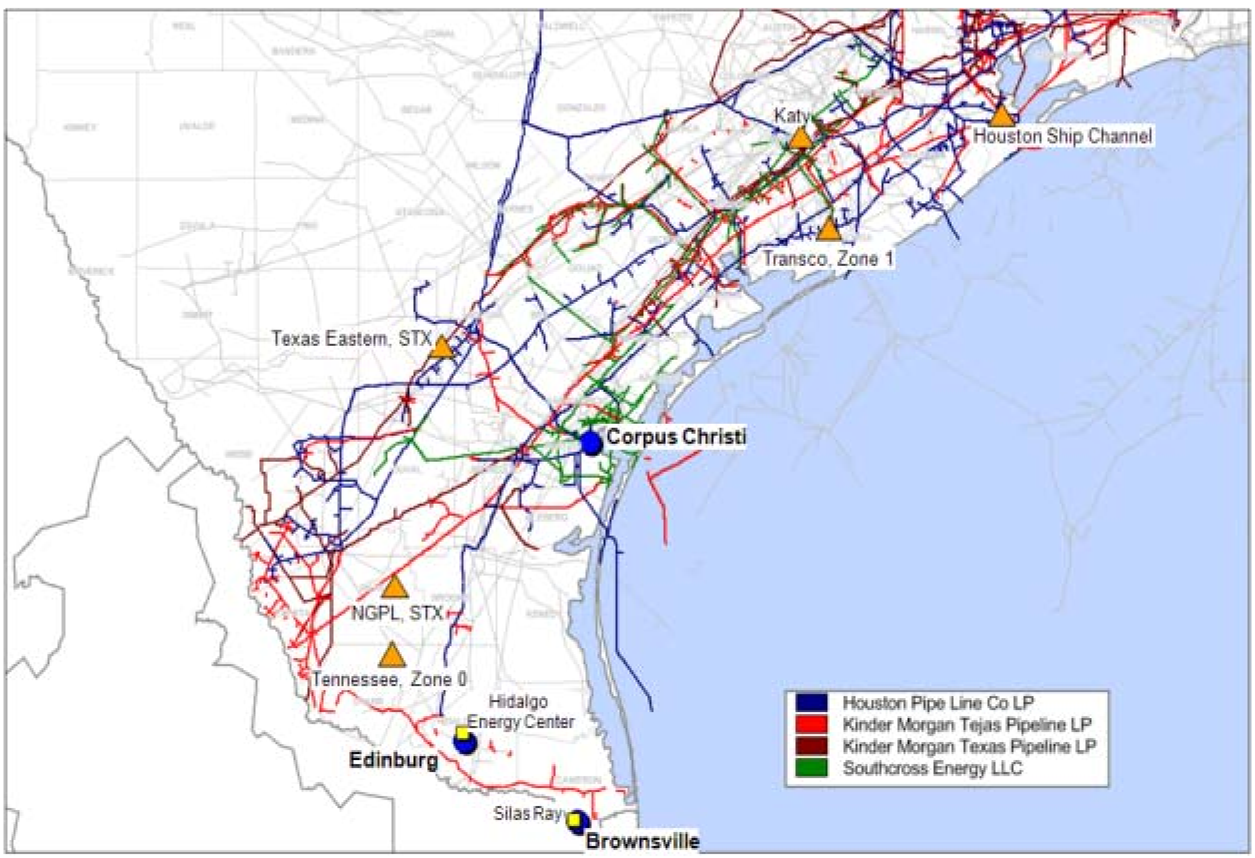


Figure 2-1 South Texas Intrastate Pipelines

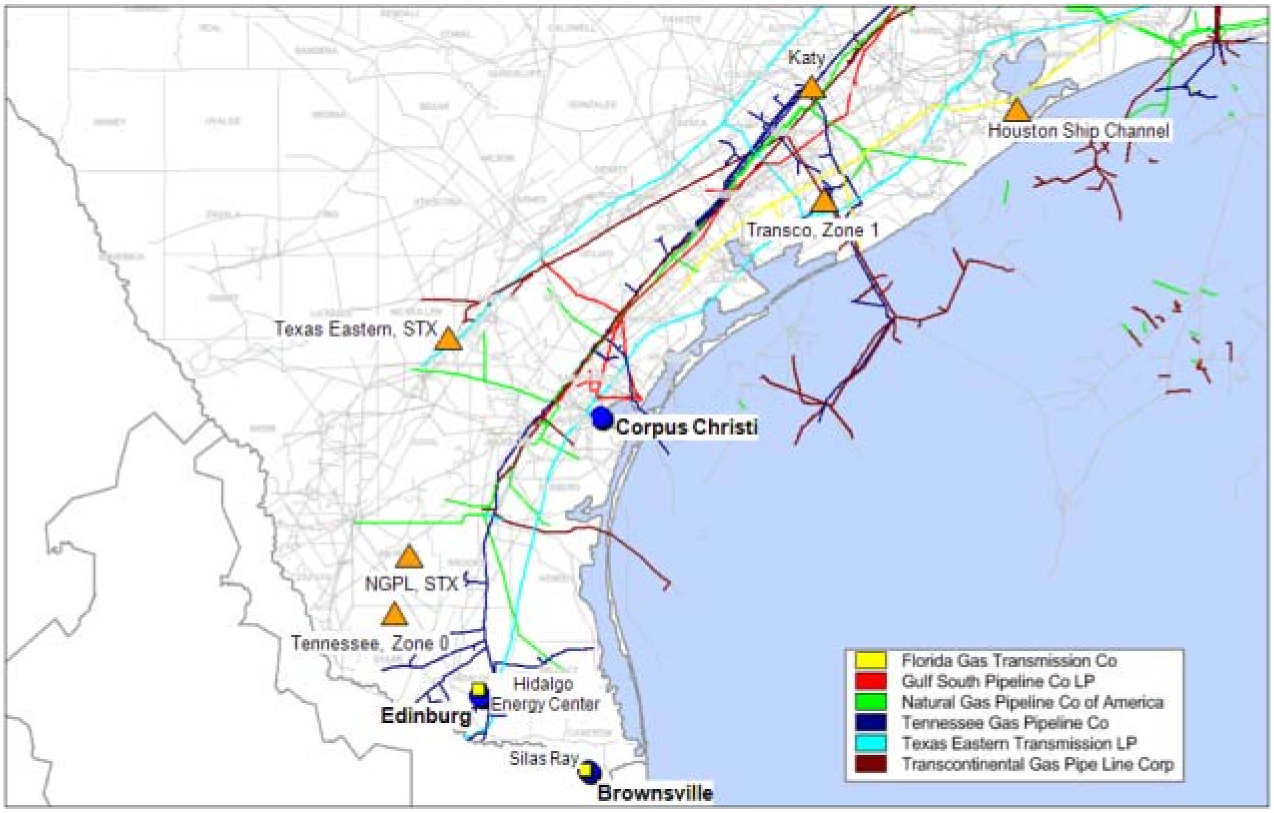


Figure 2-2 South Texas Interstate Pipeline Capacity

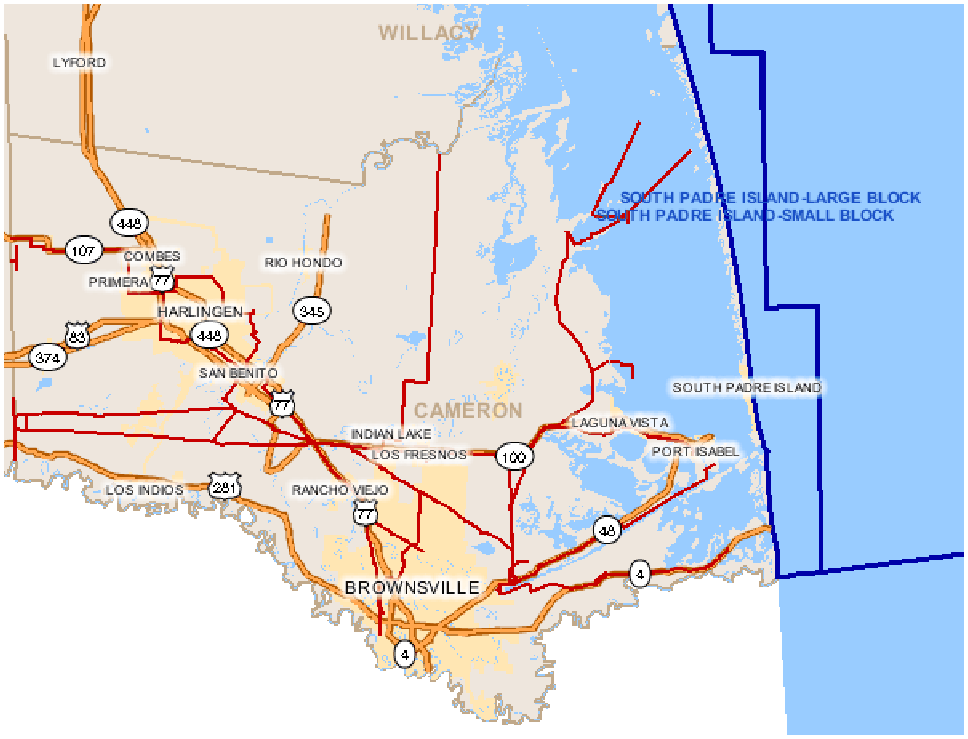


Figure 2-3 Major Pipelines in Cameron County (Source: Texas Railroad Commission)

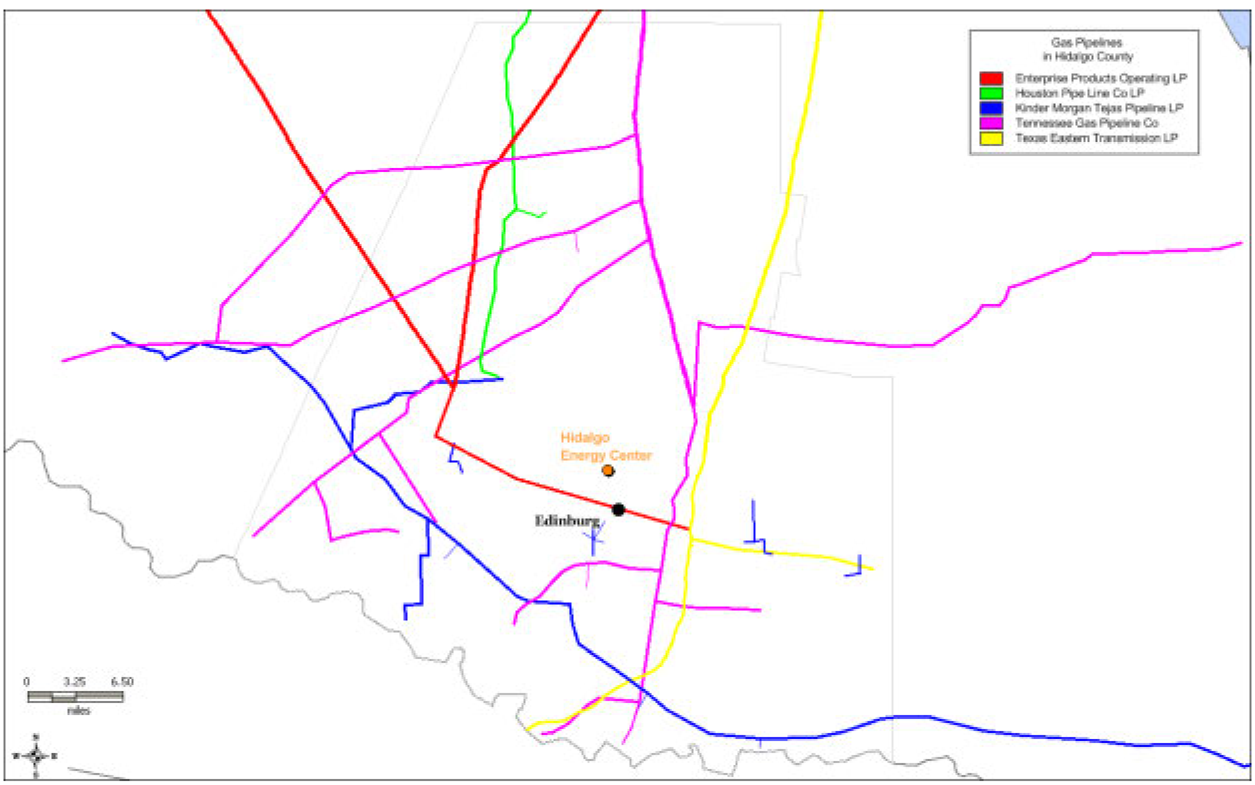


Figure 2-4 Major Pipelines in Hidalgo County (Source: Energy Velocity)

2.4.2 BPUB's Natural Gas Requirements

Table 2-4 summarizes the hourly and daily natural gas requirements at the two existing plants in which BPUB maintains ownership interests.

Table 2-4 Gas Consumption for the Silas Ray and Hidalgo Plants Based upon Available Capacity (Summer and Winter) and an Average Heat Rate (Sources: BPUB, April, 2011, and Energy Velocity)

UNIT	HEAT RATE (HHV) BTU/KWH	AVAILABLE CAPACITY		GAS CONSUMPTION		GAS CONSUMPTION	
		KW	KW	MMBTU/HOUR		MMBTU/DAY	
		WINTER	SUMMER	SUMMER	WINTER	SUMMER	WINTER
SILAS RAY – 100% BPUB OWNERSHIP							
6/9	8,924	64,000	55,000	491	571	11,780	13,707.26
10	9,330	50,000	50,000	467	467	11,196	11,196.00
Total		114,000	105,000	957	1,038	22,976	24,903.26
HIDALGO - 21% BPUB OWNERSHIP							
Total	7,304	518,000	470,000	3,433	3,783	82,389	90,803
Source: BPUB, Energy Velocity							

2.4.3 BPUB's Current Natural Gas Contracts

2.4.3.1 Silas Ray Facility

BPUB purchases natural gas for this facility from Tenaska Marketing Ventures (Tenaska). Table 2-5 summarizes the key features of the Tenaska natural gas supply contract.

Table 2-5 Tenaska Marketing Ventures Transaction Confirmation for Gas Supply to Silas Ray

[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		

BPUB purchases natural gas delivery services from Texas Gas Services (TGS) to deliver natural gas from the Tenaska contract's delivery points on the Enterprise Texas Pipeline to Silas Ray. Table 2-6 summarizes the delivery arrangements from Enterprise to the Silas Ray plant.

Table 2-6 Key Features of the BPUB Agreement with Texas Gas Services for Delivery to Silas Ray Facility

KEY FEATURES			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

2.4.3.2 Hidalgo Energy Center

BPUB has a Scheduling and Fuel Management Agreement with Calpine Energy Services, L.P. (Calpine Agreement) to provide fuel to Hidalgo Energy Center. Table 2-7 and Table 2-8 provide a summary of pertinent features of the Calpine Agreement.

Table 2-7 Pertinent Features of the Calpine Agreement

FEATURES OF CALPINE AGREEMENT			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Table 2-8 Total Quantity of TETCO Firm Capacity, Hidalgo Energy Center (Based on Calpine Agreement, Exhibit 2)

MONTH	TOTAL QUANTITY OF TETCO FIRM (MMBTU/D)	BPUB SHARE (21.47%)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

2.4.4 Potential Constraints Related to Resource Assessment and IRP

Based upon a review of the contracts summarized in the previous sections, the potential constraints are all related to the availability and service quality (firmness) of pipeline capacity. The contracted pipeline capacity terms are more favorable at Hidalgo Energy Center than at Silas Ray, but in both cases, appropriate planning and comparison of alternatives will likely resolve potential limitations and allow new gas-fired resources to be evaluated, if such a choice is made. However, in some cases, additional costs will likely be required, and such costs should be estimated and included in the resource assessment. The estimate of the additional costs for any required additional pipeline capacity is an appropriate subject for follow-up work.

2.4.4.1 Hidalgo Energy Center

The Calpine Agreement provides for highly reliable pipeline delivery for the current plant capacity. Key components of the reliability include:

- [redacted]

- [redacted]

An assessment of additional gas-fired resources at Hidalgo would require evaluation of the Calpine Agreement and its delivering pipeline (Texas Eastern), and of the plant lateral, to handle a significant increase in gas volumes. If future capacity is limited on Texas Eastern, other interstate and intrastate pipelines could be considered. Such an evaluation would consider how much firm capacity upstream of the plant lateral would be needed (hourly and daily maximum rate, by month), and a review of future cost-effective sources of gas and routes of delivery, to the plant lateral. Alternatives for supply and capacity would be compared and ranked for reliability and low cost. Calpine fuel management would be a significant asset in such an evaluation. With adequate planning and comparisons of alternatives, with their associated costs, there would be little if any constraint related to natural gas in resource assessment at Hidalgo.

2.4.4.2 Silas Ray Facility

There are several potential constraints on the planning of new gas-fired resources that require additional evaluation:

- The supply is firm from Tenaska, but is subject to availability of interruptible pipeline capacity on Enterprise Texas intrastate pipeline, therefore the supply delivery to TGS is not contractually firm. According to BPUB fuel staff, this gas supply has not been curtailed in the last 5 years. For a quantitative forecast, evaluation would consist of a fundamental supply-demand modeling of utilization on Enterprise Texas under a range of demand scenarios, discussions with Enterprise Texas as to the availability of firm or interruptible capacity on their system, and discussions with Tenaska as to their plans and capabilities to deliver future incremental gas volumes on a firm basis.
- The delivery of gas from Enterprise Texas to the plant on TGS is also interruptible, but has not been curtailed in five years. Evaluation would consist of modeling of utilization of the TGS system, and discussions with TGS as to the availability of interruptible capacity on their system. (Firm service is reportedly not available on TGS.)
- The Max Delivery Quantity on TGS is 25,000 MMBtu/d, adequate for the current plant available capacity; evaluation would consist of analysis of TGS's system, and discussions with TGS staff to determine the availability of additional capacity. If capacity is constrained, a cost estimate to expand the TGS system could be developed as part of the resource planning study.
- To potentially benefit from lower prices due to increased competition, BPUB should also evaluate construction of new lines to competing intrastate pipelines

2.4.5 Natural gas Supply/Demand Balance and Forecasted Changes

2.4.5.1 Supply to South Texas

Figure 2-5 shows the sources of forecasted volumes of gas supply to South Texas, by Railroad Commission District. Production from Districts 1 and 2 satisfying South Texas demand includes the Eagle Ford Shale.

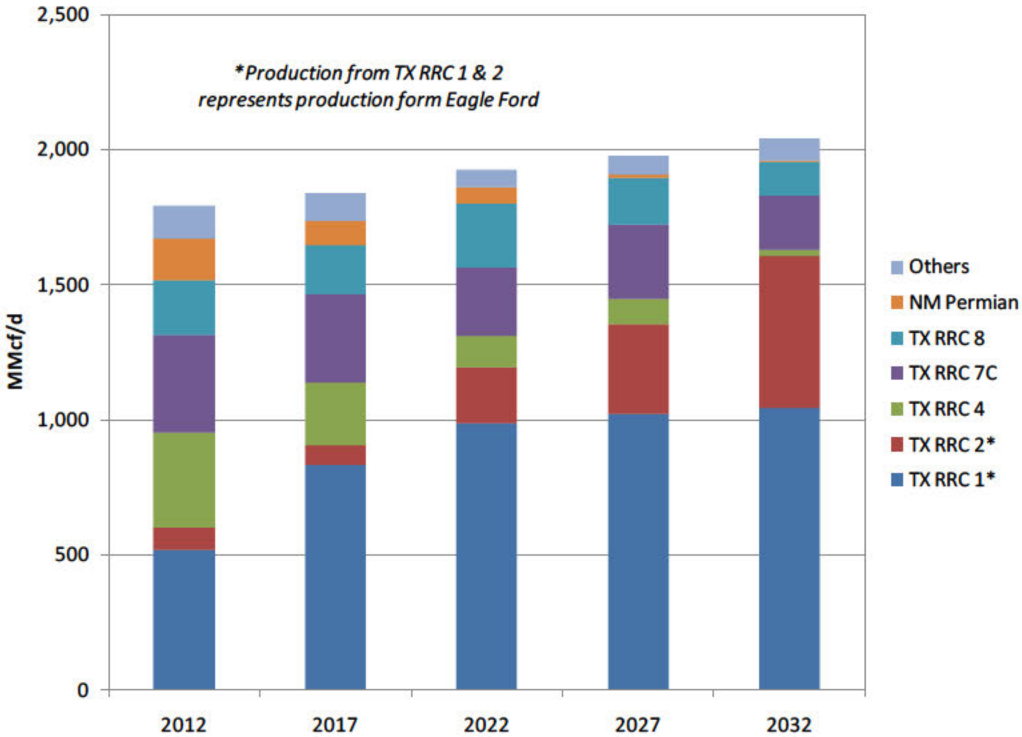


Figure 2-5 Sources of Gas Supply to South Texas. (Spring 2011 EMP for ERCOT)

The demand components included within the "South Texas" demand node are presented in Table 2-9.

Table 2-9 Demand Components Within South Texas Demand Node

CUSTOMER CODE	LOCATION CODE	CUSTOMER TYPE
San Antonio Public Service	Texas South (ERCOT)	LDC
Texas Gas Service	Texas South (ERCOT)	LDC
Texas, Austin Electric Dept: Gas-fired Gen	Texas South (ERCOT)	ELC
Texas, Brownsville: Gas-fired Gen	Texas South (ERCOT)	ELC
Texas, Central Power and Light: Gas-fired Gen	Texas South (ERCOT)	ELC
Texas, Lower Colorado River Auth: Gas-fired Gen	Texas South (ERCOT)	ELC
Texas, San Antonio PS: Gas-fired Gen	Texas South (ERCOT)	ELC
Texas, South: Ind Gas Mkt	Texas South (ERCOT)	IND
Texas, South: Other Gas-fired Gen	Texas South (ERCOT)	ELC
Texas, South: Other LDC Gas Sales	Texas South (ERCOT)	LDC
Texas, Southern Coop: Gas-fired Gen	Texas South (ERCOT)	ELC

The Eagle Ford Shale contribution in TX RRC 1 and 2 to South Texas fuel supply is forecasted to triple between 2012 and 2032. The Eagle Ford, historically regarded as the source rock for the prolific Austin Chalk, was first tested specifically for production in 2008 (Petrohawk's Hawkville Field discovery in La Salle County). By June, 2010, the Railroad Commission had registered more than 30 fields in 35 counties of Texas. From southwest to northeast, and updip to shallower depths, the shale produces dry gas, transitioning to condensate, and then oil. During the past year, international exploration concerns have entered the play, including Statoil (Norway), Talisman (Canada), CNOOC (China), and Reliance Industries (India)8

Black & Veatch's view for the Eagle Ford is that its total production flowing to all demand centers will peak at approximately 3.5 Bcf/d, and that sufficient markets will be accessible to absorb that production volume, due mainly to production decline from conventional on-shore and offshore resources, and due to exports to Mexico.

[8] Source: Lyle, Hart Energy¸ Unconventional Gas Center, January 30, 2011.

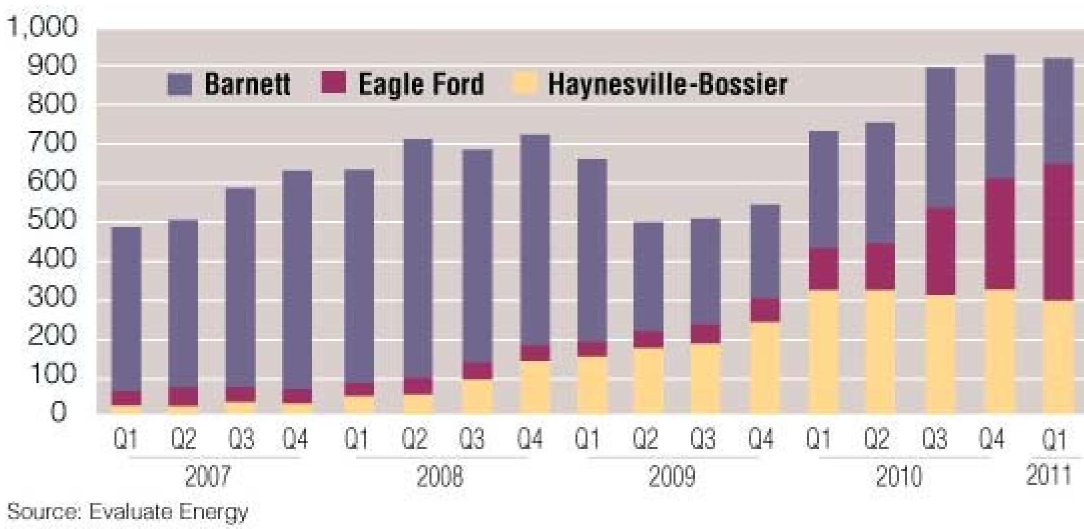
The Spring 2011 EMP for ERCOT shows about 45 percent of the gas from Eagle Ford goes to the East Texas and Houston Ship Channel market, 19 percent to Mid-Continent markets, and 36 percent goes to Louisiana, serving Northeast and Southeast markets. The forecasted flows to Waha are insignificant.

The significance of the Eagle Ford play for BPUB is that BPUB's natural gas –fired resources are located in one of the most fast-developing and economic plays in North America. BPUB thus has a supply and locational advantage in generating power from natural gas. Furthermore, Enterprise Texas pipeline, the direct source for Silas Ray's supply, is well positioned to optimize the incremental Eagle Ford Production (see Figure 2-6).

Figure 2-6 Enterprise Products System Map – Gulf Coast (Source: Enterprise Products website)

For Talisman, the top resource plays in North America for unconventional gas with liquids are Montney (British Columbia), Marcellus (Appalachian region), and Eagle Ford. In an August, 2011 panel at the Colorado Oil & Gas Association meeting, a Talisman executive stated "We see the Eagle Ford as the most economic play. It works at $1.50 to $2.00 per Mcf breakeven, obviously carried by the liquids." Such statements by producer executives must be understood to be of limited objectivity, but they are significant in shedding light on why Eagle Ford resources are attracting increasing investments.

Other factors cited in the growth of interest in Eagle Ford exploration include the relatively high reservoir energy, its high carbonate content, which makes it brittle and easy to fracture, and the potential to increase production from improving horizontal drilling. Figure 2-7 illustrates the expansion of drilling in the Eagle Ford in 2010 and 2011, while drilling in the Haynesville-Bossier and Barnett is leveling off.



Source: Hart Energy –Unconventional Gas, Steve Toon, July 13, 2011, citing Evaluate Energy

Figure 2-7 New Horizontal Wells Drilled in Texas Shale Counties

The high oil content is obviously a key factor, with liquids in many Eagle Ford wells consisting of oil, not condensate or natural gas liquids. Recent oil production from the Eagle Ford in Dimmit, Northern LaSalle, McMullen and Atascosa counties had average 70 percent liquids and 30 percent rich gas, with a reported 54 percent return at $100 per barrel oil and $4 per MCF gas.

2.4.5.2 Forecasted Natural Gas Demand by Sector

Figure 2-8 shows the forecasted moderate growth in natural gas demand in the South Texas demand center by sector through 2032. The total annual rate of increase is 0.70 percent and the annual average growth rate for electricity sector growth is 1.30 percent.

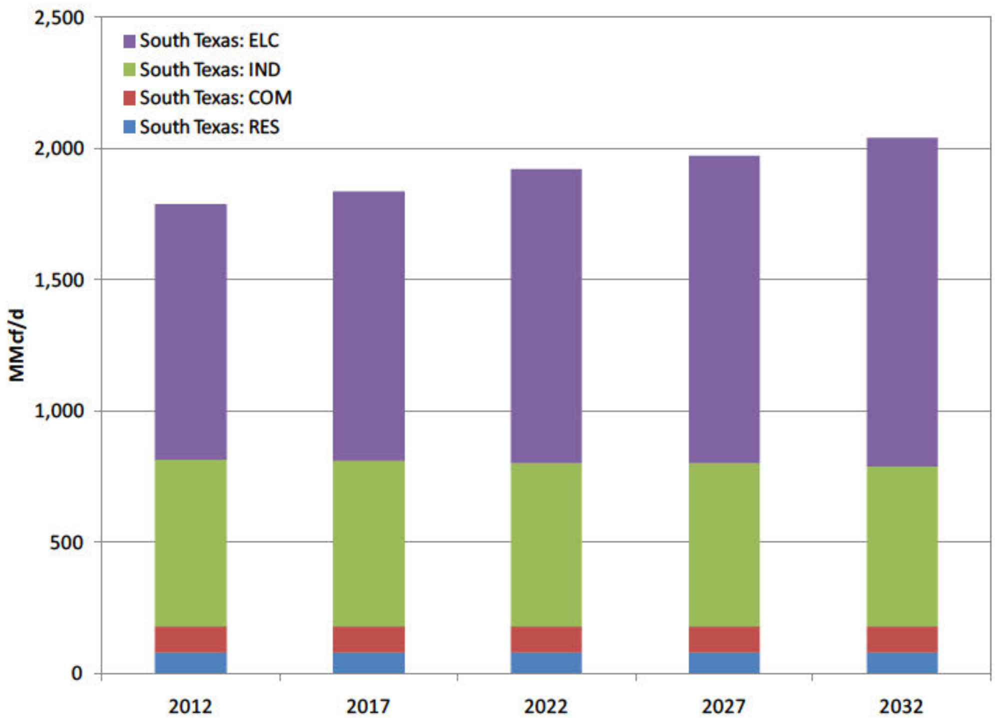


Figure 2-8 Forecasted Gas Demand by Sector, South Texas (Spring 2011 EMP for ERCOT)

Figure 2-9 shows the seasonal demand for natural gas to generate electricity in South Texas, identifying the pronounced summer peak and smaller winter peak.

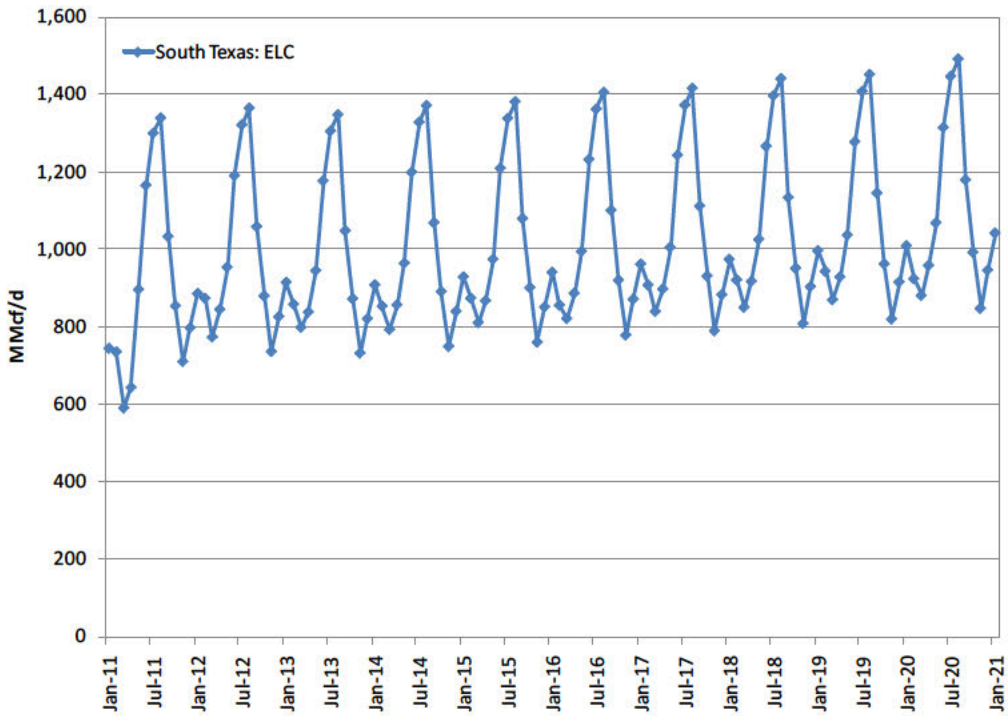


Figure 2-9 Demand for Natural Gas for Electricity Generation, South Texas (Spring 2011 EMP for ERCOT)

2.4.5.2.1 Mexico

Figure 2-10 shows the forecasted demand for natural gas exported to Mexico in South Texas. In 2022, the forecast exports to Mexico are approximately one third of the total South Texas demand. This percentage rises to nearly 60 percent of South Texas demand by 2032. Exports to Mexico flow through Tennessee Gas Pipeline on the interstate system and through two Kinder Morgan intrastate pipelines. Such exports provide another component of growing demand for Texas gas (a component not included in our conventional 4-sector demand forecast).

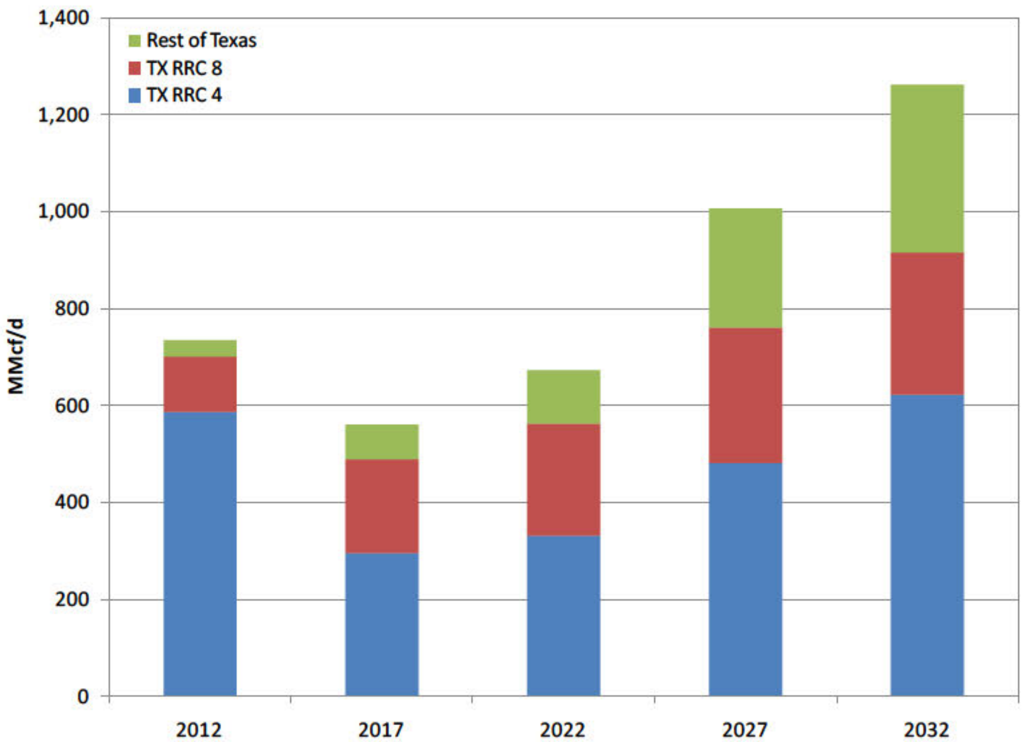


Figure 2-10 Natural Gas Export to Mexico

2.4.5.3 Supply-Demand Balance

Figure 2-11 shows the forecast of natural gas supply/demand balance for Texas in 2020 (Spring 2011 EMP for ERCOT).

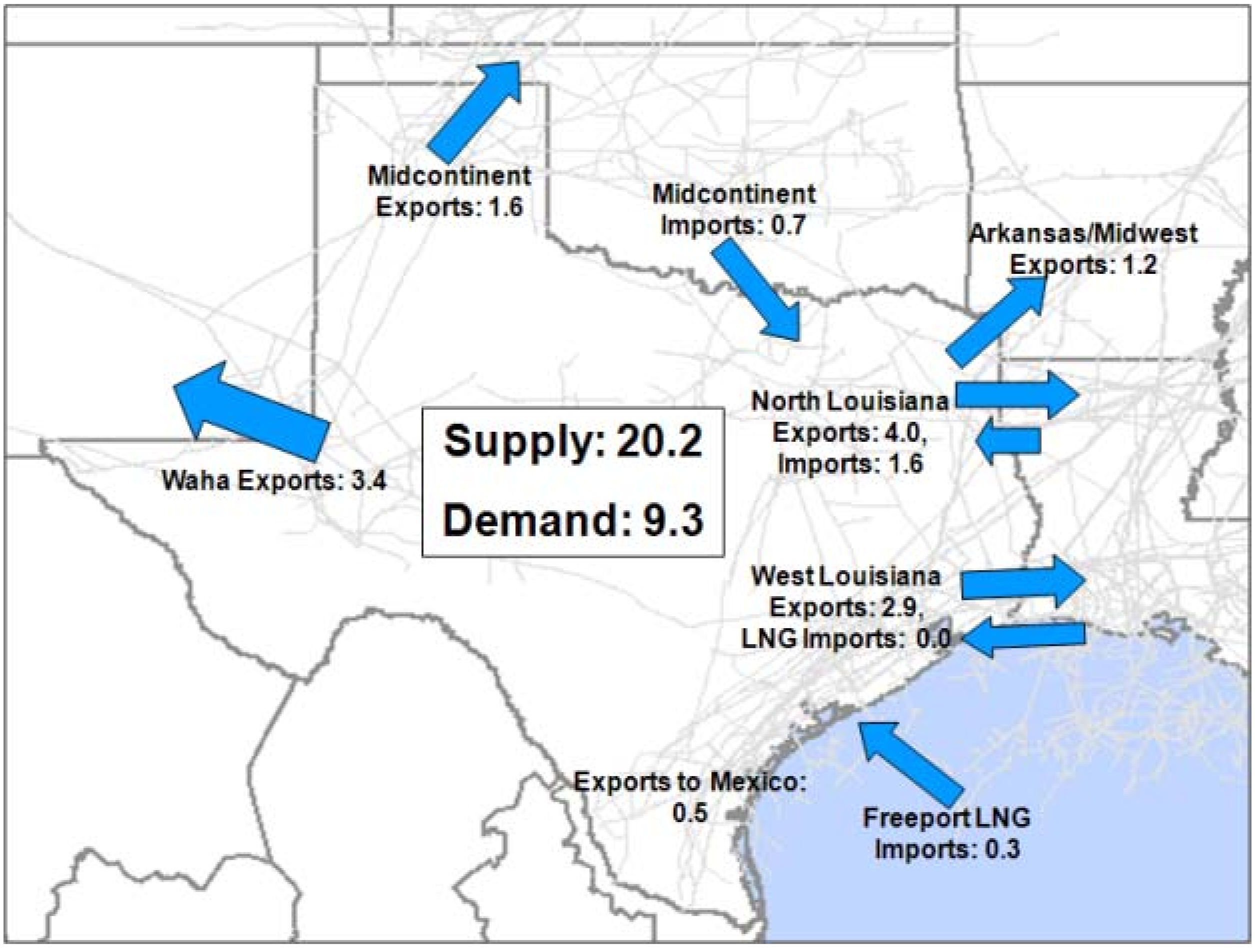


Figure 2-11 Texas 2020 Supply/Demand Balance (BCF/D) – Spring 2011EMP

2.4.6 Henry Hub Gas Price Forecast and Regional Basis Forecast

Figure 2-12 shows Black & Veatch's projected Henry Hub gas price in 2011 dollars, per the Spring 2011 EMP for ERCOT. Gas prices are forecasted to double in real terms in the forecast horizon in response to increasing demand primarily for natural gas for electric power generation, and in response to increasing drilling and completion costs for unconventional gas production as exploration moves away from sweet spots and encounters higher permitting and environmental costs and restrictions. Figure 2-13 presents forecasted basis differentials compared to Henry Hub for key market points in Texas.

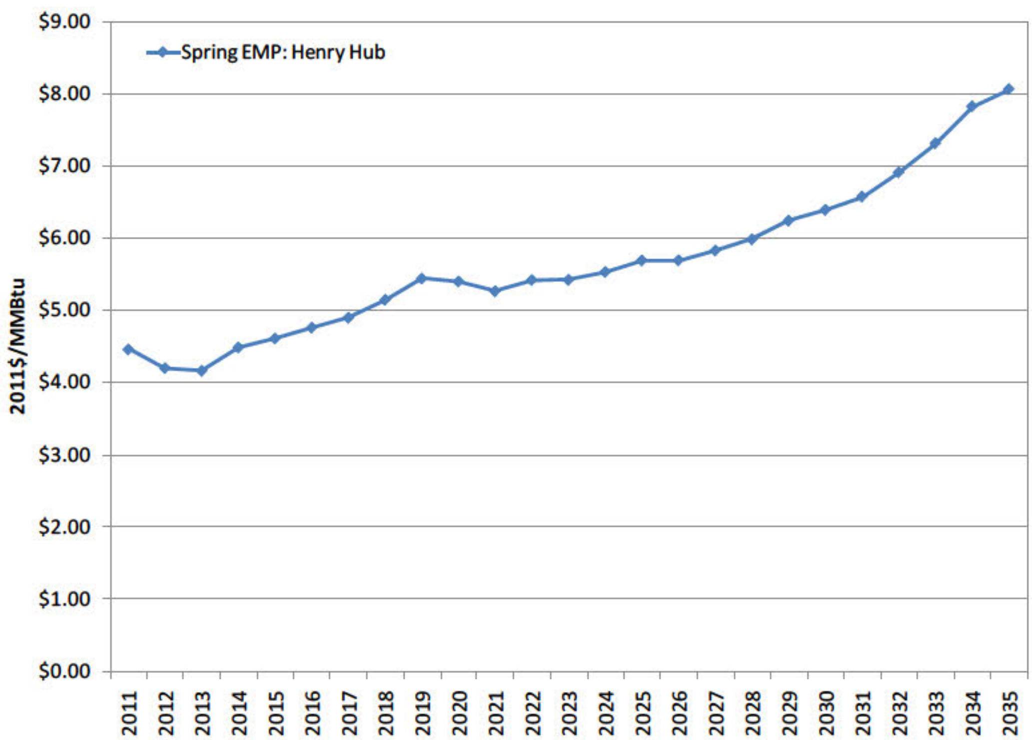


Figure 2-12 Forecast of Henry Hub Natural Gas Price (Spring, 2011 EMP)

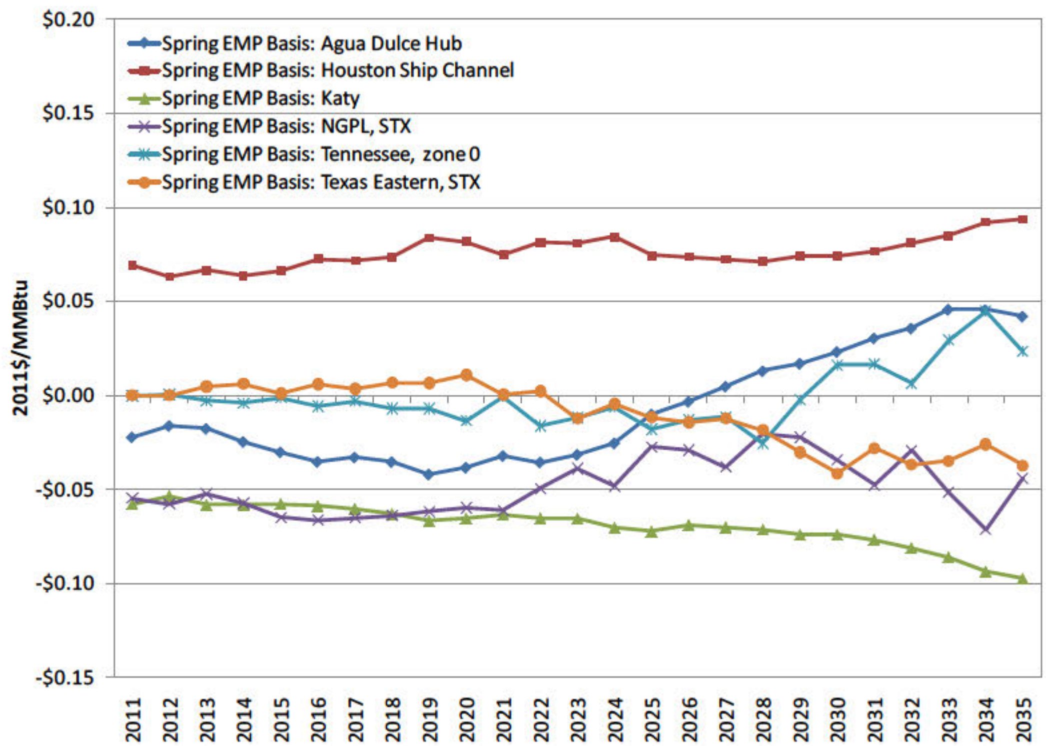


Figure 2-13 Forecasted Basis for Key Market Points in Texas (Spring 2011 EMP for ERCOT)

2.4.7 Summary of Alternatives and Recommendations

To plan for future gas-fired resources for BPUB either at Silas Ray or Hidalgo, it is recommended that analysis focus on the availability and cost of contractually or operationally firm pipeline capacity sufficient to provide for the proposed available generation capacity. Supply is abundant and will become even more abundant during the forecast horizon as the Eagle Ford Shale resources are developed. Pipeline capacity development may not keep pace with supply development.

At Hidalgo, the recommended alternatives for additional evaluation consist of:

- Negotiation of additional firm pipeline capacity with Texas Eastern, concurrently with competitive negotiation with alternative interstate or intrastate pipelines sufficiently near to the plant lateral to merit an analysis of connection economics
- Concurrent evaluation of supply sources feeding into the pipeline alternatives to draw conclusions regarding the optimum and most cost-effective supply sources and their respective pipeline routes to Hidalgo; currently the gas supply is indexed to Houston Ship Channel, a relatively expensive index. For example, is gas indexed to a less expensive market point (according to the forecast) available?

- Review of strategic alternatives and opportunities with the Calpine fuel team and evaluation of their proposals for additional fuel supply.
- Evaluation of alternatives to fuel management by Calpine subsequent to earlier of the expiration of the Ownership Agreement or 2012 (expiration of the current Fuel Management Agreement).

At Silas Ray, the recommended alternatives for additional evaluation consist of focus on pipeline capacity, then secondarily on supply:

- Evaluation of the capabilities of Texas Gas Services to provide delivery capacity for additional gas supplies, and the quality of such future service
- Evaluation of the availability and cost of either firm or operationally firm incremental upstream pipeline capacity on Enterprise Texas
- Evaluation of the Kinder Morgan Tejas Pipeline (see maps of Cameron County) for potential future direct connect
- Review of strategic alternatives and opportunities with the Tenaska fuel team and evaluation of their proposals for additional fuel supply
- Evaluation of supplier alternatives and supply sources subsequent to the expiration of the current supply agreement with Tenaska in 2014.
- To potentially benefit from lower prices due to increased competition, BPUB should also evaluate construction of new lines to competing intrastate pipelines

When gas-fired resources are considered in alternative locations, such as at the Port of Brownsville and Site FM511, it is strongly recommended that the availability of favorable pipeline capacity with the ability to accommodate future expansion be considered as a major component in the site ranking and selection.

3.0 Load Forecast

BPUB retained R. W. Beck, Inc./SAIC in 2009 to prepare a forecast of system net energy for load (NEL) and summer peak demand for the BPUB electric system (referred to herein as the 2009 R.W. Beck/SAIC load forecast). The 2009 R.W. Beck/SAIC load forecast covered the 20 year period from 2009 through 2028. The forecast of system NEL was based on an econometric model projection of retail sales and estimated distribution system losses. The system peak forecast was based on the NEL and projected load factors. BPUB provided the full 2009 R.W. Beck/SAIC load forecast report to Black & Veatch, and it is included as Appendix D.

Table 3-1 summarizes the NEL and summer peak demand used in this IRP. The values shown for 2012 (the initial year reflected in the IRP analysis) through 2028 come from the 2009 R.W.B eck/SAIC load forecast. Projected NEL and peak demand for 2029 through 2031 were developed by Black & Veatch based on the projected growth between 2027 and 2028.

Table 3-1 Projected NEL and Summer Peak Demand

YEAR	NET ENERGY FOR LOAD (NEL) (GWH)	SUMMER PEAK DEMAND (MW)
2012	1,534.8	316.8
2013	1,613.2	334.3
2014	1,680.2	348.5
2015	1,746.2	362.5
2016	1,813.4	375.8
2017	1,879.7	391.0
2018	1,944.7	405.0
2019	2,007.6	418.5
2020	2,070.1	430.8
2021	2,132.6	445.5
2022	2,195.1	459.0
2023	2,257.7	472.6
2024	2,321.4	485.2
2025	2,386.9	500.8
2026	2,457.9	516.3
2027	2,533.5	532.7
2028	2,613.7	548.7
2029	2,693.9	564.7
2030	2,774.1	580.7
2031	2,854.3	596.7

Note: Values for 2012 through 2028 from the 2009 R.W. Beck/SAIC load forecast. Values for 2029 through 2031 projected based on growth from 2027 to 2028.

4.0 Need for Capacity

BPUB must maintain sufficient capacity to meet its projected peak demand. BPUB must also have an additional margin of capacity should unforeseen events result in higher system demand and/or lower than anticipated available capacity. This section describes the reliability criteria utilized in this IRP, and summarizes BPUB's anticipated need for additional capacity to satisfy projected capacity and target reserve margin requirements.

4.1 DEVELOPMENT OF RELIABILITY CRITERIA

ERCOT currently uses a 12.5 percent minimum target reserve margin of capacity for the region. However, there has been some discussion within ERCOT about increasing the minimum target reserve margin to 13.75 percent. For purposes of this IRP, the target reserve margin for planning in the summer season is 13.75 percent of firm load obligations. The planning reserve margin covers uncertainties such as extreme weather, forced outages for generators, and uncertainty in load projections. The reserve margin is calculated as follows:

$$\frac{\text{System Net Capacity} - \text{System Firm Peak Demand}}{\text{System Firm Peak Demand}}$$

If available summer net capacity or summer firm peak demand deviates from predicted levels, the actual reserve margin will vary. For a relatively small or isolated utility system, an unanticipated plant outage or higher than expected growth in system demand can quickly reduce or eliminate the planned reserve margin. This formula calculates the reserve margin at a given point in time, but it does not indicate what the appropriate reserve margin is for a given system[9].

4.2 RELIABILITY NEED

To determine BPUB's need for power, a forecast of system summer peak demand was developed. The forecast of system summer peak demand was developed through 2031, as discussed and presented in Section 3.0. The resultant summer peak demand forecast is assumed to be the final summer peak demand forecast for BPUB. As discussed in Section 2.0, BPUB's existing generating resources provide approximately 339.5 MW of net summer capacity in 2012.

Table 4-1 presents the projected capacity balance based on the BPUB load forecast and existing resources. As shown in Table 4-1, BPUB is projected to have sufficient capacity to satisfy peak demand in 2012 and 2013; however, BPUB is projected to require additional capacity to satisfy projected target reserve margin requirements for all years of the study period. Figure 4-1 shows BPUB's annual existing capacity (by primary fuel type) as well as the annual peak demand and reserve requirement.

[9] Such analysis is beyond the scope of this IRP.

Table 4-1 Capacity Balance for BPUB (Based on Firm Capacity)

YEAR	FORECAST PEAK DEMAND (MW)	13.75% RESERVES REQUIRED (MW)	TOTAL PEAK PLUS RESERVE (MW)	SILAS RAY UNITS 6 9 (MW)	SILAS RAY UNIT 10 (MW)	HIDALGO ENERGY CENTER (HEC) (MW)	OKLAUNION (MW)	DISTRIBUTED GENERATION (MW)	TOTAL AVAILABLE CAPACITY (MW)	EXCESS/ (DEFICIT) CAPACITY TO MAINTAIN REQUIRED RESERVE MARGIN LEVEL (MW)	RESERVE MARGIN
2012	316.8	43.6	360.4	55.0	50.0	105.0	122.0	7.5	339.5	(20.9)	7.2%
2013	334.3	46.0	380.3	55.0	50.0	105.0	122.0	7.5	339.5	(40.8)	1.6%
2014	348.5	47.9	396.4	55.0	50.0	105.0	122.0	7.5	339.5	(56.9)	-2.6%
2015	362.5	49.8	412.3	55.0	50.0	105.0	122.0	7.5	339.5	(72.8)	-6.3%
2016	375.8	51.7	427.5	55.0	50.0	105.0	122.0	7.5	339.5	(88.0)	-9.7%
2017	391.0	53.8	444.8	55.0	50.0	105.0	122.0	7.5	339.5	(105.3)	-13.2%
2018	405.0	55.7	460.7	55.0	50.0	105.0	122.0	7.5	339.5	(121.2)	-16.2%
2019	418.5	57.5	476.0	55.0	50.0	105.0	122.0	7.5	339.5	(136.5)	-18.9%
2020	430.8	59.2	490.0	55.0	50.0	105.0	122.0	7.5	339.5	(150.5)	-21.2%
2021	445.5	61.3	506.8	55.0	50.0	105.0	122.0	7.5	339.5	(167.3)	-23.8%
2022	459.0	63.1	522.1	55.0	50.0	105.0	122.0	7.5	339.5	(182.6)	-26.0%
2023	472.6	65.0	537.6	55.0	50.0	105.0	122.0	7.5	339.5	(198.1)	-28.2%
2024	485.2	66.7	551.9	55.0	50.0	105.0	122.0	7.5	339.5	(212.4)	-30.0%
2025	500.8	68.9	569.7	55.0	50.0	105.0	122.0	7.5	339.5	(230.2)	-32.2%
2026	516.3	71.0	587.3	55.0	50.0	105.0	122.0	7.5	339.5	(247.8)	-34.2%
2027	532.7	73.2	605.9	55.0	50.0	105.0	122.0	7.5	339.5	(266.4)	-36.3%
2028	548.7	75.4	624.1	55.0	50.0	105.0	122.0	7.5	339.5	(284.6)	-38.1%
2029	564.7	77.6	642.3	55.0	50.0	105.0	122.0	7.5	339.5	(302.8)	-39.9%
2030	580.7	79.8	660.5	55.0	50.0	105.0	122.0	7.5	339.5	(321.0)	-41.5%
2031	596.7	82.0	678.7	55.0	50.0	105.0	122.0	7.5	339.5	(339.2)	-43.1%

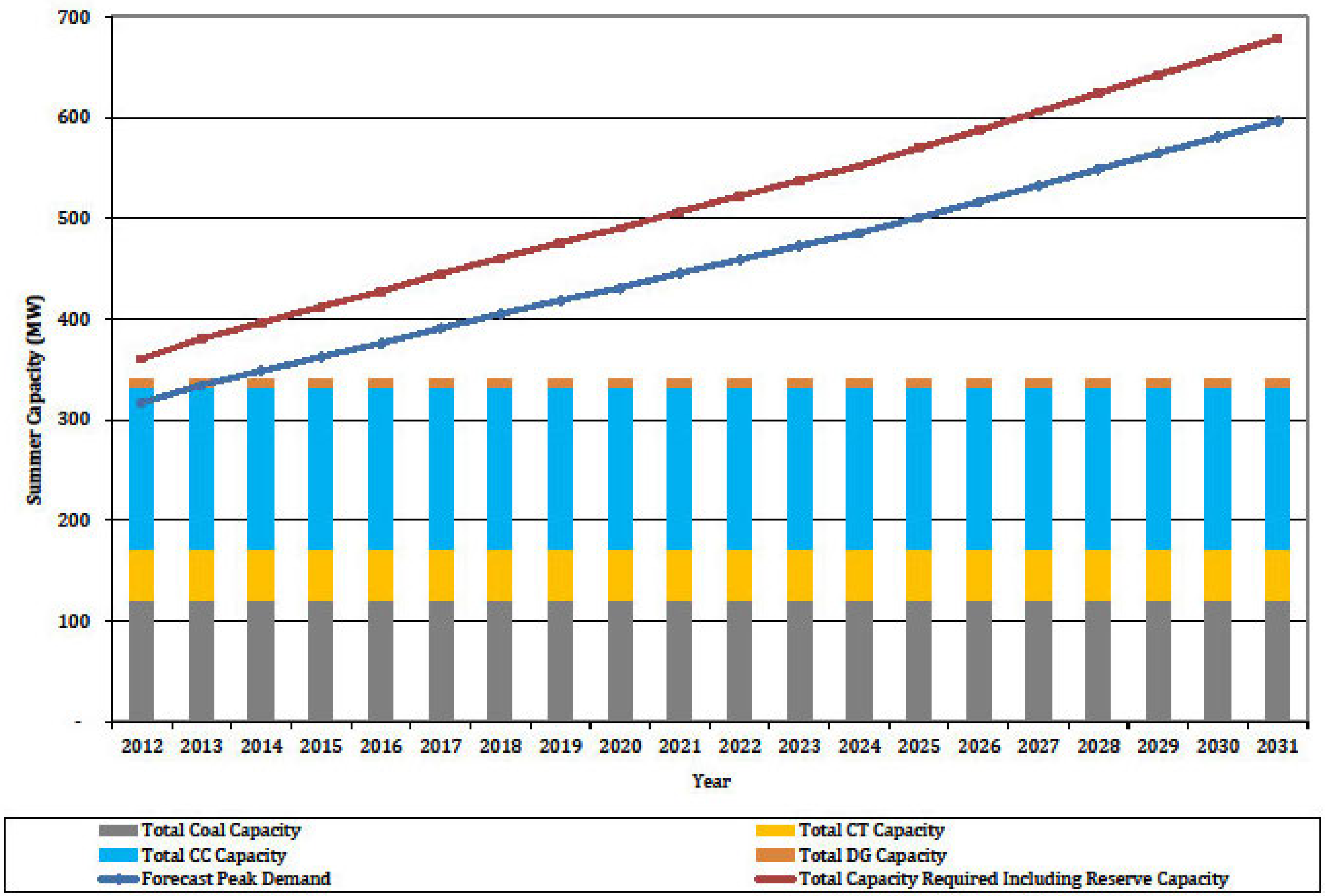


Figure 4-1 Capacity Balance

5.0 Fuel, Emissions, and Power Price Projections

This section summarizes the fuel, CO_2 emissions allowance CO_2, and power price projections used throughout this IRP. All prices are presented in nominal dollars.

5.1 OVERVIEW OF BLACK & VEATCH ENERGY MARKET PERSPECTIVE

The Black & Veatch Energy Market Perspective (EMP) is issued twice per year to provide clients with Black & Veatch's assessment of the current state of North American Energy Markets, including a base case long-term view of energy prices. It includes a view of generation fuel sources and electric power market prices over a 25 year period (2011 through 2035). Black & Veatch utilizes an integrated market model process that captures energy policy and structural market issues to arrive at a transparent and unbiased view of energy market prices. Forecasts are derived from vendor-supplied and internal models utilizing commercial and proprietary data sources. The forecast includes prices for power, coal, oil, gas, and potential emissions. The details and assumptions used to develop these price forecasts are contained in Black & Veatch's Spring 2011 EMP for ERCOT which was used to develop natural gas, CO_2 emissions allowance, and power price projections used throughout this IRP. Coal price projections used in the IRP were developed separately, as discussed later in this section.

5.2 COAL PRICE PROJECTIONS

Figure 5-1 presents the coal price projections used for the Oklaunion resource. The coal price projections are based on contract prices provided by BPUB for the years 2011 through 2017. After 2017, Black & Veatch extrapolated the coal price based on the annual coal price projections from the Spring 2011 EMP for ERCOT. The coal price projections were used in the economic analysis to simulate operation of the Oklaunion coal unit.

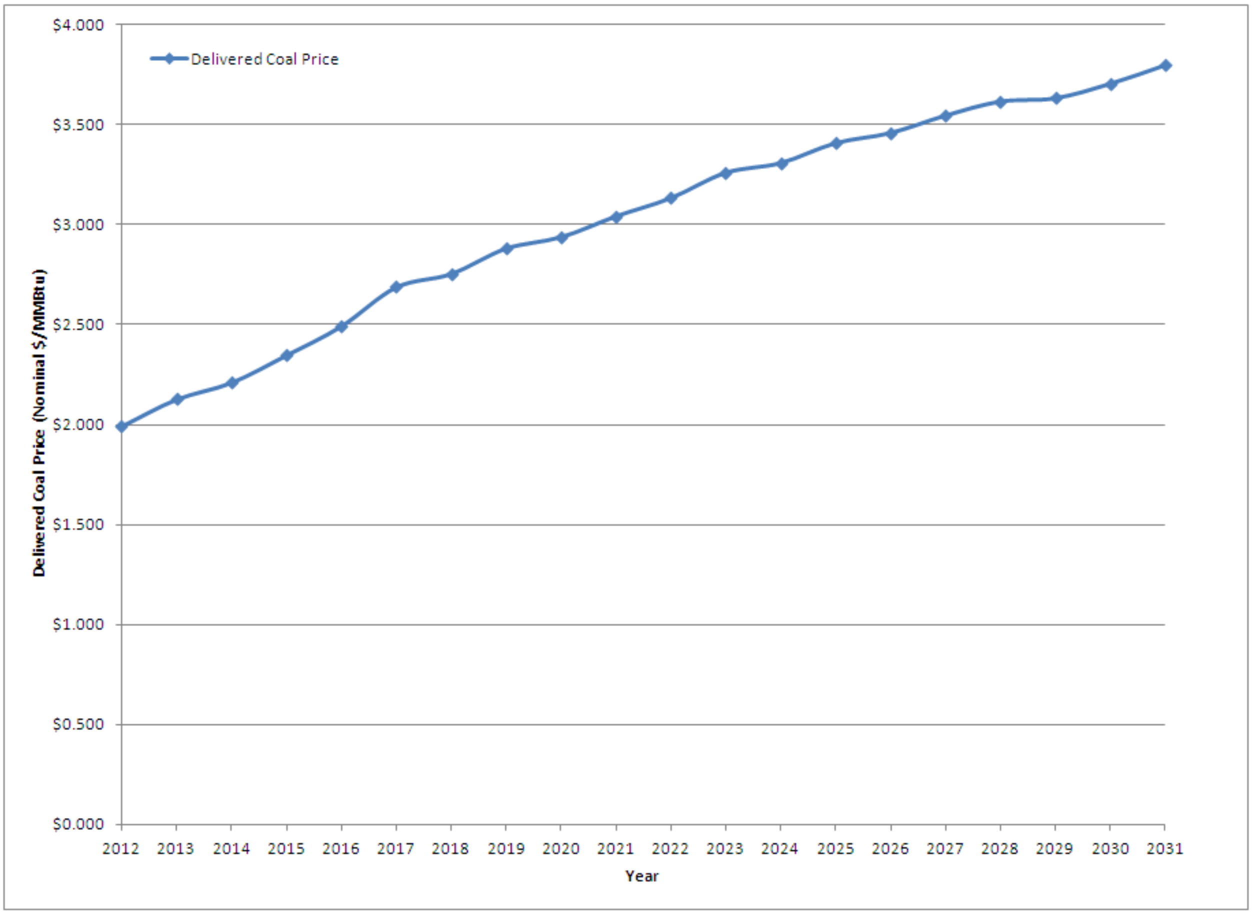


Figure 5-1 Coal Price Projections

5.3 NATURAL GAS PRICE PROJECTIONS

Figure 5-2 presents the natural gas price projections. The price for natural gas was assumed to be a regional delivered price and is based on the Spring 2011 EMP for ERCOT. The natural gas price projections were used in the economic analysis to simulate operation of the Silas Ray and Hidalgo units, as well as new combined cycle and simple cycle units.

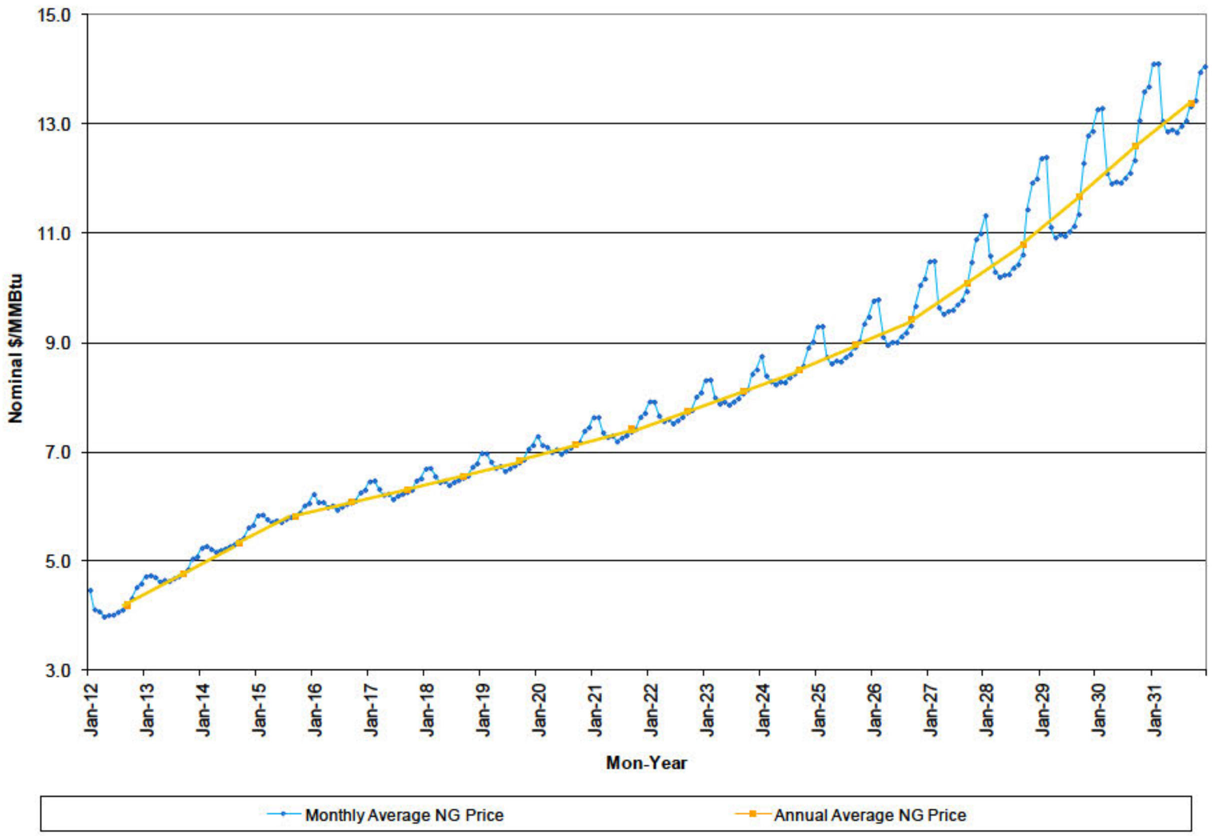


Figure 5-2 Natural Gas Prices Projections (Nominal Dollars)

5.4 DISTILLATE FUEL OIL PRICE PROJECTIONS

Figure 5-3 presents the distillate fuel oil price projections. The price for distillate fuel oil was assumed to be a regional delivered price and is based on the Spring 2011 EMP for ERCOT. The distillate fuel oil price projections were used in the economic analysis to simulate operation of the distributed generation units.

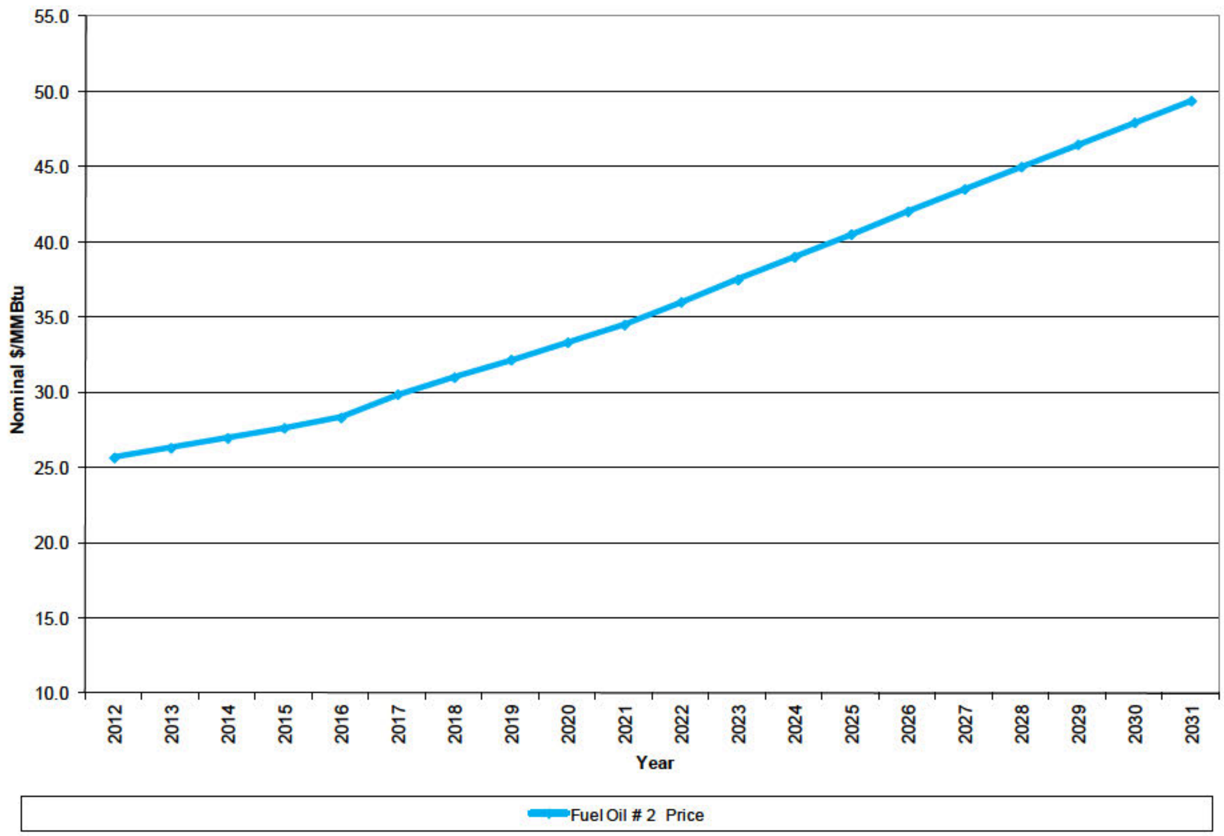


Figure 5-3 Distillate Fuel Oil Prices Projections (Nominal Dollars)

5.5 CARBON DIOXIDE EMISSIONS ALLOWANCE PRICE PROJECTIONS

Figure 5-4 presents the CO_2 emissions allowance price forecast. This IRP assumes that emissions of CO_2 will be regulated beginning in 2020. The CO_2 emissions allowance price projections are based on the Spring 2011 EMP for ERCOT and range from approximately \$27/ton in 2020 to approximately \$67/ton in 2031. The CO_2 emissions allowance price projections were levied on all units that burn fossil fuels and, hence, emit CO_2.

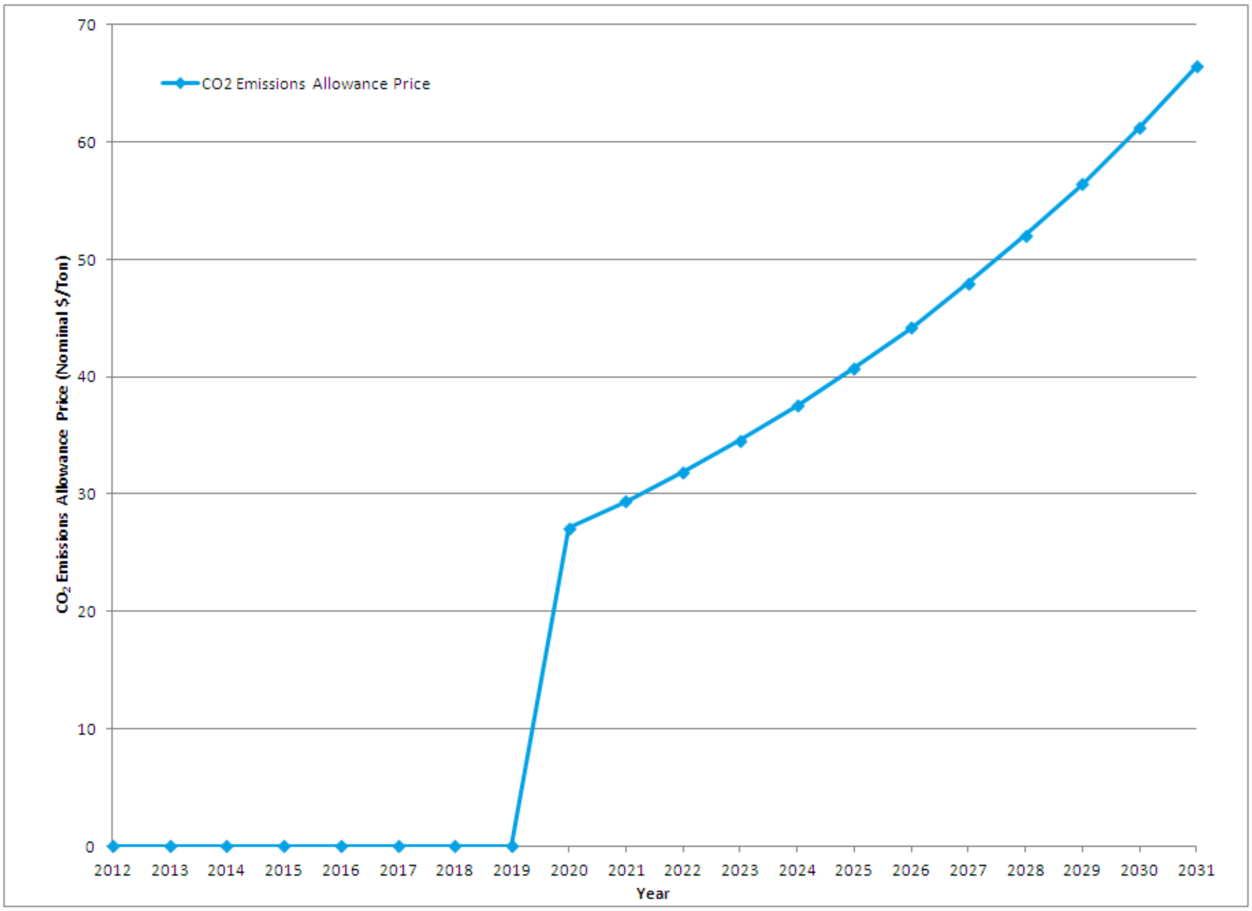


Figure 5-4 Carbon Emissions Allowance Price (Nominal Dollars)

5.6 ENERGY PRICE PROJECTIONS

Spot market energy prices utilized in this IRP are based on Black & Veatch's Spring 2011EMP for ERCOT. Monthly on- and off-peak energy prices for ERCOT were used to simulate spot market energy purchases in the applicable modeling scenarios. Figure 5-5 illustrates the on-peak energy prices used in the production cost modeling. Figure 5-6 illustrates the off-peak energy prices used in the production cost modeling. Prices are presented in nominal dollars per megawatt-hour. On-peak prices range from approximately \$34/MWh in January 2012 to approximately \$134/MWh in December 2031. Off-peak prices range from approximately \$31/MWh in January 2012 to approximately \$127/MWh in December 2031. Figure 5-7 illustrates the annual average on-peak, annual average off-peak, and annual average energy prices based on the monthly values.

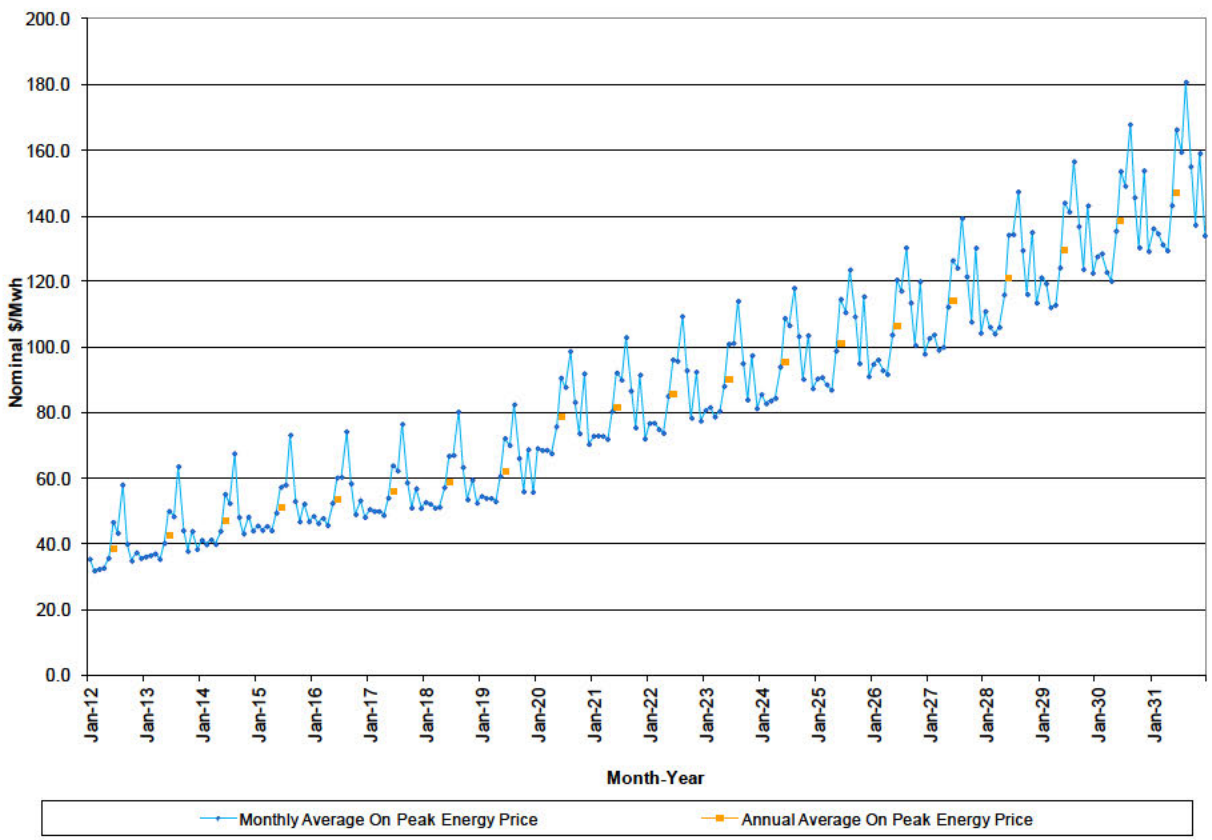


Figure 5-5 On Peak Energy Price Projection

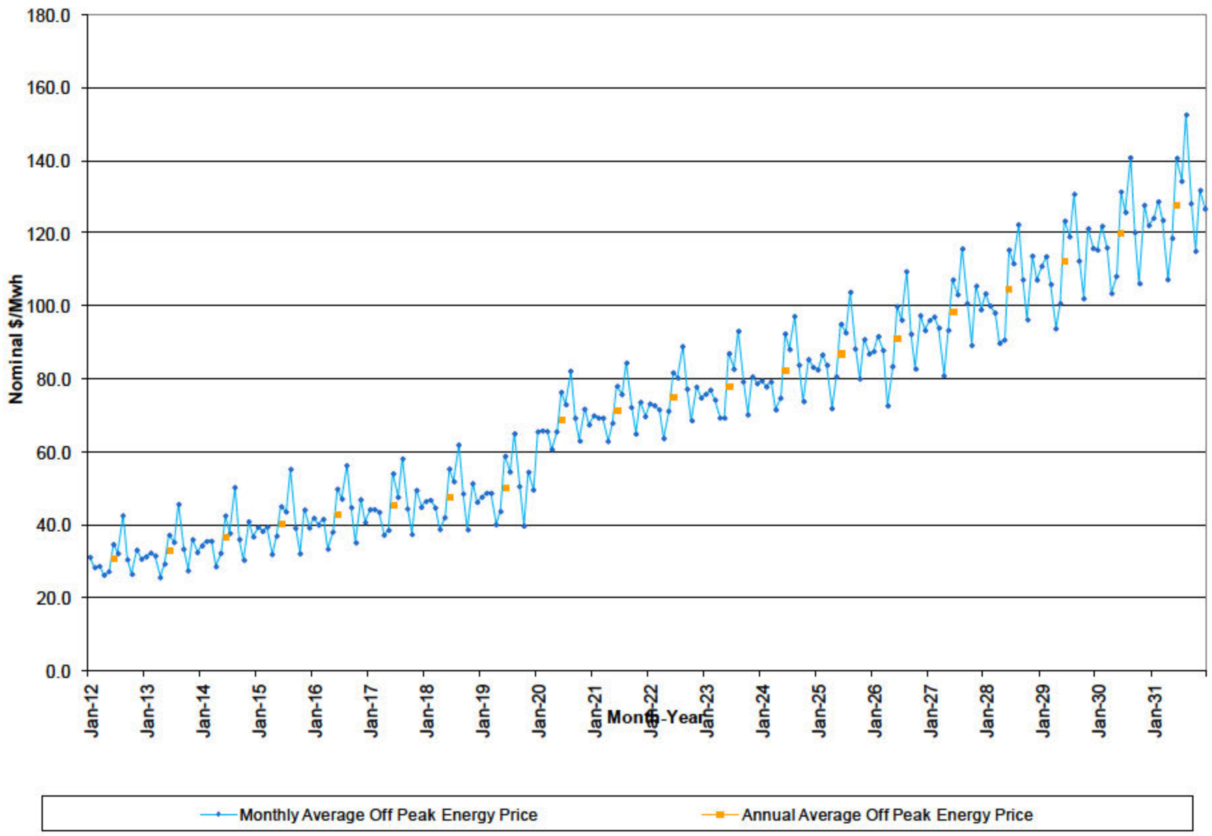


Figure 5-6 **Off Peak Energy Price Projection**

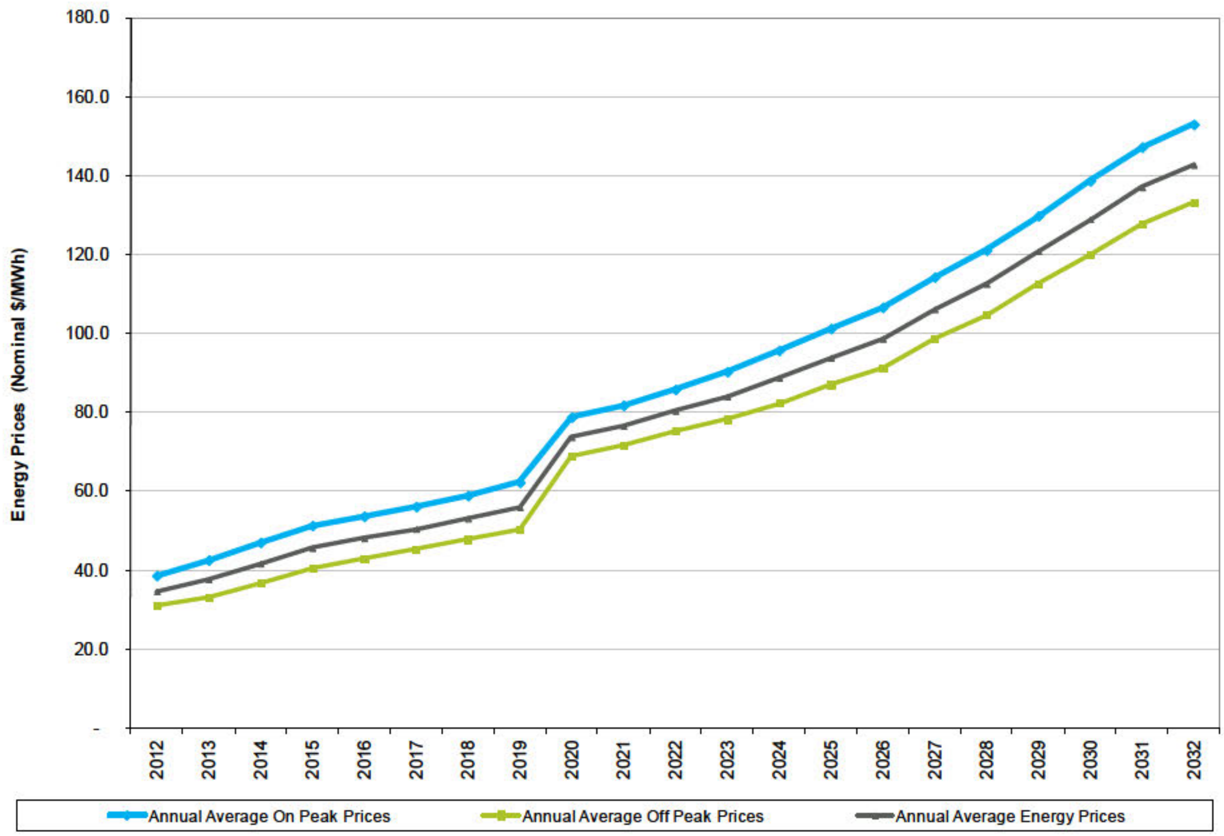


Figure 5-7 Annual Average Energy Price Projections

5.7 ANNUAL CAPACITY PRICE PROJECTIONS

Market capacity prices utilized in this IRP are based on Black & Veatch's Spring 2011EMP for ERCOT. The capacity prices used in this study are representative of costs for purchasing simple cycle capacity and represent the prices for the entire ERCOT market. Figure 5-8 illustrates the capacity prices used in the production cost modeling. Prices are presented in nominal dollars per kilowatt-year. Capacity prices range from $84/kW-yr in 2012 to $146/kW-yr in 2032.

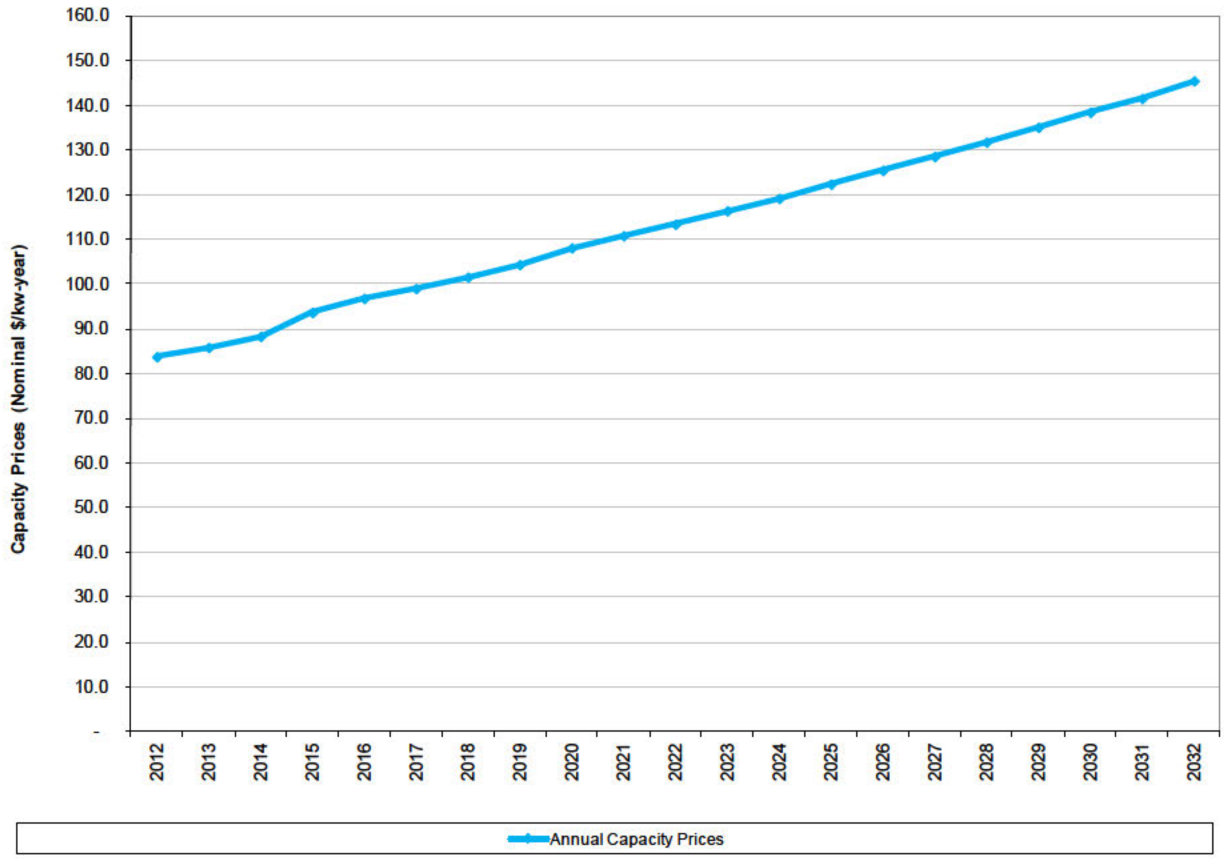


Figure 5-8 Annual Capacity Price Projection

6.0 Future Resources Considered

This section summarizes the characteristics of the future resource alternatives evaluated in this IRP. For the purposes of this study, nine different alternatives were evaluated. The alternatives evaluated included the following:

- Wartsila reciprocating engines.
- Trailer-mounted General Electric (GE) LM2500 simple cycle units.
- GE LMS100 simple cycle units.
- GE LM6000 Sprint simple cycle units.
- GE LM6000 2x1 combined cycle units.
- Utility scale solar photovoltaics (PV).
- Utility scale on-shore wind.
- Utility scale direct-fired biomass.
- Recommissioning of Silas Ray Unit 5.

Although the combustion turbines and combined cycle alternatives discussed herein assume specific manufacturers (GE and Wartsila) and specific models, doing so is not intended to limit the alternatives considered solely to GE models. Rather, such assumptions were made to provide indicative cost, output, and performance data. Several manufacturers offer similar generating technologies with similar attributes, and the data presented in this IRP should be considered indicative of comparable technologies across a wide array of manufacturers.

6.1 CONVENTIONAL AND RENEWABLE OPTIONS

The following paragraphs describe each of the conventional and renewable alternatives considered in this IRP. Table 6-1, presented at the end of Section 6.1, summarizes the cost and operating characteristics used in the analysis. Unless otherwise noted, all cost estimates are presented in 2011 dollars. With the exception of the Silas Ray Unit 5 recommissioning, the generating unit alternative cost and performance estimates are not site-specific.

6.1.1 Wartsila Reciprocating Engines

Wartsila provides preassembled packages of internal combustion, reciprocating engines in various sizes. Although available in various capacities, this IRP only considered 9 MW Wartsila engines. Wartsila engines are typically designed to operate from 1,000 to 6,000 hours per year. For purposes of this IRP, the Wartsila engines are assumed to operate on natural gas.

6.1.2 Trailer-Mounted GE LM2500 Simple Cycle

The GE LM2500 is a simple cycle gas turbine developed by GE and based on a turbofan aircraft design. This IRP considers trailer-mounted GE LM2500 units. The GE LM2500 is estimated to provide approximately 26.5 MW of capacity at summer ambient conditions.

6.1.3 GE LMS100 Simple Cycle

The GE LMS100 is a simple cycle gas turbine developed by GE and based on a turbofan aircraft design. The GE LMS100 is estimated to provide approximately 85.3 MW of capacity at summer ambient conditions.

6.1.4 GE LM6000 Sprint Simple Cycle

The GE LM6000 Sprint is a simple cycle gas turbine developed by GE and based on a turbofan aircraft design. The GE LM6000 is estimated to provide approximately 34.0 MW of capacity at summer ambient conditions.

6.1.5 GE LM6000 2x1 Combined Cycle

The GE LM6000 may also be utilized in combined cycle mode. For purposes of this analysis, a natural gas fired 2x1 GE LM6000 combined cycle resource was evaluated, which is estimated to provide approximately 97.9 MW of capacity at summer ambient conditions.

6.1.6 Utility-Scale Photovoltaics

The amount of power produced by PV installations depends on the material used and the intensity of the solar radiation incident on the cell. Single or polycrystalline silicon cells are commonly used today. PV resources in 20 MW blocks were evaluated in this IRP. A 20 MW block of PV is projected to provide approximately 12.6 MW of firm on-peak capacity.

6.1.7 Utility-Scale On-Shore Wind

Utility-scale on-shore wind power systems convert the movement of air to power by means of a rotating turbine and a generator. Typical utility-scale on-shore wind energy systems consist of multiple wind turbines that range in size from 1 to 3 MW. Wind resources in 50 MW blocks were evaluated in this IRP. Within ERCOT, 50 MW of wind energy is projected to provide approximately 4.35 MW of firm on-peak capacity.

6.1.8 Direct-Fired Biomass

A direct-fired biomass resource burns biomass derived fuel in a boiler to produce steam which is expanded through a turbine to produce electricity. Prior to its combustion in the boiler, the biomass fuel may require processing to improve the physical and chemical properties of the feedstock. A direct-fired biomass resource is estimated to provide approximately 35.0 MW of capacity at summer ambient conditions.

6.1.9 Recommissioning of Silas Ray Unit 5

BPUB's existing Silas Ray Unit 5 is currently out of service. This IRP considers the economics of recommissioning Silas Ray Unit 5 based on a study of the associated costs performed by Black & Veatch. Additional information related to the Silas Ray Unit 5 recommissioning study is presented in Section 6.2 of this IRP.

Table 6-1 Summary of Operating and Cost Characteristics of Future Resource Options[1]

OPTION	SUMMER CAPACITY MW[2]	SUMMER FULL LOAD NET PLANT HEAT RATE BTU/KWH (HHV)	CAPITAL COST $/KW[3]	FIXED O&M $/KW-YR.	VARIABLE O&M $/MWH	FIRST AVAILABLE COD[4]
CONVENTIONAL RESOURCES						
Wartsila Engine – 9 MW	9.2	8,727	1,217	15.30	5.73	5/1/2014
GE LM2500 Simple Cycle	26.5	9,332	1,505	7.19	4.00	5/1/2014
GE LMS100 Simple Cycle	85.3	9,421	1,246	19.28	3.30	5/1/2014
GE LM6000 Simple Cycle	34.0	10,472	1,452	13.03	3.70	5/1/2014
LM6000 Combined Cycle	97.9	7,400	2,177	25.47	4.76	5/1/2015
Silas Ray Unit 5	18.4	13,000	888	See Note (5)	4.92	5/1/2015
RENEWABLE RESOURCES						
PV	20.0/12.6	N/A	3,932	29.50	N/A	5/1/2014
Wind	50.0/4.35	N/A	2,200	33.90	N/A	5/1/2014
Direct-fired Biomass	35.0	13,500	5,400	164.00	5.95	5/1/2015

(1)All costs are presented in 2011 dollars.
(2)Nameplate and firm capacity per block for wind and PV.
(3)Capital costs include owner's costs and are based on summer capacity rating.
(4)Commercial operation date.
(5) It has been assumed that no incremental staffing would be necessary to operate Silas Ray Unit 5 if recommissioned.

6.2 RECOMMISSIONING OF SILAS RAY UNIT 5

6.2.1 Background

Silas Ray Unit 5 is a 25 MW natural gas fired steam cycle. The plant was run as a peaking unit until 2005 when it was put in a stacked condition. The last certification of the boiler and turbine occurred in 2006. Black & Veatch visited the Silas Ray Plant on September 1, 2011 to discuss the condition of Silas Ray Unit 5 with BPUB staff and plant personnel and to visually inspect the major pieces of equipment. BPUB personnel participating in the meeting and site visit were Rolando Lozano, Alonso Gonzalez, Marilyn Gilbert, Gustavo Hernandez, and Rick Lopez. Prior to this site visit, BPUB provided Black & Veatch with information about the plant including piping and instrumentation diagrams (P&IDs), mass and energy balances, maintenance reports, and communications with the Texas Commission on Environmental Quality (TCEQ). During the site visit the existing cost estimate to recommission Silas Ray Unit 5 was discussed and the basis behind each line item in the estimate was verified. After meeting with plant personnel, Black & Veatch was given a tour of the plant and was able to visually inspect the major pieces of equipment associated with Silas Ray Unit 5.

6.2.2 Condition of Major Pieces of Equipment

Boiler replacement is the basis for the BPUB cost estimate and Black & Veatch concurs with this assessment. During its last few years of operation, Silas Ray Unit 5 was limited to about 10 MW of power because the boiler tubes leaked when operating at the higher pressures required for higher output. When the plant was put in a stacked condition, BPUB tried to circulate dry nitrogen through the system to avoid corrosion, but they were not able to do so because of leaking. Also, the boiler was originally designed to produce steam for both Units 4 and 5 steam turbines. Based on the facts that the existing boiler would need to be retubed and that it is oversized for the Silas Ray Unit 5 steam turbine, Black & Veatch recommends that the boiler be replaced with a 250,000 lb/h package boiler.

The steam turbine needs an extensive overhaul, but it should not need to be replaced completely. Nevertheless, because BPUB was not able to maintain the system with dry nitrogen from 2005 to present, the steam turbine should have a complete inspection done to determine its condition. BPUB provided a report to Black & Veatch describing a condenser leak test performed by ARD Environmental, Inc. The condenser of the steam turbine has significant air in-leaks that should be repaired. The air in-leaks to the condenser that were identified during the helium leak testing are not unusual, especially for a turbine of this vintage. Most of these leaks can likely be addressed during the turbine overhaul. The rupture disk can be replaced and is not very expensive. The housing leaks can be taken care of when the unit is disassembled, either by hand "machining" of the mating surfaces and or by utilizing liquid sealing and gasket materials. The expansion joint leak will likely be the most expensive repair in that the most effective fix will probably be replacement of the joint. Replacement of the expansion joint can easily be accomplished during the overhaul outage. It is possible in some cases to "cut out" the leaks and patch the joint but it is likely that the current joint material condition will not support this type of repair. The basis of the BPUB cost estimate is to overhaul the nozzle block, blading, seals, and bearings. Black & Veatch agrees with this assessment and also believes that the lube oil/hydraulic oil system should be inspected and flushed and that the turbine stop and control valves should be overhauled.

The steam turbine generator is missing its exciter. The original exciter came unraveled in 2002 and a static exciter was installed at that time. The basis of the BPUB estimate is to use the same static exciter. Black & Veatch believes that the static exciter will probably work, but the best solution would be to purchase a new brushless rotating exciter. Because the static exciter would work for this situation, Black & Veatch has not included the cost of a new exciter in our cost basis. When the plant was put in a stacked condition the hydrogen seals were purged with CO_2 so the hydrogen sealing system should be in good working condition.

The Silas Ray Unit 5 transformer is gassing and BPUB will need to replace it and the GSU. Although this was not part of the basis of the BPUB cost estimate, Silas Ray personnel are aware of the need to replace this.

Silas Ray maintenance personnel indicate that the condensate and boiler feed pumps are turned by hand from time to time. While it is encouraging that they can be turned by hand, it does not mean that they are in good working order and Black & Veatch recommends that they be tested to ensure they operate properly. The visual inspection of the pumps did not indicate anything out of order and their replacement is not included in Black & Veatch's cost estimate.

The cooling tower will need minor repairs to accommodate the heat load from Silas Ray Unit 5. Most of the repairs are related to the wood work.

6.2.3 Current Air Permit Requirements

Before it was shut down in 2005, Silas Ray Unit 5 was "Permitted by Statute" under SB7. However, because the unit has been shut down for more than 2 years it will require re-permitting. Black & Veatch believes that BPUB will need to do a Best Available Control Technology (BACT) analysis under Prevention of Significant Deterioration (PSD) requirements which would require installation of selective catalytic reduction (SCR) for Silas Ray Unit 5. However, if BPUB limits the number of operating hours per year for Silas Ray Unit 5, they can probably show that it would be prohibitively expensive and avoid the installation of SCR. Continuous emission monitors for nitrogen oxides (NO_x) and carbon monoxide (CO) would need to be installed. Black & Veatch has developed estimates for recommissioning Silas Ray Unit 5 with and without SCR.

6.2.4 Cost Comparison

Black & Veatch has reviewed BPUB's cost estimate to recommission Silas Ray Unit 5. Each line item was reviewed and major costs were reviewed with internal Black & Veatch experts. Minor costs were reviewed by estimators and in most cases Black & Veatch agreed with the costs proposed by BPUB. There were some critical items that Black & Veatch believes were not included in BPUB's original estimate and were therefore added. Black & Veatch also believes that some of the major cost items were underestimated. The additions to the cost estimate and changes to BPUB's initial cost estimate are described below.

6.2.4.1 Items Added by Black & Veatch

Silas Ray personnel indicate that the new boiler would be located where the existing Boiler 6 is now located. This would require a significant demolition and removal cost that was not included in the BPUB cost estimate. Black & Veatch believes that this will add about $435,000 to the cost of recommissioning Silas Ray Unit 5. The cost for demolition and removal includes separate contractors for asbestos and demolition. If BPUB were to perform asbestos abatement and then contract demolition to the engineering, procurement, and construction (EPC) retrofit contractor, Black & Veatch believes that this cost could be reduced by $150,000 to $200,000. The cost estimate includes an allowance for scrap sold to offset demolition and removal costs. If the scrap is not sold, the demolition cost could increase by as much as $140,000. A smaller item that was not included in the original estimate, but is necessary as indicated by Silas Ray personnel, is circuit breakers.

6.2.4.2 Accuracy of Major Components

The main differences in opinion are in the boiler cost, transformer/generator step-up transformer (GSU), and continuous emissions monitoring system (CEMS) equipment. Black & Veatch believes that the cost of the packaged boiler will be about $6,250,000. This includes a new forced draft fan, low NOx burners, overfire air, etc. Silas Ray personnel believe that the cost of the transformer and GSU will be about $413,000 rather than the $5,000 in the original assessment. Black & Veatch agrees with this higher cost estimate. Lastly, the CEMS equipment is expected to be about $290,000 rather than the $35,000 in the original BPUB cost estimate. If SCR is required for NOx control, Black & Veatch expects that this will cost approximately $2,800,000. BPUB's current cost estimate includes $50,000 for emissions abatement. If SCR is required, there will be an additional $200,000 required for ammonia receiving, storage, and distribution. Other cost components that Black & Veatch believes will be different include the DCS interface, overhaul of steam turbine seals, stack and breach requirements, and vibration monitoring.

Some of the cost line items that Black & Veatch believes that BPUB overestimated include the electrical test, condenser exhaust pump (already purchased), allowance for cable and raceway, and allowance for concrete foundations.

6.2.4.3 Overall Comparison

Table 6-2 presents Black & Veatch's estimate of the cost to recommission Silas Ray Unit 5 and also presents the BPUB estimate. Black & Veatch estimates that the cost to recommission Silas Ray Unit 5 will be approximately $620/kW if SCR is not needed and $777/kW if SCR is required. The cost per kW estimates are calculated assuming 21 MW nameplate capacity for the recommissioned Silas Ray Unit 5.

Table 6-2 Estimated Recommissioning Costs for Silas Ray Unit 5

RECOMMISSIONING COST COMPONENT	ITEMIZED BUDGETARY COST ESTIMATE			
	BPUB ESTIMATE	BLACK & VEATCH ESTIMATE WITH SCR	BLACK & VEATCH ESTIMATE W/O SCR	BLACK & VEATCH COMMENTS
Boiler	4,200,000	6,250,000	6,250,000	New 250,000 lb/h packaged boiler including FD fan.
Piping & Insulation	100,000	100,000	100,000	
Control & Interface	25,000	25,000	25,000	Only interface with planned new DCS for entire plant
Stack & Breech	50,000	75,000	75,000	
Generator 5 Overhaul & Inspection	50,000	50,000	50,000	
Hydrogen Purity Panel	35,000	35,000	35,000	
Hydrogen Seal Modification	100,000	100,000	100,000	
Electrical Test	52,000	45,000	45,000	Performance test on PSS and exciter. Function tests on assembled generator.
Turbine Overhaul				
Nozzle Block	250,000	250,000	250,000	
Condenser Maintenance		30,000	30,000	Open condenser, clean tubes, leak check, expansion joint check.
Turbine stop and control valve overhaul		25,000	25,000	
Lube oil system / hydraulic oil system maintenance		15,000	15,000	Pump inspection, high pressure flush, oil replacement.
Seals all	15,000	30,000	30,000	Assumes complete replacement
Blading	700,000	700,000	700,000	
Bearings	50,000	50,000	50,000	
Labor & Machining	248,000	248,000	248,000	
Total	**5,875,000**	**8,028,000**	**8,028,000**	
MECHANICAL EQUIPMENT - OTHER				
Emissions Abatement	50,000	2,800,000	--	
Condenser Exhauster Pump	75,000	--	--	Already Purchased
Mechanical Equipment Subtotal	**125,000**	**2,800,000**	**--**	

RECOMMISSIONING COST COMPONENT	ITEMIZED BUDGETARY COST ESTIMATE			
	BPUB ESTIMATE	BLACK & VEATCH ESTIMATE WITH SCR	BLACK & VEATCH ESTIMATE W/O SCR	BLACK & VEATCH COMMENTS
ELECTRICAL & CONTROL EQUIPMENT				
Transformer, GSU	5,000	413,000	413,000	
Cable, 138 kV		--	--	
Circuit Breakers, 138 kV		65,000	65,000	
Auxiliary Transformers		--	--	
Non-Seg. Buss, 15 kV		--	--	
15 kV Switch Gear		--	--	
15 kV Cable Bus		--	--	
Local Control & Electrical Bldg		--	--	
Switchgear, 5 kV		--	--	
Switchgear, 480V		--	--	
Non-Seg. Buss, 480V		--	--	
Static Exciter Insp.	5,000	5,000	5,000	
Vibration Monitoring	40,000	75,000	75,000	
Protective Relay Board		--	--	
CEMS Equipment & Enclosure	35,000	290,000	290,000	Includes CAL Gases, RATA Testing, 5 field days
DCS Equipment	75,000	150,000	150,000	Only interface with planned new DCS for entire plant
Substation Equipment, Misc.	50,000	50,000	50,000	
Electrical & Control Equipment Subtotal	**210,000**	**1,048,000**	**1,048,000**	
Chemical Equipment				
Water Treatment System	--	--	--	
Pumps, Chem. Injection	12,000	12,000	12,000	
Pumps, Asst. Cooling/Chem/Demin	--	--	--	
Ammonia Storage & Delivery	--	200,000		
Chemical Equipment Subtotal	**12,000**	**212,000**	**12,000**	

RECOMMISSIONING COST COMPONENT	ITEMIZED BUDGETARY COST ESTIMATE			
	BPUB ESTIMATE	BLACK & VEATCH ESTIMATE WITH SCR	BLACK & VEATCH ESTIMATE W/O SCR	BLACK & VEATCH COMMENTS
SITE IMPROVEMENTS				
Demolition and Removal of Existing Boiler 6	--	435,000	435,000	Separate contractors for asbestos and demolition. Actual costs may be reduced by having BPUB remove asbestos and contracting demolition to the EPC retrofit contractor. Scrap is sold to offset demolition and removal costs
Survey & Site Preparation	--	--	--	
Fire Loop Additions	--	--	--	
Oil Water Separator Additions	--	--	--	
Cathodic Protection	--	--	--	
Potable Water Extension	--	--	--	
Plant Roadway	--	--	--	
Grading & Drainage	--	--	--	
Site Improvement Subtotal	**--**	**435,000**	**435,000**	
CONSTRUCTION				
General Construction	500,000	570,000	570,000	
Plant Lighting & Misc. Electrical	8,000	8,000	8,000	
Allowance, Cable & Raceway	50,000	40,000	40,000	
Platforms, Ladders & Railing	10,000	10,000	10,000	
Mechanical Equipment, Misc.	25,000	25,000	25,000	
Allowance, Valve, Piping, Insulation	125,000	150,000	150,000	
Allowance, Concrete Foundations	205,000	130,000	130,000	
DCS Integration & Instrumentation	25,000	25,000	25,000	
Steam Turbine Controls	25,000	25,000	25,000	
Improvements	300,000	300,000	300,000	
Construction Subtotal	**1,273,000**	**1,283,000**	**1,283,000**	

RECOMMISSIONING COST COMPONENT	ITEMIZED BUDGETARY COST ESTIMATE			
	BPUB ESTIMATE	BLACK & VEATCH ESTIMATE WITH SCR	BLACK & VEATCH ESTIMATE W/O SCR	BLACK & VEATCH COMMENTS
PROFESSIONAL SERVICES & FEES				
Plant Engineering & Design	250,000	300,000	300,000	
Permitting & Licensing	100,000	100,000	100,000	
Owner Engineer	100,000	140,000	140,000	
Sub Surface Investigation	-			
Underground Pipe Location	-			
Concrete & Paving Repair	-			
Interconnection	15,000	15,000	15,000	
Professional Services Subtotal	**465,000**	**555,000**	**555,000**	
OTHER SERVICES				
Transportation & Shipping	200,000	200,000	200,000	
Crane Services	30,000	50,000	50,000	
Technical Field Assistance, OEM	170,000	170,000	170,000	
Training, Turbine & Control, Plant	12,000	20,000	20,000	
Certification	2,060	2,060	2,060	
Legal	35,000	35,000	35,000	
Other Services Subtotal	449,060	477,060	477,060	
Project Subtotal	**8,409,060**	**14,838,060**	**11,838,060**	
BPUB Overhead Expense (10% Applied)	**9,249,966**	**16,321,866**	**13,021,866**	
Installed Cost, $/kW	**440**	**777**	**620**	**Assumes 21 MW nameplate capacity**

6.3 LEVELIZED COST OF ENERGY

This section presents analysis of the levelized cost of energy (LCOE) for each of the supply side alternatives discussed previously in this section. The LCOE represents the cost to generate power levelized over the economic life of the power plant, and is based on the economic parameters discussed in Section 8.0 of this IRP. The LCOE is a single value which is consistent for each year of the economic life of the power plant. When comparing multiple options, the LCOE provides a single point comparison which allows a comparison between multiple technologies while accounting for cost components of capital, operation, and fuel.

The LCOE involves the calculation of annual cost components to arrive at a total annual cost. The total annual cost is comprised of the following:

- Levelized annual capital cost - levelized annual capital cost is determined by applying a levelized fixed charge rate to the total capital cost. The levelized annual capital cost resulting from the application of the levelized fixed charge rate to the total capital cost will have the same series present worth as the actual capital costs associated with the power plant. Determination of the levelized fixed charge rate is discussed in Section 8.0 of this IRP.
- Annual fixed and variable O&M costs - fixed and variable O&M costs are based on first year costs. Each successive year is escalated by an assumed escalation rate
- Annual fuel and emissions allowance costs – Annual fuel and emissions allowance price projections are presented in Section 5.0 of this IRP. These price projections are taken into consideration in the LCOE calculations based on each alternative's' projected net plant heat rate and emissions rate.

To determine the LCOE, the annual total cost is divided by the annual generation assumed to be delivered to the busbar to give an annual busbar cost. Discounting the annual busbar cost by the present worth discount rate (PWDR) for each year produces the present worth or discounted annual busbar cost. By summing each discounted annual busbar cost and dividing it by the sum of the present worth factors, the LCOE is derived, as reflected in the following formula.

Table 6-3 summarizes the LCOE for each of the alternatives considered in this IRP, with the LCOE presented across a range of capacity factors to illustrate how annual generation (i.e., capacity factor) impacts levelized costs. Figure 6-1 presents the LCOE data shown in Table 6-3, and illustrates the capacity factor at which various alternatives become lower in levelized costs than others. Note that the capacity factors for which levelized costs are graphed in Figure 6-1 were selected to represent appropriate capacity factors for each alternatives' expected utilization.[10] Such analysis is informative as it illustrates the relative economics between alternatives; however, economic decisions should not be based solely on LCOE results, as the LCOE calculations do not account for how each alternative fits within the overall BPUB generating system.

[10] LCOE for the wind and solar PV alternatives are plotted as single points at capacity factors near the projected capacity factor for each resource (i.e. 37 percent for wind and 21 percent for solar PV).

Table 6-3 Levelized Cost of Energy ($/MWh)

OPTION	CAPACITY FACTOR									
	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%
Wartsila	93.07	94.78	96.91	99.66	103.32	108.44	116.12	128.93	154.55	231.40
Silas Ray 5 Repowering	113.41	114.57	116.01	117.87	120.35	123.82	129.03	137.71	155.07	207.14
LM2500 Simple Cycle.	91.99	93.92	96.34	99.44	103.58	109.37	118.06	132.55	161.52	248.43
GE LM6000 Simple Cycle	111.24	113.06	115.34	118.27	122.17	127.63	135.83	149.49	176.81	258.77
GE LMS 100 Simple Cycle	91.02	92.84	95.10	98.01	101.89	107.32	115.47	129.06	156.22	237.72
GE 2x1 LM6000 Combined Cycle	83.12	85.58	88.65	92.60	97.86	105.22	116.28	134.69	171.53	282.03
Wind							72.49	89.40	134.10	268.21
Solar PV									207.52	435.80
Direct Fired Biomass	126.92	135.49	146.21	159.98	178.35	204.07	242.65	306.94	435.53	821.30
For purposes of this IRP, it has been assumed that the wind resource would achieve a 37 percent annual capacity factor, and the solar PV resource would achieve a 21 percent annual capacity factor.										

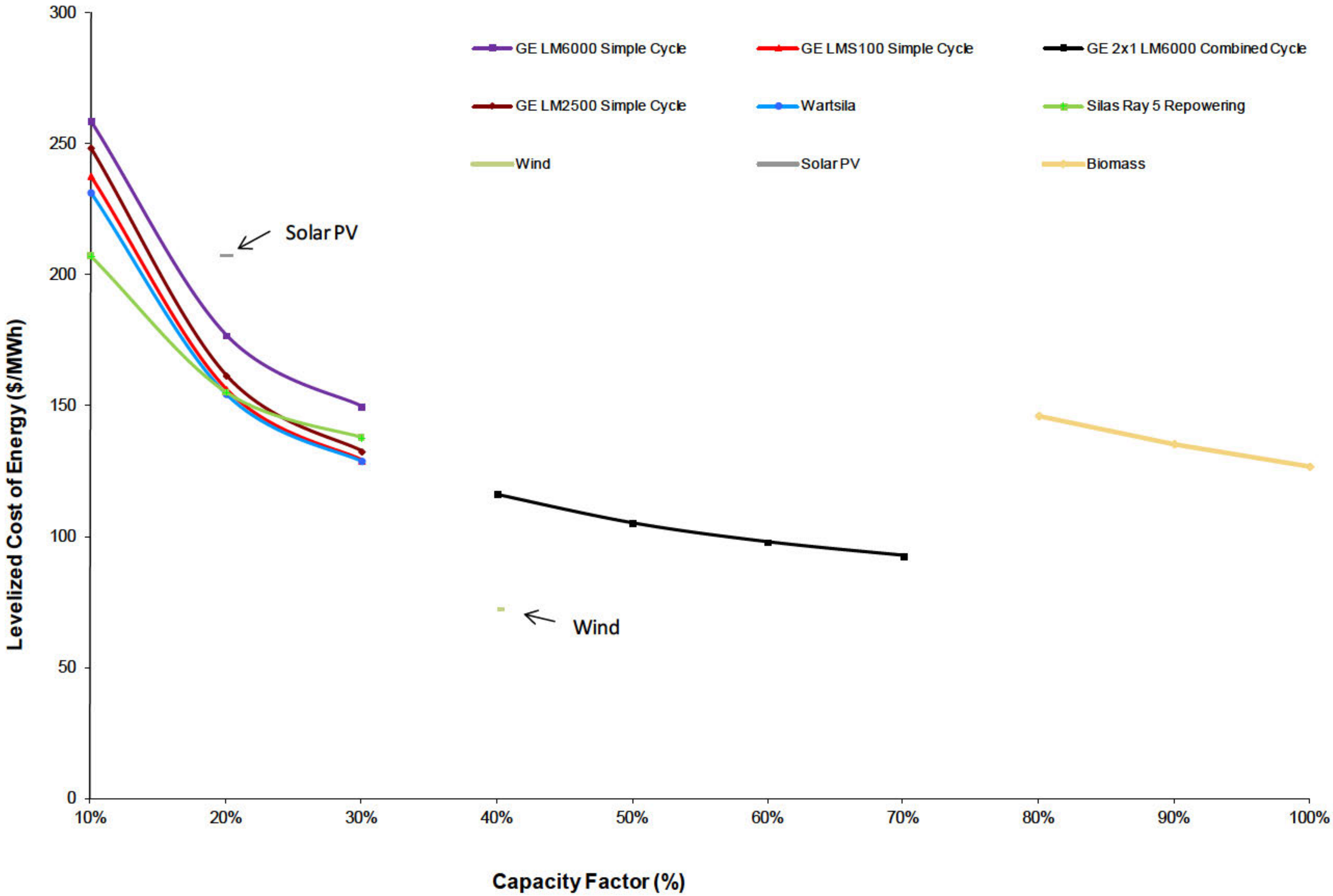


Figure 6-1 **Levelized Cost of Energy**

7.0 Energy Efficiency and Demand-Side Management

7.1 METHODOLOGY

In order to provide a high-level estimate of the magnitude of demand and energy savings that the BPUB may be able to achieve through energy efficiency and DSM programs, as well as the associated costs to BPUB, Black & Veatch reviewed publicly available information for the State of Texas. In particular, Black & Veatch reviewed the following sources of information to prepare a summary of current energy efficiency programs operating in Texas and their applicability to BPUB.

- Energy Efficiency Plan & Reports which are filed with the Public Utility Commission of Texas (PUCT) on or before April 1st Database of State Incentives for Renewables and Efficiency (DSIRE) - Utility Rebate Programs.
- Texas Energy Efficiency - http://www.texasefficiency.com/index.html.

Using information obtained from the sources listed above, Black & Veatch reviewed the energy efficiency and DSM programs offered by several utilities in the state of Texas, and developed a summary of the characteristics of the energy efficiency and DSM programs. Based on this information, Black & Veatch developed high-level estimates of potential customer participation, demand and energy savings, and associated costs to BPUB.

The remainder of this section provides a brief overview of recent activities related to energy efficiency in Texas (including a discussion of BPUB's existing energy efficiency offerings), and provides the results of the analysis performed by Black & Veatch.

7.2 ENERGY EFFICIENCY IN TEXAS

In 1999 the 75th Texas Legislature passed Senate Bill (S.B. 7) requiring that Investor Owned Utilities (IOUs) meet certain energy efficiency goals, which mandated that at least 10 percent of an IOU's annual growth in electricity demand be met through energy efficiency programs each year. Eight years later, the Legislature passed House Bill 3693 (H.B. 3693) which raised the energy efficiency goals to 20 percent of each utility's annual growth in demand by 2009, superseding the earlier requirements. During the 82nd Legislature in 2011, the goals for energy efficiency were modified once again. Senate Bill 1125 mandates that starting in 2013, IOUs must meet at least 30 percent of its annual growth in demand by December 31 of each year.

Legislation that applies to municipally owned utilities that had sales greater than 500,000 in 2005 includes the following directives:

- Municipally-owned utilities will administer energy savings incentive programs.
- Customers of a municipally-owned utility will have a choice of and access to energy efficiency alternatives that allow customers to reduce energy consumption, peak demand, or energy costs.
- Each municipally-owned utility will provide incentives sufficient for municipally owned utilities to acquire additional cost-effective energy efficiency.

- The governing body of a municipally-owned utility shall provide oversight and adopt rules and procedures, as necessary, to ensure that the utility can achieve the goal of the legislature.
- Municipally-owned utilities must report to the State Energy Efficiency Conservation office, in a form and manner determined by the utility in consultation with the office.

Recent data from the DSIRE indicates that there are several municipally-owned utilities that offer energy efficiency programs to their customers. This information, along with information from the annual Energy Efficiency Plan & Reports filed by the IOU's, illustrates the types of energy efficiency activities taking place in Texas.

The following presents a summary off the energy efficiency and DSM programs offered by both publicly owned utilities and IOUs. It is important to note that the detail provided by the IOU's in their annual filings provides more robust information than is available for municipally-owned utilities.

7.3 PUBLICLY OWNED UTILITIES

Table 7-1 compares the characteristics of BPUB's customer base to the customer bases of other public power utilities offering energy efficiency programs, while Table 7-2 summarizes the programs offered by other utilities. As seen in Table 7-3, the most commonly offered programs within the publicly-owned utilities are the residential energy efficiency rebate programs, the residential solar rebate programs, and the commercial lighting programs. Table 7-3 provides descriptions of programs offered by public utilities that are comparable to BPUB.

Table 7-1 Public Utilities Customer Base

Utility Name	Type	City	# Residential Customers	Small Commercial	Large Commercial /Industrial	Total
New Braunfels Utilities	Public Power	New Braunfels	24,187	4,838	13	29,038
Bandera Electric Coop	Electric Cooperative	Bandera	27,275	4,363	40	31,678
College Station Utilities	Public Power	College Station	32,936	2,722	0	35,658
Denton Municipal Electric	Public Power	Denton	39,185	4,584	111	43,880
Brownsville	**Public Power**	**Brownsville**	**39,495**	**4,496**	**660**	**44,651**
Bryan Texas Utilities	Public Power	Bryan	40,624	6,611	17	47,252
Farmers Electric Coop	Electric Cooperative	Greenville	41,464	5,820	3	47,287
Guadalupe Valley Electric Cooperative	Electric Cooperative	Gonzales	61,409	4,938	32	66,379
Garland Power & Light	Public Power	Garland	61,691	6,257	8	67,956
United Cooperative Services	Electric Cooperative	Cleburne	63,515	10,834	49	74,398
Tri-County Electric Cooperative	Electric Cooperative	Azle	73,889	13,951	65	87,905
Magic Valley Electric Cooperative	Electric Cooperative	Mercedes	83,867	15,376	560	99,803
CoServ (Denton County Elec Coop Inc)	Electric Cooperative	Corinth	136,358	9,797	1,894	148,049
Pedernales Electric Cooperative	Electric Cooperative	Johnson City	212,007	19,829	917	232,753
Austin Energy	Public Power	Austin	364,554	44,747	80	409,381
CPS Energy	Public Power	San Antonio	622,818	78,468	72	701,358

Table 7-2 Energy Efficiency Programs Offered by Public Utilities in the State of Texas

Note: Program names and measures may be interchangeable due to the nature of the individual companies' nomenclature and program design. For example, an "Energy Efficiency Rebate Program" typically consists of a group of household items that rebates are available for, which may include heating & cooling and home efficiency improvements(i.e., attic insulation).	BPUB	Austin Energy	Bandera Electric Coop	Bryan Texas Utilities	College Station Utilities	CoServ	Denton Municipal Electric	CPS Energy	Farmers Electric Coop	Garland Power & Light	Guadalupe Valley Electric Coop	New Braunfels Utilities	Magic Valley Electric Coop	Pedernales Electric Coop	Tri-County Electric Coop	United Coop Services
RESIDENTIAL PROGRAMS																
Low Income Weatherization*		X							X							
Multi-Family Energy Efficiency Rebate Program		X														
New Residential Construction	X				X	X		X	X						X	X
Energy Audits					X	X	X	X	X						X	X
RESIDENTIAL ENERGY EFFICIENCY REBATE PROGRAM (the italicized items below are common measures found in Residential Energy Efficiency Rebate Programs)																
Residential Heat Pump Rebate Program			X			X									X	X
Photovoltaic (PV) Solar Rebate		X	X	X	X	X	X	X			X	X				
Residential/Agricultural Program																
Solar Water Heating Rebate		X		X			X	X	X		X	X				
High-Efficiency Water Heating Rebate	X		X			X			X		X		X			X
HVAC/Heat Pump Rebate/Tune-Up Programs (This can include Central A/C and Window Replacement AC)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Duct Replacement/Performance	X										X					
Compact Fluorescent Lighting				X	X	X			X						X	
Light Emitting Diode (LED) Lighting Rebate				X					X							
Solar Screens & Film Rebates	X						X	X			X	X				
Energy Efficient Windows	X						X			X						
Insulation	X						X	X		X	X				X	X
Programmable Thermostat							X	X								X
Household Appliances (i.e., Refrigerators, dishwashers, washing machines, etc.)								X	X		X	X			X	
Efficient Toilets	X											X				
Radiant Barrier	X															

Note: Program names and measures may be interchangeable due to the nature of the individual companies' nomenclature and program design. For example, an "Energy Efficiency Rebate Program" typically consists of a group of household items that rebates are available for, which may include heating & cooling and home efficiency improvements(i.e., attic insulation).	BPUB	Austin Energy	Bandera Electric Coop	Bryan Texas Utilities	College Station Utilities	CoServ	Denton Municipal Electric	CPS Energy	Farmers Electric Coop	Garland Power & Light	Guadalupe Valley Electric Coop	New Braunfels Utilities	Magic Valley Electric Coop	Pedernales Electric Coop	Tri-County Electric Coop	United Coop Services
COMMERCIAL/INDUSTRIAL/SMALL BUSINESS PROGRAMS																
Commercial New Construction		X						X								
Small Business Energy Efficiency Rebate Program		X														
Commercial Lighting Program				X		X		X		X				X		
Standard Offer Rebate Program (Comm & Ind)							X	X	X							
Commercial Energy Efficiency Rebates		X					X	X	X	X					X	
HVAC Rebate Program				X			X	X	X					X		
Renewable Energy Rebates											X					
Energy Efficient Water Heater Program (Res & Comm)	X														X	

Table 7-3 Public Utility Energy Efficiency Program Information

UTILITY	PROGRAM NAME	CUSTOMER CLASS	ELIGIBLE EFFICIENCY TECHNOLOGIES	PROGRAM BUDGET	MAX INCENTIVE
Denton Municipal Electric	GreenSense Energy Efficiency Rebate	• Commercial • Residential • Construction, Installer/ Contractor	• Central A/C: $600/unit • Central Heat Pumps: $700/unit • Geothermal Heat Pumps: $700/unit • Attic Reflective Radiant Barrier: $200 - $300 • Solar Screens: 30% of invoice • Energy Efficient Windows: 30% of invoice • Attic Insulation: 50% of invoice or ($0.01 x sq ft of insulated space x R-Value)	$210,000	Solar Screens: $200 Energy Efficient Windows: $500 Programmable Thermostat: $50 Attic Insulation: $400
Denton Municipal Electric	GreenSense Solar Rebate Program	• Commercial • Residential	• PV: $3.00 per AC watt* (based on the calculated expected performance of the system)	$120,000	PV: $15,000 per structure Solar Water Heater: 50% of project cost
Denton Municipal Electric	Standard Offer Rebate Program	• Commercial • Industrial	• Less than or equal to 100 kW: $100/kW saved over the minimum set by city, state, and federal energy efficiency standards.		50 percent of total project cost.
Bryan Texas Utilities	Commercial Lighting Program	Commercial	• Lighting, LED Lighting	Up to 50% of cost	
Bryan Texas Utilities	Solar Hot Water Rebate Program	All BTU Customers	• Solar Water Heat		$1,500
Bryan Texas Utilities	Solar PV Rebate Program	Any BTU Customer	• Photovoltaics		• Residential: 80% of invoice cost or $6,000 (whichever is less) • Commercial: $20,250
College Station Utilities	Residential Energy Back II Rebate Program	Residential	• Central A/C, Heat Pumps: $200 - $600, varies by efficiency rating		
Farmers Electric Cooperative	Residential/Agricultural Energy Efficiency Rebate Program	• Residential • Agricultural	• Electric Water Heaters: $100 • Air-Source Heat Pumps: $150 • Geothermal Heat Pumps: $1,000		

UTILITY	PROGRAM NAME	CUSTOMER CLASS	ELIGIBLE EFFICIENCY TECHNOLOGIES	PROGRAM BUDGET	MAX INCENTIVE
Bandera Electric Cooperative	Residential Heat Pump Rebate Program	Residential	• Heat pumps: $200		
Austin Energy	Power Saver Program	Residential	• Central A/C, $180 - $600 and Heat Pumps, $240 - $650 varies by efficiency rating		
Austin Energy	Air Conditioner Rebate Program	Residential	• $50 rebate on ENERGY STAR qualified window air conditioner		
CPS Energy	Central Air Conditioning and Heat Pump Rebate Program	Residential	• Rebates from $110/ton to $160/ton varies by efficiency rating		
CPS Energy	Air Conditioner Rebate Program	Residential	• $50 – 8,000 Btu/hr or smaller and $100 greater than 8,000 Btu/hr.		
CPS Energy	Air Flow Performance Rebates	Residential	• Duct Repair or Replacement – anywhere from 20% to 35% of the cost depending on method selected		
Garland Power & Light	Central A/C & Heat Pump Program	Residential	• Central A/C $400 - $600/unit and Central Heat Pumps $500 - $700 depending on efficiency ratings		
Garland Power & Light	Window Air Conditioning Program	Residential	• $50 – 8,000 Btu/hr or smaller and $100 greater than 8,000 Btu/hr.		
Garland Power & Light	Ceiling Insulation	Residential	• $0.15 per square foot of attic		
Garland Power & Light	Windows/Doors Insulation	Residential	• $5.00 per square foot		
Garland Power & Light	Window Solar Screens and Film	Residential	• $0.50 per square foot of windows covered		
Garland Power & Light	Duct Insulation or Replacement/Test Repair & Sealing	Residential	• $0.25 per square foot of conditioned space; leak testing, repairs and sealing: 50% of the cost.		

7.4 BPUB ENERGY EFFICIENCY /WATER CONSERVATION PROGRAMS

Like many other public utilities in Texas, BPUB has taken steps to promote energy conservation. Most recently (October 2011) BPUB introduced the GreenLiving program, which is a comprehensive residential and small business rebate program that provides incentives BPUB's customers for both energy efficiency and water conservation efforts. The program incentives are summarized in Table 7-4.

Table 7-4 BPUB GreenLiving Program Rebates

MEASURE DESCRIPTION	INCENTIVE SUMMARY	BUDGET (OCT 1, 2011 – SEPT 30, 2012)
HVAC (Heating, Ventilating and Air Conditioning)*	Up to $600 for qualifying units	$50,000
Duct Flow Performance	A rebate of 25% of cost to replace or repair, up to $500	$20,000
Solar Screens and Films	$0.50 per square foot installed	$1,800
ENERGY STAR Windows	30% of invoice, up to $500	$20,000
Radiant Barrier	$0.40 per square foot installed; up to $500	$20,000
ENERGY STAR Water Heaters	Capacity of 50 gallons or less qualify for $100 rebate Capacity over 50 gallons will qualify for $200 rebate	$12,000
WaterSense High Efficiency Toilets	$50 rebate per toilet; limit three toilets per customer	$4,000
Attic/ Ceiling Insulation	Up to $500	$16,000
New Homes Program	$300 per ENERGY STAR Home: Version 2.0** $500 per ENERGY STAR Home: Version 2.5** $150 Additional Premium for Version 3.0 $30 to HERS rater	$50,000
Promotion Related Expenses		$71,200
Total		**$265,000**

*This program has been available since September 2010.
**Home must be completed & certified by 12/31/2011

BPUB's air conditioning rebate program has been offered since September of 2010. The first reported results of this program are presented in Table 7-5.

Table 7-5 BPUB Air Conditioning Rebate Program Results

SEPTEMBER 2010 – DECEMBER 14, 2011	
Total Customer Participation	65
Total Number of EE A/Cs Installed	75
Average Tonnage	3.4
Average SEER	16.2
Total Amount Rebated to Customers	$32,150
Total Amount Paid to Raters	$6,875
Total Amount Given Back to the Community	$39,025

In addition to the incentivized program offerings, BPUB also has educational tools available to both its residential and commercial customers - Home Energy Suite and Commercial Energy Suite. These tools, which can be accessed via the Internet, provide self-help resources on energy conservation. The Energy Suite includes the following.

7.4.1 Residential

- Interactive Energy Home is designed to help customers understand where and how energy is used in the home, and how to use it wisely.
- The Home Energy Calculator provides quick estimates of customers' home's current energy-use costs.
- Lighting Calculator calculates how much money can be saved by switching from standard bulbs to compact fluorescent lights.
- Appliance Calculator provides down-to-the-penny energy operating costs for more than 50 different home appliances and electronic devices.
- Television Calculator compares the energy use and cost of LCD, DLP, plasma, and traditional tube televisions.
- Home Energy Library provides information related to home design and construction techniques and the latest in energy-efficiency equipment and appliances.
- Kids Korner provides colorful, interactive energy information and games.
- Fundamentals of Electricity presents the basics of electricity step by step - from power generation and energy delivery to electrical safety.

7.4.2 Commercial

- The Commercial Energy Calculator provides quick, detailed estimates of energy use costs for customers' business facilities, and allows for comparison to other businesses. More than 60 different business types modeled.
- The Commercial Energy Library contains thousands of pages of information in a format designed to make the information interesting and easily accessible.
- The Understanding Demand tool assists business customers in understanding the two distinct components to their electric bill: electricity demand and electricity usage.

In addition to these energy related tools BPUB also offers similar tools for water conservation.

7.5 INVESTOR OWNED UTILITIES

In addition to reviewing public power utility programs, Black & Veatch reviewed the Energy Efficiency Plan & Reports filed with the PUCT for each of the IOUs. These reports provided detail on costs and overall savings for those programs offered by the IOUs. Table 7-6 provides a high-level overview of the energy efficiency programs by each of the IOUs, which represent a combination of Standard Offer Programs (SOP) and Market Transformation Programs (MTP). SOPs are a type of energy efficiency program where parties enter into a contract with standard terms and conditions, and utilities offer standard incentives for a wide range of installed energy efficiency measures bundles together as a project. MTPs are programs designed to encourage lasting structural or behavioral changes in the market that result in increased adoption of energy efficient technologies, services, and/or practices.

Table 7-6 IOUs Energy Efficiency Program Information

PROGRAM TYPE	TYPE	AEP[(1)]	CNP	ETI	EPE	TNMP	ONCOR
Commercial & Industrial	SOP	X	X		X	X	X
Residential & Small Commercial	SOP	X	X	X	X	X	X
Hard-to-Reach	SOP	X	X	X	X	X	X
Load Management	SOP	X	X	X	X		X
Underserved Area	SOP					X	
Low-Income Weatherization	SOP	X	X	X		X	X
ENERGY STAR® New Homes[(2)]	MTP	X	X	X		X	X
Air Conditioning Distributor	MTP		X				X
Air Conditioning Installer Training	MTP		X				X
Retro-Commissioning	MTP		X				
Large C&I Solutions	MTP	X		X	X		
Residential and Small Commercial Solutions	MTP				X		
Hard-to-Reach Solutions	MTP				X		
LivingWise Education	MTP				X		X
Texas SCORE/CitySmart[(3)]	MTP	X	X	X	X	X	
A/C Tune-Up	MTP						X
Appliance Recycling[(4)]	MTP	X			X		X
Small Distributed Renewable Generation (Solar PV)	MTP	X		X	X	X	X
Residential Demand Response [(5)]	MTP	X					X
Texas Statewide CFL	MTP	X	X	X	X	X	X

[(1)]AEP includes AEP-TNC, AEP-TCC and AEP-SWEPCO in this table.
[(2)]Available in AEP-Texas Central only.
[(3)]Available in SWEPCO and Texas Central only.
[(4)]Available in Texas Central Company only.

Table 7-7 provides a high-level overview of the 2010 energy efficiency program costs and savings for each of the IOUs. The costs are reported into three categories: 1) Incentives 2) Administrative and 3) Research and Development costs. Both the energy and demand savings are reported for the 2010 program year.

Table 7-7 Public Utility Energy Efficiency Program Rebates/Incentives

Utility	Incentive Funds Expended ($)	Administrative Funds Expended ($)	Research & Development ($)	Funds Expended ($)	Demand Savings (MW)	Energy Savings (MWh)
AEP-SWEPCO	3,710,638	385,906	185,999	4,282,543	15	18,478
AEP-Texas Central	11,739,620	1,158,660	228	12,898,508	27	57,665
AEP-Texas North	2,003,280	234,820	95	2,238,195	5	14,194
CenterPoint	24,980,211	3,826,698	1,282,626	30,089,535	121	139,665
El Paso Electric	3,885,444	131,974	71,665	4,089,083	10	21,404
Entergy Texas, Inc.	6,407,000	625,000	----	7,032,000	13	28,630
Oncor Electric Delivery	36,361,584	4,202,264	750,245	41,314,093	101	225,785
Texas New Mexico Power (TNMP)	2,461,669	293,072	----	2,754,741	5	11,937

7.6 HIGH-LEVEL ESTIMATE OF ENERGY EFFICIENCY AND DSM FOR BPUB

In order to develop the high-level estimates of energy efficiency and DSM program savings and costs for BPUB, the IOUs program level information was utilized. Specifically, the following data as reported by the IOUs was used:

- Number of participants.
- Program costs:
  - Administrative
  - Incentive
- kW and kWh savings.

Using the reported IOU's program participation, costs, and savings, Black & Veatch created a high-level estimate of the participation, costs, and savings that might be realized if BPUB were to offer similar programs.

7.6.1 Description of IOU Programs

7.6.1.1 Residential Programs

ENERGY STAR® New Homes

This program targets several groups, primarily homebuilders and consumers. The program's goal is to create conditions in which consumers demand energy-efficient ENERGY STAR®-qualified homes, and homebuilders will supply them. Incentives are paid to homebuilders who construct ENERGY STAR®-qualified homes. A third-party implementer is contracted to implement and market the program as well as to provide specialized training to the builders and raters.

Residential Standard Offer Program

Utility contracts with Project Sponsors to deliver peak demand savings (measured in kilowatts, or kW) and/or annual energy savings (measured in kilowatt-hours, or kWh) by installing qualifying energy efficient measures at existing homes. The utility pays a fixed price in the form of incentives for kW and kWh savings resulting from the energy efficient measures installed. Project Sponsors may begin work upon the receipt of the "Approved" email notice. All installations must be submitted on an Invoice Report within 45 days of the installation.

Low-Income Energy Efficiency Program

This program is designed to cost-effectively reduce the energy consumption and energy costs for low-income residential customers. Weatherization service providers install eligible weatherization and energy efficiency measures in the homes of qualified residential customers who meet the current DOE income eligibility guidelines. 11

Typically the utility selects a program implementer through a competitive solicitation RFP process. The program implementer conducts outreach targeting existing weatherization service providers in the utility service territory. These weatherization service providers verify customer eligibility and conduct an energy use assessment of eligible customers' homes.

Demand Response SOP

This program is designed to offer residential demand response capabilities as a means to lessen on-peak electric demand. This Program allows the utility to curtail and/or cycle residential customer's central air conditioner (NC) compressor(s) with technology attached to the customer's equipment. Only central air conditioning units and single-family homes are eligible to participate in the program.

[11] This Senate Bill 712 Weatherization Program also provides targeted eligible residential customers with basic on-site energy education to satisfy the requirements of Substantive Rule 25.181(p).

7.6.1.2 Commercial Programs

Small Commercial and Large Commercial Standard Offer Program

This program targets commercial customers of all sizes. Incentives are paid to project sponsors for certain eligible measures installed in new or retrofit applications, based upon verified demand and energy savings. Any eligible project sponsor may submit an application for a project that meets minimum requirements.

Load Management

This program targets commercial customers with a peak electric demand of 500 kW or more. Incentives are paid to project sponsors to reduce peak electric load on 1-hour-ahead notice for load reduction periods of 2 to 4 hours duration. Incentive payments are based upon the metered peak demand reduction as called by the utility. Any eligible project sponsor may submit an application for a project in the area identified by meeting the minimum requirements.

7.6.2 Analysis of IOU Programs

Table 7-8 illustrates the average participation, costs, and savings from the reported programs. Table 7-9 presents a high level estimate of the participation, costs and savings that might be expected for BPUB. Actual participation, costs and savings will depend on the characteristics of BPUB's customer base and program design.

Analysis of Table 7-9 indicates that, based on the methodology described previously in this section, BPUB may realize demand reductions of approximately 1.5 MW and energy reductions of approximately 1,845 MWh. Costs to BPUB, based on Table 7-9, are approximately $198/kW and $0.16/kWh, respectively. These estimated savings and costs are calculated based on the totals shown in Table 7-8, and it should be noted that projected costs per kW and kWh saved vary by program and customer class. While these costs are representative of what may be experienced by BPUB, costs may be significantly different from those shown based on the ultimate program structure designed and implemented by BPUB. These estimates do not include any initial program start-up costs. We recommend that BPUB conduct a detailed program design to refine these estimates before initiating any programs.

Another factor to consider when viewing the results of the analyses presented herein is that the differences in demographics between BPUB's customer base and the customer bases of other utilities will affect BPUB's ability to achieve the same demand and energy reductions as realized by other utilities. In particular, customers with limited discretionary income may not view spending it on energy efficiency improvements as the most appropriate use of their income. In addition to considerations in differences in discretionary income, customers may choose to participate (or not to participate) in programs for various reasons. Stated otherwise, those customers that may choose to participate in a given DSM program will do so based on consideration of their own personal energy usage, their discretionary income, and other, non-quantifiable factors (such as the non-monetary value they place on energy efficiency).

When reviewing the results of the cost-effectiveness evaluations, all of the aforementioned factors should be considered. Taking such factors into consideration, the results of the cost-effectiveness evaluations should be viewed as useful for informational purposes, but not a definitive determinant of the overall benefits associated with DSM and energy efficiency programs that BPUB may offer.

Table 7-8 Program Costs and Savings

A	B	C	D	E	F	G	H	I	J
Program Type	# of Customers	# of Participants	Participation Rate (%)	Cost Per Participant (Incentive)	Cost per Participant (Admin)	Annual Utility Incentive Costs	Annual Utility Admin Costs	Annual kW Savings per Participant	Annual kWh Savings per Participant
RESIDENTIAL									
Energy Star New Homes	875,460	906	0.1035%	$703	$95	$1,529,020	$207,534	2	1,989
Standard Offer	278,880	3,113	1.1162%	$415	$43	$5,162,524	$531,536	1	2,591
Low Income	329,466	244	0.0742%	$230	$17	$2,371,436	$179,457	1	3,045
Demand Response SOP	1,807,001	8,478	0.4692%	$40	$15	$335,439	$126,563	1	-
COMMERCIAL									
Small Commercial SOP	541,421	30	0.0055%	$8,526	$1,914	$1,517,692	$340,707	27	131,221
Large Commercial SOP	753,375	188	0.0250%	$14,413	$1,306	$8,143,222	$738,155	228	196,575
Load Management	541,421	26	0.0048%	$64	$ 1,868	$2,045,098	$289,546	414	5,183

Table 7-9 Estimated Program Costs and Savings

A	B	C	D	E	F	G	H	I
Program Type	**# of Customers**	**Estimated BPUB Participation**	**Estimated Annual Incentive Costs**	**Estimated Annual Administrative Cost**	**Expected kW Annual Savings**	**Expected kWh Annual Savings**	**$/kW**	**$/kWh**
Residential	**39,495**	=Table 7-9 Column (B) x Table 7-8 Column D)	= Table 7-9 (Column C) x Table 7-8 (Column E)	= Table 7-9 (Column C) x Table 7-8 (Column F)	= Table 7-9 (Column C) x Table 7-8 (Column I)	= Table 7-9 (Column C) x Table 7-8 (Column J)	= Table 7-9 Total Cost (Column D + Column E)/ (Column F)	= Table 7-9 Total Cost (Column D + Column E)/ (Column G)
Energy Star New Homes		41	$28,810	$3,910	71	81,538	$461	$0.40
Standard Offer		441	$182,836	$18,825	395	1,142,762	$511	$0.18
Low Income		30	$6,901	$522	27	91,364	$275	$0.08
Demand Response		186	$7,359	$2,777	107	-	$95	N/A
Commercial	**5,156**							
Small Commercial SOP		1	$8,526	$1,914	27	131,221	$387	$0.08
Large Commercial SOP		2	$28,826	$2,613	456	393,151	$69	$0.08
Load Management		1	$32	$1,868	414	5,183	$5	$0.37
Total	**44,651**	**797**	**$263,290**	**$32,429**	**1,497**	**1,845,220**	**$198**	**$0.16**

8.0 Economic Modeling of Expansion Plan Scenarios

The assumptions and methodology used in the expansion planning and production cost modeling, as well as the results of the analyses performed by Black & Veatch, are presented in this section.

8.1 MODELING ASSUMPTIONS AND METHODOLOGY

Black & Veatch used the capacity expansion optimization computer model, Strategist™, to evaluate combinations of resources available to BPUB to meet future demand and energy requirements. Strategist™ has been used by Black & Veatch in various public service commission resource planning filings in Colorado, Florida, Ohio, Michigan, and other states, and has also been used by Black & Veatch to support clients' internal resource planning efforts. Strategist™ evaluates a typical week in each month of the year over the analysis period to optimize the least-cost generation alternatives considering peak demand, energy needs, fuel and emissions prices, fixed and variable operating costs, capital costs, and other factors, and estimates annual system costs. The software was used to evaluate the economics of conventional and renewable resources discussed in Section 7.0 of this IRP, as well as the economics of the DSM/energy efficiency bundle discussed in Section 8.0 of this IRP.

As discussed in Section 4.0 of this IRP, BPUB plans to maintain a 13.75 percent minimum reserve margin for firm load obligations. This target reserve margin criterion was held constant in all of the Strategist evaluations performed for this IRP. Based on the peak demand forecast in Section 3.0 BPUB will need approximately 21 MW in 2012, 41 MW in 2013, and 57 MW of additional capacity in 2014 to maintain a 13.75 percent reserve margin. For purposes of the economic analyses performed as part of this IRP, it has been assumed that the earliest that new generation could be brought on-line is 2014.

Black & Veatch used Strategist™ to develop capacity expansion plans in which the combination of existing capacity, in conjunction with new generating resources and DSM/energy efficiency added over the evaluation period, provided an economic solution to maintaining minimum target reserve margin requirements. In addition to firm capacity additions added throughout the planning horizon, Strategist™ was also allowed to utilize economy energy purchases from the market to meet the system energy requirements, subject to the constraints discussed in Section 2.0 of this IRP, when doing so was economic for the BPUB system. For this analysis, Black & Veatch's Proprietary Spring 2011 EMP for ERCOT ERCOT data set was utilized to provide hourly ERCOT power prices to dispatch the resources against in the decision of making economy energy purchases. The EMP is described further in Section 5.0.

Strategist™ was used to simulate the operation of the power supply system over the 20 year planning period by economically dispatching available resources to meet the projected capacity and energy requirements. Strategist™ included variable O&M, emissions costs, and fuel costs when determining the dispatch order for available generating resources. Black & Veatch developed specific energy production profiles for the wind and PV alternatives. In considering whether to select these alternatives, Strategist™ initially considers the energy production profile, with other units dispatched against the remaining energy requirements.

Based on the expansion plans developed using Strategist,™ Black & Veatch used PROMOD™ to provide CPWC estimates of the various expansion plans. PROMOD™ utilizes the same data inputs as Strategist™ and is frequently used to provide production cost analysis based on hourly, chronological load projections. The ability to analyze production costs on an hourly, chronological basis is advantageous when considering variable renewable energy resources (such as wind and PV), production profiles for which vary by the hour. PROMOD™ provides for a determination of CPWCs considering the hourly, chronological load projections and accounts for annual system costs (fuel and energy, fixed O&M, variable O&M, emissions, and levelized capital) for each year of the planning period. For purposes of this IRP, the CPWC were determined by discounting future cash flows back to 2012 at the assumed present worth discount rate of 5.0 percent. The total of these annual present worth costs over the 2012 through 2031period is the resulting CPWC of the expansion plan being considered. Such analysis allows a comparison of CPWC between various capacity expansion plans, and the plan with the lowest CPWC is considered the least-cost capacity expansion plan.

8.2 ECONOMIC PARAMETERS

The economic parameters used in this IRP include the annual inflation and escalation rates, present worth discount rate, and levelized fixed charge rates for new capital additions. The economic parameters used in this IRP are discussed below.

8.2.1 Inflation and Escalation Rates

Escalation rates have been developed for capital and O&M costs and are consistent with the general inflation rate. A 2.5 percent rate was used for annual general inflation and escalation.

8.2.2 Cost of Capital and Present Worth Discount Rates

The cost of capital and present worth discount rate are assumed to be 5.0 percent.

8.2.3 Levelized Fixed Charge Rates

Levelized fixed charge rates were developed for new capital additions based on the cost of capital. The levelized fixed charge rates were based on the assumption of using 100 percent tax exempt financing, and include 0.5 percent for property insurance.

Different types of generating units may have different economic lives. For purposes of this IRP, it has been assumed the new simple cycle and renewable alternatives have 20 year economic lives, while combined cycle units have 30 year economic lives. The resulting levelized fixed charge rates used in the analysis are 7.110 percent for 30 year financing and 8.788 percent for 20 year financing.

8.3 ADDITIONAL RELEVANT ASSUMPTIONS

Previous sections of this IRP present information utilized in developing the expansion planning and production cost models. In addition to the inputs previously discussed, the following general assumptions apply to the economic modeling performed for this IRP.

- With the exception of BPUB's share of Okalunion, all of BPUB's existing generating units are assumed to continue to operate through the entire planning period with performance consistent with the performance information provided by BPUB to Black & Veatch.
- Regarding Oklaunion, BPUB provided projected NO_x emissions reductions corresponding to planned emissions control retrofits for the unit. No projected performance or operating cost impacts associated with the retrofits were provided. Capital costs associated with the retrofits have not been reflected in the expansion planning analyses as such costs will be the same for all scenarios considered and therefore have no impact on the relative economics of the cases considered.
- It has been assumed that all new generating resources, including conventional and renewable, will be located in BPUB's service territory and will not impact the available transmission import or export capability discussed in Section 2.0 of this IRP.
- It has been assumed that all of BPUB's existing natural gas fired generating resources, including Hidalgo Energy Center, will continue to have an adequate supply of natural gas for the entire planning horizon. New natural gas generating resources are assumed to maintain adequate natural gas supply as well.
- All new generating resource alternatives, with the exception of the LM6000 combined cycle, Silas Ray Unit 5 recommissioning, and the biomass alternative are assumed to be available beginning in 2014. The LM6000 combined cycle, recommissioning of Silas Ray Unit 5, and the biomass alternative are assumed to be available beginning in 2015.
- Despite a projected need for capacity to maintain target reserve margin requirements beginning in 2012 and growing thereafter, given the lead time associated with new generating unit additions it has been assumed that the earliest a new resource could be added is 2014. The expansion planning and production costing models treat 2012 and 2013 identically between cases evaluated, and therefore these years have no impact on the relative economics of the cases considered.

8.4 RESULTS OF THE ECONOMIC ANALYSES

8.4.1 Reference Case

The Reference Case was developed to evaluate the economics of an expansion plan in which BPUB is assumed able to elect from the conventional and renewable alternatives discussed in Section 6.0 of this IRP. For purposes of the Reference Case analysis, it was assumed that a total of 200 MW (nameplate) of wind energy could be added to the BPUB system over the expansion planning horizon, as determined to be economic by Strategist™. The Reference Case is intended to be illustrative of an expansion plan that economically meets BPUB's projected capacity and energy requirements through the addition of new generation resources that are sized to be consistent with BPUB's project load growth and ability to solely pursue or develop. Stated otherwise, larger units that may offer economies of scale, such as a 300 MW 1x1 combined cycle, were not included in the Reference Case analysis as the capital requirements are considered to be in excess of what BPUB could absorb into its system without experiencing significant increase in rates. The opportunity to participate as a joint owner in such a unit, and the opportunity to enter into contracts for firm capacity and energy in the form of a PPA, were not considered in the economic analyses performed for this IRP, as such opportunities will be pursued through a RFP process subsequent to completion of this IRP.

Results of the Reference Case are summarized in Table 8-1, and indicate an expansion plan including the addition of a LM2500, several Wartsila units, four 50 MW (nameplate) wind resources, and recommissioning of Silas Ray Unit 5. The CPWC of the Reference Case is approximately $2,596,803,000. Review of the results presented in Table 8-1 indicates that at one least capacity addition is shown for every year of the expansion planning horizon for the Reference Case, with numerous years showing two capacity additions. BPUB may be able to avoid annual capacity additions (and logistics associated with such requirements) through obtaining a share of a larger unit in varying capacity amounts, or through a PPA that allows for annual flexibility in the level of capacity purchased. Such opportunities should be sought through the RFP that BPUB is planning on issuing following completion of this IRP.

Table 8-1 Summary of Reference Case Expansion Plan

YEAR	LM2500 (26.5 MW SUMMER)	WARTSILA (9.2 MW SUMMER)	WIND (4.4 MW SUMMER)	DSM COMPOSITE PROGRAM (0.7 MW SUMMER)	SILAS RAY UNIT 5 RECOMMISSIONING (18.4 MW SUMMER)	ANNUAL TOTAL UNITS ADDED	ANNUAL FIRM SUMMER CAPACITY ADDED (MW)
2014	1	4		1		6	64.0
2015					1	1	18.4
2016			2			2	8.8
2017		2				2	18.4
2018		2				2	18.4
2019		1				1	9.2
2020		1	2			3	18.0
2021		2				2	18.4
2022		1				1	9.2
2023		2				2	18.4
2024		2				2	18.4
2025		2				2	18.4
2026		2				2	18.4
2027		2				2	18.4
2028		2				2	18.4
2029		2				2	18.4
2030		2				2	18.4
2031		2				2	18.4
Total Units Added	1	31	4	1	1	38	
Firm Summer Capacity Added (MW)	26.5	285.2	17.6	0.7	18.4	0	348.4

8.4.2 No Wind Alternatives Case

As summarized previously, the Reference Case includes the addition of 200 MW (nameplate capacity) of wind, with 100 MW (nameplate) added in 2016 and 100 MW (nameplate) added in 2020. Selection of the wind resources by Strategist™ indicates that wind may be an economical resource for the BPUB system. An inherent assumption in this IRP is that all new generating resources, including wind, would be sited within BPUB's service territory so as to not impact BPUB's ability to import up to 50 MW of power from the spot market, when economic. Given the uncertainty associated with the ability to find a suitable site or sites for construction of 200 MW (nameplate) of wind generation within BPUB's service territory, Strategist™ was used to develop an alternative generation expansion plan that did not allow for selection of wind generation. Besides removing the wind alternative, all of the other parameters for the No Wind Alternative Case are identical to the Reference Case.

Results of the No Wind Alternative Case are summarized in Table 8-2, and indicate an expansion plan including the addition of a LM2500, several Wartsila units, and recommissioning of Silas Ray Unit 5. The overall expansion plan for this case is similar to the expansion plan in the Reference Case, with the timing of unit additions differing and the total number of Wartsila units added being one greater than the Reference Case. The CPWC of the No Wind Alternatives Case is approximately $2,642,609,000, which is approximately 1.8 percent higher than the CPWC of the Reference Case. As for the Reference Case, review of the results presented in Table 8-2 indicates that at one least capacity addition is shown for every year of the expansion planning horizon for the No Wind Alternatives Case, with numerous years showing two capacity additions. Regardless of whether BPUB pursues new wind generating resources, BPUB may be able to avoid annual capacity additions (and logistics associated with such requirements) through obtaining a share of a larger unit in varying capacity amounts, or through a PPA that allows for annual flexibility in the level of capacity purchased. Such opportunities should be sought through the RFP that BPUB is planning on issuing following completion of this IRP.

Table 8-2 Summary of No Wind Alternatives Case Expansion Plan

YEAR	LM2500 (26.5 MW SUMMER)	WARTSILA (9.2 MW SUMMER)	WIND (4.4 MW SUMMER)	DSM COMPOSITE PROGRAM (0.7 MW SUMMER)	SILAS RAY UNIT 5 RECOMMISSIONING (18.4 MW SUMMER)	ANNUAL TOTAL UNITS ADDED	ANNUAL FIRM SUMMER CAPACITY ADDED (MW)
2014	1	4	N/A	1		6	64.0
2015			N/A		1	1	18.4
2016		1	N/A			1	9.2
2017		2	N/A			2	18.4
2018		2	N/A			2	18.4
2019		1	N/A			1	9.2
2020		2	N/A			2	18.4
2021		2	N/A			2	18.4
2022		1	N/A			1	9.2
2023		2	N/A			2	18.4
2024		2	N/A			2	18.4
2025		2	N/A			2	18.4
2026		1	N/A			1	9.2
2027		2	N/A			2	18.4
2028		2	N/A			2	18.4
2029		2	N/A			2	18.4
2030		2	N/A			2	18.4
2031		2	N/A			2	18.4
Total Units Added	1	32	N/A	1	1	35	
Firm Summer Capacity Added (MW)	26.5	294.4	N/A	0.7	18.4	0	340.0

8.4.3 Avoided Costs

Based on the expansion plan and PROMOD™ simulation performed for the *Reference Case*, Black & Veatch developed an estimate of the associated avoided costs. The avoided costs include both capacity and energy components, with avoided capacity costs representing the cost of capacity additions necessary to maintain annual reserve margin requirements and avoided energy costs representing the cost to serve the last kWh of load.

8.4.3.1 Avoided Capacity Costs

In order to estimate avoided capacity costs, the annual capital and fixed O&M costs associated with the *Reference Case* expansion plan presented in Section 8.1 of this IRP were determined. As shown in Table 8-1 (presented previously in this IRP). The *Reference Case* expansion plan includes various capacity additions in the 2014 through 2031 timeframe. For each conventional capacity addition, the annual levelized capital cost was calculated by applying the levelized fixed charge to the installed capital cost estimate and annual fixed O&M costs were calculated based on the unit's estimate capacity and fixed O&M cost per kW[12]. For example, the *Reference Case* includes the addition of a GE LM2500 unit in 2014, with estimated capital and fixed O&M costs of $39,810,000 and $7.19/kW-year, respectively, in 2011 dollars. Escalation of the capital cost at 2.5 percent annually to 2014 dollars and application of the levelized fixed charge rate of 8.790 percent results in an annual levelized capital cost of $3,768,000 for the LM2500. Escalation of the fixed O&M costs at 2.5 percent annually results in 2014 costs of $811,000 for the LM2500. The levelized capital cost remains at $3,768,000 for all years of the planning horizon, while the fixed O&M costs of $811,000 escalate at 2.5 percent annually for all years of the planning horizon.

The methodology to calculate levelized capital and annual fixed O&M costs described in the previous paragraph was repeated for all conventional capacity additions throughout the 2014 through 2031 period, and annual levelized capital and fixed O&M costs were aggregated and then divided by the cumulative annual capacity additions to arrive at annual avoided capacity costs for the 2014 through 2031 period. Calculation of the avoided capacity costs in this manner ensures consistency with the avoided energy costs discussed below. The resulting annual avoided levelized capital, avoided fixed O&M, and overall avoided capacity costs are summarized in Table 8-3.

[12] Although the Reference Case expansion plan includes 100 MW (nameplate) of wind being added in 2016 and an additional 100 MW (nameplate) of wind being added in 2020, the calculation of avoided capacity costs excludes the wind resources as these resources are added primarily to lower system generation costs, and not for capacity purposes. Inclusion of capacity costs associated with the wind additions would distort the avoided capacity cost calculations.

Table 8-3 Avoided Capacity Costs (all costs in nominal dollars)

YEAR	AVOIDED LEVELIZED CAPITAL COST ($000)	AVOIDED FIXED O&M COST ($000)	TOTAL AVOIDED CAPACITY COST ($000)	CUMULATIVE CAPACITY ADDED (MW)	TOTAL AVOIDED CAPACITY COST ($/KW)
2014	$8,007.73	$811.15	$8,818.88	63	$139.42
2015	$9,591.36	$831.42	$10,422.79	82	$127.65
2016	$9,591.36	$852.21	$10,443.57	82	$127.90
2017	$11,874.02	$1,199.99	$13,074.01	100	$130.67
2018	$14,213.74	$1,564.63	$15,778.37	118	$133.20
2019	$15,412.85	$1,775.25	$17,188.10	128	$134.65
2020	$16,641.94	$1,995.42	$18,637.36	137	$136.19
2021	$19,161.56	$2,405.68	$21,567.24	155	$138.92
2022	$20,452.87	$2,650.51	$23,103.38	164	$140.49
2023	$23,100.05	$3,095.38	$26,195.43	183	$143.26
2024	$25,813.41	$3,560.85	$29,374.26	201	$145.96
2025	$28,594.61	$4,047.65	$32,642.25	220	$148.61
2026	$31,445.33	$4,556.56	$36,001.89	238	$151.24
2027	$34,367.32	$5,088.40	$39,455.72	256	$153.85
2028	$37,362.37	$5,643.97	$43,006.34	275	$156.47
2029	$40,432.28	$6,224.15	$46,656.43	293	$159.10
2030	$43,578.95	$6,829.80	$50,408.75	312	$161.75
2031	$46,804.28	$7,461.85	$54,266.13	330	$164.42

8.4.3.2 Avoided Energy Costs

Avoided energy costs were queried out of the PROMOD™ production cost model results for the *Reference Case*. The magnitude of avoided energy costs will vary on an hourly basis due to changes in hourly loads, the resources that are being dispatched, and at what point in the dispatch curve each resource is operating. However, given the volume of hourly data that results from a 20 year, hourly simulation (20 years x 8,760 hours per year = 175,200 data points), the avoided energy costs presented in Table 8-4 represent the annual average of annual monthly on-peak, off-peak, and average avoided energy costs.

Table 8-4 Avoided Energy Costs (all costs in nominal dollars)

YEAR	ON-PEAK ($/MWH)	OFF-PEAK ($/MWH)	AVERAGE ($/MWH)
2012	49.40	35.68	42.43
2013	56.72	38.92	47.39
2014	60.26	42.20	50.75
2015	58.04	48.37	53.09
2016	58.69	47.95	53.01
2017	61.74	48.11	54.61
2018	64.37	51.76	57.79
2019	69.88	53.15	61.26
2020	83.42	72.25	77.72
2021	87.16	73.51	80.02
2022	94.16	77.58	85.57
2023	96.65	81.37	88.58
2024	102.14	86.13	93.78
2025	107.63	91.00	98.93
2026	115.42	96.16	105.33
2027	121.93	103.88	112.38
2028	130.30	111.57	120.28
2029	140.49	120.72	130.00
2030	150.76	129.29	139.38
2031	159.54	137.45	147.87

8.4.3.3 Interpretation of Results

The discussion of avoided costs presented thus far summaries the avoided capacity and energy costs associated with the Reference Case. As stated previously, avoided capacity costs represent the cost of capacity additions necessary to maintain annual reserve margin requirements and avoided energy costs represent the cost to serve the last kWh of load. As shown in Tables 8-3 and 8-4, the avoided capacity and energy costs vary by year as new capacity is added to maintain reserve margin requirements and system dispatch costs reflect the impact of new generating units, changes in loads, and changes in fuel, power, and emissions prices. The avoided capacity and energy costs may be used to provide insight into the level of incentives that may result in cost-effective DSM program offerings. However, it should be noted that more detailed analysis into the impact on BPUB's rates associated with DSM programs is an appropriate step in BPUB's evaluation of the cost-effectiveness of DSM. Such a study is beyond the scope of this IRP.

To illustrate how the avoided capacity and energy costs may be used to estimate the level of incentive that may be cost-effective, Black & Veatch reviewed the 2010 Demand-Side Management Plan (2010 DSM Plan) of Florida Power & Light Company (FPL), which is a publicly available document. While FPL's 2010 DSM Plan included information on a number of DSM programs, the example calculation below is based on FPL's Residential Air Conditioning program. Based on review of FPL's 2010 DSM Plan, the Residential Air Conditioning program is projected to reduce summer peak demand by 0.56 kW per participating customer and reduce annual energy consumption by 1,030 kWh per customer. Analysis of Table 8-3 indicates that the cumulative present value of the avoided capacity costs for the 10-year period of 2014 through 2023 is approximately$1,093/kW, and the cumulative present value of the avoided energy costs for this same period (based on the annual average avoided energy costs shown in Table 8-4) is approximately $538/MWh. Multiplying these projected avoided capacity and energy cost savings by the respective demand and energy reductions (0.56 kW and 1,030 kWh, per participating customer) and adding them together results in a value of approximately $1,150. The $1,150 value may be viewed as indicative of the current incentive that BPUB may offer customers to participate in an air conditioning program that is structured similarly to that offered by FPL, upon which this example is based, assuming the air conditioner has a useful life of 10 years.

8.4.4 Assessment of Impact to Retail Rates

In addition to developing the Reference Case, which was determined by Strategist™ as the most economical expansion plan given constraints placed on the amount of wind that could be added to BPUB's system, Black & Veatch also analyzed the amount of wind that could be added without increasing the retail rates by more than 2 percent in 2014.

8.4.4.1 Study Period

Analysis of the rate impact in 2014 was performed as doing so allows for consideration of the rate impacts in the short term instead of the long term. Longer-term rate studies are done periodically, and typically utility stakeholders and regulators are more focused on the near term rate increases compared to long term.

8.4.4.2 Study Approach

Black & Veatch first modified the Reference Case to not include any of the renewable resources selected during through 2016. In the Reference Case, 100 MW (nameplate capacity) of wind was added in 2016. None of the conventional resources selected in the Reference Case through 2016 were changed. The firm summer capacity of the 100 MW wind resource was assumed to be approximately 8.8 MW. To maintain the target reserve margin of 13.75 percent in all years after removing the wind resources selected in the Reference Case, Black & Veatch added a Wartsila unit, with firm capacity 9.2 MW, in 2016. Black & Veatch then used PROMOD™ to develop the projected annual system cost for the 2012 through 2016 period. This new case, referred to as the No Wind Case, was used as the baseline scenario purposes of the retail rate analysis.

The resulting annual system cost for each year in the baseline scenario, as obtained from the PROMOD™ run, was then divided by the forecast annual system energy sales for each year to determine the unit cost of electricity generation in these years. The forecast of annual system sales was computed by reducing the NEL by 7 percent on account of system losses.

The "non-generation" cost rate for each year from 2012 through 2016 was then added to the system cost rate for the corresponding year (as obtained from the PROMOD™ run described above) to determine the required average electricity rates for each of those years. For this analysis, Black & Veatch assumed that the base year would be 2012 and the average retail electricity rates for BPUB in 2012 would be 10 cents per kilowatt hour(cents/kWh). This assumption was based on the fact that BPUB's average retail electricity rate for 2010 was around 9 cents/kWh and the assumption that there would be rate increases in 2010-2011 and 2011-2012 periods, such that rates for 2012 would be approximately 10 cents/kWh. The difference between the average retail electricity rates and the cost of generation (in cents/kWh) for 2012 was assumed to be the "non-generation" cost rate (cents/kWh). This rate was kept constant for the 2012 through 2016 period. Black & Veatch then calculated the percent increase in the annual average electricity rates by comparing them against the base year electricity rates. The percent rate increase thus obtained provided the baseline scenario of annual rate increases that would be required to meet load and reserve margin requirements for 2012 through 2016 without adding any wind or other renewable resources.

Since the first year that new generation, including wind, is assumed available for purposes of developing this IRP is 2014, Black & Veatch used 2014 as the year for comparison with the baseline scenario to determine how much wind capacity could be added in 2014 without increasing the rates for 2014 by more than 2 percent as compared to the required rate increase computed in the baseline scenario described above.

This was an iterative process where Black & Veatch added small increments of wind resources in 2014 (and not change any other expansion units) and obtained system costs from PROMOD™ runs and then repeated the steps described above to estimate the additional rate increase required for 2014 compared to the baseline scenario required rate increase. Black & Veatch stopped the iteration when the additional rate increase exceeded 2 percent.

8.4.4.3 Study Results

Based on the PROMOD run results, the average cost of generation for 2012 was computed to be 5.54 cents/kWh. Backing off from the assumed retail electricity rate of 10 cents/kWh in 2012, the "non-generation" cost for 2012 was computed to be 4.45 cents/kWh and this was kept constant for 2014 Black & Veatch then computed the baseline scenario of annual percent rate increase compared to the base year of 2012. The rate increase for 2014 was computed to be approximately 12.4 percent compared to the base year rate of 10 cents/kWh.

After several iterations of PROMOD™ runs Black & Veatch established that by adding 33 MW of wind in 2014 the resulting rate increase would be 14.4 percent compared to the base year rate of 10 cents/kWh. The difference between this increase and the increase in the baseline scenario (14.4 percent minus 12.4 percent = 2.0 percent) indicates that the additional increase in rates for 2014 is approximately 2.0 percent. Adding additional wind resources beyond 33 MW in 2014 caused the additional rate increase to exceed 2 percent.

8.4.5 Additional Economic Evaluations

As development of this IRP progressed, BPUB requested that Black & Veatch perform additional analyses to evaluate the economics of three specific alternatives that had not previously been considered. These alternatives, along with the evaluation approach and the results of the additional economic evaluations, are discussed in the remainder of this section.

8.4.5.1 Additional Alternatives Considered

The additional analysis considered three alternatives, described as follows:

- Inlet Fogging - the addition of inlet fogging on Silas Ray Unit 6/9, which BPUB indicated is estimated to provide 7 MW of incremental summer capacity at a capital cost of $1.9 million.
- Tenaska Alternative - participation in a unit proposed by Tenaska through a build-own-transfer arrangement in a new 2x1 7FA combined cycle unit to be constructed within BPUB's service territory. Costs and performance for this alternative were provided by Tenaska.
- Transmission Alternative - construction of a new transmission line that, based on information provided by BPUB, will allow for 100 MW of additional import capability into the BPUB system at a cost of $18.5 million.

8.4.5.2 Methodology for Additional Economic Evaluations

The overall methodology used in performing the additional economic evaluations was largely similar to that described previously in the IRP, with the exception being how projected capacity requirements in the 2012 through 2015 timeframe were met. Due to the timing of when the Tenaska Alternative and the Transmission Alternative would be in commercial operation (assumed to be 2016), adjustments needed to be made to the previously described Reference Case to allow for a consistent basis of comparison. Specifically, the Modified Reference Case was developed to evaluate the economics of an expansion plan in which BPUB's projected capacity requirements were satisfied in the 2012 through 2015 timeframe through market purchases, with pricing based on the market prices included in the Spring 2011 EMP for ERCOT. Beginning in 2016, Strategist™ was used to develop the Modified Reference Case in which the same alternatives considered in the Reference Case plus the inlet fogging option for Silas Ray Unit 6/9 as were evaluated. Once the expansion plan was determined, PROMOD™ was used to develop the CPWC of the Modified Reference Case. It should be noted that the results of the Modified Reference Case are not intended to be compared to the results of the Reference Case, but instead was developed specifically to allow for consistent comparisons between the three alternatives considered in the additional economic evaluations, as there will be no differences in resource additions prior to 2016 that impact the economics of the various cases.

In order to evaluate the Tenaska Alternative, the years 2012 through 2015 were treated in the same manner as in the Modified Reference Case. Two different expansion plans including the Tenaska Alternative were evaluated as follows:

- Beginning in 2016, the Tenaska Alternative was modeled as a 100 MW ownership share, and Strategist™ was used to develop an expansion plan in which the same alternatives considered in the Modified Reference Case were evaluated. Once the expansion plan was determined, PROMOD™ was used to develop the CPWC of the expansion plan including the Tenaska Alternative.
- For the Modified Tenaska Alternative, the expansion plan developed in analyzing the Tenaska Alternative as described above was held constant through 2016, and capacity requirements beyond 2016 were met through the addition of 50 MW of incremental capacity from Tenaska. The new wind generation selected in the previous Tenaska evaluation was carried forward to the Modified Tenaska Alternative evaluation.

The Transmission Alternative was evaluated by treating the years 2012 through 2015 in the same manner as in the Modified Reference Case. Beginning in 2016, the Transmission Alternative was modeled as providing 100 MW of incremental firm capacity capability, with costs for market purchases associated with the Transmission Alternative based on the Spring 2011 EMP for ERCOT. Strategist™ was then used to develop an expansion plan in which the same alternatives considered in the Modified Reference Case were evaluated. Once the expansion plan was determined, PROMOD™ was used to develop the CPWC of the expansion plan including the Transmission Alternative.

8.4.5.3 Results of the Additional Economic Evaluations

The expansion plans associated with the Modified Reference Case, the Tenaska Alternative, and the Transmission Alternative, along with corresponding CPWCs for each evaluation, are presented in Table 8-5. As shown in Table 8-5, the CPWC of the expansion plan including the Tenaska Alternative is approximately $63.8 million (2.5 percent) lower than the CPWC of the Modified Reference Case. Additionally, the CPWC of the expansion plan including the Transmission Alternative is approximately $69.5 million (2.7 percent) lower than the CPWC of the Modified Reference Case, and is approximately $5.8 million (0.2 percent) lower than the expansion plan including the Tenaska Alternative. The CPWC of the expansion plan including the Modified Tenaska Alternative is approximately $200.5 million (7.7 percent) lower than the CPWC of the Modified Reference case, making it the lowest cost expansion plan of those discussed in this section.

Based on the results of the additional economic evaluation as summarized in Table 8-5, it the addition of inlet fogging for Silas Ray Unit 6/9 appears to be economic, as it is included in each of the expansion plans presented in Table 8-5. It can also be concluded that, based on the cost and performance characteristics assumed for purposes of this analysis, an expansion plan including the Tenaska Alternative offers economic benefits compared to an expansion plan in which only units that provide capacity increments aligned with BPUB's capacity requirements are considered. That is, the opportunity to participate on an equity basis in a larger, more economic unit, which is the opportunity afforded by the Tenaska Alternative, should be evaluated further by BPUB. In evaluating opportunities of this sort, BPUB should pay close attention to the overall capacity subscription level of a proposed new unit. That is, BPUB making a commitment for 100 MW of a unit proposed as a 2x1 combined cycle with net capacity in excess of 700 MW is likely not sufficient for the project to move forward without additional commitments by other entities. Additionally, analysis of the Tenaska Alternative assumes that BPUB would have full dispatch control over the unit such that operation of the unit is consistent with BPUB's system requirements; with other entities participating in a jointly owned unit, this may not be the case and the extent to which operational aspects may impact the economics should be considered.

When considering the results of the expansion plan associated with Modified Tenaska Alternative, BPUB should consider implications to system reliability as they relate to the amount of capacity associated with any particular resource. While the results of the analysis discussed in this section indicate that increased capacity from the Tenaska Alternative may be economic, the ability to serve load in the event the unit is out of service for a prolonged period of time, particularly an unexpected outage during a peak period, should be factored into the decision of how much capacity is optimal.

Table 8-5 Summary of Expansion Plans for Additional Economic Evaluations

YEAR	MODIFIED REFERENCE CASE	TENASKA ALTERNATIVE	MODIFIED TENASKA ALTERNATIVE	TRANSMISSION ALTERNATIVE
2012 - 2015	Market Purchases	Market Purchases	Market Purchases	Market Purchases
2016	85.3 MW LMS100 DSM Composite Program Unit 6/9 Inlet Fogging	100 MW Tenaska DSM Composite Program Unit 6/9 Inlet Fogging	100 MW Tenaska DSM Composite Program Unit 6/9 Inlet Fogging	100 MW PPA DSM Composite Program Unit 6/9 Inlet Fogging Recommission Silas Ray Unit 5 (2) x 50 MW (nameplate) Wind
2017	(2) x 9.2 MW Wartsila			
2018	(2) x 9.2 MW Wartsila	(2) x 9.2 MW Wartsila	50 MW Tenaska	
2019	(1) x 9.2 MW Wartsila (1) x 50 MW (nameplate) Wind	(2) x 9.2 MW Wartsila		(1) x 9.2 MW Wartsila
2020	(2) x 50 MW (nameplate) Wind	(2) x 50 MW (nameplate) Wind	(2) x 50 MW (nameplate) Wind	(2) x 50 MW (nameplate) Wind
2021	(2) x 9.2 MW Wartsila	(2) x 9.2 MW Wartsila	50 MW Tenaska	(2) x 9.2 MW Wartsila
2022	(2) x 9.2 MW Wartsila	(1) x 9.2 MW Wartsila (1) x 50 MW (nameplate) Wind	(1) x 50 MW (nameplate) Wind	(2) x 9.2 MW Wartsila
2023	(2) x 9.2 MW Wartsila	(1) x 9.2 MW Wartsila (1) x 50 MW (nameplate) Wind	(1) x 50 MW (nameplate) Wind	(1) x 9.2 MW Wartsila
2024	(2) x 9.2 MW Wartsila	(2) x 9.2 MW Wartsila		(2) x 9.2 MW Wartsila
2025	(1) x 9.2 MW Wartsila	(2) x 9.2 MW Wartsila	50 MW Tenaska	(2) x 9.2 MW Wartsila
2026	(2) x 9.2 MW Wartsila	(2) x 9.2 MW Wartsila		(2) x 9.2 MW Wartsila
2027	(2) x 9.2 MW Wartsila	(2) x 9.2 MW Wartsila		(2) x 9.2 MW Wartsila
2028	(2) x 9.2 MW Wartsila	(2) x 9.2 MW Wartsila	50 MW Tenaska	(2) x 9.2 MW Wartsila
2029	(2) x 9.2 MW Wartsila	(2) x 9.2 MW Wartsila		(2) x 9.2 MW Wartsila
2030	(2) x 9.2 MW Wartsila	(2) x 9.2 MW Wartsila		(1) x 26.5 MW LM2500 (1) x 9.2 MW Wartsila
2031	(1) x 26.5 MW LM2500	(2) x 9.2 MW Wartsila	50 MW Tenaska	
CPWC ($1000s)	2,594,868	$2,531,111	$2,394,369	$2,525,341

Regarding the Transmission Alternative, while the economics may be favorable compared to the Modified Reference Case and to a lesser degree compared to the Tenaska Alternative, it should be noted that the analysis performed for this IRP is based on projections of market power prices, and not on a specific offer for firm power delivered to BPUB. To the extent BPUB receives offers for market power that differ from the prices evaluated herein, the relative economics between relying on the market for power versus building new generation within BPUB's service territory will be affected. Additionally, BPUB should ensure that offers for power are firm in nature, including transmission capability, if BPUB is going to rely on the power purchase to satisfy target reserve margin requirements and serve firm load obligations.

9.0 Conclusions and Recommendations

The following conclusions and recommendations can be drawn based on the input parameters, assumptions, and analyses discussed throughout this IRP. A high level summary of the findings is presented first, followed by more detailed conclusions and recommendations.

9.1 HIGH LEVEL SUMMARY FINDINGS

- The economic analysis indicates that 100 MW share of proposed Tenaska project may be economical for BPUB, and increased capacity from the proposed unit improves overall economics of the system.
- The economies of scale associated with more efficient, larger generating unit as compared to generating unit alternatives that are sized to be consistent with BPUB's projected load growth and ability to pursue or develop without involvement from other utility (or utilities) or developer (i.e. relatively smaller units) are reflected in the results of the economic analysis.
- Brownsville is located in a load pocket in the ERCOT grid. As a result of its physical location, at the current time, there is limited available transmission that can be used to bring additional supplies of power into the Brownsville area. As loads grow or resources retire, new generation needs to be located within the Brownsville geographic area unless additional transmission is built into the Brownsville area. While ERCOT is considering building additional transmission into the Brownsville area, to date it has not committed to doing soBPUB's need for new power in the future is small in comparison to the size of the most economical new power plants. Therefore, if new power supplies are to be built in the Brownsville area (i.e., because transmission is not sufficient to bring in power supplies from outside the Brownsville area), then the technology of choice seems to be the Wartsila unit with net capacity of approximately 9.2 MW. These units provide capacity increments that are aligned with the Brownsville need for new power supply. However, smaller units like these are typically more expensive to build and operate than larger units on a per kW and per kWh basis. Alternative, more economical sources of power may be identified through a competitive solicitation (such as a power supply request for proposals, or RFP), as supported by the analysis of the Tenaska Alternative and the Transmission Alternative.
- When BPUB conducts a competitive solicitation for new power supplies, it should require bidders to demonstrate how they plan to deliver the power so that it can be used to serve Brownsville retail loads. Bidders of power from generating units located outside of the Brownsville area will need to discuss transmission needs with ERCOT and/or plan on financing/building the needed transmission themselves and including those costs in their bids.

- Renewable resources (i.e., wind) could be used to help meet BPUB's need for additional power to serve their retail customers. Under an assumption that regulation of emissions of CO_2 will begin adding considerable costs to the burning of fossil fuels in the future, it appears that wind can be added starting in the year 2016 and will be shown to be economic over the life of the wind plant. However, if emissions of CO_2 are not regulated, then the wind may not be economic over its life.
- With respect to impact on Brownsville retail rates in the early years, PROMOD™ analysis indicates that Brownsville could add approximately 33MW (nameplate) of new wind to its portfolio starting in the year 2014 without increasing retail rates by more than 2 percent in that year.

9.2 CONCLUSIONS

- Expansion of BPUB's demand-side management and energy efficiency program offerings appears to be economic, based on the analysis performed as part of this IRP. Additional study is required to determine optimum program design and implementation strategies for BPUB to consider. Such a study is beyond the scope of this IRP.
- BPUB's existing agreements for natural gas supply appear to provide for adequate and reliable natural gas capacity. However, as additional natural gas fired generating units are added to serve load, BPUB must ensure sufficient natural gas capacity is reserved.
- As demand for natural gas increases through 2035, the Henry Hub natural gas price is projected to double (in real terms). As BPUB's system becomes increasingly reliant on natural gas, the cost of natural gas will have a greater impact on BPUB's cost to serve load.
- The load forecast utilized for purposes of this IRP was developed by R.W. Beck/SAIC in the 2009 period. Coupled with capacity available from BPUB's existing generating resources, BPUB is projected to require approximately an additional 21 MW to maintain reserve margin requirements in the summer of 2012, increasing to approximately 41 MW in the summer of 2013 and approximately 57 MW in the summer of 2014. By the end of the planning horizon considered in this IRP, BPUB's need for additional capacity to maintain reserve margin requirements is approximately is approximately 339 MW.
- The results of the economic analyses presented in this IRP indicate that the addition of inlet fogging for Silas Ray Unit 9 is an economic decision.
- The results of the economic analyses presented in this IRP indicate that recommissioning Silas Ray Unit 5 in the 2015 timeframe is an economic decision.
- The economic analyses indicate that the addition of wind energy may be economic for BPUB. However, careful consideration should be given to the impact wind may have on BPUB's transmission system.

- Economies of scale associated with ability to obtain capacity from larger, more economical units than BPUB may be able to pursue/develop without involvement from other utility (or utilities) or developers (i.e. relatively smaller units) are demonstrated by analysis of the Tenaska alternative.
- The Transmission Alternative case indicates that purchasing power from the market to meet system requirements may be more economic than adding generating units sized in proportion to the BPUB system.

9.3 RECOMMENDATIONS

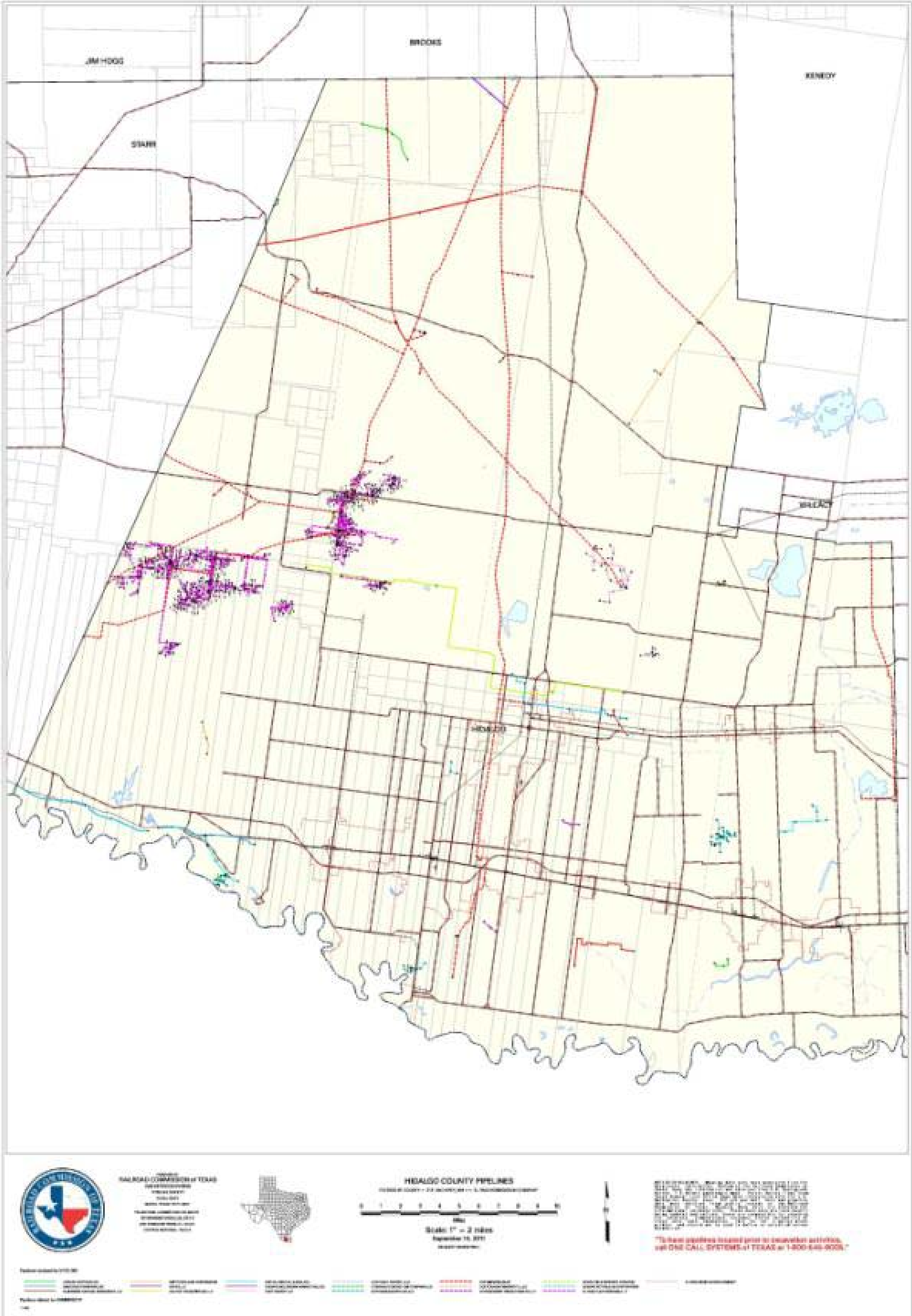
- BPUB should continue to monitor program costs and participation levels associated with its GreenLiving program to ensure the program achievements are beneficial to BPUB and its customers.
- BPUB should evaluate the potential benefits of expanding its demand-side management and energy efficiency program offerings through a DSM/energy efficiency potential study.
- BPUB is interested in demonstrating to potential industrial development companies that it has the ability to serve them reliably. Showing the existence of sufficient transmission capacity from the LRGV area to the greater Brownsville area is one way to make this demonstration. If the Public Utility Commission of Texas does not approve the new Cross Valley transmission line, or if ERCOT chooses not to build transmission for speculative loads, BPUB may want to consider building and owning such transmission itself. BPUB may want to study the possibility of building such transmission in advance of the load materializing. If it does so, BPUB may end up owning transmission that is not needed for load. BPUB may have value in owning such a line simply to allow it to import more spot market power and avoid running more expensive generation it owns within its service territory.
- BPUB should continue to monitor ERCOT studies related to transmission capabilities into and out of the Brownsville area, as the ability to import generation from new resources located outside of the Brownsville area is currently limited to approximately 80 MW. Should BPUB pursue power purchase agreements and/or joint ownership opportunities associated with generating resources outside of the Brownsville area, BPUB must ensure that adequate and reliable firm transmission capability is available.
- Increased reliance on natural gas fired generation resources will result in BPUB's cost to serve load becoming more correlated to the cost of natural gas. In recent years and in the near-term, natural gas prices have been and are projected to be at or near historic lows. However, as demand for natural gas increases over the next 20 years, the projected price of natural gas at Henry Hub is projected to double in real terms. In addition, a prolonged disruption in natural gas supplies will have an increasingly adverse impact on BPUB's ability to serve load. As such, BPUB should

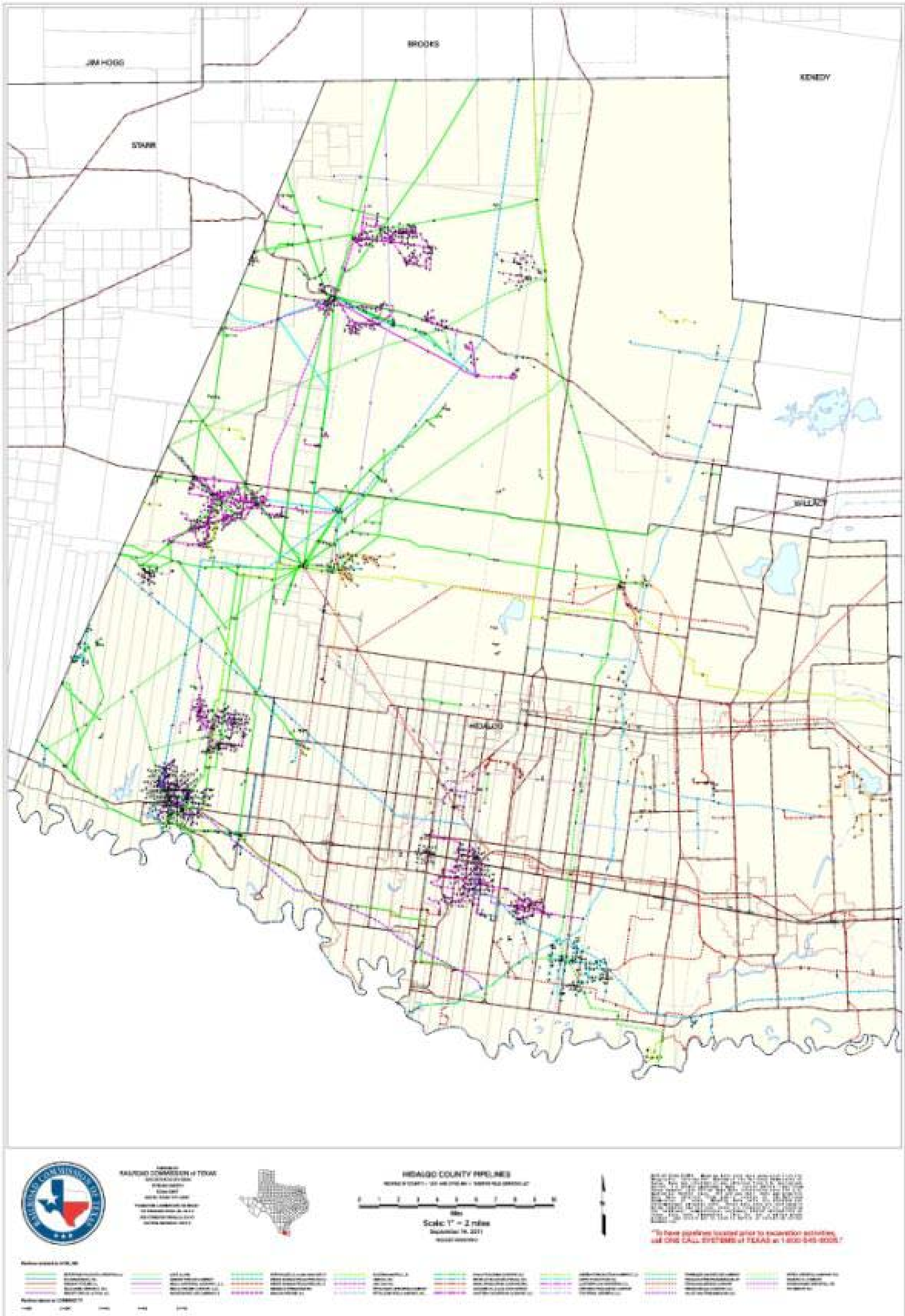
give consideration to making its resource decisions based in part upon a risk analysis that considers the impact of increasing natural gas prices on its generation expansion planning.

- It is recommended that analysis focus on the availability and cost of contractually or operationally firm pipeline capacity sufficient to provide for the proposed available generation capacity. Supply is abundant and will become even more abundant during the forecast horizon as the Eagle Ford Shale resources are developed. Pipeline capacity development may not keep pace with supply development.
- BPUB should evaluate the possibility of alternative transporters and suppliers of natural gas to the Hidalgo and Silas Ray sites, as outlined in more detail in Section 2.4.7 of this IRP.
- When gas-fired resources are considered in alternative locations, such as at the Port of Brownsville and Site FM 511, it is strongly recommended that the availability of favorable pipeline capacity with the ability to accommodate future expansion be considered as a major component in the site ranking and selection.
- The load forecast used in this IRP was developed by R.W. Beck/SAIC in the 2009 timeframe, and resulted in projected summer peak demand growing at an average annual rate of approximately 3.4 percent, and annual energy requirement growing at approximately 3.3 percent. Given the vintage of this load forecast and the current state of the economy, consideration should be given to evaluating resource planning decisions in light of sensitivities to these projected growth rates.
- BPUB has indicated the possibility of a relatively large industrial load being added in the near-term. Such a load addition would represent a significant step increase in both peak demand and annual energy requirements, and would likely affect the determination of the most cost-effective near-term resource additions. BPUB should consider evaluations to gauge the impact of such a potential large load addition on both its generation and transmission planning efforts.
- BPUB should continue to explore recommissioning Silas Ray Unit 5, as doing so appears to be a cost-effective source of reliable capacity. Analysis of details related to the recommissioning process (including permitting requirements) was beyond the scope of this IRP.
- The addition of inlet fogging on Silas Ray Unit 6/9 appears to be an economic source of incremental capacity that may be available to the BPUB system in the near-term, and as such may warrant further consideration.
- As BPUB continues to explore the addition of wind energy, additional study may be appropriate in order to better evaluate the impact that wind may have on operations of BPUB's conventional generating units and on BPUB's transmission system.

- While the Tenaska Case, Modified Tenaska Case, and Transmission Case may be economic compared to the Modified Reference Case, there are other considerations to keep in mind. Since BPUB initially needs about 100 MW of capacity from the unit, this commitment from BPUB will likely not be sufficient to drive development of the proposed Tenaska unit. Therefore, it is recommended that BPUB consider the likelihood of the unit being constructed as proposed. In addition, increasing capacity allocation from single unit (i.e. Tenaska) leads to increased reliability risk as outage of the unit would have impact on BPUB's ability to serve customer requirements and the cost to do so. For power generated outside of BPUB's service territory, BPUB needs to ensure firm delivery of power is available to meet BPUB's system requirements.
- The Reference Case is intended to be illustrative of an expansion plan that economically meets BPUB's projected capacity and energy requirements through the addition of new generation resources that are sized to be consistent with BPUB's projected load growth and ability to pursue or develop without involvement from other utility (utilities) or developer (i.e. relatively smaller units). . Stated otherwise, larger units that may offer economies of scale, such as a 300 MW 1x1 combined cycle, were not included in the Reference Case analysis as the capital requirements are considered to be in excess of what BPUB could absorb into its system without experiencing significant increase in rates. The opportunity to participate as a joint owner in such a unit, and the opportunity to enter into contracts for firm capacity and energy in the form of a PPA, should be pursued through a RFP process subsequent to completion of this IRP. Potential economic advantages of such opportunities have been illustrated in this IRP through the evaluations of the Tenaska Alternative and the Transmission Alternative. The RFP should also allow for proposals involving renewable generating resources. Offers received through the RFP should be evaluated based not only on economics, but reliability and contributions to fuel diversity as well.
- When soliciting and evaluating proposals as part of the RFP process, proper consideration should be given to transmission system constraints to ensure the ability to secure firm delivery of power into the Brownsville system.
  - In addition to the relative economics discussed previously, there may be advantages realized in the Brownsville community associated with development of a unit such as that proposed by Tenaska. Such benefits may include job creation during construction and operation of the unit, property tax revenue for the portion of the proposed unit owned by taxable entities, stimulus to local economy during construction phase, increased local generation resource that may increase system reliability as compared to relying on imported power. Further, a new, relatively large and efficient source of generation may be viewed as attractive by industries considering locating in the Brownsville area.

Appendix A. Hidalgo County Pipelines


JIM HOGG
BROOKS
KENEDY
STARR
HIDALGO
RAILROAD COMMISSION of TEXAS
HIDALGO COUNTY PIPELINES
Scale: 1" = 2 miles
"To have pipelines located prior to excavation activities, call ONE CALL SYSTEMS of TEXAS at 1-800-545-6005."


BROOKS
JIM HOGG
KENEDY
STARR
WILLACY
HIDALGO
HIDALGO COUNTY PIPELINES
Scale: 1" = 2 miles

Appendix B. Cameron County Pipelines

Appendix C. Natural Gas Transmission Pipelines – Texas

HIDALGO COUNTY									
Operator	Commodity	System Type	System Name	Sub System Name	Diameter	Operator P5	T4 Permit	Status	Interstate
APACHE CORPORATION	Natural Gas	Gas Transmission	WESLACO GATHERING	JUAN JOSE HINOJOSA DE BALLI SURVEY A-54	4.5	27200	7141	In Service	No
BALCONES STARR PIPELINE	Natural Gas	Gas Transmission	BALCONES STARR PL.		4.5	47185	1239	In Service	No
BALCONES STARR PIPELINE	Natural Gas	Gas Transmission	BALCONES STARR PL.		4.5	47185	1648	Abandoned	No
CALPINE TEXAS PIPELINE, L.P.	Natural Gas	Gas Transmission	MAGIC VALLEY	MAGIC VALLEY EAST PIPELINE	16	125949	5829	In Service	No
CALPINE TEXAS PIPELINE, L.P.	Natural Gas	Gas Transmission	MAGIC VALLEY	MAGIC VALLEY WEST PIPELINE	16	125949	5829	In Service	No
DCP HINSHAW PIPELINE, LLC	Natural Gas	Gas Transmission	HINSHAW SYSTEM	10" NEW BUILT	10.75	195926	5768	In Service	No
DCP HINSHAW PIPELINE, LLC	Natural Gas	Gas Transmission	HINSHAW SYSTEM	HINSHAW 12" PIPELINE	12.75	195926	5768	In Service	No
DCP HINSHAW PIPELINE, LLC	Natural Gas	Gas Transmission	HINSHAW SYSTEM	HINSHAW 12" PIPELINE	14	195926	5768	In Service	No
DCP HINSHAW PIPELINE, LLC	Natural Gas	Gas Transmission	HINSHAW SYSTEM	HS-1-LOOP TIE TO HS-1-2	10.75	195926	5768	In Service	No
DCP HINSHAW PIPELINE, LLC	Natural Gas	Gas Transmission	HINSHAW SYSTEM	LAUNCHER TO RECEIVER	10.75	195926	5768	In Service	No
DCP HINSHAW PIPELINE, LLC	Natural Gas	Gas Transmission	HINSHAW SYSTEM	LINE 1A-100	10.75	195926	5768	In Service	No

HIDALGO COUNTY									
Operator	**Commodity**	**System Type**	**System Name**	**Sub System Name**	**Diameter**	**Operator P5**	**T4 Permit**	**Status**	**Interstate**
DCP HINSHAW PIPELINE, LLC	Natural Gas	Gas Transmission	HINSHAW SYSTEM	LINE 1A-100	12.75	195926	5768	In Service	No
DCP HINSHAW PIPELINE, LLC	Natural Gas	Gas Transmission	HINSHAW SYSTEM	LINE 1A-100-RR	10.75	195926	5768	In Service	No
DCP HINSHAW PIPELINE, LLC	Natural Gas	Gas Transmission	HINSHAW SYSTEM	LOOP TIE-IN TO HS-1-EXT	10.75	195926	5768	In Service	No
DCP MIDSTREAM, LP	Natural Gas	Gas Transmission	LA GLORIA	SOUTH TEXAS GATHERING SYS	8.63	195918	5362	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	3C		4.5		93883	Abandoned	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	49A/1		2.38		93883	Abandoned	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	508/20		4.5	253368	6107	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	SOUTH TEXAS-TX150	FRONTERA POWER PLANT 10" LATERAL	10.75	253368	3883	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	SOUTH TEXAS-TX150	GILMORE EAST RESIDUE	24	253368	3883	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	SOUTH TEXAS-TX150	GILMORE EAST RESIDUE TO CELANESE INTERCO	12.75	253368	3883	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	SOUTH TEXAS-TX150	GILMORE EAST TO TENNECO INTERCONNECT	12.75	253368	3883	In Service	No

HIDALGO COUNTY									
Operator	Commodity	System Type	System Name	Sub System Name	Diameter	Operator P5	T4 Permit	Status	Interstate
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	SOUTH TEXAS-TX150	GILMORE EAST TO TEXAS EASTERN INTERCONNE	12.75	253368	3883	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	SOUTH TEXAS-TX150	GILMORE TO THOMPSONVILLE	12.75	253368	3883	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	SOUTH TEXAS-TX150	HIDALGO COUNTY	20	253368	3883	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	SOUTH TEXAS-TX150	HIDALGO COUNTY TO PENITAS LATERAL EXTENS	16	253368	3883	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	SOUTH TEXAS-TX150	MCALLEN RANCH LATERAL	12.75	253368	3883	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	SOUTH TEXAS-TX150	MCALLEN RANCH LATERAL	14	253368	3883	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	SOUTH TEXAS-TX150	PENITAS - PEMEX DELIVERY	24	253368	3883	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	SOUTH TEXAS-TX150	SHELL MCALLEN TO GILMORE RESIDUE	10.75	253368	3883	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	SOUTH TEXAS-TX150	TEXACO - SANTELLANA LATERAL	8.63	253368	3883	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	SOUTH TEXAS-TX150	TEXAS EASTERN DELIVERY	6.63	253368	3883	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	SOUTH TEXAS-TX150	TEXAS GARDENS LATERAL	4.5	253368	3883	Abandoned	No

HIDALGO COUNTY									
Operator	Commodity	System Type	System Name	Sub System Name	Diameter	Operator P5	T4 Permit	Status	Interstate
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	TX150 - FORMER	PHASE I SOUTH TEXAS SYSTEM	16		93883	Abandoned	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	TX800 - A SYSTEM OF NATURAL GAS PIPELINE	402C-900	6.63	253368	654	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	TX800 - A SYSTEM OF NATURAL GAS PIPELINE	402C-900	10.75	253368	654	In Service	No
HESCO PIPELINE COMPANY, L.L.C.	Natural Gas	Gas Transmission	HESCO SYSTEM		2.38	381632	5252	In Service	No
HESCO PIPELINE COMPANY, L.L.C.	Natural Gas	Gas Transmission	W. B. MISSION #502		3.5	381632	6127	In Service	No
HOUSTON PIPE LINE COMPANY LP	Natural Gas	Gas Transmission	1219 MONTE CHRISTO HAMMOND FIELD		8.63	404520	749	In Service	No
HOUSTON PIPE LINE COMPANY LP	Natural Gas	Gas Transmission	3025 HPL EDINBURG - FALFURRIAS PL		24	404520	749	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	Natural Gas	Gas Transmission	CORAL MEXICO		24	463338	5807	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	Natural Gas	Gas Transmission	CPL BATES	TRANSFERRED FROM ONYX PERMIT 05798	12.75		94625	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	Natural Gas	Gas Transmission	GEPC SOUTH TEXAS	374-500	8.63	463338	1872	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	Natural Gas	Gas Transmission	GEPC SOUTH TEXAS	423-300	8.63	463338	1872	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	Natural Gas	Gas Transmission	GEPC SOUTH TEXAS	423-310A	8.63	463338	1872	In Service	No

HIDALGO COUNTY									
Operator	Commodity	System Type	System Name	Sub System Name	Diameter	Operator P5	T4 Permit	Status	Interstate
KINDER MORGAN TEJAS PIPELINE LLC	Natural Gas	Gas Transmission	J.L. BATES	ONYYX LATERAL	12.75	463338	4625	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	Natural Gas	Gas Transmission	J.L. BATES PIPELINE		8.63	463338	4625	In Service	No
MISSION PIPELINE, LLC	Natural Gas	Gas Transmission	16A	LINE 16-A	8.63	570402	5795	In Service	No
MISSION PIPELINE, LLC	Natural Gas	Gas Transmission	LINE NO. 16-A-1		4.5	570402	5795	In Service	No
MISSION PIPELINE, LLC	Natural Gas	Gas Transmission	MISSION PIPELINE		8.63	570402	5795	In Service	No
MISSION PIPELINE, LLC	Natural Gas	Gas Transmission	MISSION PIPELINE		10.75	570402	5795	In Service	No
SANTERRA MIDSTREAM COMPANY, LLC	Natural Gas	Gas Transmission	TEXAS GAS TO ENTERPRISE	300# SUCTION LINE	6.63	748108	8469	In Service	No
SANTERRA MIDSTREAM COMPANY, LLC	Natural Gas	Gas Transmission	TEXAS GAS TO ENTERPRISE	500# SUCTION LINE	6.63	748108	8469	In Service	No
SANTERRA MIDSTREAM COMPANY, LLC	Natural Gas	Gas Transmission	TEXAS GAS TO ENTERPRISE	DISCHARGE SALES LINE	6.63	748108	8469	In Service	No
TENNESSEE GAS PIPELINE COMPANY	Natural Gas	Gas Transmission	407D-100		8.63	841530	1006	Abandoned	Yes
TENNESSEE GAS PIPELINE COMPANY	Natural Gas	Gas Transmission	408A-200		4.5	841530	1006	Abandoned	Yes
TENNESSEE GAS PIPELINE COMPANY	Natural Gas	Gas Transmission	409A-300		3.5	841530	1006	Abandoned	Yes
TENNESSEE GAS PIPELINE COMPANY	Natural Gas	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	2.38	841530	1006	In Service	Yes

HIDALGO COUNTY									
Operator	Commodity	System Type	System Name	Sub System Name	Diameter	Operator P5	T4 Permit	Status	Interstate
TENNESSEE GAS PIPELINE COMPANY	Natural Gas	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	4.5	841530	1006	In Service	Yes
TENNESSEE GAS PIPELINE COMPANY	Natural Gas	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	6.63	841530	1006	In Service	Yes
TENNESSEE GAS PIPELINE COMPANY	Natural Gas	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	8.63	841530	1006	In Service	Yes
TENNESSEE GAS PIPELINE COMPANY	Natural Gas	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	10.75	841530	1006	In Service	Yes
TENNESSEE GAS PIPELINE COMPANY	Natural Gas	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	12.75	841530	1006	In Service	Yes
TENNESSEE GAS PIPELINE COMPANY	Natural Gas	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	16	841530	1006	In Service	Yes
TENNESSEE GAS PIPELINE COMPANY	Natural Gas	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	24	841530	1006	In Service	Yes
TENNESSEE GAS PIPELINE COMPANY	Natural Gas	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	26	841530	1006	In Service	Yes
TENNESSEE GAS PIPELINE COMPANY	Natural Gas	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	30	841530	1006	In Service	Yes
TEXAS EASTERN TRANSMISSION, LP	Natural Gas	Gas Transmission	LINE 14-V		3.5	845690	4143	Abandoned	Yes

HIDALGO COUNTY									
Operator	Commodity	System Type	System Name	Sub System Name	Diameter	Operator P5	T4 Permit	Status	Interstate
TEXAS EASTERN TRANSMISSION, LP	Natural Gas	Gas Transmission	LINE 16-B-1		3.5	845690	4143	Abandoned	Yes
TEXAS EASTERN TRANSMISSION, LP	Natural Gas	Gas Transmission	LINE 16-R		4.5	845690	4143	Abandoned	Yes
TEXAS EASTERN TRANSMISSION, LP	Natural Gas	Gas Transmission	MEXI-STFE		3.5	845690	4143	In Service	Yes
TEXAS EASTERN TRANSMISSION, LP	Natural Gas	Gas Transmission	MEXI-STFE		4.5	845690	4143	In Service	Yes
TEXAS EASTERN TRANSMISSION, LP	Natural Gas	Gas Transmission	MEXI-STFE		6.63	845690	4143	In Service	Yes
TEXAS EASTERN TRANSMISSION, LP	Natural Gas	Gas Transmission	MEXI-STFE		8.63	845690	4143	In Service	Yes
TEXAS EASTERN TRANSMISSION, LP	Natural Gas	Gas Transmission	MEXI-STFE		20	845690	4143	In Service	Yes
TEXAS EASTERN TRANSMISSION, LP	Natural Gas	Gas Transmission	MEXI-STFE		30	845690	4143	In Service	Yes
TEXAS EASTERN TRANSMISSION, LP	Natural Gas	Gas Transmission	MEXI-STFE		32	845690	4143	In Service	Yes
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	AMERICAN PETROFINA SLAVIK		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	AMOCO PRODUCTION TO SEADRIFT		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	BALLENGER LATERAL 4"		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	BARNES WELL		2.38	845951	534	In Service	No

HIDALGO COUNTY									
Operator	Commodity	System Type	System Name	Sub System Name	Diameter	Operator P5	T4 Permit	Status	Interstate
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	CANO LATERAL		6.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	CELANESE LA BLANCA 12"		12.75	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	CELANESE LA BLANCA 14"		14	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	CELANESE REYNOSA 12"		12.75	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	CELANESE REYNOSA 6"		6.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	CELANESE REYNOSA TO ALAMO LAND		6.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	COASTAL STATES #2 STATE LATERAL		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	CORPUS CHRISTIE O&G #1 DRAWE-SEADRIFT		2.38	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	DONNA LATERAL		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	DONNA-TANNER INTERCONNECT		6.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	DUER WAGNER #1 & #2 ROBINETTE LATERAL		2.38	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	ECTOR LATERAL LINE		2.38	845951	534	In Service	No

HIDALGO COUNTY									
Operator	Commodity	System Type	System Name	Sub System Name	Diameter	Operator P5	T4 Permit	Status	Interstate
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	ECTOR LATERAL LINE		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	HIDALGO PLANT-BATES POWER PLANT TIE OVER		6.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	INLET TO HIDALGO GAS PLANT		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	INLET TO HIDALGO GAS PLANT		10.75	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	LAGUNA GAS / POPE #1 DAUGHERTY LATERAL		2.88	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	MERCEDES FIELD #1		2.38	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	MERCEDES FIELD #2		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	MERCEDES FIELD #3		6.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	MERCEDES FIELD #4		8.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	MERCEDES FIELD #5 (EOG)		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	MONTE CRISTO-MISSION LOOP TO CPL		6.63	845951	534	In Service	No

HIDALGO COUNTY									
Operator	Commodity	System Type	System Name	Sub System Name	Diameter	Operator P5	T4 Permit	Status	Interstate
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	MONTE CRISTO-MISSION LOOP TO CPL		8.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	MOODY LATERAL		6.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	NORTH HIDALGO		5.56	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	NORTH HIDALGO LOOP		8.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	PENITAS FIELD LATERAL		6.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	PENITAS MAINLINE		10.75	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	PROGRESSO GU#1 TO SEADRIFT 4"		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	RGV 12"		12.75	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	RIO BRAVO NO. 1 WELL LATERAL		2.38	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	RUEDA LATERAL		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	SAN SALVADOR TO MONTE CRISTO 8"		8.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	SAN SALVADOR TO SAN BENITO 10"		10.75	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	SEADRIFT 14"		14	845951	534	In Service	No

HIDALGO COUNTY									
Operator	Commodity	System Type	System Name	Sub System Name	Diameter	Operator P5	T4 Permit	Status	Interstate
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	SEADRIFT 16"		16	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	TEXACO TO HIDALGO GAS PLANT		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	TGT DELIVERY		6.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	TRANSVALLEY LATERAL		10.75	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	TRANSVALLEY LATERAL		14	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	TRANSVALLEY TO HIDALGO		10.75	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	UNION PRODUCTION / POPE ESTATE LATERAL		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	USDA LATERAL		2.38	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	V FAULCONER-SAMANO #1 LATERAL		2.88	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	VALLEY INDUSTRIAL LATERAL		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	VALLEY INDUSTRIAL LATERAL UNION CARBIDE		6.63	845951	534	In Service	No

HIDALGO COUNTY									
Operator	Commodity	System Type	System Name	Sub System Name	Diameter	Operator P5	T4 Permit	Status	Interstate
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	VALLEY INDUSTRIAL TO UNION CARBIDE		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	VENTEX HOVDA #1 TO SEADRIFT 2"		2.38	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	VENTO LATERAL		3.5	845951	534	In Service	No
TRUNKLINE GAS COMPANY, LLC	Natural Gas	Gas Transmission	NT3100	NT3-100	0	872122	262	Abandoned	Yes
VIRTEX OPERATING COMPANY, INC.	Natural Gas	Gas Transmission	WERNER #1 TO HESCO TIE-IN		4.5	886261	5672	In Service	No

CAMERON COUNTY									
OPERATOR	COMMODITY	SYSTEM TYPE	SYSTEM NAME	SUB SYSTEM NAME	DIAMETER	OPERATOR P5	T4 PERMIT	STATUS	INTERSTATE
ENTERPRISE PRODUCTS OPERATING LLC	Natural Gas	Gas Transmission	189/7		2.38	253368	3883	Abandoned	No
ENTERPRISE PRODUCTS OPERATINGLLC	Natural Gas	Gas Transmission	189A	189A	6.63	253368	3883	Abandoned	No
KINDER MORGAN TEJAS PIPELINE LLC	Natural Gas	Gas Transmission	GEPC SOUTH TEXAS	423-300	8.63	463338	1872	In Service	No
SANTERRA MIDSTREAM COMPANY, LLC	Natural Gas	Gas Transmission	LA PITA SYSTEM		4.5	748108	8182	In Service	No
STANLEY SWABBING & WELL SERVICE	Natural Gas	Gas Transmission	ME-3801		0		90116	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	BROWNSVILLE PUB LATERAL		10.75	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	BROWNSVILLE PUB LATERAL		12.75	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	DYNAMIC PRODUCTION		2.38	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	HOLLY BEACH TO PORT AREA		6.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	HOLLY BEACH TO PORT AREA		8.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	LOS EBANOS HONEYDALE LATERAL 6"		6.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	PASO REAL FIELD LATERAL		4.5	845951	534	In Service	No

CAMERON COUNTY									
OPERATOR	COMMODITY	SYSTEM TYPE	SYSTEM NAME	SUB SYSTEM NAME	DIAMETER	OPERATOR P5	T4 PERMIT	STATUS	INTERSTATE
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	PORT OF BROWNSVILLE		6.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	SAN BENITO TO BROWNSVILLE 8"		8.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	SAN BENITO TO BROWNSVILLE 8" & 10"		8.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	SAN SALVADOR TO SAN BENITO 10"		10.75	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	SEADRIFT 16"		16	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	SEADRIFT TO SAN BENITO 8" JUMPER		8.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	SHRIMP HARBOR		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	SHRIMP HARBOR		6.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	SKELLY OIL TO SHRIMP HARBOR		4.5	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	THREE ISLANDS TO HOLLY BEACH LATERAL 6"		6.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	TIE OVER RGV CAPACITY RELIEF LATERAL 8"		8.63	845951	534	In Service	No
TEXAS GAS SERVICE COMPANY	Natural Gas	Gas Transmission	VISTA DEL MAR LATERAL		4.5	845951	534	In Service	No

Appendix D. 2009 Load Forecast

Appendix E. Financial Analysis

INTRODUCTION

This section presents results of the Financial Analysis for each of the expansion plans discussed in Section 8. The analysis was used to determine the impact each case has on the revenue and revenue requirements. Initially, Black & Veatch analyzed one reference case and three alternatives. These cases, referred to as (Group 1), are the Reference Case, No New Generation Case, No Wind Alternatives Case, and 2.0 Percent Rate Increase Case. Black & Veatch was then asked to analyze a modified reference case and two alternatives. These cases, referred to as (Group 2), are the Modified Reference Case, Tenaska Case, and Transmission Case. The following sections explain the principal assumptions, the financial impact of each alternative, and the methodology used to run the analysis.

PRINCIPAL ASSUMPTIONS

The following section presents the principle assumptions used in development of the financial analysis. The starting point for the financial forecast was the financial model developed in the 2009 Electric Cost of Service and Rate Study.

- The forecast of electric sales is based on the 2009 Load Forecast prepared by R.W.Beck/SAIC .
- The 2009 Load Forecast provides the generation requirements that were used as the basis for the PROMOD™ simulations. PROMOD™ was used to simulate operation of the BPUB system to meet projected generation requirements and provides corresponding projections of fuel expenses, incremental production O&M expenses, off-system sales revenue, and required generation capital projects under each alternative case. The revenue forecast under existing rates was generated by applying the 2011 average retail unit rate(s) (with FY 2012 rates adjusted for an increase of 5 percent effective October 1, 2011) to the 2009 Load Forecast.
- The forecast of all other Operation and Maintenance expenses is based on 2012 budgeted expenses escalated at rates ranging from 3 to 5 percent.
- The baseline forecast of Production Operation and Maintenance expenses is based on 2012 budgeted expenses escalated at 2.5 and then held constant. This is then increased by the forecasted cumulative change of production operation and maintenance expenses from the PROMOD™ model.
- The Other Revenue forecast is based on the 2012 budget escalated at 0.5 percent per year.
- Retail Fuel and Purchased Energy Charge (FPEC) and off-system sales revenues are calculated for each alternative based on 100 percent recovery of fuel and purchased power expenses from the PROMOD™ runs. For 2011, the FPEC was set equal to $0.412 /kWh.

- Off-system sales fuel expense is calculated as 78 percent of the off-system sales revenue projected in PROMOD™.
- The forecast of cash financed capital is based on the surplus revenues from the current and prior year. The goal was to keep funding at a minimum of $5-$10 million each year for each alternative. The total projected capital costs are based on the consideration of the existing ten year capital plan for electric utility routine additions (average of last two years of the ten year forecast escalated at 2.5 percent for remaining years) plus the additional capital project costs related to each supply side alternative.
- The Reference Case and Group 2 have a study period of 10 years. The No New Generation Case and No Wind Alternative Case have a study period of 5 years. The 2.0 Percent Rate Increase Case has a study period of 3 years.

METHODOLOGY

The overall impact on Electric Utility rates is tested by comparing retail revenues under existing rates with the forecast revenue requirements. The results for each of the PROMOD™ cases were applied to the revenue requirements portion of the rate model, designed for the 2009 rate study. This allowed Black & Veatch to evaluate the financial impact and resulting rate increases for each alternative.

There are two rate components that impact the annual rate increase for the utility. The first is base rate impact for the additional capital projects and operating expenses related to each new supply side addition. The surplus revenue is used to cash finance the projects and adjustment to base rates is made when debt service coverage drops below 1.50 (net revenues divided by total debt service). The second rate component is for 100 percent revenue recovery of the fuel and purchased power expense. This rate is determined by the annual fuel and purchased power expense (less fuel for off-system sales) divided by sales. The fuel and purchased power expense for each alternative was determined by PROMOD™.

FINDINGS OVERVIEW

The following section highlights the results of the financial forecast for each of the supply side alternatives. In Group 1, the Reference case was used for comparison of the No New Generation Case, No Wind Alternatives Case, and 2.0 Percent Rate Increase Case. In Group 2, the Modified Reference Case was used for comparison of the Tenaska Case and Transmission Case.

Key Findings

- Findings are based on using the sales forecast and reflect off-system sales revenue from PROMOD™.
- All the cases, except the Transmission Case, forecast a base rate increase by 2016 that range from 3-5 percent. In addition, the Reference Case forecast a base rate increase of 3 percent in 2015. All this is shown in Table E-3.

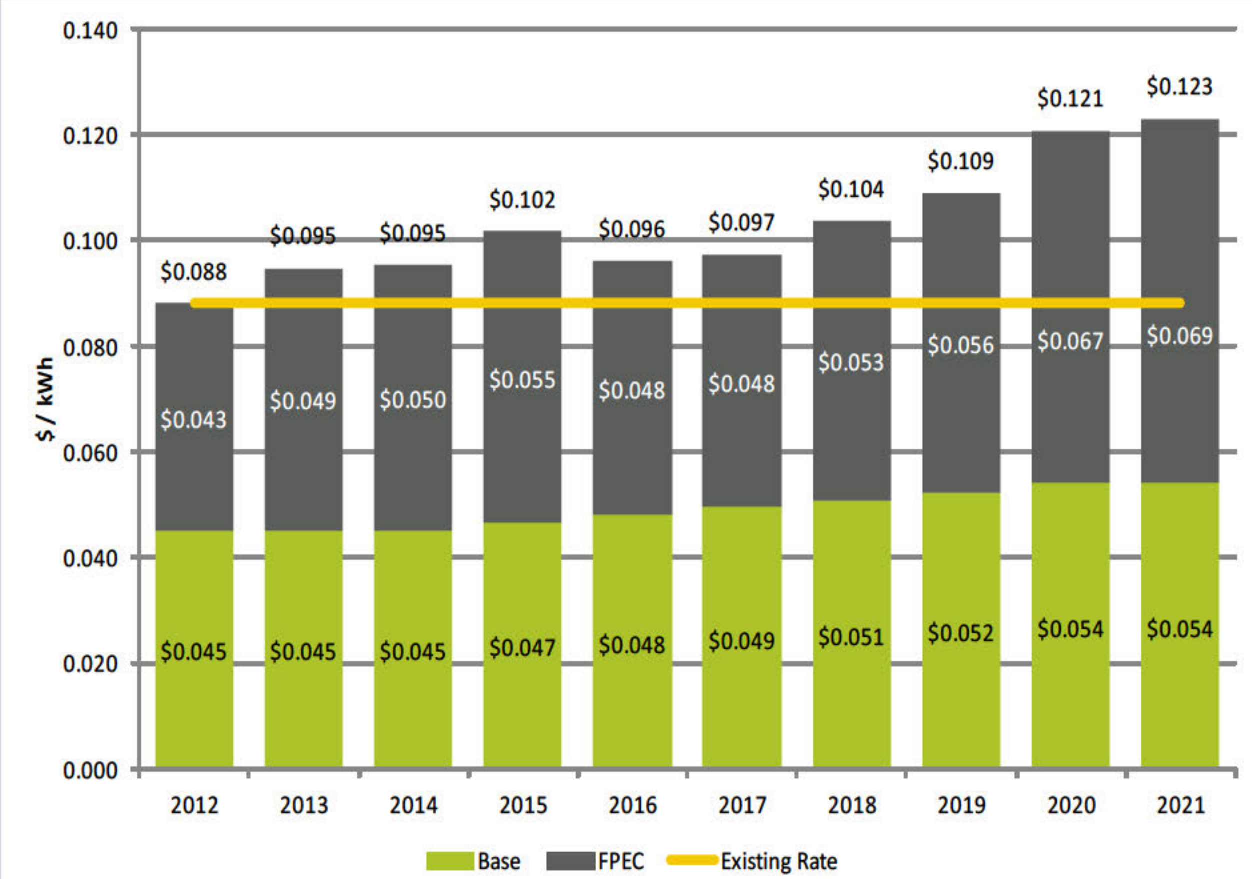
- In Group 1, the Reference Case has the lowest total rate (Base + FPEC) by 2016, excluding the 2.0 Percent Rate Increase Case that only goes to 2014. As shown in Table E-2, the Reference Case indicates the total average rate rising from $0.088/kWh in 2012 to $0.096/kWh in 2016. This includes a base rate increase of 3% in 2015 and 2016 as shown in Table E-3, Line 1.
- In Group 2, the Transmission Case has the lowest total rate (Base + FPEC) by 2021; however, it has the same forecast rate in 2016 as the Tenaska Case. As shown in Table E-2, the Transmission Case indicates the total average rate rising from $0.088/kWh in 2012 to $0.118/kWh by 2021. This does not include a base rate increase.
- Two sensitivity cases were completed on the Reference Case. For the first sensitivity, the kWh sales forecast was reduced to the 2012 budget and then escalated at 3 percent each year moving forward. The results forecast increases in base rates of 6 percent in 2013, 5 percent in 2014-2016, and 3 percent 2017-2021. For the second sensitivity, the off-system sales margin was adjusted to zero. The results show projected increases in base rates of 3 percent 2014-2021.

Overview

Figures E-1 through E- 7 show the results, for the base and the FPEC rate, for each case and includes a line that highlights the existing rate for 2012. All the cases are based on using the Load Forecast prepared by R.W.Beck/SAIC and results from PROMOD™. The main rate drivers in the cases are from the FPEC rate and base rate adjustments to maintain the debt service coverage ratio. In Group 1, the lowest total rate (Base + FPEC) by the year 2016 is found in the Reference Case at $0.096/kWh and the highest with the No New Generation Case at $0.106/kWh. In Group 2, the lowest total rate (Base + FPEC) by the year 2021 is found in the Transmission Case at $0.118/kWh and the highest with the Tenaska Case at $0.128/kWh.

Figure E-8 through E-10 highlight the comparison of each case in regards to the FPEC unit cost $/kWh, the total projected off-system sales revenue, and the total projected off-system sales margin. As shown in Table E-1, all cases remain above the 1.5 debt service coverage requirement. Table E-2 highlights the total annual rate forecast for each case from 2012 through 2021. Table E-3 highlights the annual base rate adjustment forecast for each case. As shown in the table, base rate adjustments are not needed for any case until 2015, for the Reference Case, and 2016, for all the other cases excluding the Transmission Case which has no rate adjustment. Table E-4 highlights the total annual rate adjustment for the total rate (Base + FPEC). As shown when comparing Table E-3 and E-4, the FPEC rate has the most influence on the total rate. For example, in 2016 there is an increase in the base rate and a decrease in the total rate. Table E-5 shows the cumulative annual rate adjustment for the total rate (Base + FPEC), Base rate, and FPEC. In this table each rate is broken out into two different columns, one for 2012-2016 and 2012-2021, as not all the cases in Group 1 go beyond 2016.

Figure E-1 Reference Case

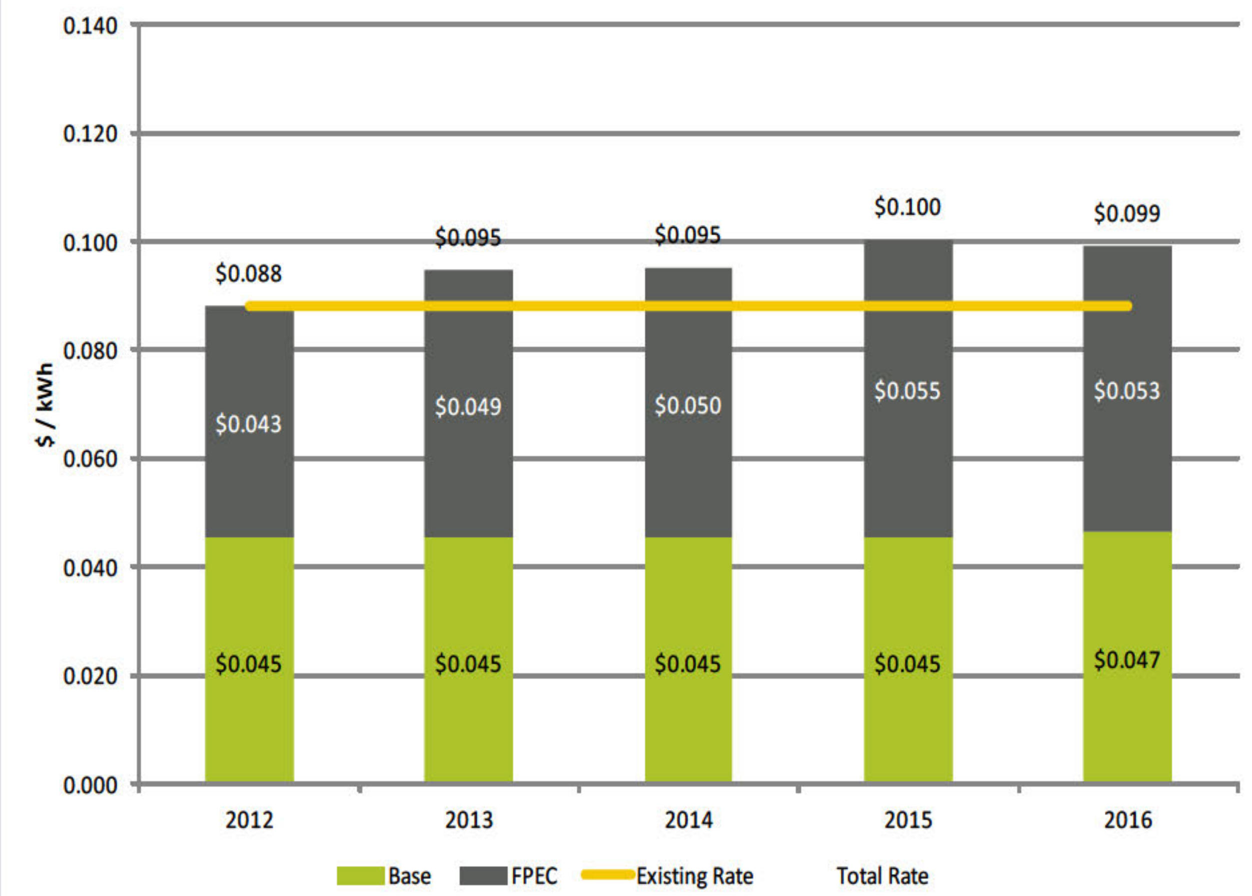


LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Base Rate Adjustment	5.00%	0.00%	0.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	0.00%
2	FPEC Rate Adjustment	3.73%	15.52%	1.10%	10.20%	-12.72%	-0.23%	10.09%	7.10%	18.17%	3.35%
3	Total Rate Adjustment	4.51%	7.54%	0.57%	6.77%	-5.51%	1.39%	6.49%	5.08%	10.86%	1.85%

Figure E-2 No New Generation Case

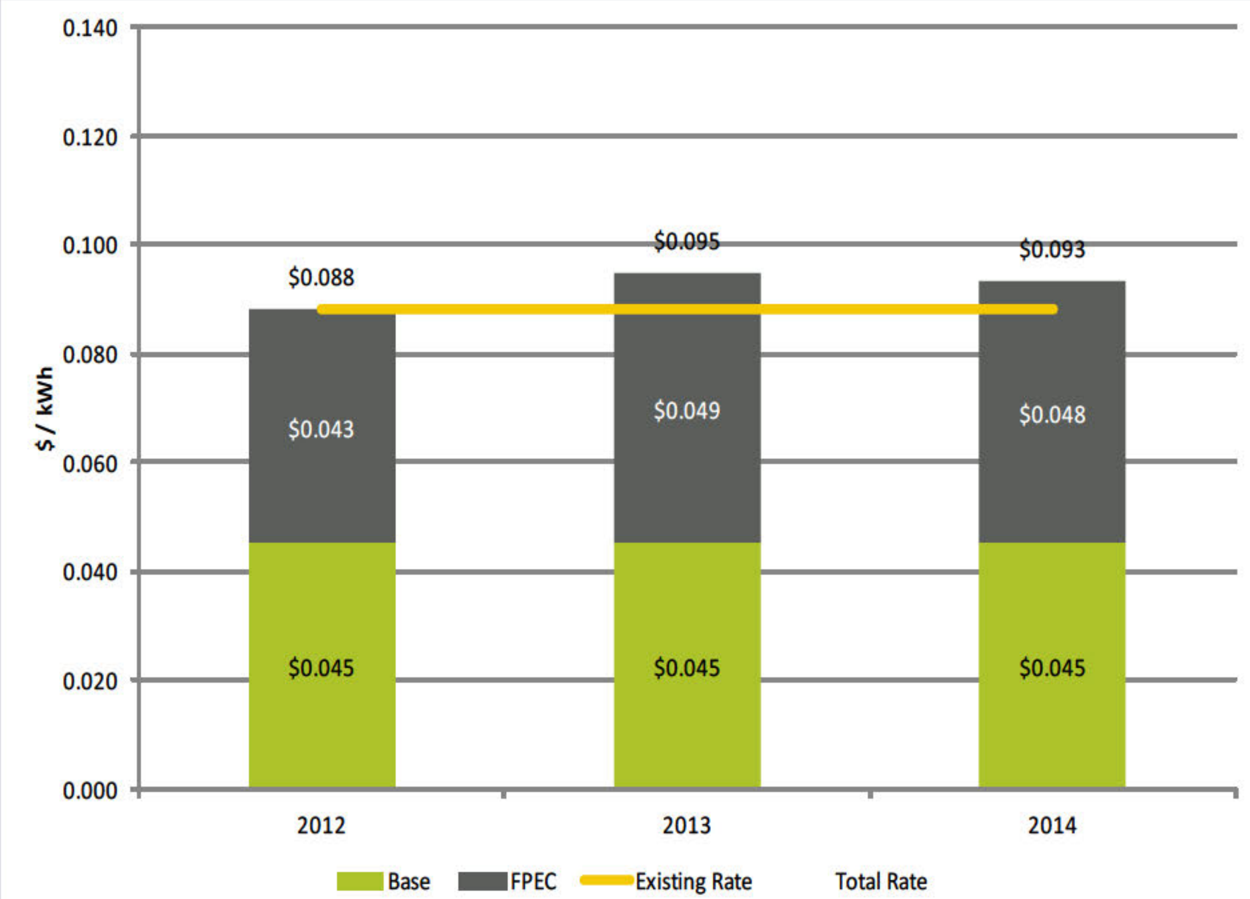
LN	DESCRIPTION	2012	2013	2014	2015	2016
1	Base Rate Adjustment	5.00%	0.00%	0.00%	0.00%	0.00%
2	FPEC Rate Adjustment	3.73%	15.52%	12.39%	12.96%	-3.48%
3	Total Rate Adjustment	4.51%	7.54%	6.46%	7.14%	-2.02%

Figure E-3 No Wind Alternatives Case



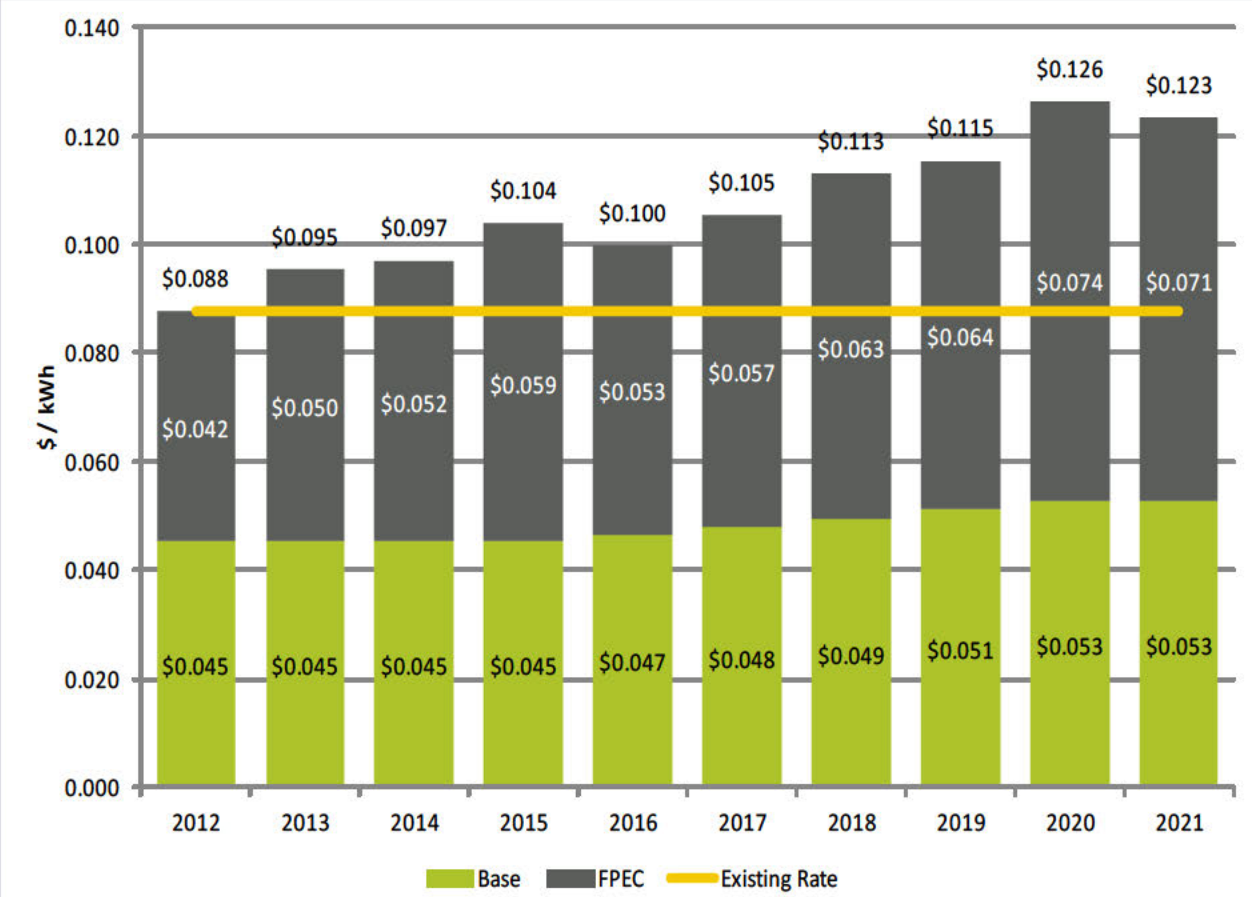
LN	DESCRIPTION	2012	2013	2014	2015	2016
1	Base Rate Adjustment	5.00%	0.00%	0.00%	0.00%	3.00%
2	FPEC Rate Adjustment	3.73%	15.52%	1.10%	10.20%	-4.52%
3	Total Rate Adjustment	4.51%	7.54%	0.57%	5.35%	-1.13%

Figure E-4 2.0 Percent Rate Increase Case



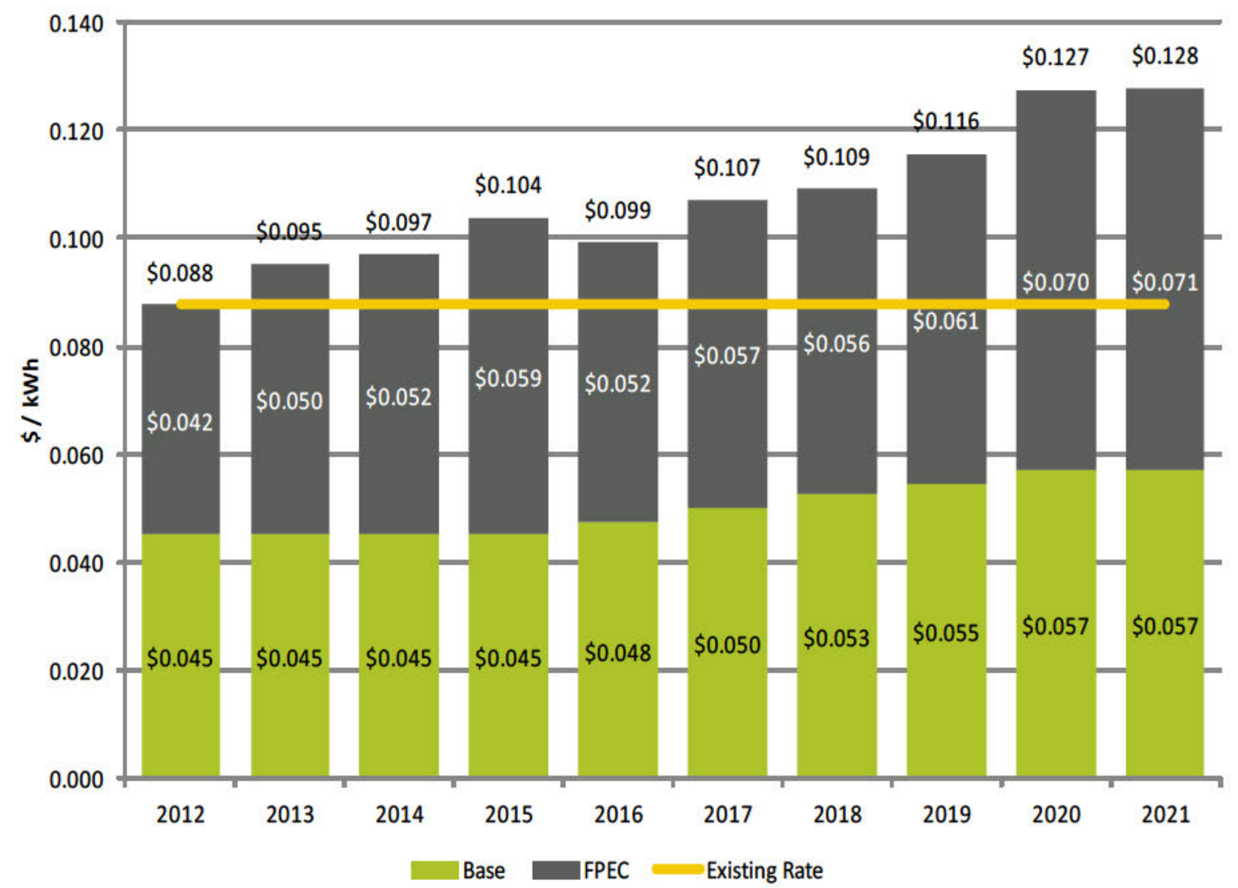
LN	DESCRIPTION	2012	2013	2014
1	Base Rate Adjustment	5.00%	0.00%	0.00%
2	FPEC Rate Adjustment	3.73%	15.52%	-2.70%
3	Total Rate Adjustment	4.51%	7.54%	-1.41%

Figure E-5 Modified Reference Case



LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Base Rate Adjustment	5.00%	0.00%	0.00%	0.00%	3.00%	3.00%	3.00%	3.50%	3.00%	0.00%
2	FPEC Rate Adjustment	2.80%	18.01%	3.43%	13.18%	-9.26%	7.88%	10.70%	1.16%	14.76%	-3.99%
3	Total Rate Adjustment	4.06%	8.71%	1.80%	7.03%	-3.91%	5.60%	7.19%	2.18%	9.54%	-2.33%

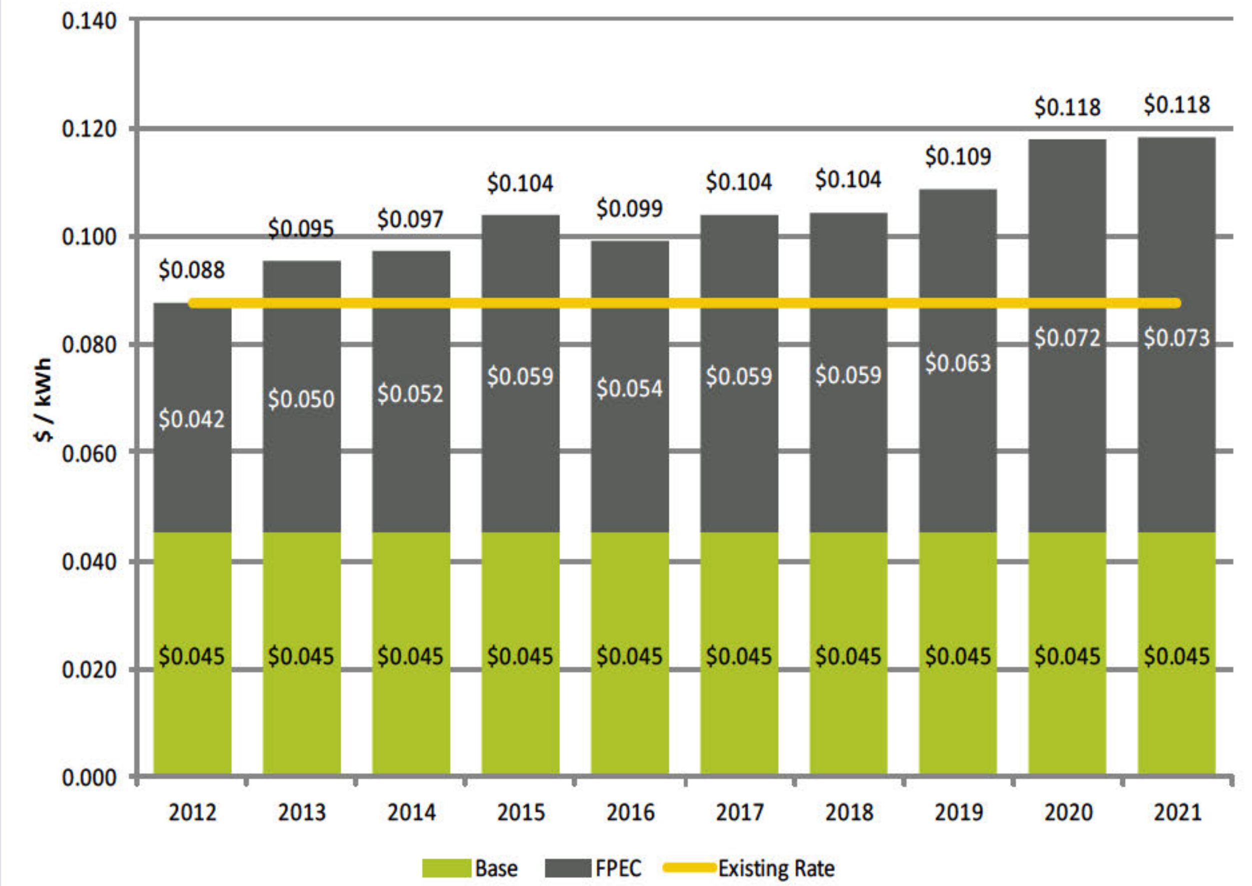
Figure E-6 Tenaska Case



LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Base Rate Adjustment	5.00%	0.00%	0.00%	0.00%	5.00%	5.50%	5.00%	3.50%	4.50%	0.00%
2	FPEC Rate Adjustment	2.80%	18.01%	3.43%	13.18%	-11.59%	9.99%	-0.76%	8.24%	15.28%	0.51%
3	Total Rate Adjustment	4.06%	8.71%	1.80%	7.03%	-4.36%	7.84%	1.94%	5.95%	10.20%	0.28%

Note: Tenaska participation begins in 2016

Figure E-7 Transmission Case



LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Base Rate Adjustment	5.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	FPEC Rate Adjustment	2.80%	18.01%	3.43%	13.18%	-7.98%	8.73%	0.81%	7.32%	14.40%	0.49%
3	Total Rate Adjustment	4.06%	8.71%	1.80%	7.03%	-4.50%	4.74%	0.46%	4.14%	8.40%	0.30%

Figure E-8 FPEC Unit Cost - $/kWh

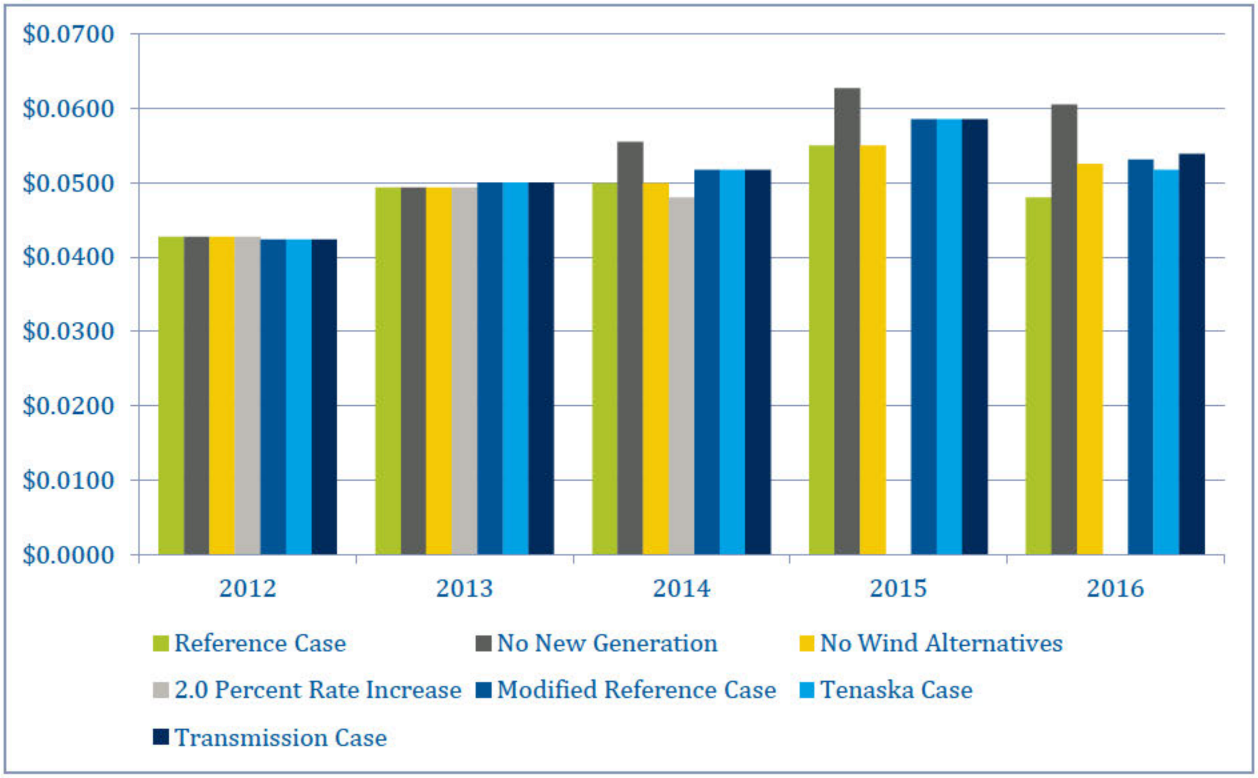


Figure E-9 Forecast Off-system Sales Revenue

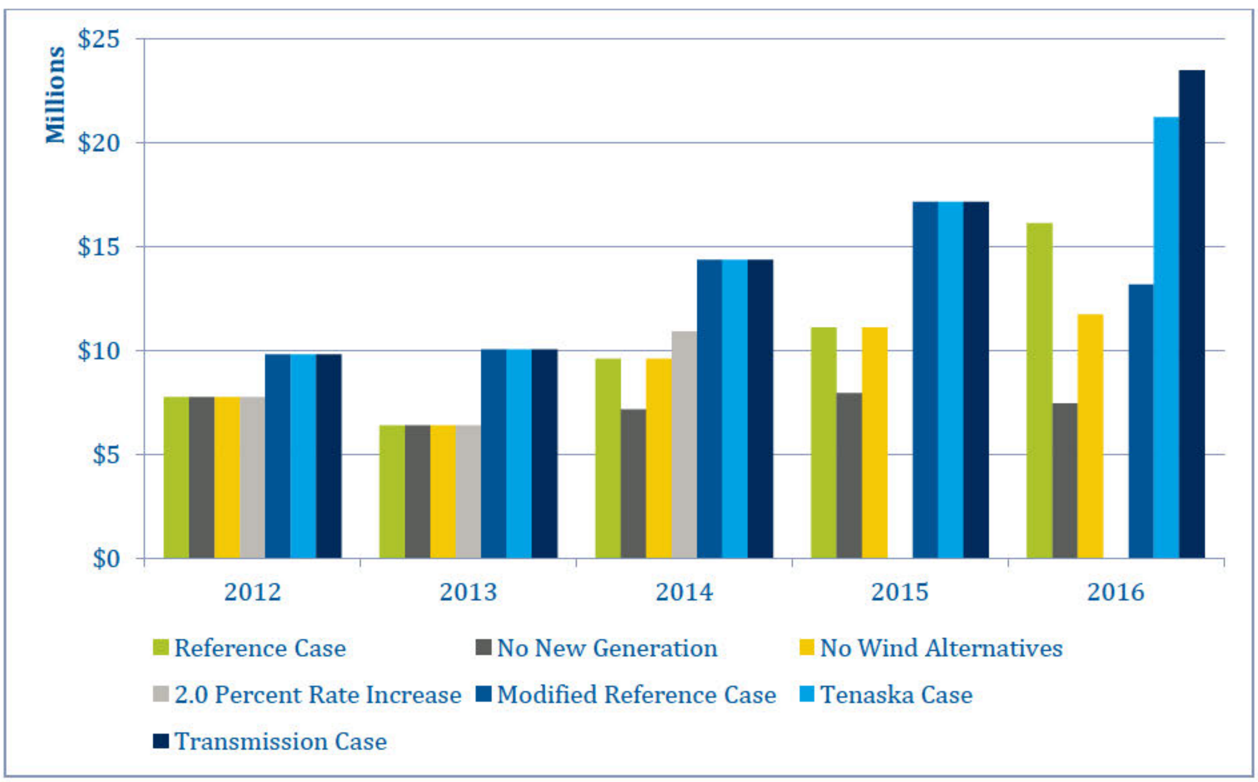


Figure E-10 Forecast Off-system Sales Margin

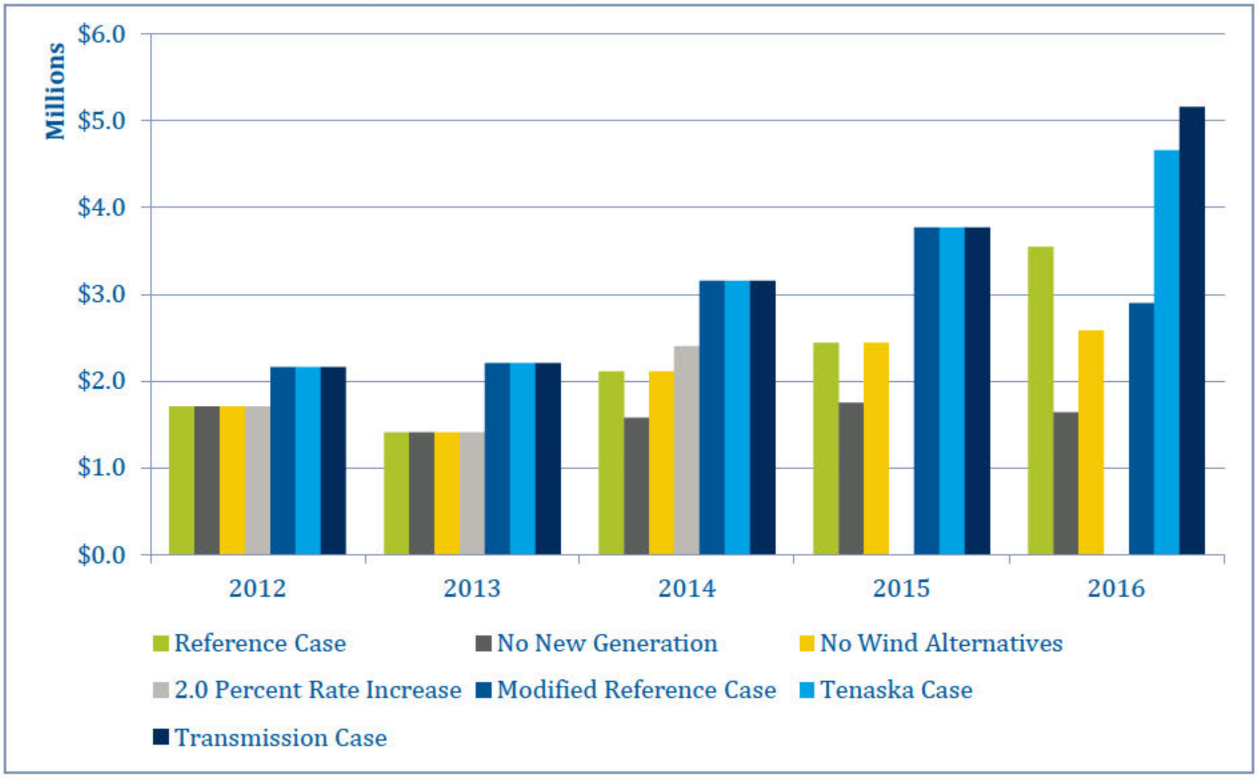


Table E-1 Forecast Debt Service Coverage

LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Reference Case	2.40	1.90	1.64	1.59	1.65	1.68	1.71	1.63	1.66	1.63
2	No New Generation	2.40	2.47	2.52	2.42	2.49	NA	NA	NA	NA	NA
3	No Wind Alternatives	2.40	1.89	1.64	1.52	1.53	NA	NA	NA	NA	NA
4	2.0 Percent Rate Increase	2.40	1.91	1.68	NA	NA	NA	NA	NA	NA	NA
5	Modified Reference Case	2.43	2.54	2.65	1.88	1.57	1.58	1.56	1.53	1.58	1.54
6	Tenaska Case	2.43	2.54	2.65	2.60	1.66	1.52	1.59	1.53	1.64	1.58
7	Transmission Case	2.43	2.54	2.65	2.21	2.23	2.40	2.45	2.37	2.23	2.14

Table E-2 Annual Rate Projections (Combined Base and FPEC Rate) - $/kWh

LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Reference Case	$0.088	$0.095	$0.095	$0.102	$0.096	$0.097	$0.104	$0.109	$0.121	$0.123
2	No New Generation	$0.088	$0.095	$0.101	$0.108	$0.106	NA	NA	NA	NA	NA
3	No Wind Alternatives	$0.088	$0.095	$0.095	$0.100	$0.099	NA	NA	NA	NA	NA
4	2.0 Percent Rate Increase	$0.088	$0.095	$0.093	NA	NA	NA	NA	NA	NA	NA
5	Modified Reference Case	$0.088	$0.095	$0.097	$0.104	$0.100	$0.105	$0.113	$0.115	$0.126	$0.123
6	Tenaska Case	$0.088	$0.095	$0.097	$0.104	$0.099	$0.107	$0.109	$0.116	$0.127	$0.128
7	Transmission Case	$0.088	$0.095	$0.097	$0.104	$0.099	$0.104	$0.104	$0.109	$0.118	$0.118

Table E-3 Annual Base Rate Adjustment

LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Reference Case	5.00%	0.00%	0.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	0.00%
2	No New Generation	5.00%	0.00%	0.00%	0.00%	3.00%	NA	NA	NA	NA	NA
3	No Wind Alternatives	5.00%	0.00%	0.00%	0.00%	3.00%	NA	NA	NA	NA	NA
4	2.0 Percent Rate Increase	5.00%	0.00%	0.00%	NA	NA	NA	NA	NA	NA	NA
5	Modified Reference Case	5.00%	0.00%	0.00%	0.00%	3.00%	3.00%	3.00%	3.50%	3.00%	0.00%
6	Tenaska Case	5.00%	0.00%	0.00%	0.00%	5.00%	5.50%	5.00%	3.50%	4.50%	0.00%
7	Transmission Case	5.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table E-4 Total Annual Rate Adjustment (Combined Base and FPEC Rate)

LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Reference Case	4.51%	7.54%	0.57%	6.77%	-5.51%	1.39%	6.49%	5.08%	10.86%	1.85%
2	No New Generation	4.51%	7.54%	6.46%	7.14%	-2.02%	NA	NA	NA	NA	NA
3	No Wind Alternatives	4.51%	7.54%	0.57%	5.35%	-1.13%	NA	NA	NA	NA	NA
4	2.0 Percent Rate Increase	4.51%	7.54%	-1.41%	NA	NA	NA	NA	NA	NA	NA
5	Modified Reference Case	4.06%	8.71%	1.80%	7.03%	-3.91%	5.60%	7.19%	2.18%	9.54%	-2.33%
6	Tenaska Case	4.06%	8.71%	1.80%	7.03%	-4.36%	7.84%	1.94%	5.95%	10.20%	0.28%
7	Transmission Case	4.06%	8.71%	1.80%	7.03%	-4.50%	4.74%	0.46%	4.14%	8.40%	0.30%

Table E-5 Cumulative Annual Rate Adjustment (Combined Base and FPEC Rate)

LN	DESCRIPTION	COMBINED RATE		BASE RATE		FPEC	
		2012-2016	2012-2021	2012-2016	2012-2021	2012-2016	2012-2021
1	Reference Case	9.12%	40%	6.09%	19.41%	12.32%	61.36%
2	No New Generation	20.18%	NA (1)	0.00%	NA (1)	41.55%	NA (1)
3	No Wind Alternatives	12.65%	NA (1)	3.00%	NA (1)	22.88%	NA (1)
4	2.0 Percent Rate Increase	NA (1)	NA (1)	NA (1)	NA (1)	NA (1)	NA (1)
5	Modified Reference Case	13.81%	41%	3.00%	16.49%	25.36%	66.83%
6	Tenaska Case	13.28%	46%	5.00%	25.80%	22.13%	67.20%
7	Transmission Case	13.11%	35%	0.00%	0.00%	27.13%	71.93%

(1) Study period does not go out far enough to be included in the comparison.

Table E-6 Financial Forecast – Reference Case (1,000's)

LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	**Retail Sales at Meter (MWh)**	1,450	1,525	1,588	1,650	1,714	1,776	1,838	1,897	1,956	2,015
2	**Net Energy for Load (MWh)**	1,535	1,613	1,680	1,746	1,813	1,880	1,945	2,008	2,070	2,133
3	**REVENUES: ($)**										
4	Retail Base Rate Revenues	65,675	69,031	71,897	74,720	77,595	80,433	83,214	85,906	88,577	91,251
5	Fuel Charge Revenues (includes COB)	62,008	75,291	79,280	90,794	82,289	85,105	96,929	107,165	130,578	139,020
6	**Gross Operating Revenues**	127,683	144,322	151,177	165,514	159,884	165,538	180,142	193,070	219,156	230,270
7	**Off-system Sales Revenues**	7,746	6,389	9,594	11,091	16,114	18,799	21,345	21,581	32,287	35,766
8	**Total Sales Revenues**	135,429	150,711	160,771	176,605	175,997	184,337	201,487	214,651	251,442	266,037
9	Other Revenues	2,993	3,008	3,023	3,038	3,053	3,069	3,084	3,099	3,115	3,130
10	Interest from Investments	300	315	339	348	360	371	379	395	404	413
11	Other Non-operating revenues	1,227	1,233	1,239	1,246	1,252	1,258	1,264	1,271	1,277	1,283
12	**Gross Revenues Under Existing Rates**	139,949	155,268	165,373	181,237	180,662	189,035	206,215	219,416	256,237	270,863
13	Revenue Adjustment	5.00%	0.00%	0.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	0.00%
14	Additional Base Rate Revenue	-	-	-	2,242	4,726	7,458	10,444	13,683	17,189	17,707
15	**Total Revenue**	139,949	155,268	165,373	183,478	185,387	196,494	216,659	233,099	273,426	288,570
16	**EXPENSES: ($)**										
17	**Fuel and Purchased Power Expense**										
18	**Retail Fuel Recovered through FPEC**										
19	Generation Fuel Costs	53,909	65,118	68,306	80,318	70,552	72,488	83,627	92,924	113,008	120,048
20	Purchased Power Fuel Cost	8,098	10,173	10,674	10,168	8,887	8,426	9,006	9,837	10,249	10,076
21	Wind and DSM	-	-	301	308	2,850	4,192	4,296	4,404	7,322	8,896
22	**Total FPEC Expense**	62,008	75,291	79,280	90,794	82,289	85,105	96,929	107,165	130,578	139,020
23	**Unit Cost $/kWh**	0.0428	0.0494	0.0499	0.0550	0.0480	0.0479	0.0527	0.0565	0.0668	0.0690
24	**Other Fuel Expense**										
25	Off-system Sales Fuel Expense	6,042	4,984	7,483	8,651	12,569	14,664	16,649	16,833	25,184	27,898

LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
26	**Total Fuel Expense**	68,050	80,274	86,763	99,445	94,857	99,769	113,578	123,998	155,762	166,917
27	**Adjusted Gross Revenues**	71,899	74,993	78,609	84,034	90,530	96,725	103,081	109,101	117,664	121,653
28	**Operation and Maintenance Expense**										
29	Production O&M Existing Units	4,670	4,787	4,787	4,787	4,787	4,787	4,787	4,787	4,787	4,787
30	Production O&M Proposed Plan	-	620	1,426	2,667	2,505	3,226	4,838	5,952	6,736	7,684
31	Non Production	29,453	30,615	31,822	33,077	34,381	35,736	37,145	38,608	40,130	41,710
32	**Total O&M Expense**	34,123	36,021	38,034	40,530	41,673	43,748	46,769	49,347	51,652	54,181
33	Other Non-Operating Expense	1,620	1,661	1,702	1,745	1,788	1,833	1,879	1,926	1,974	2,023
34	**Net Revenues**	36,156	37,311	38,873	41,759	47,069	51,143	54,433	57,828	64,038	65,449
35	**Debt Service**										
36	Existing Debt Service	15,083	15,091	15,112	16,043	15,999	15,950	15,908	16,428	17,782	17,738
37	Proposed Debt Service	-	4,178	8,293	9,283	12,362	13,651	15,685	18,791	19,735	22,154
38	Commercial Paper Interest Expense	-	350	275	925	225	900	325	275	950	225
39	**Total Debt Service**	15,083	19,619	23,680	26,251	28,585	30,501	31,918	35,494	38,467	40,117
40	Available After Debt Service	21,073	17,692	15,193	15,508	18,484	20,643	22,514	22,334	25,572	25,332
41	Less: City of Brownsville Usage	3,837	4,583	4,722	4,857	4,995	5,129	5,260	5,388	5,515	5,642
42	Balance Available to Surplus	17,236	13,109	10,471	10,651	13,489	15,514	17,254	16,946	20,057	19,690
43	Transfer to COB	7,190	7,499	7,861	8,403	9,053	9,673	10,308	10,910	11,766	12,165
44	Less: COB Usage	3,837	4,583	4,722	4,857	4,995	5,129	5,260	5,388	5,515	5,642
45	Cash Transfer to COB	3,353	2,916	3,139	3,546	4,058	4,543	5,048	5,523	6,252	6,523
46	Balance Available for Transfers Out	13,883	10,193	7,333	7,105	9,431	10,970	12,206	11,424	13,805	13,166
47	Improvement Fund- CIP Funding	5,539	10,168	6,389	6,844	8,699	10,559	11,527	10,497	13,309	12,438
48	Balance Available to BPUB:										
49	Improvement Fund - Surplus Revenues	8,344	25	944	261	732	412	679	927	496	729
50	Debt Service Coverage Ratio	2.40	1.90	1.64	1.59	1.65	1.68	1.71	1.63	1.66	1.63

Table E-7 Financial Forecast – No New Generation Case (1,000's)

LN	DESCRIPTION	2012	2013	2014	2015	2016
1	**Retail Sales at Meter (MWh)**	1,450	1,525	1,588	1,650	1,714
2	**Net Energy for Load (MWh)**	1,535	1,613	1,680	1,746	1,813
3	**REVENUES: ($)**					
4	Retail Base Rate Revenues	65,675	69,031	71,897	74,720	77,595
5	Fuel Charge Revenues (includes COB)	62,008	75,291	88,130	103,460	103,704
6	**Gross Operating Revenues**	127,683	144,322	160,027	178,180	181,299
7	**Off-system Sales Revenues**	7,746	6,389	7,158	7,940	7,448
8	**Total Sales Revenues**	135,429	150,711	167,185	186,120	188,747
9	Other Revenues	2,993	3,008	3,023	3,038	3,053
10	Interest from Investments	300	301	301	302	302
11	Other Non-operating revenues	1,227	1,233	1,239	1,246	1,252
12	**Gross Revenues Under Existing Rates**	139,949	155,253	171,748	190,706	193,354
13	Revenue Adjustment	5.00%	0.00%	0.00%	0.00%	0.00%
14	Additional Base Rate Revenue	-	-	-	-	-
15	**Total Revenue**	139,949	155,253	171,748	190,706	193,354
16	**EXPENSES: ($)**					
17	**Fuel and Purchased Power Expense**					
18	**Retail Fuel Recovered through FPEC**					
19	Generation Fuel Costs	53,909	65,118	68,956	81,098	79,972
20	Purchased Power Fuel Cost	8,098	10,173	19,174	22,362	23,732
21	Wind and DSM	-	-	-	-	-
22	**Total FPEC Expense**	62,008	75,291	88,130	103,460	103,704
23	**Unit Cost $/kWh**	0.0428	0.0494	0.0555	0.0627	0.0605
24	**Other Fuel Expense**					
25	Off-system Sales Fuel Expense	6,042	4,984	5,583	6,193	5,809
26	**Total Fuel Expense**	68,050	80,274	93,713	109,653	109,513
27	**Adjusted Gross Revenues**	71,899	74,978	78,035	81,053	83,841
28	**Operation and Maintenance Expense**					
29	Production O&M Existing Units	4,670	4,787	4,787	4,787	4,787
30	Production O&M Proposed Plan	-	620	1,022	2,077	2,383
31	Non Production	29,453	30,615	31,822	33,077	34,381
32	**Total O&M Expense**	34,123	36,021	37,631	39,940	41,551
33	Other Non-Operating Expense	1,620	1,661	1,702	1,745	1,788
34	**Net Revenues**	36,156	37,297	38,703	39,368	40,502
35	**Debt Service**					
36	Existing Debt Service	15,083	15,091	15,112	16,043	15,999

LN	DESCRIPTION	2012	2013	2014	2015	2016
37	Proposed Debt Service	-	-	-	-	-
38	Commercial Paper Interest Expense	-	-	250	250	250
39	**Total Debt Service**	15,083	15,091	15,362	16,293	16,249
40	Available After Debt Service	21,073	22,205	23,341	23,075	24,253
41	Less: City of Brownsville Usage	3,837	4,583	4,722	4,857	4,995
42	Balance Available to Surplus	17,236	17,622	18,619	18,218	19,258
43	Transfer to COB	7,190	7,498	7,804	8,105	8,384
44	Less: COB Usage	3,837	4,583	4,722	4,857	4,995
45	Cash Transfer to COB	3,353	2,915	3,082	3,248	3,390
46	Balance Available for Transfers Out	13,883	14,707	15,537	14,970	15,869
47	Improvement Fund- CIP Funding	5,539	11,213	15,348	12,229	8,883
48	Balance Available to BPUB:					
49	Improvement Fund - Surplus Revenues	8,344	3,494	189	2,741	6,986
50	Debt Service Coverage Ratio	2.40	2.47	2.52	2.42	2.49

Table E-8 Financial Forecast – No Wind Alternatives Case (1,000's)

LN	DESCRIPTION	2012	2013	2014	2015	2016
1	**Retail Sales at Meter (MWh)**	1,450	1,525	1,588	1,650	1,714
2	**Net Energy for Load (MWh)**	1,535	1,613	1,680	1,746	1,813
3	**REVENUES: ($)**					
4	Retail Base Rate Revenues	65,675	69,031	71,897	74,720	77,595
5	Fuel Charge Revenues (includes COB)	62,008	75,291	79,280	90,794	90,022
6	**Gross Operating Revenues**	127,683	144,322	151,177	165,514	167,617
7	**Off-system Sales Revenues**	7,746	6,389	9,594	11,091	11,731
8	**Total Sales Revenues**	135,429	150,711	160,771	176,605	179,348
9	Other Revenues	2,993	3,008	3,023	3,038	3,053
10	Interest from Investments	300	316	340	348	357
11	Other Non-operating revenues	1,227	1,233	1,239	1,246	1,252
12	**Gross Revenues Under Existing Rates**	139,949	155,269	165,374	181,236	184,010
13	Revenue Adjustment	5.00%	0.00%	0.00%	0.00%	3.00%
14	Additional Base Rate Revenue	-	-	-	-	2,328
15	**Total Revenue**	139,949	155,269	165,374	181,236	186,338
16	**EXPENSES: ($)**					
17	**Fuel and Purchased Power Expense**					
18	**Retail Fuel Recovered through FPEC**					
19	Generation Fuel Costs	53,909	65,118	68,306	80,318	78,754
20	Purchased Power Fuel Cost	8,098	10,173	10,674	10,168	10,952
21	Wind and DSM	-	-	301	308	317
22	**Total FPEC Expense**	62,008	75,291	79,280	90,794	90,022
23	**Unit Cost $/kWh**	0.0428	0.0494	0.0499	0.0550	0.0525
24	**Other Fuel Expense**					
25	Off-system Sales Fuel Expense	6,042	4,984	7,483	8,651	9,150
26	**Total Fuel Expense**	68,050	80,274	86,763	99,445	99,172
27	**Adjusted Gross Revenues**	71,899	74,994	78,610	81,792	87,166
28	**Operation and Maintenance Expense**					
29	Production O&M Existing Units	4,670	4,787	4,787	4,787	4,787
30	Production O&M Proposed Plan	-	620	1,426	2,667	3,056
31	Non Production	29,453	30,615	31,822	33,077	34,381
32	**Total O&M Expense**	34,123	36,021	38,034	40,530	42,224
33	Other Non-Operating Expense	1,620	1,661	1,702	1,745	1,788
34	**Net Revenues**	36,156	37,312	38,874	39,517	43,154
35	**Debt Service**					
36	Existing Debt Service	15,083	15,091	15,112	16,043	15,999

LN	DESCRIPTION	2012	2013	2014	2015	2016
37	Proposed Debt Service	-	4,453	8,353	9,205	11,734
38	Commercial Paper Interest Expense	-	250	300	775	388
39	**Total Debt Service**	15,083	19,794	23,765	26,023	28,120
40	Available After Debt Service	21,073	17,518	15,109	13,494	15,034
41	Less: City of Brownsville Usage	3,837	4,583	4,722	4,857	4,995
42	Balance Available to Surplus	17,236	12,935	10,387	8,637	10,039
43	Transfer to COB	7,190	7,499	7,861	8,179	8,717
44	Less: COB Usage	3,837	4,583	4,722	4,857	4,995
45	Cash Transfer to COB	3,353	2,916	3,139	3,322	3,722
46	Balance Available for Transfers Out	13,883	10,019	7,248	5,315	6,317
47	Improvement Fund- CIP Funding	5,539	9,168	6,563	5,092	6,236
48	Balance Available to BPUB:					
49	Improvement Fund - Surplus Revenues	8,344	851	685	224	81
50	Debt Service Coverage Ratio	2.40	1.89	1.64	1.52	1.53

Table E-9 Financial Forecast – 2.0 Percent Rate Increase Case (1,000's)

LN	DESCRIPTION	2012	2013	2014
1	**Retail Sales at Meter (MWh)**	1,450	1,525	1,588
2	**Net Energy for Load (MWh)**	1,535	1,613	1,680
3	**REVENUES: ($)**			
4	Retail Base Rate Revenues	65,675	69,031	71,897
5	Fuel Charge Revenues (includes COB)	62,008	75,291	76,300
6	**Gross Operating Revenues**	127,683	144,322	148,197
7	**Off-system Sales Revenues**	7,746	6,389	10,915
8	**Total Sales Revenues**	135,429	150,711	159,112
9	Other Revenues	2,993	3,008	3,023
10	Interest from Investments	300	315	338
11	Other Non-operating revenues	1,227	1,233	1,239
12	**Gross Revenues Under Existing Rates**	139,949	155,268	163,713
13	Revenue Adjustment	5.00%	0.00%	0.00%
14	Additional Base Rate Revenue	-	-	-
15	**Total Revenue**	139,949	155,268	163,713
16	**EXPENSES: ($)**			
17	**Fuel and Purchased Power Expense**			
18	**Retail Fuel Recovered through FPEC**			
19	Generation Fuel Costs	53,909	65,118	65,847
20	Purchased Power Fuel Cost	8,098	10,173	9,308
21	Wind and DSM	-	-	1,145
22	**Total FPEC Expense**	62,008	75,291	76,300
23	**Unit Cost $/kWh**	0.0428	0.0494	0.0481
24	**Other Fuel Expense**			
25	Off-system Sales Fuel Expense	6,042	4,984	8,514
26	**Total Fuel Expense**	68,050	80,274	84,814
27	**Adjusted Gross Revenues**	71,899	74,993	78,899
28	**Operation and Maintenance Expense**			
29	Production O&M Existing Units	4,670	4,787	4,787
30	Production O&M Proposed Plan	-	620	1,340
31	Non Production	29,453	30,615	31,822
32	**Total O&M Expense**	34,123	36,021	37,949
33	Other Non-Operating Expense	1,620	1,661	1,702
34	**Net Revenues**	36,156	37,311	39,248
35	**Debt Service**			
36	Existing Debt Service	15,083	15,091	15,112

LN	DESCRIPTION	2012	2013	2014
37	Proposed Debt Service	-	4,178	8,018
38	Commercial Paper Interest Expense	-	250	250
39	**Total Debt Service**	15,083	19,519	23,380
40	Available After Debt Service	21,073	17,792	15,868
41	Less: City of Brownsville Usage	3,837	4,583	4,722
42	Balance Available to Surplus	17,236	13,209	11,146
43	Transfer to COB	7,190	7,499	7,890
44	Less: COB Usage	3,837	4,583	4,722
45	Cash Transfer to COB	3,353	2,916	3,168
46	Balance Available for Transfers Out	13,883	10,293	7,978
47	Improvement Fund- CIP Funding	5,539	9,524	7,645
48	Balance Available to BPUB:			
49	Improvement Fund - Surplus Revenues	8,344	769	334
50	Debt Service Coverage Ratio	2.40	1.91	1.68

Table E-10 Financial Forecast – Modified Reference Case (1,000's)

LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	**Retail Sales at Meter (MWh)**	1,450	1,525	1,588	1,650	1,714	1,776	1,838	1,897	1,956	2,015
2	**Net Energy for Load (MWh)**	1,535	1,613	1,680	1,746	1,813	1,880	1,945	2,008	2,070	2,133
3	**REVENUES: ($)**										
4	Retail Base Rate Revenues	65,675	69,031	71,897	74,720	77,595	80,433	83,214	85,906	88,577	91,251
5	Fuel Charge Revenues (includes COB)	61,456	76,231	82,119	96,595	91,023	101,784	116,566	121,729	144,036	142,456
6	**Gross Operating Revenues**	127,131	145,262	154,016	171,315	168,618	182,217	199,779	207,634	232,613	233,707
7	**Off-system Sales Revenues**	9,809	10,029	14,343	17,142	13,159	14,147	15,570	18,970	30,879	36,719
8	**Total Sales Revenues**	136,940	155,291	168,359	188,457	181,778	196,364	215,349	226,604	263,493	270,426
9	Other Revenues	2,993	3,008	3,023	3,038	3,053	3,069	3,084	3,099	3,115	3,130
10	Interest from Investments	300	301	301	323	353	361	371	389	397	410
11	Other Non-operating revenues	1,227	1,233	1,239	1,246	1,252	1,258	1,264	1,271	1,277	1,283
12	**Gross Revenues Under Existing Rates**	141,460	159,833	172,923	193,064	186,435	201,051	220,069	231,363	268,281	275,249
13	Revenue Adjustment	5.00%	0.00%	0.00%	0.00%	3.00%	3.00%	3.00%	3.50%	3.00%	0.00%
14	Additional Base Rate Revenue	-	-	-	-	2,328	4,898	7,716	11,251	14,607	15,047
15	**Total Revenue**	141,460	159,833	172,923	193,064	188,763	205,950	227,785	242,615	282,888	290,297
16	**EXPENSES: ($)**										
17	**Fuel and Purchased Power Expense**										
18	**Retail Fuel Recovered through FPEC**										
19	Generation Fuel Costs	49,774	57,200	56,984	63,705	80,076	86,757	98,261	102,861	122,541	122,285
20	Purchased Power Fuel Cost	11,682	19,031	25,135	32,890	9,371	9,820	10,136	9,776	12,175	10,593
21	Wind and DSM	-	-	-	-	1,576	5,208	8,169	9,092	9,320	9,578
22	**Total FPEC Expense**	61,456	76,231	82,119	96,595	91,023	101,784	116,566	121,729	144,036	142,456
23	**Unit Cost $/kWh**	0.0424	0.0500	0.0517	0.0585	0.0531	0.0573	0.0634	0.0642	0.0736	0.0707
24	**Other Fuel Expense**										
25	Off-system Sales Fuel Expense	7,651	7,823	11,188	13,371	10,264	11,035	12,145	14,797	24,086	28,641

LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
26	**Total Fuel Expense**	69,107	84,054	93,306	109,966	101,288	112,819	128,710	136,525	168,122	171,097
27	**Adjusted Gross Revenues**	72,353	75,779	79,616	83,098	87,475	93,131	99,075	106,089	114,766	119,200
28	**Operation and Maintenance Expense**										
29	Production O&M Existing Units	4,670	4,787	4,787	4,787	4,787	4,787	4,787	4,787	4,787	4,787
30	Production O&M Proposed Plan	-	320	740	1,290	4,338	5,835	7,267	8,329	9,066	9,538
31	Non Production	29,453	30,615	31,822	33,077	34,381	35,736	37,145	38,608	40,130	41,710
32	**Total O&M Expense**	34,123	35,722	37,348	39,153	43,506	46,358	49,198	51,723	53,982	56,035
33	Other Non-Operating Expense	1,620	1,661	1,702	1,745	1,788	1,833	1,879	1,926	1,974	2,023
34	**Net Revenues**	36,610	38,397	40,566	42,201	42,181	44,940	47,998	52,440	58,810	61,142
35	**Debt Service**										
36	Existing Debt Service	15,083	15,091	15,112	16,043	15,999	15,950	15,908	16,428	17,782	17,738
37	Proposed Debt Service	-	-	-	6,047	10,643	11,506	14,420	17,564	18,370	21,888
38	Commercial Paper Interest Expense	-	-	175	388	200	975	400	250	1,000	200
39	**Total Debt Service**	15,083	15,091	15,287	22,477	26,841	28,431	30,728	34,242	37,152	39,827
40	Available After Debt Service	21,527	23,306	25,279	19,724	15,340	16,509	17,270	18,198	21,658	21,315
41	Less: City of Brownsville Usage	3,837	4,583	4,722	4,857	4,995	5,129	5,260	5,388	5,515	5,642
42	Balance Available to Surplus	17,690	18,723	20,557	14,867	10,345	11,380	12,010	12,811	16,144	15,673
43	Transfer to COB	7,235	7,578	7,962	8,310	8,748	9,313	9,908	10,609	11,477	11,920
44	Less: COB Usage	3,837	4,583	4,722	4,857	4,995	5,129	5,260	5,388	5,515	5,642
45	Cash Transfer to COB	3,399	2,995	3,240	3,453	3,753	4,184	4,647	5,221	5,962	6,278
46	Balance Available for Transfers Out	14,291	15,728	17,317	11,414	6,593	7,196	7,363	7,589	10,182	9,395
47	Improvement Fund- CIP Funding	5,539	10,805	16,919	10,837	6,383	7,081	7,330	7,502	9,254	9,339
48	Balance Available to BPUB:										
49	Improvement Fund - Surplus Revenues	8,753	4,923	398	577	210	115	32	87	927	56
50	Debt Service Coverage Ratio	2.43	2.54	2.65	1.88	1.57	1.58	1.56	1.53	1.58	1.54

Table E-11 Financial Forecast – Tenaska Case (1,000's)

LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	**Retail Sales at Meter (MWh)**	1,450	1,525	1,588	1,650	1,714	1,776	1,838	1,897	1,956	2,015
2	**Net Energy for Load (MWh)**	1,535	1,613	1,680	1,746	1,813	1,880	1,945	2,008	2,070	2,133
3	**REVENUES: ($)**										
4	Retail Base Rate Revenues	65,675	69,031	71,897	74,720	77,595	80,433	83,214	85,906	88,577	91,251
5	Fuel Charge Revenues (includes COB)	61,456	76,231	82,119	96,595	88,681	101,106	103,805	115,996	137,884	142,766
6	**Gross Operating Revenues**	127,131	145,262	154,016	171,315	166,275	181,539	187,019	201,902	226,462	234,017
7	**Off-system Sales Revenues**	9,809	10,029	14,343	17,142	21,199	27,368	30,661	32,086	46,344	49,110
8	**Total Sales Revenues**	136,940	155,291	168,359	188,457	187,474	208,907	217,680	233,988	272,806	283,127
9	Other Revenues	2,993	3,008	3,023	3,038	3,053	3,069	3,084	3,099	3,115	3,130
10	Interest from Investments	300	301	301	302	333	363	375	394	401	413
11	Other Non-operating revenues	1,227	1,233	1,239	1,246	1,252	1,258	1,264	1,271	1,277	1,283
12	**Gross Revenues Under Existing Rates**	141,460	159,833	172,923	193,043	192,112	213,597	222,404	238,751	277,598	287,954
13	Revenue Adjustment	5.00%	0.00%	0.00%	0.00%	5.00%	5.50%	5.00%	3.50%	4.50%	0.00%
14	Additional Base Rate Revenue	-	-	-	-	3,880	8,667	13,575	17,512	22,855	23,544
15	**Total Revenue**	141,460	159,833	172,923	193,043	195,992	222,263	235,979	256,263	300,453	311,498
16	**EXPENSES: ($)**										
17	**Fuel and Purchased Power Expense**										
18	**Retail Fuel Recovered through FPEC**										
19	Generation Fuel Costs	49,774	57,200	56,984	63,705	80,803	93,586	96,393	107,982	127,271	130,656
20	Purchased Power Fuel Cost	11,682	19,031	25,135	32,890	7,665	7,196	7,081	7,674	7,468	7,484
21	Wind and DSM	-	-	-	-	212	324	332	340	3,145	4,627
22	**Total FPEC Expense**	61,456	76,231	82,119	96,595	88,681	101,106	103,805	115,996	137,884	142,766
23	**Unit Cost $/kWh**	0.0424	0.0500	0.0517	0.0585	0.0517	0.0569	0.0565	0.0611	0.0705	0.0708
24	**Other Fuel Expense**										
25	Off-system Sales Fuel Expense	7,651	7,823	11,188	13,371	16,535	21,347	23,916	25,027	36,148	38,306

LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
26	**Total Fuel Expense**	69,107	84,054	93,306	109,966	105,216	122,453	127,721	141,023	174,033	181,072
27	**Adjusted Gross Revenues**	72,353	75,779	79,616	83,077	90,776	99,810	108,258	115,239	126,420	130,426
28	**Operation and Maintenance Expense**										
29	Production O&M Existing Units	4,670	4,787	4,787	4,787	4,787	4,787	4,787	4,787	4,787	4,787
30	Production O&M Proposed Plan	-	320	740	1,290	8,924	13,191	14,385	16,142	17,243	18,033
31	Non Production	29,453	30,615	31,822	33,077	34,381	35,736	37,145	38,608	40,130	41,710
32	**Total O&M Expense**	34,123	35,722	37,348	39,153	48,092	53,714	56,316	59,537	62,159	64,530
33	Other Non-Operating Expense	1,620	1,661	1,702	1,745	1,788	1,833	1,879	1,926	1,974	2,023
34	**Net Revenues**	36,610	38,397	40,566	42,179	40,896	44,264	50,063	53,777	62,287	63,873
35	**Debt Service**										
36	Existing Debt Service	15,083	15,091	15,112	16,043	15,999	15,950	15,908	16,428	17,782	17,738
37	Proposed Debt Service	-	-	-	-	8,521	12,091	15,225	18,407	19,190	22,488
38	Commercial Paper Interest Expense	-	-	175	175	175	1,000	375	250	1,000	250
39	**Total Debt Service**	15,083	15,091	15,287	16,218	24,695	29,041	31,508	35,085	37,972	40,477
40	Available After Debt Service	21,527	23,306	25,279	25,962	16,201	15,223	18,555	18,692	24,315	23,397
41	Less: City of Brownsville Usage	3,837	4,583	4,722	4,857	4,995	5,129	5,260	5,388	5,515	5,642
42	Balance Available to Surplus	17,690	18,723	20,557	21,105	11,207	10,094	13,295	13,304	18,801	17,755
43	Transfer to COB	7,235	7,578	7,962	8,308	9,078	9,981	10,826	11,524	12,642	13,043
44	Less: COB Usage	3,837	4,583	4,722	4,857	4,995	5,129	5,260	5,388	5,515	5,642
45	Cash Transfer to COB	3,399	2,995	3,240	3,451	4,083	4,852	5,566	6,136	7,127	7,401
46	Balance Available for Transfers Out	14,291	15,728	17,317	17,654	7,124	5,242	7,730	7,168	11,673	10,354
47	Improvement Fund- CIP Funding	5,539	10,805	16,919	12,020	6,995	5,162	7,167	6,972	11,040	9,692
48	Balance Available to BPUB:										
49	Improvement Fund - Surplus Revenues	8,753	4,923	398	5,634	129	81	562	196	634	662
50	Debt Service Coverage Ratio	2.43	2.54	2.65	2.60	1.66	1.52	1.59	1.53	1.64	1.58

Table E-12 Financial Forecast – Transmission Case (1,000's)

LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	**Retail Sales at Meter (MWh)**	1,450	1,525	1,588	1,650	1,714	1,776	1,838	1,897	1,956	2,015
2	**Net Energy for Load (MWh)**	1,535	1,613	1,680	1,746	1,813	1,880	1,945	2,008	2,070	2,133
3	**REVENUES: ($)**										
4	Retail Base Rate Revenues	65,675	69,031	71,897	74,720	77,595	80,433	83,214	85,906	88,577	91,251
5	Fuel Charge Revenues (includes COB)	61,456	76,231	82,119	96,595	92,309	104,042	108,515	120,223	141,810	146,810
6	**Gross Operating Revenues**	127,131	145,262	154,016	171,315	169,904	184,475	191,729	206,128	230,387	238,060
7	**Off-system Sales Revenues**	9,809	10,029	14,343	17,142	23,452	33,618	34,614	34,999	53,774	57,845
8	**Total Sales Revenues**	136,940	155,291	168,359	188,457	193,356	218,093	226,344	241,128	284,161	295,905
9	Other Revenues	2,993	3,008	3,023	3,038	3,053	3,069	3,084	3,099	3,115	3,130
10	Interest from Investments	300	301	301	311	321	322	322	323	333	342
11	Other Non-operating revenues	1,227	1,233	1,239	1,246	1,252	1,258	1,264	1,271	1,277	1,283
12	**Gross Revenues Under Existing Rates**	141,460	159,833	172,923	193,052	197,982	222,741	231,014	245,820	288,886	300,661
13	Revenue Adjustment	5.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
14	Additional Base Rate Revenue	-	-	-	-	-	-	-	-	-	-
15	**Total Revenue**	141,460	159,833	172,923	193,052	197,982	222,741	231,014	245,820	288,886	300,661
16	**EXPENSES: ($)**										
17	**Fuel and Purchased Power Expense**										
18	**Retail Fuel Recovered through FPEC**										
19	Generation Fuel Costs	49,774	57,200	56,984	63,705	56,673	52,793	54,028	63,881	70,510	72,280
20	Purchased Power Fuel Cost	11,682	19,031	25,135	32,890	32,892	47,058	50,192	51,938	63,978	65,634
21	Wind and DSM	-	-	-	-	2,745	4,192	4,296	4,404	7,322	8,896
22	**Total FPEC Expense**	61,456	76,231	82,119	96,595	92,309	104,042	108,515	120,223	141,810	146,810
23	**Unit Cost $/kWh**	0.0424	0.0500	0.0517	0.0585	0.0539	0.0586	0.0590	0.0634	0.0725	0.0728
24	**Other Fuel Expense**										
25	Off-system Sales Fuel Expense	7,651	7,823	11,188	13,371	18,293	26,222	26,999	27,300	41,944	45,119

LN	DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
26	**Total Fuel Expense**	69,107	84,054	93,306	109,966	110,602	130,264	135,515	147,522	183,754	191,928
27	**Adjusted Gross Revenues**	72,353	75,779	79,616	83,086	87,380	92,477	95,499	98,298	105,132	108,732
28	**Operation and Maintenance Expense**										
29	Production O&M Existing Units	4,670	4,787	4,787	4,787	4,787	4,787	4,787	4,787	4,787	4,787
30	Production O&M Proposed Plan	-	320	740	1,290	1,572	1,884	2,465	3,494	4,269	5,002
31	Non Production	29,453	30,615	31,822	33,077	34,381	35,736	37,145	38,608	40,130	41,710
32	**Total O&M Expense**	34,123	35,722	37,348	39,153	40,739	42,407	44,396	46,889	49,185	51,499
33	Other Non-Operating Expense	1,620	1,661	1,702	1,745	1,788	1,833	1,879	1,926	1,974	2,023
34	**Net Revenues**	36,610	38,397	40,566	42,189	44,853	48,238	49,225	49,484	53,973	55,210
35	**Debt Service**										
36	Existing Debt Service	15,083	15,091	15,112	16,043	15,999	15,950	15,908	16,428	17,782	17,738
37	Proposed Debt Service	-	-	-	2,639	3,744	3,744	3,744	3,744	6,273	7,332
38	Commercial Paper Interest Expense	-	-	175	400	400	400	400	725	125	725
39	**Total Debt Service**	15,083	15,091	15,287	19,081	20,143	20,094	20,052	20,897	24,180	25,795
40	Available After Debt Service	21,527	23,306	25,279	23,107	24,710	28,144	29,172	28,587	29,794	29,415
41	Less: City of Brownsville Usage	3,837	4,583	4,722	4,857	4,995	5,129	5,260	5,388	5,515	5,642
42	Balance Available to Surplus	17,690	18,723	20,557	18,250	19,716	23,015	23,912	23,199	24,279	23,773
43	Transfer to COB	7,235	7,578	7,962	8,309	8,738	9,248	9,550	9,830	10,513	10,873
44	Less: COB Usage	3,837	4,583	4,722	4,857	4,995	5,129	5,260	5,388	5,515	5,642
45	Cash Transfer to COB	3,399	2,995	3,240	3,452	3,743	4,119	4,290	4,442	4,998	5,231
46	Balance Available for Transfers Out	14,291	15,728	17,317	14,799	15,972	18,896	19,622	18,757	19,281	18,542
47	Improvement Fund- CIP Funding	5,539	10,805	16,919	14,269	11,095	7,444	14,487	18,399	18,877	17,863
48	Balance Available to BPUB:										
49	Improvement Fund - Surplus Revenues	8,753	4,923	398	530	4,878	11,452	5,135	358	403	679
50	Debt Service Coverage Ratio	2.43	2.54	2.65	2.21	2.23	2.40	2.45	2.37	2.23	2.14

SENSITIVITY

A sensitivity case was completed for the Reference Case in order to determine the impact of adjusting the sales forecast to the 2012 budget amount and then escalating by 3 percent each year to account for growth in the system. A second sensitivity case was completed for the Reference Case in order to determine the impact of having no off-system sales margin. The outputs from PROMOD™ remained the same as the amount projected in the Reference Case for both sensitivities. Adjustments were made to the base rate, for both sensitivities, in order to keep coverage above the minimum requirement of 1.50. Table E-13 shows the comparison of base rate adjustments for 2012 through 2021.

Table E-13 Reference Case Base Rate Increase Comparison

DESCRIPTION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Reference Case	5.00%	0.00%	0.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	0.00%
Sales Forecast Sensitivity	5.00%	6.00%	5.00%	5.00%	5.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Off-system Sales Margin Sensitivity	5.00%	0.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%