BPUB INTEGRATED RESOURCE PLAN

Privileged & Confidential Competitive Sensitive Matters

B&V PROJECT NO. 193020

PREPARED FOR

Brownsville Public Utilities Board

1 MAY 2017

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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 AND APPROACH

The Brownsville Public Utilities Board (BPUB) provides reliable and economical electric services to nearly 49,000 residential, commercial, industrial, and municipal customers through a combination of solely and jointly owned generating resources plus power purchases. Black & Veatch was retained by BPUB in 2016 to develop an Integrated Resource Plan (IRP) and rate impact assessment in order to analyze, evaluate, and recommend the preferred expansion plan option among a limited number of power supply alternatives considered. In an IRP, power resources are selected to meet the projected peak demand over a long-term period. In this IRP, the projected peak demand during the 2017 through 2036 planning period is forecasted to increase from 304.9 MW in 2017 to 373.6 MW in 2036. As seen in Table 1-1, the current forecast is approximately 237 MW lower than the forecast in the previous planning study through 2031 and reflects the low growth realized on the BPUB system in the past several years that has also been experienced in most regions of the country.

When the Base Case load forecast is compared to the existing BPUB capacity resources under the base study assumption that the Oklaunion I and II coal-fired units retire in 2020, a need for incremental capacity on the BPUB system arises in 2020 when a 71.9 MW deficit is projected. This deficit grows slowly and reaches 130.6 MW in 2036.

Table 1-1 Peak Load Forecast Comparison: 2017 IRP vs. 2011 IRP

YEAR	MW PEAK W/O DG OR LOAD SHEDDING	YEAR	MW PEAK W/O DG OR LOAD SHEDDING	MW DIFFERENCE
2011 IRP		2017 IRP		2011-2017
2017	391.0	2017	308.3	82.7
2018	405.0	2018	311.1	93.9
2019	418.5	2019	314.3	104.2
2020	430.8	2020	317.6	113.2
2021	445.5	2021	320.8	124.7
2022	459.0	2022	330.5	128.5
2023	472.6	2023	333.8	138.8
2024	485.2	2024	337.0	148.2
2025	500.8	2025	340.3	160.5
2026	516.3	2026	343.5	172.8
2027	532.7	2027	346.8	185.9
2028	548.7	2028	350.0	198.7
2029	564.7	2029	353.3	211.4
2030	580.7	2030	356.5	224.2
2031	596.7	2031	359.8	236.9
2032	NA	2032	363.0	NA
2033	NA	2033	366.3	NA
2034	NA	2034	369.6	NA
2035	NA	2035	372.9	NA
2036	NA	2036	376.3	NA

To fill this future need for capacity, a number of gas-fired simple cycle, combined cycle, and reciprocating engines were evaluated as self-owned candidate options. The capacity of the self-owned options considered in this study ranged from 9 MW to 285 MW. These self-build options were supplemented by PPA purchase options from new or existing combined cycle capacity and by a wind PPA in selected sensitivity cases. The capacity expansion plans developed around these technologies consisted of the following:

1. **Base Case**: Consisting of the best BPUB self-build expansion plan with natural gas-fired simple cycle and combined cycle units ranging in size from 9 MW to 285 MW as the candidate resource options. New wind or conventional PPAs (from Tenaska or the market) were not part of the Base Case list of candidate options considered.
2. **Sensitivity 1**: Consisting of the Base Case assumptions except Oklaunion is assumed to retire in 2017 rather than in 2020.
3. **Sensitivity 2**: Consisting of the Base Case assumptions except a stair-step increase in load of 100 MW is assumed in 2025.
4. **Sensitivity 3**: Consisting of a 200 MW purchase from a possible 800 MW future Tenaska combined cycle option.
5. **Sensitivity 4**: Consisting of an alternative power purchase from Tenaska or another IPP involving an initial purchase amount of 100 MW in 2020 that increases to 132 MW in 2025 to closely match the BPUB need for power. In this sensitivity case, the PPA capacity price is solved for such that the CPWC of the plan is 2 percent lower than the better of the Base Case or Sensitivity 3 (a 2 percent difference in CPWC is usually on the threshold of being considered a significant difference in most planning studies). This sensitivity was not part of the original scope but was added in 2017.
6. **Sensitivity 5**: Consisting of an 84 MW wind PPA option (27.7 MW firm), combined with the most economical expansion plan among the Base Case, Sensitivity 3, or Sensitivity 4. Since Sensitivity 4 was the best of these three plans, the wind PPA option was combined with the 100 MW (132 MW) purchase in 2020 (2025) to form Sensitivity 5.

Various inputs impacting the economic analysis were developed and considered in this IRP. Key inputs included assumptions about cost and performance characteristics of the technologies considered, the ability to import and export power over the regional power system, fuel prices, natural gas availability, emissions, and regional power price projections. These inputs and other data were developed in conjunction with the BPUB staff and major assumptions made independently by Black & Veatch staff were reviewed with BPUB.

The project data was entered and used as a basis for developing an optimization expansion planning model in Strategist™, an optimization expansion planning tool developed and licensed by Ventyx. Strategist™ enables the determination of the least-cost plan and the economics of 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 allowed for the development and analysis of more detailed (hourly) production cost modeling. The PROMOD™ results were used as the basis for the economic analyses presented in Section 7.0 of this IRP. Assumptions regarding the ERCOT market were developed using Black & Veatch's Proprietary Energy Market Perspective ERCOT Spring 2016 data set.

1.2 CPWC AND STUDY FINDINGS

1.2.1 CPWC Conceptual Calculation Process

The economic analysis and ranking of capacity alternatives is done using the standard approach in expansion planning studies, which involves developing the cumulative present worth cost (CPWC) of an expansion plan. The CPWC calculation is shown conceptually in Figure 1-1. In this approach, annual fuel and variable O&M costs are determined using a production costing model. Added to these system wide variable costs are the fixed costs associated with new unit additions. Fixed costs include the carrying charge on new capital investments plus fixed O&M costs for the new options added to the system. Also included are the costs of market purchases from the ERCOT market or through power purchase agreements, and the revenue associated with market sales of power from self-owned generating units.

Once the annual costs of meeting energy requirements are determined, these annual costs are discounted to the start of the planning period and summed. The summation of the present worth of all annual costs is the CPWC of a plan.

	2017	2018	2019	2020	2021	... 2036
Variable Costs	$	$	$	$	$	$
System fuel Costs	$	$	$	$	$	$
System Variable O&M	$	$	$	$	$	$
Fixed Costs	$	$	$	$	$	$
Fixed O&M	$	$	$	$	$	$
Capital Cost, New Generation	$	$	$	$	$	$
Market Purchases of Power	$	$	$	$	$	$
Market Revenues from Regional Dispatch	$	$	$	$	$	$
Total Incremental Annual Cost	$	$	$	$	$	$

CPWC $

Figure 1-1 Conceptual View of the CPWC Calculation

The least-cost plan in any scenario is the expansion plan having the lowest CPWC. The plan that is the least-cost under the Base Case or most likely assumptions is often selected as the best overall plan, but this is not always the case. It is possible that the plan with the lowest Base Case CPWC cost may not be the selected plan if it contains significant risk that can be avoided in other plans, if the plan is not considered attainable, if it does not include cost-effective resource options found in other plans, or if the plan becomes relatively expensive in a number of the sensitivities performed. For this reason, it is appropriate to determine the CPWC across a number of possible future conditions and scenarios. As mentioned, a Base Case expansion plan and five sensitivity cases were developed for the BPUB IRP; the results are presented below.

1.2.2 CPWC Results and Rankings

Table 1-2 summarizes the CPWC results and rankings. Of the expansion plansthat are strictly comparable in terms of CPWC (all but Sensitivity 1 and 2), the best BPUB plan involves Sensitivity 5, which consists of the 84 MW (27.7 MW firm) wind PPA in late 2018, followed by the stair-step purchase from an existing combined cycle in 2020 (100 MW) and 2027 (132 MW of which 32 MW is incremental). Note, however, that this expansion plan solved-for capacity price needed to make the case 2 percent lower in cost than the Base Case, a savings margin that is usually considered to be significant in planning studies. This break-even capacity cost is $144/kW-year. Based on the assumed fixed charges of an existing 1x1 7FA combined cycle unit, Section 7.0 explains that it is reasonable to believe that a competitive capacity solicitation could produce proposals with capacity prices at or below the required break-even capacity price.

The second best plan involves the stair-step purchase from an existing combined cycle plant without the wind PPA. This analysis also involved determining the capacity price needed to make the expansion plan 2 percent lower than the Base Case. The resulting capacity price was found to be $130/kW-year for the combined cycle capacity, meaning that if BPUB received offers or otherwise negotiated for combined cycle capacity at no more than $130/kW-year, the option would have a significant cost advantage over the Base Case.

The third best plan is the Base Case, which included only BPUB self-build simple cycle and combined cycle options ranging in size from 9 MW to 285 MW. Due to the projected 2020 retirement of Oklaunion, the best self-build option is the 285 MW 1x1 combined cycle unit.

The 200 MW Tenaska purchase option from a possible future 800 MW combined cycle is the fourth-ranked option, but this is 6.3 percent higher in CPWC than the least-cost expansion plan (Sensitivity 5).

The other two sensitivities in Table 1-2 are not strictly comparable to the Base Case and other sensitivity cases (as the PPA options were not among the candidate units), but are useful in that they indicate the best addition for BPUB under single variable sensitivities from the Base Case. In the event that a 100 MW increase in BPUB load occurs during the planning period (the increase was assumed to occur in 2025), the expansion plan selected a 1x1 285 MW combined cycle as the best self-build option for BPUB. In the event that the Oklaunion plant retires in 2017, the best self-build option for BPUB would consist of the same expansion plan as the Base Case, assuming that for the period 2018-2019, BPUB will use a short term Bridge PPA as new units will likely not be built in this period.

Table 1-2 CPWC Comparison and Ranking of Plans

EXPANSION PLAN	CPWC ($ MILLIONS)	% HIGHER THAN BEST PLAN	RANK	COMMENT
Sensitivity 5. Wind PPA (2018) with Stair-Step Purchase from an Existing Combined Cycle	1,031	-	1st	Based on a max. break-even capacity price of $144/kW-year that would make the plan approx. 2% lower than the Base Case
Sensitivity 4. Stair-Step Purchase from an Existing Combined Cycle	1,032	-	2nd	Based on a max. break-even capacity price of $130/kW-year that would make the plan approx. 2% lower than the Base Case
Base Case. BPUB Self-build Case Involving a 285 MW, 1x1 7FA Combined Cycle	1,052	2.0%	3rd	Candidate units include natural gas fired simple and combined cycle options from 9 MW to 285 MW
Sensitivity 3. 200 MW Purchase from Possible 800 MW Tenaska Unit	1,096	6.3%	4th	Considered less likely to be built based on current market conditions. An option involving an existing combined cycle as in Sensitivity 4 and 5 is more likely
Single Variable Sensitivities on the Base Case (CPWC not strictly comparable with other sensitivity cases)				
Sensitivity 2. 2017 Retirement of Oklaunion	$1,045	NA	NA	Short Term Bridge PPA and BPUB Self-build Case Involving a 285 MW, 1x1 Combined Cycle
Sensitivity 1. 100 MW increase in industrial load in 2025	$1,169	NA	NA	This plan involves the selection of a 1x1 285 MW self-build option (the Tenaska 200 MW purchase and the stair-step purchase from an existing combined cycle were not candidate units in this run since this is a sensitivity off of the Base Case)

A high level rate impact analysis of the expansion plan options was performed for this study and is presented in Section 8.0. The conclusions from this analysis are that the three best scenarios are the Base Case, Sensitivity 4, and Sensitivity 5. Even though the two latter sensitivities are higher in total costs, they have much better debt service coverage and generate greater surplus revenues, these are the preferred options. BPUB would be taking on more risk by issuing bonds for a self-build option so the PPA options are preferable.

1.2.3 Recommendations

Based on the above conclusion that the least-cost plan among those considered involves Sensitivity 5, consisting of a future additional wind PPA and the purchase of combined cycle capacity from an existing unit, the following recommendations apply:

- Given that: a) [redacted] has indicated that it will likely provide pricing to BPUB from an existing combined cycle (with a total capacity of the unit expected to be in the range of 400-600MW) instead of building a new 800 MW unit, and since b) other utilities and IPPs in the region could also propose competitively priced combined cycle capacity to BPUB through the recently-increased regional transmission network, it is appropriate that the two options making up Sensitivity 5—the wind PPA and the purchase from existing combined cycle capacity—should be the focus of BPUB planning efforts in the near-term. When pursuing these options, the ability of the seller to shape the offer to meet the timing and amount of BPUB's capacity needs will strongly impact the overall cost-effectiveness of the plan. Experience has also shown that competition in the form of a capacity solicitation RFP can be the most effective means of securing low-cost power supplies and so an RFP is recommended.
- On-going monitoring of the available export capacity out of the BPUB service area and into LRGV and other ERCOT areas will be important to allow for the economical exchange of power over the long-term. This monitoring can be likely be accomplished by keeping abreast of ERCOT studies, although such studies have not always been historically accurate. Directly performing load flow studies is also an option.
- It will be prudent for BPUB to maintain contingency plans for increased power supplies, to continue to monitor market prices, and to confirm that it remains economical to operate with no planning reserve margin.
- While it should be realistic to expect that BPUB, Tenaska, or another regional project will be able to arrange for natural gas supplies, continued monitoring of developments and progress toward making a final resource selection should occur.

- As negotiations with potential sellers of capacity and energy progress, it will be appropriate to check the on-going competitiveness of these options and to evaluate the cost impact of specific provisions being negotiated. For many negotiated items related to price, and operational flexibility, this can be done using an expansion planning program. For some issues related specifically to large amounts of intermittent renewable energy, load flow and transient stability studies could be required or appropriate to perform.
- As negotiations progress, it will also be appropriate to continue to update the rate impact studies and a more detailed study may be appropriate to perform in the future.

2.0 Description of Existing System

BPUB is a citizen-owed, municipal utility that was formally chartered in 1960, but has roots dating to 1904. In 2015, BPUB provided reliable and economical electric services to 47,671 residential, commercial, industrial, and municipal customers. BPUB also provided water and wastewater services to approximately 49,000 customers in 2015. Total electric operating revenues for BPUB were more than $146 million in 2014 and made up approximately 76 percent of the total BPUB revenues of $192 million that year.

The management and operation of BPUB occurs under the utility's seven member Board of Directors, consisting of the city mayor and six members who are appointed by the City Commission to four-year terms. The utility's stated mission is that "by 2018, BPUB will be the foundation for our community's future by providing reliable infrastructure, competitive rates, and exceptional customer service."

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 that are not counted as firm resources for planning purposes. The BPUB electrical distribution system consists of fourteen substations and approximately 1,200 miles of transmission and distribution lines. BPUB is also an active participant in the Electric Reliability Council of Texas (ERCOT) market. 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 the regional 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). The Silas Ray units typically provide peaking capacity and though they are more inefficient (their heat rates are higher) than new peaking units, the Silas Ray units continue to provide capacity value and have black start capability, meaning that they are valuable even if they are not dispatched. If these units were retired and new peaking units were built, BPUB would incur additional investment expendituresfor the replacement units. As such, it is assumed that the Silas Ray units will remain in operation over the period of study.

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. BPUB also owns 124 MW of the coal-fired, 680 MW Oklaunion plant in Wichita Falls, Texas and has a long-term PPA with the 78 MW Sendero Wind Farm for all of the generation produced. As per ERCOT guidelines, coastal wind farms are allowed to claim 32.9 percent firm capacity and so the firm capacity allocated to this project is 25.4 MW. BPUB's total firm capacity is approximately 369.7 MW, divided among the generating resources listed 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)	6/9	45.0	Natural Gas	1996	9.000	2,945	3.00	0.0006	0.0474	118.9
Silas Ray (Simple Cycle)	9	20.0	Natural Gas	1996	13.096	920	2.00	0.0006	0.0474	118.9
Silas Ray	10	50.0	Natural Gas	2004	12.04	346	3.00	0.0005	0.0214	118.9
Sendero Wind	--	78 (25.7 firm)	Wind	2016	--	--	--		--	--
Hidalgo Energy Center	N/A	105.0	Natural Gas	2000	7.350	336	5.00	0.0006	0.0072	118.0
Oklaunion	1/2	124.0	Coal	1986	10.980	912	12.50	0.014	0.3385	212

2.2 EXISTING DSM PROGRAMS

BPUB has taken steps to promote energy conservation and the environmental health of the Brownsville community. While program funding has been limited, a brief summary of the programs is provided.

In October 2011, BPUB introduced the Green Living Rebate 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 Green Living program are summarized in Table 2-2.

Table 2-2 BPUB Green Living Program Rebates

MEASURE DESCRIPTION	INCENTIVE SUMMARY
HVAC (Heating, Ventilating and Air Conditioning)*	Up to $1,200 for qualifying units
Duct Flow Performance	A rebate of 25% of cost to replace or repair, up to $500
Solar Screens and Films	$1 per square foot installed, up to $500
ENERGY STAR Windows	30% of invoice, up to $500
Radiant Barrier	$0.40 per square foot installed; up to $500
Water Sense High Efficiency Toilets	$50 rebate per toilet; limit three toilets per customer
Attic/ Ceiling Insulation	$0.01/square foot, up to $500

In addition to the incentivized program offerings, BPUB has educational tools available to both its residential and commercial customers that are contained in its *Home Energy Suite* and *Commercial Energy Suite*. These programs offer online self-help to residential and commercial customers and include an online calculation tool to help customers calculate potential savings. BPUB also has a *Water Conservation Suite* and a *Go Paperless* program aimed at reducing vehicle emissions and saving customer time by allowing online payment. These tools, which can be accessed via the Internet, provide self-help resources on energy conservation.

While economic factors are believed to be primarily responsible for the low load growth projection in this IRP, any historical impacts of the BPUB conservation and energy efficiency measures is reflected in the historical measures of peak demand and energy requirements. This impact, in turn, influences the projection of peak load and energy requirements developed in Section 3.0, which assumes that the BPUB programs will continue into the future.

2.3 REGIONAL AND BPUB TRANSMISSION SYSTEM OVERVIEW

Brownsville is interconnected with the Lower Rio Grande Valley (LRGV) region and with the rest of the Electric Reliability Council of Texas (ERCOT) grid through the existing high voltage transmission network. These regional and ERCOT interconnections have become increasingly important in recent years due to the ERCOT integrated dispatch of generation resources and as new transmission projects have been studied and implemented in an effort to increase the power supply reliability in the LRGV region.

Historically, there has been limited generation capacity and high voltage transmission capacity in the LRGV area, and this has resulted in occasional power curtailments, limitations on the ability of ERCOT to dispatch generation on a merit order basis, and the general recognition that there is a high risk of rotating outages on extreme temperature days. Regional power curtailments impacting Brownsville occurred in July, 2008 (Hurricane Dolly), in September, 2010 (Tropical Storm Hermine), in February 2011 (extreme cold weather), and in February, 2016, when ERCOT called for firm load to be shed across the grid.[1] These issues led to a number of transmission load flow and reliability studies by regional utilities and ERCOT. The resulting major transmission projects that have come about due to these studies are described below.

In addition to the need for increased reliability, ERCOT's assessment of power supply risks and the need for additional generation also rely on the projected load growth. In 2014, ERCOT summarized the capacity supply and demand balance for the LRGV as follows:

> The peak demand for power in the Valley is more than 2,300 megawatts (MW) and is expected to grow to 2,600 by summer 2015 and more than 2,900 MW by 2020. Currently, about 2,300 MW of electric generation capacity is available within the Valley region, including about 600 MW of wind power. Two high-voltage transmission lines provide 1,100-1,500 MW of transmission capacity to import additional power into the region, along with a 170 MW direct current tie that could send power to or from the electric grid in Mexico.[2]

ERCOT also reported that two LNG export facilities have begun construction (the Freeport LNG facility on Quintana Island and the Cheniere LNG facility in Corpus Christi) and up to six new LNG export facilities in the Brownsville area are being studied (Gulf Coast, Eos, Barca, Annova, Texas LNG, Rio Grande LNG), of which five have applied to the DOE for export licenses.[3] The combined export quantity of these facilities would be approximately 19 Bcf/d if all came into operation. Power demands for an LNG export facility could be as high as approximately 700 MW (for Freeport LNG, but could be also be much less for other facilities, depending on the process utilized), and these facilities could dramatically impact the regional demand for power in the future.

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[1] From Sharyland Utilities & BPUB's *Cross Valley Brownsville Loop Study*, Power Point presentation of May 15, 2011, Slide 4.

[2] From *Addressing Electric Reliability: Risks in the Lower Rio Grande Valley*, ERCOT, August, 2014

[3] From ERCOT's *Electrical System Constraints and Needs, December 2015, pp. 21-23.*

While BPUB has indicated that the direct impact on BPUB resources is expected to be minor (a 100 MW demand impact is studied as a sensitivity case), the regional impact could be dramatic and require the import of a significant amount of power as well as utilize much of the increased transmission capacity resulting from the recent 345-kV projects described below. In total, ERCOT reports that $1.3 billion in transmission improvements among the following three projects have been undertaken to improve the reliability and power flows in the LRGV region.[4]

2.3.1 The Lobos to North Edinburg 345-kV Transmission Project

The Lower Rio Grande Valley Project is one of three significant projects undertaken in the region. This project primarily involves a new transmission line coming into the LRGV from the Laredo area. The project was approved by the Public Utility Commission of Texas (PUCT) in May of 2013.[5]

According to the PUCT, the project is a double-circuit capable 345-kV transmission line constructed on single pole structures. The project covers a total distance of approximately 156 miles and connects the Lobo Substation near Laredo, Texas with the North Edinburg Substation in the Rio Grande Valley. The project is broken into two segments. The first is the Lobo to Rio Bravo segment that originates from the existing Lobo substation outside of Laredo and extends to a new substation near the existing AEP Rio Bravo substation in Webb County. The Rio Bravo to North Edinburg segments extends from the new substation to a new substation located near the AEP North Edinburg substation. Figure 2-1 shows the route of the project and also shows the associated project, described in the next section, that terminates at BPUB's Loma Alta's substation.[6]

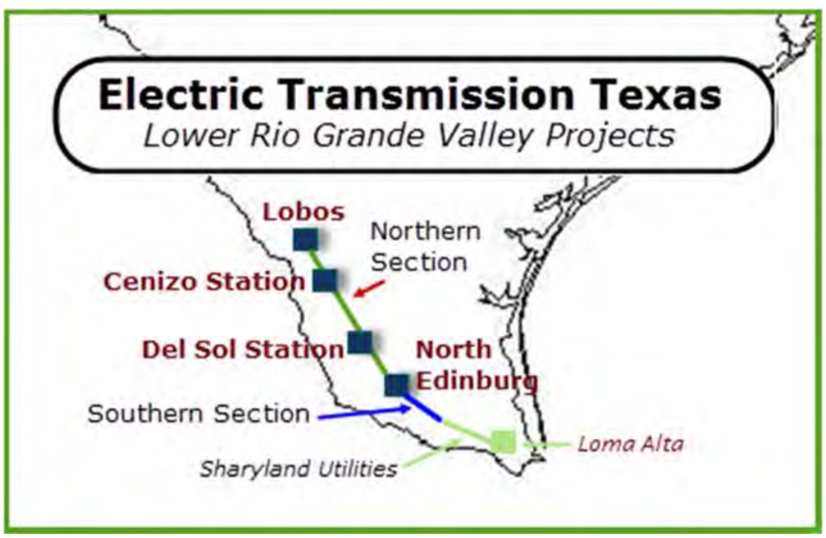

Figure 2-1 Lobos to North Edinburg Transmission Project

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[4] Ibid

[5] The order is available on-line at http://www.ettexas.com/projects/docs/RioGrandeValleyFinalOrder.pdf.

[6] From *New ETT 345-kV lines begin delivering power to LRGV*, available online at http://www.ettexas.com/news/docs/NewETT345intheLRGV.PDF

Construction on the lines started in October, 2014. The northern section of the line between Lobo substation and Edinburg became commercially operational in late May of 2016, with the southern segment following a few days later. The northern segment was built by Electric Transmission Texas (ETT) and Sharyland Utilities constructed the southern section that interconnected with the Loma Alta Station, owned by BPUB. In addition to providing the benefit of increased reliability, the line will allow future projects to deliver power to the grid. ETT reports that wind farm between Lobo and North Edinburg have already requested connections with the line.[7]

2.3.2 The North Edinburg to Loma Alta Project

The second major project in the LRGV region is the North Edinburg to Loma Alta Project, which is part of the larger effort called Cross Valley Project that also includes the previous transmission project described in Subsection 2.3.1. The project involves a new 345-kV transmission line between the North Edinburg substation and BPUB's Loma Alta substation near the Brownsville Shipping Channel. An application for the project was filed in mid-2013 and the final project route was approved by the Public Utility Commission of Texas in April, 2014. The approved route is one of 42 routes considered and is approximately 96 miles in length. The project cost was initially estimated to cost more than $310 million.[8]

The project was endorsed by ERCOT in January 2012 and was found to be a critical project for the region and the lowering of the risk of severe power curtailments in the future. The project was undertaken two companies, Electric Transmission Texas, LLC (constructing the western half) and Sharyland Utilities, L.P (constructing the eastern half). Figure 2-2 shows the final route of the project.

2.3.3 Re-conductored Lines between Corpus Christi and LRGV

The third major project in the LRGV region involving 345-kV lines is an estimated $500 million project that involved the re-conductoring of two 345-kV lines between Corpus Christi and the LRGV. These lines complement the previous 345-kV projects in that the lines allow additional power to be brought into the LRGV from the coastal Corpus Christi area to the north. This project was completed in November, 2015 by AEP Transmission with ETT investing in project.[9]

[7] Ibid
[8] From *ETT and Sharyland Utilities File Joint CCN Application for Cross Valley 345-kV Transmission Line Project from North Edinburg to Loma Alta*, available online at: https://www.aeptexas.com/info/news/viewRelease.aspx?releaseID=1422
[9] Ibid

Figure 2-2 North Edinburg to Loma Alta 345-kV Transmission Project

2.3.4 Import/Export Assumptions for the IRP

For the purposes of this IRP, it was agreed with BPUB that the regional market modeling and dispatch analysis would assume that BPUB has the ability to import or export up to 1,100 MW of power. While this assumed import and export capability could fluctuate over time, recent transmission upgrades and expected load growth suggest that ERCOT will continue to monitor the region and react to the need for on-going increases in transmission import and export capabilities.

The IRP analysis assumes that there are no wheeling or loss 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 a 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, at least for the near-term.

For purposes of dispatching the Oklaunion and Hidalgo projects, the IRP analysis assumes that these resources are dispatched at their incremental cost. The spot market price assumption used in the IRP analysis is 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.

2.4 NATURAL GAS SUPPLY ADEQUACIES

2.4.1 Overview of Natural Gas Supply and Delivery Capacity

This section addresses the adequacies of natural gas supply and delivery capacity to BPUB's existing natural gas-fueled resources and also addresses the potential impacts on possible resource additions that could arise from this IRP. The section includes a summary of the hourly and daily rates of natural gas consumption required to operate the plants at full capacity, a review of the BPUB gas supply and delivery contracts , a natural gas price forcast,, and identification of fuel supply and delivery alternatives recommended for further study.

Figure 2-3 and Figure 2-4 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 2-5 and Figure 2-6 show natural gas pipelines in Cameron County and Hidalgo County, respectively. Appendix A and B include maps showing additional details of gas pipelines in these two counties. This information is supplemented by the natural gas pipeline information in Appendix C.

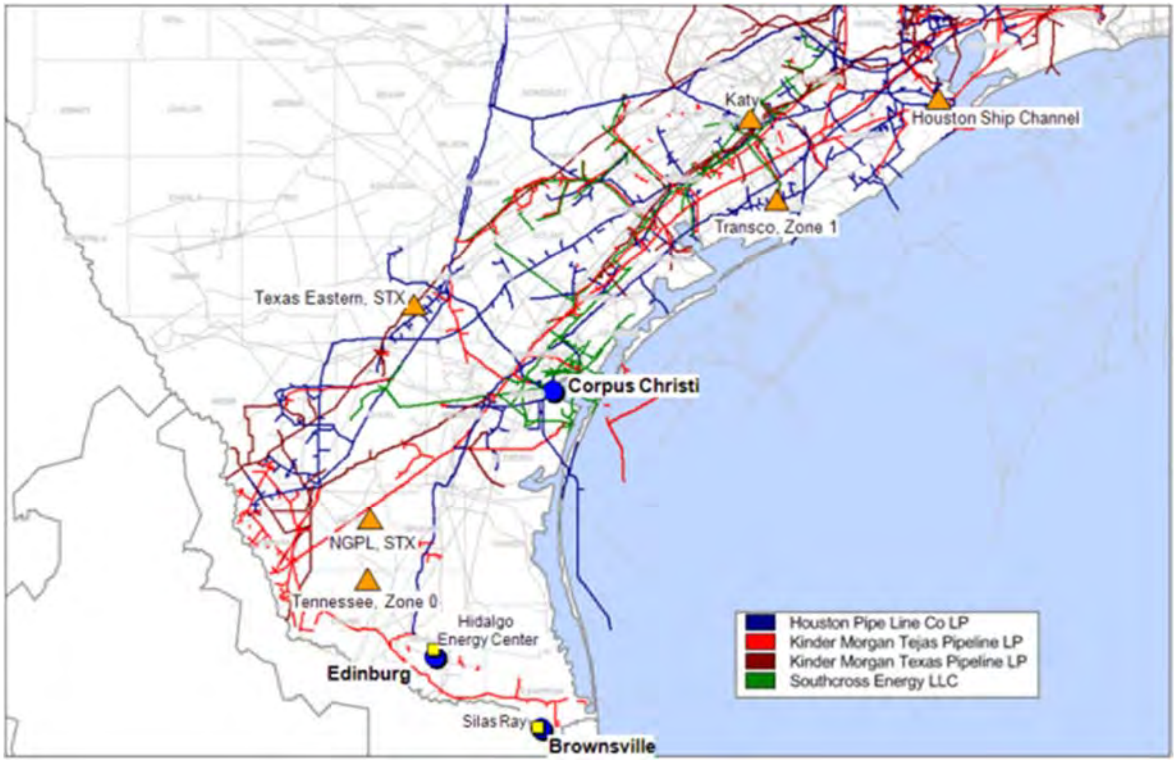


Figure 2-3 South Texas Intrastate Pipelines

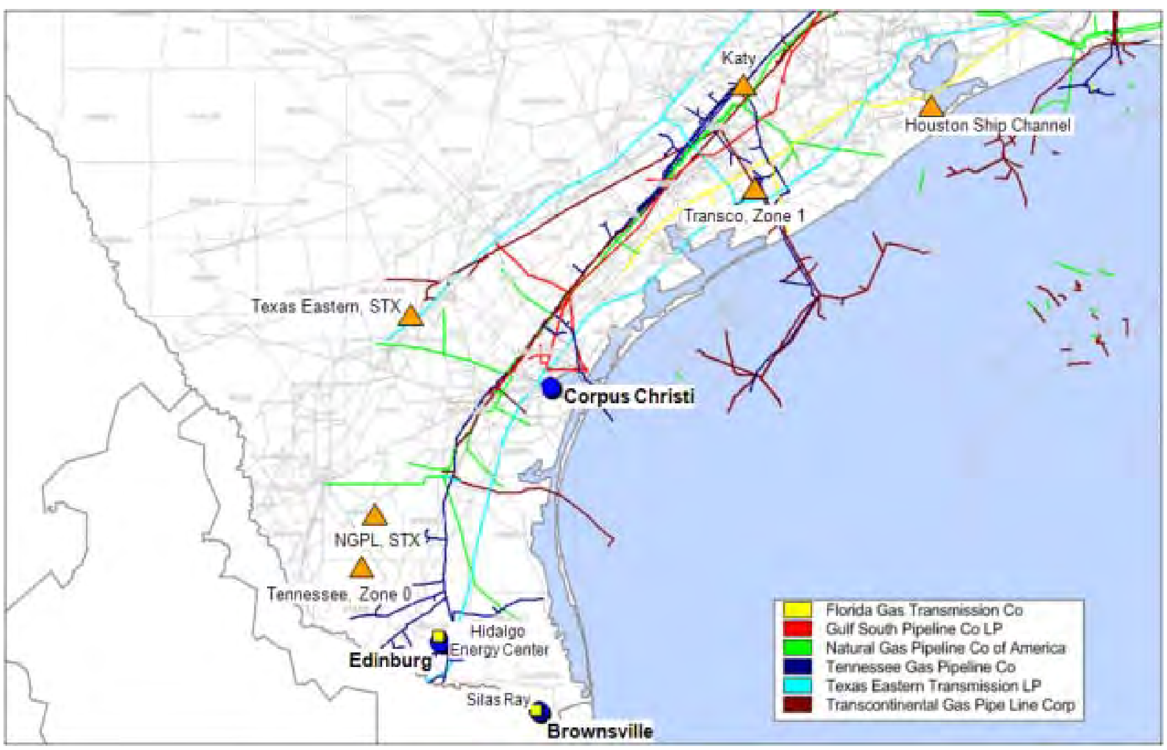


Figure 2-4 South Texas Interstate Pipeline Capacity

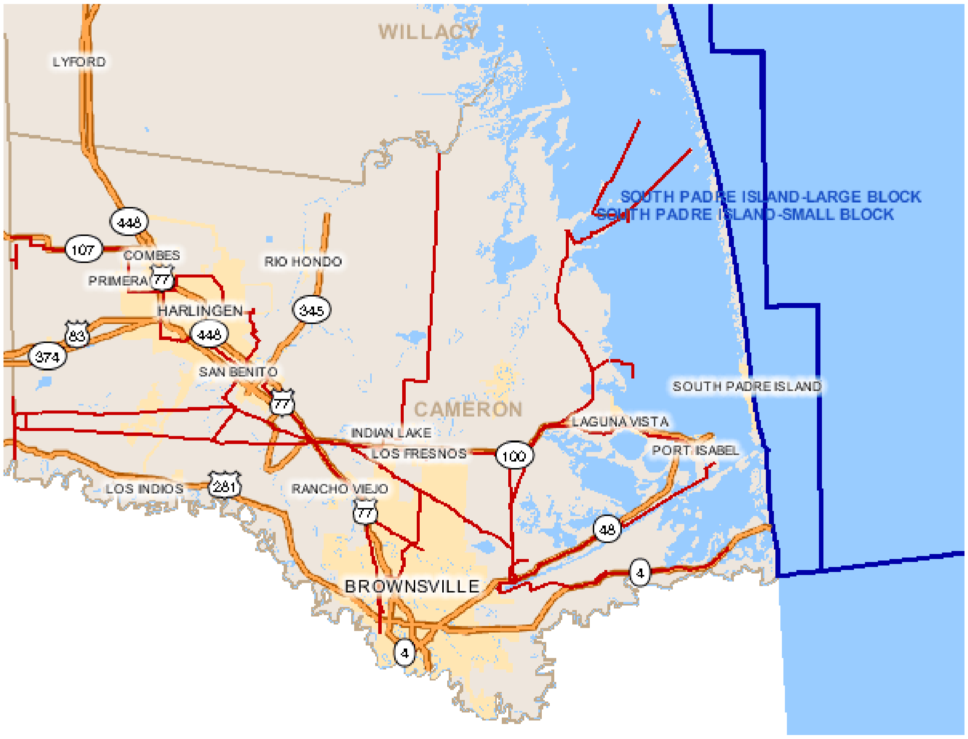


Figure 2-5 Major Pipelines in Cameron County (Source: Texas Railroad Commission)

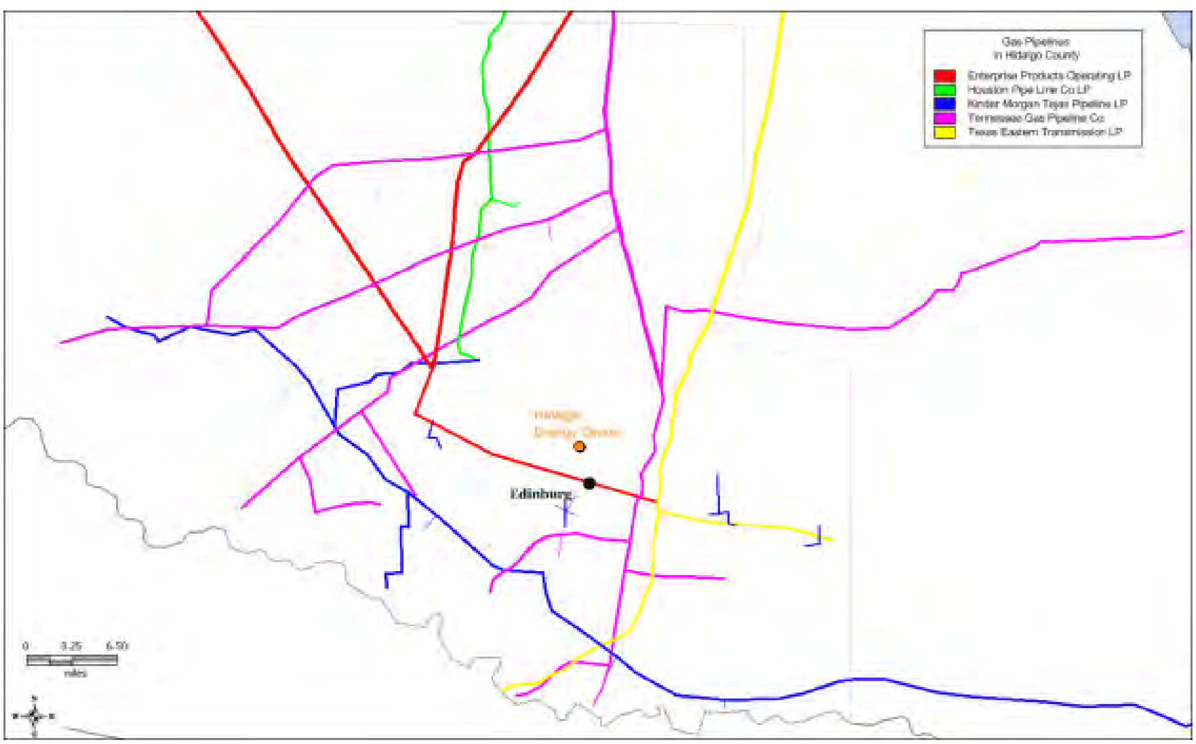


Figure 2-6 Major Pipelines in Hidalgo County (Source: Energy Velocity)

2.4.2 BPUB's Natural Gas Requirements

Table 2-3 summarizes the maximum hourly and daily natural gas requirements at the two existing gas-fired power plants in which BPUB maintains ownership interests.

Table 2-3 Gas Consumption for the Silas Ray and Hidalgo Plants Based upon Available Capacity (Summer and Winter) and an Average Heat Rate

UNIT	HEAT RATE (HHV) BTU/KWH	AVAILABLE CAPACITY		GAS CONSUMPTION		GAS CONSUMPTION	
		MW	MW	MMBTU/HOUR		MMBTU/DAY	
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
SILAS RAY – 100% BPUB OWNERSHIP							
6/9	8,924	55	64	491	571	11,780	13,707.26
10	9,330	50	50	467	467	11,196	11,196.00
Total		105	114	957	1,038	22,976	24,903.26
HIDALGO – 21% BPUB OWNERSHIP							
Total	7,304	470	518	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 2-4 summarizes the key features of the Tenaska natural gas supply contract.

Table 2-4 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]	[redacted]		

BPUB contracts for Interruptible Transportation Services from Texas Gas Services (TGS) to transport natural gas from the Tenaska contract's delivery points on the Enterprise Texas Pipeline to Silas Ray. Table 2-5 summarizes the Interruptible Transpiration Agreement from Enterprise to the Silas Ray plant.

Table 2-5 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, including the subsequent amendments. Table 2-6 and Table 2-7 provide a summary of pertinent features of the Calpine Agreement.

Table 2-6 Pertinent Features of the Calpine Agreement

FEATURES OF CALPINE AGREEMENT			
Date	[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]		

Table 2-7 Total Quantity of TETCO Firm Capacity, Hidalgo Energy Center (Based on Calpine Agreement, Exhibit 2, as Amended)

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 related to the availability and service quality (firmness) of pipeline capacity. Only Hidalgo is connected to an interstate pipeline with access to firm transportation capacities, but for both facilities, appropriate planning and comparison of alternatives would likely resolve potential limitations and support new gas-fired resources. However, additional costs would likely be required. The estimate of the additional costs for any required additional pipeline capacity is an appropriate subject for follow-up work, if there is a need.

2.4.4.1 Hidalgo Energy Center

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

- Firm capacity on Texas Eastern to the plant lateral ("Duke Hinshaw") that is equivalent to 66% of the plant maximum daily requirement in summer months and 22%-28% of the plant maximum daily requirement in the other months (see Table 2-8). The firm capacity contracts, supplemented by the interruptible transportation capacities, are adequate to support the current level of the plant generations. However, any increase in gas consumption may require additional firm capacity, depending upon the projected utilization; if so, the availability of the additional capacity would have to be evaluated with Calpine and with Texas Eastern.

- Firm capacity on the dedicated plant lateral to the plant is 90,000 MMBtu/d, currently very adequate.
- Calpine has an obligation to arrange for delivery of an alternate source of electrical energy (under the BPUB Ownership Agreement, which this analysis has not reviewed), during such period as the facility is not available.

An assessment of additional gas-fired resources at Hidalgo would require a more detailed evaluation of the Calpine Agreement and its delivering pipeline (Texas Eastern) and of the plant lateral's ability 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, there should be little, if any, constraint related to securing natural gas resources at Hidalgo.

2.4.4.2 Silas Ray Facility

There are several potential constraints impacting possible new gas-fired resources at Silas Ray that would require additional evaluation:

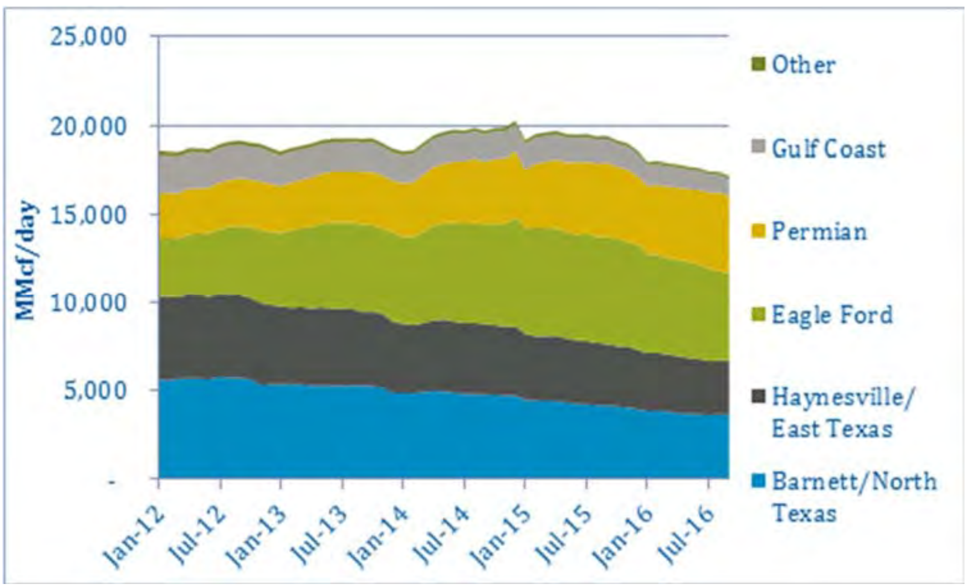
- The supply of natural gas from Tenaska if firm, but the supply is subject to availability of interruptible pipeline capacity on Enterprise Texas intrastate pipeline. Therefore, the supply delivery to TGS is not contractually firm. While there has been a large amount of Texas gas production with little historical gas curtailment , it is likely that the interruptible arrangement is adequate to support the current generation needs of the Silas Ray facility.. However, if more gas were required to support a new facility, additional evaluation would be needed in the form of a fundamental supply-demand modeling of utilization on Enterprise Texas under a range of demand scenarios, plus 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 the previous 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, which is adequate for the current plant . Evaluation for new capacity would requirean analysis of TGS's system and discussions with TGS staff to determine the availability of additional capacity. If capacity were likely to be constrained, a cost estimate to expand the TGS system could be developed as part of the resource planning study.

2.4.5 Natural Gas Supply/Demand Balance and Forecasted Changes

2.4.5.1 Supply to South Texas

The source of natural gas supplies to South Texas for the 2012 through 2016 period are shown in Figure 2-7. As seen in the figure, the supply of natural gas originates from a number of production areas, the most prominent are the Barnett formation, Eagle Ford, Permian, and Haynesville in East Texas.



Source: Black & Veatch graphed based on Point Logic data

Figure 2-7 Historical Texas Natural Gas Productions

Due to the declining oil prices, the dry gas production in Texas has been reduced to approximately 17 bcf/day currently, down from the more than 20 bcf/day that was reached in 2014. Eagle Ford is estimated to be producing approximately 5 bcf/day currently, down from over 6 bcf/day that was reached in 2014. With improving oil prices, Eagle Ford dry gas production is expected to grow to more than 7 bcf/day by 2035 to support increasing natural gas demand, including LNG exports and Mexico exports. Figure 2-8 shows the sources of forecasted volumes of gas supply to South Texas, for selected years, as projected by the Railroad Commission District.

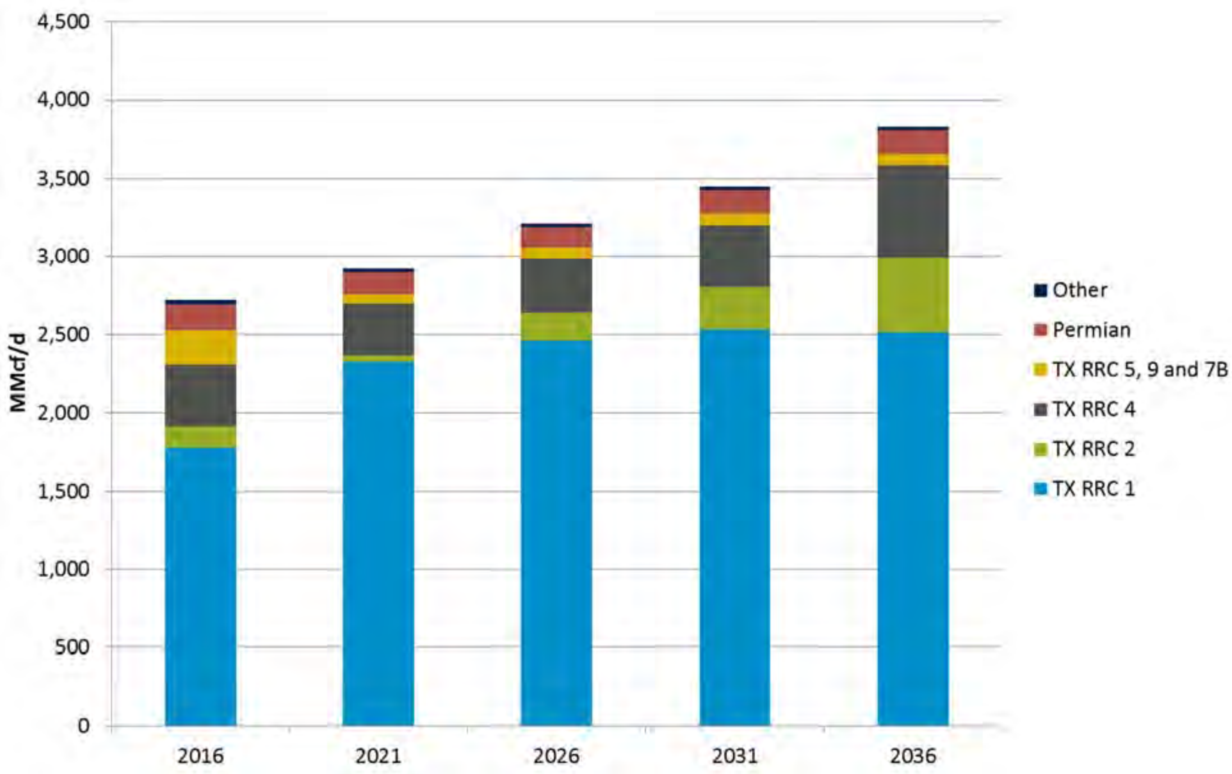


Figure 2-8 Sources of Gas Supply to South Texas

2.4.5.2 Forecasted Natural Gas Demand by Sector

Figure 2-9 shows the forecasted moderate growth in natural gas demand in the South Texas demand center by sector through 2036. The total annual average rate of increase is projected to be 1.03 percent. The growth is primarily driven by increases in industrial demand resulting from the low natural gas prices that are expected to lead to additional petrochemical facilities in South Texas.

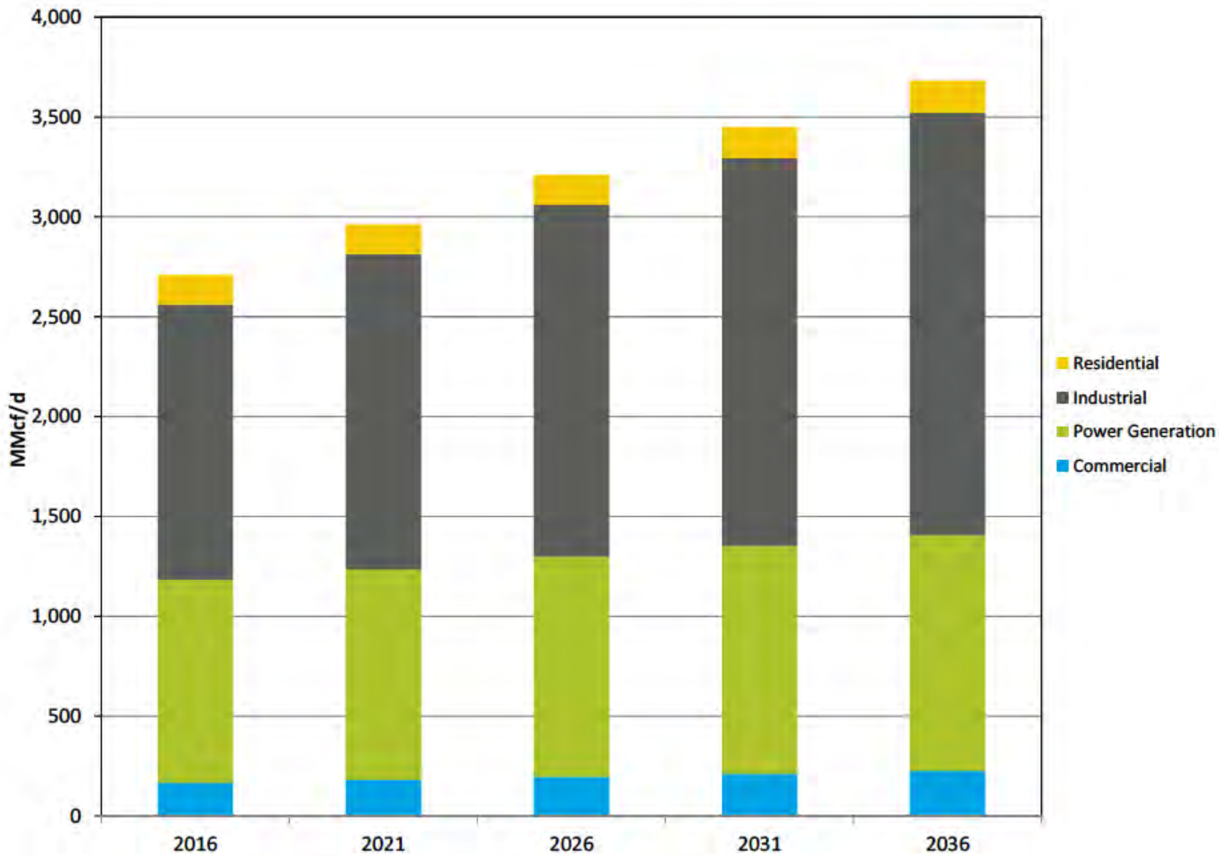


Figure 2-9 Forecasted Gas Demand by Sector, South Texas

Figure 2-10 shows the seasonal demand for natural gas used to generate electricity in South Texas. The figure illustratesthe pronounced summer peak and smaller winter peak.

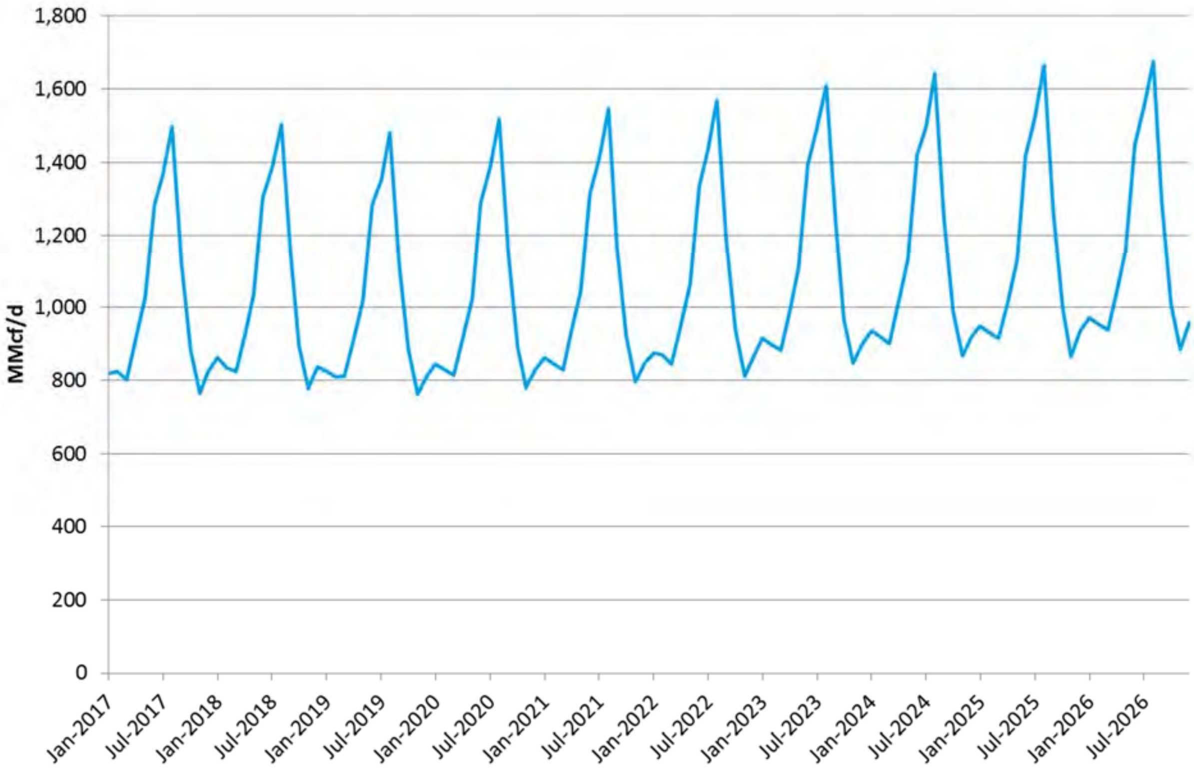


Figure 2-10 Demand for Natural Gas for Electricity Generation, South Texas

2.4.5.2.1 Mexico Exports

Historically, 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 the Black & Veatch conventional 4-sector demand forecast). During the past several years, the interstate and intrastate Texas pipelines have been expanded or enhanced to allow for an increasing level of Mexico exports, and there may be more development projects to address the need for increasing exports and changes in the natural gas flow patterns. Figure 2-11 indicates the pipelines in South Texas that export to Mexico.

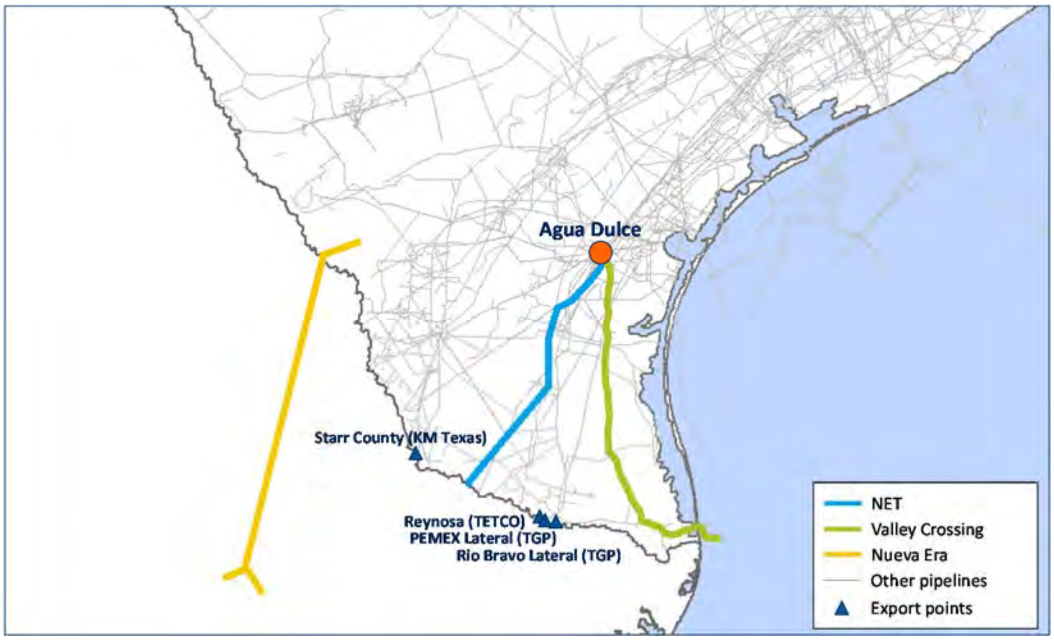
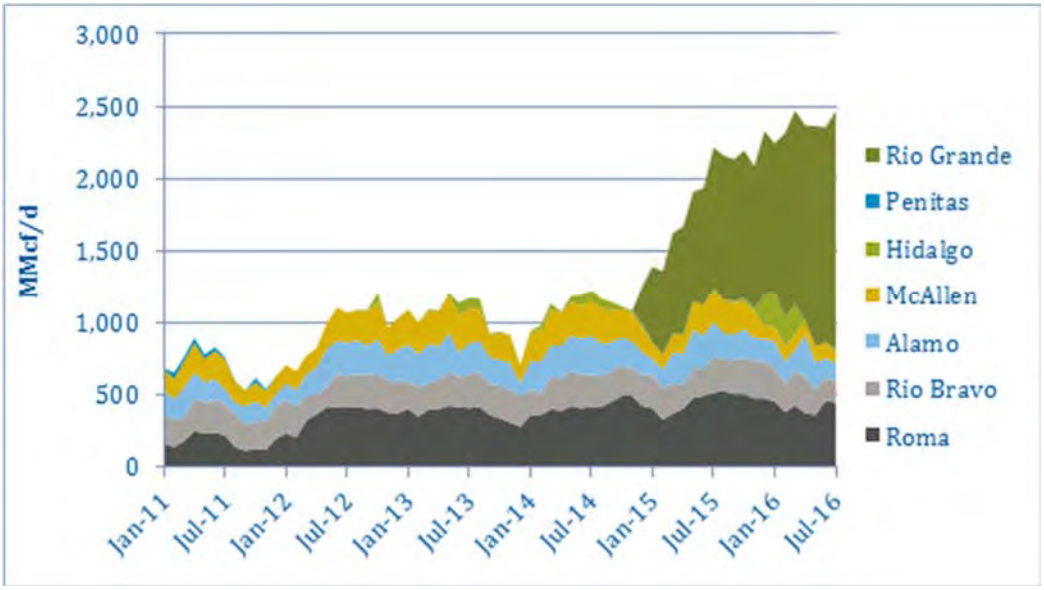


Figure 2-11 South Texas Export Pipelines to Mexico

Since 2014, the 2.1 bcf/day NET Mexico Pipeline (acquired by NextEra Energy Partners in 2015) has been exporting to the Los Ramones pipeline in Mexico. Another pipeline export projects will be the Howard Energy Partners' (HEP) Nueva Era Pipeline system that will originate in Agua Dulce, connecti with the gas gathering system in Eagle Ford and will have a design capacity of 1.12 bcf/day to export to Mexico starting in mid-2017. Separately, Spectra's 2.6-bcf/day Valley Crossing Pipeline will supply gas from the Agua Dulce hub to a southern coast near Brownsville, where it will connect with the Sur de Texas offshore pipeline and deliver gas to Tuxpan, Veracruz in central Mexico. The Spectra Valley Crossing Pipeline may also be able to serve new gas requirements for generators located in or around the Brownsville area. BPUB is currently in discussions with Spectra regarding interconnection points on the Valley Cross Pipeline and potentially start servicing the Silas Ray plant from 2019.

As seen in Figure 2-12, South Texas is currently exporting an average of 2.5 bcf/day to Mexico, approximately 70 percent of the total Mexico exports of 3.5 bcf/day. Most of the increases in exports can be attributed to the NET Mexico Pipeline export at Rio Grande, currently at approximately 1.6 bcf/day. With increasing Mexican demand and the completion of the new export pipelines, South Texas export to Mexico is expected to increase to more than 4.5 bcf/day by 2035.



Source: US Natural Gas Exports by Points of Exits

Figure 2-12 South Texas Natural Gas Exports to Mexico

2.4.5.2.2 Potential LNG Exports Near Brownsville

Section 2.3 discussed potential LNG export projects that could locate to the Brownsville area. These projects are in various stages of development, and three of these LNG projects listed in Table 2-8 are in the FERC filing process. If approved by FERC, the LNG facilities could start LNG export starting in the early 2020's. If all three of these projects are constructed, there would be an additional 5.2 bcf/day pipeline transportation capacity to supply gas from the Agua Dulce Hub to the project sites near the Port of Brownsville. At present, only the Rio Grande LNG project has conducted an open season for the associated Rio Bravo Pipeline Project, which has a design capacity of 4.5 bcf/day. The other LNG projects intend to contract or build Texas intrastate pipelines to serve the LNG projects in the future. Such an intrastate project will not be part of the FERC review process for the LNG projects.

In addition to feed gas for the LNG plant, there are likely to be additional electricity requirements to run the liquefaction process. Consequently, there are likely to be additional gas needs if associated with future LNG plants.

Table 2-8 Proposed LNG Export Projects near Brownsville in the FERC Filing Process

PROJECT	EXPORT CAPACITY (MTPA)	EQUIVALENT NATURAL GAS PIPELINE CAPACITY (BCF/DAY)
Texas LNG Brownsville	2.0	0.3
Rio Grande LNG - Next Decade	27.0	4.0
Annova LNG Brownsville	6.0	0.9

2.4.6 Henry Hub Gas Price Forecast and Regional Basis Forecast

Figure 2-13 shows Black & Veatch's projected Henry Hub gas price in 2016 dollars, per the 2016 Outlook of 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, but also due 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 2-14 presents forecasted basis differentials compared to Henry Hub for key market points in Texas. In this basis differential graph, a line in the negative (positive) range indicates lower (higher) costs relative to Henry Hub. The figure reflects the expectation that increasing shale gas production in South Texas will lead to declining regional basis values relative to the Henry Hub benchmark prices forecast, creating a cost advantage for generators located in this area.

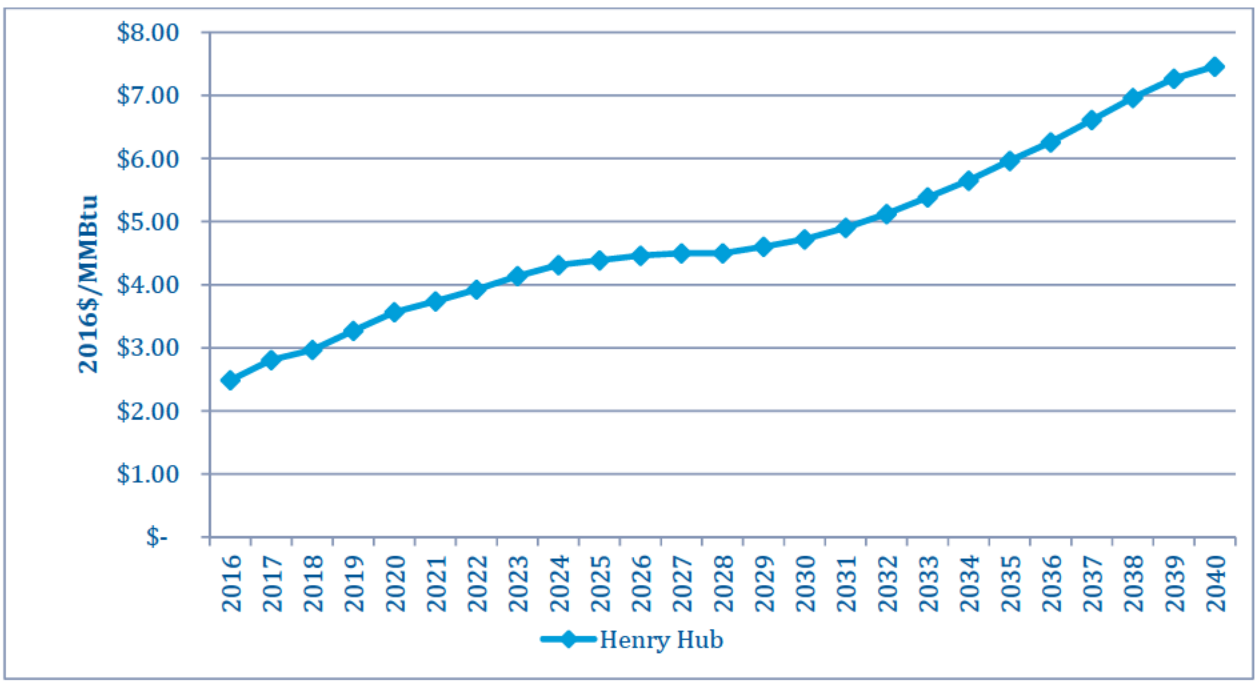


Figure 2-13 Forecast of Henry Hub Natural Gas Price (2016 Outlook EMP)

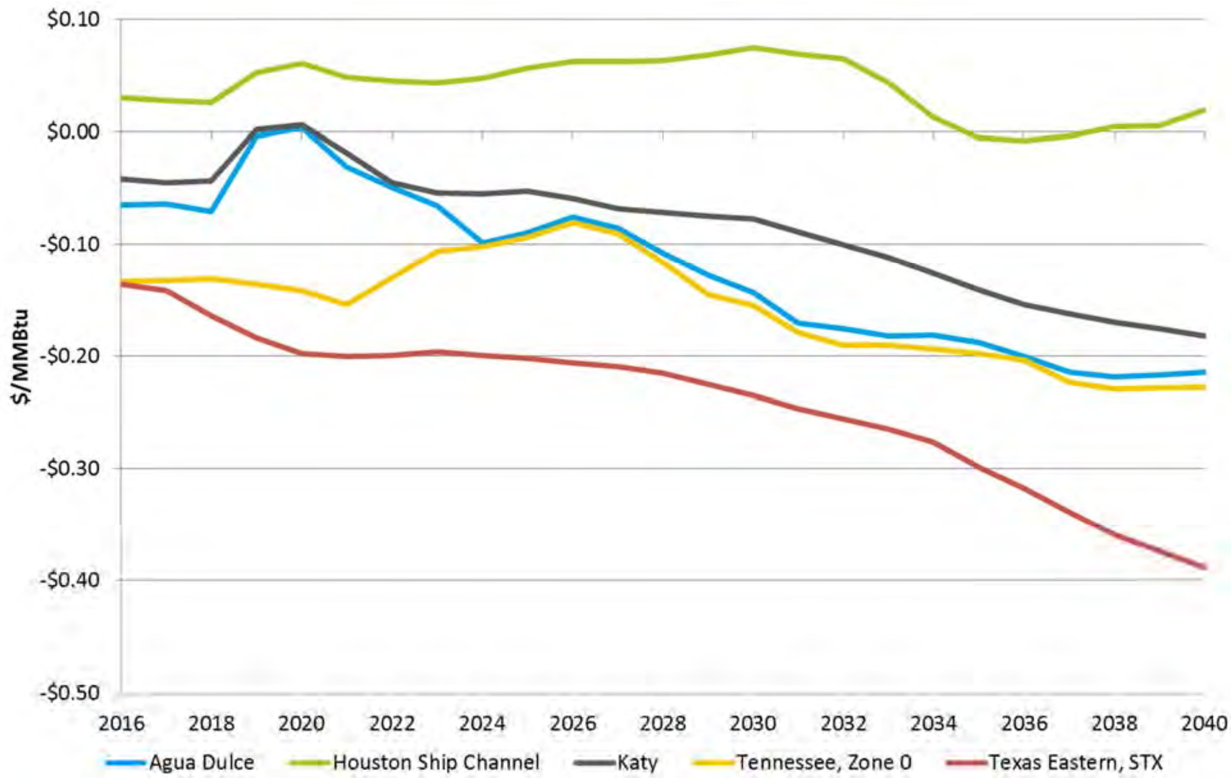


Figure 2-14 Forecasted Basis for Key Market Points in Texas Relative to Henry Hub (2016 Outlook of EMP for ERCOT)

2.4.7 Summary of Alternatives and Recommendations

The existing natural gas supplies and transportation capacities are adequate for the existing generation level for Hidalgo and Silas Ray. With the growing Texas intra-state, in particular Eagle Ford natural gas productions, there is an abundant natural gas supply that should be adequate for future BPUB and area power generation needs. With the growing exports to Mexico, and the proposed LNG export projects, there are potentially significant changes in the regional gas flow patterns and price relationships. Additional analysis would be needed to optimize the gas supply and capacity contracts that could reduce the gas supply costs and improve the gas supply reliability for BPUB. There is a significant amount of new pipeline development activity between Agua Dulce and Brownsville; BPUB may wish to investigate these opportunities if additional firm pipeline capacities are needed for new generation at the current or alternative BPUB sites.

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

- Evaluate the need and alternatives for providing firm transportation capacities, which will include Texas Eastern, the proposed Valley Crossing and Rio Bravo pipelines, and other potential projects.
- Review and evaluate the current supply by a combination of Firm and Interruptible supplies, whether alternative supplies and/or transportation capacities are needed.

- Analyze and evaluate the regional gas flows, price relationship, and the gas supplies to the plant, concurrent with the transportation capacity analysis, whether alternative supplies or price indices are desired, such as Eagle Ford supplies that are linked to Agua Dulce. This may entail renegotiate the Calpine Fuel Management Agreement or contact other potential fuel suppliers or asset managers.
- Investigate if alternative or additional natural gas pipeline capacities can be developed or acquired to support capacity expansions at the power plant.

At Silas Ray, the recommended alternatives for additional evaluation consist of:

- Analyze the impact of increasing Mexican exports and proposed LNG projects on the supply reliability of the Texas intrastate pipelines including Texas Gas services, Enterprise Texas, and Kinder Morgan Texas, and evaluate whether the plant can continue to rely on the interruptible intrastate pipeline capacities.
- Investigate alternatives for providing firm transportation through the proposed Valley Crossing (in progress) and Rio Bravo pipelines, and other potential projects.
- Analyze and evaluate the regional gas flows, price relationship, and the gas supplies to the plant, concurrent with the transportation capacity analysis, whether alternative supplies or price indices are desired, such as Eagle Ford supplies that are linked to Agua Dulce. This may entail renegotiate the Tenaska Natural Supply Agreement or contact other potential fuel suppliers or asset managers.
- Concurrent with the firm transportation capacity analysis, investigate if reliable long-term gas supplies can be acquired to support additional generation or potential capacity expansion at the site.

When gas-fired resources are considered in alternative locations, such as at the Port of Brownsville and Site 511, it is strongly recommended that the availability of favorable pipeline capacity and interconnection with the ability to accommodate future expansion be considered as a major component in the site ranking and selection. The proposed LNG export projects and related infrastructure also provide some joint development opportunities for BPUB to acquire additional pipeline capacities and develop new power plants.

3.0 Load Forecast

In 2016, an energy and peak load forecast was developed for BPUB system by Black & Veatch for the period of 2016-2033. The BPUB forecast was prepared using an econometric model developed specifically for the BPUB system and utilized publicly available information for the independent variables used the forecasting equations. The load forecast consisted of multiple econometric equations that utilize various economic, socioeconomic, time trend, and weather data series as independent variables to project energy sales and peak demand, with the net energy for load and system load factor linked to the energy and peak forecasts.

The 2016 econometric forecast results were used as the basis for this IRP, with the forecast extended for the 2034-2036 period based on the 2032-2033 rates of growth for energy and peak demand. The resulting 2016-2036 forecast results are summarized below

Total BPUB energy sales projections were derived by summing up the individual end user class forecasts. The total BPUB system energy sales forecast is shown in Table 3-1 and graphically in Figure 3-1 for the 2007-2036 historical and forecast period. As seen at the bottom of the table, energy sales are projected to increase at an annual average growth rate of 1.96 percent and are forecasted to increase from 1,395,606 MWh to 2,059,183 MWh during the 2016 through 2036 forecast period.

Also shown in Table 3-1 is the net energy for load (NEL) forecast. The NEL forecast is equal to the total energy sales plus losses, which are assumed to be 5.5 percent based on historical data. As a result, the NEL is projected to increase from 1,472,365 MWh in 2016 to 2,172,439 MWh in 2036 and is forecast to increase at a 1.96 percent annual average growth rate during the forecast period.

The BPUB peak demand is a key forecast variable because it drives the determination of when additional capacity may be needed on the BPUB system. In this study, the average annual growth rate for the peak demand is projected to be 1.05 percent during the 2016-2036 period and is projected to reach 376.3 MW in 2036, as seen in Table 3-2. This end of period peak demand projection is nearly 237 MW below the 2011 IRP forecast through 2031. As seen in Table 3-3, the difference in the forecast is 70.8 MW in 2016 and increases steadily thereafter, reaching a 236.9 MW difference by 2031, the last forecast year of the 2011 IRP. (Note: a 2013 load forecast update was performed in 2013 by Black & Veatch. In that update, the 2016 projected peak load was 350.9 MW and was 526.7 MW in 2031.)

Table 3-1 Total BPUB Energy Sales and NEL Forecasts

	RESIDENTIAL SALES		GENERAL SERVICES NON-DEMAND SALES		GENERAL SERVICE DEMAND SALES		MUNI SALES		VPLMP		TOTAL BPUB SALES		NET ENERGY FOR LOAD
YEAR	MWh	Annual % Change	MWh	Annual % Change	MWh	Annual % Change	MWh	Annual % Change	MWh	Annual % Change	MWh	Annual % Change	MWh
Historical													
1994	295,430		27,929		387,392		47,951				758,702		
1995	310,173	4.99%	29,101	4.20%	391,075	0.95%	48,179	0.48%			778,528	2.61%	
1996	323,353	4.25%	29,155	0.19%	403,140	3.09%	51,603	7.11%			807,251	3.69%	
1997	324,617	0.39%	99,935	242.77%	344,025	-14.66%	55,151	6.88%			823,728	2.04%	
1998	342,964	5.65%	108,167	8.24%	366,855	6.64%	53,692	-2.65%			871,678	5.82%	
1999	352,046	2.65%	108,953	0.73%	383,223	4.46%	54,312	1.15%			898,534	3.08%	
2000	379,617	7.83%	114,716	5.29%	432,894	12.96%	56,252	3.57%			983,479	9.45%	
2001	396,987	4.58%	113,009	-1.49%	467,743	8.05%	61,571	9.46%			1,039,310	5.68%	
2002	433,898	9.30%	115,434	2.15%	487,948	4.32%	62,758	1.93%			1,100,038	5.84%	
2003	430,979	-0.67%	116,419	0.85%	473,533	-2.95%	67,111	6.94%			1,088,042	-1.09%	
2004	448,140	3.98%	130,325	11.94%	479,530	1.27%	67,244	0.20%	1,985		1,127,224	3.60%	
2005	465,001	3.76%	131,019	0.53%	494,998	3.23%	65,495	-2.60%	2,067	4.13%	1,158,580	2.78%	
2006	462,364	-0.57%	131,241	0.17%	520,012	5.05%	66,444	1.45%	2,166	4.79%	1,182,227	2.04%	
2007	487,263	5.39%	154,707	17.88%	554,915	6.71%	64,927	-2.28%	2,249	3.83%	1,264,061	6.92%	
2008	480,321	-1.42%	138,760	-10.31%	547,886	-1.27%	68,822	6.00%	2,188	-2.72%	1,237,975	-2.06%	
2009	515,246	7.27%	132,978	-4.17%	544,409	-0.63%	69,281	0.67%	2,164	-1.09%	1,264,078	2.11%	
2010	525,596	2.01%	131,962	-0.76%	546,108	0.31%	69,372	0.13%	2,179	0.69%	1,275,217	0.88%	
2011	558,470	6.25%	136,341	3.32%	558,953	2.35%	68,145	-1.77%	2,206	1.25%	1,324,115	3.83%	
2012	552,920	-0.99%	137,874	1.12%	582,104	4.14%	67,426	-1.05%	2,234	1.24%	1,342,559	1.39%	
2013	542,263	-1.93%	135,120	-2.00%	565,216	-2.90%	80,821	19.86%	2,228	-0.28%	1,325,647	-1.26%	
2014	554,085	2.18%	130,286	-3.58%	555,511	-1.72%	93,144	15.25%	2,228	0.00%	1,335,253	0.72%	
2015	556,820	0.49%	130,369	0.06%	559,450	0.71%	103,747	11.38%	2,265	1.69%	1,352,651	1.30%	

	RESIDENTIAL SALES		GENERAL SERVICES NON-DEMAND SALES		GENERAL SERVICE DEMAND SALES		MUNI SALES		VPLMP		TOTAL BPUB SALES		NET ENERGY FOR LOAD
YEAR	MWh	Annual % Change	MWh	Annual % Change	MWh	Annual % Change	MWh	Annual % Change	MWh	Annual % Change	MWh	Annual % Change	MWh
Forecast													
2016	562,886	1.09%	141,082	8.22%	587,534	5.02%	101,811	-1.87%	2,292	1.20%	1,395,606	3.18%	1,472,365
2017	585,934	4.09%	147,796	4.76%	619,128	5.38%	103,214	1.38%	2,310	0.76%	1,458,382	4.50%	1,538,593
2018	595,524	1.64%	150,494	1.83%	631,542	2.01%	104,398	1.15%	2,327	0.75%	1,484,286	1.78%	1,565,921
2019	605,209	1.63%	153,245	1.83%	644,185	2.00%	105,447	1.00%	2,344	0.74%	1,510,431	1.76%	1,593,504
2020	614,992	1.62%	156,051	1.83%	657,059	2.00%	106,420	0.92%	2,362	0.74%	1,536,883	1.75%	1,621,412
2021	633,381	2.99%	167,781	7.52%	688,818	4.83%	110,698	4.02%	2,379	0.73%	1,603,056	4.31%	1,691,225
2022	643,363	1.58%	170,698	1.74%	702,169	1.94%	111,524	0.75%	2,396	0.73%	1,630,151	1.69%	1,719,809
2023	653,449	1.57%	173,673	1.74%	715,766	1.94%	112,350	0.74%	2,414	0.72%	1,657,651	1.69%	1,748,822
2024	663,640	1.56%	176,706	1.75%	729,613	1.93%	113,211	0.77%	2,431	0.72%	1,685,601	1.69%	1,778,309
2025	673,938	1.55%	179,799	1.75%	743,715	1.93%	114,121	0.80%	2,448	0.71%	1,714,021	1.69%	1,808,292
2026	684,345	1.54%	182,953	1.75%	758,077	1.93%	115,108	0.86%	2,466	0.71%	1,742,948	1.69%	1,838,811
2027	694,864	1.54%	186,169	1.76%	772,703	1.93%	116,233	0.98%	2,483	0.70%	1,772,452	1.69%	1,869,937
2028	705,496	1.53%	189,449	1.76%	787,599	1.93%	117,390	1.00%	2,500	0.70%	1,802,436	1.69%	1,901,570
2029	716,245	1.52%	192,794	1.77%	802,771	1.93%	118,579	1.01%	2,518	0.69%	1,832,906	1.69%	1,933,716
2030	727,111	1.52%	196,204	1.77%	818,222	1.92%	119,756	0.99%	2,535	0.69%	1,863,828	1.69%	1,966,339
2031	738,098	1.51%	199,682	1.77%	833,960	1.92%	120,788	0.86%	2,552	0.68%	1,895,080	1.68%	1,999,309
2032	749,208	1.51%	203,228	1.78%	849,988	1.92%	121,799	0.84%	2,569	0.68%	1,926,792	1.67%	2,032,766
2033	760,443	1.50%	206,844	1.78%	866,313	1.92%	122,860	0.87%	2,587	0.67%	1,959,047	1.67%	2,066,794
2034	771,846	1.50%	210,525	1.78%	882,951	1.92%	123,930	0.87%	2,604	0.67%	1,991,857	1.67%	2,101,409
2035	783,421	1.50%	214,271	1.78%	899,909	1.92%	125,010	0.87%	2,622	0.67%	2,025,232	1.67%	2,136,620
2036	795,169	1.50%	218,083	1.78%	917,193	1.92%	126,099	0.87%	2,639	0.67%	2,059,183	1.67%	2,172,439

YEAR	RESIDENTIAL SALES		GENERAL SERVICES NON-DEMAND SALES		GENERAL SERVICE DEMAND SALES		MUNI SALES		VPLMP		TOTAL BPUB SALES		NET ENERGY FOR LOAD
	MWh	Annual % Change	MWh	Annual % Change	MWh	Annual % Change	MWh	Annual % Change	MWh	Annual % Change	MWh	Annual % Change	MWh
2016-2036 AAGR	1.74%		2.20%		2.25%		1.08%		0.71%		1.95%		1.95%
Overall Growth 2016-2036	41.3%		54.6%		56.1%		23.9%		15.1%		47.5%		47.5%

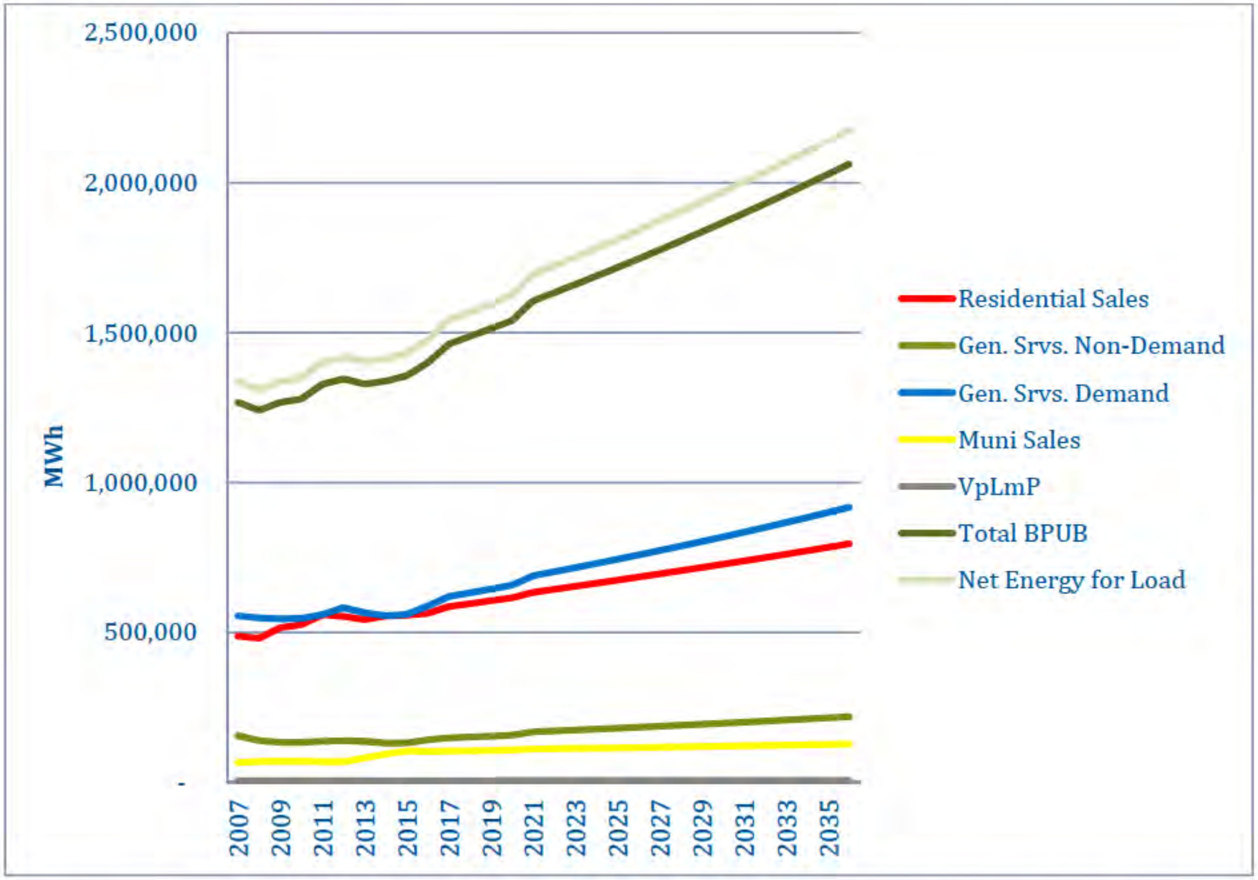


Figure 3-1 **Historical and Projected Energy Requirements, Total and by End Use Class, 2007-2036**

Table 3-2 The BPUB Base Case Peak Load Forecast, MW

YEAR	MW PEAK W/O DG OR LOAD SHEDDING	YEAR	MW PEAK W/O DG OR LOAD SHEDDING
Historical		Forecast	
1996	177	2016	304.9
1997	194	2017	308.3
1998	193	2018	311.1
1999	197	2019	314.3
2000	217	2020	317.6
2001	229	2021	320.8
2002	234	2022	330.5
2003	241	2023	333.8
2004	241	2024	337.0
2005	262	2025	340.3
2006	258	2026	343.5
2007	270	2027	346.8
2008	267	2028	350.0
2009	279	2029	353.3
2010	277	2030	356.5
2011	301	2031	359.8
2012	300	2032	363.0
2013	296	2033	366.3
2014	301	2034	369.6
2015	289	2035	372.9
		2036	376.3

Table 3-3 2016-2031 Peak Load Forecast Comparison: 2017 IRP vs. 2011 IRP

YEAR	MW PEAK W/O DG OR LOAD SHEDDING	YEAR	MW PEAK W/O DG OR LOAD SHEDDING	MW DIFFERENCE
2011 IRP		2017 IRP		2011-2017
2016	375.8	2016	304.9	70.8
2017	391.0	2017	308.3	82.7
2018	405.0	2018	311.1	93.9
2019	418.5	2019	314.3	104.2
2020	430.8	2020	317.6	113.2
2021	445.5	2021	320.8	124.7
2022	459.0	2022	330.5	128.5
2023	472.6	2023	333.8	138.8
2024	485.2	2024	337.0	148.2
2025	500.8	2025	340.3	160.5
2026	516.3	2026	343.5	172.8
2027	532.7	2027	346.8	185.9
2028	548.7	2028	350.0	198.7
2029	564.7	2029	353.3	211.4
2030	580.7	2030	356.5	224.2
2031	596.7	2031	359.8	236.9

4.0 Need for Capacity

BPUB must maintain sufficient capacity resources to meet its projected peak demand. The need for additional capacity resources over the 2017-2036 planning period is described in this section.

4.1 BPUB'S ADOPTED RELIABILITY CRITERIA

ERCOT currently uses a 13.75 percent minimum target reserve margin of capacity for the region. For this IRP, BPUB has chosen to adopt a zero percent planning reserve margin. This means that the need for incremental capacity resources will be determined through a direct comparison of peak load and available capacity resources. Capacity Balance and need for Power

To determine BPUB's need for new capacity resources, the forecasted system summer peak demand presented in Section 3.0 is compared to BPUB's existing generating resources that provided approximately 369.7 MW of net summer capacity in 2016.

Table 4-1 presents the projected 2017-2036 capacity balance, based on the BPUB load forecast and existing resources. As shown in the table, BPUB is projected to have a need for additional capacity resources in 2020 due to the projected retirement of Oklaunion I and II. No other unit retirements are assumed during the planning horizon and the cost and performance characteristics of the existing BPUB units are assumed to continue through the study period. With the loss of a combined 124 MW from the two Oklaunion units, a need for 71.9 MW arises in 2020. This need for power steadily rises during the remainder of the planning period and is driven by peak demand load growth; no other unit retirements are assumed during the planning horizon. The total increase in required capacity is projected to by 130.6 MW in 2036. Figure 4-1 illustrates the projected BPUB capacity balance in graphical form. The aim of the economic analysis and modeling described in subsequent sections is to determine how BPUB can best meet these incremental needs.

Table 4-1 Capacity Balance for BPUB (Based on Firm Capacity and No Planning Reserves)

YEAR	FORECAST PEAK DEMAND (MW)	RESERVES REQUIRED (MW)	TOTAL PEAK + RESERVE (MW)	SILAS RAY UNIT 6 (MW)	SILAS RAY UNIT 9 (MW)	SILAS RAY UNIT 10 (MW)	HIDALGO ENERGY CENTER (HEC) (MW)	OKLAUNION I (MW)	OKLAUNION II (MW)	WIND GENERATION (MW)	TOTAL AVAILABLE CAPACITY (MW)	EXCESS/ (DEFICIT) CAPACITY
2017	308.3	0	308.3	20.0	45.0	50.0	105.0	70.0	54.0	25.7	369.7	61.4
2018	311.1	0	311.1	20.0	45.0	50.0	105.0	70.0	54.0	25.7	369.7	58.6
2019	314.3	0	314.3	20.0	45.0	50.0	105.0	70.0	54.0	25.7	369.7	55.3
2020	317.6	0	317.6	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(71.9)
2021	320.8	0	320.8	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(75.2)
2022	330.5	0	330.5	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(84.8)
2023	333.8	0	333.8	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(88.1)
2024	337.0	0	337.0	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(91.3)
2025	340.3	0	340.3	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(94.6)
2026	343.5	0	343.5	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(97.8)
2027	346.8	0	346.8	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(101.1)
2028	350.0	0	350.0	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(104.3)
2029	353.3	0	353.3	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(107.6)
2030	356.5	0	356.5	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(110.8)

YEAR	FORECAST PEAK DEMAND (MW)	RESERVES REQUIRED (MW)	TOTAL PEAK + RESERVE (MW)	SILAS RAY UNIT 6 (MW)	SILAS RAY UNIT 9 (MW)	SILAS RAY UNIT 10 (MW)	HIDALGO ENERGY CENTER (HEC) (MW)	OKLAUNION I (MW)	OKLAUNION II (MW)	WIND GENERATION (MW)	TOTAL AVAILABLE CAPACITY (MW)	EXCESS/ (DEFICIT) CAPACITY
2031	359.8	0	359.8	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(114.1)
2032	363.0	0	363.0	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(117.4)
2033	366.3	0	366.3	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(120.6)
2034	369.5	0	369.5	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(123.9)
2035	373.6	0	373.6	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(127.2)
2036	376.3	0	376.3	20.0	45.0	50.0	105.0	0	0	25.7	245.7	(130.6)

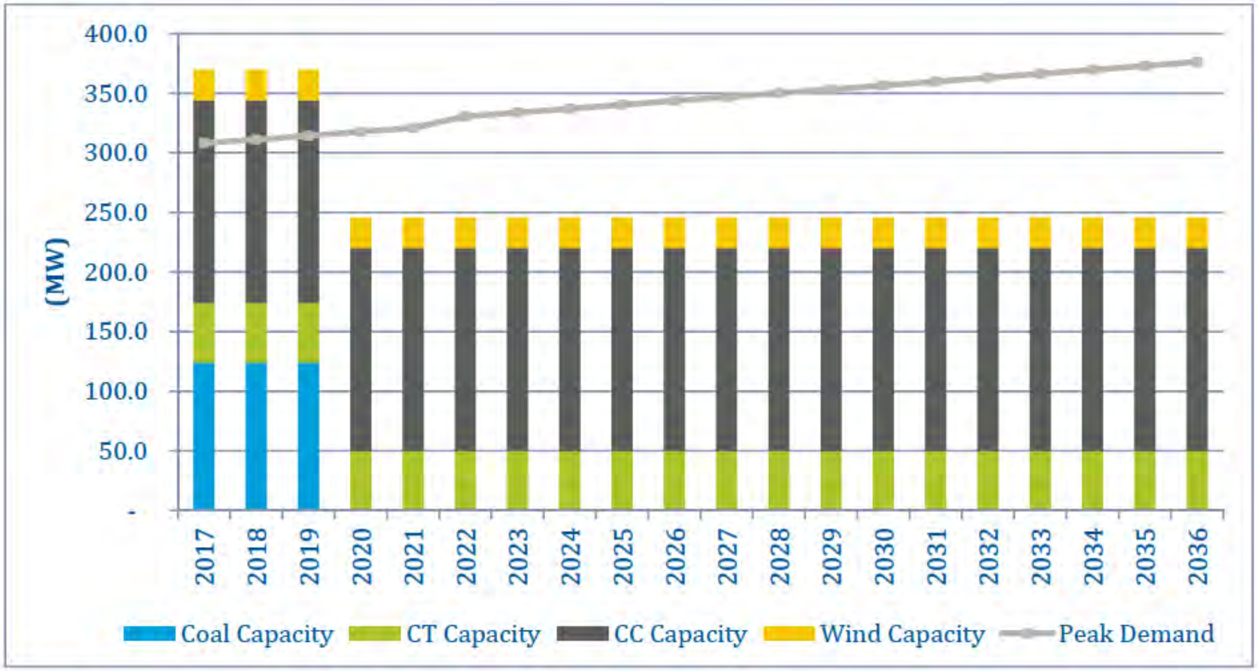


Figure 4-1 **The Projected BPUB Capacity Balance, 2017-2036**

5.0 Fuel, Emissions, and Power Price Projections

This section summarizes the fuel 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 fundamental assessment of the current state of North American Energy Markets, including a Base Case long-term view of energy prices. The market model includes a view of generation fuel sources and electric power market prices over a 20-year period (2017 through 2036). 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 mentioned in Black & Veatch's 2017 Outlook of EMP for ERCOT, which was used to develop natural gas and power price projections used throughout this IRP. Coal price projections used in the IRP were developed separately, as discussed below.

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 2015 and 2016. After 2016, Black & Veatch kept the coal prices constant in real terms and escalated it at 2.5 percent for nominal inflation. The coal price projections were used in the economic analysis to simulate operation of the Oklaunion coal unit until retirement in 2020 (or 2017 as a sensitivity).

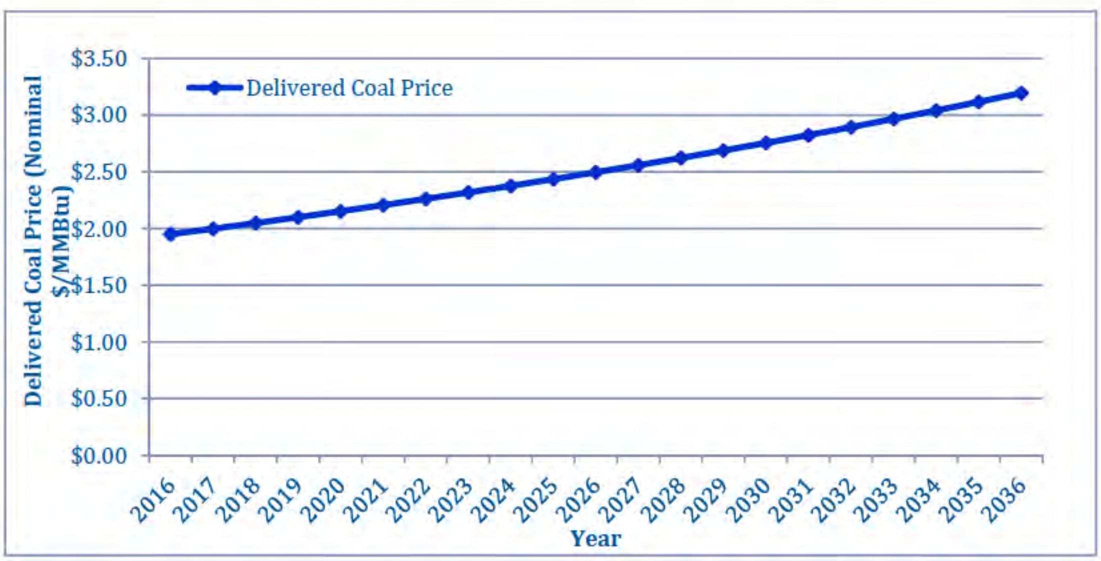


Figure 5-1 Coal Price Projections

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 2017 Outlook of 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 2017 Outlook of EMP for ERCOT. The distillate fuel oil price projections were used in the economic analysis to simulate operation of the distributed generation units.

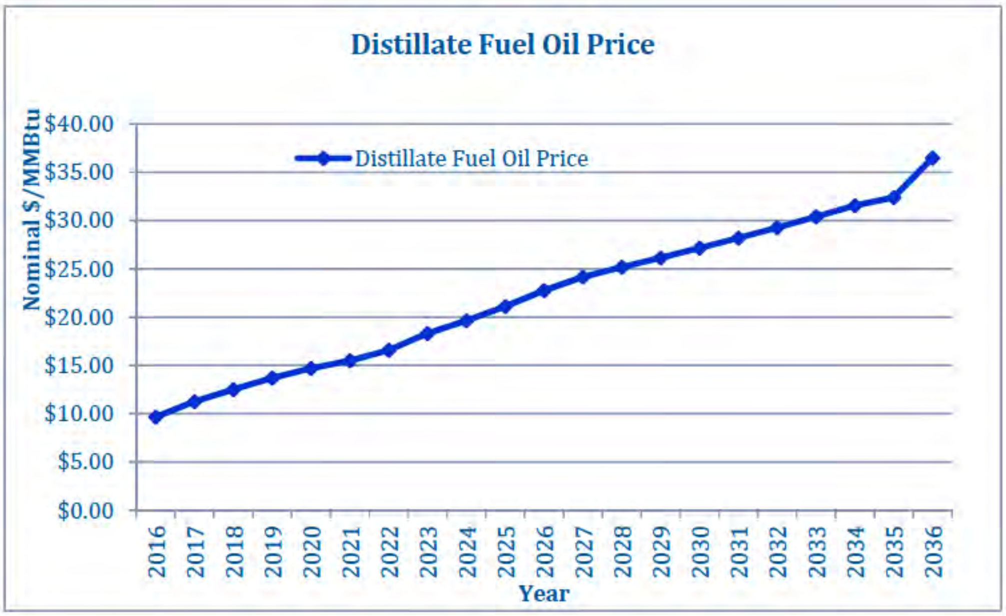


Figure 5-3 Distillate Fuel Oil Prices Projections (Nominal Dollars)

5.5 CARBON DIOXIDE EMISSIONS ALLOWANCE PRICE PROJECTIONS

CO_2 emissions allowance price projections are not included in this IRP study.

5.6 ENERGY PRICE PROJECTIONS

Spot market energy prices utilized in this IRP are based on Black & Veatch's 2017 Outlook of the EMP forecast. Monthly on- and off-peak energy prices for ERCOT-South were used to simulate spot market energy purchases in the applicable modeling scenarios. Figure 5-4 illustrates the on-peak energy prices used in the production cost modeling. Figure 5-5 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 $22.7/MWh in January 2017 to approximately $84.6/MWh in December 2036. Off-peak prices range from approximately $14.3/MWh in January 2016 to approximately $50.6/MWh in December 2036. Figure 5-6 illustrates the annual average on-peak, annual average off-peak, and annual average energy prices based on the monthly values.

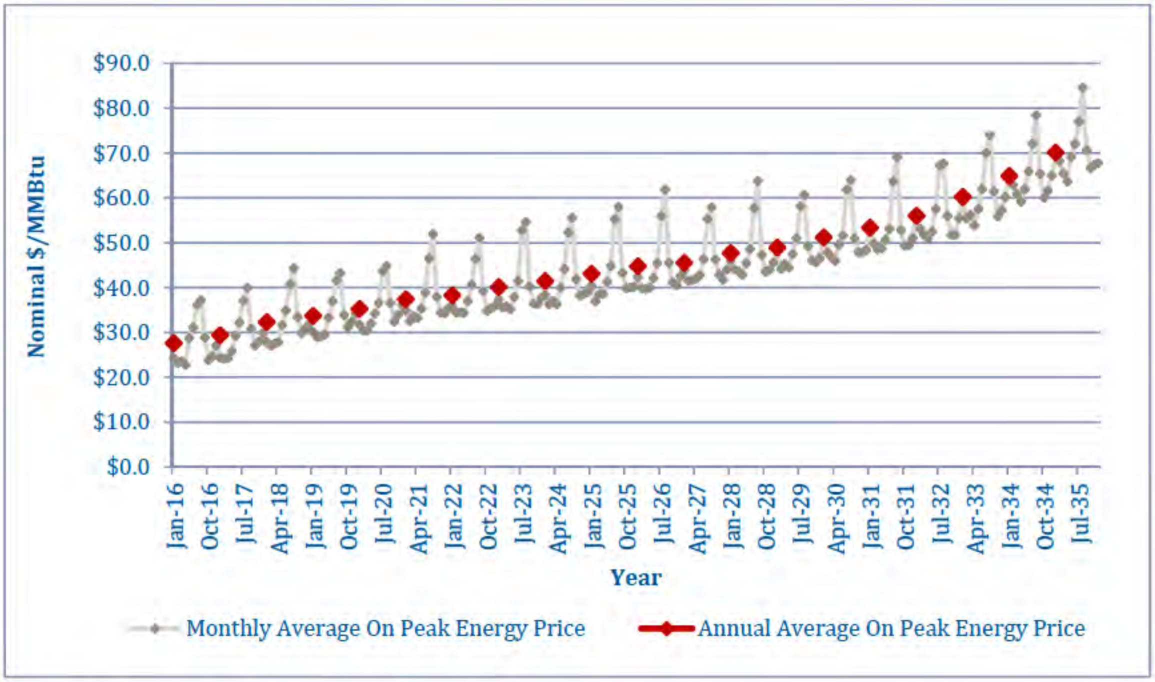


Figure 5-4 **On Peak Energy Price Projection**

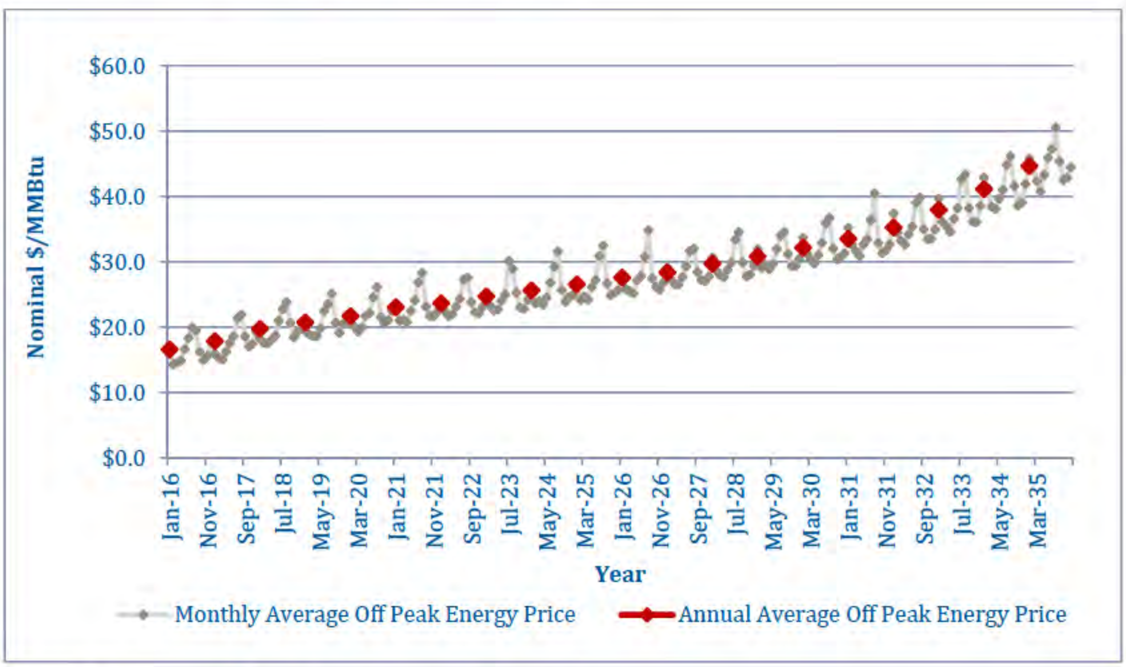


Figure 5-5 **Off Peak Energy Price Projection**

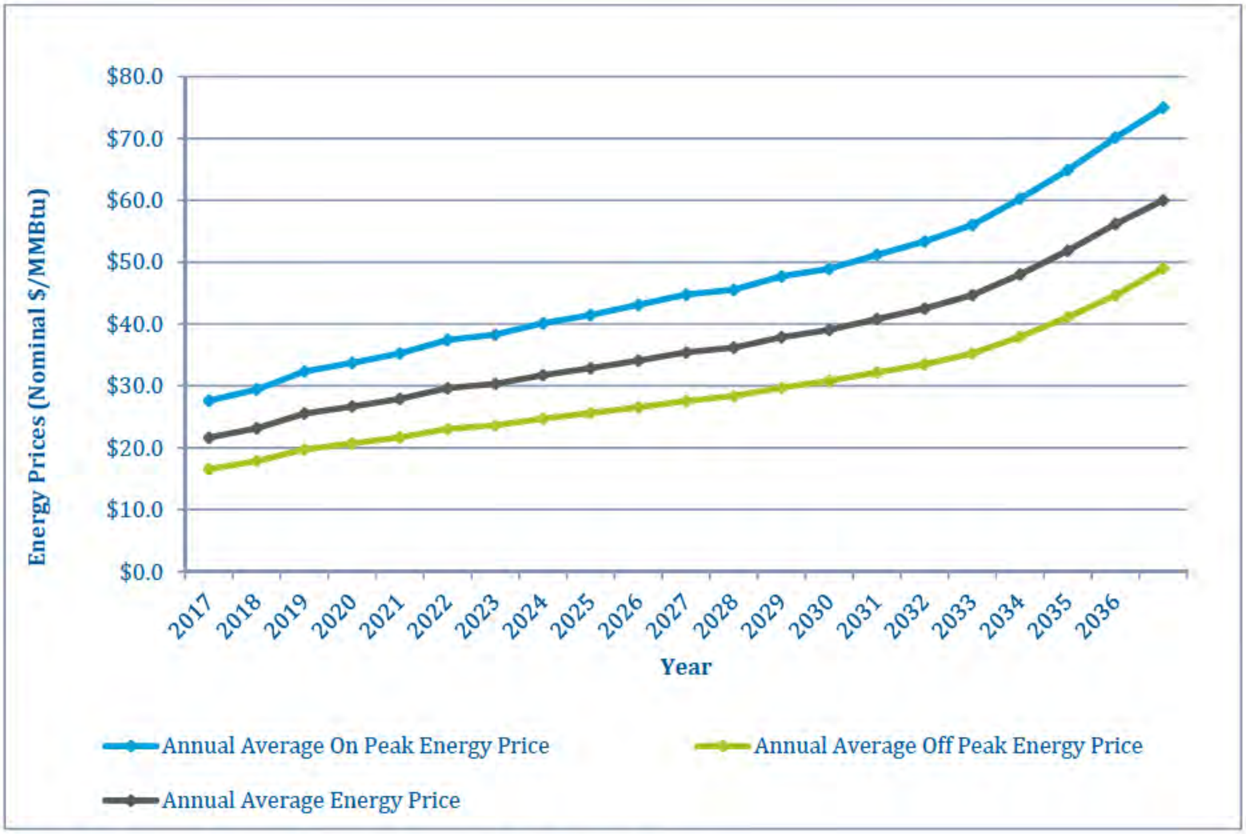


Figure 5-6 Annual Average Energy Price Projections

6.0 Future Resources Considered

This section summarizes the characteristics of the future resource alternatives evaluated in this IRP. Section 6.1 lists the self-build options considered for BPUB in the Base Case expansion plan. Section 6.2 lists the PPA options considered in some of the sensitivity cases evaluated. For the purposes of this study, six self-build generic alternatives were evaluated. The alternatives included:

- Wartsila reciprocating engines.
- Trailer-mounted General Electric (GE) LM2500 simple cycle units.
- GE LMS100 simple cycle units.
- GE LM6000 Sprint simple cycle units.
- GE 7FA simple cycle units.
- 1x1 GE 7FA combined cycle units

Although the combustion turbines and combined cycle alternatives discussed herein assume specific manufacturers (GE and Wartsila) and specific models, this approach is not intended to limit the alternatives considered solely to the specific models evaluated. 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 SELF-BUILD OPTIONS

The following paragraphs and Table 6-1 describe the self-build alternatives and present the cost and operating characteristics of these options . Unless otherwise noted, all cost estimates are presented in 2016 dollars.

6.1.1 Wartsila Reciprocating Engines

Wartsila and other manufacturers provide preassembled packages of reciprocating internal combustion engines (RICE units) in various sizes. Although available in various capacities, this IRP only considered 9 MW Wartsila engines. Larger unit sizes could be considered and may have slight cost and performance advantages, but would have little impact on the overall long-term cumulative cost of serving load. 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. Black & Veatch estimates that the additional investments required for gas pipeline infrastructure improvements required to supply natural gas to the new units would be approximately $0.6-$1.1 million per mile for a gas lateral to connect to the transmission line, plus costs for metering and other incremental facilities. The range is not necessarily a function of the pipe diameter as there are other factors causing regional/project-specific variances, although theoretically large diameter pipes cost more everything else being equal.

6.1.2 Trailer-Mounted LM2500 Simple Cycle

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

6.1.3 LMS100 Simple Cycle

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

6.1.4 LM6000 Sprint Simple Cycle

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

6.1.5 GE 7FA Simple Cycle

The GE 7FA is a heavy duty gas turbine developed by GE equipped with DLN 2,6 combustion system. 7FA is coupled with 14-stage axial compressor and three dimensional aerodynamics airfoils and a hybrid radial compressor diffuser. For purposes of this analysis, a natural gas fired GE 7FA simple cycle resource was evaluated, which is estimated to provide approximately 188 MW of capacity at summer ambient conditions.

6.1.6 GE 7FA Combined Cycle

The GE 7FA may also be utilized in combined cycle mode. For purposes of this analysis, a natural gas fired 1x1 GE 7FA combined cycle resource was evaluated, which is estimated to provide approximately 285 MW of capacity at summer ambient conditions.

6.2 POWER PURCHASE AND RENEWABLE OPTIONS

6.2.1 Part Ownership of 2x1 Tenaska Combined Cycle

For several years, Tenaska has explored developing a new 800 MW 2x1 combined cycle unit in the Brownsville vicinity and this was originally expected to be available during the 2020 timeframe. While Tenaska has more recently indicated that the project may not occur due to economic conditions in the ERCOT market, this option was evaluated as a sensitivity case in this IRP assuming BPUB procured 200 MW (summer capacity) of capacity having the general cost and performance listed in Table 6-1.

6.2.2 Purchase from an Existing Combined Cycle

Based on recent indications from Tenaska, if the new combined cycle unit described in Section 6.2.1 is not built, Tenaska could still offer capacity to BPUB from an existing combined cycle unit in ERCOT. It is also possible that a combined cycle capacity purchase option could emerge from another provider through a capacity solicitation request for proposals. While the specifics of such offers are not now known, the IRP assumed that a 100 MW purchase from an existing 7FA 1x1 combined cycle would be available in 2020, with another 32 MW added to the contracted purchase level in 2025. This "stair-step" purchase level matches the BPUB need for power fairly closely. Since the capacity pricing that may be offered from an existing unit was not known when this case was evaluated, the approach taken was to solve for the capacity price that could be paid for the existing combined cycle capacity and have the expansion plan be lower in CPWC by 2 percent over the best plan between the self-build option (Base Case) and the 800 MW, 2x1 Tenaska combined cycle option.

6.2.3 Wind Purchase Option

The sensitivity cases also included the evaluation of an option received by BPUB related to a 25-year (or 12-year) option to purchase 84 MW of wind generation, of which 27.7 MW would count as firm capacity. The PPA would begin in December of 2018. The pricing and production of this purchase option is shown in Table 6-1 and was provided by BPUB.

It is noted that additional low cost west Texas wind energy may be available to BPUB by means of long term power purchase agreements in the future during off peak to augment BPUB resources in addition to the above resources. However, at this time, no specific information for such PPA options for additional future wind resources were available to BPUB at this time and hence was not considered for modeling purposes for this IRP study.

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(2)	FIXED O&M $/KW-YR.	VARIABLE O&M $/MWH	FIRST AVAILABLE COD(3)
Wartsila Engine – 9 MW	9.2	8,700	1,406	16.90	6.40	2020
GE LM2500 Simple Cycle	26.5	9,330	1,641	8.00	4.00	2020
GE LMS100 Simple Cycle	98.0	9,000	1,233	20.788	3.37	2020
GE LM6000 Simple Cycle	42.0	9,400	1,582	14.11	3.78	2020
GE 7 FA Simple Cycle	188.0	10,200	760	7.53	16.74	2020
GE 7 FA 1x1 Combined Cycle	285.0	6,625	1,280	11.68	3.83	2020
POWER PURCHASE OPTIONS						
Tenaska Combined Cycle (share of 800 MW, 2x1 facility)	200	6,600	967	7.79	3.83	2020
Market purchase from an existing 1x1 7FA Combined Cycle	100 (2020), 132 (2025)	7,000	Solved for the break-even capacity payment vs self-build or the Tenaska 2x1 option	11.68	3.83	2018
New wind PPA, beginning in December, 2018	84 MW (27.7 MW firm)	The wind PPA is based on an estimated average 42.4 % capacity factor for 32 Siemens turbines and would be priced at $28.00/MWh for 25 years, fixed. An alternative option is for 12 years at $28.85/MWh fixed.				

(1)All costs are presented in 2016 dollars.
(2)Capital costs include owner's costs and are based on summer capacity rating.
(3)Commercial operation date.

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.

$$LCOE = \frac{\sum_{n=1}^{Y} Discounted\ Annual\ Busbar\ Cost}{\sum_{n=1}^{Y} \frac{1}{(1 + PWDR)^n}}$$

Table 6-2 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 graphically presents the LCOE data listed in Table 6-2, and illustrates the capacity factor at which various alternatives become lower in levelized costs than other options.

As seen in Figure 6-1, the option having the lowest levelized cost at a 90 percent capacity factor is 2x17FA CC. This remains the lowest cost option until a capacity factor of approximately 20 percent, at which time the Tenaska option becomes less costly.

Note that the capacity factors for which levelized costs are graphed in Figure 6-1 were selected to represent a wide range of possible utilization. Such an analysis is informative as it illustrates the relative economics between alternatives. However, LCOE calculations do not account for how each alternative, having different sizes and efficiencies, fit within the overall BPUB generating system and in the ERCOT region. For this reason, an integrated production costing and regional market model analysis is required before a firm conclusion about the economic merits of candidate options can be reached. This analysis is provided in Section 7.0.

Table 6-2 Levelized Cost of Energy ($/MWh)

OPTION		CAPACITY FACTOR								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
GE LM6000 SC		72.40	74.90	78.12	82.40	88.40	97.40	112.39	142.39	232.37
GE LMS 100 SC		67.07	69.22	71.99	75.68	80.85	88.60	101.52	127.35	204.86
GE 7FA SC		83.28	84.49	86.06	88.14	91.06	95.44	102.74	117.34	161.13
LM2500 SC		71.98	74.43	77.58	81.79	87.68	96.51	111.24	140.68	229.02
2×1 Tenaska SC		34.86	36.38	38.33	40.93	44.57	50.03	59.13	77.34	131.96
Wartsila SC		40.50	42.81	45.79	49.75	55.30	63.63	77.50	105.25	188.51
1×1 GE 7FA CC		28.87	30.56	32.73	35.62	39.67	45.75	55.87	76.12	136.86

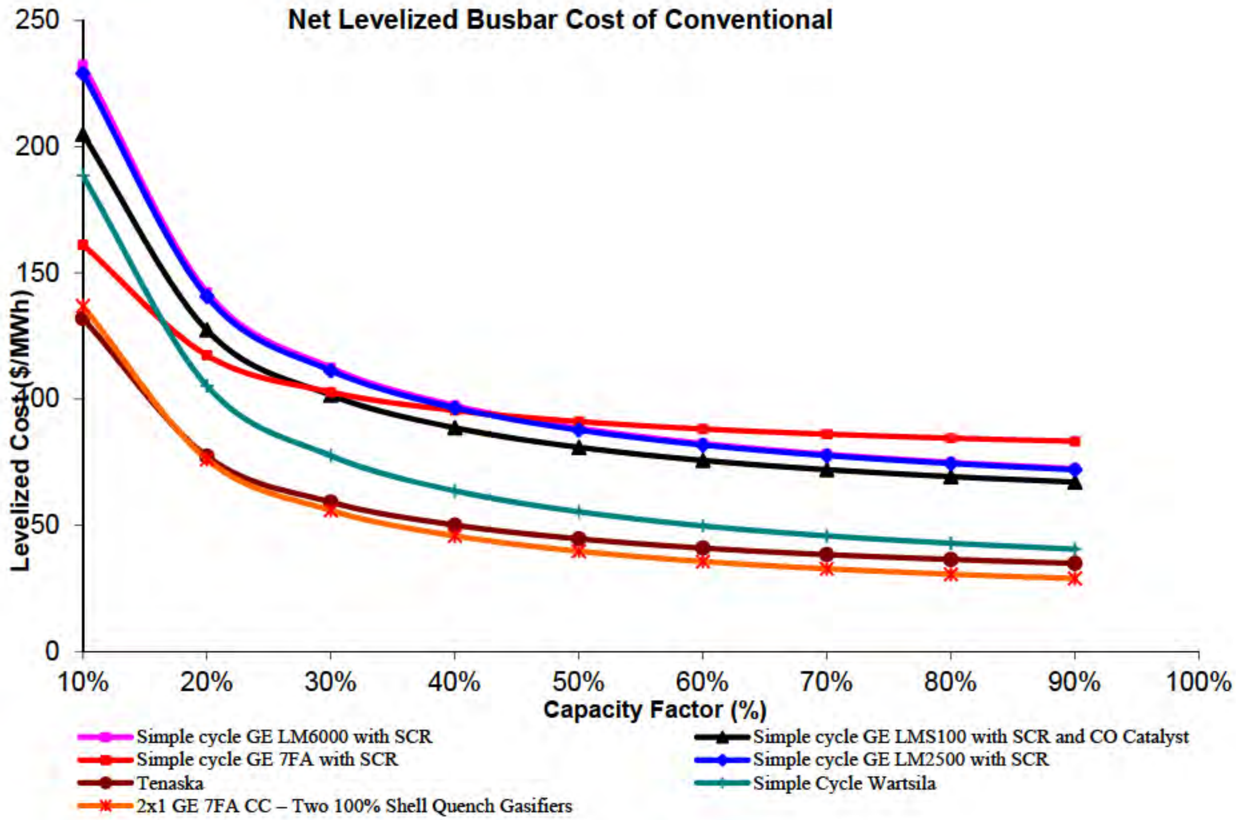


Figure 6-1 Levelized Cost of Energy

7.0 Economic Modeling of Expansion Plan Scenarios

7.1 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 in the 2017-2036 planning period. 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 6.0 of this IRP.

The Strategist™ model developed alternative capacity expansion plans involving the candidate units described in Section 6.0 were added to serve BPUB's load requirements. Strategist™ was also setup to allow economy energy purchases from the ERCOT market or sales into the ERCOT market if cost-effective. .

To perform the market analysis, Black & Veatch's proprietary 2017 Outlook of EMP for ERCOT data set was utilized and resulted in projected hourly ERCOT power prices against which the cost of BPUB resources were compared. The 2017 Outlook of EMP for ERCOT is described further in Section 5.0.

Based on data provided by BPUB. Utilizing the expansion plans developed using Strategist,™ Black & Veatch then used PROMOD™ to develop more detailed cumulative present worth cost (CPWC) estimates of the various expansion plans. PROMOD™ utilizes the same data inputs as Strategist™ but utilizes an hourly, chronological approach and is generally considered to produce more accurate production costing results than Strategist™.

The CPWC of an expansion plan in PROMOD™ consists of the system-wide costs of fuel, fixed O&M, variable O&M, emissions (if any), and capital-related costs for new units each year of the planning period. Interaction with the market is also captured in the form of market purchase costs and revenues from sales into the market. The net cost of serving utility load each year are then discounted to the start of the study period and summed to derive the CPWC of a plan. This process is illustrated in Figure 7-1.

	2017	2018	2019	2020	2021	... 2036
Variable Costs	$	$	$	$	$	$
System fuel Costs	$	$	$	$	$	$
System Variable O&M	$	$	$	$	$	$
Fixed Costs	$	$	$	$	$	$
Fixed O&M	$	$	$	$	$	$
Capital Cost, New Generation	$	$	$	$	$	$
Market Purchases of Power	$	$	$	$	$	$
Market Revenues from Regional Dispatch	$	$	$	$	$	$
Total Incremental Annual Cost	$	$	$	$	$	$
CPWC $						

Figure 7-1 Conceptual View of CPWC Calculation

7.2 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. These economic parameters are discussed below.

7.2.1 Inflation and Escalation Rates

A 2.5 percent rate was assumed for annual general inflation and this rate was used to escalate capital and O&M costs. Fuel costs were forecasted separately as described in Section 5.0.

7.2.2 Cost of Capital and Present Worth Discount Rates

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

7.2.3 Levelized Fixed Charge Rates

A levelized fixed charge rate refers to a percentage rate that, when applied to the total in-service capital cost of a generating unit, provides the revenue needed to offset all financing costs associated with the unit. For investor-owned utilities, the levelized fixed charge rate will include the cost of equity and debt. For municipal utilities or cooperatives, the financing usually assumes all debt or bond financing. Other adders can be included in the fixed charge rate to cover costs for property taxes, insurance, or other fixed charges.

Different types of generating units may have different economic lives and different capital recovery periods. For purposes of this IRP, it has been assumed the new simple cycle and renewable alternatives have 20-year economic lives and capital recovery periods, while combined cycle units have 30-year economic lives and capital recovery periods. The resulting levelized fixed charge rates used in the analysis for self-owned BPUB units are 7.110 percent for 30 year financing and 8.788 percent for 20 year financing. These are the same rates assumed in the 2011 IRP study and assume 100 percent tax exempt financing at a 5.0 percent cost of capital for BPUB, as well as a 0.5 percent cost adder for insurance.

7.3 EXPANSION PLANS EVALUATED

The IRP scope of work and subsequent modifications resulted in the development of the following expansion plans:

1. **Base Case**: Consisting of the best BPUB self-build expansion plan not involving any new wind or any combined cycle PPA from Tenaska or another entity.
2. **Sensitivity 1**: Consisting of the Base Case assumptions except Oklaunion is assumed to retire in 2017 rather than in 2020.
3. **Sensitivity 2**: Consisting of the Base Case assumptions except a stair-step increase in load of 100 MW is assumed in 2025.
4. **Sensitivity 3**: Consisting of a 200 MW purchase from a possible 800 MW future Tenaska combined cycle option in 2020.
5. **Sensitivity 4**: Consisting of an alternative purchase from Tenaska or another IPP involving an initial purchase amount of 100 MW in 2020 that increases to 132 MW in 2025 to approximately match the BPUB need for power. In this sensitivity case, the capacity price of the purchase is solved for such that the CPWC of the plan is 2 percent lower than the better of the Base Case or Sensitivity 3.
6. **Sensitivity 5**: Consisting of an 84 MW wind PPA option (27.7 MW firm), combined with the most economical expansion plan among the Base Case, Sensitivity 3, or Sensitivity 4.

The results of these expansion plans are presented in Section 7.4 and Section 7.5.

7.4 RESULTS OF THE ECONOMIC ANALYSES

7.4.1 Base Case

The Base Case was developed to evaluate the economics of an expansion plan in which BPUB is assumed to build, own, and operate the incremental resources needed to serve its load. The candidate units used in the self-build scenario were listed in Table 7-1.

Results of the Base Case expansion plan are summarized in Table 7-1 and indicate that the best self-build expansion plan would include the addition of a 285 MW 1x1 7FA combined cycle in 2020. This unit addition would provide sufficient capacity for BPUB through the end of the study period under Base Case assumptions. The CPWC of the Base Case is $1,052,127,000 ($1,052 million) and the details are shown in Table 7-8A. This CPWC figure establishes the base-line cost against which other expansion plan results are compared.

Table 7-1 Summary of Base Case (Self-Build) Expansion Plan

YEAR	LM2500 (26.5 MW SUMMER)	WARTSILA (9.2 MW SUMMER)	LM 6000 CT	LMS 100 CT	7FA SIMPLE CYCLE	1X1 7FA COMBINED CYLCE	ANNUAL TOTAL UNITS ADDED	ANNUAL FIRM SUMMER CAPACITY ADDED (MW)
2017	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	285-	1	285
2021	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-
2033-36	-	-	-	-	-	-	-	-
Total New Units	-	-	-	-	-	1	1	-
Firm MW Added						285		285

7.4.2 Sensitivity 1 – Retirement of the Oklaunion Coal Plant, Year-End 2017

The Base Case assumes that the Oklaunion coal plant will be retired in 2020. In the first sensitivity, the projected retirement date is changed to the end of 2017. All other inputs and assumptions remained unchanged from the Base Case.

As the Oklaunion unit is retired at the end of 2017, there is a shortfall in capacity. It is assumed that no self-build alternatives can be built and made operational before 2020 and as such Black & Veatch has assumed that for 2018 and 2019, BPUB will use a short term PPA to cover the capacity shortfall. From 2020 onwards, it has the same resource options available to be self-build as in the Base Case. Hence it was assumed that a 75MW short term PPA from a representative combined cycle unit would be used for 2018 and 2019. Results indicate that, as seen in Table 7-2, the least-cost expansion plan option in this sensitivity involved the addition of the 285 MW 1x1 CC unit in 2020 as in the Base Case in addition to the short term bridge PPA.

The CPWC of this plan is $1,045 million as detailed out in Table 7-8B. This plan is lower in cost than the Base Case plan by approximately 0.7 percent. The results suggest that it would be slightly beneficial to BPUB if the retirement of Oklaunion were preponed. However, the difference in CPWC is generally within the margin of error between plans (usually 1.5 to 2.0 percent is reasonable to assume) and so there seems to be little benefit in retiring the unit earlier.

Table 7-2 Summary of Sensitivity 1, the Oklaunion 2017 Retirement Case Expansion Plan

YEAR	LM2500 (26.5 MW SUMMER)	WARTSILA (9.2 MW SUMMER)	LM 6000 CT	LMS 100 CT	1X1 7FA COMBINED CYLCE	ANNUAL TOTAL UNITS ADDED	ANNUAL FIRM SUMMER MW ADDED
2017	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-
2020	-	-	-	-	-	285	1
2021	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-
2033-36	-	-	-	-	-	-	-
Total New Units	-	-	-	-	-	1	1

7.4.3 Sensitivity 2 – The BPUB High Load Case

The load forecast used in the Base Case analysis and developed in Section 3.0 reflects a gradual growth pattern of load on the BPUB system during the planning horizon. In the second sensitivity, it was assumed that a 100 MW load occurs in 2025 as the result of a large industrial facility presumed to locate in the Brownsville area.

The expansion plan results of this high load case are shown in Table 7-3 and indicate that the best self-build expansion plan would consist of the addition of a 1x1 7FA combined cycle with 285 MW of capacity. This is the same option as selected in the Base Case and shows the flexibility that this option would provide BPUB in meeting load growth deviations.

The CPWC of this expansion plan is $1,169 million as detailed out in Table 7-8C. This CPWC is 11.1 percent higher than the Base Cases CPWC ($1,052 million) due to the higher load and energy requirements.

Table 7-3 Summary of Sensitivity 2, the BPUB High Load Case Expansion Plan

YEAR	LM2500 (26.5 MW SUMMER)	WARTSILA (9.2 MW SUMMER)	LM 6000 CT	LMS 100 CT	1X1 7FA COMBINED CYLCE	ANNUAL TOTAL UNITS ADDED	ANNUAL FIRM SUMMER MW ADDED
2017	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-
2020	-	-	-	-	285	1	285
2021	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-
2032-36	-	-	-	-	-	-	-
New Units	-	-	-	-	1	-	-
Firm MW Added					285		285

7.4.4 Sensitivity 3: 200 MW Tenaska Purchase Option

In the third sensitivity case, a 200 MW purchase from a possible 800 MW Tenaska-owned 2x1 advance combined cycle unit is assumed to occur in 2020. The results of this sensitivity indicate that, (as shown in Table 7-4) the 200 MW purchase would be the only unit added during the study period. The CPWC of this plan is $1,096 million (as shown in Table 7-8D), or approximately 4.2 percent higher than the Base Case in which only self-build BPUB options were considered.

7.4.5 Sensitivity 4: Stair-Step Purchase from an Existing Combined Cycle

In this sensitivity, it is assumed that BPUB would purchase capacity from an existing 1x1 combined cycle located near its service area. This case was created based on indications that the large Tenaska project may not be built due to economic conditions in ERCOT, but that Tenaska would provide an alternative offer from an existing combined cycle unit. Presumably, similar options could be identified through a capacity solicitation request for proposal (RFP).

The cost and performance for this option were the same as is shown for the 1x1 7FA combined cycle in Table 6-1 except a full load net plant heat rate of 7,000 Btu/kWh was assumed. Another assumption impacting the economics of this option was the assumption that BPUB could match its need for power fairly closely through the associated PPA such that 100 MW of initial capacity could be purchased in 2020, with the purchase increasing to 132 MW in 2027 and beyond, as shown in Table 7-5.

A critical component of this sensitivity was the determination of the assumed the PPA capacity price. Because no specific offer had been received at the time of this simulation, the evaluation of this offer involved a determination of the break-even capacity cost that would place the option and expansion as the most cost-effective compared to the Base Case alternative. The capacity cost was adjusted under this approach until the CPWC of the plan was 2 percent lower than the Base Case. In this manner, BPUB would have an idea of the price at which a capacity purchase from an existing combined cycle may be beneficial .

Results of this case indicate that if the capacity shown in Table 7-5 were purchased through a PPA at a capacity charge of $130/kW-year, the option would have a CPWC of $1,032 million as shown in Table 7-8E. This CPWC would be 2 percent lower than the Base Case CPWC ($1,052 million).

In assessing whether this capacity price could be expected in a competitive bid involving an existing 1x1 7FA combined cycle, it is useful to reference two additional capacity costs. If BPUB were to self-build a new 1x1 7FA combined cycle, the annual capacity cost would be approximately $91/kW-year based on the assumed 30-year levelized fixed charge rate of 7.11 percent applied to the installed capital cost per kW of $1,280 from Table 6-1. On the basis of this cost, it would seem reasonable to assume that a competitively procured bid of $130/kW-year or lower could be obtained.

Table 7-4 Summary of Sensitivity 3, 200 MW of a Possible 800 MW Tenaska Combined Cycle

YEAR	LM2500 (26.5 MW SUMMER)	WARTSILA (9.2 MW SUMMER)	LM 6000 CT	LMS 100 CT	1X1 7FA COMBINED CYLCE	200 MW OF AN 800 MW TENASKA COMBINED CYCLE	ANNUAL TOTAL UNITS ADDED	ANNUAL FIRM SUMMER MW ADDED
2017	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	200	1	200
2021	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-
2032-36	-	-	-	-	-	-	-	-
New Units	-	-	-	-	-	1	-	-
Firm MW Added						200		200

Table 7-5 Summary of Sensitivity 4, Stair Step Purchase of 100 MW to 132 MW from an Existing Combined Cycle

YEAR	LM2500 (26.5 MW SUMMER)	WARTSILA (9.2 MW SUMMER)	LM 6000 CT	LMS 100 CT	1X1 7FA COMBINED CYLCE	100 MW IN 2020, 132 MW IN 2027 FROM EXISTING 1X1 COMBINED CYCLE	ANNUAL TOTAL UNITS ADDED	ANNUAL FIRM SUMMER MW ADDED
2017	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	100	1	100
2021	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	32 (incremental)	-	32-
2028	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-
2032-36	-	-	-	-	-	-	-	-
New Units	-	-	-	-	-	1	-	-
Firm MW Added						132		132

On the other hand, it is probable the combined cycle offers for 1x1 7FA combined cycle capacity could come primarily from IPPs or investor-owned utilities that have a higher cost of capital than BPUB. If a levelized fixed charge rate of 11.88 is assumed for such entities (as it was for the 800 MW advanced Tenaska combined cycle), the break-even capacity price would be approximately $152/kW-year. While this is above the calculated break-even price of $130/kW-year, depending on the revenue recovered on the unit to date by the owner, as well as the owner's outlook for other market for sales, it is very possible that a price at less than the $152/kW-year could be received through a competitive process.

Based on the above results and discussion, it is realistic to rank this PPA option as the preferred alternative and ahead of the self-build 1x1 7FA option. This ranking can be finalized as one or more firm offers are received from Tenaska and, ideally, other participants in the market.

7.4.6 Sensitivity 5: Wind PPA Combined with the Step-up Purchase from an Existing Combined Cycle

The final sensitivity case involved the addition of a wind PPA for 84 MW, of which 27.7 MW would be considered firm. This option was combined with the most cost effective option among the Base Case, Sensitivity 3 (the 200 MW Tenaska option), and Sensitivity 4 (step-up purchase from an existing combined cycle). Based on the results reported above, the wind PPA was combined with the Sensitivity 4 option.

The cost of the wind PPA option was taken from information provided by BPUB and summarized in Table 6-1. As in Sensitivity 4, the approach taken was to model the wind generation with the other existing resources and then to solve for the break-even capacity price that would still allow the CPWC of this case to come in approximately 2 percent below the Base Case CPWC of $1,052 million.

Results indicate that Sensitivity 5, including the wind PPA and the step-up capacity purchased from an existing combined cycle unit, would be preferred over the Base Case as long as the combined cycle capacity price were less than $144/kW-year. The CPWC of this sensitivity is approximately $1,031 million at the $144/kW-year capacity cost. This break-even capacity price is higher than the break-even capacity price in Sensitivity 4, meaning that the overall economics of Sensitivity 5 are preferred over Sensitivity 4. The higher break-even price for this case of $144/kW-year makes it increasingly likely that an offer from an entity owning existing combined cycle capacity (such as Tenaska, another IPP, or a utility) can be obtained . It is also possible that this case could be further optimized to account for the capacity credit associated with the wind PPA provided offers for combined cycle capacity are able to closely match the BPUB capacity needs after the wind capacity credit is considered. Even without such adjustments, however, Sensitivity 5 is ranked highest overall in terms of economics. Table 7-6 shows the expansion plan for this sensitivity and the CPWC is shown in Table 7-8F.

Table 7-6 Summary of Sensitivity 5, Wind PPA in 2018 with Stair-Step Purchase (100 MW to 132 MW) from an Existing Combined Cycle

YEAR	84 MW (27.7 MW FIRM) WIND PPA	LM2500 (26.5 MW SUMMER)	WARTSILA (9.2 MW SUMMER)	LM 6000 CT	LMS 100 CT	1X1 7FA COMBINED CYLCE	100 MW IN 2020, 132 MW IN 2027 FROM EXISTING 1X1 COMBINED CYCLE	ANNUAL TOTAL UNITS ADDED	ANNUAL FIRM SUMMER MW ADDED
2017		-	-	-	-	-	-	-	27.7
2018	84/27.7 (December)	-	-	-	-	-	-	-	-
2019		-	-	-	-	-	-	-	-
2020		-	-	-	-	-	105	1	105
2021		-	-	-	-	-	-	-	-
2022		-	-	-	-	-	-	-	-
2023		-	-	-	-	-	-	-	-
2024		-	-	-	-	-	-	-	-
2025		-	-	-	-	-	-	-	-
2026		-	-	-	-	-	-	-	-
2027		-	-	-	-	-	-	-	-
2028		-	-	-	-	-	-	-	-
2029		-	-	-	-	-	-	-	-
2030		-	-	-	-	-	-	-	-
2031		-	-	-	-	-	-	-	-
2032-36		-	-	-	-	-	-	-	-
New Units		-	-	-	-	-	1	-	-
Firm MW Added							132		132.5

7.4.7 Summary of CPWC Results

Table 7-7 provides a summary ranking of the CPWC results and the individual CPWC calculation summaries are included in Table 7-8A through Table 7-8F. Table 7-7 indicates that of the expansion plans that are strictly comparable in terms of CPWC (all but Sensitivity 1 and 2), the best BPUB plan involves the 84 MW (27.7 MW firm) wind PPA in 2018 followed by the stair-step purchase from an existing combined cycle in 2020 (100 MW) and 2027 (132 MW). Note, however that while this expansion plan solved-for capacity price needed to make the case 2 percent lower in cost than the Base Case, it is believed that this capacity price for existing combined cycle capacity ($144/kW-year or lower) could reasonably be expected to obtained through a competitive solicitation.

The second best plan involves the stair-step purchase from an existing combined cycle plant without the wind PPA. This also involved determining the capacity price needed to make the plan 2 percent lower than the Base Case. The resulting capacity price was found to be $130/kW-year for the combined cycle capacity, meaning that if BPUB received offers or otherwise negotiated for combined cycle capacity at no more than $130/kW-year the option would be preferred over the Base Case.

The third best plan is the Base Case, which included only BPUB self-build simple cycle and combined cycle options ranging in size from 9 MW to 285 MW. The Base Case modeling selected the 1x1 285 MW 7FA combined cycle unit as the best self-build BPUB option.

The 200 MW Tenaska purchase option is the fourth-ranked option, but this is 6.3 percent higher than the best CPWC. This result, together with the indication from Tenaska that it may not pursue the construction of this option suggests that it is of limited benefit to pursue further at the present time.

The other two sensitivities in the table are not strictly comparable to the Base Case and other sensitivity cases, but are useful in that they indicate the best addition for BPUB under single variable sensitivities from the Base Case. In the event that a 100 MW increase in BPUB load occurs in the future, the expansion plan selected a 1x1 285 MW combined cycle as the best self-build option for BPUB (the Tenaska 200 MW purchase and the stair-step existing combined cycle option were not candidate units in this run). In the event that the Oklaunion plant retires in 2017, the best self-build option for BPUB (again, combined cycle PPAs were not part of this run since it was a sensitivity off of the Base Case) would consist of the same expansion plan as the Base Case.

Table 7-7 CPWC Comparison and Ranking of Plans

EXPANSION PLAN	CPWC ($ MILLIONS)	% HIGHER THAN BEST PLAN	RANK	COMMENT	REFERENCE TABLE FOR CPWC DETAILS
Sensitivity 5. Wind PPA (2018) with Stair-Step Purchase from an Existing Combined Cycle	1,031	-	1st	Based on a max. break-even capacity price of $144/kW-year that would make the plan approx. 2% lower than the Base Case	Table 7-8F
Sensitivity 4. Stair-Step Purchase from an Existing Combined Cycle	1,032	-	2nd	Based on a max. break-even capacity price of $130/kW-year that would make the plan approx. 2% lower than the Base Case	Table 7-8E
Base Case. BPUB Self-build case involving a 285 MW, 1x1 7FA combined cycle	1,052	2.0%	3rd	Candidate units include natural gas fired simple and combined cycle options from 9 MW to 285 MW	Table 7-8A
Sensitivity 3. 200 MW Purchase from Possible 800 MW Tenaska Unit	1,096	6.3%	4th	Considered less likely to be built based on current market conditions. An option involving an existing combined cycle as in Sensitivity 4 and 5 is more likely	Table 7-8D
Single Variable Sensitivities on the Base Case (not strictly comparable with other sensitivity cases)					
Sensitivity 1. 2017 Retirement of Oklaunion	$1,045	NA	NA	Short Term Bridge PPA and BPUB Self-build Case Involving a 285 MW, 1x1 Combined Cycle	Table 7-8B
Sensitivity 2. 100 MW increase in industrial load in 2025	$1,169	NA	NA	This plan involves the selection of a 1x1 285 MW self-build option (the Tenaska 200 MW purchase and the stair-step purchase from an existing combined cycle were not candidate units in this run since this is a sensitivity off of the Base Case)	Table 7-8C

Table 7-8A Base Case - CPWC of 285 MW Self Build Option ($000's)

Data Item	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Fuel Cost	23,090	29,368	27,401	42,440	44,483	41,823	41,451	40,609	40,947	41,306	40,925	41,922	40,454	40,910	40,692	40,949	43,462	47,857	49,224	59,768
VOM Cost	2,132	2,491	2,174	3,070	3,211	2,831	2,628	2,430	2,399	2,333	2,254	2,283	2,082	2,053	1,955	1,868	1,926	2,080	2,098	2,446
FOM Cost	14,024	14,024	13,642	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788
Wind Generation Cost	9,022	8,796	11,055	7,234	7,089	9,549	10,840	12,313	12,994	13,511	14,344	15,082	17,019	18,136	19,911	21,619	22,856	23,329	25,141	22,883
Energy Market Purchase Cost	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420
Emergency Energy Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Market Sales Revenue	(4,176)	(4,993)	(4,731)	(31,627)	(31,727)	(27,891)	(25,521)	(23,750)	(23,221)	(22,084)	(20,783)	(20,744)	(18,421)	(18,220)	(17,121)	(16,211)	(16,576)	(19,124)	(18,228)	(26,087)
Capital Cost for New Units	-	-	-	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,129
Total System Cost	**55,478**	**61,071**	**60,926**	**70,453**	**72,357**	**75,614**	**78,700**	**80,938**	**82,421**	**84,368**	**86,042**	**87,879**	**90,436**	**92,180**	**94,739**	**97,561**	**100,970**	**103,443**	**107,536**	**108,347**
PW of System Cost	**55,478**	**58,163**	**55,262**	**60,860**	**59,528**	**59,245**	**58,727**	**57,521**	**55,786**	**54,385**	**52,822**	**51,381**	**50,358**	**48,885**	**47,850**	**46,929**	**46,255**	**45,132**	**44,683**	**42,877**
CPWC of System Cost	**1,052,127**																			

Table 7-8B Sensitivity 1- CPWC of the 2017 Oklaunion Retirement ($000's)

Data Item	UOM	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Fuel Cost	(K$)	22,413	11,075	10,496	42,440	44,483	41,823	41,451	40,609	40,947	41,306	40,925	41,922	40,454	40,910	40,692	40,949	43,462	47,857	49,224	59,768
VOM Cost	(K$)	2,053	1,819	1,444	3,070	3,211	2,831	2,628	2,430	2,399	2,333	2,254	2,283	2,082	2,053	1,955	1,868	1,926	2,080	2,098	2,446
FOM Cost	(K$)	14,024	9,284	9,284	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788
Wind Generation Cost	(K$)	9,294	11,429	14,528	7,234	7,089	9,549	10,840	12,313	12,994	13,511	14,344	15,082	17,019	18,136	19,911	21,619	22,856	23,329	25,141	22,883
Energy Market Purchase Cost	(K$)	11,385	13,417	13,417	11,420	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420
Emergency Energy Cost	(K$)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Market Sales Revenue	(K$)	(3,546)	(1,594)	(1,289)	(31,627)	(31,727)	(27,891)	(25,521)	(23,750)	(23,221)	(22,084)	(20,783)	(20,744)	(18,421)	(18,220)	(17,121)	(16,211)	(16,576)	(19,124)	(18,228)	(26,087)
Capital Cost for New Units	(K$)	-	10,800	10,800	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,129
Total System Cost	**(K$)**	**55,623**	**56,230**	**58,680**	**70,453**	**72,357**	**75,614**	**78,700**	**80,938**	**82,421**	**84,368**	**86,042**	**87,879**	**90,436**	**92,180**	**94,739**	**97,561**	**100,970**	**103,443**	**107,536**	**108,347**
PW of System Cost	**$(00**	**55,623**	**53,552**	**53,224**	**60,860**	**59,528**	**59,245**	**58,727**	**57,521**	**55,786**	**54,385**	**52,822**	**51,381**	**50,358**	**48,885**	**47,850**	**46,929**	**46,255**	**45,132**	**44,683**	**42,877**
CPWC of System Cost	$(00	**1,045,624**																			
CPW of Energy Demand	(GWI	23,531																			
CPW of System Cost	**($/M**	**$ 44.44**																			

Table 7-8C Sensitivity 2- CPWC of the 100 MW Load Addition in 2025 ($000's)

Data Item	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Fuel Cost	22,413	29,105	27,079	42,440	44,483	41,823	41,451	40,575	40,965	41,316	40,925	41,927	40,454	40,910	40,692	40,949	43,462	47,857	51,864	57,243
VOM Cost	2,053	2,412	2,092	3,070	3,211	2,831	2,628	2,425	2,401	2,335	2,254	2,283	2,082	2,053	1,955	1,868	1,926	2,080	2,196	2,361
FOM Cost	14,024	14,024	13,642	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788	12,788
Wind Generation Cost	9,294	8,861	11,099	7,234	7,089	9,549	10,840	12,313	19,117	20,020	21,158	22,361	24,940	26,563	29,185	31,662	33,612	34,163	35,549	35,574
Energy Market Purchase Cost	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420
Emergency Energy Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Market Sales Revenue	(3,546)	(4,817)	(4,347)	(31,627)	(31,727)	(27,891)	(25,521)	(23,711)	(12,877)	(11,833)	(10,818)	(10,739)	(8,874)	(8,703)	(8,009)	(7,314)	(7,302)	(8,884)	(9,775)	(11,947)
Capital Cost for New Units	-	-	-	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,128	25,129
Total System Cost	**55,623**	**60,971**	**60,949**	**70,453**	**72,357**	**75,614**	**78,700**	**80,938**	**98,907**	**101,139**	**102,821**	**105,168**	**107,903**	**110,124**	**113,125**	**116,501**	**120,999**	**124,517**	**129,136**	**132,569**
PW of System Cost	**55,623**	**58,067**	**55,283**	**60,860**	**59,528**	**59,245**	**58,727**	**57,521**	**66,944**	**65,195**	**63,123**	**61,490**	**60,085**	**58,401**	**57,136**	**56,039**	**55,431**	**54,326**	**53,659**	**52,462**
CPWC of System Cost	**1,169,147**																			

Table 7-8D Sensitivity 3- CPWC of the 200 MW Purchase from a Tenaska 800 MW Unit ($000s)

Data Item	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Fuel Cost	22,413	29,105	27,079	28,859	30,554	29,115	28,983	28,406	28,136	28,352	27,775	29,057	27,109	27,851	27,346	27,069	29,226	33,068	35,317	42,473
VOM Cost	2,053	2,412	2,092	4,863	5,099	4,598	4,329	4,083	3,972	3,912	3,791	3,875	3,514	3,510	3,357	3,197	3,304	3,580	3,582	4,213
FOM Cost	14,024	14,024	13,642	10,924	10,924	10,924	10,924	10,924	10,924	10,924	10,924	10,924	10,924	10,924	10,924	10,924	10,924	10,924	10,924	10,924
Wind Generation Cost	9,294	8,861	11,099	10,260	10,775	12,765	14,472	15,995	16,786	17,950	18,864	19,617	22,204	23,389	25,750	28,214	29,388	29,622	31,245	30,042
Energy Market Purchase Cost	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420
Emergency Energy Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Market Sales Revenue	(3,546)	(4,817)	(4,347)	(16,141)	(16,256)	(13,201)	(11,999)	(11,117)	(9,773)	(9,059)	(8,048)	(8,626)	(6,570)	(6,804)	(5,989)	(5,244)	(5,417)	(6,603)	(6,604)	(10,947)
Capital Cost for New Units	-	-	-	25,367	25,367	25,367	25,367	25,367	25,367	25,367	25,367	25,367	25,367	25,367	25,367	25,367	25,367	25,367	25,367	25,367
Total System Cost	**55,623**	**60,971**	**60,949**	**75,553**	**77,849**	**80,954**	**83,462**	**85,079**	**86,797**	**88,832**	**90,058**	**91,635**	**93,935**	**95,623**	**98,141**	**100,948**	**104,177**	**107,344**	**111,217**	**113,492**
PW of System Cost	**55,623**	**58,067**	**55,283**	**65,266**	**64,047**	**63,430**	**62,281**	**60,464**	**58,748**	**57,262**	**55,288**	**53,577**	**52,306**	**50,711**	**49,568**	**48,558**	**47,725**	**46,834**	**46,213**	**44,913**
CPWC of System Cost	**1,096,162**																			

Table 7-8E Sensitivity 4- CPWC of the Stair-Step Purchase from an Existing Combined Cycle ($000s)

Data Item	UOM	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Fuel Cost	(K$)	22,413	29,105	27,079	20,028	21,330	19,762	18,974	18,096	17,134	16,857	17,507	18,015	16,411	16,583	15,313	14,911	16,615	19,733	22,434	27,573
VOM Cost	(K$)	2,053	2,412	2,092	2,737	2,906	2,505	2,252	2,045	1,879	1,791	1,812	1,841	1,603	1,568	1,393	1,286	1,396	1,606	1,749	2,100
FOM Cost	(K$)	14,024	14,024	13,642	10,063	10,063	10,063	10,063	10,063	10,063	10,063	10,313	10,313	10,313	10,313	10,313	10,313	10,313	10,313	10,313	10,313
Wind Generation Cost	(K$)	9,294	8,861	11,099	14,843	15,485	19,045	21,832	24,166	26,340	28,443	28,939	30,044	33,434	35,173	38,607	41,710	43,640	44,031	45,517	44,811
Energy Market Purchase Cost	(K$)	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420	11,385	11,385	11,385	11,420
Emergency Energy Cost	(K$)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Market Sales Revenue	(K$)	(3,546)	(4,817)	(4,347)	(4,366)	(3,780)	(3,030)	(2,544)	(2,248)	(1,444)	(1,138)	(1,605)	(1,553)	(1,158)	(1,220)	(988)	(812)	(775)	(909)	(936)	(1,816)
Capital Cost for New Units	(K$)				13,000	13,000	13,000	13,000	13,000	13,000	13,000	17,160	17,160	17,160	17,160	17,160	17,160	17,160	17,160	17,160	17,160
Total System Cost	**(K$)**	**55,623**	**60,971**	**60,949**	**67,726**	**70,389**	**72,730**	**74,964**	**76,542**	**78,357**	**80,401**	**85,511**	**87,240**	**89,149**	**90,962**	**93,183**	**95,988**	**99,734**	**103,319**	**107,623**	**111,562**
PW of System Cost	**$(00**	**55,623**	**58,067**	**55,283**	**58,504**	**57,909**	**56,986**	**55,939**	**54,397**	**53,035**	**51,827**	**52,496**	**51,007**	**49,641**	**48,239**	**47,064**	**46,172**	**45,689**	**45,078**	**44,719**	**44,149**
CPWC of System Cost	$(00	**1,031,826**																			

Table 7-8F Sensitivity 5 -Wind PPA plus Stair-Step Purchase from an Existing Combined Cycle ($000s)

Data Item	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Fuel Cost	22,413	29,105	27,079	19,870	21,642	19,473	18,477	17,468	16,717	16,280	16,032	16,886	15,414	15,434	14,258	14,075	15,645	18,755	21,348	25,571
VOM Cost	2,053	2,412	2,092	2,685	2,935	2,432	2,165	1,945	1,817	1,712	1,651	1,707	1,498	1,451	1,289	1,203	1,302	1,513	1,652	1,937
FOM Cost	14,024	14,024	13,642	10,102	10,102	10,102	10,102	10,102	10,102	10,102	10,102	10,102	10,102	10,102	10,102	10,102	10,102	10,102	10,102	10,102
Wind Generation Cost	9,294	8,861	11,099	10,405	10,570	13,809	16,292	18,455	20,172	21,928	23,183	23,966	26,847	28,456	31,841	34,210	36,093	36,089	37,545	37,221
Energy Market Purchase Cost	11,385	11,385	11,385	19,792	19,777	19,777	19,777	19,833	19,777	19,777	19,777	19,833	19,777	19,777	19,777	19,833	19,777	19,777	19,777	19,833
Emergency Energy Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Market Sales Revenue	(3,546)	(4,817)	(4,347)	(7,254)	(7,054)	(5,097)	(4,541)	(3,885)	(3,044)	(2,335)	(2,233)	(2,511)	(1,816)	(1,719)	(1,710)	(1,282)	(1,280)	(1,897)	(2,221)	(2,969)
Capital Cost for New Units	-	-	-	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120	15,120
Total System Cost	**55,623**	**60,971**	**60,949**	**70,721**	**73,091**	**75,616**	**77,391**	**79,039**	**80,662**	**82,584**	**83,633**	**85,104**	**86,941**	**88,622**	**90,677**	**93,261**	**96,759**	**99,460**	**103,323**	**106,816**
PW of System Cost	**55,623**	**58,067**	**55,283**	**61,091**	**60,133**	**59,247**	**57,751**	**56,172**	**54,595**	**53,235**	**51,343**	**49,758**	**48,412**	**46,998**	**45,798**	**44,860**	**44,327**	**43,394**	**42,933**	**42,271**
CPWC of System Cost	**1,031,290**																			

8.0 Financial and Rate Impacts

This section presents results of the Financial Analysis for the six expansion plans discussed in Section 7.0. The analysis was used to determine the impact each case has on the BPUB revenue and revenue requirements. The plans evaluated are:

1. Base Case
2. High Load Case
3. Oklaunion 2017 Retirement Case.
4. Tenaska 200 MW PPA Case
5. Step-up Tenaska with B/E
6. New Wind w/ Step-up Tenaska

Cases 1, 2, and 3 assume BPUB will self-build a 285 MW 1x1 CC generating facility and will own and operate it. The Capital Costs from the PROMOD™ output is the assumed annual debt service payment for the bonds BPUB would issue to finance the plant. Cases 4, 5, and 6 assume BPUB will have no ownership share in the generation choice and all costs are treated like a PPA and passed through the Fuel and Purchased Energy Charge (FPEC). No future debt financing is needed.

The following sections explain the principal assumptions, the financial impact of each alternative, and the methodology used to run the analysis.

8.1 PRINCIPAL ASSUMPTIONS

The following section presents the principle assumptions used in development of the financial analysis. The starting point for the financial forecast was a baseline model developed in coordination with BPUB, and the following inputs:

- The forecast of electric sales was based on the 2016 Load Forecast prepared by Black & Veatch and reflected in this IRP.
- The 2016 Load Forecast and the resulting capacity balance produced a projection of the BPUB generation requirements. This capacity balance was reflected in the PROMOD™ simulations that simulated operation of the BPUB system over the planning horizon and produced projections of fuel expenses, incremental production O&M expenses, off-system sales revenue and purchases, and generation capital expenditures under each alternative case. The revenue forecast under existing rates was generated by applying the fiscal year (FY) 2017 average retail unit rate(s) to the 2016 Load Forecast.
- The baseline forecast of Operation and Maintenance expenses is based on 2017 budgeted expenses escalated at 2 percent. This is then increased by the forecasted cumulative change of production operation and maintenance expenses from the PROMOD™ model.

- 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, less fuel for off-system sales. No surplus revenues are used to reduce the FPEC rate.
- Off-system sales fuel expense is calculated as 65 percent of the off-system sales revenue projected in PROMOD™, which is consistent with the 2017 budget.
- The forecast of cash financed capital (Improvement Fund- CIP Funding) is based on BPUB's 5-year Capital Improvement Plan (CIP) through 2021. The forecast is for $9 million in most years. A 3 percent escalation rate is applied to a base of $9 million from 2022 – 2027.
- All cases are evaluated for 10 years beyond the budget year of 2017 (2018-2027).

8.2 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 a baseline financial forecast developed with BPUB. This allowed Black & Veatch to evaluate the financial impact and resulting rate impacts of each alternative.

There are two rate components that impact the annual rate increase for the utility. The first is the base rate impact for the additional capital projects and operating expenses related to each new supply side addition. The second rate component is for recovery of fuel and purchased power expenses. This rate is determined by the annual fuel and purchased power expense (less fuel for off-system sales) divided by sales. The incremental fuel and purchased power expenses for each alternative were determined by PROMOD™.

Surplus annual revenues are used to either reduce the FPEC rate applied to customers or added to future base rate revenue to meet debt service coverage and offset the need for a base rate increase. The target debt service coverage ratio that would trigger the need for a base rate increase is 1.50 (net revenues divided by total debt service).

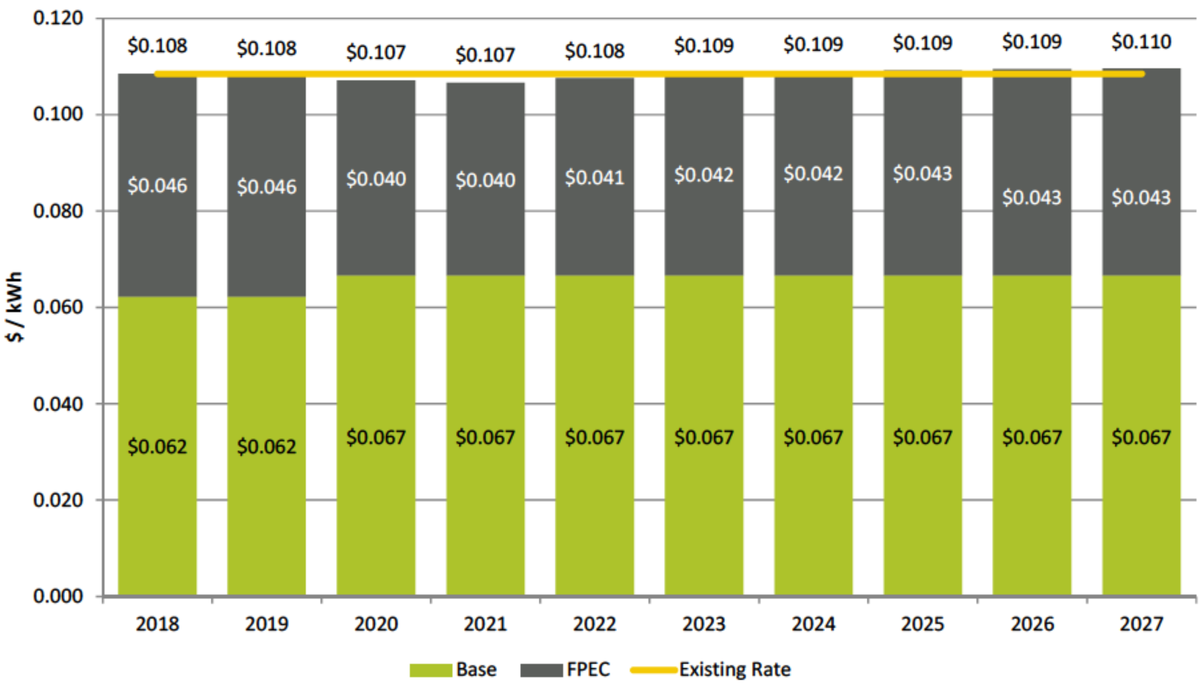
8.3 FINDINGS OVERVIEW

The results of the financial forecast for each of the supply side alternatives are summarized below:

- Findings are based on using the sales forecast and reflect off-system sales revenue from PROMOD™.
- A base rate increase of 7 percent in 2020 is required in the self-build options (Scenarios 1 through 3). No base rate increases are needed in the PPA options (Scenarios 4 through 6).
- The self-build options have generally lower fuel and purchased power costs.

- Scenarios 4 through 6, where BPUB does not self-build generation, results in lower base rates, but higher fuel and purchase power costs. The higher total rate could be offset with continued use of surplus revenues to reduce the FPEC below cost. These scenarios have significantly more surplus revenues.
- Scenarios 4 through 6 results in much higher debt service coverage due to no future bonds being issued for a self-build option.

Figures 8-1 through 8-6 show the results, for the average base and the FPEC rates, for each case and include a line that highlights the projected rate for 2018. Figure 8-7 shows a side by side comparison of the average FPEC rates for each scenario and Figure 8-8 shows the same comparison on a Total Rate basis. Tables 8-1 through 8-6 show the full financial forecasts of each of the six scenarios.



LN	DESCRIPTION	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Base Rate Adjustment	0.0%	0.0%	7.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	FPEC Rate Adjustment	37.9%	-1.0%	-11.5%	-1.0%	2.2%	2.3%	1.2%	0.4%	0.7%	0.2%
3	Total Rate Adjustment	13.3%	-0.4%	-0.9%	-0.4%	0.8%	0.9%	0.5%	0.1%	0.3%	0.1%

Figure 8-1 Average Annual Rates – Base Case

In the Base Case shown above, a 7 percent base rate increase is required in 2020 when bonds are issued for the investment in the 285 MW generating facility. The FPEC drops in 2020 because the additional fuel costs related to the new plant are offset by additional off system sales. Overall rates are quite stable through the study period.

LN	DESCRIPTION	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Base Rate Adjustment	0.00%	0.00%	7.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	FPEC Rate Adjustment	38.58%	-0.92%	-11.43%	-1.05%	2.19%	2.31%	1.15%	-7.40%	0.97%	0.25%
3	Total Rate Adjustment	13.51%	-0.39%	-0.84%	-0.40%	0.83%	0.88%	0.44%	-2.89%	0.36%	0.09%

Figure 8-2 Average Annual Rates – High Load Case

In the High Load Case shown above, a 7 percent base rate increase is required in 2020 when bonds are issued for the investment in the 285 MW generating facility. This case is essentially the same as the Base Case through 2025 when a significant increase in load/sales occurs. This results in a significant decreases in the FPEC rate as the additional base rate revenue resulting from the additional load reduces the average unit cost of production.

LN	DESCRIPTION	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Base Rate Adjustment	0.00%	0.00%	7.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	FPEC Rate Adjustment	37.39%	2.59%	2.74%	-1.54%	1.59%	1.71%	0.75%	0.06%	0.39%	-0.05%
3	Total Rate Adjustment	13.09%	1.10%	5.16%	-0.65%	0.66%	0.72%	0.32%	0.02%	0.17%	-0.02%

Figure 8-3 Average Annual Rates – Oklaunion 2017 Retirement Case

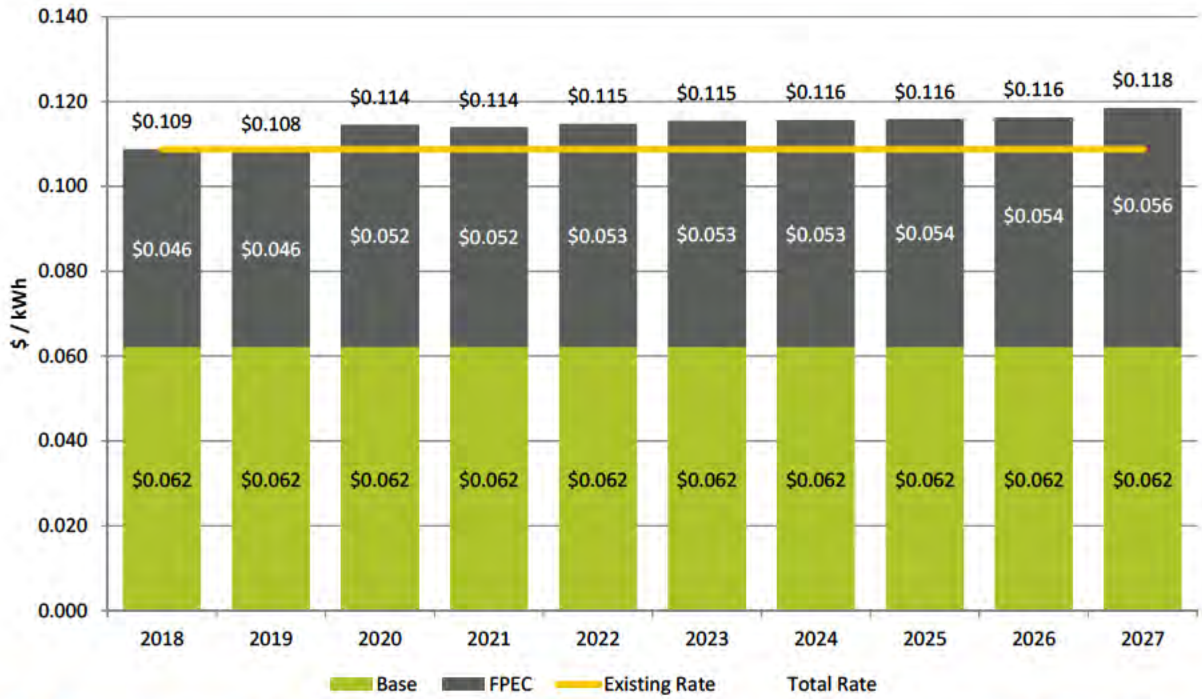
The Oklaunion 2017 Retirement Case requires a 7 percent base rate increase in 2020 when bonds are issued for the investment in the 285 MW generating facility. Fuel and purchased power costs are generally higher than the other self build options due to the early retirement of Oklaunion. The total rate remains quite stable after 2020.

DESCRIPTION	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Base Rate Adjustment	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FPEC Rate Adjustment	38.58%	-0.92%	27.49%	-1.62%	1.31%	1.02%	0.06%	-0.18%	0.32%	-0.62%
Total Rate Adjustment	13.51%	-0.39%	11.69%	-0.79%	0.63%	0.49%	0.03%	-0.09%	0.15%	-0.30%

Figure 8-4 Average Annual Rates – 200 MW Tenaska PPA Case

In the 200 MW Tenaska PPA Case shown above, there are no base rate increases needed in the study period, but this is offset by higher FPEC rates if no surplus revenues are used to reduce the rate passed through to customers. No base rate increases are required due to the fact that future generation alternatives are treated as a PPA with no BPUB ownership. Therefore BPUB does not need to issue future bonds and therefore maintains much higher debt service coverage.

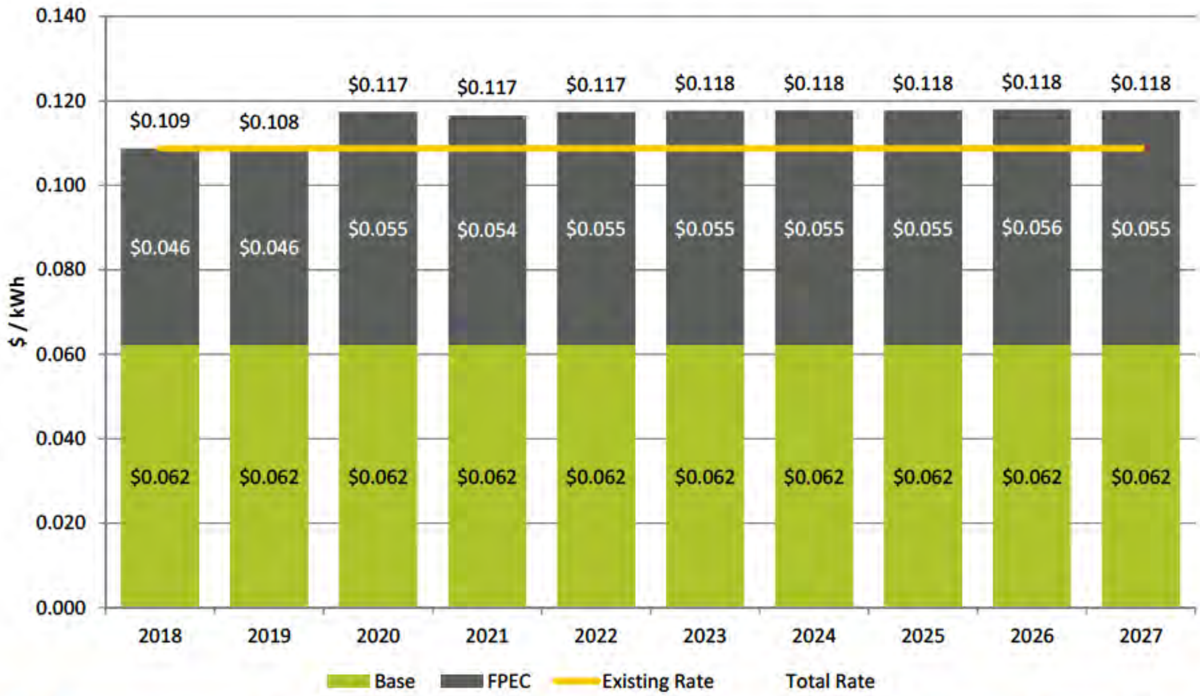
On a total rate and FPEC basis, this scenario results in higher rates, but has much better debt service coverage and greater surplus revenues are generated annually.



LN	DESCRIPTION	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Base Rate Adjustment	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	FPEC Rate Adjustment	38.58%	-0.92%	13.47%	-1.07%	1.59%	1.28%	0.41%	0.39%	0.73%	4.12%
3	Total Rate Adjustment	13.51%	-0.39%	5.73%	-0.49%	0.72%	0.58%	0.19%	0.18%	0.34%	1.91%

Figure 8-5 Average Annual Rates – Step-up Tenaska with B/E Case

In the Step-up Tenaska with B/E Case shown above, there are no base rate increases needed in the study period and the FPEC is higher after 2020. The results for this Case are generally similar to the 200 MW Tenaska Case, with slightly improved overall results.



LN	DESCRIPTION	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Base Rate Adjustment	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	FPEC Rate Adjustment	38.58%	-0.92%	19.76%	-1.53%	1.26%	0.58%	0.28%	0.03%	0.37%	-0.47%
3	Total Rate Adjustment	13.51%	-0.39%	8.40%	-0.72%	0.59%	0.27%	0.13%	0.01%	0.17%	-0.22%

Figure 8-6 Average Annual Rates – New Wind w/ Step-up Tenaska Case

In the New Wind w/ Step-up Tenaska Case shown above, there are no base rate increases needed in the study period and the FPEC is comparable to the other Tenaska step-up option. The results for this Case are generally similar to the 200 MW Tenaska Case, with slightly improved overall results.

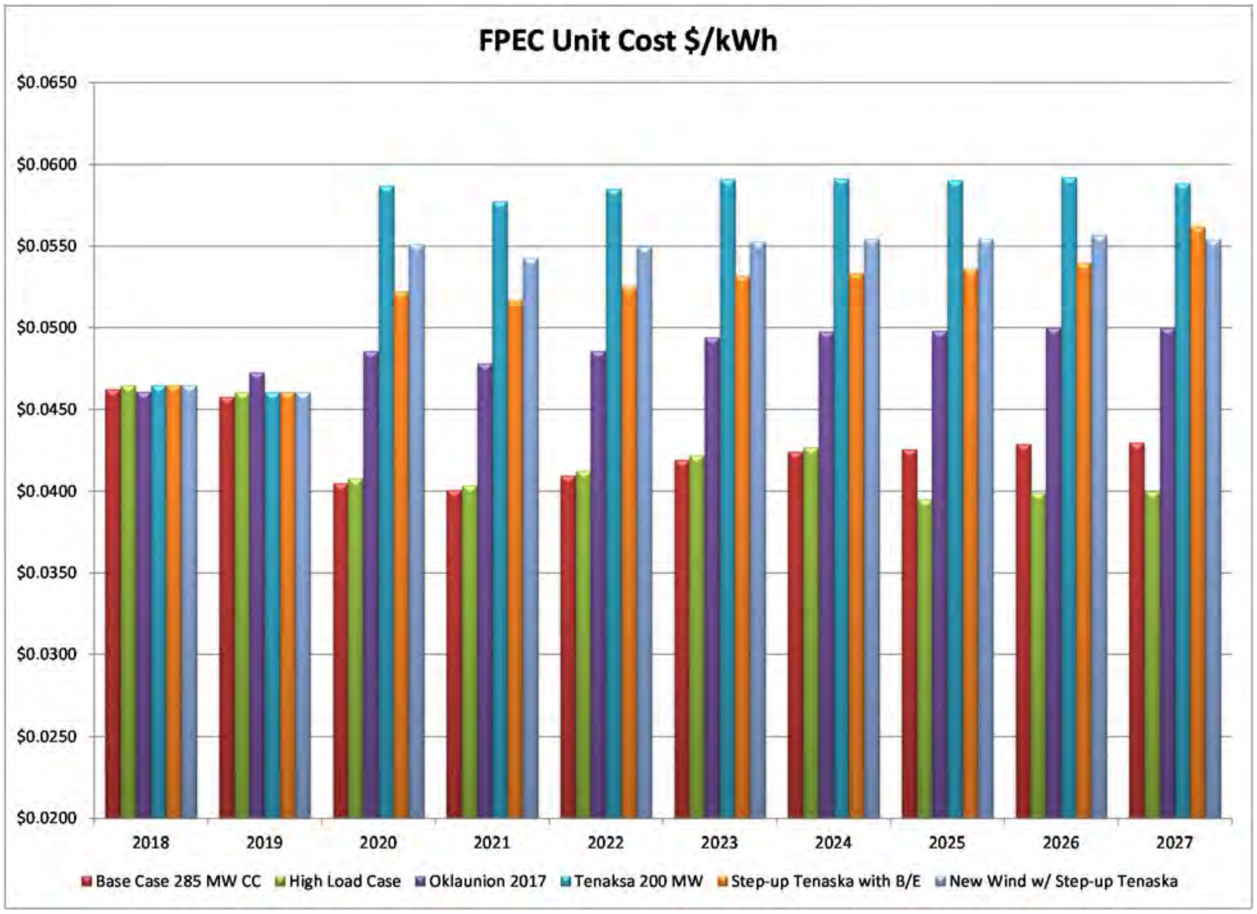


Figure 8-7 Comparison of Average FPEC Rates

As shown in Figure 8-7 above, the first three scenarios, which are all self-build options, have the lowest FPEC rates after 2020. However, it should be noted that if BPUB were to continue its current practice of using surplus revenues to reduce the FPEC, the overall results of the PPA would be much closer to the self-build options. By the end of the study period, the Base Case and High Load Case have the lowest average FPEC rates.

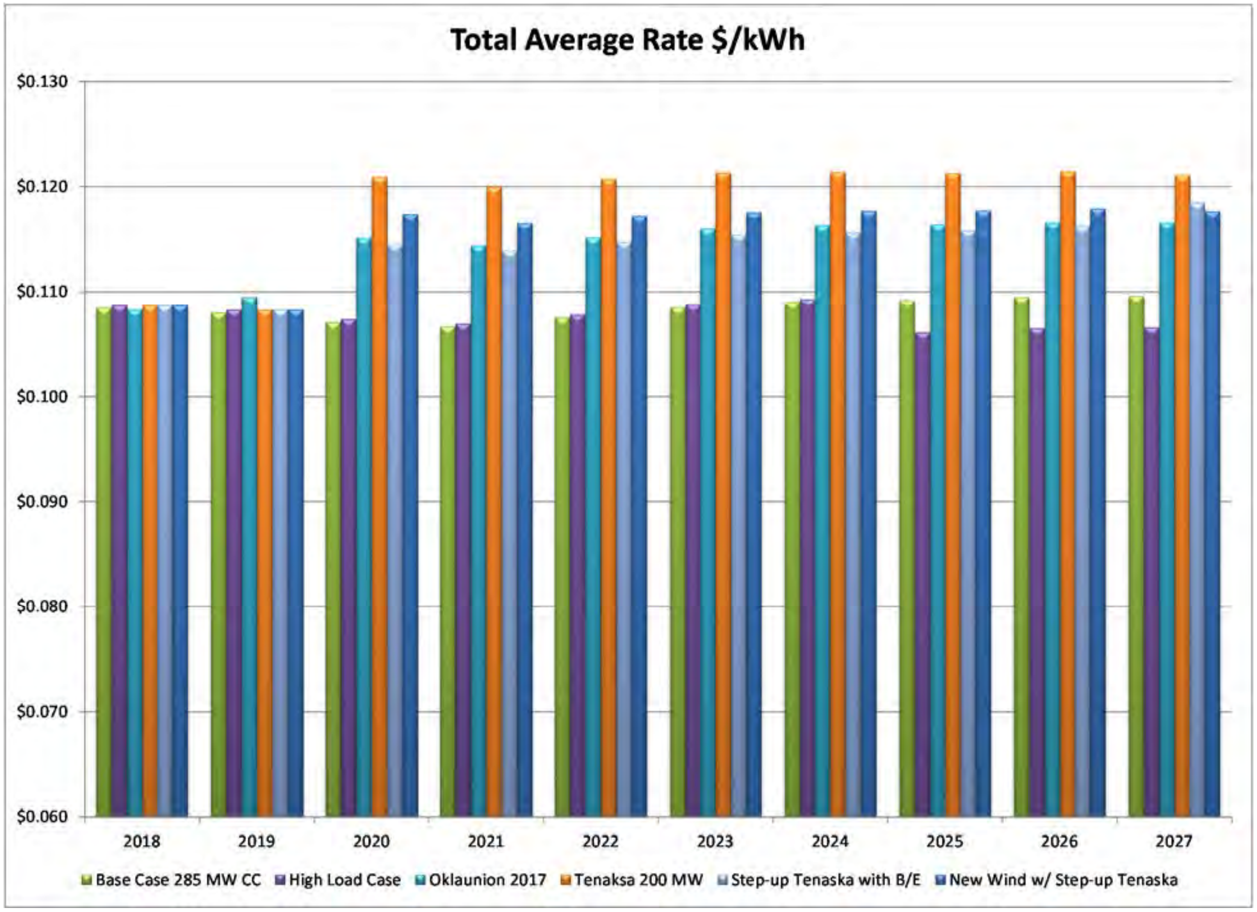


Figure 8-8 Comparison of Average FPEC Rate

On a total rate basis, the Base Case and High Load scenarios are the lowest, but carry much lower debt service coverage and less annual surplus revenues. Scenarios 5 and 6, the Step-up Tenaska scenarios have the lowest total costs of the PPA scenarios and carry much better debt service coverage and produce larger annual surpluses that could be used to reduce the overall rate impact to customers.

Table 8-1 Financial Forecast – Base Case (2 pages)

Ln	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Retail Sales at Meter (MWh)	1,340,289	1,364,005	1,388,018	1,447,284	1,471,914	1,496,912	1,522,310	1,548,123	1,574,378	1,601,124
2	Net Energy for Load (MWh)	1,565,890	1,593,510	1,621,400	1,691,195	1,719,760	1,748,820	1,778,310	1,808,280	1,838,830	1,869,900
	REVENUES: ($1,000)										
3	Retail Base Rate Revenues	$83,435	$84,912	$86,407	$90,096	$91,629	$93,185	$94,766	$96,373	$98,008	$99,673
4	Recovery Revenue Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Recovery Revenue Fuel	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	FPEC Revenue	$61,968	$62,431	$56,201	$57,999	$60,293	$62,752	$64,568	$65,898	$67,512	$68,811
7	**Gross Operating Revenues**	**$145,403**	**$147,342**	**$142,607**	**$148,094**	**$151,922**	**$155,938**	**$159,335**	**$162,271**	**$165,520**	**$168,483**
8	Off-system Sales Revenues	$4,993	$4,731	$31,627	$31,727	$27,891	$25,521	$23,750	$23,221	$22,084	$20,783
9	**Total Sales Revenues**	**$150,397**	**$152,073**	**$174,234**	**$179,822**	**$179,813**	**$181,458**	**$183,085**	**$185,492**	**$187,604**	**$189,266**
10	Other Revenues	$8,312	$8,395	$8,479	$8,564	$8,649	$8,736	$8,823	$8,911	$9,001	$9,091
11	Interest from Investments	$494	$509	$525	$540	$556	$573	$590	$608	$626	$645
12	Other Non-operating revenues	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290
13	**Gross Revenues Under Existing Rates**	**$160,493**	**$162,267**	**$184,527**	**$190,216**	**$190,309**	**$192,057**	**$193,789**	**$196,301**	**$198,521**	**$200,292**
14	Base Rate Increases	0.0%	0.0%	7.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	Additional Base Rate Revenue	$0	$0	$6,049	$6,307	$6,414	$6,523	$6,634	$6,746	$6,861	$6,977
16	**Total Revenue**	**$160,493**	**$162,267**	**$190,576**	**$196,523**	**$196,723**	**$198,580**	**$200,422**	**$203,048**	**$205,381**	**$207,269**

Table 8-1 Financial Forecast – Base Case (Continued)

Ln	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	EXPENSES: ($1,000)										
	Fuel and Purchased Power Expense										
17	Retail Fuel and PP Recovered through FPEC	$61,968	$62,431	$56,201	$57,999	$60,293	$62,752	$64,568	$65,898	$67,512	$68,811
18	Off-system Sales Fuel Expense	$3,246	$3,075	$20,557	$20,623	$18,129	$16,588	$15,438	$15,094	$14,354	$13,509
19	Total Fuel and Purch Power Expense	$65,214	$65,506	$76,758	$78,621	$78,422	$79,341	$80,006	$80,991	$81,867	$82,319
20	**Adjusted Gross Revenues**	**$95,279**	**$96,762**	**$113,818**	**$117,901**	**$118,301**	**$119,240**	**$120,416**	**$122,056**	**$123,514**	**$124,950**
	Operation and Maintenance Expense										
21	Total O&M Expense	$47,038	$47,979	$48,939	$49,917	$50,916	$51,934	$52,973	$54,032	$55,113	$56,215
22	Incremental Production O&M Proposed Plan	$359	($340)	($298)	($157)	($537)	($739)	($937)	($969)	($1,035)	($1,114)
23	Other Non-Operating Expense	$927	$936	$946	$955	$965	$974	$984	$994	$1,004	$1,014
24	**Balance Available for Debt Service**	**$46,955**	**$48,187**	**$64,232**	**$67,185**	**$66,957**	**$67,071**	**$67,397**	**$68,000**	**$68,432**	**$68,835**
25	Existing Debt Service	$17,226	$17,065	$17,615	$17,573	$17,535	$17,489	$17,444	$17,405	$17,363	$17,384
26	Expansion Plan Capital	$0	$0	$25,128	$25,128	$25,128	$25,128	$25,128	$25,128	$25,128	$25,128
27	Commercial Paper Interest Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Available After Debt Service**	**$29,729**	**$31,122**	**$21,489**	**$24,484**	**$24,294**	**$24,454**	**$24,826**	**$25,467**	**$25,942**	**$26,323**
29	COB Cash Transfer	$5,261	$5,313	$5,367	$5,420	$5,474	$5,529	$5,584	$5,640	$5,697	$5,754
30	COB Usage	$4,226	$4,308	$4,391	$4,475	$4,562	$4,649	$4,739	$4,830	$4,923	$5,018
31	Total Cash/Utility Benefit COB	$9,487	$9,621	$9,757	$9,896	$10,036	$10,179	$10,323	$10,470	$10,620	$10,772
32	**Balance Available to Surplus for Transfers Out**	**$24,468**	**$25,809**	**$16,122**	**$19,064**	**$18,820**	**$18,925**	**$19,241**	**$19,826**	**$20,245**	**$20,569**
33	Operating Subaccount-Fuel Adjustment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34	Improvement Fund- CIP Funding	$9,000	$9,000	$9,000	$7,775	$9,270	$9,550	$9,840	$10,140	$10,440	$10,750
35	Improvement Fund Subaccount - COB USACE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Tenaska Power Plant Equity Funding	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Balance Available to BPUB:										
37	Improvement Fund - Surplus Revenues	$15,468	$16,809	$7,122	$11,289	$9,550	$9,375	$9,401	$9,686	$9,805	$9,819
38	**Debt Service Coverage Ratio**	**2.73**	**2.82**	**1.50**	**1.57**	**1.57**	**1.57**	**1.58**	**1.60**	**1.61**	**1.62**

Table 8-2 Financial Forecast – High Load Case (2 pages)

Ln	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Retail Sales at Meter (MWh)	1,340,289	1,364,005	1,388,018	1,447,284	1,471,914	1,496,912	1,522,310	2,003,345	2,032,591	2,062,752
2	Net Energy for Load (MWh)	1,566,000	1,594,020	1,620,990	1,690,980	1,720,010	1,749,000	1,777,970	2,340,000	2,374,010	2,409,020
	REVENUES: ($1,000)										
3	Retail Base Rate Revenues	$83,435	$84,912	$86,407	$90,096	$91,629	$93,185	$94,766	$124,712	$126,532	$128,410
4	Recovery Revenue Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Recovery Revenue Fuel	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	FPEC Revenue	$62,291	$62,807	$56,606	$58,404	$60,698	$63,158	$64,966	$79,167	$81,100	$82,507
7	**Gross Operating Revenues**	**$145,726**	**$147,719**	**$143,013**	**$148,500**	**$152,328**	**$156,343**	**$159,732**	**$203,878**	**$207,632**	**$210,917**
8	Off-system Sales Revenues	$4,817	$4,347	$31,627	$31,727	$27,891	$25,521	$23,711	$12,877	$11,833	$10,818
9	**Total Sales Revenues**	**$150,543**	**$152,066**	**$174,639**	**$180,227**	**$180,218**	**$181,864**	**$183,443**	**$216,755**	**$219,465**	**$221,735**
10	Other Revenues	$8,312	$8,395	$8,479	$8,564	$8,649	$8,736	$8,823	$8,911	$9,001	$9,091
11	Interest from Investments	$494	$509	$525	$540	$556	$573	$590	$608	$626	$645
12	Other Non-operating revenues	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290
13	**Gross Revenues Under Existing Rates**	**$160,640**	**$162,260**	**$184,933**	**$190,621**	**$190,714**	**$192,463**	**$194,147**	**$227,565**	**$230,382**	**$232,761**
14	Base Rate Increases	0.0%	0.0%	7.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	Additional Base Rate Revenue	$0	$0	$6,049	$6,307	$6,414	$6,523	$6,634	$8,730	$8,857	$8,989
16	**Total Revenue**	**$160,640**	**$162,260**	**$190,981**	**$196,928**	**$197,128**	**$198,986**	**$200,781**	**$236,294**	**$239,240**	**$241,750**

Table 8-2 Financial Forecast – High Load Case (Continued)

Ln	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	EXPENSES: ($1,000)										
	Fuel and Purchased Power Expense										
17	Retail Fuel and PP Recovered through FPEC	$62,291	$62,807	$56,606	$58,404	$60,698	$63,158	$64,966	$79,167	$81,100	$82,507
18	Off-system Sales Fuel Expense	$3,131	$2,826	$20,557	$20,623	$18,129	$16,588	$15,412	$8,370	$7,692	$7,032
19	Total Fuel and Purch Power Expense	$65,422	$65,633	$77,164	$79,027	$78,827	$79,746	$80,378	$87,537	$88,791	$89,539
20	**Adjusted Gross Revenues**	**$95,218**	**$96,627**	**$113,818**	**$117,901**	**$118,301**	**$119,240**	**$120,403**	**$148,758**	**$150,448**	**$152,211**
	Operation and Maintenance Expense										
21	Total O&M Expense	$47,038	$47,979	$48,939	$49,917	$50,916	$51,934	$52,973	$54,032	$55,113	$56,215
22	Incremental Production O&M Proposed Plan	$359	($343)	($219)	($77)	($458)	($660)	($864)	($887)	($954)	($1,035)
23	Other Non-Operating Expense	$927	$936	$946	$955	$965	$974	$984	$994	$1,004	$1,014
24	**Balance Available for Debt Service**	**$46,893**	**$48,055**	**$64,152**	**$67,106**	**$66,878**	**$66,992**	**$67,310**	**$94,619**	**$95,285**	**$96,017**
25	Existing Debt Service	$17,226	$17,065	$17,615	$17,573	$17,535	$17,489	$17,444	$17,405	$17,363	$17,384
26	Expansion Plan Capital	$0	$0	$25,128	$25,128	$25,128	$25,128	$25,128	$25,128	$25,128	$25,128
27	Commercial Paper Interest Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Available After Debt Service**	**$29,667**	**$30,991**	**$21,409**	**$24,405**	**$24,215**	**$24,375**	**$24,738**	**$52,086**	**$52,795**	**$53,505**
29	COB Cash Transfer	$5,261	$5,313	$5,367	$5,420	$5,474	$5,529	$5,584	$5,640	$5,697	$5,754
30	COB Usage	$4,226	$4,308	$4,391	$4,475	$4,562	$4,649	$4,739	$4,830	$4,923	$5,018
31	Total Cash/Utility Benefit COB	$9,487	$9,621	$9,757	$9,896	$10,036	$10,179	$10,323	$10,470	$10,620	$10,772
32	**Balance Available to Surplus for Transfers Out**	**$24,406**	**$25,677**	**$16,043**	**$18,985**	**$18,740**	**$18,846**	**$19,154**	**$46,446**	**$47,098**	**$47,751**
33	Operating Subaccount-Fuel Adjustment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34	Improvement Fund- CIP Funding	$9,000	$9,000	$9,000	$7,775	$9,270	$9,550	$9,840	$10,140	$10,440	$10,750
35	Improvement Fund Subaccount - COB USACE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Tenaska Power Plant Equity Funding	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Balance Available to BPUB:										
37	Improvement Fund - Surplus Revenues	$15,406	$16,677	$7,043	$11,210	$9,470	$9,296	$9,314	$36,306	$36,658	$37,001
38	**Debt Service Coverage Ratio**	**2.72**	**2.82**	**1.50**	**1.57**	**1.57**	**1.57**	**1.58**	**2.22**	**2.24**	**2.26**

Table 8-3 Financial Forecast – Oklaunion 2017 Retirement Case (2 pages)

Ln	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Retail Sales at Meter (MWh)	1,340,289	1,364,005	1,388,018	1,447,284	1,471,914	1,496,912	1,522,310	1,548,123	1,574,378	1,601,124
2	Net Energy for Load (MWh)	1,565,890	1,593,510	1,621,400	1,691,195	1,719,760	1,748,820	1,778,310	1,808,280	1,838,830	1,869,900
	REVENUES: ($1,000)										
3	Retail Base Rate Revenues	$83,435	$84,912	$86,407	$90,096	$91,629	$93,185	$94,766	$96,373	$98,008	$99,673
4	Recovery Revenue Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Recovery Revenue Fuel	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	FPEC Revenue	$61,755	$64,472	$67,406	$69,204	$71,498	$73,958	$75,774	$77,103	$78,718	$80,016
7	**Gross Operating Revenues**	**$145,190**	**$149,384**	**$153,813**	**$159,300**	**$163,128**	**$167,143**	**$170,540**	**$173,476**	**$176,726**	**$179,689**
8	Off-system Sales Revenues	$1,594	$1,289	$31,627	$31,727	$27,891	$25,521	$23,750	$23,221	$22,084	$20,783
9	**Total Sales Revenues**	**$146,784**	**$150,673**	**$185,439**	**$191,027**	**$191,018**	**$192,664**	**$194,291**	**$196,697**	**$198,809**	**$200,471**
10	Other Revenues	$8,312	$8,395	$8,479	$8,564	$8,649	$8,736	$8,823	$8,911	$9,001	$9,091
11	Interest from Investments	$494	$509	$525	$540	$556	$573	$590	$608	$626	$645
12	Other Non-operating revenues	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290
13	**Gross Revenues Under Existing Rates**	**$156,880**	**$160,867**	**$195,733**	**$201,421**	**$201,514**	**$203,263**	**$204,994**	**$207,507**	**$209,726**	**$211,497**
14	Base Rate Increases	0.0%	0.0%	7.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	Additional Base Rate Revenue	$0	$0	$6,049	$6,307	$6,414	$6,523	$6,634	$6,746	$6,861	$6,977
16	**Total Revenue**	**$156,880**	**$160,867**	**$201,781**	**$207,728**	**$207,928**	**$209,786**	**$211,628**	**$214,253**	**$216,587**	**$218,474**

Table 8-3 Financial Forecast – Oklaunion 2017 Retirement Case (Continued)

Ln	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	EXPENSES: ($1,000)										
	Fuel and Purchased Power Expense										
17	Retail Fuel and PP Recovered through FPEC	$61,755	$64,472	$67,406	$69,204	$71,498	$73,958	$75,774	$77,103	$78,718	$80,016
18	Off-system Sales Fuel Expense	$1,036	$838	$20,557	$20,623	$18,129	$16,588	$15,438	$15,094	$14,354	$13,509
19	Total Fuel and Purch Power Expense	$62,791	$65,310	$87,964	$89,827	$89,627	$90,546	$91,212	$92,197	$93,072	$93,525
20	**Adjusted Gross Revenues**	**$94,090**	**$95,557**	**$113,818**	**$117,901**	**$118,301**	**$119,240**	**$120,416**	**$122,056**	**$123,514**	**$124,950**
	Operation and Maintenance Expense										
21	Total O&M Expense	$47,038	$47,979	$48,939	$49,917	$50,916	$51,934	$52,973	$54,032	$55,113	$56,215
22	Incremental Production O&M Proposed Plan	($4,974)	($5,349)	($219)	($77)	($458)	($660)	($858)	($890)	($955)	($1,035)
23	Other Non-Operating Expense	$927	$936	$946	$955	$965	$974	$984	$994	$1,004	$1,014
24	**Balance Available for Debt Service**	**$51,098**	**$51,990**	**$64,152**	**$67,106**	**$66,878**	**$66,992**	**$67,318**	**$67,920**	**$68,353**	**$68,755**
25	Existing Debt Service	$17,226	$17,065	$17,615	$17,573	$17,535	$17,489	$17,444	$17,405	$17,363	$17,384
26	Expansion Plan Capital	$0	$0	$25,128	$25,128	$25,128	$25,128	$25,128	$25,128	$25,128	$25,128
27	Commercial Paper Interest Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Available After Debt Service**	**$33,872**	**$34,926**	**$21,409**	**$24,405**	**$24,215**	**$24,375**	**$24,746**	**$25,387**	**$25,862**	**$26,243**
29	COB Cash Transfer	$5,261	$5,313	$5,367	$5,420	$5,474	$5,529	$5,584	$5,640	$5,697	$5,754
30	COB Usage	$4,226	$4,308	$4,391	$4,475	$4,562	$4,649	$4,739	$4,830	$4,923	$5,018
31	Total Cash/Utility Benefit COB	$9,487	$9,621	$9,757	$9,896	$10,036	$10,179	$10,323	$10,470	$10,620	$10,772
32	**Balance Available to Surplus for Transfers Out**	**$28,611**	**$29,612**	**$16,043**	**$18,985**	**$18,740**	**$18,846**	**$19,162**	**$19,747**	**$20,166**	**$20,490**
33	Operating Subaccount-Fuel Adjustment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34	Improvement Fund- CIP Funding	$9,000	$9,000	$9,000	$7,775	$9,270	$9,550	$9,840	$10,140	$10,440	$10,750
35	Improvement Fund Subaccount - COB USACE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Tenaska Power Plant Equity Funding	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Balance Available to BPUB:										
37	Improvement Fund - Surplus Revenues	$19,611	$20,612	$7,043	$11,210	$9,470	$9,296	$9,322	$9,607	$9,726	$9,740
38	**Debt Service Coverage Ratio**	**2.97**	**3.05**	**1.50**	**1.57**	**1.57**	**1.57**	**1.58**	**1.60**	**1.61**	**1.62**

Table 8-4 Financial Forecast – 200 MW Tenaska PPA (2 pages)

Ln	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Retail Sales at Meter (MWh)	1,340,289	1,364,005	1,388,018	1,447,284	1,471,914	1,496,912	1,522,310	1,548,123	1,574,378	1,601,124
2	Net Energy for Load (MWh)	1,565,890	1,593,510	1,621,400	1,691,195	1,719,760	1,748,820	1,778,310	1,808,280	1,838,830	1,869,900
	REVENUES: ($1,000)										
3	Retail Base Rate Revenues	$83,435	$84,912	$86,407	$90,096	$91,629	$93,185	$94,766	$96,373	$98,008	$99,673
4	Recovery Revenue Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Recovery Revenue Fuel	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	FPEC Revenue	$62,291	$62,807	$81,485	$83,585	$86,122	$88,478	$90,032	$91,392	$93,236	$94,230
7	**Gross Operating Revenues**	**$145,726**	**$147,719**	**$167,892**	**$173,681**	**$177,751**	**$181,664**	**$184,799**	**$187,765**	**$191,244**	**$193,903**
8	Off-system Sales Revenues	$4,817	$4,347	$16,141	$16,256	$13,201	$11,999	$11,117	$9,773	$9,059	$8,048
9	**Total Sales Revenues**	**$150,543**	**$152,066**	**$184,033**	**$189,937**	**$190,953**	**$193,663**	**$195,916**	**$197,539**	**$200,303**	**$201,951**
10	Other Revenues	$8,312	$8,395	$8,479	$8,564	$8,649	$8,736	$8,823	$8,911	$9,001	$9,091
11	Interest from Investments	$494	$509	$525	$540	$556	$573	$590	$608	$626	$645
12	Other Non-operating revenues	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290
13	**Gross Revenues Under Existing Rates**	**$160,640**	**$162,260**	**$194,326**	**$200,331**	**$201,448**	**$204,262**	**$206,620**	**$208,348**	**$211,220**	**$212,977**
14	Base Rate Increases	0.0%	0.0%	0.0%	0.0%	0 0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	Additional Base Rate Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	**Total Revenue**	**$160,640**	**$162,260**	**$194,326**	**$200,331**	**$201,448**	**$204,262**	**$206,620**	**$208,348**	**$211,220**	**$212,977**

Table 8-4 Financial Forecast – 200 MW Tenaska PPA (Continued)

Ln	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	EXPENSES: ($1,000)										
	Fuel and Purchased Power Expense										
17	Retail Fuel and PP Recovered through FPEC	$62,291	$62,807	$81,485	$83,585	$86,122	$88,478	$90,032	$91,392	$93,236	$94,230
18	Off-system Sales Fuel Expense	$3,131	$2,826	$10,492	$10,566	$8,581	$7,800	$7,226	$6,353	$5,889	$5,231
19	Total Fuel and Purch Power Expense	$65,422	$65,633	$91,977	$94,151	$94,703	$96,278	$97,259	$97,745	$99,124	$99,461
20	**Adjusted Gross Revenues**	**$95,218**	**$96,627**	**$102,349**	**$106,180**	**$106,746**	**$107,984**	**$109,361**	**$110,604**	**$112,095**	**$113,515**
	Operation and Maintenance Expense										
21	Total O&M Expense	$47,038	$47,979	$48,939	$49,917	$50,916	$51,934	$52,973	$54,032	$55,113	$56,215
22	Incremental Production O&M Proposed Plan	$359	($343)	($289)	($53)	($554)	($824)	($1,070)	($1,181)	($1,240)	($1,362)
23	Other Non-Operating Expense	$927	$936	$946	$955	$965	$974	$984	$994	$1,004	$1,014
24	**Balance Available for Debt Service**	**$46,893**	**$48,055**	**$52,755**	**$55,360**	**$55,419**	**$55,899**	**$56,474**	**$56,759**	**$57,219**	**$57,648**
25	Existing Debt Service	$17,226	$17,065	$17,615	$17,573	$17,535	$17,489	$17,444	$17,405	$17,363	$17,384
26	Expansion Plan Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	Commercial Paper Interest Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Available After Debt Service**	**$29,667**	**$30,991**	**$35,139**	**$37,787**	**$37,884**	**$38,411**	**$39,030**	**$39,354**	**$39,856**	**$40,264**
29	COB Cash Transfer	$5,261	$5,313	$5,367	$5,420	$5,474	$5,529	$5,584	$5,640	$5,697	$5,754
30	COB Usage	$4,226	$4,308	$4,391	$4,475	$4,562	$4,649	$4,739	$4,830	$4,923	$5,018
31	Total Cash/Utility Benefit COB	$9,487	$9,621	$9,757	$9,896	$10,036	$10,179	$10,323	$10,470	$10,620	$10,772
32	**Balance Available to Surplus for Transfers Out**	**$24,406**	**$25,677**	**$29,773**	**$32,367**	**$32,410**	**$32,881**	**$33,446**	**$33,713**	**$34,160**	**$34,511**
33	Operating Subaccount-Fuel Adjustment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34	Improvement Fund- CIP Funding	$9,000	$9,000	$9,000	$7,775	$9,270	$9,550	$9,840	$10,140	$10,440	$10,750
35	Improvement Fund Subaccount - COB USACE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Tenaska Power Plant Equity Funding	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Balance Available to BPUB:										
37	Improvement Fund - Surplus Revenues	$15,406	$16,677	$20,773	$24,592	$23,140	$23,331	$23,606	$23,573	$23,720	$23,761
38	**Debt Service Coverage Ratio**	**2.72**	**2.82**	**2.99**	**3.15**	**3.16**	**3.20**	**3.24**	**3.26**	**3.30**	**3.32**

Table 8-5 Financial Forecast – Step-up Tenaska with B/E (2 pages)

Ln	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Retail Sales at Meter (MWh)	1,340,289	1,364,005	1,388,018	1,447,284	1,471,914	1,496,912	1,522,310	1,548,123	1,574,378	1,601,124
2	Net Energy for Load (MWh)	1,565,890	1,593,510	1,621,400	1,691,195	1,719,760	1,748,820	1,778,310	1,808,280	1,838,830	1,869,900
	REVENUES: ($1,000)										
3	Retail Base Rate Revenues	$83,435	$84,912	$86,407	$90,096	$91,629	$93,185	$94,766	$96,373	$98,008	$99,673
4	Recovery Revenue Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Recovery Revenue Fuel	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	FPEC Revenue	$62,291	$62,807	$72,523	$74,813	$77,292	$79,609	$81,290	$82,990	$85,015	$90,018
7	**Gross Operating Revenues**	**$145,726**	**$147,719**	**$158,930**	**$164,909**	**$168,922**	**$172,794**	**$176,057**	**$179,364**	**$183,023**	**$189,691**
8	Off-system Sales Revenues	$4,817	$4,347	$4,366	$3,780	$3,030	$2,544	$2,248	$1,444	$1,138	$1,605
9	**Total Sales Revenues**	**$150,543**	**$152,066**	**$163,296**	**$168,689**	**$171,952**	**$175,338**	**$178,305**	**$180,808**	**$184,161**	**$191,296**
10	Other Revenues	$8,312	$8,395	$8,479	$8,564	$8,649	$8,736	$8,823	$8,911	$9,001	$9,091
11	Interest from Investments	$494	$509	$525	$540	$556	$573	$590	$608	$626	$645
12	Other Non-operating revenues	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290
13	**Gross Revenues Under Existing Rates**	**$160,640**	**$162,260**	**$173,590**	**$179,083**	**$182,448**	**$185,937**	**$189,009**	**$191,617**	**$195,078**	**$202,322**
14	Base Rate Increases	0.0%	0.0%	0.0%	0.0%	0 0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	Additional Base Rate Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	**Total Revenue**	**$160,640**	**$162,260**	**$173,590**	**$179,083**	**$182,448**	**$185,937**	**$189,009**	**$191,617**	**$195,078**	**$202,322**

Table 8-5 Financial Forecast – Step-up Tenaska with B/E (Continued)

Ln	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	EXPENSES: ($1,000)										
	Fuel and Purchased Power Expense										
17	Retail Fuel and PP Recovered through FPEC	$62,291	$62,807	$72,523	$74,813	$77,292	$79,609	$81,290	$82,990	$85,015	$90,018
18	Off-system Sales Fuel Expense	$3,131	$2,826	$2,838	$2,457	$1,970	$1,654	$1,462	$939	$740	$1,043
19	Total Fuel and Purch Power Expense	$65,422	$65,633	$75,361	$77,270	$79,262	$81,262	$82,752	$83,929	$85,755	$91,061
20	**Adjusted Gross Revenues**	**$95,218**	**$96,627**	**$98,228**	**$101,813**	**$103,186**	**$104,675**	**$106,257**	**$107,688**	**$109,323**	**$111,260**
	Operation and Maintenance Expense										
21	Total O&M Expense	$47,038	$47,979	$48,939	$49,917	$50,916	$51,934	$52,973	$54,032	$55,113	$56,215
22	Incremental Production O&M Proposed Plan	$359	($343)	($3,276)	($3,108)	($3,509)	($3,762)	($3,968)	($4,135)	($4,222)	($3,952)
23	Other Non-Operating Expense	$927	$936	$946	$955	$965	$974	$984	$994	$1,004	$1,014
24	**Balance Available for Debt Service**	**$46,893**	**$48,055**	**$51,620**	**$54,049**	**$54,814**	**$55,528**	**$56,269**	**$56,797**	**$57,429**	**$57,983**
25	Existing Debt Service	$17,226	$17,065	$17,615	$17,573	$17,535	$17,489	$17,444	$17,405	$17,363	$17,384
26	Expansion Plan Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	Commercial Paper Interest Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Available After Debt Service**	**$29,667**	**$30,991**	**$34,005**	**$36,475**	**$37,279**	**$38,039**	**$38,825**	**$39,392**	**$40,066**	**$40,599**
29	COB Cash Transfer	$5,261	$5,313	$5,367	$5,420	$5,474	$5,529	$5,584	$5,640	$5,697	$5,754
30	COB Usage	$4,226	$4,308	$4,391	$4,475	$4,562	$4,649	$4,739	$4,830	$4,923	$5,018
31	Total Cash/Utility Benefit COB	$9,487	$9,621	$9,757	$9,896	$10,036	$10,179	$10,323	$10,470	$10,620	$10,772
32	**Balance Available to Surplus for Transfers Out**	**$24,406**	**$25,677**	**$28,639**	**$31,055**	**$31,804**	**$32,510**	**$33,240**	**$33,752**	**$34,369**	**$34,846**
33	Operating Subaccount-Fuel Adjustment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34	Improvement Fund- CIP Funding	$9,000	$9,000	$9,000	$7,775	$9,270	$9,550	$9,840	$10,140	$10,440	$10,750
35	Improvement Fund Subaccount - COB USACE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Tenaska Power Plant Equity Funding	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Balance Available to BPUB:										
37	Improvement Fund - Surplus Revenues	$15,406	$16,677	$19,639	$23,280	$22,534	$22,960	$23,400	$23,612	$23,929	$24,096
38	**Debt Service Coverage Ratio**	**2.72**	**2.82**	**2.93**	**3.08**	**3.13**	**3.18**	**3.23**	**3.26**	**3.31**	**3.34**

Table 8-6 Financial Forecast – New Wind w/ Step-up Tenaska (2 pages)

Ln	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Retail Sales at Meter (MWh)	1,340,289	1,364,005	1,388,018	1,447,284	1,471,914	1,496,912	1,522,310	1,548,123	1,574,378	1,601,124
2	Net Energy for Load (MWh)	1,565,890	1,593,510	1,621,400	1,691,195	1,719,760	1,748,820	1,778,310	1,808,280	1,838,830	1,869,900
	REVENUES: ($1,000)										
3	Retail Base Rate Revenues	$83,435	$84,912	$86,407	$90,096	$91,629	$93,185	$94,766	$96,373	$98,008	$99,673
4	Recovery Revenue Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Recovery Revenue Fuel	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	FPEC Revenue	$62,291	$62,807	$76,543	$78,593	$80,935	$82,784	$84,422	$85,878	$87,657	$88,731
7	**Gross Operating Revenues**	**$145,726**	**$147,719**	**$162,949**	**$168,689**	**$172,565**	**$175,969**	**$179,188**	**$182,251**	**$185,665**	**$188,404**
8	Off-system Sales Revenues	$4,817	$4,347	$7,254	$7,054	$5,097	$4,541	$3,885	$3,044	$2,335	$2,233
9	**Total Sales Revenues**	**$150,543**	**$152,066**	**$170,203**	**$175,743**	**$177,662**	**$180,510**	**$183,073**	**$185,295**	**$188,000**	**$190,637**
10	Other Revenues	$8,312	$8,395	$8,479	$8,564	$8,649	$8,736	$8,823	$8,911	$9,001	$9,091
11	Interest from Investments	$494	$509	$525	$540	$556	$573	$590	$608	$626	$645
12	Other Non-operating revenues	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290
13	**Gross Revenues Under Existing Rates**	**$160,640**	**$162,260**	**$180,496**	**$186,137**	**$188,158**	**$191,109**	**$193,776**	**$196,105**	**$198,917**	**$201,662**
14	Base Rate Increases	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	Additional Base Rate Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	**Total Revenue**	**$160,640**	**$162,260**	**$180,496**	**$186,137**	**$188,158**	**$191,109**	**$193,776**	**$196,105**	**$198,917**	**$201,662**

Table 8-6 Financial Forecast – New Wind w/ Step-up Tenaska (Continued)

Ln	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	EXPENSES: ($1,000)										
	Fuel and Purchased Power Expense										
17	Retail Fuel and PP Recovered through FPEC	$62,291	$62,807	$76,543	$78,593	$80,935	$82,784	$84,422	$85,878	$87,657	$88,731
18	Off-system Sales Fuel Expense	$3,131	$2,826	$4,715	$4,585	$3,313	$2,952	$2,525	$1,978	$1,518	$1,451
19	Total Fuel and Purch Power Expense	$65,422	$65,633	$81,257	$83,179	$84,249	$85,736	$86,947	$87,856	$89,175	$90,182
20	**Adjusted Gross Revenues**	**$95,218**	**$96,627**	**$99,239**	**$102,959**	**$103,909**	**$105,374**	**$106,830**	**$108,248**	**$109,742**	**$111,480**
	Operation and Maintenance Expense										
21	Total O&M Expense	$47,038	$47,979	$48,939	$49,917	$50,916	$51,934	$52,973	$54,032	$55,113	$56,215
22	Incremental Production O&M Proposed Plan	$359	($343)	($3,290)	($3,040)	($3,543)	($3,810)	($4,030)	($4,158)	($4,263)	($4,324)
23	Other Non-Operating Expense	$927	$936	$946	$955	$965	$974	$984	$994	$1,004	$1,014
24	**Balance Available for Debt Service**	**$46,893**	**$48,055**	**$52,645**	**$55,126**	**$55,571**	**$56,276**	**$56,903**	**$57,380**	**$57,888**	**$58,575**
25	Existing Debt Service	$17,226	$17,065	$17,615	$17,573	$17,535	$17,489	$17,444	$17,405	$17,363	$17,384
26	Expansion Plan Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	Commercial Paper Interest Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Available After Debt Service**	**$29,667**	**$30,991**	**$35,030**	**$37,553**	**$38,036**	**$38,787**	**$39,459**	**$39,975**	**$40,525**	**$41,191**
29	COB Cash Transfer	$5,261	$5,313	$5,367	$5,420	$5,474	$5,529	$5,584	$5,640	$5,697	$5,754
30	COB Usage	$4,226	$4,308	$4,391	$4,475	$4,562	$4,649	$4,739	$4,830	$4,923	$5,018
31	Total Cash/Utility Benefit COB	$9,487	$9,621	$9,757	$9,896	$10,036	$10,179	$10,323	$10,470	$10,620	$10,772
32	**Balance Available to Surplus for Transfers Out**	**$24,406**	**$25,677**	**$29,663**	**$32,133**	**$32,562**	**$33,258**	**$33,875**	**$34,335**	**$34,829**	**$35,437**
33	Operating Subaccount-Fuel Adjustment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34	Improvement Fund- CIP Funding	$9,000	$9,000	$9,000	$7,775	$9,270	$9,550	$9,840	$10,140	$10,440	$10,750
35	Improvement Fund Subaccount - COB USACE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Tenaska Power Plant Equity Funding	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Balance Available to BPUB:										
37	Improvement Fund - Surplus Revenues	$15,406	$16,677	$20,663	$24,358	$23,292	$23,708	$24,035	$24,195	$24,389	$24,687
38	**Debt Service Coverage Ratio**	**2.72**	**2.82**	**2.99**	**3.14**	**3.17**	**3.22**	**3.26**	**3.30**	**3.33**	**3.37**

9.0 Conclusions and Recommendations

This section presents the conclusions and recommendations flowing from the previous sections in this IRP study.

9.1 STUDY CONCLUSIONS

This study evaluated the following expansion plans to determine the CPWC of serving BPUB load during the 2017-2036 period under the adopted project assumptions:

1. **Base Case**: Consisting of the best BPUB self-build expansion plan with natural gas-fired simple cycle and combined cycle units ranging in size from 9 MW to 285 MW as candidate units. No new wind PPA or conventional PPA (from Tenaska or the market) was part of the Base Case list of options.
2. **Sensitivity 1**: Consisting of the Base Case assumptions except Oklaunion is assumed to retire in 2017 rather than in 2020.
3. **Sensitivity 2**: Consisting of the Base Case assumptions except a stair-step increase in load of 100 MW is assumed in 2025.
4. **Sensitivity 3**: Consisting of a 200 MW purchase from a possible 800 MW future Tenaska combined cycle option.
5. **Sensitivity 4**: Consisting of an alternative power purchase from Tenaska or another IPP involving an initial purchase amount of 100 MW in 2020 that increases to 132 MW in 2025 to match the BPUB need for power. In this sensitivity case, the capacity price of the purchase is solved for such that the CPWC of the plan is 2 percent lower than the better of the Base Case or Sensitivity 3 (a 2 percent difference in CPWC is usually on the threshold of being considered a significant difference in most planning studies).
6. **Sensitivity 5**: Consisting of an 84 MW wind PPA option (27.7 MW firm), combined with the most economical expansion plan among the Base Case, Sensitivity 3, or Sensitivity 4. Since Sensitivity 4 was the best of these three plans, it was paired with the wind PPA option in this expansion plan.

The expansion plans were simulated over the 2017-2036 planning period using PROMOD™, which is a chronological production costing model. The resulting CPWC estimates for each plan are comparable as they consist of the present worth cost of serving BPUB's energy requirements over the planning period.

Table 9-1 summarizes the CPWC results and rankings. Of the expansion that are strictly comparable in terms of CPWC (all but Sensitivity 1 and 2), the best BPUB plan involves Sensitivity 5, which consists of the 84 MW (27.7 MW firm) wind PPA in late 2018, followed by the stair-step purchase from an existing combined cycle in 2020 (100 MW) and 2027 (132 MW). Note, however that this expansion plan solved-for capacity price needed to make the case 2 percent lower in cost than the Base Case , but it is believed that this capacity price for existing combined cycle capacity ($144/kW-year or lower) could be reasonably be expected through a competitive solicitation.

Table 9-1 CPWC Comparison and Ranking of Plans

EXPANSION PLAN	CPWC ($ MILLIONS)	% HIGHER THAN BEST PLAN	RANK	COMMENT
Sensitivity 5. Wind PPA (2018) with Stair-Step Purchase from an Existing Combined Cycle	1,031	-	1st	Based on a max. break-even capacity price of $144/kW-year that would make the plan approx. 2% lower than the Base Case
Sensitivity 4. Stair-Step Purchase from an Existing Combined Cycle	1,032	-	2nd	Based on a max. break-even capacity price of $130/kW-year that would make the plan approx. 2% lower than the Base Case
Base Case. BPUB Self-build Case Involving a 285 MW, 1x1 7FA Combined Cycle	1,052	2.0%	3rd	Candidate units include natural gas fired simple and combined cycle options from 9 MW to 1xxxx MW
Sensitivity 3. 200 MW Purchase from Possible 800 MW Tenaska Unit	1,096	6.3%	4th	Considered less likely to be built based on current market conditions. An option involving an existing combined cycle as in Sensitivity 4 and 5 is more likely
Single Variable Sensitivities on the Base Case (CPWC not strictly comparable with other sensitivity cases)				
Sensitivity 2. 2017 Retirement of Oklaunion	$1,045	NA	NA	Short Term Bridge PPA and BPUB Self-build Case Involving a 285 MW, 1x1 Combined Cycle
Sensitivity 1. 100 MW increase in industrial load in 2025	$	NA	NA	This plan involves the selection of a 1x1 285 MW self-build option (the Tenaska 200 MW purchase and the stair-step purchase from an existing combined cycle were not candidate units in this run since this is a sensitivity off of the Base Case)

The second best plan involves the stair-step purchase from an existing combined cycle plant without the wind PPA. This analysis also involved determining the capacity price needed to make the expansion plan 2 percent lower than the Base Case. The resulting capacity price was found to be $130/kW-year for the combined cycle capacity, meaning that if BPUB received offers or otherwise negotiated for combined cycle capacity at no more than $130/kW-year the option would have a significant cost advantage over the Base Case.

The third best plan is the Base Case, which included only BPUB self-build simple cycle and combined cycle options ranging in size from 9 MW to 285 MW. The 200 MW Tenaska purchase option is the fourth-ranked option, but this is 6.3 percent higher in CPWC than the least-cost expansion plan (Sensitivity 5).

The other two sensitivities in Table 9-1are not strictly comparable to the Base Case and other sensitivity cases but are useful in that they indicate the best addition for BPUB under single variable sensitivities from the Base Case. In the event that a 100 MW increase in BPUB load occurs during the planning period (the increase was assumed to occur in 2025), the expansion plan selected a 1x1 285 MW combined cycle as the best self-build option for BPUB (the Tenaska 200 MW purchase and the stair-step existing combined cycle option were not candidate units in this run). In the event that the Oklaunion plant retires in 2017, the best self-build option for BPUB (again, combined cycle PPAs were not part of this run since this sensitivity was based off of the Base Case) would consist of the same expansion plan as the Base Case.

Additional Conclusions from this IRP include the following:

- The addition of multiple 345-kV projects in the Lower Rio Grande Valley (LRGV) region should significantly improve the reliability of the BPUB and other regional power suppliers. In addition to the reliability benefits, it is possible that increased import and export capability into the broader ERCOT market will result from the recently completed 345-kV project in the region. This increased capacity could be realized during the entire planning period although, on the other hand, the addition of significant new loads in the Brownsville area for several LNG export facilities being proposed could quickly account for much of the increased transfer limits. While import and export transmission capabilities of 1,100 MW were assumed in this study, on-going observation of load flow conditions by BPUB will be appropriate.
- BPUB's existing agreements for natural gas supply appear to provide for adequate and reliable natural gas capacity. While reliable natural gas supplies for future projects can pose some risk, it is likely that with advanced planning, sufficient natural gas supplies at competitive costs can be arranged for future projects installed in the Brownsville area.
- The projected load growth for BPUB is approximately 2 percent per year through 2036. This is substantially below the projection in the 2011 IRP study but is reflective of the growth pattern nation-wide over the past several years.

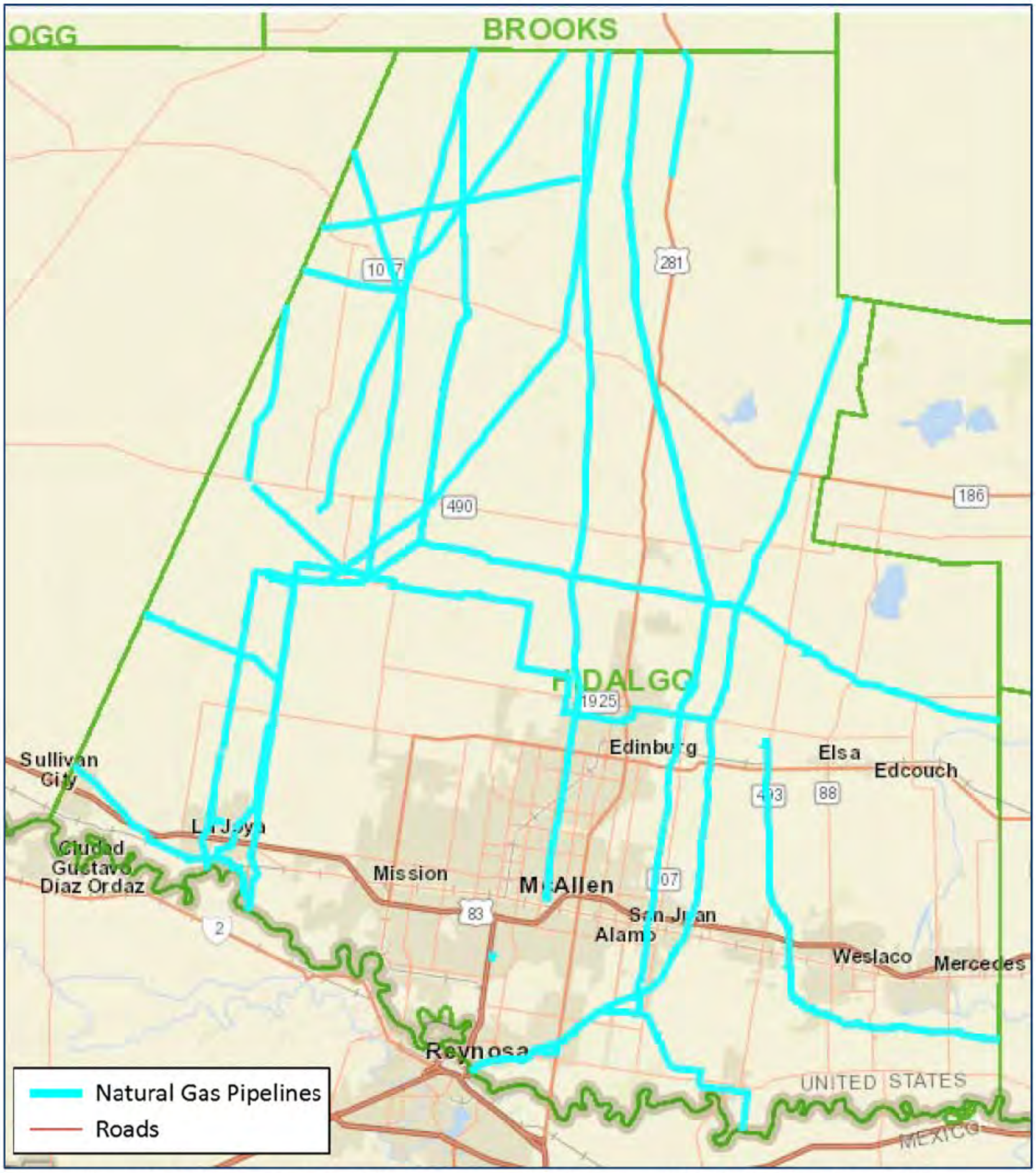
- From a rate impact perspective, it is anticipated that none of the alternatives would require a base rate increase. This is due to the four-year rate plan previously approved and in place provides sufficient revenue for all generation alternatives.
- Depending on the magnitude and timing of the capital costs for future generation additions, BPUB should be able to continue its current practice of using surplus revenues to reduce the FPEC rate charged to customers to below the actual cost of power.

9.2 STUDY RECOMMENDATIONS

Based on the above conclusions, the following recommendations apply:

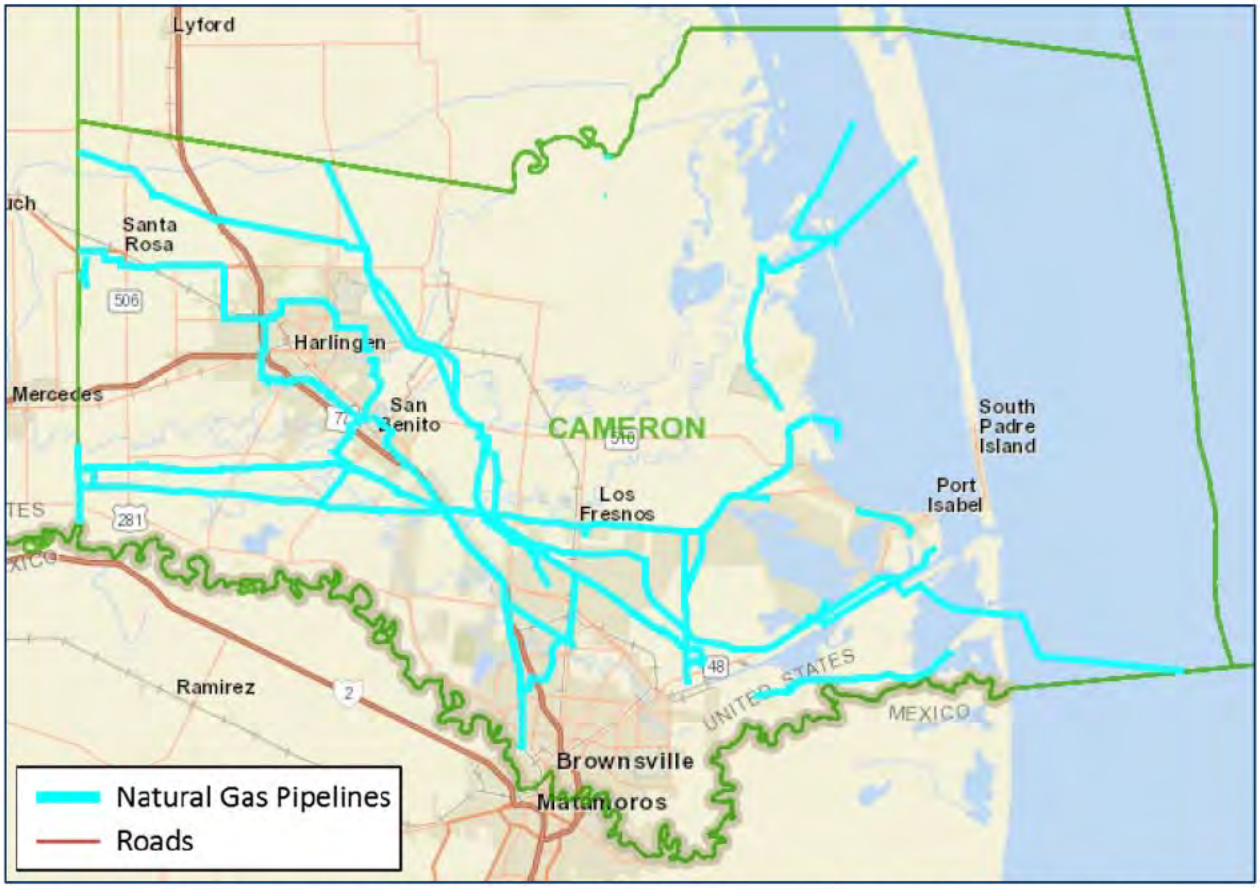
- Given that: a) Sensitivity 5 is the least-cost option, b) Tenaska has indicated that it will provide pricing from an existing combined cycle instead of building a new 800 MW unit, and since c) other utilities and IPPs in the region could also propose competitively priced combined cycle capacity to BPUB through the recently-increased regional transmission network, it is appropriate that the two options making up Sensitivity 5—the wind PPA and the purchase from existing combined cycle capacity—should be the focus of BPUB planning efforts in the near-term. When pursuing these options, the ability of the seller to shape the offer to meet the timing and amount of BPUB's capacity needs will strongly impact the overall cost-effectiveness of the plan. Experience has also shown that competition in the form of a capacity solicitation RFP can be the most effective means of securing low-cost power supplies and so an RFP is recommended.
- On-going monitoring of the available export capacity out of the BPUB service area and into LRGV and other ERCOT areas will be important to allow for the economical exchange of power over the long-term. This can be likely be accomplished by keeping abreast of ERCOT studies although such studies have not always been historically accurate. Directly performing load flow studies is also an option.
- The decision to move to a zero percent reserve margin means that a number of factors, such as an extended unit outage of a BPUB unit or a single large industrial customer requesting service from BPUB could put BPUB in a capacity short situation. It will be prudent for BPUB to have contingency plans for increased power supplies on hand and to continue to monitor market prices and confirm that it remains economical to operate with no planning reserve margin.
- While it should be realistic to expect that BPUB, Tenaska, or another regional project will be able to arrange for natural gas supplies, continued monitoring of developments and progress toward making a final resource selection should occur.

Appendix A. Hidalgo County Pipelines Greater than 12" Diameter



Sources: Texas RRC GIS Viewer, Esri, HERE, DeLorme, USGS, Intermap, INCREMENT P, NRCan, NGCC, OpenStreetMap contributors, and the GIS User Community

Appendix B. Cameron County Pipelines



Sources: Texas RRC GIS Viewer, Esri, HERE, DeLorme, USGS, Intermap, INCREMENT P, NRCan, NGCC, OpenStreetMap contributors, and the GIS User Community

Appendix C. Natural Gas Transmission Pipelines – Hidalgo County & Cameron County

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	HENSHAW SYSTEM	HS-1	12.75	null	5768	In Service	No
DCP HINSHAW PIPELINE, LLC	NATURAL GAS	Gas Transmission	HENSHAW SYSTEM	HS-1-MP	10.75	null	5768	In Service	No
DCP HINSHAW PIPELINE, LLC	NATURAL GAS	Gas Transmission	HENSHAW SYSTEM	HS-1-2	10.75	null	5768	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	FRONTERA GENERATION	FRONTERA GENERATION	8.63	null	774	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	ONYX BATES LATERAL	ONYX BATES LATERAL	8.63	null	774	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	SULLIVAN DELIVERY	SULLIVAN DELIVERY	8.63	null	774	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	MOODY LATERAL	null	6.63	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	UNKNOWN SYSTEM	null	4.5	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	VALLEY INDUSTRIAL LATERAL TO UNION CARB*	null	6.63	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	CELANESE LA BLANCA 14"	null	14	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	NORTH HIDALGO LOOP	null	8.63	null	534	In Service	No
TEXAS EASTERN TRANSMISSION, LP	NATURAL GAS	Gas Transmission	MEXI-STFE	null	6.63	null	4143	In Service	Yes

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	CELANESE LA BLANCA 12"	null	12.75	null	534	In Service	No
SANTERRA MIDSTREAM COMPANY, LLC	NATURAL GAS	Gas Transmission	TEXAS GAS TO ENTERPRISE	300# SUCTION LINE	6.63	null	8469	Abandoned	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	UNKNOWN SYSTEM	null	6.63	null	534	In Service	No
ENERGY TRANSFER COMPANY	NATURAL GAS	Gas Transmission	RAYMONDVILLE SYSTEM	USDA PIPELINE	2.38	null	7158	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	TRANSVALLEY LATERAL	null	14	null	534	Abandoned	No
DCP HINSHAW PIPELINE, LLC	NATURAL GAS	Gas Transmission	HENSHAW SYSTEM	HS-1-EXT-RR	10.75	null	5768	In Service	No
DCP HINSHAW PIPELINE, LLC	NATURAL GAS	Gas Transmission	HENSHAW SYSTEM	HS-1-2	6.63	null	5768	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	STARR 8"	CORAL MEXICO JCT TO MOREFIELD RD	8.63	null	774	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	TEXACO TO HIDALGO GAS PLANT	null	4.5	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	DONNA-TANNER INTERCONNECT	null	6.63	null	534	In Service	No
TEXAS EASTERN TRANSMISSION, LP	NATURAL GAS	Gas Transmission	MEXI-STFE	null	20	null	4143	In Service	Yes
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	VALLEY INDUSTRIAL LATERAL	null	6.63	null	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	SAN SALVADOR TO SAN BENITO 10"	null	10.75	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	NORTH HIDALGO	null	6.63	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	V FAULCONER-SAMANO #1 LATERAL	null	2.38	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	CELANESE REYNOSA TO ALAMO LAND	null	6.63	null	534	Abandoned	No
ENTERPRISE PRODUCTS OPERATINGLLC	NATURAL GAS	Gas Transmission	49A/1	null	2.38	null	3883	Abandoned	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	AMERICAN PETROFINA SLAVIK	null	4.5	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	LAGUNA GAS / POPE #1 DAUGHERTY LATERAL	null	2.38	null	534	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	STARR 8"	MOREFIELD RD TO LA PALMA (INACTIVE)	8.63	null	774	In Service	No
DCP MIDSTREAM, LP	NATURAL GAS	Gas Transmission	LA GLORIA	SOUTH TEXAS GATHERING SYS	8.63	null	5362	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	MONTE CRISTO-MISSION LOOP TO CPL	null	6.63	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	UNKNOWN SYSTEM	null	10.75	null	534	Abandoned	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	BALLENGER LATERAL 4"	null	4.5	null	534	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	CPL BATES	TRANSFERRED FROM ONYX PERMIT 05798	12.75	null	94625	In Service	No
OXY USA INC.	NATURAL GAS	Gas Transmission	MCALLEN PHARR SYSTEM	null	8.63	null	848	In Service	No
TENNESSEE GAS PIPELINE CO,L.L.C.	NATURAL GAS	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	5.56	null	1006	In Service	Yes
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	BROOKS COMPRESSOR STATION TO LONGORIA		24	null	774	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	ARCO DONNA (INACTIVE)	ARCO DONNA	6.63	null	774	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	SEADRIFT 14" & 16"	null	16	null	534	In Service	No
TEXAS EASTERN TRANSMISSION, LP	NATURAL GAS	Gas Transmission	MEXI-STFE	null	30	null	4143	In Service	Yes
TEXAS EASTERN TRANSMISSION, LP	NATURAL GAS	Gas Transmission	MEXI-STFE	null	32	null	4143	In Service	Yes
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	CANO LATERAL	null	6.63	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	TEXACO TO HIDALGO GAS PLANT	null	8.63	null	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	UNKNOWN SYSTEM	null	4.5	null	534	Abandoned	No
CONSOL ASSET MNGT SVCS (TX),LLC	NATURAL GAS	Gas Transmission	LINE NO. 16-A-1	null	4.5	null	5795	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	NORTH HIDALGO	null	5.56	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	UNKNOWN SYSTEM	null	12.75	null	534	Abandoned	No
TEXAS EASTERN TRANSMISSION, LP	NATURAL GAS	Gas Transmission	MEXI-STFE	null	4.5	null	4143	In Service	Yes
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	MERCEDES FIELD #5 (EOG)	null	4.5	null	534	In Service	No
TEXAS EASTERN TRANSMISSION, LP	NATURAL GAS	Gas Transmission	LINE 16-B-1	null	3.5	null	4143	Abandoned	Yes
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	MONTE CRISTO-MISSION LOOP TO CPL	null	8.63	null	534	In Service	No
TENNESSEE GAS PIPELINE CO,L.L.C.	NATURAL GAS	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	10.75	null	1006	In Service	Yes
ENTERPRISE PRODUCTS OPERATINGLLC	NATURAL GAS	Gas Transmission	SOUTH TEXAS-TX150	MCALLEN RANCH LATERAL	14	null	3883	In Service	No
URBAN OIL & GAS GROUP, LLC	NATURAL GAS	Gas Transmission	LA BLANCA	null	4	null	8566	In Service	No
EOG RESOURCES, INC.	NATURAL GAS	Gas Transmission	SCHUSTER SYSTEM	SCHUSTER GU #1	2.88	null	9230	In Service	No

HIDALGO COUNTY									
OPERATOR	COMMODITY	SYSTEM TYPE	SYSTEM NAME	SUB SYSTEM NAME	DIAMETER	OPERATOR P5	T4 PERMIT	STATUS	INTERSTATE
ENERGY TRANSFER COMPANY	NATURAL GAS	Gas Transmission	RAYMONDVILLE SYSTEM	WB MISSION PIPELINE	3.5	null	7158	In Service	No
DCP HINSHAW PIPELINE, LLC	NATURAL GAS	Gas Transmission	HENSHAW SYSTEM	HS-1-EXT-2	10.75	null	5768	In Service	No
DCP HINSHAW PIPELINE, LLC	NATURAL GAS	Gas Transmission	HENSHAW SYSTEM	HS-1-EXT	10.75	null	5768	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	MCALLEN TRUNKLINE DEL (INACTIVE)	MCALLEN TRUNKLINE DEL (INACTIVE)	8.63	null	774	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	SOUTHERN UNION - MCALLEN	SOUTHERN UNION - MCALLEN	6.63	null	774	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	VENTO LATERAL	null	6.63	null	534	Abandoned	No
TENNESSEE GAS PIPELINE CO,L.L.C.	NATURAL GAS	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	16	null	1006	In Service	Yes
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	CORAL MEXICO	null	24	null	5807	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	UNKNOWN SYSTEM	null	6.63	null	534	Abandoned	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	DONNA LATERAL	null	4.5	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	LAGUNA GAS / POPE #1 DAUGHERTY LATERAL	null	2.88	null	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	null	6.63	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	DUER WAGNER #1 & #2 ROBINETTE LATERAL	null	2.38	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	TRANSVALLEY TO HIDALGO	null	8.63	null	534	In Service	No
ENERGY TRANSFER COMPANY	NATURAL GAS	Gas Transmission	RAYMONDVILLE SYSTEM	RAYMONDVILLE PIPELINE	10.75	null	7158	In Service	No
TENNESSEE GAS PIPELINE CO,L.L.C.	NATURAL GAS	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	2.38	null	1006	In Service	Yes
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	MERCEDES FIELD #3	null	6.63	null	534	In Service	No
TEXAS EASTERN TRANSMISSION, LP	NATURAL GAS	Gas Transmission	MEXI-STFE	null	3.5	null	4143	In Service	Yes
VIRTEX OPERATING COMPANY, INC.	NATURAL GAS	Gas Transmission	WERNER #1 TO HESCO TIE-IN	null	4.5	null	5672	Abandoned	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	TRANSVALLEY TO HIDALGO	null	6.63	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	UNKNOWN SYSTEM	null	14	null	534	Abandoned	No
ENTERPRISE PRODUCTS OPERATINGLLC	NATURAL GAS	Gas Transmission	SOUTH TEXAS-TX150	SHELL MCALLEN TO GILMORE RESIDUE	10.75	null	3883	In Service	No
TEXAS EASTERN TRANSMISSION, LP	NATURAL GAS	Gas Transmission	MEXI-STFE	null	8.63	null	4143	In Service	Yes

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	HENSHAW SYSTEM	HS-1-LOOP	10.75	null	5768	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	VALLEY INDUSTRIAL TO UNION CARBIDE	null	4.5	null	534	In Service	No
TENNESSEE GAS PIPELINE CO,L.L.C.	NATURAL GAS	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	30	null	1006	In Service	Yes
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	INLET TO HIDALGO GAS PLANT	null	10.75	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	CELANESE REYNOSA 12"	null	12.75	null	534	Abandoned	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	SEADRIFT 14" & 16"	null	14	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	INLET TO HIDALGO GAS PLANT	null	4.5	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	ECTOR LATERAL LINE	null	4.5	null	534	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	NATURAL GAS	Gas Transmission	SOUTH TEXAS-TX150	GILMORE EAST RESIDUE TO CELANESE INTERCO	12.75	null	3883	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	CELANESE REYNOSA 6"	null	6.63	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	VENTO LATERAL	null	3.5	null	534	Abandoned	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	null	2.38	null	534	Abandoned	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	RGV 12"	null	12.75	null	534	In Service	No
CONSOL ASSET MNGT SVCS (TX),LLC	NATURAL GAS	Gas Transmission	MISSION PIPELINE	null	8.63	null	5795	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	MERCEDES FIELD #2	null	4.5	null	534	In Service	No
TENNESSEE GAS PIPELINE CO,L.L.C.	NATURAL GAS	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	4.5	null	1006	In Service	Yes
TEXAS EASTERN TRANSMISSION, LP	NATURAL GAS	Gas Transmission	LINE 16-R	null	4.5	null	4143	Abandoned	Yes
CONSOL ASSET MNGT SVCS (TX),LLC	NATURAL GAS	Gas Transmission	MISSION PIPELINE	null	10.75	null	5795	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	NATURAL GAS	Gas Transmission	SOUTH TEXAS-TX150	TEXAS GARDENS LATERAL	4.5	null	3883	Abandoned	No
BALCONES STARR PIPELINE	NATURAL GAS	Gas Transmission	BALCONES STARR PL.	null	4.5	null	1648	Abandoned	No
ENTERPRISE PRODUCTS OPERATINGLLC	NATURAL GAS	Gas Transmission	SOUTH TEXAS-TX150	GILMORE EAST TO TEXAS EASTERN INTERCONNE	12.75	null	3883	In Service	No
CALPINE TEXAS PIPELINE, L.P.	NATURAL GAS	Gas Transmission	MAGIC VALLEY	MAGIC VALLEY EAST PIPELINE	16	null	5829	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	NATURAL GAS	Gas Transmission	SOUTH TEXAS-TX150	GILMORE EAST RESIDUE	24	null	3883	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	UNKNOWN SYSTEM	null	10.75	null	534	In Service	No
TEXAS EASTERN TRANSMISSION, LP	NATURAL GAS	Gas Transmission	LINE 14-V	null	3.5	null	4143	Abandoned	Yes
SANTERRA MIDSTREAM COMPANY, LLC	NATURAL GAS	Gas Transmission	TEXAS GAS TO ENTERPRISE	500# SUCTION LINE	6.63	null	8469	Abandoned	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	TRANSVALLEY LATERAL	null	10.75	null	534	Abandoned	No
EOG RESOURCES, INC.	NATURAL GAS	Gas Transmission	SCHUSTER SYSTEM	SCHUSTER GU #1 GATHERLINE	2.38	null	9230	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	COASTAL STATES #2 STATE LATERAL	null	4.5	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	TGT DELIVERY	null	6.63	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	VALLEY INDUSTRIAL LATERAL	null	4.5	null	534	In Service	No
DEWBRE PETROLEUM CORPORATION	NATURAL GAS FWS	Gas Transmission	MCALLEN RANCH PRODUCTION UNIT SYSTEMS	HIDALGO SAVAGE SALES	4	null	7023	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	V FAULCONER-SAMANO #1 LATERAL	null	2.88	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	CELANESE REYNOSA 12"	null	6.63	null	534	Abandoned	No
ENTERPRISE PRODUCTS OPERATINGLLC	NATURAL GAS	Gas Transmission	SOUTH TEXAS-TX150	TEXAS EASTERN DELIVERY	6.63	null	3883	In Service	No

HIDALGO COUNTY									
OPERATOR	COMMODITY	SYSTEM TYPE	SYSTEM NAME	SUB SYSTEM NAME	DIAMETER	OPERATOR P5	T4 PERMIT	STATUS	INTERSTATE
DEWBRE PETROLEUM CORPORATION	NATURAL GAS FWS	Gas Transmission	MCALLEN RANCH PRODUCTION UNIT SYSTEMS	VALDERAS 4.0 SALES	4	null	7023	In Service	No
CALPINE TEXAS PIPELINE, L.P.	NATURAL GAS	Gas Transmission	MAGIC VALLEY	MAGIC VALLEY WEST PIPELINE	16	null	5829	In Service	No
DEWBRE PETROLEUM CORPORATION	NATURAL GAS FWS	Gas Transmission	MCALLEN RANCH PRODUCTION UNIT SYSTEMS	VALDERAS 3.5 SALES	3.5	null	7023	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	RIO BRAVO NO. 1 WELL LATERAL	null	2.38	null	534	In Service	No
HOUSTON PIPE LINE COMPANY LP	NATURAL GAS	Gas Transmission	20140122 EDINBURGH EXTENSION 24IN	null	24	null	749	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	STARR 8"	RIO GRANDE STA TO CORAL MEXICO JCT	8.63	null	774	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	ONYX BATES TO 423-310A		8.63	null	774	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	UNION PRODUCTION / POPE ESTATE LATERAL	null	4.5	null	534	In Service	No
TENNESSEE GAS PIPELINE CO,L.L.C.	NATURAL GAS	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	24	null	1006	In Service	Yes
TENNESSEE GAS PIPELINE CO,L.L.C.	NATURAL GAS	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	12.75	null	1006	In Service	Yes

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"	null	16	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	NORTH HIDALGO	null	4.5	null	534	In Service	No
OXY USA INC.	NATURAL GAS	Gas Transmission	MCALLEN PHARR SYSTEM	null	10.75	null	848	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	NATURAL GAS	Gas Transmission	SOUTH TEXAS-TX150	HIDALGO COUNTY TO PENITAS LATERAL EXTENS	16	null	3883	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	SAN SALVADOR TO MONTE CHRISTO 8"	null	8.63	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	UNKNOWN SYSTEM	null	8.63	null	534	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	NATURAL GAS	Gas Transmission	SOUTH TEXAS-TX150	TEXACO - SANTELLANA LATERAL	8.63	null	3883	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	TRANSVALLEY LATERAL	null	10.75	null	534	In Service	No
EOG RESOURCES, INC.	NATURAL GAS	Gas Transmission	SCHUSTER SYSTEM	SCHUSTER GU #2 FLOWLINE	2.38	null	9230	In Service	No
TENNESSEE GAS PIPELINE CO,L.L.C.	NATURAL GAS	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	8.63	null	1006	In Service	Yes
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	SAN SALVADOR TO SAN BENITO 10"	null	8.63	null	534	In Service	No
ENTERPRISE PRODUCTS OPERATINGLLC	NATURAL GAS	Gas Transmission	SOUTH TEXAS-TX150	HIDALGO COUNTY	20	null	3883	In Service	No

HIDALGO COUNTY									
OPERATOR	COMMODITY	SYSTEM TYPE	SYSTEM NAME	SUB SYSTEM NAME	DIAMETER	OPERATOR P5	T4 PERMIT	STATUS	INTERSTATE
DEWBRE PETROLEUM CORPORATION	NATURAL GAS FWS	Gas Transmission	MCALLEN RANCH PRODUCTION UNIT SYSTEMS	N. WESLACO SALES	6.63	null	7023	In Service	No
BROWNSVILLE PUBLIC UTILITIES BRD	NATURAL GAS	Gas Transmission	CROSS VALLEY PIPELINE SYSTEM	null	24	null	9388	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	CALPINE EXPANSION LATERAL	TAP ON 421-000 TO RIO CS	16	null	774	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	ONYX LATERAL	ONYX LATERAL	12.75	null	774	In Service	No
TENNESSEE GAS PIPELINE CO,L.L.C.	NATURAL GAS	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	26	null	1006	In Service	Yes
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	UNKNOWN SYSTEM	null	2.38	null	534	Abandoned	No
CONSOL ASSET MNGT SVCS (TX),LLC	NATURAL GAS	Gas Transmission	16A	LINE 16-A	8.63	null	5795	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	TRANSVALLEY TO HIDALGO	null	10.75	null	534	In Service	No
URBAN OIL & GAS GROUP, LLC	NATURAL GAS	Gas Transmission	WESLACO GATHERING	JUAN JOSE HINOJOSA DE BALLI SURVEY A-54	4.5	null	7141	In Service	No
TENNESSEE GAS PIPELINE CO,L.L.C.	NATURAL GAS	Gas Transmission	TENNESSEE GAS PIPELINE COMPANY	TENNESSEE GAS PIPELINE COMPANY	6.63	null	1006	In Service	Yes
ENTERPRISE PRODUCTS OPERATINGLLC	NATURAL GAS	Gas Transmission	SOUTH TEXAS-TX150	GILMORE TO THOMPSONVILLE	12.75	null	3883	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	MERCEDES FIELD #1	null	2.38	null	534	Abandoned	No
DEWBRE PETROLEUM CORPORATION	NATURAL GAS FWS	Gas Transmission	MCALLEN RANCH PRODUCTION UNIT SYSTEMS	MSU 1 SALES	2.38	null	7023	Abandoned	No
ENTERPRISE PRODUCTS OPERATINGLLC	NATURAL GAS	Gas Transmission	SOUTH TEXAS-TX150	PENITAS - PEMEX DELIVERY	24	null	3883	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	TRANSVALLEY LATERAL	null	14	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	UNKNOWN SYSTEM	null	8.63	null	534	Abandoned	No
ENTERPRISE PRODUCTS OPERATINGLLC	NATURAL GAS	Gas Transmission	SOUTH TEXAS-TX150	MCALLEN RANCH LATERAL	12.75	null	3883	In Service	No
SANTERRA MIDSTREAM COMPANY, LLC	NATURAL GAS	Gas Transmission	TEXAS GAS TO ENTERPRISE	DISCHARGE SALES LINE	6.63	null	8469	Abandoned	No
ENTERPRISE PRODUCTS OPERATINGLLC	NATURAL GAS	Gas Transmission	SOUTH TEXAS-TX150	GILMORE EAST TO TENNECO INTERCONNECT	12.75	null	3883	In Service	No

CAMERON COUNTY									
OPERATOR	COMMODITY	SYSTEM TYPE	SYSTEM NAME	SUB SYSTEM NAME	DIAMETER	OPERATOR P5	T4 PERMIT	STATUS	INTERSTATE
BROWNSVILLE PUBLIC UTILITIES BRD	NATURAL GAS	Gas Transmission	CROSS VALLEY PIPELINE SYSTEM	null	24	null	9388	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	UNKNOWN SYSTEM	null	16	null	534	Abandoned	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	BROWNSVILLE PUB LATERAL	null	12.75	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	SEADRIFT 16"	null	6.63	null	534	In Service	No
ENERGY TRANSFER COMPANY	NATURAL GAS	Gas Transmission	HARLINGTON SYSTEM	HARLINGEN PIPELINE	4.5	null	5083	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	PASO REAL FIELD LATERAL	null	4.5	null	534	Abandoned	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	FRUIT OF THE LOOM LATERAL (INACTIVE)	FRUIT OF THE LOOM LATERAL (INACTIVE)	6.63	null	774	Abandoned	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	UNKNOWN SYSTEM	null	2.38	null	534	Abandoned	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	SEADRIFT 16"	null	10.75	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	BROWNSVILLE PUB LATERAL	null	10.75	null	534	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	FRUIT OF THE LOOM LATERAL (INACTIVE)	FRUIT OF THE LOOM LATERAL (INACTIVE)	6.63	null	774	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	SAN BENITO TO BROWNSVILLE 8"	null	8.63	null	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	SAN SALVADOR TO SAN BENITO 10"	null	10.75	null	534	In Service	No
STANLEY SWABBING & WELL SERVICE	NATURAL GAS	Gas Transmission	ME-3801	null	0	null	90116	In Service	No
SANTERRA MIDSTREAM COMPANY, LLC	NATURAL GAS	Gas Transmission	LA PITA SYSTEM	null	4.5	null	8182	Abandoned	No
VALLEY CROSSING PIPELINE, LLC	NATURAL GAS	Gas Transmission	VALLEY PIPELINE SYSTEM (PROPOSED)	AGUA-BRWN	48	null	9611	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	SEADRIFT TO SAN BENITO 8" JUMPER	null	8.63	null	534	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	STARR 8"	MOREFIELD RD TO LA PALMA (INACTIVE)	8.63	null	774	In Service	No
VALLEY CROSSING PIPELINE, LLC	NATURAL GAS	Gas Transmission	VALLEY PIPELINE SYSTEM (PROPOSED)	BRWN-EOLN	42	null	9611	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	HOLLY BEACH TO PORT AREA	null	6.63	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	HOLLY BEACH TO PORT AREA	null	8.63	null	534	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	LA PALMA LATERAL (INACTIVE)	LA PALMA LATERAL (INACTIVE)	10.75	null	774	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	SAN BENITO TO BROWNSVILLE 8" & 10"	null	8.63	null	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	THREE ISLANDS TO HOLLY BEACH LATERAL 6"*	null	6.63	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	250/189-1	null	8.63	null	534	In Service	No
KINDER MORGAN TEJAS PIPELINE LLC	NATURAL GAS	Gas Transmission	GEPC SOUTH TEXAS	(TRANSFERRED FROM 01872)	8.63	null	774	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	SEADRIFT 16"	null	16	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	LOS EBANOS HONEYDALE LATERAL 6"	null	6.63	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	HOLLY BEACH TO PORT AREA	null	4.5	null	534	In Service	No
TEXAS GAS SERVICE COMPANY	NATURAL GAS	Gas Transmission	UNKNOWN SYSTEM	null	8.63	null	534	Abandoned	No