Independent Review of Austin Energy Resource Plan

Prepared for:
City of Austin, dba Austin Energy

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Disclaimer

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Introduction

Navigant Consulting, Inc., submits this Independent Review of Austin Energy Resource Plan Report (the "Report") to City of Austin dba Austin Energy ("AE"). In accordance with the scope of work of Navigant Consulting's engagement, this Report presents the work performed in connection with our independent review of a new Gas Plant and other options such as renewables, energy efficiency (EE), demand response (DR), and purchased power, including observations and findings of our work. The Report presents the findings and recommendation in the context of the renewable generation and carbon reduction goals of the city while managing risk and affordability of the overall AE portfolio. It is our understanding that the Report will be disclosed to the general public.

Navigant has made its best effort, given the available time and resources, to conduct an impartial, independent, and extensive review into the economic, financial, and environmental issues regarding the Gas Plant and other options and the impact to AE load zone and costs projected over the next 2 decades.

This Report examines the costs and risks using a modeling methodology that employs industry standard methods and tools and assumptions developed by Navigant. This modeling methodology simulates the hourly dispatch and operations of the entire Electric Reliability Council of Texas (ERCOT) market on a day-ahead basis for the entire 20-year period reviewed.

The Executive Summary is based on our review, modeling results, explanations, and limitations described in the Report and should be read with the Report itself. Standing alone, it does not, and cannot, provide a full understanding of the analysis and results underlying our conclusions.

About Navigant and Navigant's Subcontractors

A global and independent consulting firm, Navigant's reputation is for assisting our clients across core industries to address the critical opportunities and challenges of new markets, evolving customer demands, regulation and business model changes, new technologies, risk, and disputes. Navigant is recognized as a trusted advisor with a track record for helping clients make informed, strategic decisions and developing and implementing operational practices, organizational and process improvements, and engineering and technology solutions that drive performance excellence and ensure competitive advantage. With more than 450 consultants, Navigant's Global Energy Practice is the largest energy management consulting team in the industry. Our team of experienced professionals serves leading energy companies to address their most complex business opportunities and challenges. The principal authors of this report include: Dan Bradley, Matt Tanner, Ph.D., Rob Patrylak, Amanvir Chahal, Shalom Goffri, Ph.D., Sarah Pinter and Mark Klan, Ph.D..

Quality Power, LLC (QP) is in the business to own and operate renewable energy plants, combined heat and power (CHP) plants, and district heating and cooling plants. QP develops projects that are environmentally responsible and economical. QP has dedicated most of its resources to research and developing biomass energy renewable power projects. QP is integrating renewable power, CHP, and district heating and cooling energy facilities in order to provide a comprehensive renewable energy system.

Energy Utility Group, LLC partners have 20 years of experience in energy deregulation in both wholesale and retail markets. Energy deregulation creates both advantages and disadvantages for enterprise customers. Deregulation provides choices and inherent complexities in this emerging industry. Energy Utility Group's expertise provides customers with a breadth and depth of industry knowledge, product offerings and associated risks, and contract terms to navigate these windows of opportunity in ways that benefit customers now and in the future.

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List of Abbreviations

2025 Generation Plan *or* the Plan	*Resource, Generation, and Climate Protection Plan to 2025: An Update of the 2020 Plan*
AC	Alternating current
ACFT	Acre feet
AE	Austin Energy
BACT	Best-available air emissions control technology
Bcfd	Billion cubic feet per day
BOP	Blowout preventer
Btu	British thermal units
CAES	Compressed air energy storage
CAGR	Compound annual growth rate
CAIR	Clean Air Interstate Rule
CC	Combined cycle
CDR	Report on Capacity, Demand, and Reserves
CHP	Combined heat and power
CO	Carbon monoxide
CO_2	Carbon dioxide
Council	City Council of Austin
CPP	Clean Power Plan
CREZ	Competitive Renewable Energy Zone
CSAPR	Cross-State Air Pollution Rule
CT	Combustion turbine
DC	Direct current
DCS	Distributed Control System
Decker	Decker Creek plant site
DSM	Demand-side management
DR	Demand response
EE	Energy efficiency
EIA	Energy Information Administration
ELCC	Effective Load-Carrying Capability
EPA	U.S. Environmental Protection Agency
EPC	Engineering, procurement, and construction
ERCOT	Electric Reliability Council of Texas
EVA	Energy Ventures Analysis
FERC	Federal Energy Regulatory Commission
FPP	Fayette Power Project
Gas Plant	500 MW combined cycle natural gas plant at Decker or Sand Hill
G&T	Generation and transmission
GPCM	Gas Pipeline Competition Model
GW	Gigawatt
HHV	Higher heating value
High NG	High Natural Gas Price

HRSG	Heat Recovery Steam Generator
ITC	Investment tax credit
kW	Kilowatt
kWh	Kilowatt-hour
LCRA	Lower Colorado River Authority
LHV	Lower heating value
Li-ion	Lithium ion
LMP	Locational marginal price
Low NG	Low Natural Gas Price
MATS	Mercury and Air Toxics Standards
MMBtu	Million British thermal units
MW	Megawatt
MWh	Megawatt-hour
NH_3	Ammonia
Navigant	Navigant Consulting, Inc.
NERC	North American Electric Reliability Corporation
NO_x	Nitrogen oxide
NPV	Net present value
NYMEX	New York Mercantile Exchange
O_2	Oxygen
O&M	Operations and maintenance
PM	Particulate matter
POM	Portfolio Optimization Model
PPA	Power purchase agreement
ppmvd	Parts per million by volume
psig	Pounds per square inch gage
PSS/E	Power System Simulation for Engineering
PTC	Production tax credit
PV	Photovoltaic
QP	Quality Power, LLC
RFP	Request for proposals
ROE	Return on equity
RPS	Renewable Portfolio Standards
Sand Hill	Sand Hill Energy Center plant site
SAR	South Austin Regional Water Treatment Plant
SCF	Standard cubic foot
SCR	Selective catalytic reduction
SME	Subject matter expert
SO_2	Sulfur dioxide
UPS	Uninterruptible power system
VOC	Volatile organic compound
W	Watt
WACC	Weighted average cost of capital
WTI	West Texas Intermediate

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Executive Summary

Background and Methodology

This report is Navigant's economic and financial assessment of the costs and benefits of a nominal 500 MW natural gas combined cycle plant ("Gas Plant") to AE's portfolio to be constructed in the Austin area at either the Decker Creek plant site or the Sand Hill Energy Center site. This report includes the costs and benefits of alternatives such as renewables, and demand response, and purchased power. Our review is intended to provide an economic cost/benefit perspective of the Gas Plant taking into consideration the construction and operating costs, changes in emissions and water usage, along with potential wholesale market revenue and benefits to the AE load zone and costs and risks.

Description

AE is the municipal electric utility owned and operated by the City of Austin, Texas and engaged in the generation, distribution, and transmission of electricity to over 450,000 residential, commercial, and industrial customers in Travis and Williamson County, Texas. AE's governing body is the Austin City Council.

As part of its 2014 Resource Plan update, AE has identified the potential for retirements and additions to its generation fleet. In particular, it projects the potential retirement of 735 MW of steam gas-fired generation at its Decker power plant site and the construction of a new combined cycle (CC) gas unit with a nominal rating of 500 MW ("Gas Plant") by the end of 2018. AE plans to reduce dispatch beginning in 2020 and retire its 602 MW share of Fayette Power Project (FPP) by as early as 2023.

The AE 2025 Generation Plan calls for an independent economic, financial, and environmental review of a new gas plant and other options. Navigant conducted a financial assessment of the costs and benefits of a nominal 500 MW natural gas CC plant to be constructed in the Austin area at either Decker or Sand Hill. Beyond an assessment of the Gas Plant and consistent with AE's approved 2025 Generation Plan ("Plan"), Navigant also assessed the costs and benefits of other portfolio options for 500 MW of nameplate resources, which included solar, wind, demand response (DR), energy efficiency (EE), and purchased power ("portfolios").

This review provides an economic cost/benefit perspective for each portfolio taking into consideration costs, emissions, and water usage along with potential wholesale market revenue and benefits to the AE load zone and costs and risks. In an effort to measure the risk, each portfolio is modeled in four different future scenarios that reflect different future natural gas prices and solar penetration in the Electric Reliability Council of Texas (ERCOT) market.

Navigant's Approach

Navigant used an industry standard production cost model (PROMOD) that considers transmission topology in a security constrained economic dispatch approach based on the ERCOT market on an hourly level dispatch basis. To assess financial and environmental impacts to AE, modeling the entire ERCOT market in our PROMOD model is critical. Navigant models the entire ERCOT system, which includes AE.

Using its market modeling suite, Navigant performed simulations to project market prices, unit dispatch, total emissions, and other information for the ERCOT market. The main modeling steps include the following:

- Develop a baseline ERCOT generation capacity expansion plan scenario
- Develop a high ERCOT Solar generation capacity expansion plan scenario
- Develop base, low, and high fuel price forecast scenarios
- Develop an emissions price forecast
- Perform detailed energy production cost modeling, representing hourly dispatch for the Gas Plant and other options

During this independent study, Navigant requested and AE provided data to enable Navigant to conduct our analysis. In particular, Navigant solicited input from AE to help ensure that our modeling assumptions aligned with the local system (e.g., system-specific data, load forecasts, transmission, and generation).

Portfolio Cases

The portfolios Navigant analyzed are described in Table 1. In all portfolios, Navigant included all elements of the Plan with the exception of the Gas Plant. The difference among the portfolios is the inclusion of either the Gas Plant or other options in which AE may invest. Note that the modeled plan was prior to the City of Austin's recent decision to procure 438MW of solar PPAs that accelerated the procurement schedule.

Table 1. AE Portfolio Cases

Case #	Case Name	Description
C0	All Market	AE Plan without the addition of a 500 MW CC
C1	Decker CC	C0 + 500 MW CC addition at Decker
C2	Sand Hill CC	C0 + 500 MW CC addition at Sand Hill
C3	500 MW Solar	C0 + 500 MW of additional solar
C4	500 MW Wind	C0 + 500 MW of additional wind
C5	Alternative Mix	C0 + portfolio of renewable resources and DR with energy storage (200 MW wind, 200 MW solar, 50 MW DR, and 50 MW EE)
C6	Accelerated Solar	AE Plan with all solar additions coming online in 2017

Source: Navigant

Forecast of ERCOT Market Scenarios

Scenario Definitions

To model the risk of each portfolio, Navigant constructed four ERCOT power market scenarios. The four power market scenarios are the Base case, High Natural Gas Price (High Gas) case, Low Natural Gas Price (Low Gas) case, and the High ERCOT Solar case.

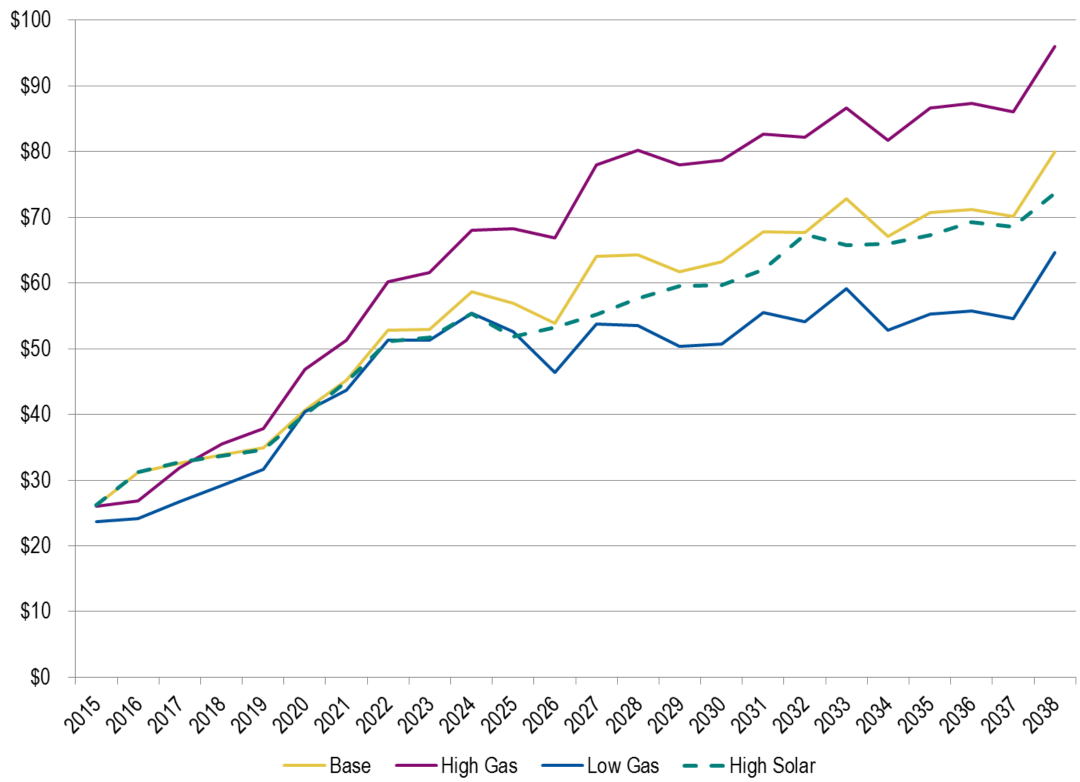
Navigant's market scenarios test the robustness of the AE portfolios to different market conditions. Gas prices are the largest potential source of uncertainty affecting the value of the portfolios. Higher gas prices will lead to higher power prices. Lower gas prices reduce power prices. The High Gas and Low Gas scenarios capture the effect of gas price uncertainty and volatility on the projected value of gas and renewable portfolio options and on market prices.

While Navigant's Base case contains substantial wind construction, consistent with recent trends and forward-looking wind costs, the High ERCOT Solar penetration case tests the portfolios' value with high grid-tied solar penetration in the ERCOT market layered on top of the wind build. Solar and wind are both intermittent resources that peak at different times in ERCOT (wind at night and solar during the day).

Scenario Forecast Results

Figure 1 compares adjusted locational marginal prices (LMPs) at ERCOT's South hub across the four ERCOT market scenarios. LMPs increase in real terms throughout the study period in all four market scenarios. LMPs in the Base, High Gas, and Low Gas scenarios share similar trends year-over-year but are not symmetric due to the non-linear deviation in gas price assumptions. LMPs in the High Solar scenario are less volatile than in other scenarios late in the forecast period due to more available on-peak generation.

Figure 1. Summary of All-Hours Adjusted Average LMPs, ERCOT South Hub (2014$)



Source: Navigant

A number of market factors drive the increase and variations in energy prices in the forecast. The main drivers include:

- The introduction of a carbon price due to the Clean Power Plan.
    - The introduction of a carbon policy in 2020 and the subsequent ramp-up of CO_2 prices into 2022 result in an increase in wholesale power prices. Natural gas-fired plants increase their variable costs by about half as much as coal plants; however, overall thermal generation cost increases result in a higher clearing price across all hours.
- Tightening capacity reserves within ERCOT
    - As demand and retirements outpace capacity additions into the early 2020s, ERCOT's reserve margin decreases. This causes a larger number of scarcity pricing hours, which are necessary to create an economic environment to entice new generation builds. The somewhat jagged pattern shown in the Base, High Gas, and Low Gas scenarios beyond 2024 is a reflection of this cyclical market dynamic. As reserves tighten and scarcity pricing hours increase, new resources are built to meet the higher demand.
- Natural Gas price rising in real terms
    - Natural gas prices are a major driver in power prices in ERCOT and tend to become more significant as coal retirements occur and additional gas generation is assumed to

come online. The Low Gas, High Gas, and Base cases tend to follow very similar patterns, as the total variable cost of gas-fired generation is lower. The High Solar case is less reliant on gas and displaces some baseload generation with solar generation, which serves as a price taker in the market.

It is important to note that there are local impacts on AE's cost to serve load that are separate from the overall ERCOT price trends. Austin Energy is a load zone and there are transmission limits that can cause congestion and impact local prices separate from ERCOT. ERCOT's LMP takes into account both supply bid prices and demand offers and the physical operational constraints of the transmission system referred to as transmission congestion. By design, this market construct rewards generation that is physically close to load and that can react, when needed, to address the physical constraints of the transmission system. Given the retirement of the Decker Steam units and the Fayette Coal units, there is significant risk of increased congestion in the AE load zone that would raise costs. The Gas Plant would mitigate this risk while the other portfolios will not, with the exception of demand response, which, if able to reduce demand in response to ERCOT market signals, it can reduce exposure to transmission congestion. This study incorporates an estimate of these local impacts but also acknowledges that there is a risk of significantly higher costs due to transmission congestion with all of the local retirements without adding the Gas Plant.

Findings

Navigant recognizes that AE has diverse goals, and this analysis considers the tradeoffs between them. To show the impacts of different portfolios, Navigant aggregated results into a scorecard that provides calculated metrics including utility cost, rates, water usage, renewable power, emissions, local economic impacts, and water usage. The scorecard provides a framework to consider the costs, benefits, and risks of the portfolios in the different scenarios. The aggregated results enable the synthesis of study recommendations.

Total System Costs

The market risks to portfolios are evaluated by considering the system costs of each portfolio across market scenarios. It is important to recognize that market scenarios define the conditions that AE must operate within but are outside the utility's control, such as natural gas prices. As the future is uncertain, it is important for AE not to plan to a single potential future outcome. Instead, a good portfolio balances having low costs across most scenarios and avoids outlier scenarios in which costs are much higher than the alternative.

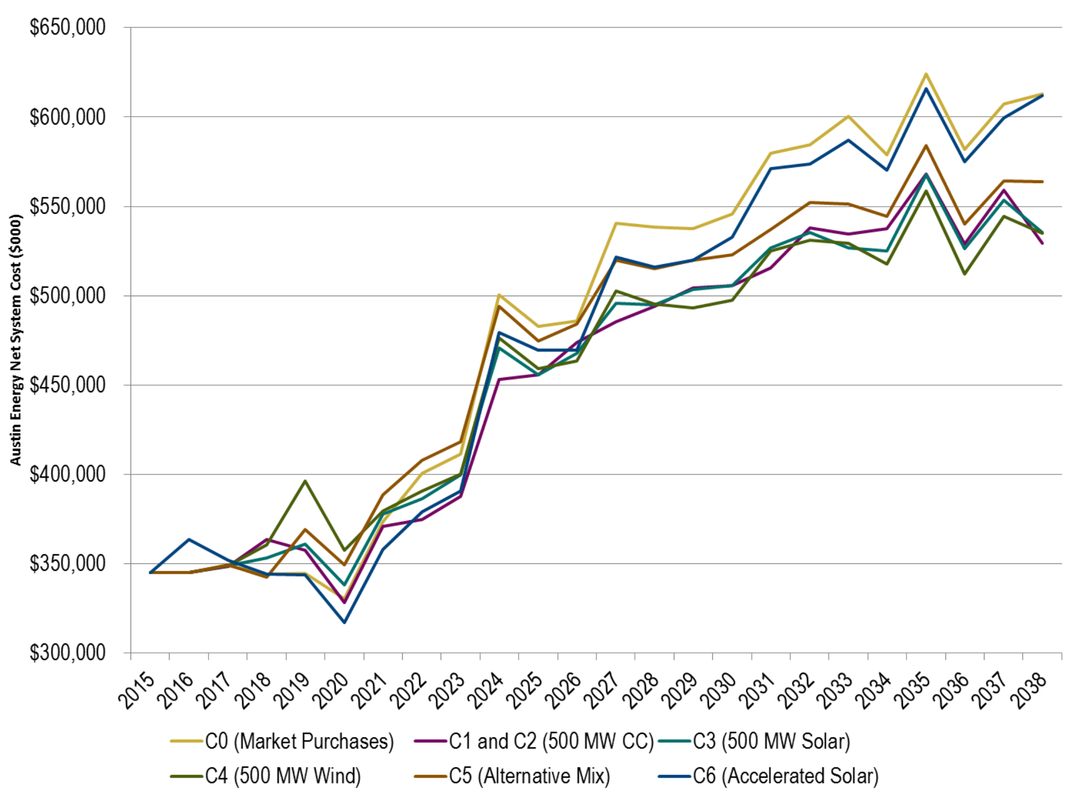
Total system costs are a representation of every cost that AE incurs while providing power to customers, including all of the legacy capital and operating costs from the existing portfolio. It is important to note that this study only considers incremental changes to AE's resource plan, and thus the majority of costs are common between all portfolios and outside the scope of the decision of whether to build a CC, build a different set of resources, or rely on market purchases.

In accordance with the scope of work, Navigant used a 20-year Net Present Value (NPV) period of analysis. For both the Gas Plant and other alternatives, the modeled all costs and revenues in the 20-year period of analysis. In reality, many of the resources included in the analysis have a useful life that extends well beyond a 20-year period. While Navigant recognizes there is a likely economic benefit beyond the 20-year period, our assessment of the costs, benefits and risks of each of the portfolios does not consider the residual value of any added AE resources. In line with the study scope of work, this is a conservative approach to estimating the value of the alternative portfolios. The recommendations of this study are driven by the changes in system costs between portfolios.

To calculate total system cost, Navigant modeled the operation of the AE portfolio within ERCOT, calculated the total cost to serve load, and calculated the operating costs of all of AE's units in each portfolio. Using data from AE, Navigant then added the non-modeled costs of operating the system to each portfolio.

As market conditions in ERCOT tighten and gas prices and carbon prices rise in the early- to mid-2020s, AE's investment in new resources becomes more profitable. However, there is still little difference in the annual system costs for any of the portfolios except that the All Market and Accelerated Solar portfolios—which rely on more market purchases than the other scenarios—are significantly more expensive. This concludes that AE benefits by owning resources; however, in comparing other portfolios that do not rely as heavily on market purchases, there is no clear advantage in terms of base cost. Additionally, it is necessary to consider the additional financial risks of the portfolios and the extent to which the different portfolios meet AE's goals.

Figure 2. Net Austin Energy System Cost by Year



Source: Navigant

The analysis results for total system costs are given in Table 2. The costs are reported in net present value (NPV) and in real 2014$ and for each scenario. The impacts of the planning decision that AE faces can be seen by comparing system costs across portfolios. The low cost portfolio is in bold font and for each portfolio the difference in NPV from the low cost portfolio is given in parentheses. The impacts of market conditions can be seen by comparing system costs for a single portfolio among the four scenarios. These scenarios represent the impact to AE of the costs that AE cannot control (e.g., natural gas prices).

Table 2. Net System Cost (NPV 2014 $MM)

	Scenarios			
Portfolio	**Base**	**High Gas**	**Low Gas**	**High Solar**
All Market	8,025 (452)	8,682 (691)	7,419 (429)	8,024 (314)
C1: Decker CC	**7,573 (0)**	8,097 (106)	**6,990 (0)**	7,754 (44)
C2: Sand Hill CC	7,574 (1)	8,097 (106)	6,991 (1)	7,754 (44)
C3: 500 MW Solar	7,608 (35)	8,025 (34)	7,158 (168)	7,775 (65)
C4: 500 MW Wind	7,639 (66)	**7,991 (0)**	7,240 (250)	**7,710 (0)**
C5: Alternative Mix	7,830 (257)	8,235 (244)	7,392 (402)	7,931 (221)
C6: Accelerated Solar	7,866 (293)	8,502 (511)	7,278 (288)	7,869 (159)

Source: Navigant

In every scenario, All Market is the most expensive option, suggesting that AE’s generation portfolio provides benefits to its ratepayers by reducing exposure to risk in the ERCOT market. Building the gas plant has slightly better economics than adding either 500MW of Solar or 500MW of wind in the Base scenario, and has significantly better economics in the Low Gas scenario, and worse economics in the High Gas scenario. The portfolio C5: Alternative Resources is more expensive than the other resource portfolios, largely due to the high procurement cost of incremental EE and DR. The conclusion from these results is that the resource decision should depend on risk avoidance to AE as there is no clear advantage in the costs across the market scenarios.

There is no material difference in terms of cost for developing a CC at Decker or at Sand Hill and the decision of which of the two sites to put the gas plant is not dependent on the energy market economics considered in this study.

The four scenarios are designed to show drivers and risks to wholesale power prices in ERCOT. A key finding is that AE’s system costs are exposed to more risk due to gas prices than to changes in the generation portfolio considered in this study. The seven portfolios show real differences in costs, but the ranking of portfolios in terms of costs changes among scenarios.

Value of Local, Dispatchable Capacity

One metric that a production cost model like PROMOD tends to underestimate is the value of dispatchable generation versus non-dispatchable generation. PROMOD does value the aspect of renewable generation in that there is no control over the operating profile and that the units receive whatever price is available when the unit is operating. However, since PROMOD is a deterministic model of the day-ahead market prices, it does not represent the impacts of forecast error for load and renewable generation in the real-time market prices.

As renewable generation on a system increases, the number of spikes in real-time energy prices tend to increase, as there is further need for flexible generation to maintain system balance with an increased penetration of intermittent or variable generation.

If the flexible generation is not available, real-time prices can increase to very high levels. Since AE purchases wholesale power from the ERCOT market to meet 100% of its load, AE is exposed to this risk of high real-time prices.

Congestion costs are the higher costs to serve the load in AE if localized generation is not built. In fact, the Generation Plan and this analysis include the retirement of ~1,300 MW of generation in the AE load zone, which increases the risk of higher congestion costs to AE and its customers.

The value of reducing congestion is driven by the fact that AE is located in a transmission-constrained section of the ERCOT bulk transmission system, limiting its import and export capability into neighboring areas. As localized generation retires as planned, prices in AE will rise to average levels above that of ERCOT South due to binding constraints on the import capability of AE. This difference in electricity prices (LMPs) between AE and ERCOT South, or basis differential, results in higher costs to serve the load within the AE load zone. Our analysis concludes that if the Gas Plant is built within the AE load zone as opposed to adding to the portfolio through resources located outside of AE, this congestion cost is reduced and the risk of much greater congestion costs is addressed, in part.

The biggest concern for AE with all of these risk factors is that the risks tend to be asymmetric and without mitigation may make the city vulnerable to worse outcomes than forecast with PROMOD. While all of these risks are difficult to estimate, it is critical to consider them when determining what portfolio to pursue. Table 3 gives Navigant's best estimates of the potential for additional financial risk that AE could be under without local, dispatchable generation.

The risk on local congestion is developed starting with Navigant's forecast of the value of mitigating congestion due to the Gas Plant compared to the other portfolios. The risk for AE is that there is no historical data on the impacts of planned retirements of local generation to use to benchmark the modeling results. Thus it would not be surprising for the costs to AE of not replacing that capacity with new, local generation to be much higher than our modeling results. Relying on our experience, we have estimated the risk as the potential to triple the incremental congestion cost.

The real-time price volatility risk was estimated by simulating the operation of a combined cycle in the ERCOT market against historical prices. The benefits of an efficient combined cycle for providing real-time price hedging is somewhat limited as the units largely operate in the day-ahead but there are time periods when the unit is operating at the minimum generation level and can ramp up in response to real-time price spikes to realize additional revenue. The estimate is the 20 year NPV of the average value of this ramping capability.

The ancillary services risk is estimated considering the impacts of an increase in demand for operating reserve and frequency regulation as renewable generation penetration in ERCOT increases. The concern for AE is that there could be a large increase in the need for these ancillary services. This would cause the prices to rise somewhat but there is an upper bound on the total amount they can rise as a price increase would spur entry of new resources into the market. We have estimated the potential rise as a 50% increase on market prices.

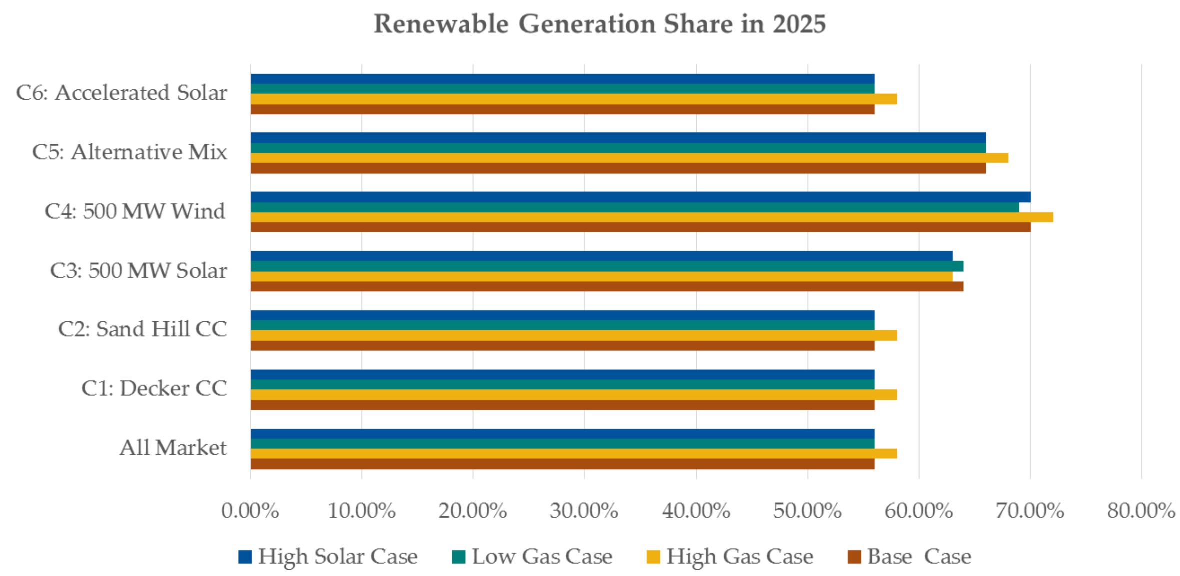
Table 3: Potential Financial Risk for Non-Local, Non-Dispatchable Generation

Risk Factor	Cost Estimated in Study (000's $2014 NPV)	Estimated Added Risk (000's $2014 NPV)
Local Congestion	70,000	130,000
Real-Time Price Volatility	0	16,000 – 32,000
Ancillary Services	84,000 – 102,000	42,000 – 51,000
Total	**154,000 – 172,000**	**188,000 – 213,000**

Renewable Generation by Portfolio

All portfolios meet AE's goal of 55% renewable generation by 2025. This is because all of the renewable generation in the approved plan is included in all portfolios. The renewable share by portfolio is shown in Figure 3, the Wind, Solar, and Alternative Mix portfolios increase the share above 60%.

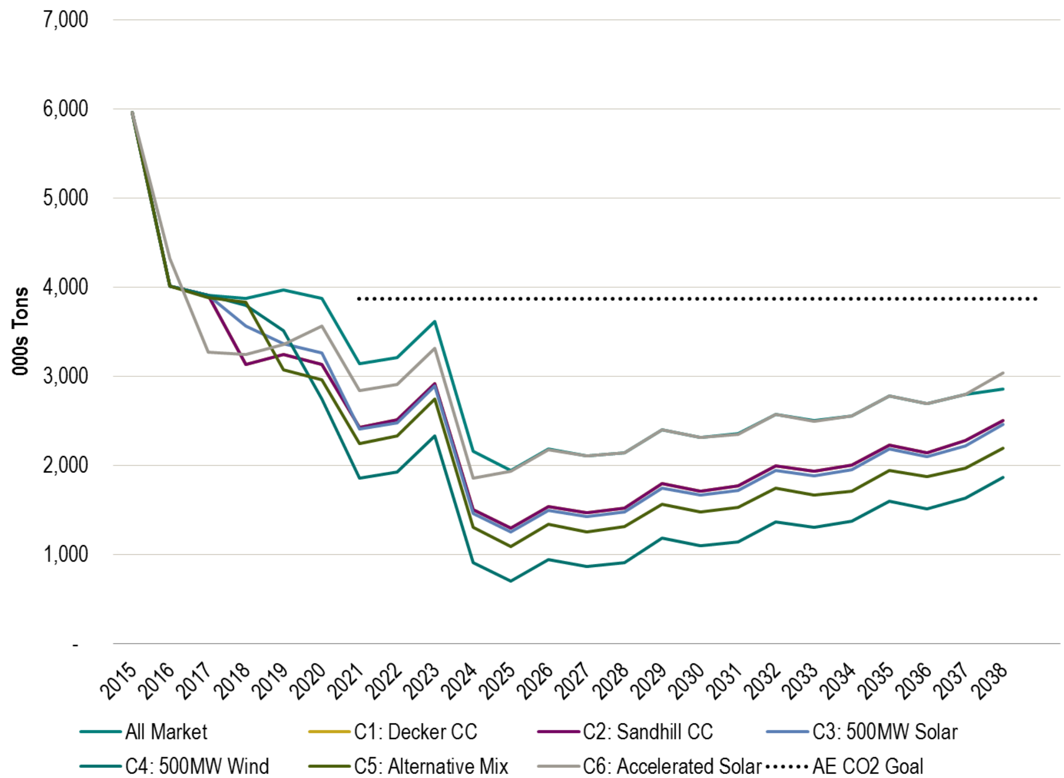
Figure 3: AE Renewable Generation Share in 2025



Emissions

AE's current goal requires reduction of total CO_2 by 20% from 2005 levels (~4.8mil tons) by 2020 and this is met in all portfolios. Note that the rising emissions in the later years of the forecast is due to this study holding AE generating resources constant even though in reality additional AE-owned resources would likely be procured.

Table 4: AE CO_2 Emissions by Year in Base Case



The total emissions for NO_x and SO_2 are shown in Table 5 and Table 6. The pattern of emissions is similar to that of CO_2 except that the gas generation has an even larger reduction than for CO_2 because gas generation is much less intensive in these pollutants than coal or the ERCOT system average.

Table 5. NO_x Emissions Results (000s tons)

Portfolio	Base Case	High Gas Case	Low Gas Case	High Solar Case
All Market	37	39	34	37
C1: Decker CC	20	22	16	20
C2: Sand Hill CC	20	22	16	20
C3: 500 MW Solar	30	35	28	30
C4: 500 MW Wind	25	28	23	26
C5: Alternative Mix	28	31	26	28
C6: Accelerated Solar	35	37	33	35

Source: Navigant

Table 6. SO_2 Emissions Results (000s tons)

Portfolio	Base Case	High Gas Case	Low Gas Case	High Solar Case

All Market	139	150	129	140
C1: Decker CC	90	100	76	91
C2: Sand Hill CC	90	100	76	90
C3: 500 MW Solar	123	138	112	124
C4: 500 MW Wind	110	121	101	111
C5: Alternative Mix	118	128	107	117
C6: Accelerated Solar	135	146	126	136

Source: Navigant

Water Usage

The Gas Plant uses 65% less water per MWh than the steam units at Decker and Fayette that it is replacing, but still requires access to significant water resources. As water is a local resource, this metric is calculated only for local, AE-owned resources.

Water usage is the same across all portfolios that do not add a new thermal unit and are about 15% higher in the portfolios with the Gas Plant. All of these levels of water usage are less than is used with the steam units that will retire under the approved 2025 Generation Plan.

Table 7. Water Usage Results (ACFT)

Portfolio	Base Case	High Gas Case	Low Gas Case	High Solar Case
All Market	228,425	228,786	231,305	225,121
C1: Decker CC	267,782	268,767	274,013	265,016
C2: Sand Hill CC	267,780	268,770	274,020	265,019
C3: 500 MW Solar	227,156	228,057	230,581	224,402
C4: 500 MW Wind	227,320	228,265	230,781	224,632
C5: Alternative Mix	227,163	228,159	230,750	224,948
C6: Accelerated Solar	227,705	228,711	231,102	225,018

Source: Navigant

Land Use Impacts

There are no identifiable land use impacts for the All Market option. For both of the Gas Plant build options (C1: Decker and C2: Sand Hill), the existing sites have more than adequate land available.

Local Economic Impacts

Although no detailed economic impact study or modeling has been performed, local impacts for gas CC construction and operation have been roughly estimated based on various information, including: cost and labor breakdowns in the AE engineer’s report, recent/planned new builds in Texas and other U.S.

locations, wage rate data for Travis County and the capital area (Texas), and assumptions. For a 500 MW CC natural gas plant built over a period of 2 years, total local/regional construction spending is estimated to be roughly $74 million, of which 75% is assumed to be labor ($55 million). This corresponds to about 400 full-time equivalent construction-related jobs (including support). Approximately 20 full-time jobs will be added for O&M after the Gas Plant begins commercial operation.

Recommendation

Navigant's analysis highlights the uncertainty in the ERCOT market, driven by market drivers such as natural gas pricing, environmental regulations, reserve margin, transmission congestion, real time price volatility, ancillary services costs and impact of increasing penetration of renewables such as solar and wind technologies.

A key finding from our assessment is that AE's policy of owning generation and in particular, local generation, mitigates ERCOT market price risks. Our results show that all portfolios assessed produce benefits for AE and its customers compared with the All Market portfolio which assumes no 500 MW resource(s) addition of any kind.

The results between the portfolios assessed are very close which is why it is important to consider the range of risks to AE and its customers that can be mitigated by the Gas Plant. The portfolios with the Gas Plant (at Decker or Sand Hill) resulted in the best mix of value and risk mitigation among the portfolios studied. The Gas Plant portfolios are the lowest-cost portfolio in two of the four scenarios and not catastrophic in any scenario. Our estimates of additional risks show that in the ERCOT nodal LMP market, location matters. With the planned retirement of ~1,300 MW of local generation in the AE load zone, we expect the locational costs and risks to AE's customers, principally transmission congestion, real time price volatility and ancillary services costs, to increase. As a part of the portfolio of Plan resources, the Gas Plant mitigates locational market risks while supporting goals such as 55% renewable portfolio by 2025, reduction of total CO_2 by 20% from 2005 levels (~4.8mil tons) by 2020. The Gas Plant reduces water uses less water per megawatt hour than either Decker or FPP and the construction and operation of the plant provide positive local economic impacts.

Our recommendation to Council on the basis of the benefits and costs and impacts of each of the scenarios we assessed is that AE build the Gas Plant in the AE load zone to replace the Decker Creek Power Station's steam units when they are retired, and to support the planned retirement of FPP.

Additional Observations and Findings:

- » **Selecting Solar Early Produces Benefits**: We ran a portfolio accelerating 600 MW of solar PPA selections to 2016 in order to estimate the benefits of selecting 600 MW now vs. over time. Subsequent to the start of our analysis 438MW was approved by the city. Our study results support this decision.
- » **Pace of change in technology**: Given the pace of change in renewable and storage costs, AE should continue to monitor and consider these resources.
- » **EE and DR resources are often highly valuable if they can be procured cost-effectively**: To the extent that AE can continue to develop additional programs to cost-effectively incentivize

customers to participate in EE and DR and provide those resources, AE should continue to pursue these opportunities.

- **AE should consider other quick-starting generating technologies that were not in this scope of work:** This study finds the ERCOT market is evolving rapidly and technology costs are changing. These trends are likely to reward dispatchable quick-starting resources such as reciprocating engines, some combustion turbines, and storage. Installed locally, these technologies can also help mitigate local congestions risks. We recommend that AE, in its next generation plan, should consider this class of resource.

1. Background and Methodology

1.1 Background

This report is Navigant's economic and financial assessment of the costs and benefits of a nominal 500 MW natural gas combined cycle plant to AE's portfolio to be constructed in the Austin area at either the Decker Creek plant site or the Sand Hill Energy Center site. This report includes the costs and benefits of alternatives such as renewables, and demand response, and purchased power. Our review is intended to provide an economic cost/benefit perspective of the Gas Plant taking into consideration the construction and operating costs, changes in emissions and water usage, along with potential wholesale market revenue and benefits to the AE load zone and costs and risks.

As part of its 2014 Resource Plan update, AE has identified the potential for retirements and additions to its generation fleet. In particular, it projects the potential retirement of 735 MW of steam gas-fired generation at its Decker power plant site and the construction of a new combined cycle (CC) gas unit with a nominal rating of 500 MW by the end of 2018. AE plans to reduce dispatch beginning in 2020 and retire its 602 MW share of Fayette Power Project ("FPP") by as early as 2023.

As part of its Plan, AE committed to sponsoring this independent economic, financial, and environmental review of the Gas Plant to address the cost and risk to the AE load zone. In addition to the 500 MW Gas Plant, this review considers other 500 MW portfolio options of solar, wind, demand response (DR), energy efficiency (EE), and purchased power ("portfolios").

This review provides an economic cost/benefit perspective for each portfolio taking into consideration costs, emissions, water usage, along with potential wholesale market revenue and benefits to the AE load zone and costs and risks. In an effort to measure the risk, each portfolio is modeled in four different future scenarios that reflect different future natural gas prices and solar penetration in the Electric Reliability Council of Texas (ERCOT) market. In addition, the risks of the level of capital costs for the Gas Plant and alternative portfolios are addressed.

1.2 Overview of Austin Energy

The following two sections provide an overview of AE and its 2014 Generation Plan update.

1.2.1 AE Is a Municipal Utility

AE is a municipal electric utility owned and operated by the City of Austin, Texas and engaged in the generation, transmission, and distribution of electricity to more than 450,000 residential, commercial, and industrial customers in Travis and Williamson Counties, Texas. AE's governing body is the Austin City Council.

AE has approximately 4,400 MW of generation capacity, either wholly owned or subject to long-term power purchase agreements (PPAs).[1] This diverse portfolio includes nuclear, coal, natural gas, biomass, wind, and solar resources.

AE is fully integrated into the ERCOT market, which serves about 24 million Texas customers. ERCOT serves as the balancing authority and is responsibility for reliability and the integration of AE's generating resources with the market. ERCOT balances renewable and dispatchable generation to meet load at the lowest possible cost assuring reliability is met. AE's generating resources compete with other sources of electricity to earn wholesale market revenue. AE meets its demand by buying all power to meet its load from the ERCOT market. Thus, any generation additions must earn sufficient wholesale revenue in the ERCOT market to justify the investment by the owner.

The local system affects customer costs as AE experiences the impacts of localized congestion, which, during a number of hours, causes wholesale power price basis differentials between AE and the ERCOT South Zone. In the ERCOT nodal market, each generator has to compete to earn wholesale market revenue, which is set by ERCOT at the node to which the generator interconnects. The price at that node known in ERCOT as the locational marginal price (LMP) and is set by the cost of the last increment of generation needed to serve load plus the impact of transmission congestion. By design, this market construct rewards generation that is physically close to load and that can react, when needed, to address the physical constraints of the transmission system. Therefore, within ERCOT, location matters. Localized generation will lower prices in AE relative to ERCOT South Zone, and thereby reduce the cost to serve load for AE.

1.2.2 AE Recently Updated Its Generation Plan

On October 9, 2014, AE presented the Council with an update to its *Resource, Generation, and Climate Protection Plan to 2020*, entitled *Resource, Generation, and Climate Protection Plan to 2025: An Update of the 2020 Plan* ("2025 Generation Plan" or the Plan). The following is a summary of the 2025 Generation Plan approved in December 2014, which provides a path forward for the next 10 years.

The approved Plan balances affordability and risk management by using revenue and capacity created by a new Gas Plant investment and investments in local storage and DR by 2025. Doing so allows for the retirement of older fossil fuel generation and supports an increase in the amount of renewable energy to 55% of customer demand. This combination of investments offers the potential to provide additional headroom within the affordability metrics to expand other important programs, if desired.

The Plan adopts and directs action on the following activities:

1. Commencing a third-party economic and environmental review to replace the steam units at the Decker Creek plant site (Decker) and FPP.

[1] A PPA is a contract between two parties: one that generates electricity (the seller) and one that is looking to purchase electricity (the buyer). The terms of a PPA include when the project will begin commercial operation, the schedule for delivery of electricity, penalties for under delivery, payment terms, and termination.

2. Supporting creation of a cash reserve fund for FPP retirement. Reserves would be approved through the budgeting process and targeted to retire AE's share of the plant beginning in 2022. Retiring AE's portion of FPP is contingent upon cash available to pay off debts and other costs associated with retirement while maintaining affordability.
3. Issuing a request for proposal for up to 600 MW of utility-scale solar to commence the process toward a generation portfolio consisting of 55% renewable energy.
4. Maintaining the current goal of 800 MW of EE and DR by 2020, and adding an incremental 100 MW of DR to achieve at least 900 MW of demand-side management (DSM) by 2025.
5. Developing an implementation plan for distribution connected local storage of at least 10 MW, complemented by as much as 20 MW of thermal storage.

The Plan also recommends the following, contingent upon further study, technological development, progress toward goals, and rate adjustments or restructuring:

- An additional 100 MW of DR or EE to increase the DSM achieved to 1,000 MW by 2025.
- Issuing a request for information for 170 MW of large-scale energy storage, such as compressed air energy storage.

Table 8 shows the projected resource mix and timing of the approved 2025 Generation Plan. Table 9 describes additional objectives and initiatives that are included in the Plan.

Table 8. 2025 Generation Plan Resource Mix

Action	Capacity	Resource	Description	Timing
Retire	602 MW	Coal	AE's share of the FPP	By end of 2023
	735 MW	Natural gas (steam)	Decker steam unit	2018
Add	500 MW	Natural gas (CC)	The Gas Plant at Sand Hill or Decker	By beg. of 2018
	100 MW	DR/DSM	Incremental	By 2025
	450 MW (minimum)	Wind	Contracts for coastal and western wind resources	By 2025
Maintain	800 MW	EE and DR	Current goal	By 2020
Increase	950 MW (minimum)	Solar	• Reaching the city's goal of 200 MW of local solar including at least 100 MW of customer-sited local solar • Adding 600 MW of utility-scale solar from AE's request for proposals (RFP) • Assuming the full build-out of the announced 150 MW of solar power currently contracted with Recurrent Energy	By 2025
Obtain	30 MW (minimum)	Thermal and electrical storage	Local	By 2025

Source: Resource, Generation, and Climate Protection Plan to 2025: An Update of the 2020 Plan

Table 9. Additional Objectives and Initiatives

Objective Category	Objectives and Initiatives
Affordability and due diligence	1. AE and this updated Plan will continue to adhere to the affordability goal for rates and services for all classes of customers as approved by the Council in February 2011. 2. Before taking action to acquire a generation resource of 10 MW or more, or an aggregate of 10 MW from a single program, and to the extent practicable and consistent with sound management and financial responsibility, AE will present such action for approval at least once to each applicable commission and twice to the Council. 3. Promote robust community involvement in revisions to the AE business model. 4. Ensure that future resource planning advisory or stakeholder groups include representatives of residential and low-income customer advocacy organizations.
Customer assistance	5. Evaluate the potential to expand EE and weatherization programs for low-income citizens.
EE and DR	6. Continue to evaluate EE and DR potential and, if viable and cost-effective, increase the EE and DR goal to 1,200 MW by 2025. 7. Continue to evaluate the potential for DR and, if viable and cost-effective, increase the DR goal from 100 MW to 300 MW.
Renewables	8. Study the feasibility to achieve a 65% renewable energy goal by 2025. 9. Develop a comprehensive strategy for the deployment and use of local energy storage technologies, including assessment of compressed air energy storage (CAES).
Coal	10. AE will strive to retire its share of the FPP as soon as legally, economically, and technologically possible. While AE should continue to discuss with the Lower Colorado River Authority (LCRA) retiring Units 1 and 2 as soon as economically and technologically feasible, AE will explore negotiation with LCRA for control of one unit to chart a path toward an early retirement of AE's share of FPP starting in 2022.
Natural gas	11. Continually assess the long-term risk of natural gas price fluctuations. 12. AE should study methane emissions associated with gas production and delivery and best practices to prevent methane and hydrocarbon leaks in the gas fields. 13. AE and the Council should support further regulations in gas fields to prevent leaks and vents of methane because of its severe impacts on climate disruption. 14. Conduct an analysis of the community economic development impact of AE generation facilities and planned replacements. 15. Conduct an analysis of the use of water by AE's generation facilities and its impact on the community.
Complementary strategies	16. Continue work to transform AE's basic business model to address and integrate increased deployment of distributed energy resources, including distributed energy generation. Among the issues that AE will address on an ongoing basis are unbundled rate structures, service offerings that rely less on volumetric pricing structures, rationalization of fuel charge-related costs, modifications to GreenChoice product offerings, and products and services demonstrated in the Pecan Street Project Energy Internet Demonstration Project. Work to reflect business model changes and opportunities in upcoming reviews of electric rates. 17. Continue active participation in the development and deployment of smart grid technologies, and continue with an active leadership role in the Pecan Street Project and other partnerships. 18. Continue and, as appropriate, expand efforts to increase electric vehicle utilization and facilitate integration of electric vehicles in the utility service area, and, as able, utilize these vehicles as a valid distributed storage technology.

Source: Resource, Generation, and Climate Protection Plan to 2025: An Update of the 2020 Plan

1.3 Objectives and Scope of Work

1.3.1 AE Commissioned a Local Study of Its 2025 Generation Plan

As discussed in Section 1.2.2, the AE 2025 Generation Plan calls for an independent economic, financial, and environmental review of a new Gas Plant and other options. Navigant conducted a financial assessment of the costs and benefits of a nominal 500 MW natural gas CC plant to be constructed in the Austin area at either Decker or Sand Hill. Beyond an assessment of the Gas Plant and consistent with AE's approved 2025 Generation Plan, Navigant also assessed the costs and benefits of other portfolio options for 500 MW of nameplate resources.

1.3.2 The Study's Objectives and Scope of Work Analyze the Impacts of the 2025 Generation Plan

This report addresses the following objectives:

- Assess the costs and benefits of a nominal 500 MW natural gas CC plant to be constructed in the Austin area at either Decker or Sand Hill
- Compare with alternative resource portfolios consisting of one or more of the following resources: storage, renewables, DR, and purchased power

Specifically, the scope of work includes the following:

- The expected, high case, and low case construction costs of the Gas Plant, including direct and financing costs.
- The projected operation and dispatch of the Gas Plant facility, which includes:
    - Detailed facility performance characteristics, including heat rates, ramp constraints, and other relevant operational limits.
    - Hourly dispatch using an appropriate production cost model that considers transmission topology in a security-constrained economic dispatch approach based on the ERCOT market.
    - Expected, high case, and low case ongoing operating costs, including operations and maintenance, fuel, and financing.
    - Expected, high case, and low case power market prices and plant revenue derived from energy and ancillary services.
- The impact to revenue, cost, and associated risks in the AE load zone under the options below, incorporating the Generation Plan goals for solar, EE, storage, and DR as presented in the approved Generation Plan:
    - A retirement of its Decker steam units and FPP without a new generator in the AE load zone.
    - A retirement of its Decker steam units with the construction of a new 500 MW natural gas CC plant at Decker.
    - A retirement of its Decker steam units with the construction of a new 500 MW natural gas CC plant at Sand Hill.

- A comparison with up to four portfolio scenarios that use reasonable combinations of wind, solar, DR, EE, and purchased power in lieu of investing in a new natural gas plant. Alternatives to be analyzed could include:
    - Lowest-cost combination of solar and/or wind energy (new or used facilities) with EE and DR
    - Lowest-cost combination of solar and/or wind energy (new or used facilities) without EE or DR
- A validation or documentation of inputs to be used for the 20-year net present value (NPV) period of analysis.
- Other benefits and impacts associated with the alternatives, such as:
    - Resultant water use
    - Resultant impact on local criteria pollutants and broader effects of these pollutants
    - Land use impacts at Sand Hill or Decker
    - Revenue benefits and costs to AE customers
    - Local economic impacts of the project/plant
- Recommendations to the Council of the benefits, costs, and impacts of each of the scenarios.

1.4 Study Approach

1.4.1 Navigant Approached This Local Study by Modeling the ERCOT Wholesale Power Market

To assess financial and environmental impacts to AE, modeling the entire ERCOT market is critical. Navigant models the entire ERCOT system, which includes AE, for the following reasons:

- ERCOT serves as the balancing authority and maintains reliability, per North American Electric Reliability Corporation (NERC) requirements.
- ERCOT operates wholesale power markets to ensure reliability of the transmission grid at the most economical dispatch of individual resources across the grid. It is a financial, not a physical, market that ensures reliability of the transmission grid.
- ERCOT assumes responsibility for the integration of AE’s resources with the ERCOT market.
- AE buys and sells all of the energy needed to serve its load through the ERCOT nodal market.
- AE’s generation competes with other resources in ERCOT to sell electricity and ancillary services, which generates revenue for AE.
- Changes to the ERCOT system affect the cost of load to AE.
- Cost impacts result from physical interaction of the AE load zone and ERCOT, which include transmission congestion, ancillary services, and day-ahead and real-time prices.

1.4.2 Navigant Employed Industry-Accepted Methods and Tools in Performing Its Analysis

Using its market modeling suite, Navigant performed simulations to project market prices, unit dispatch, total emissions, and other information for the ERCOT market. The main modeling steps include the following:

- Develop a baseline ERCOT generation capacity expansion plan scenario
- Develop a high ERCOT Solar generation capacity expansion plan scenario
- Develop a base, low, and high fuel price forecast scenarios
- Develop an emissions price forecast
- Perform detailed energy production cost modeling, representing hourly dispatch for the Gas Plant and other options

Navigant's proprietary Portfolio Optimization Model (POM) is a linear optimization model used to optimize generation capacity expansion. POM simulates economic investment decisions and power plant dispatch on a zonal basis subject to capital costs, reserve margin planning requirements, Renewable Portfolio Standards (RPS), fuel costs, fixed and variable operations and maintenance (O&M) costs, emissions allowance costs, and zonal transmission interface limits. The generation expansion results from POM are used as inputs to the fundamental energy price forecast performed in PROMOD.

PROMOD is a detailed energy production cost model that simulates hourly chronological operation of generation and transmission (G&T) resources on a nodal basis. PROMOD dispatches generating resources to match hourly electricity demand, dispatching the least expensive generation first. The supply offer of the marginally dispatched unit in each hour sets the hourly market-clearing price. Navigant uses PROMOD to develop its fundamental wholesale energy market price and plant performance forecast. Note that plant performance is not modeled in terms of dollars per megawatt-hour ($/MWh), but instead models the system costs and incorporates capital and fixed costs, resulting in a detailed hourly dispatch forecast.

As part of the system modeling applied in PROMOD, Navigant maintains a detailed representation of the bulk electric transmission system. This relies on Federal Energy Regulatory Commission (FERC) Form 715 transmission load flow as a starting point, with ERCOT transmission expansion projects incorporated depending on their development status. Navigant uses Siemens' Power System Simulation for Engineering (PSS/E) as our power flow simulation tool.

Navigant also uses the Gas Pipeline Competition Model (GPCM) to develop our gas price forecasts. GPCM is a commercial linear programming model of the North American gas marketplace and infrastructure. Navigant applies its own analysis to provide macroeconomic outlook and natural gas supply and demand data for the model, including infrastructure additions and configurations and its own supply and demand elasticity assumptions. The GPCM runs are iterated with POM in order to converge on electricity sector demand and price.

Navigant models ERCOT using the peak demand and energy requirements forecasts from the ERCOT *Report on Capacity, Demand, and Reserves* (CDR).[2] This includes data on existing generation, new named projects, demand-side resources, imports, and new capacity construction that is needed to meet energy needs or that meets economic requirements for new builds.

Three emissions prices are considered in the modeling: nitrogen oxide (NO_X), sulfur dioxide (SO_2), and carbon dioxide (CO_2). For NO_X and SO_2, Navigant's price forecast is based on the Clean Air Interstate Rule (CAIR). SO_2 prices are zero due to the large amount of coal retirements announced and expected due to the original announcement of the Mercury and Air Toxics Standards (MATS) policy and the Clean Power Plan (CPP). The structure the U.S. Environmental Protection Agency's (EPA's) proposed regulations of CO_2 emissions from existing power plants (Option 2) is modeled. The national carbon policy goes into effect in 2020 in Navigant's forecast. Emissions rates of other pollutants, such as carbon monoxide (CO) and particulate matter (PM), are included in our assumptions about the Gas Plant technology. See Section 0 for an overview of Navigant's Gas Plant emissions assumptions and Appendix B for full details.

1.4.3 Navigant Solicited Input from AE to Ensure Our Model Aligned with the Local System

During this independent study, Navigant requested and AE provided data to enable Navigant to conduct our analysis. In particular, Navigant solicited input from AE to help ensure that our modeling assumptions aligned with the local system (e.g., system-specific data, load forecasts, transmission, and generation). AE provided the following data:

- Distributed and utility-scale solar generation shapes and capacity factors for owned and potential AE resources
- AE hourly load shape
- Wind generation shapes and capacity factors for owned and potential AE resources
- Operating details of AE plants
    - Must-run status
    - Capacity (seasonal)
    - Minimum generation, maximum generation, duct firing MW levels (seasonal)
    - Minimum up and minimum down time
    - Heat rate curves (seasonal)
    - Ramp rates
    - Fuel and non-fuel start costs (hot, warm, and cold start)
    - Location
- PPA contracts for renewables and thermal plants
- Marginal procurement costs for EE and DR
- Fuel prices
- Emissions prices (CO_2, SO_2, and NO_X)
- Assumed new unit additions/retirements in ERCOT
- DSM Market Potential Assessment

[2] See http://www.ercot.com/content/gridinfo/resource/2015/adequacy/cdr/CapacityDemandandReserveReport-Dec2014.pdf

- New transmission projects
- Transmission bus locations of any utility-scale renewables expected in the scenarios
- Distribution patterns for distributed solar or other distributed renewables
- Any transmission system upgrade information for new plants at Decker and Sand Hill
- Other completed AE studies that were identified as helpful during the kickoff meeting

1.4.4 Navigant Analyzed Seven AE Portfolios Within Four ERCOT Market Scenarios

1.4.4.1 What Portfolios Did Navigant Analyze?

The portfolios that Navigant analyzed are described in Table 10. In all portfolios, Navigant included all elements of the Plan with the exception of the Gas Plant. The difference among the portfolios is either the Gas Plant or other options in which AE may invest. Note that the modeled plan was prior to the City of Austin's recent decision to procure 438MW of solar PPAs that accelerated the procurement schedule.

Table 10. AE Portfolio Cases

Case #	Case Name	Description
C0	All Market	AE current 10-year plan without the addition of a 500 MW CC
C1	Decker CC	C0 + 500 MW CC addition at Decker
C2	Sand Hill CC	C0 + 500 MW CC addition at Sand Hill
C3	500 MW Solar	C0 + 500 MW of additional solar
C4	500 MW Wind	C0 + 500 MW of additional wind
C5	Alternative Mix	C0 + portfolio of renewable resources and DR with energy storage (200 MW wind, 200 MW solar, 50 MW DR, and 50 MW EE)
C6	Accelerated Solar	AE current 10-year plan with all solar additions coming online in 2017

Source: Navigant

See Sections 4.1.3.1 and 4.3 for an analysis of how each portfolio addresses the city's climate policy.

1.4.4.2 What Rationale Underlies Navigant's Market Scenarios?

To model the risk of each portfolio, Navigant constructed four ERCOT power market scenarios. The four power market scenarios are the Base case, High Natural Gas Price (High Gas) case, Low Natural Gas Price (Low Gas) case, and High ERCOT Solar case.

Navigant's market scenarios test the robustness of the AE portfolios to different market conditions. Gas prices are the largest potential source of uncertainty affecting the value of the portfolios. Higher gas prices will lead to higher power prices. Lower gas prices reduce power prices. The High Gas and Low Gas scenarios capture the effect of gas price uncertainty and volatility on the projected value of gas and renewable portfolio options and on market prices.

While Navigant's Base case contains substantial wind construction, consistent with recent trends and forward-looking wind costs, the High ERCOT Solar penetration case tests the portfolios' value with high solar penetration layered on top of the wind build. Solar and wind are both intermittent resources that peak at different times in ERCOT (West zone wind at night and Texas Gulf Coast wind and solar during the day).

1.4.5 Navigant's Analysis Considered Financial, Risk, and Other Metrics

Our analysis of the market scenarios and AE portfolios described in the previous section considers the following metrics.

Table 11. Navigant Analysis Metrics

Metric	Analysis Methodology
Cost	Calculated directly from modeling results
Exposure to risk	Evaluate spread of outcomes between market scenarios
Renewable generation	Calculate share of load served by renewables
CO_2 emissions	Calculate total impact of portfolio on CO_2 emissions
Water usage	Calculate the water usage of generation units
Local economic impacts	Estimate the economic impacts in Austin

Source: Navigant

Navigant conducted a financial assessment of the costs and benefits of each of the alternative resource portfolios. Each portfolio was designed to be 500 MW of nameplate capacity despite varying production of energy. Navigant equalized the portfolios using nameplate 500 MW capacity for comparison purposes. Had we equalized the portfolios on an energy basis, approximately 1,340 MW of solar at a 28% capacity factor would be needed to generate the same quantity of energy as a 500 MW Gas Plant operating at a 75% capacity factor.

For purposes of this analysis, we assumed that AE would own all the resources in each of the alternative resource portfolios except for wind energy and any solar procured prior to the projected reduction in the Federal Investment Tax Credit at the end of 2016. For solar acquired prior to the end of 2016, Navigant assumed it would be secured through a PPA at prices provided to us by AE.

The following incremental cost elements are included in our analysis:

- Capital cost
- Fuel cost
- O&M cost
- Insurance costs for owned resources
- Carbon prices
- Costs and benefits related to the EPA's Clean Power Plan (included via carbon price)
- Costs and benefits related to relieving congestion in AE

Hedging costs, regulatory costs, A/S procurement, and ERCOT fees are included as part of an estimate of AE's non-incremental costs and are assumed to be constant across all portfolios and scenarios.

1.4.5.1 What Benefits and Impacts Does This Study Analyze?

The final step in the analysis was to summarize the benefits and impacts of each alternative against the modeled scenarios and sensitivities. In addition to the direct benefits and impacts described above, Navigant quantified impacts using primary data, secondary data, and data provided by AE on the following other items:

- Water: estimated water use by the Gas Plant
- Pollutants: estimated pollutants derived from PROMOD (SO_2, NO_x, and CO_2)
- Land use impacts: estimates for the Sand Hill or Decker sites
- Estimated local economic impact
- Revenue benefits and costs to AE customers

Navigant considered the acreage footprint (use of increasing or decreasing relative to existing) of nearby existing land use and zoning of undeveloped nearby land within a radius of the Gas Plant site. Other significant impacts that could be known and measured were included in the analysis. Local economic impacts that would result from a specific scenario that can be known and measured were also considered. Financial risks are explicitly included; climate and drought risks are included only through the water usage metric. Finally, Navigant calculated the 20-year NPV of net benefits and impacts for each alternative against each scenario.

1.4.5.2 What Do the Scorecards Represent?

The outcome is a set of scorecards for AE for each alternative portfolio across the four market scenarios. These scorecards report the results of the portfolio across the financial and non-financial metrics considered in the analysis. The scorecards provide an accounting of the tradeoffs between different portfolios in each scenario and allow for comparison among scenarios. This approach is designed to identify portfolios that best meet AE's range of metrics at the lowest level of risk.

2. Forecast of ERCOT Market Scenarios

As previously discussed, Navigant's ERCOT market forecast underlies our analysis of AE's generation portfolio options. This section outlines Navigant's PROMOD market modeling assumptions, followed by a discussion of the results for each of the four market scenarios (Base, High Gas, Low Gas, and High Solar scenarios).

2.1 Modeling Assumptions

The following sections describe Navigant's PROMOD modeling assumptions. Note that these assumptions represent Navigant's generic, baseline assumptions, which we adapted as appropriate for each of the four market scenarios defined in Section 1.4.4.

Table **12** provides an overview of the source of each assumption.

Table 12. Sources of Key ERCOT Market Modeling Assumptions

#	Assumption	Source	Source Description
1	Capacity additions	Navigant and ERCOT	Named projects identified in ERCOT planning reports and that have passed Navigant's analysis screens. Generic additions found to be economic in the expansion plan.
2	Wind capacity additions to include	Navigant and ERCOT	Modeled as intermittent and non-dispatchable resources.
3	Solar additions (High Solar case)	Navigant	In the High Solar scenario, much of the new gas development in ERCOT is replaced with grid-tied solar PV resources.
4	Retirements	Navigant and ERCOT	Announced retirements from ERCOT with economic retirements projected by Navigant's analysis.
5	Load	ERCOT	Peak demand and energy forecasts for ERCOT are taken from the December 2014 CDR.
6	Reserve margin	Navigant	Calculated using Assumptions 1-5.
7	Natural gas prices (Base case)	Navigant	Navigant's Winter/Spring 2015 Reference Case Natural Gas Forecast.
8	Natural gas prices (scenarios)	Navigant and EIA	The ratio of the low and high resource prices to the U.S. Energy Information Administration's (EIA's) reference case were applied to Navigant's Base case.
9	Coal prices	Energy Ventures Analysis (EVA)	Coal price data from EVA.

10	Oil prices	Navigant	For the U.S. forecast, the first 1-2 years of the forecast are based on a New York Mercantile Exchange (NYMEX) 10-day average futures price, and the rest on a Navigant-developed Brownian motion simulation model. For regional residual and distillate fuel oil prices, the forecast uses a Navigant-developed regression model.
11	NO_X and SO_2 emissions prices	Navigant	Based on careful review of past policy proposals and recent judiciary, regulatory, and political developments and forecast by Navigant.
12	CO_2 emissions prices	Navigant	Based on careful review of the CPP[3] and forecast using Navigant's proprietary POM.
13	Transmission	Navigant and FERC and ERCOT	Uses FERC Form 715 transmission load flow representation as a starting point, Simulates power flow using Siemens's PSS/E.

Source: Navigant

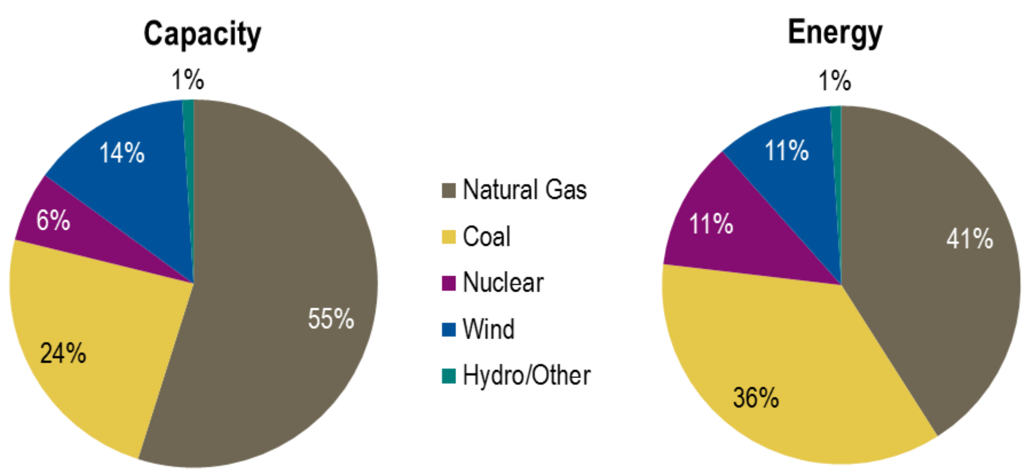
2.1.1 Supply and Demand Assumptions Indicate a Decreasing Reserve Margin in ERCOT

The following sections describe Navigant's baseline supply and demand assumptions.

2.1.1.1 What Does Navigant Assume About ERCOT's Generating Capacity?

Most installed capacity in ERCOT is natural gas, with coal, wind, and nuclear providing sizable contributions. Even though the installed capacity of natural gas-fired generation is higher than other resources in the region, the energy generated from gas is lower than that of baseload generating capacity, such as nuclear and coal, due to higher marginal cost of production, as seen in Figure 4. Wind is reported at net summer capacity below.

Figure 4. 2014 Capacity and 2014 Energy Use by Fuel Type in ERCOT

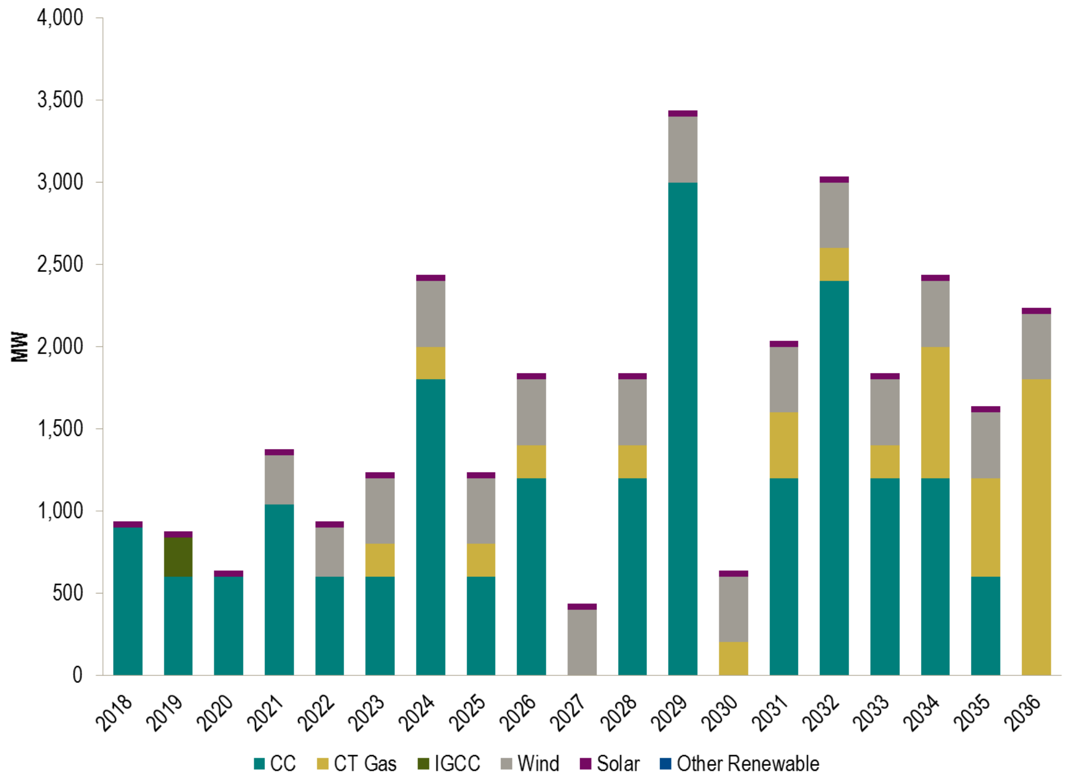


Source: Navigant (data from ERCOT 2015 Quick Facts)

[3] Navigant's Reference case was released prior to the final CPP rule. For detailed discussion, see Section 2.1.3.

Navigant's forecast includes existing generation that is grid-connected.[4] Starting with existing resources defined in the ERCOT CDR, Figure 5 shows the capacity additions in ERCOT throughout the study period. Named new projects are included in this forecast if they have commenced construction or they have been identified in ERCOT planning reports and have passed Navigant's analysis screens.

Figure 5. Capacity Additions by Type by Year[5]



Source: Navigant's PROMOD ERCOT Reference Case Database, May 2015

2.1.1.2 How Do the Production Tax Credit for Texas Wind and the Clean Power Plan Impact Supply?

In the near term, the majority of additions are in the form of CC plants and wind units. The CC plants included in the expansion plan are units that Navigant has determined are likely to be constructed based on economics.

[4] Generation that serves "behind-the-fence" load or is not grid-connected is not modeled. Load served by this self-supply generation is also not included in the demand forecast.
[5] Data in Appendix Table A-1.

The wind units coming online through 2015 are currently under construction or met the threshold for eligibility for the production tax credit (PTC) of having spent 5% of their total budget. Since the PTC has not been renewed, Navigant expects wind construction to taper off before growing again, spurred by rising gas prices and implementation of the CPP. The forecast also includes announced and generic solar additions when they were found to be economic in the expansion plan. The long-term build-out includes generic combustion turbines (CTs) and CC plants that have an acceptable return on equity based on energy and ancillary services market revenue. Generic new unit characteristic assumptions are provided in Table 13.

Table 13. Generic Unit Characteristics

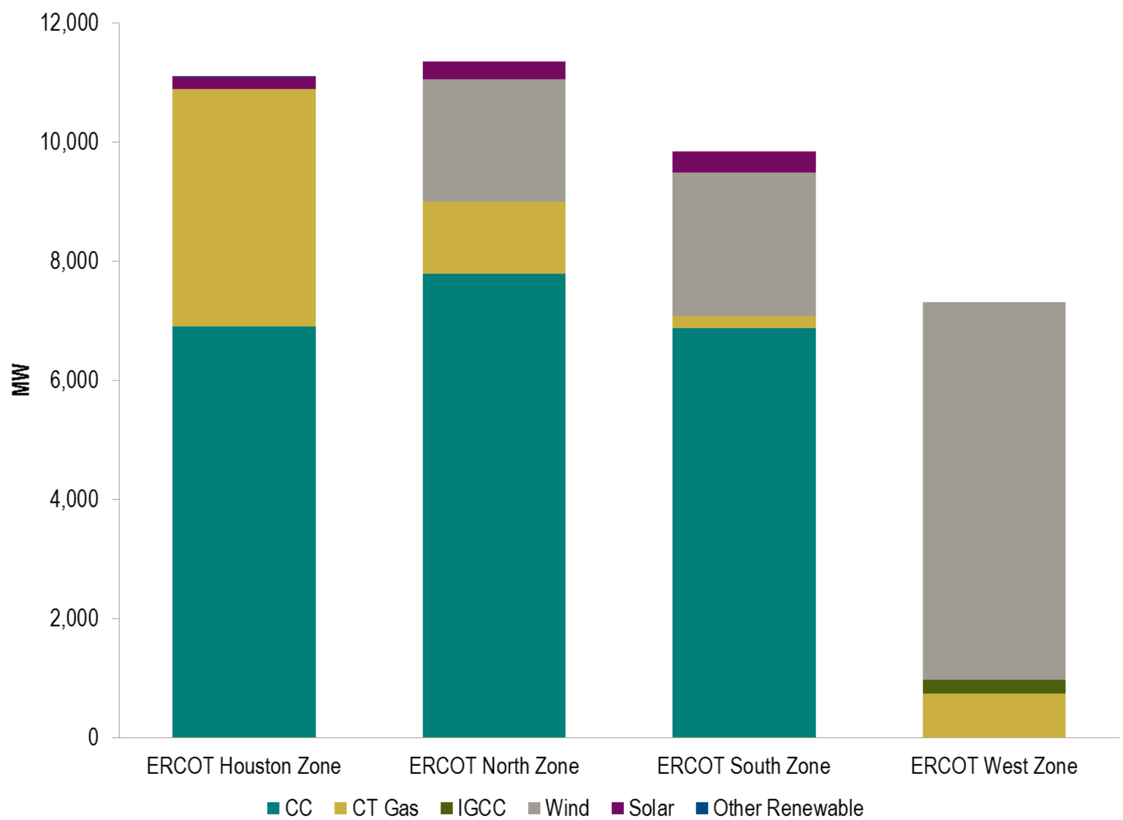
	CC	CT
Maximum Capacity	600 MW	200 MW
Heat Rate	6.633 MMBtu/MWh	9.012 MMBtu/MWh
Variable O&M Cost	$3.38/MWh	$10.19/MWh
Fixed O&M Cost	$12/kW-year	$5/kW-year
Forced Outage Rate	4%	3%

Note: The following abbreviations appear in the table above: million British thermal units (MMBtu) and kilowatt (kW).
Source: Navigant

2.1.1.3 Where Is New Capacity Being Built?

Figure 6 shows the capacity additions throughout the study period by zone. Much of the new CC plant construction is in ERCOT's Houston and South zones, spurred by higher near-term spark spreads.[6] Many of these additions are named units. Most of the wind construction is in the West zone, as well as in the North and South zones. Much of the wind construction in South zone is along the coast.

Figure 6. Capacity Additions by Type by Zone[7]



Source: Navigant's PROMOD ERCOT Reference Case Database, May 2015

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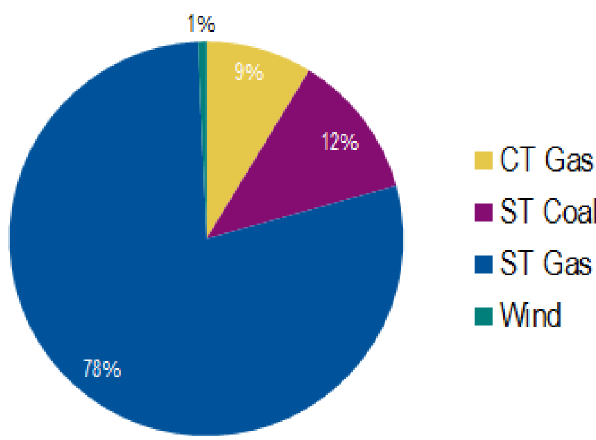
[6] "Spark spread" refers to the theoretical gross margin that a natural gas-fired power plant receives from selling a unit of electricity, having purchased the fuel required to produce this unit of electricity.

[7] Data in Appendix Table A-2.

2.1.1.4 What Retirements Are Projected in ERCOT and Included in the PROMOD Forecast?

ERCOT's retirements can be seen in Figure 7. The chart shows that 78% of all retirements will be in the form of ST Gas. In addition to announced retirements, economic retirements projected by Navigant's detailed analysis are included in the forecast. These economic retirements are driven by a combination of competition from low natural gas prices and added costs from existing or pending environmental regulations.

Figure 7. Retirements by Type through 2036[8]



Source: Navigant's PROMOD ERCOT Reference Case Database, May 2015

[8] Data in Appendix Table A-3.

2.1.1.5 What Underlies Navigant's Load Assumptions?

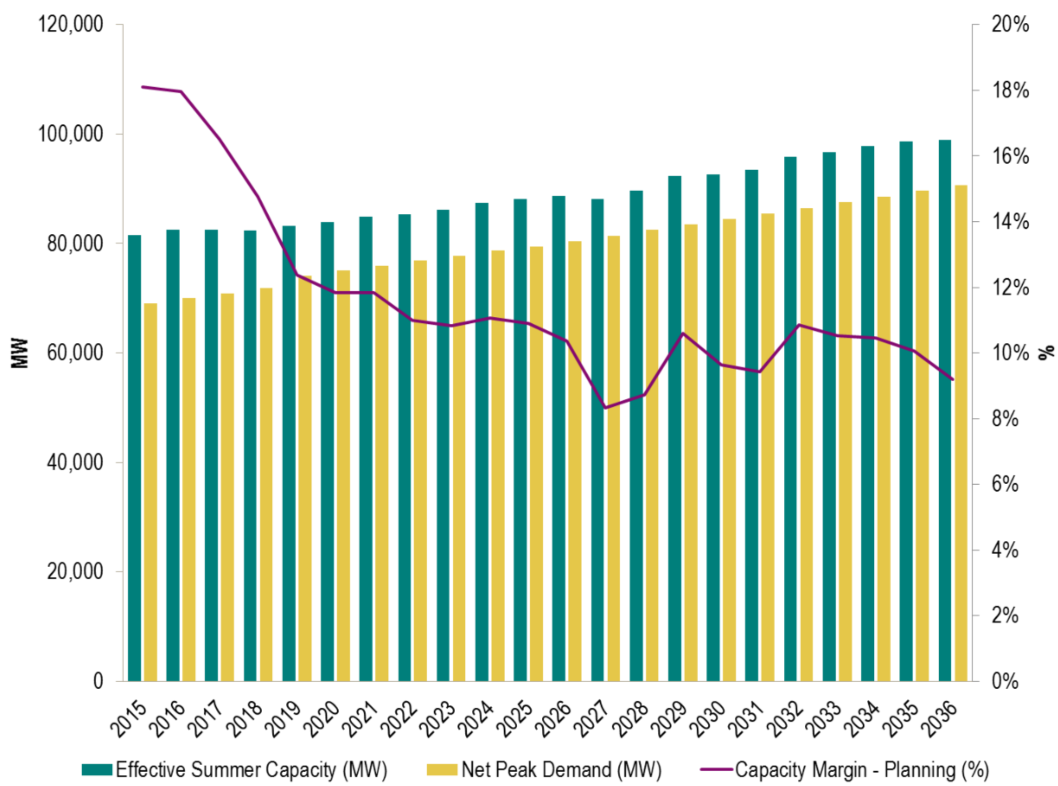
The peak demand and energy forecasts for ERCOT are taken from the December 2014 CDR. Figure 8 shows the annual peak demand forecast through 2023. The peak demand grows at an average of 1% annually over the study period, with a slightly greater escalation in the later years.

2.1.1.6 What Does Navigant Assume about ERCOT's Demand-Supply Balance?

Figure 8 shows the supply, demand, and reserve margin in ERCOT through 2036. Reserve margin is defined as available resources minus peak load, divided by peak load. Available resources equal non-wind capacity plus firm import capacity, plus 8.7% of wind capacity, which is known as the Effective Load-Carrying Capability (ELCC) of wind. EE and DR are also accounted for as demand-side resources.

As the capacity margin tightens, there are a larger number of high pricing hours due to resource scarcity. These price spikes in turn entice new economic builds to come online.

Figure 8. Supply-Demand Balance[9]



Source: Navigant's PROMOD Reference Case Database, May 2015

2.1.2 Fuel Prices Escalate in Real Terms

The following sections describe Navigant's natural gas, coal, and oil fuel price forecasts.

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[9] Data in Appendix Table A-4.

2.1.2.1 What Underlies Navigant's Natural Gas Base Case Assumptions?

Natural gas prices are the single largest driver of risk and changes in the cost of AE's market purchases. Navigant's Winter/Spring 2015 Reference Case Natural Gas Forecast[10] was used in this analysis and is shown in Figure 9.

The natural gas price forecasting model incorporates seasonal consumption estimates and delivery basis differentials. The first 18 months of the forecast are based on forward pricing at the time of this analysis and then are blended into our long-term fundamental forecast. The long-term forecast is created using the GPCM. The major assumptions in Navigant's long-term forecast include the following:

- Natural gas supply is strong throughout the forecast period due to unconventional gas shale supply growth
- Imports from Canada and Mexico tighten throughout the forecast
- Natural gas demand growth is led by increases in natural gas-fired U.S. electric generation, in part due to fuel switching from coal to gas, concerns over emissions regulations, and other U.S. public policy initiatives favoring natural gas

Specific key drivers of Navigant's forecast include the following:

- Increased fuel switching from coal to natural gas for power generation, driven by price competition and public policy
- Price recovery for natural gas in the coming years, leading to renewed drilling and increased supply from dormant dry plays
- Growth of shale gas as a share of total North American gas production, offsetting declines in conventional production
- Gas prices stabilizing over the long term
- More than 9 billion cubic feet per day (Bcfd) of exports from North America by 2021
- Incremental demand growth of more than 24 Bcfd in the power generation sector by 2035

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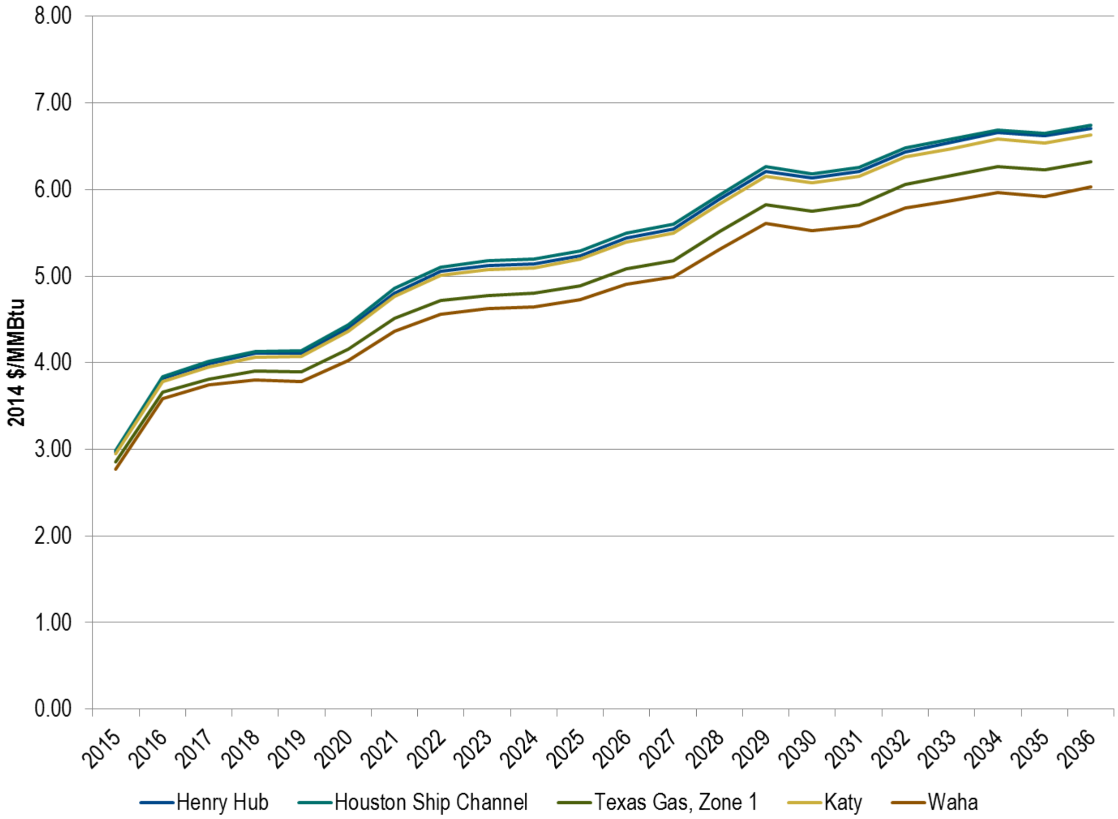
[10]For more information, see Navigant's *North American Natural Gas Market Outlook, Year-End 2014: A View to 2035*, available at:
http://www.navigant.com/~/media/WWW/Site/Insights/Energy/2015/EN_NANGMarketOutlook2014_BR_0315%20FINAL.ashx

Figure 9. Annual Average Natural Gas Prices[11]



Source: Navigant's Winter/Spring 2015 Fuel Forecast

2.1.2.2 How Did Navigant Develop Its Natural Gas Scenarios?

Due to high volatility and uncertainty in the natural gas market, both a High Gas and Low Gas case were developed and analyzed in addition to the Base case for this study. The one area of dispute going forward regards the natural gas supply that will be available, particularly from shale gas reserves across the United States, including within Texas. For this reason, the High and low forecasts were developed by utilizing the EIA's Low and High Gas resources cases.[12] These two cases are not symmetric; the EIA notes that there is more uncertainty about the potential for greater gains in production than about the potential for lower production levels.

Navigant did not use the EIA's price data directly; rather, the ratio of the low and high resource prices to the EIA's reference case were applied to Navigant's Base case Henry Hub price to create two additional price streams. When creating delivered prices across ERCOT, Navigant used forecast basis differentials generated from the GPCM. Information about the assumptions underlying the EIA's high and Low Gas resources cases is provided below for reference.

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[11] Data in Appendix Table A-5.

[12] For a full description, see the EIA's 2014 *Annual Energy Outlook:* http://www.eia.gov/forecasts/archive/aeo14/pdf/0383(2014).pdf

The EIA's underlying assumptions for its High Gas resources case are as follows:

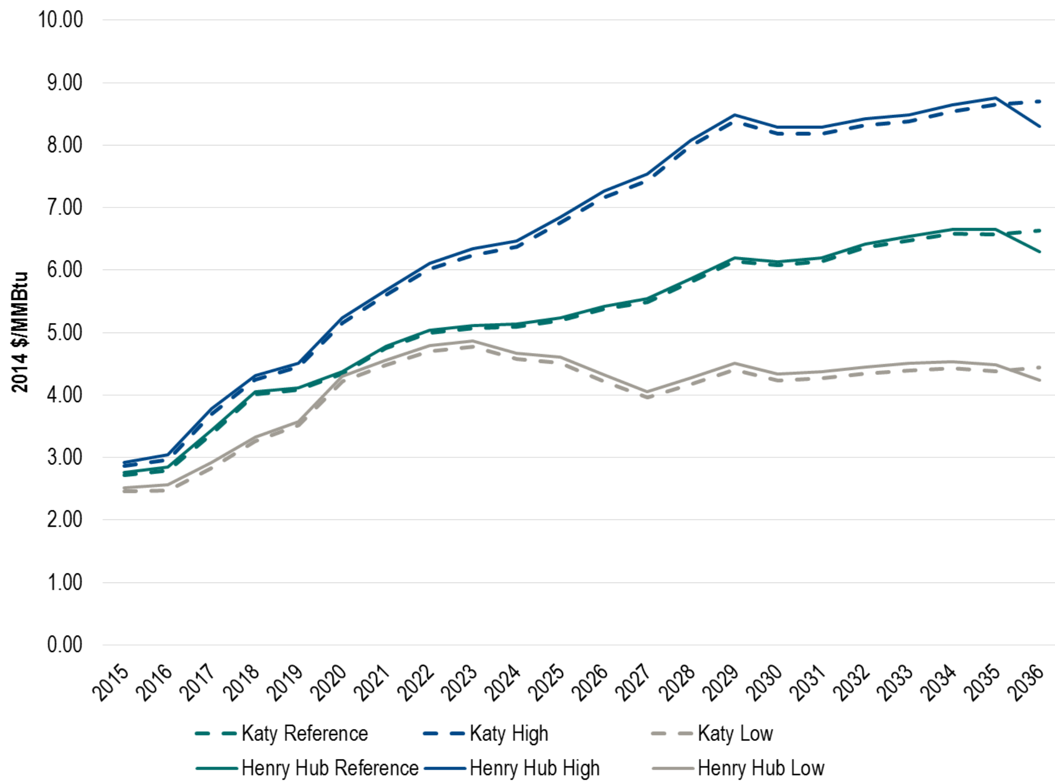
- Estimated ultimate recoveries[13] for tight oil, tight gas, and shale gas wells are 50% higher than in the EIA's reference case
- Additional tight oil resources, as well as 50% lower well spacing (i.e., wells are closer together), with a downward limit of 40 acres per well for existing and potential future tight oil resources, to capture the possibility that additional layers or new areas of low-permeability zones will be identified or developed
- Long-term technology improvements beyond those assumed in the EIA's reference case, represented as a 1% annual increase in the estimated ultimate recoveries for tight oil, tight gas, and shale gas wells
- More resources in Alaska and in the lower 48 offshore, including the development of tight oil in Alaska and 50% higher technically recoverable undiscovered resources for other Alaska crude oil and the lower 48 offshore (which reflects more favorable resolution of the uncertainty surrounding undeveloped areas where there has been little or no exploration and development activity, and where modern seismic survey data is lacking)

The EIA's Low Gas resource case reflects only the uncertainty around tight and shale crude oil and natural gas resources—specifically, whether the performance of current and future wells drilled will be less than estimated. For the Low Gas resource case, the estimated ultimate recovery per tight and shale well is assumed to be 50% lower than in the EIA's reference case (by scaling all applicable production decline curves). All other resource assumptions are unchanged from the EIA's reference case.

Figure 10 shows High Gas and Low Gas prices at Katy and Henry Hub, compared to the Base (Reference) case. The hump in gas prices in the low case reflects anticipated coal-to-gas switching because of the CPP.

[13] "Estimated ultimate recovery" is a production method commonly used in the oil and gas industry. It approximates the quantity of oil or gas that is potentially recoverable or has already been recovered from a reserve or well.

Figure 10. Annual Average Natural Gas Scenario Prices[14]



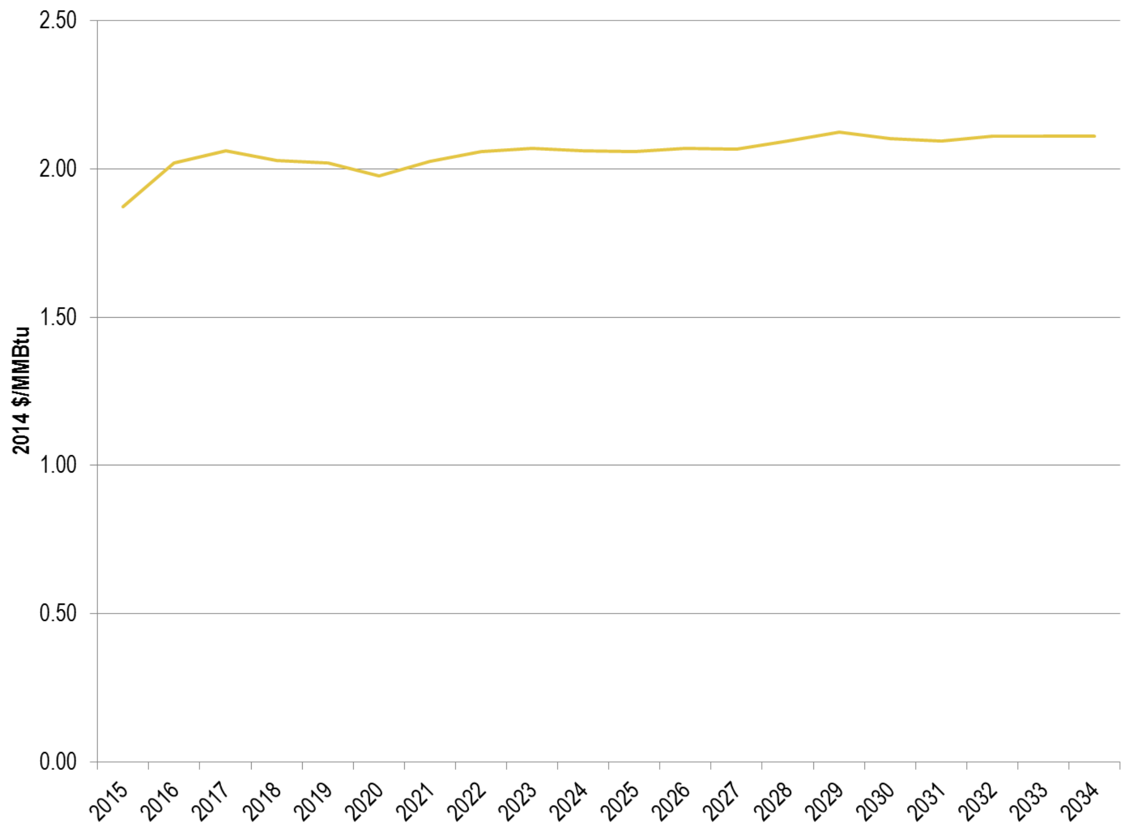
Source: Navigant's Winter/Spring 2015 Fuel Forecast

[14] Data in Appendix Table A-6 and Table A-7.

2.1.2.3 What Are Navigant's Coal Price Assumptions?

Forecast capacity-weighted coal prices in ERCOT are shown in Figure 11. ERCOT coal prices have real escalation driven by global demand, despite decreases in North American coal consumption due to retirements in coal generation.

Figure 11. Annual Capacity-Weighted Coal Prices[15]



Source: Navigant, Energy Ventures Analysis

2.1.3 Emissions Prices, Specifically Carbon Prices, Affect Navigant's Forecast of the ERCOT Market

Navigant explicitly modeled the impact of CO_2, SO_2, and NO_X on the ERCOT wholesale power market. Specifically, these emissions prices affect the ERCOT energy prices under which AE operates. Emissions rates of other pollutants, such as CO and PM, are included in our assumptions about the Gas Plant technology. See Appendix B for Navigant's Gas Plant emissions assumptions.

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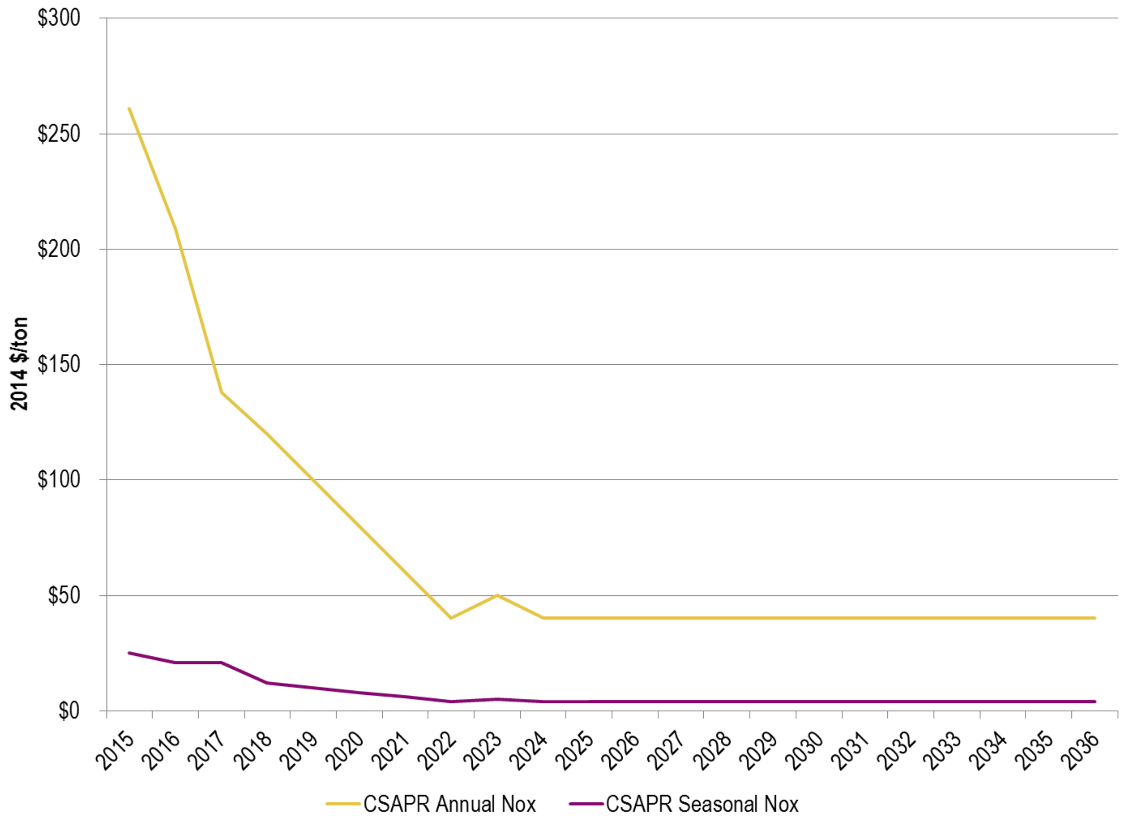
[15] Data in Appendix Table A-8.

2.1.3.1 How Did Navigant Forecast NO_X and SO_2 Prices?

Navigant's emission price assumptions are based on review of past policy proposals and recent judiciary, regulatory, and political developments. For NO_X and SO_2, our price forecast is based on the implementation of the Cross-State Air Pollution Rule (CSAPR) in 2015, as seen in Figure 12 and Figure 13.

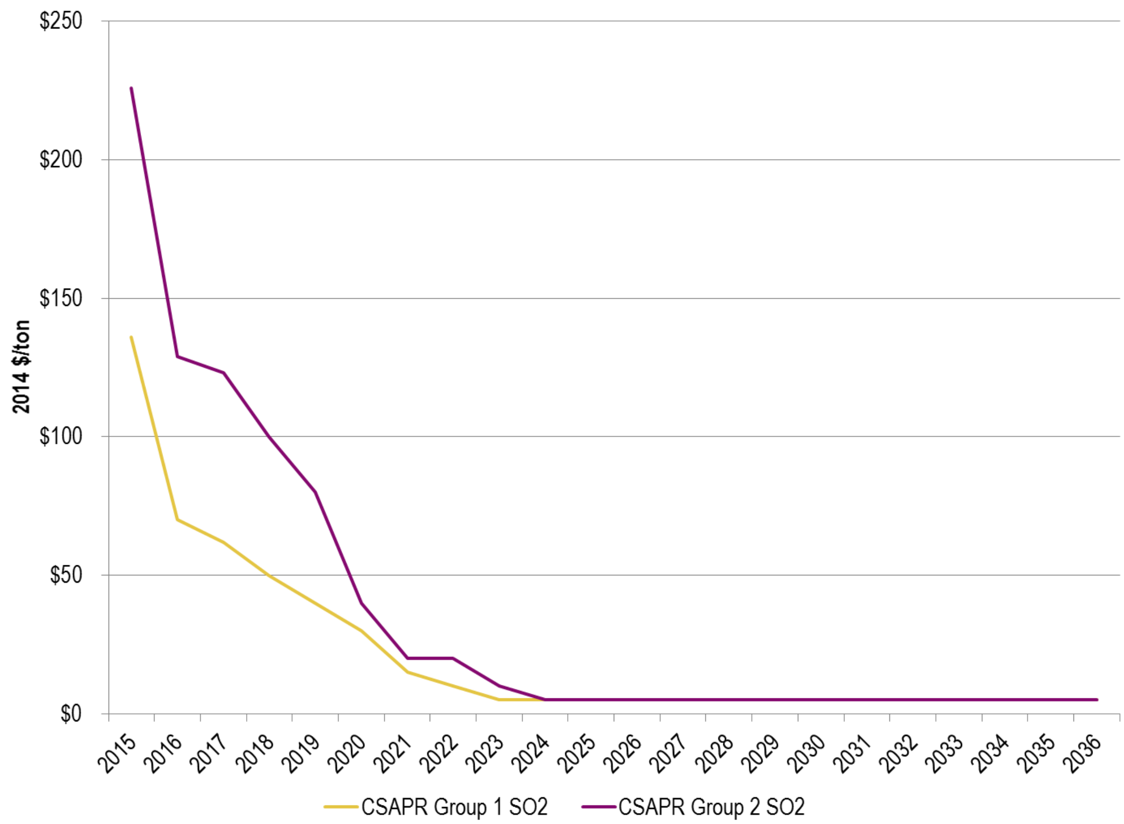
Figure 12. Annual NO_X Prices[16]



Source: Navigant's PROMOD Reference Case Database, May 2015

[16] Data in Appendix Table A-9.

Figure 13. Annual SO_2 Prices[17]



Source: Navigant's PROMOD Reference Case Database, May 2015

[17] Data in Appendix Table A-9.

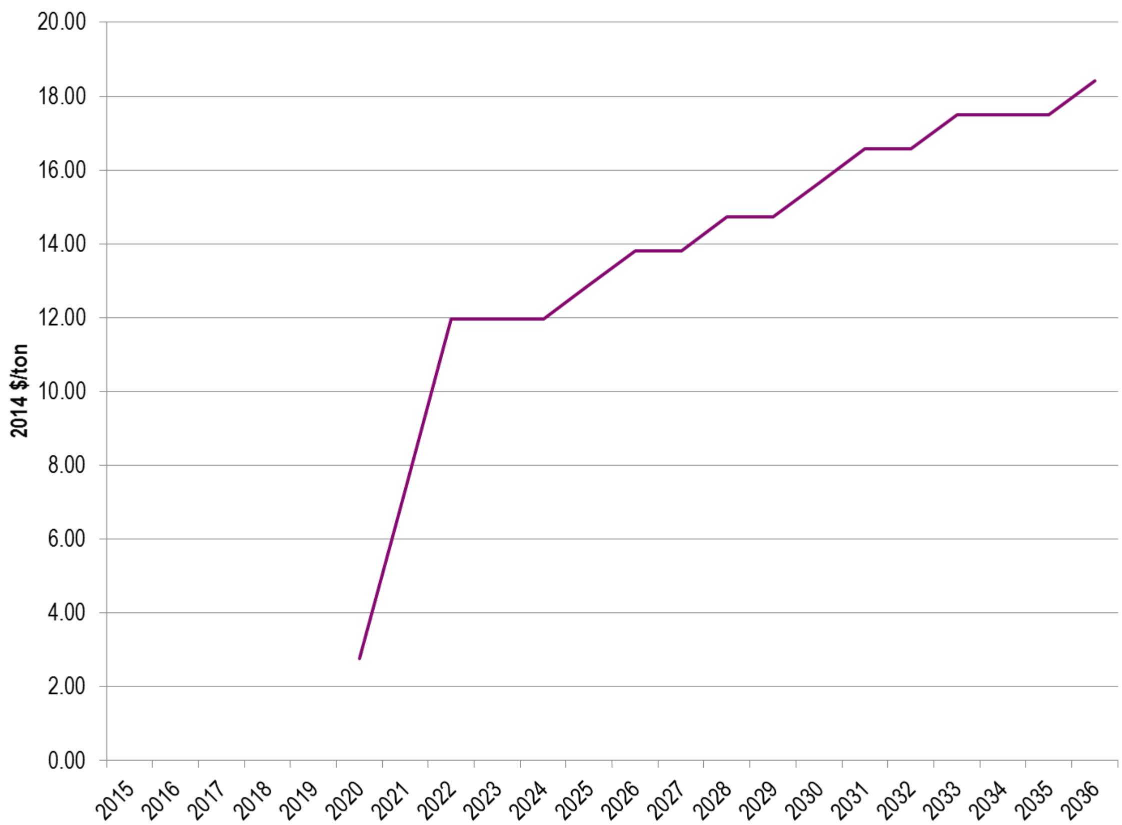
2.1.3.2 *What Assumptions Did Navigant Make to Develop Its Carbon Allowance Price Forecast for ERCOT?*

The EPA recently released the CPP, which limits state CO_2 emissions beginning in 2022. Navigant's Reference case was released prior to the final rule. After careful review of the CPP, Navigant developed its current assumption that the EPA's Option 2 targets as described in the CPP go into effect in 2020.

Navigant used its proprietary POM to forecast CO_2 emissions prices using a national cap on power plant emissions equivalent to a 23% reduction below 2005 emissions levels starting in 2020 and a 24% reduction starting in 2025, with 3-year averaging available. National CO_2 prices start below $3/ton in 2020, rise steeply to $12/ton in 2022, and then rise to over $17/ton in 2033 (real 2014 dollars), as seen in Figure 14. For context, at the time of the issuance of this report, California's Cap and Trade carbon market price was ~$13/ton and the results of Auction 29 of the Regional Greenhouse Gas Initiative an initiative of the Northeast and Mid-Atlantic States of the U.S. cleared carbon prices at $6.02/ton.

Navigant examines CO_2 emissions from a national market perspective, rather than for the city of Austin specifically.

Figure 14. Annual CO_2 Prices[18]



Source: Navigant's PROMOD Reference Case Database, May 2015

2.1.3.3 What Does Navigant's Carbon Price Forecast Represent?

In its Base case, Navigant's assumed carbon prices are based on a cap-and-trade type policy set up by the state of Texas under the CPP. While cap-and-trade policies are designed to internalize some of the negative externalities of air pollutants into the energy market, they are not typically able to internalize all of the negative externalities.

However, under cap-and-trade policies, pollutant allowance prices are based on the cost to emitters to reduce their emissions to meet the cap. Under perfect market conditions, the cost of CO_2 in any market would approach the cost to society of emitting that pollutant, but never exceed it. Therefore, the CO_2 allowance price forecast used in this analysis is below that of the Social Cost of Carbon developed by the U.S. Interagency Working Group on Social Cost of Carbon in May 2013.[19]

2.1.4 Assumed Transmission Projects Support the Integration of Renewable Resources

Navigant maintains a detailed representation of the bulk electric transmission system for our energy market modeling and project assessment studies. The transmission representation relies on the FERC Form 715 transmission load flow representation as a starting point, with regional transmission expansion projects incorporated depending on the development status of the specific project. We rely on the detailed transmission representation for asset operational assessments, site selections, and congestion studies. Navigant uses Siemens's PSS/E as our power flow simulation tool. PSS/E is an integrated, interactive program for simulating, analyzing, and optimizing power system performance. It offers probabilistic analyses, advanced dynamics modeling capabilities, and a broad range of other tools for use in simulating the operation of transmission networks. The transmission representation is used for power flow analysis and to support our energy market modeling and energy project analysis services. The transmission representation is a critical input into our nodal market modeling services.

2.2 ERCOT Market Scenario Forecast Results

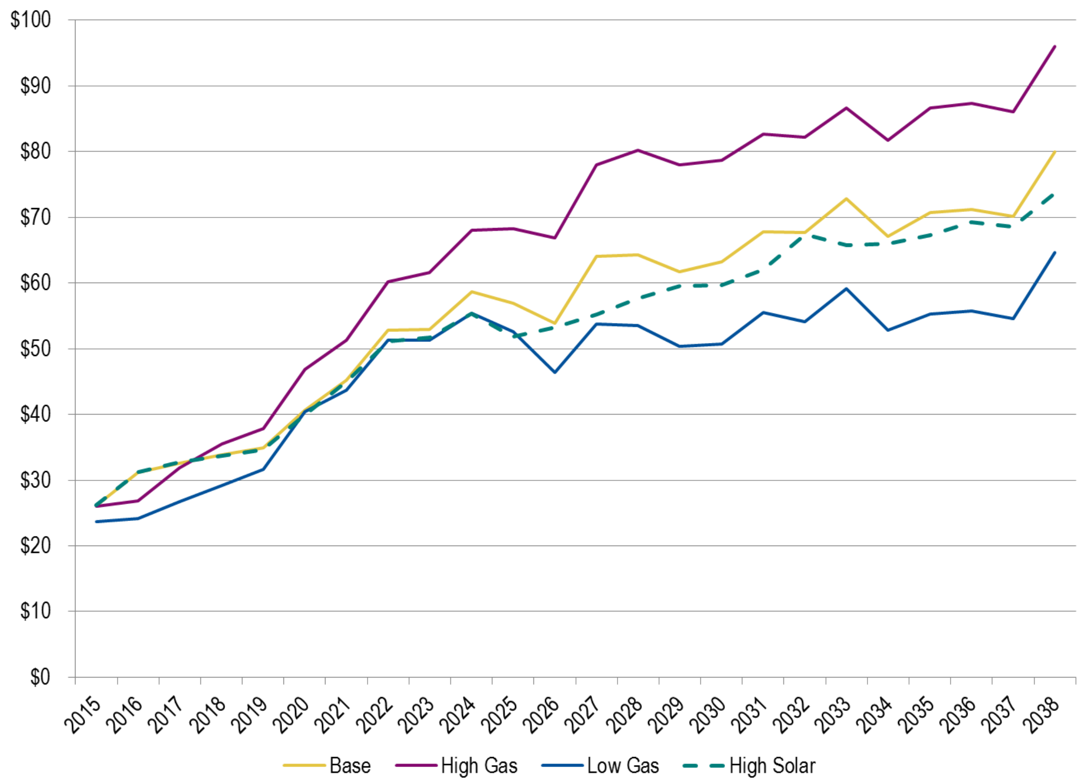
2.2.1 ERCOT Market Prices Rise in Real Terms in All Scenarios

Figure 15 compares adjusted LMPs at ERCOT's South hub across the four ERCOT market scenarios. LMPs increase in real terms throughout the study period in all four market scenarios. LMPs in the Base, High Gas, and Low Gas scenarios share similar trends year-over-year but are not symmetric, as is expected based on the gas price forecast assumptions (see Section 2.1.2.2). LMPs in the High Solar scenario are less volatile than in other scenarios late in the forecast period.

The specific drivers that influence the forecast results are discussed in the next section.

[19] For the Social Cost of Carbon, see *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*, May 2013: https://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf

Figure 15. Summary of All-Hours Adjusted Average LMPs, ERCOT South Hub (2014$)



Source: Navigant

Further detail is provided in Table 14.

Table 14. All-Hours Adjusted Average LMPs, ERCOT South Hub (2014$/MWh)

	Base	High Gas	Low Gas	High Solar
2015	$26.16	$26.07	$23.65	$26.20
2016	$31.21	$26.89	$24.21	$31.22
2017	$32.60	$31.86	$26.69	$32.73
2018	$33.88	$35.55	$29.22	$33.68
2019	$34.92	$37.81	$31.65	$34.64
2020	$40.66	$46.86	$40.44	$39.86
2021	$45.23	$51.33	$43.74	$45.08
2022	$52.83	$60.26	$51.35	$51.08
2023	$52.96	$61.56	$51.33	$51.74
2024	$58.62	$68.06	$55.43	$55.34
2025	$56.89	$68.23	$52.62	$51.89
2026	$53.89	$66.90	$46.37	$53.24
2027	$64.02	$78.05	$53.81	$55.22
2028	$64.26	$80.18	$53.57	$57.67
2029	$61.74	$77.94	$50.37	$59.50
2030	$63.22	$78.71	$50.78	$59.64
2031	$67.77	$82.71	$55.56	$61.99
2032	$67.66	$82.25	$54.14	$67.44
2033	$72.82	$86.71	$59.20	$65.80
2034	$67.09	$81.70	$52.78	$66.02
2035	$70.70	$86.60	$55.32	$67.30
2036	$71.22	$87.35	$55.79	$69.26
2037	$70.14	$86.06	$54.58	$68.54
2038	$80.04	$96.04	$64.68	$73.72

Source: Navigant

2.2.2 Several Market Factors Drive Energy Prices

A number of market factors drive the increase and variations in energy prices in the forecast.

2.2.2.1 What Is the Impact of the CPP?

The introduction of a carbon policy in 2020 and the subsequent ramp-up of CO_2 prices into 2022 result in an increase in wholesale power prices. Natural gas-fired plants increase their variable costs by about half as much as coal plants; however, overall thermal generation cost increases result in a higher clearing price across all hours. The volatility pricing is unchanged due to the CO_2 prices directly; however, over time, the carbon policy spurs new renewable development, which increases the system's volatility.

Under a typical cap-and-trade market, carbon allowances raise the wholesale power prices overall as they are a cost to carbon emitted generation that typically sets the wholesale power prices in ERCOT. This means that revenue paid to all generators under a cap-and-trade scheme increase whether generators produce carbon or not. Those generators that produce carbon will also have the added (typically higher cost) to purchase carbon allowances.

2.2.2.2 What Is the Impact of ERCOT's Tightening Reserves?

As demand and retirements outpace capacity additions into the early 2020s, ERCOT's reserve margin decreases. This causes a larger number of scarcity pricing hours, which are necessary to create an economic environment to entice new generation builds. The somewhat jagged pattern shown in the Base, High Gas, and Low Gas scenarios beyond 2024 is a reflection of this cyclical market dynamic. As reserves tighten and scarcity pricing hours increase, new resources are built to meet the higher demand.

After new resources are built, there is generally a year or two of lower pricing until an uptick in scarcity pricing again entices new development. The High Solar scenario displays a limited version of this pattern as it both assumes a more consistent amount of solar integration year-over-year, and solar generation depresses on-peak generation needs, limiting summer emergency or scarcity pricing events.

2.2.2.3 What Is the Impact of Natural Gas Prices?

Natural gas prices are a major driver in power prices in ERCOT and tend to become more significant as coal retirements occur and additional gas generation is assumed to come online. The Low Gas, High Gas, and Base cases tend to follow very similar patterns, as the total variable cost of gas-fired generation is lower. However, scarcity pricing events are still in line, as they depend on the supply/demand balance, which remains identical among the Scenarios. The High Solar case is less reliant on gas and displaces some baseload generation with solar generation, which serves as a price taker in the market.

3. AE Portfolio Market Context and Resource Assumptions

3.1 Resource Assumptions

This section describes the assumptions underlying our assessment.

3.1.1 The Gas Plant Is Efficient and Highly Available

3.1.1.1 What Is the Market Context of Natural Gas Resources in ERCOT?

The 2014 ERCOT State of the Market Report[20] concludes that the ERCOT market presently does not bear the cost of a new Gas Plant by a significant margin. Based on the EIA's updated estimates of investment costs for new units, ERCOT determined that the net revenue required to satisfy the annual fixed costs (including capital carrying costs) of a new CC gas unit range from $110 to $125 per kW-year. These estimates of annual fixed costs reflect power plant equipment costs, and ERCOT further reduced them to reflect Texas-specific construction costs as estimated by ERCOT. The net revenue[21] in 2014 for a new CC gas unit was calculated to be approximately $57 per kW-year, below the estimated cost of new CC generation. ERCOT concludes that 2011 has been the only year in which net revenue would have been sufficient to support either new gas turbine or new CC generation.

AE's costs are somewhat lower because of the availability of the existing sites for brownfield[22] development which includes access to pre-existing infrastructure for transmission interconnection, gas supply and water and municipal financing costs, which are advantageous compared with financing costs assumed for merchant power plant development.. Our forecast is consistent with this report in the sense that the market for new CC development is relatively negative in the near term and do not improve until the mid-term when ERCOT reserve margins tighten.

Shortage pricing plays a central role in providing investment incentives in an energy-only market like ERCOT. In ERCOT, net revenue is expected to be less than required to support new investment in most years. In the small number of years that are much worse than normal, the sharp increase in the frequency of shortage pricing should cause net revenue in those years to be multiples of the annual level required to support investment. This pattern over the long run creates an expectation that net revenue, on average, will support new investments.

Separate from overall ERCOT economics, there is value for locating a Gas Plant in the AE load zone. A local Gas Plant also has the effect of reducing local costs, such as congestion, real time pricing spikes and ancillary services costs that AE and its rate payers are exposed to and the Gas Plant earns the revenues

[20] This report is available at:
https://www.potomaceconomics.com/uploads/ercot_documents/2014_ERCOT_State_of_the_Market_Report.pdf

[21] For natural gas units, net revenue is calculated by assuming that the unit will produce energy in any hour for which it is profitable and by assuming that it will be available to sell reserves and regulation in all other hours.

[22] Brownfield is a term which describes land previously used for industrial purposes, in this instance land currently used as a power plant site.

for the electricity it produces during these periods. This additional value to the Gas Plant specific to AE customers is not included in the style of analysis that is conducted by ERCOT. The ERCOT report states on page 85 that "the energy net revenues are computed based on the generation-weighted settlement point prices from the real-time energy market. Weighting the energy values in this way facilitates comparisons between geographic zones, but will mask what could be very high values for a specific generator location".

3.1.1.2 What Are Navigant's Assumptions for the Gas Plant?

Our Gas Plant assumptions underlie the following AE portfolio cases:

- C1: Decker CC
- C2: Sand Hill CC

Key assumptions for the Gas Plant resource are highlighted in Table 15.

Table 15. Resource Assumptions: Gas Plant

Resource Characteristics	Assumptions	Basis for Assumptions
$/kW, 2015-2035	$700/kW-$900/kW	Navigant, Quality Power, LLC, and AE engineer's report
Heat rate	6,631 Btu/kWh	Navigant and Quality Power, LLC
Production curve[23]	N/A	N/A

Source: Navigant

Assumptions regarding analysis of the Gas Plant fall into three categories:

- ERCOT-generic, including existing and planned resources/capacity for known resources
- AE-specific, including inflation rate, discount rate, fixed O&M costs, plant size and performance, timing for construction and operations, capital cost per kW (range), debt/equity ratio, and interest rates for financing (weighted average cost of capital [WACC])
- Other Navigant assumptions, including future natural gas prices (obtained from forecast model), carbon-related costs, non-fuel operating cost, term of debt and projected life, cost of debt issuance, insurance rate and escalation, depreciation schedule, spare parts and inventory, and generic new resource additions

For the purpose of this review, Navigant considered only advanced-class gas turbines for the 500 MW CC plant. The advanced-class gas turbine usually comes in one-on-one (1x1) configuration. That means that the plant will have one gas turbine, one heat recovery steam generator (HRSG), and one steam turbine. This configuration is more efficient than a 2x2x1 configuration, as it has only one set of balance of plant equipment as opposed to two sets of balance of plant equipment, as in the case of a 2x2x1 configuration.

[23] Applicable to renewable resources only.

As part of our independent review, Quality Power, LLC, a Navigant subcontractor, solicited and obtained cost and plant information from three major gas turbine manufacturers: General Electric Power Systems, Mitsubishi Electric, and Siemens Power Corporation. All three vendors provided a summary base capital cost estimate based on Navigant's scope of supply for engineering, procurement, and construction (EPC) of a nominal 500 MW natural gas-fired CC power plant at either Decker or Sand Hill. Navigant provided a high-level scope of supply, shown in Table 16, to all three vendors to obtain the cost estimate.

Table 16. Scope of Gas Plant Supply

Characteristic	Specification
Configuration	1x1 or 2x1
Fuel	Natural gas
Type of supply	EPC – turnkey
Number of gas turbines	1 or 2 (depending on supplier)
Number of steam turbines	1 (with LO systems and all auxiliaries, valves, etc.)
Number of generators	2 (1 gas turbine each and 1 steam turbine)
Number of generator excitation systems	1
Number of generator step-up transformers	1 (also used as startup transformer)
Number of HRSGs	1 or 2 (depending on configuration)
Number of condensers	1
Number of air evacuation systems	1 with 2x100% pumps
Number of condensate pumps	2
Number of feed pumps	2x100%
Number of cooling water pumps	2+1
Number of water treatment systems	1
Natural gas compressor	Not required
Steam turbine bypass	100%
Electrical equipment	Switch gears, motors, enclosure, battery chargers, uninterruptible power system (UPS), transformers, etc.
Number of turbine control systems	1
Number of plant Distributed Control Systems (DCSs)	1
Number of emissions control equipment	1
Condenser cooling	Include cooling tower and circulating water pumps; include water treatment equipment
Instrumentation and control equipment	Valves, instruments, analyzers, etc.

Source: Quality Power LLC and Navigant

The specific resource to be added meets the specifications described in Table 17. These specifications underlie Navigant's modeling assumptions. Where the three vendors provided different estimates, a range of values is reported.

Table 17. Gas Plant Manufacturer's Specification Sheet: Modeling Assumptions

Specification	Description
EPC cost estimate:	
Net output (MW)	495-508
Net heat rate (higher heating value [HHV], Btu per kilowatt-hour [kWh])	6,631
Capital cost – EPC ($million)	$350.0-$401.1
Cost per kW EPC ($/kW)	$700-$789
Owner's costs:	
Owner's engineer's cost ($million)	$5.0
Permit fees ($million)	$1.0
Underwriter fees ($million)	$2.6
Total owner's cost ($million)	$8.6
Total project cost ($million):	$350-$450
O&M expenses:	
Estimated fixed O&M cost ($million per year)	$6.6
Estimated variable O&M cost ($/MWh)	$3.5/MWh
Operations and performance:	
Heat rate	Varies with load; approx. 6,000 Btu/kWh or less lower heating value (LHV)
Ramp rate (MW/min)	40
Water use:	A conventional ST unit is about 36% efficient, whereas a high-efficiency CC plant is about 60% efficient. To produce 500 MW of electricity, the high-efficiency CC plant uses only 150 MW steam turbine capacity, compared to 500 MW steam turbine capacity, which means that only 30% of steam will need to be cooled. In other words, the high-efficiency CC plant will use about 65% less water for cooling the condenser.
Emissions:	
NO_X emissions rate (abated parts per million by volume [ppmvd] @ 15% oxygen [O_2])	2[(1)]
CO emissions rate (abated ppmvd@15%O_2)	2-3[(1)]

Specification	Description
Volatile organic compound (VOC) emissions rate (abated ppmvd@15%O_2)	1(2)
PM lb/MMBtu HHV	0.00393(2)
Fuel specification:	
Methane CH_4 (percentage by volume)	93.9
Ethane C_2H_6 (percentage by volume)	3.2
Propane C_3H_8 (percentage by volume)	0.7
n-Butane C_4H (percentage by volume)	0.4
CO_2 (percentage by volume)	1.0
Nitrogen N (percentage by volume)	0.8
Btu/lb	20,552 (LHV), 22,972 (HHV)
Btu per standard cubic foot (SCF)	939 (LHV), 1,040 (HHV)

Notes
(1) General Electric did not provide an estimate.
(2) General Electric and Siemens did not provide an estimate.
Source: Quality Power LLC and Navigant

We assume the brownfield development—industry terminology for use of a site that already serves as a power generation site—of a highly efficient natural gas CC project designed to the best-available air emissions control technology (BACT) standard at either Decker or Sand Hill. Capital costs range from $700/kW to $900/kW (installed cost), based on recent engineering reports and independent review and discussions with vendors. Note that this installed cost range is based on site-specific estimates. The costs of a brownfield development are lower than the costs of a similar plant on a greenfield site. We also assume that both Decker and Sand Hill can accommodate a Gas Plant without significant additional investment in natural gas or transmission capacity (i.e., we assume that existing infrastructure will be used).

With respect to water usage, we assume that Decker can accommodate the Gas Plant without significant additional investment for water, whereas Sand Hill requires some investment to deliver greywater from South Austin Regional Water Treatment Plant (SAR). Specifically, Decker uses lake water for condenser cooling. The existing cooling water intake infrastructure will be more than adequate and could be used for the Gas Plant. Decker also has a boiler water treatment facility and water storage tanks. These are more than adequate in capacity for the Gas Plant and could be used. Meanwhile, Sand Hill uses a cooling tower for condenser cooling and has two sources for cooling water makeup: river water and greywater from SAR. Sand Hill does not have spare capacity for supplying cooling water to the cooling tower of the Gas Plant. SAR has more water to supply the Gas Plant. Sand Hill does not have excess capacity for a boiler water treatment facility or storage tank. AE would need to add infrastructure for treating boiler water and cooling water that could be piped in from SAR.

For full details on the Gas Plant assumptions, see Appendix B.

3.1.2 Solar Resources Are Becoming More Cost-Effective

3.1.2.1 What Is the Market Context of Solar in ERCOT?

According to UBS Global Research, solar PV is gaining momentum throughout the world. UBS expects utility-scale solar to continue to drive global growth due to better economics than smaller-scale solar, declining installation costs, and regulatory support to achieve climate policies and energy independence. UBS expects utilities to capture a growing share of the solar value pool and believes that solar may provide approximately 20 years of top-line growth to early adopters.[24]

In the United States, the Federal Investment Tax Credit ("ITC") for corporate investors is scheduled to decrease from 30% to 10% at the beginning of 2017. To date, the ITC has played a major role in catalyzing growth in solar installations. It is uncertain how the ITC drop-down will affect PPA prices. A report by the faculty at the Stanford Graduate School of Business[25] found that the elimination of the ITC is likely to increase the levelized cost of solar power by a significant margin. Greentech Media Research also expects PPA prices to rise in the near term with the loss of the ITC, but as the installation cost of utility-scale solar continues to fall, PPA prices are expected to return to present levels in 2019. This indicates that utility-scale solar is reaching cost parity with natural gas throughout the United States.[26]

Utility-scale solar power plants[27] in the United States account for approximately 8 GW-alternating current (AC), or around half of all solar PV installed capacity. Between 2011 and 2014, annual installations in the utility-scale sector grew more than 400%, reaching 3.2 GW-AC in 2014. Navigant forecasts the annual market to reach 5.2 GW-AC in 2016, reaching a peak before the end of the 30% federal ITC.

Following the 70% compound annual growth rate (CAGR) between 2010 and 2016, Navigant anticipates the ITC expiration to result in a material reduction in the utility-scale sector in 2017. Navigant expects to see a return to modest growth of utility-scale solar installations.

[24] For more information, see https://neo.ubs.com/shared/d1HeFCV8SppuSFx/

[25] To access the report, see http://www.gsb.stanford.edu/faculty-research/working-papers/us-investment-tax-credit-solar-energy-alternatives-anticipated-2017

[26] For more information, see http://www.greentechmedia.com/articles/read/Utility-Scale-Solar-Reaches-Cost-Parity-With-Natural-Gas-Throughout-America?utm_source=feedburner&utm_medium=feed&utm_campaign=Feed%3A+GreentechMedia+%28Greentech+Media%29

[27] The utility-scale solar PV market is defined as projects typically larger than 1 MW and installed on the utility side of the meter, though there are some installations at that size that are installed onsite at the customer location.

The United States has represented approximately 12% of all utility-scale solar PV installed globally during the past 4 years. First Solar, SunEdison, AES Solar, and 8minutenergy are some of the largest utility-scale companies. Due to the combination of scaled-up global manufacturing capacity, efficiency improvements, and a growing number of experienced utility-scale developers now operating in the United States, utility-scale PV is poised for continued cost reduction through 2020 and beyond. Price declines are expected to continue with leading companies, such as First Solar, stating installed prices as low as $1.00 per W-direct current (DC) by 2017.[28]

Utility-scale solar projects are being developed at record-low prices and are offering record-low PPAs. Recently, NV Energy signed a PPA to buy power at $0.0387/kWh from the 100 MW-DC Playa Solar 2 project being developed by First Solar. This price was a fixed-rate contract for 20 years. The best PPA price last year (2014) was $0.0460/kWh by SunPower for the Boulder Solar project, also signed by NV Energy. Another milestone for large-scale utility solar is the 30 MW Barilla Solar Project in West Texas. This project is being developed without a signed PPA. While First Solar, the developer, may eventually sign a PPA, the project is moving ahead with the intent of selling the power on the open market.[29] Recently, AE released information pertaining to an RFP of 600 MW of solar capacity with some prices reported to be below $40/MWh. While these rates take advantage of the federal 30% ITC, they are still among the lowest globally, even when comparing cost on an unsubsidized basis.[30]

According to the *Houston Chronicle,* solar energy is poised to "expand dramatically" in Texas, spurred by rising PV efficiency, decreasing production costs, and growing consumer and investor interest.[31] Solar power is proving to be commercially viable and low-risk. Nationally, it is the fastest-growing segment of the electricity market, and it represented 32% of new generation capacity added in 2014. The per-MW cost of solar energy has decreased 53% since 2009, due to less expensive and more efficient panels. In Texas, solar capacity represents only 387 MW (less than 1% of ERCOT's generation capacity), but 129 MW of that capacity was installed in 2014. Another 260 MW will connect to the grid by the end of 2015. Recent utility-scale solar projects in Texas are priced below $50/MWh, putting them on par with natural gas over a 20-year period, although this is due in part to the federal ITC.

On October 16, 2015, ERCOT released a report entitled *ERCOT Analysis of the Impacts of the Clean Power Plan Final Rule Update*[32] based on the final rule released by the EPA in August. In the baseline scenario, ERCOT forecasts the addition of 13,000 MW of solar capacity added to the ERCOT market by 2030. It should be noted that the ERCOT analysis also assumes the expiration of the Production Tax Credit and step-down of the ITC, as per current law, consistent with the Navigant assumptions. In the scenarios with the CPP, the ERCOT analysis adds an additional 400 MW-1,100 MW of solar capacity.

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[28] "By 2017, We'll Be Under $1.00 per Watt Fully Installed", First Solar CEO, June 2015.

[29] First Solar, September 2014, http://investor.firstsolar.com/releasedetail.cfm?releaseid=869379

[30] See http://www.greentechmedia.com/articles/read/cheapest-solar-ever-austin-energy-gets-1.2-gigawatts-of-solar-bids-for-less

[31] Tomlinson, Chris. "Solar energy is ready to expand dramatically in Texas." *Houston Chronicle*, October 1, 2015: http://www.houstonchronicle.com/business/columnists/tomlinson/article/Solar-energy-is-ready-to-expand-dramatically-in-6543744.php

[32] ERCOT releases report on potential Clean Power Plan impacts http://www.ercot.com/news/press_releases/show/76880

3.1.2.2 What Are Navigant's Assumptions for Solar Resources?

Navigant's solar assumptions underlie the following AE portfolio cases:

- C3: 500 MW Solar
- C5: Alternative Mix
- C6: Accelerated Solar

Key assumptions for solar resources are highlighted in Table 18.

Table 18. Resource Assumptions: Solar

Resource Characteristics	Assumptions	Basis for Assumptions
Capital Costs $/kW, 2015-2035	$1,130-$1,350	Navigant subject matter expert (SME), validated with recent AE data and Texas market outreach by Navigant subcontractor Energy Utility Group.
Capacity factor	28%	Data from AE and Texas market outreach by Navigant subcontractor Energy Utility Group
Production curve	See Figure 18	Data from AE
Degradation	0.45% per year	Navigant SME

Source: Navigant and Energy Utility Group, LLC

Several key factors influence power generation economics from solar PV plants: the solar resource, mounting technology (tracking vs. fixed tilt), panel technology, and ownership structure:

- **Solar Resource:** Solar plants in West Texas are able to take advantage of a favorable solar resource, as the availability of solar in Texas is among the highest in the country.
- **Tracking vs. Fixed Tilt:** Tracking can increase the PV plant output with systems in the western part of the United States benefiting more than systems in the east. To determine if the use of tracking is beneficial in a project, the developer weighs the increase in power output against the increased cost. In West Texas, single axes tracking systems provide around a 25% increase in energy generation and are favored.
- **Panel Energy Output: Crystalline Silicon vs. Thin-Film:** Panel selection also affects the power output due to different panel technology performance at various temperatures. In hot climates, thin-film panels produce more power; in colder climates, crystalline silicon has an advantage. In West Texas, thin-film is expected to produce around 5% more energy for the same nameplate capacity relative to a similar crystalline silicon panel. However, similar to tracking, this gain is also weighed against changes in cost.

Navigant's key assumptions for solar resources are as follows:

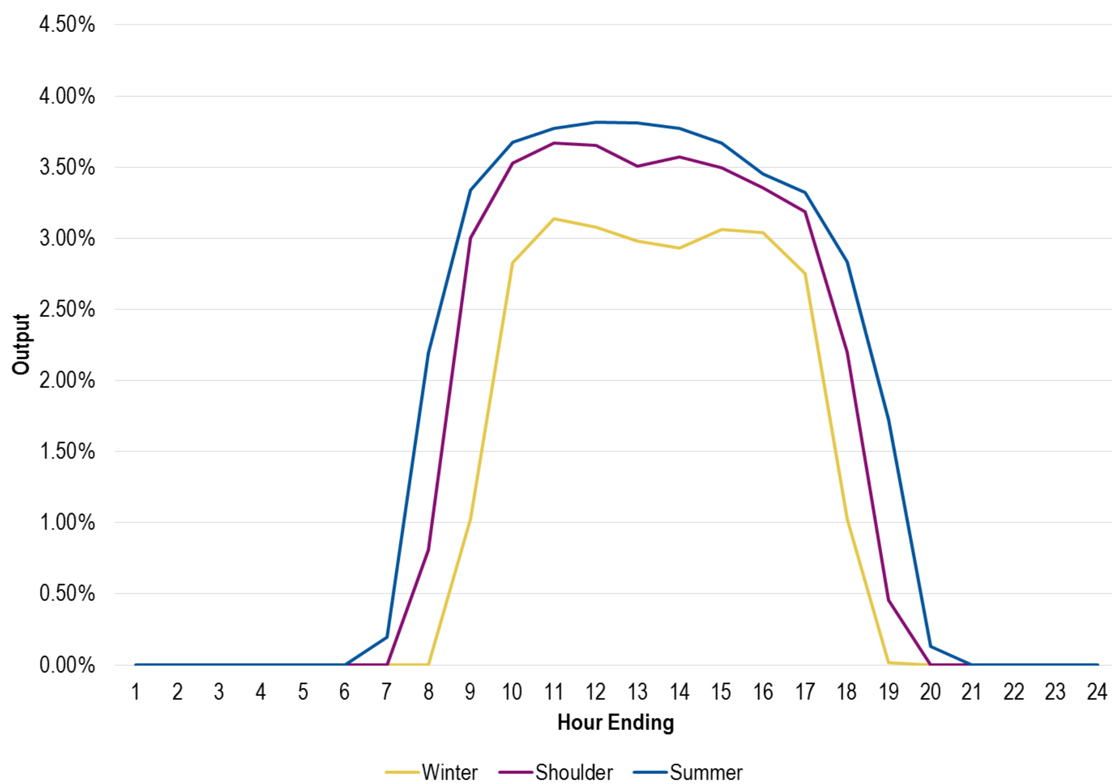
- Single-axis tracking utility-scale grid-tied solar PV tends to generate more power during peak periods.

NAVIGANT

- We assume that the ITC drops to 10% at end of 2016. After 2016, we assume that AE owns new solar capacity because AE's low cost of debt combined with the drop-down in ITC is projected to make it less expensive for AE to own solar capacity than to enter into a PPA.
- We adopt AE's prices for solar resources in the short term; thereafter, our own projections, which are based on developer information in ERCOT on projected prices, are used. See Section 3.1.2.3.

The assumed solar output curve is shown in Figure 16. The curve is based on data provided by AE and confirmed by data used by Navigant. It was created by normalizing a representative solar output profile for ERCOT's West zone first by typical day by season. In ERCOT, the winter months include December, January, and February; the summer months include June, July, and August; and the shoulder months include March, April, May, September, October, and November.

Figure 16. Assumed Solar Output Curve, ERCOT West



Source: Navigant

3.1.2.3 How Do Navigant's Solar Assumptions Relate to AE's Approved 2025 Generation Plan?

As discussed in Section 1.2.2, AE's approved 2025 Generation Plan calls for AE to increase its solar resources to a minimum of 950 MW by 2025 by taking the following actions:

- Reach the city's goal of 200 MW of local solar, including at least 100 MW of customer-sited local solar

- Add 600 MW of utility-scale solar from AE's RFP
- Assume the full build-out of the announced 150 MW of solar power currently contracted with Recurrent Energy

All of Navigant's portfolio cases include the 950 MW described above.

However, in different portfolio cases, Navigant assumes that the 600 MW of utility-scale solar comes online in different periods. As summarized in Table 19 below, C0 through C5 assume that this capacity comes online gradually in 200 MW blocks; C6 assumes that all 600 MW comes online before the ITC decreases to 10% in 2017. Some cases also consider additional solar capacity, all of which is assumed to come online after 2017. In all cases, the same basic pricing methodology applies:

- We assume that capacity that comes online before 2017 is priced at the $40/MWh PPA price provided to Navigant by AE.
- During and after 2017, the current PPA pricing no longer applies. Therefore, Navigant's own projections, which are based on developer information in ERCOT on projected prices, apply to capacity that comes online during and after 2017.

We assume that AE owns solar capacity that comes online during and after 2017 because AE's low cost of debt combined with the drop-down in the ITC is projected to make it less expensive for AE to own solar capacity than to enter into a PPA.

Table 19 describes the cost assumptions for both the solar resources in AE's approved 2025 Generation Plan and the additional solar capacity that Navigant analyzed in relevant portfolio cases.

Table 19. Solar Assumptions Relative to AE's 2025 Generation Plan

AE Portfolio Case(s)	Resource	Cost Assumptions
All cases	200 MW of local solar, including at least 100 MW of customer-sited local solar	Current AE actual costs
All cases	150 MW of solar currently contracted with Recurrent Energy	Current AE actual costs
C0-C5	600 MW of utility-scale solar coming online in 200 MW blocks (before and after 2017)	• Capacity before 2017 is priced at AE's current PPA prices ($40/MWh). • After 2017, the current PPA pricing no longer applies. Navigant's own projections, which are based on developer information in ERCOT on projected prices, are used for capacity that comes online during and after 2017. AE owns this capacity.
C3: 500 MW Solar	500 MW of utility-scale solar in addition to the 950 MW included in AE's 2025 Generation Plan	Capacity comes online after 2017, so the current PPA pricing does not apply. Navigant's own projections, which are based on developer information in ERCOT on projected prices, are used. AE owns this capacity.

AE Portfolio Case(s)	Resource	Cost Assumptions
C5: Alternative Mix	200 MW of utility-scale solar in addition to the 950 MW included in AE's 2025 Generation Plan	Capacity comes online after 2017, so the current PPA does not apply. Navigant's own projections, which are based on developer information in ERCOT on projected prices, are used. AE owns this capacity.
C6: Accelerated Solar	600 MW of utility-scale solar, all online by 2017	Current AE PPA prices ($40/MWh)

Source: Navigant

3.1.2.4 How Did Navigant Approach the Development of Its PV Forecast?

Navigant maintains a forecast model based on historical industry learning rates (both global and local) for hardware and installation, internal assumptions for annual market growth, module efficiency, regulatory considerations, and profitability.

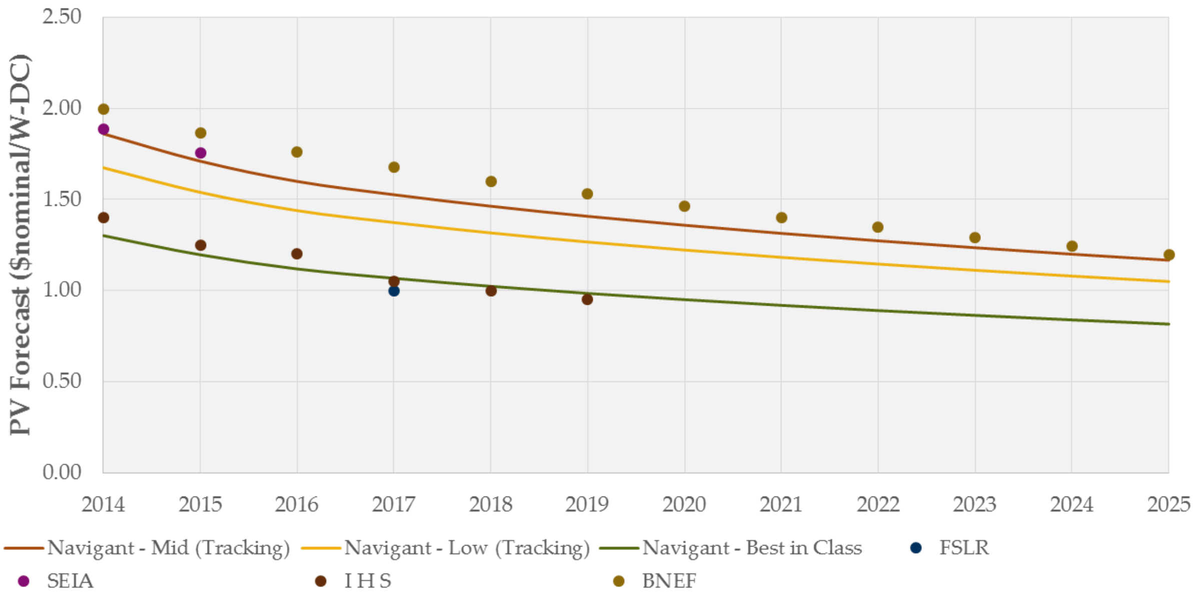
In order to validate the model, in the short-term forecast (2015-2020), Navigant and its subcontractor Energy Utility Group, LLC relied on interviews with solar industry key informants, including module manufacturers, EPC firms, and vertically integrated solar PV companies. Navigant also leveraged publicly available pricing information from investor relations documents in addition to benchmarking against other industry forecasts from government and private sources.

3.1.2.5 What Are Navigant's Assumptions Regarding PV System Costs?

As previously discussed, Navigant adopts AE's current PPA costs for utility-scale solar PV capacity added before 2017. After 2017, Navigant's own independent forecast is used. This forecast is discussed in detail below.

Utilities' PV system costs are becoming more attractive in the broader energy market, with best-in-class companies able to offer lowest prices due to scale, experience, and financing. The Low, Mid, and Best-in-Class price scenarios in Figure 17 represent the range in installed price for utility-scale solar PV plants in the United States for both tracking and fixed tilt systems, with price reductions mostly coming from incremental price reductions from hardware, consistent with historical learning curves and efficiency improvements.

Figure 17. U.S. PV Installed System Costs, 2014-2025 ($Nominal, $/W-DC)



Source: Navigant, 2015; SEIA Q2 2015; IHS, 2015; BNEF 2015; FSLR 2015

For large (>100 MW) utility-scale projects in West Texas, we expect prices to be on the lower end of observed and expected prices in the United States, in line with Navigant's Best-in-Class price forecast in Figure 17.

In our report Navigant provided a PV forecast that was benchmarked against several sources. Our forecast includes high, mid, and low price scenarios that we develop in house using internal models and benchmark against third-party forecasts and industry communications. For large solar plants in West TX, specifically for the AE procurement, we expect prices to be in line with our low case based on several factors including observed industry trends.

- Large solar installations in West TX are achieving some of the lowest pricing in the US and globally. Most large projects are built by leading developers and solar companies that are able to achieve significant cost savings due to factors such as economies of scale and vertical integration.
- The lowest observed and expected prices are likely only attainable by a handful of industry leaders but these are often the ones that move into construction. While the lowest bids are submitted by select industry leaders bids from other developers will most likely be higher. Not all bids are selected based on the lowest price.
- The US utility scale solar market in 2019 will likely have increased competition due to increased downward price pressures. At the end of 2016 the federal investment tax credit (ITC) is set to decline from 30% to 10%. This decline will impact project economics and force consolidation in the industry as weaker players will struggle to survive, be acquired, or be forced out of business.

The industry will also likely face oversupply throughout the value chain putting further downward pressure on prices.

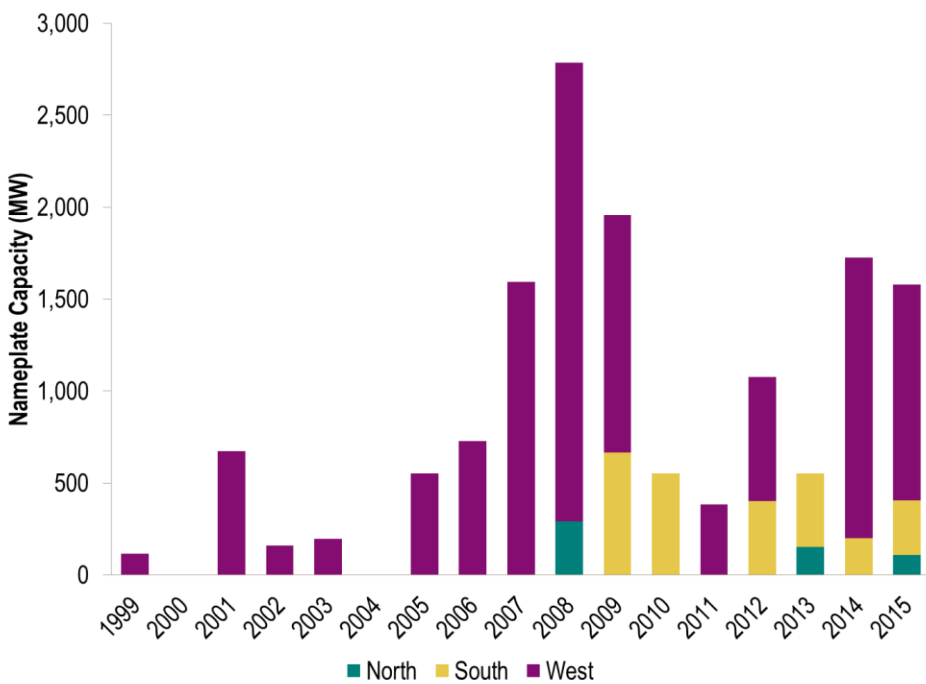
There is a risk that this does not turn out to be the case and that AE would actually only be able to procure solar at the Low cost (the mid cost is unlikely for West Texas). This risk is incorporated in Navigant's discussion of capital cost risks.

3.1.3 Wind Development in ERCOT Remains Strong

3.1.3.1 What Is the Market Context of Wind in ERCOT?

A large amount of wind power has been developed recently or will be developed in the next few years in ERCOT. Texas has some of the best wind resources in the country, particularly in the western region of the state, and the recently completed Competitive Renewable Energy Zone (CREZ) transmission lines are designed to connect up to 18.5 GW of wind capacity in the west to the rest of the state. Today, nearly 80% of all currently operating wind power in ERCOT is located in the West zone. Despite the fact that the PTC expired at the end of 2014, the addition of wind resources in ERCOT was strong in 2015 and is expected to continue as installation costs fall and technological improvements allow for greater capacity factors and smoother grid integration.

Figure 18. Current Operating Wind Capacity in ERCOT by Online Year by Zone



Source: Navigant (data from Energy Velocity, retrieved September 2015)

High penetration of wind can present operating and financial challenges to ERCOT market participants. The continued increase in non-synchronous generation like wind is causing reductions in system inertia, which could make the effects of generator or transmission outages in the system more severe in low-load, high-wind hours, which creates the need for other resources to react to these swift impacts within the ERCOT market. ERCOT is revisiting the structure of its ancillary services market to address these issues.

In its 2014 State of the Market Report, ERCOT states that wind generation erodes the amount of energy available to be served by baseload coal units while doing very little to reduce the amount of capacity necessary to reliably serve peak load.[33]

3.1.3.2 What Are Navigant's Assumptions for Wind Resources?

Navigant's wind assumptions underlie the following AE portfolio cases:

- C4: 500 MW Wind
- C5: Alternative Mix

Key assumptions for wind resources are highlighted in Table 20.

Table 20. Resource Assumptions: Wind

Resource Characteristics	Assumptions	Basis for Assumptions
PPA $/MWh, 2015-2035	$44 in ERCOT West, $49 in ERCOT South	Data from AE, Navigant and Electric Utility Group, LLC
Capital cost uncertainty range	Mature technology via PPA, so no uncertainty assumed	Assumed to be PPA due to maturity of ERCOT wind PPA market.
Capacity factor	47%	Data from AE and Navigant
Production curve	See Figure 19 and Figure 20	Data from AE and Navigant

Source: Navigant

Navigant's key assumptions for wind resources are as follows:

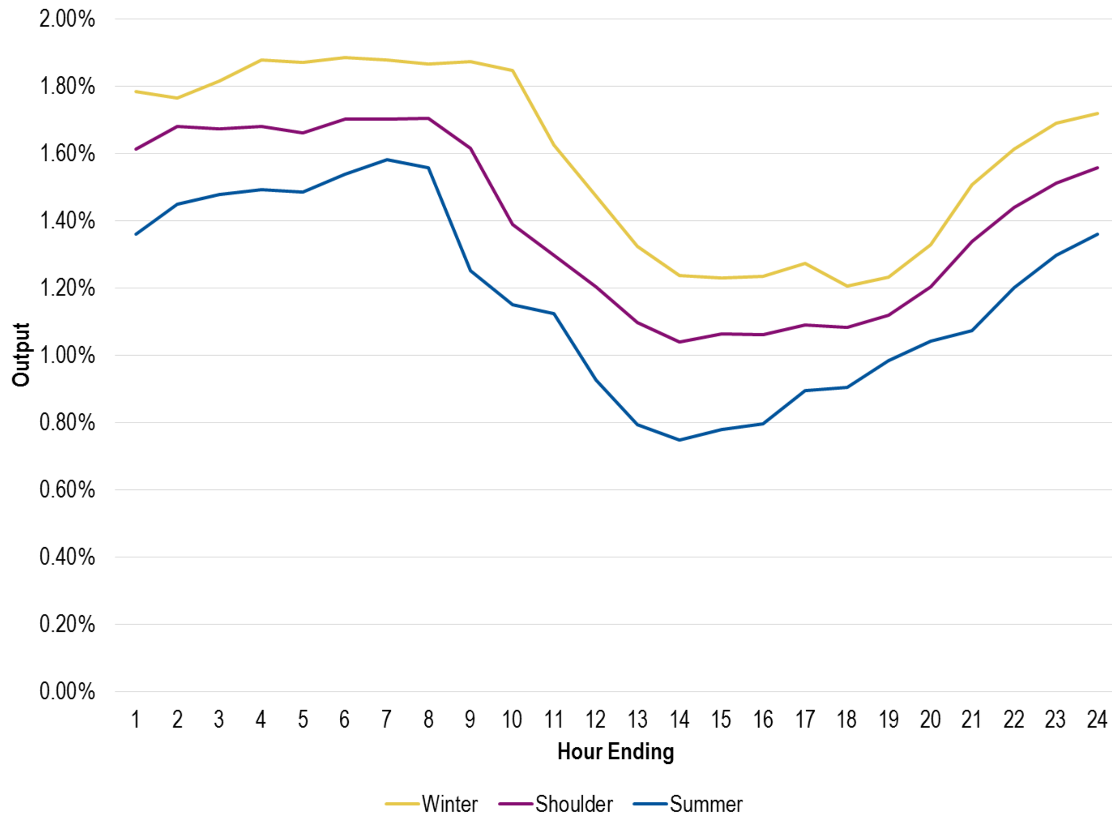
1. We assume AE enters into PPAs for 300 MW of West Texas wind and 200 MW of coastal wind.
2. Since West Texas wind tends to generate during off-peak hours and coastal wind tends to generate during on-peak hours, a mix of these two resources provides for generation that is more constant. West Texas wind generates primarily during off-peak hours, whereas the output shape for coastal wind is flatter during the winter and shoulder months and primarily on-peak during the summer months.
3. Our PPA pricing for coastal and West Texas wind is benchmarked such that PPA prices for coastal wind are approximately 10% greater than PPA prices for West Texas wind.
4. The analysis assumes the PTC expires at the end of 2017 and that AE enters into PPAs for new wind.

The assumed West Texas wind output curve is shown in Figure 19, and the assumed coastal wind output curve is shown in Figure 20. The curve is based on data provided by AE and compared against Navigant data. Each was created by normalizing a representative wind output profile for ERCOT's West

[33] 2014 State of the Market Report for the ERCOT Wholesale Electricity Markets, Potomac Economics, page xv.

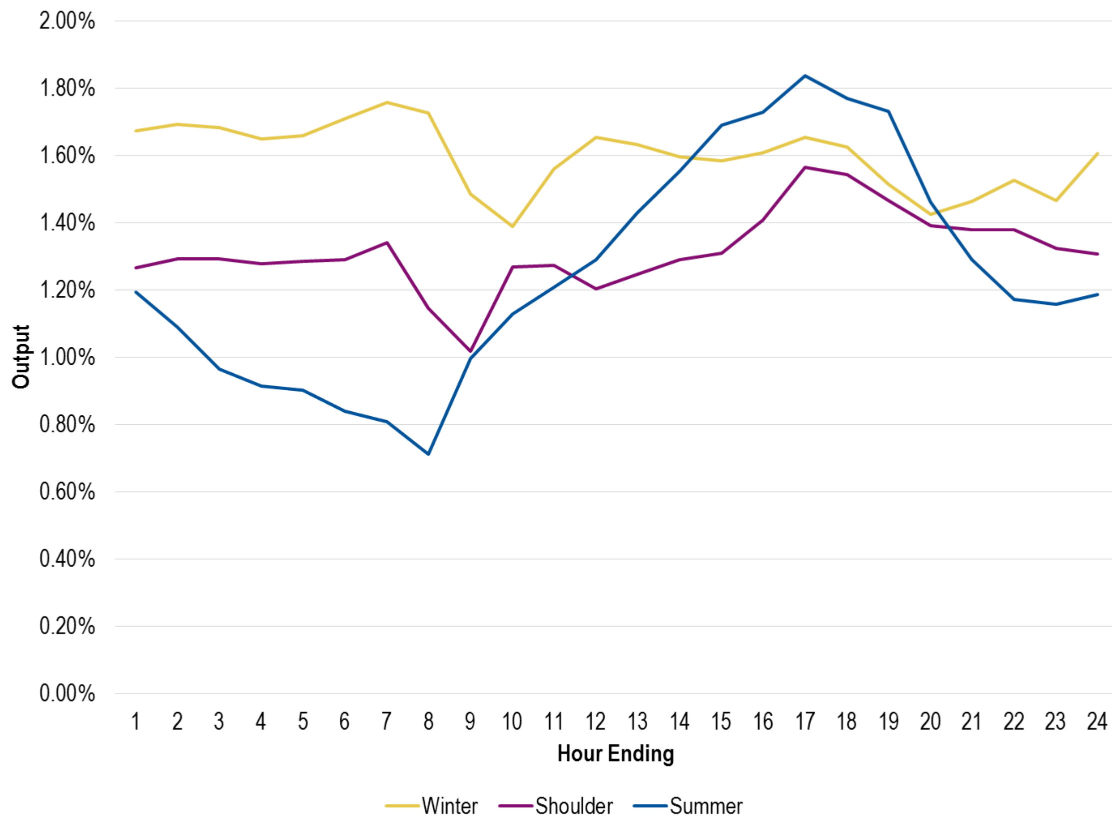
zone (for West Texas wind) and South zone (for coastal wind) by typical day by season. In ERCOT, the winter months include December, January, and February; the summer months include June, July, and August; and the shoulder months include March, April, May, September, October, and November.

Figure 19. Assumed Wind Output Curve, ERCOT West (West Texas Wind)



Source: Navigant

Figure 20. Assumed Wind Output Curve, ERCOT South (Coastal Wind)



Source: Navigant

3.1.4 Demand Response (DR) and Energy Efficiency (EE) Are Compelling Load Reduction Strategies

3.1.4.1 What Is the Market Context of DR Resources in ERCOT?

DR refers to load that can curtail when called upon by a grid operator such as ERCOT. DR allows ERCOT to manage supply and demand during peak periods when demand exceeds supply and during demand fluctuations. DR started as a utility-side program and did not originally participate in energy markets. DR programs have expanded from large industrial customers to include smaller industrial customers, commercial customers, and residential customers, usually through an aggregator. DR resources are increasing across the country as zero-emitting resources are needed to replace retiring fossil fuel power plants and as fast-ramping resources are needed to help integrate greater penetrations of intermittent renewable resources. DR is also increasing as electric customers demand more choices. Technological advances are improving the way that utilities communicate with DR and expanding the customer base that is able and interested in participating as a demand resource. For instance, two-way communicating thermostats allow utilities to control a customer's heating and cooling load directly.

ERCOT's DR programs include resources that respond during emergencies and resources that respond to price signals in the ancillary services market. At the end of 2014, ERCOT had 3,154 MW of registered Load Resources, which participate in the ancillary services market. Also in 2014 (February 2014 through

January 2015), ERCOT had up to approximately 900 MW of resources registered for its Emergency Response Service.

AE offers a menu of DR programs for residential and commercial/industrial customers. AE's Power Partner Thermostat program focuses on reducing residential summer peak demand and is uniquely able to respond directly to high summer energy demand, thereby supporting efforts to decrease AE's costs and minimize power disruptions during hot Texas summers. DR is also a successful component of AE's commercial energy savings program. AE's Load Co-op program focuses on commercial customers who are able to reduce their load at nearly a moment's notice in response to hot summer days.[34] AE operates several district cooling systems in the city, which offset approximately 15 MW of electricity in 2013 during peak demand times.[35] AE also strategizes to facilitate the integration of electric vehicles in its service area by utilizing these vehicles' batteries as distributed storage technologies.[36]

3.1.4.2 What Are Navigant's Assumptions for DR Resources?

Navigant's DR assumptions underlie the following AE portfolio case:

- C5: Alternative Mix (incorporates 50 MW incremental DR)

Key assumptions for DR resources are highlighted in Table 21.

Table 21. Resource Assumptions: DR

Resource Characteristics	Assumptions	Basis for Assumptions
$/kW-yr, 2015-2035	$395	Navigant
Modeled uncertainty range	$123 - 603	Navigant
Capacity factor	N/A	N/A
Production curve	Dispatch at high prices	Navigant

Source: Navigant

As modeled in this analysis, DR is a demand-side program for customers to shift their load at the direction of ERCOT from times when energy prices are high to off-peak times when energy prices are lower. DR's value is that it can lower the quantity of wholesale power purchased during periods of high prices.

AE's approved 2025 Generation Plan includes procurement of 200 MW of DR and recommends increasing the goal to 300 MW, if feasible. In most regions of the country—particularly ERCOT with its high energy price volatility—DR can be a cost-effective way to avoid needing to procure generation

[34] See AE's 2013-2014 *Customer Energy Solutions Program Progress Report* for more information: http://austinenergy.com/wps/wcm/connect/0cd540f6-41e0-48ba-96e4-a1bf8a505c91/energySolutionsProgressReport.pdf?MOD=AJPERES

[35] See AE's 2013 Annual Report: http://austinenergy.com/wps/wcm/connect/e1cdc885-e38d-4be5-8883-c9ba54e33f44/2013AnnualReport.pdf?MOD=AJPERES

[36] See AE's 2025 Generation Plan: https://austinenergy.com/wps/wcm/connect/461827d4-e46e-4ba8-acf5-e8b0716261de/aeResourceGenerationClimateProtectionPlan2025.pdf?MOD=AJPERES

capacity. The limiting factor is the ability to design incentive programs to convince customers to participate in DR programs. This analysis assumes that AE can procure the additional 50 MW of DR.

While average-cost DR is often highly economic, AE is already procuring nearly 10% of peak load as DR in the 2025 Generation Plan. This means that the lowest-cost resources will already be procured and incremental expansion of the program is likely to be much higher in costs. The cost assumptions in this study are assumed to be high but also highly uncertain to represent the difficulty of procuring resources at the far right of the resource curve.

3.1.4.3 What Are Navigant's Assumptions for EE Resources?

Navigant's EE assumptions underlie the following AE portfolio case:

- C5: Alternative Mix (incorporates 50 MW of incremental EE)

As modeled in this analysis, EE is a demand-side resource that reduces AE load due to customer installations reducing their demand. Average EE tends to be highly cost-effective, but the limiting factor is whether programs can be designed to procure it, since that depends on customer behavior. AE's approved 2025 Generation Plan includes 700 MW of EE with a recommendation to increase to 1,200 MW if economically viable. This study values an incremental 50 MW of EE but does not include a full study of the viability of this procurement or the costs to do so.

The cost assumptions used in this study are based on the *2012 Austin Energy DSM Market Potential Study*.[37] The results of this study provide incremental costs of EE programs to increase yield from the planned 700 MW up to 900 MW and beyond. The 700 MW is nearly the feasible potential for the programs and so the incremental cost for this 50 MW increment is significant. The uncertainty around how much EE can be procured and at what cost is incorporated in large uncertainty bounds.

Key assumptions for EE resources appear in Table 22.

Table 22. Resource Assumptions: EE

Resource Characteristics	Assumptions	Basis for Assumptions
$/kW, 2015-2035	$2,521	AE Potential Study
Modeled uncertainty range	$783-$3,849	AE Potential Study
Capacity factor	50%	Navigant
Production curve	Load-following	Navigant
Economic lifespan of asset	20 years	Navigant

Source: Navigant

[37] Austin Energy DSM Market Potential Assessment, 2012.

3.1.5 Energy Storage Is a Resource Option that Should Continue To Be Examined Further by AE Outside This Study

3.1.5.1 What Is the Market Context of Storage in ERCOT?

Storage is a small component of the ERCOT market. The only large storage project currently in ERCOT is Duke Energy's 36 MW lead-acid battery Notrees storage plant, which Duke completed in 2012.[38] According to a recent report on Utility Dive, Duke is planning to overhaul the facility's design because the storage is being used for grid balancing rather than storing wind energy. Grid balancing (otherwise known as frequency regulation) balances second-to-second changes in load in the system by moving generation or energy consumption up or down in response to small imbalances. Certain types of storage are well-suited to this application because it can respond more rapidly to these changes than any other resource type and can provide benefit to the system both during the charge and discharge cycles. As renewable penetration in ERCOT increases, so does the need for ancillary services such as those that can be addressed by storage.

While there are many types of storage technologies, two of the most frequently proposed in the ERCOT market are CAES and lithium ion (Li-ion) battery storage. Conventional CAES relies on large caverns for air storage. CAES co-fires natural gas with the air in order to heat the air as it is decompressed. Because CAES burns natural gas, it has fuel costs, but they are lower than those of a CC unit. CAES can have much more capacity to store energy than batteries, which can improve CAES's attractiveness for energy arbitrage. Two CAES facilities are currently operating in the United States: the 110 MW McIntosh facility in Alabama, which has been operating since 1991, and the 1.5 MW Seabrook project in New Hampshire, which has been operating since 2013. Table 23 describes the typical operating characteristics of CAES.

Table 23. CAES Operating Characteristics

Metric	Current Status
Max. Discharge Time	12-20 hours
Cycle Life	7,000-12,000 cycles
Calendar Life	25-30 years
Round-Trip Efficiency	50-70%
Advantages	Cost
Disadvantages	Siting limitations; a gas-burning technology
Manufacturers	Dresser Rand, MAN Turbo, Hydrostor, GCX Energy (formerly SustainX and General Compression), APEX, RWE, Highview
Typical Applications	Load Leveling

Source: Argonne National Laboratory

Li-ion cells are gaining market share due to a decrease in price and their relatively flexible operating characteristics. Typical operating characteristics of Li-ion batteries are shown in Table 24.

[38] Duke has announced that they intend to upgrade this facility to a lithium-ion battery.

Table 24. Li-Ion Battery Operating Characteristics

Metric	Current Status
Energy Density	60-240 Wh/kg
Max. Discharge Time	4-12 hours
Cycle Life	300-25,000 cycles
Calendar Life	7-10 years
Round-Trip Efficiency	90-95%
Advantages	High power density, decreasing costs
Disadvantages	Potential thermal runaway
Manufacturers	Saft, Toshiba, AltairNano, Electrovaya, Dow Kokam, LG Chem, BYD, Tesla, Alevo, and others
Typical Applications	Load Leveling, Grid Operational Support, Grid Stabilization,

Source: DOE/EPRI 2013 Electricity Storage Handbook

3.1.5.2 Why Did Navigant Exclude Energy Storage from the Portfolios?

Navigant excluded storage from this analysis because this analysis methodology is not well-suited to valuing storage. As AE considers procuring utility-scale storage, it is necessary to complete an in-depth study of the specific technologies. Storage is distinct from other resources in AE's portfolio because the primary value is not necessarily derived solely from the energy market, but is instead due to the flexibility of storage technologies. In ERCOT, storage can receive some value from purchasing energy during low-price times and selling during high-price times, but most of the value derives from the flexibility to participate in the ancillary services market and the real-time market. This analysis focuses on energy values, risk, and costs in particular in the day-ahead ERCOT market; we believe it would undervalue any storage being considered.

3.2 Water Usage Context

Different resources require different levels of water usage, which is a key analysis metric for this study. The following subsections explain why water usage is a concern in ERCOT and describe the water usage requirements of the generation resources analyzed in this study.

3.2.1 Travis County Water Demand Will Increase Substantially by 2070

The city of Austin is located in Travis County, Texas. Table 25 shows the regional water demand projections for Travis County for the period 2020-2070. Although water demands for irrigation and livestock are expected to decrease and stay the same, respectively, water demand in all other categories is expected to increase significantly.

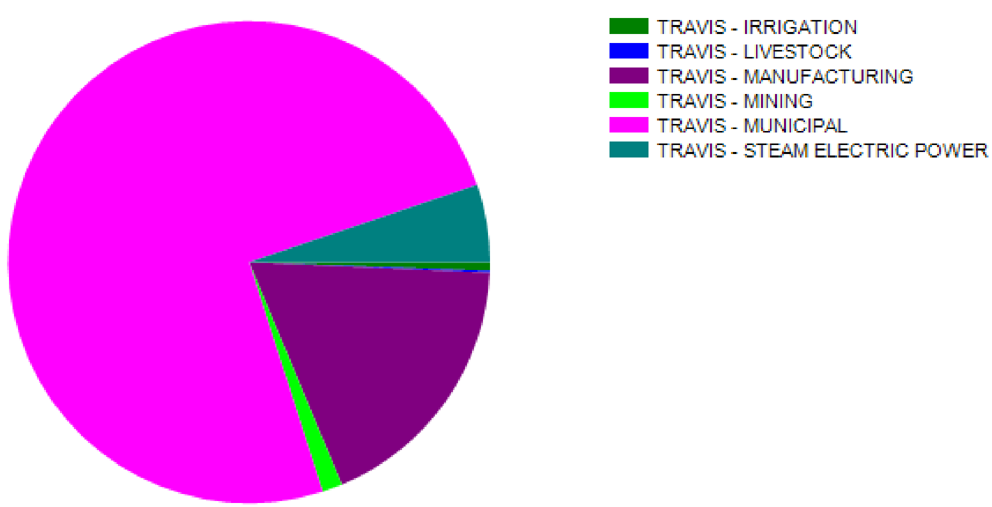
Table 25. 2016 Regional Water Plan: Water Demand Projections for 2020-2070, Travis County Summary in ACFT

Demand Category	2020	2030	2040	2050	2060	2070
Irrigation	4,322	3,975	3,657	3,364	3,097	2,885
Livestock	704	704	704	704	704	704
Manufacturing	35,790	48,710	63,858	72,991	81,781	91,630
Mining	3,502	4,108	4,762	5,374	6,046	6,817
Municipal	227,879	266,070	303,161	331,059	354,312	380,499
Steam electric power	18,500	22,500	22,500	23,500	24,500	26,500
County Total	**290,697**	**346,067**	**398,642**	**436,992**	**470,440**	**509,035**

Source: Energy Utility Group analysis; data from Texas Water Development Board

Water demand distribution in 2070 is shown in Figure 21. Municipal demand accounts for the largest share of demand.

Figure 21. Water Demand Distribution in Travis County, 2070



Source: Energy Utility Group

3.2.2 The Electric Supply That Is Vulnerable to Water Shortages Should Be Minimized

3.2.2.1 What Is the Outlook for Water Shortages in Texas?

Using tree-ring analysis, a study conducted by geoscientists for the University of Texas found that the central Texas 2011 drought, which is regarded as the state's worst single-year drought, was "was not especially remarkable." Evidence showed that there are historically a number of longer, more severe droughts. Now called mega-droughts, these droughts lasted 20-30 years and date back to the 1500s. Climate models predict more frequent and severe droughts in Texas; thus, there is a risk that the state will again experience mega-droughts with impacts more severe than seen in 2011 and in the 1950s.[39]

3.2.2.2 What Are the Implications for Power Generation Resources?

Power plants consume only about 3% of the water in Texas because most of the water returns to lakes and rivers after passing through the plants. However, on any given day, power plants have significant water needs—about 43% of all water withdrawals in the state, according to the U.S. Geological Survey.

3.2.3 The Water Needs of Alternative Resources Are Significantly Less Than the Water Needs of the Gas Plant

3.2.3.1 What Are the Water Needs of the Gas Plant?

Assuming a 65% reduction in water usage for a CC plant, the water needs of the Gas Plant are as shown in Table 26 compared to the current Decker steam units. The Gas Plant will require significant acre feet (ACFT) of water per year.

Table 26. 500 MW Gas Plant Water Usage Reduction (ACFT)

County	Demand Category	2020
Travis	Steam electric power	18,500
Proposed	CC plant	6,475
	Total water reduction	**12,025**

Source: Energy Utility Group

3.2.3.2 What Are the Water Needs of Solar?

Depending on the location of the solar resource, installation panels may need to be cleaned with water up to once per week to operate optimally due to dust and wind. Worst-case assumptions for water usage for 500 MW of solar are as follows:

- Approximately 2.75 million PV panels
- Cleaning every week (based on location and dust)
- 1 liter of water to clean one PV panel, which equals 2.2294 ACFT of water
- Water usage to clean panels does not change over time[40]

Based on these assumptions, the water usage for one 500 MW Solar project is a maximum of 115.9288 ACFT. Two 500 MW Solar projects will use a maximum of 231.8576 ACFT.

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[39] Additional information can be found here: https:/www.utexas.edu/what-starts-here/finding-solutions/preparing-future-water-shortages

[40] See http://news.stanford.edu/pr/2014/pr-solar-water-crops-040914.html

3.2.3.3 What Are the Water Needs of Wind?

Wind resources require no water.

3.2.3.4 What Are the Water Needs of Portfolios of Alternative Resources?

Wind resources require no water, and Energy Utility Group assumes DR and EE resources also do not require water. Therefore, the solar resources in the Alternative Mix portfolio determine the water usage of that portfolio.

Using the same solar water usage assumptions described above, a portfolio consisting of 200 MW wind, 200 MW solar, 50 MW DR, and 50 MW EE will use a maximum of 0.891784 ACFT, which is equivalent to the water usage for 200 MW of solar resources.

3.3 Financial Analysis Assumptions

Navigant's financial assumptions for this analysis are described in Table 27 below.

Table 27. Financial Analysis Assumptions

Assumption Description	Assumption	Units
Financing Assumptions		
Term of Debt	20	years
Projected Life (Book)	20	years
Return on Equity (ROE)	0.00%	%
Cost of Issuance (% of total debt financing raised)	1.5%	%
Requirement for a bond reserve?	N	Y or N
Capital Structure		
Construction		
Debt Ratio	100%	%
Equity Ratio	0%	%
Permanent Financing		
Debt Ratio	100%	%
Equity Ratio	0%	%
Interest Rates		
Interest Rate on Bond Reserve (1/2 Year) Fund	0.54%	%
Project Debt	4.82%	%
Construction Financing (rate also used for IDC)	4.82%	%
Tax Assumptions		
Effective Tax Rate	0.00%	%
Discount Rates		
Utility Discount Rate (nominal)	5.00%	%
Inflation Rate	2.10%	%

Discount to Year	2014	Year
Insurance (Developer)		
Rate per $1,000 of Capital Cost	$8.00	$yr/$1,000
Insurance Escalation	2.50%	%
Depreciation Schedule		
Straight-line 20-year	Y	Y or N

Source: Navigant

4. Findings

Navigant recognizes that AE has diverse goals, and this analysis considers the tradeoffs between them. To show the impacts of different portfolios, Navigant aggregated results into a scorecard that provides calculated metrics including utility cost, rates, water usage, renewable power, emissions, local economic impacts, and water usage. The scorecard provides a framework to consider the costs, benefits, and risks of the portfolios in the different scenarios. The aggregated results enable the synthesis of study recommendations.

For each metric described in this section, the outcomes are provided in a table of results for every portfolio across each scenario. The results are described to help provide meaningful takeaways from the tables of numerical values. This approach is designed to identify portfolios that best meet AE's goals and to develop the support for the conclusions given in Section 5.

4.1 Austin Energy System Cost

When considering investments in a generation portfolio, utilities first review the impact on the total cost of serving customer load. The total costs to the system should be compared within market scenarios to understand conditions in which one portfolio results in lower costs and risks than another.

The market risks to portfolios are evaluated by considering the system costs of each portfolio across market scenarios. It is important to recognize that market scenarios define the conditions that AE must operate within but are outside the utility's control, such as natural gas prices. As the future is uncertain, it is important for AE not to plan to a single potential future outcome. Instead, a good portfolio balances having low costs across most scenarios and avoids outlier scenarios in which costs are much higher than the alternative.

Total system costs are a representation of every cost that AE incurs while providing power to customers, including all of the legacy capital and operating costs from the existing portfolio. It is important to note that this study only considers *incremental* changes to AE's resource plan, and thus the majority of costs are common between all portfolios and outside the scope of the decision of whether to build the Gas Plant, build a different set of resources, or rely on market purchases. The NPV is calculated over the 20 year study period and does not consider the residual value of any added AE resources. In line with the study scope of work, this is a conservative approach to estimating the value of the alternative portfolios.

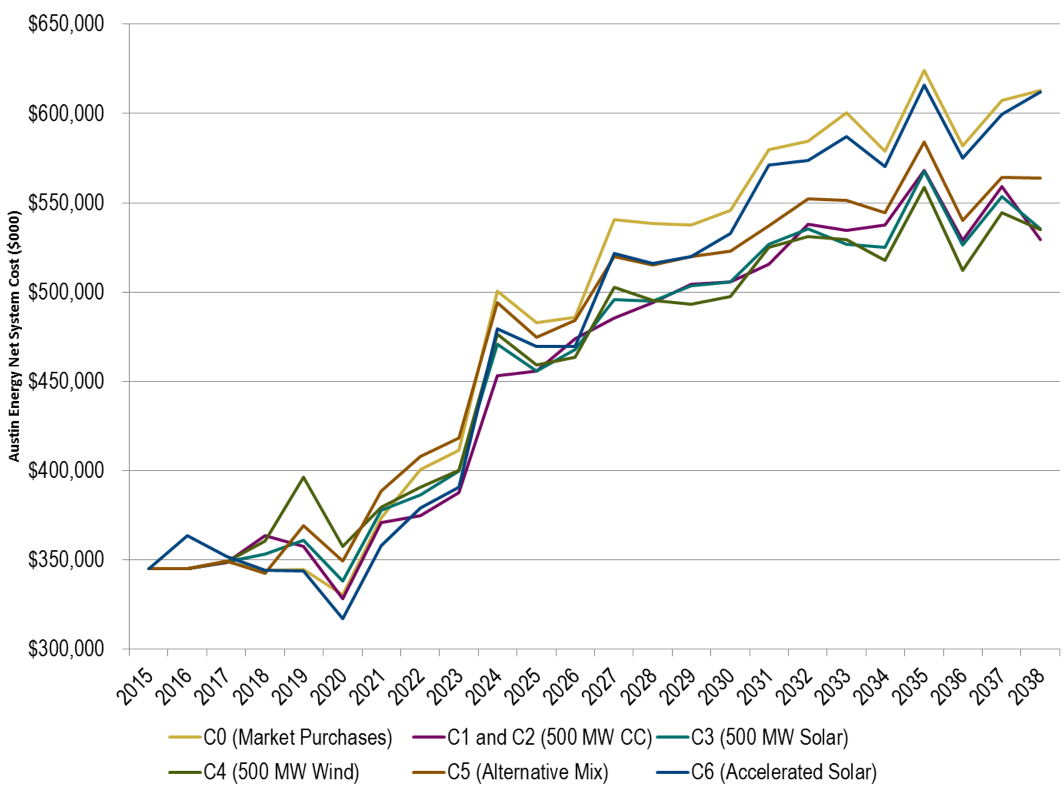
To calculate total system cost, Navigant modeled the operation of the AE portfolio within ERCOT, calculated the total cost to serve load, and calculated the operating costs of all of AE's units in each portfolio. Using data from AE, Navigant then added the non-modeled costs of operating the system to each portfolio.

4.1.1 Total System Costs Vary Over Time and across Portfolios, with Increases in the Early 2020s in All Portfolios

Figure 22 shows the annual cost of each portfolio case in the Base scenario. Early in the forecast, even after the portfolios start to diverge in 2018, there is little difference between the portfolios, and little value is added to AE by the new developed resources.

As market conditions in ERCOT tighten and gas prices and carbon prices rise in the early- to mid-2020s, AE's investment in new resources becomes more profitable. However, there is still little difference in the annual system costs for any of the portfolios except that the All Market and Accelerated Solar portfolios, which rely on more market purchases than the others, are significantly more expensive. This concludes that AE benefits by owning resources; however, in comparing other portfolios that do not rely as heavily on market purchases, there is no clear advantage in terms of base cost. Additionally, it is necessary to consider the additional financial risks of the portfolios and the extent to which the different portfolios meet AE's goals.

Figure 22. Net Austin Energy System Cost by Year



Source: Navigant

4.1.1.1 What Is the Net System Cost of Each Portfolio and Scenario?

The analysis results for total system costs are given in Table 28. The costs are reported at NPV and in real 2014$. The impacts of the planning decision that AE faces can be seen by comparing system costs across portfolios. The low cost portfolio is in bold font and for each portfolio the difference in NPV from the low cost portfolio is given in parentheses. The impacts of market conditions can be seen by comparing system costs for a single portfolio among the four scenarios. These scenarios represent the impact to AE of the costs that AE cannot control (e.g., natural gas prices).

Table 28. Net System Cost (NPV 2014 $MM)

	SCENARIOS			
Portfolio	**Base**	**High Gas**	**Low Gas**	**High Solar**
All Market	8,025 (452)	8,682 (691)	7,419 (429)	8,024 (314)
C1: Decker CC	**7,573** (0)	8,097 (106)	**6,990** (0)	7,754 (44)
C2: Sand Hill CC	7,574 (1)	8,097 (106)	6,991 (1)	7,754 (44)
C3: 500 MW Solar	7,608 (35)	8,025 (34)	7,158 (168)	7,775 (65)
C4: 500 MW Wind	7,639 (66)	**7,991** (0)	7,240 (250)	**7,710** (0)
C5: Alternative Mix	7,830 (257)	8,235 (244)	7,392 (402)	7,931 (221)
C6: Accelerated Solar	7,866 (293)	8,502 (511)	7,278 (288)	7,869 (159)

Source: Navigant

4.1.1.2 What Do These Results Indicate?

The four scenarios are designed to show drivers and risks to wholesale power prices in ERCOT. A key finding is that AE's system costs are exposed to more risk due to gas prices than to changes in the generation portfolio considered in this study. For example, costs vary over $1 billion across scenarios for any of the portfolios, and these costs shift in concert for all portfolios. The total costs move the most with gas prices, which is unsurprising because gas prices are the single largest driver of electricity prices. The total costs are reduced in the High Solar scenario, as high solar penetration in ERCOT reduces wholesale power prices by reducing on-peak energy prices.

The seven portfolios show real differences in costs, but the ranking of portfolios in terms of costs changes among scenarios.

In every scenario, All Market is the most expensive option, suggesting that AE's generation portfolio provides benefits to its ratepayers by reducing exposure to risk in the ERCOT market. Building the gas plant has slightly better economics than adding either 500MW of Solar or 500MW of wind in the Base scenario, and has significantly better economics in the Low Gas scenario, and worse economics in the High Gas scenario. The portfolio C5: Alternative Resources is more expensive than the other resource portfolios, largely due to the high procurement cost of incremental EE and DR. The conclusion from these results is that the resource decision should be dependent on reducing risks to AE as there is no clear advantage in the costs across the market scenarios.

There is no material difference in terms of cost for developing a CC at Decker or at Sand Hill and the decision of where to put the gas plant is not dependent on the energy market economics considered in this study. There is a marginal benefit for accelerating the procurement of solar by adding 600 MW of PPAs in 2017 compared to the All Market Portfolio.

4.1.1.3 What Are the Results through 2025?

The NPV of the system costs through 2025 are shown in Table 29. These results are valuable to consider when evaluating portfolios because market uncertainty increases over longer outlook periods. If a portfolio is not valuable in the mid-term versus inaction, then it may be a better option to defer development a few years until more information on system needs is available.

Building the CC plant is more cost-effective than All Market in every scenario except the High Solar case, suggesting that it is likely cost-effective to build even when only considering the near term.

Table 29. System Cost through 2025 (NPV 2014 $MM)

Portfolio	Base Case	High Gas Case	Low Gas Case	High Solar Case
All Market	3,548 (70)	3,619 (109)	3,501 (72)	3,515 (60)
C1: Decker CC	**3,478 (0)**	**3,510 (0)**	**3,429 (0)**	3,496 (41)
C2: Sand Hill CC	**3,478 (0)**	**3,510 (0)**	**3,429 (0)**	3,496 (41)
C3: 500 MW Solar	3,518 (40)	3,526 (16)	3,491 (62)	3,526 (71)
C4: 500 MW Wind	3,583 (105)	3,579 (69)	3,555 (126)	3,567 (112)
C5: Alternative Mix	3,597 (119)	3,601 (91)	3,571 (142)	3,594 (139)
C6: Accelerated Solar	3,485 (7)	3,537 (27)	3,455 (26)	**3,455 (0)**

Source: Navigant

4.1.1.4 The Value of Dispatchable Capacity in ERCOT

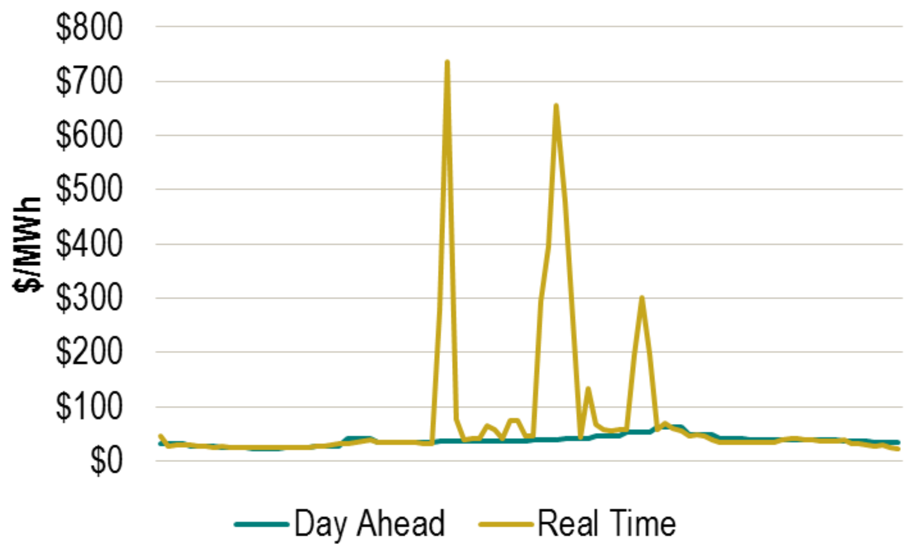
One metric that a production cost model like PROMOD tends to underestimate is the value of dispatchable generation versus non-dispatchable generation. PROMOD does value the aspect of renewable generation in that there is no control over the operating profile and that the units receive whatever price is available when the unit is operating. However, since PROMOD is a deterministic model of the day-ahead prices, it does not represent the impacts of forecast error for load and renewable generation on real-time power prices.

As renewable generation on a system increases, the number of spikes in real-time energy prices tend to increase, as there is further need for flexible generation to maintain system balance with an increased penetration of intermittent or variable generation.

If the flexible generation is not available, real-time prices can increase to very high levels. Since AE purchases wholesale power from the ERCOT market to meet 100% of its load, AE is exposed to this risk of high real-time prices.

Figure 23 shows the ERCOT South real-time and day-ahead prices on April 29, 2014, when real-time prices reached many multiples of the day-ahead prices during levels of high expected wind penetration.

Figure 23. Day-Ahead and Real-Time Prices on April 19, 2014



Source: Navigant

For AE, this illustrates a risk of relying too heavily on non-dispatchable resources. A gas plant such as a CC plant would very likely be operating during these times and would have the opportunity to earn revenues from such price spikes.

4.1.1.5 Local Congestion Value

Congestion costs are the higher costs to serve the load in AE if localized generation is not built. In fact, the Generation Plan and this analysis include the retirement of ~1,300 MW of generation in the AE load zone, which increases the risk of higher congestion costs to AE and its customers.

The value of reducing congestion is driven by the fact that AE is located in a transmission-constrained section of the ERCOT bulk transmission system, limiting its import and export capability into neighboring areas. As localized generation retires as planned, prices in AE will rise to average levels above that of ERCOT South due to binding constraints on the import capability of AE. This difference in LMPs between AE and ERCOT South, or basis differential, results in higher costs to serve the load within the AE footprint. Our analysis concludes that if the Gas Plant is built within the AE load zone versus adding to the portfolio through resources located outside of AE, this congestion cost is reduced and the risk of much greater congestion costs is mitigated.

In order to measure this benefit, the basis differential was calculated for the case with All Market purchases and for the Decker CC case. The hourly difference in LMP was multiplied by the AE demand for that hour and the totals were summed for the year. The reduction in the cost to serve load per year by adding the Decker CC through 2030 can be seen in Table 30. Note that there is no benefit prior to Decker coming online in 2019.

An additional concern with the local congestion value for AE is that the modeled value is an estimate of the average value. This is a difficult value to forecast and there is potential for it to be a higher cost than modeled in this study. It would not be surprising to us if it were $100-$200 million rather than the $70 million forecast here. The reason for the large uncertainty is that there is no historical data showing the impact of retiring ~1,300 MW in the AE load zone.

Table 30. $70 Million Reduction in Cost to Serve AE Load with Gas Plant at Decker

Year	2014 $
2019	$1,965,885
2020	$4,842,951
2021	$3,590,251
2022	$8,506,126
2023	$10,010,883
2024	$8,297,185
2025	$1,105,468
2026	$1,993,444
2027	$4,220,693
2028	$5,289,781
2029	$9,853,187
2030	$10,348,072
Total	**$70,023,926**

Source: Navigant

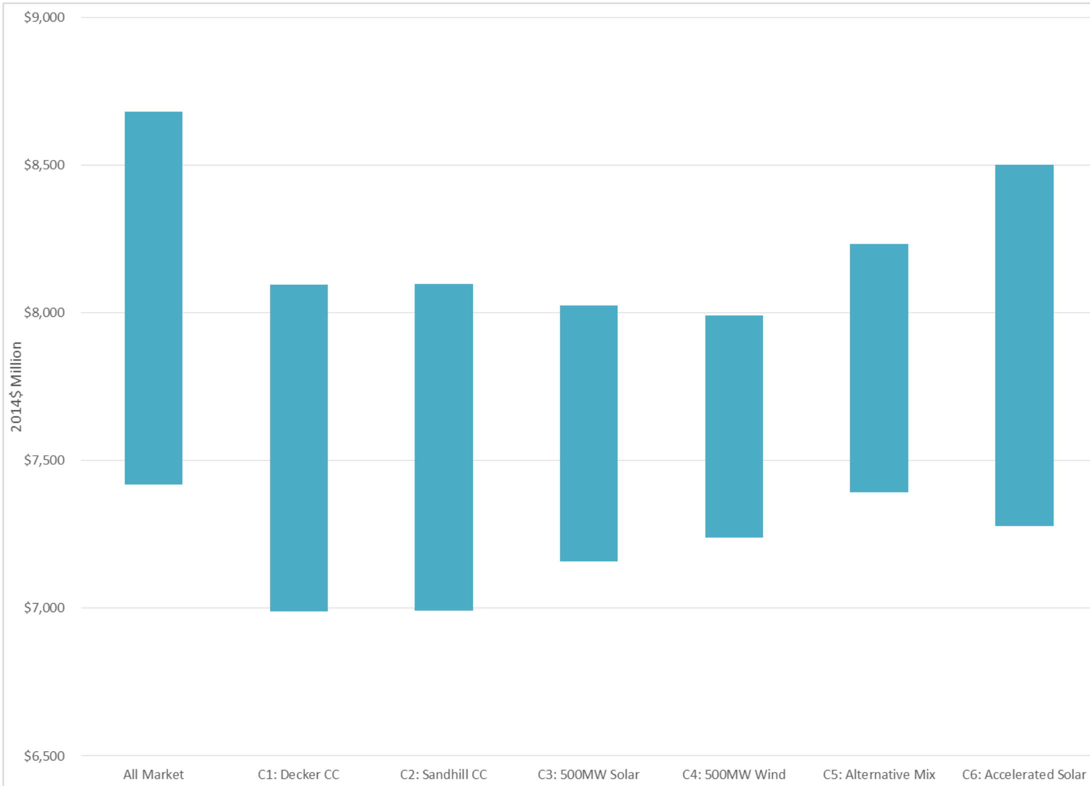
4.1.2 Capital Cost, Gas Prices, CO_2 Policy Risk, and ERCOT Resource Mix Comprise the Modeled Financial Risk of the Portfolios

As mentioned previously, a good portfolio helps to mitigate the risk of adverse outcomes and scenarios. This analysis explicitly considers three avenues for risk and discusses sources of risk that AE should consider that are not modeled. All of the risk charts are on the same scale; it should be noted that the fuel/energy price risk is much larger than the other sources of risk as fuel prices affect the entire AE system.

- **Gas/energy price risk** represents the risk to AE of changes in natural gas price and hence the ERCOT wholesale market price.

The range of this risk is seen by comparing system costs in the Low Gas scenario and the High Gas scenario. For all portfolios, this varies over $1 billion. As can be seen in Figure 24, portfolios of renewable resources are helped by high gas prices and hurt by low gas prices. Development of a Gas Plant is also helped by high gas prices and hurt by low gas prices, as the Gas Plant often has lower fuel costs than competing gas plants in ERCOT.

Figure 24. Gas/Energy Price Risk by Portfolio



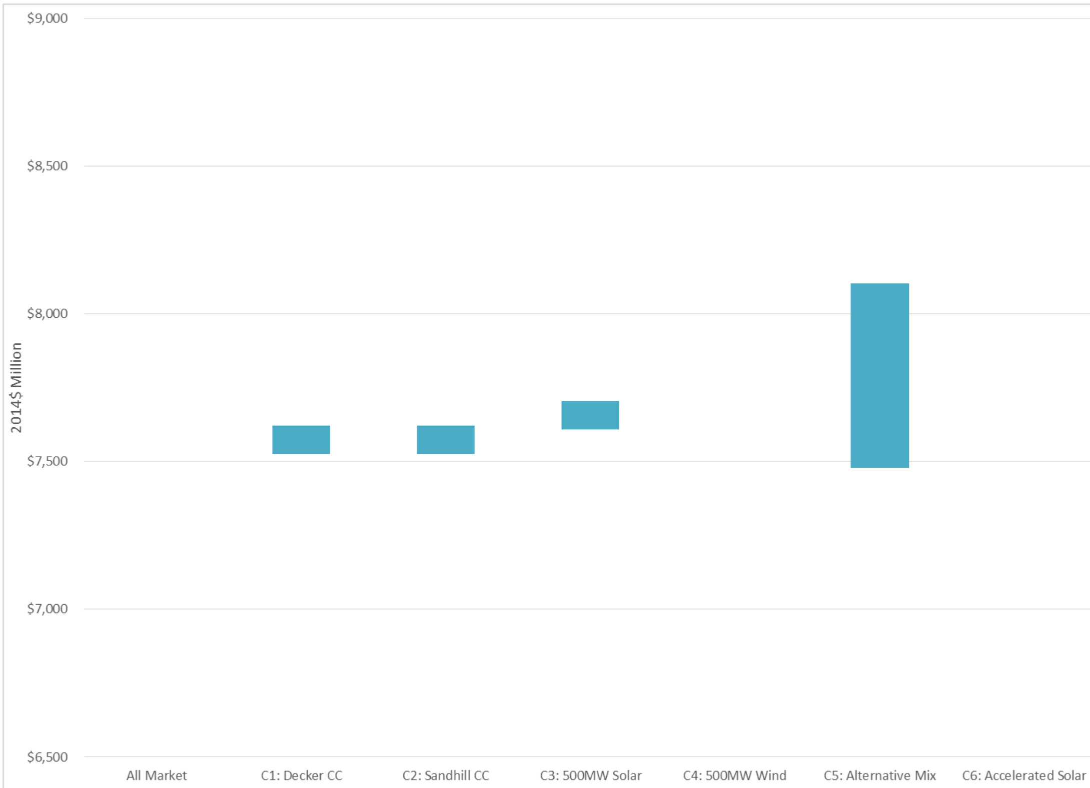
Source: Navigant

- **Capital cost risk** is the risk that the cost to develop or procure resources is different from what this study assumes.

In the portfolios building the Gas Plant and in future development of solar resources, there is risk that the projects are either more expensive or less expensive than expected. The results shown in Figure 25 show the variance in system costs from the Base scenario using the assumed capital cost risks. Solar has slightly more capital cost risk than the gas unit, but overall the risk is lower than the market risk from energy prices. The mix of alternative resources has the highest range of capital cost risk due to the uncertainty surrounding the procurement cost of incremental EE and DR resources. The All Market Portfolio does not have capital cost risk, and the wind PPAs are assumed to have no risk due to the maturity of the technology.

It is important to note that capital cost risk is different from the other considered risks in the sense that AE is not forced to procure future resources if capital costs rise and the resource plan should be changed.

Figure 25. Capital Cost Risk

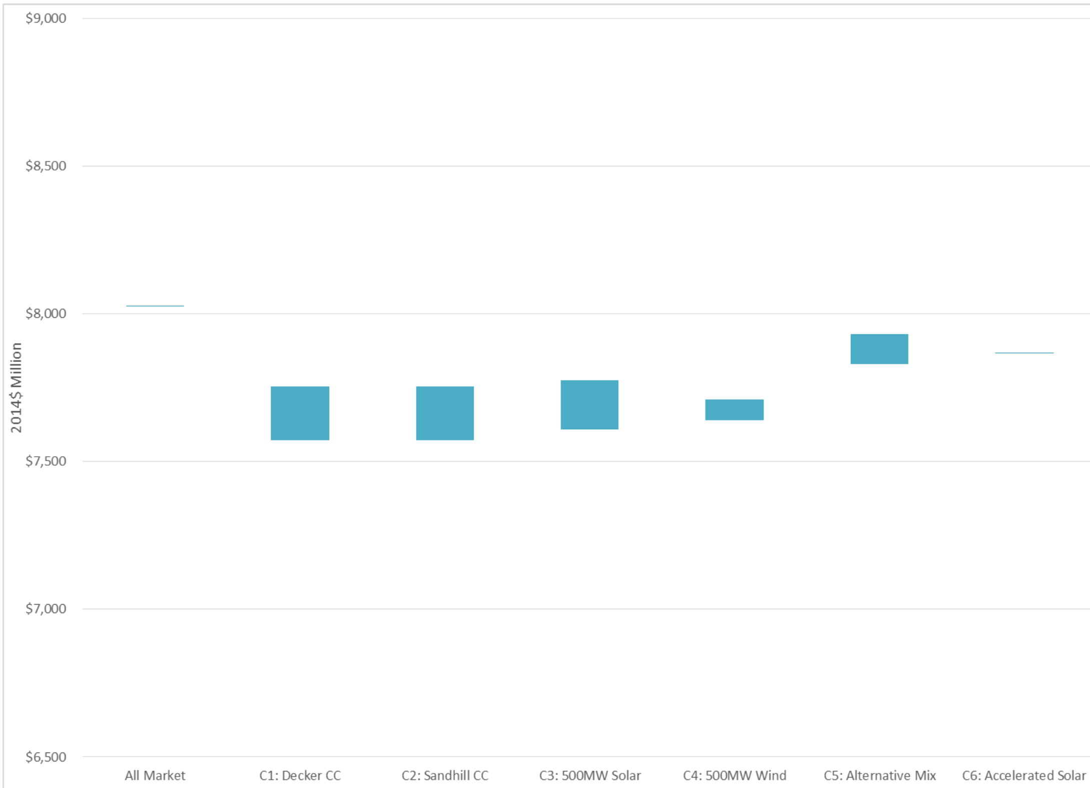


Source: Navigant

- **ERCOT resource mix/solar penetration risk** is the risk that the solar capacity is developed in ERCOT at a much higher rate than is assumed in the Base scenario.

AE is procuring solar power as a significant proportion of total resources in all portfolios and is procuring even more in the 500 MW Solar portfolio and the Alternative Mix portfolio. A risk to these portfolios is as market participants develop solar, it will suppress peak prices and hence reduce AE's revenue potential from solar investments and even the Gas Plant. As can be seen in the system costs, the wind portfolio performs significantly better than other resources in this scenario as it generates at different times than all the new solar on the ERCOT system. This suggests that AE should be cautious of over-investment in a particular type of resource, such as solar PV.

Figure 26. ERCOT Resource Mix Risk



Source: Navigant

4.1.2.1 Estimating Risk from Non-Local, Non-Dispatchable Generation

The biggest concern for AE with all of these risk factors is that the risks tend to be asymmetric and without mitigation may make the city vulnerable to worse outcomes than forecast with PROMOD. While all of these risks are difficult to estimate, it is critical to consider them when determining what portfolio to pursue. Table 31 gives Navigant's best estimates of the potential for additional financial risk that AE could be under without local, dispatchable generation.

The risk on local congestion is developed starting with Navigant's forecast of the value of mitigating congestion due to the Gas Plant compared to the other portfolios. The risk for AE is that there is no historical data on the impacts of planned retirements of local generation to use to benchmark the modeling results. Thus it would not be surprising for the costs to AE of not replacing that capacity with new, local generation to be much higher than the modeling results. We have estimated the risk as the potential to increase the incremental congestion cost by a factor of 2 – 3.

The real-time price volatility risk was estimated by simulating the operation of a combined cycle in the ERCOT market against historical prices. The benefits of an efficient combined cycle for providing real-time price hedging is somewhat limited as the units largely operate in the day-ahead but there are time periods when the unit is operating at the minimum generation level and can ramp up in response to real-time price spikes to realize additional revenue. The estimate is the 20 year NPV of the average value of this ramping capability.

The ancillary services risk is estimated considering the impacts of an increase in demand for operating reserve and frequency regulation as renewable generation penetration in ERCOT increases. The concern for AE is that there could be a large increase in the need for these ancillary services. This would cause the prices to rise somewhat but there is an upper bound on the total amount they can rise as a price increase would, over time, spur entry of new resources into the market. We have estimated the potential rise as a 50% increase on market prices.

Table 31: Potential Financial Risk for Non-Local, Non-Dispatchable Generation

Risk Factor	Cost Estimated in Study (000's $2014 NPV)	Estimated Added Risk (000's $2014 NPV)
Local Congestion	70,000	130,000
Real-Time Price Volatility	0	16,000 – 32,000
Ancillary Services	84,000 – 102,000	42,000 – 51,000

4.1.2.2 Other Financial Risks Have Larger Downsides than Upsides for AE and Are Better Mitigated by a Dispatchable Gas Unit than by Renewable Portfolios

In developing the portfolio plan, additional risks that were not directly modeled should be considered. These can affect the different portfolios both on the upside and on the downside.

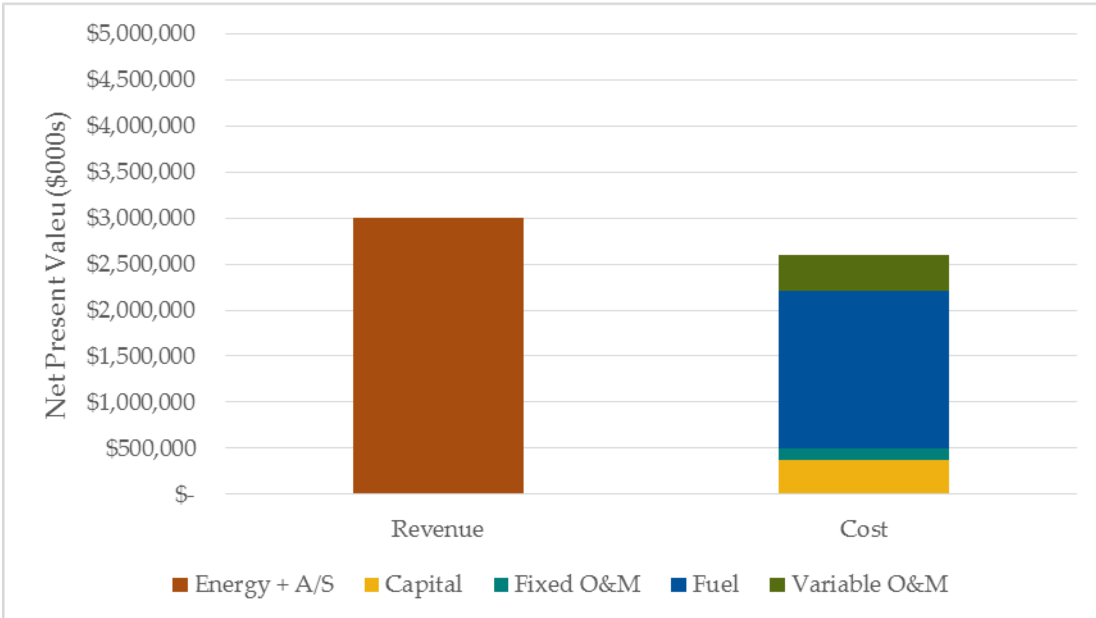
The following values and risks are excluded from this analysis:

- The residual value of the resources after the end of the study period.
- There is a risk that ERCOT complies with the CPP with a mechanism other than carbon prices. Depending on how it is implemented, it could depress energy prices, which would tend to hurt the value of all generating resources. Since renewable power is carbon-free, its value to AE would be lower a no-carbon price forecast.

4.1.3 Cost and Revenue Comparison for portfolios

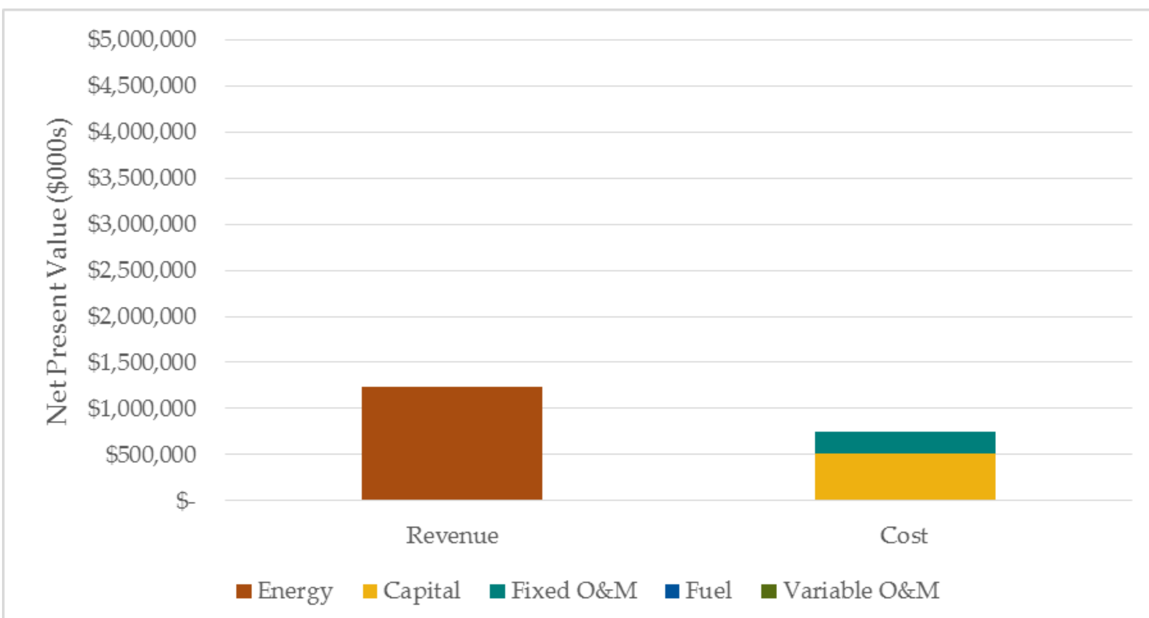
Figure 27 through Figure 31 break down the costs for each of the portfolios and compare them with the revenue for that portfolio. The Gas Plant has the highest revenue but also the highest cost, largely due to fuel costs. The renewable and alternative portfolios (C3-C5) represent higher capital investment or PPA costs than the Gas Plant but have lower overall costs as a percentage of revenue due to the lack of fuel costs and result in higher overall return to AE. The Accelerated Solar portfolio has relatively low capital costs because it offsets solar capacity procured a few years later, but also relatively low revenue because power prices remain low over the life of the portfolio.

Figure 27. Cost and Revenue Comparison – C1 (Decker CC)



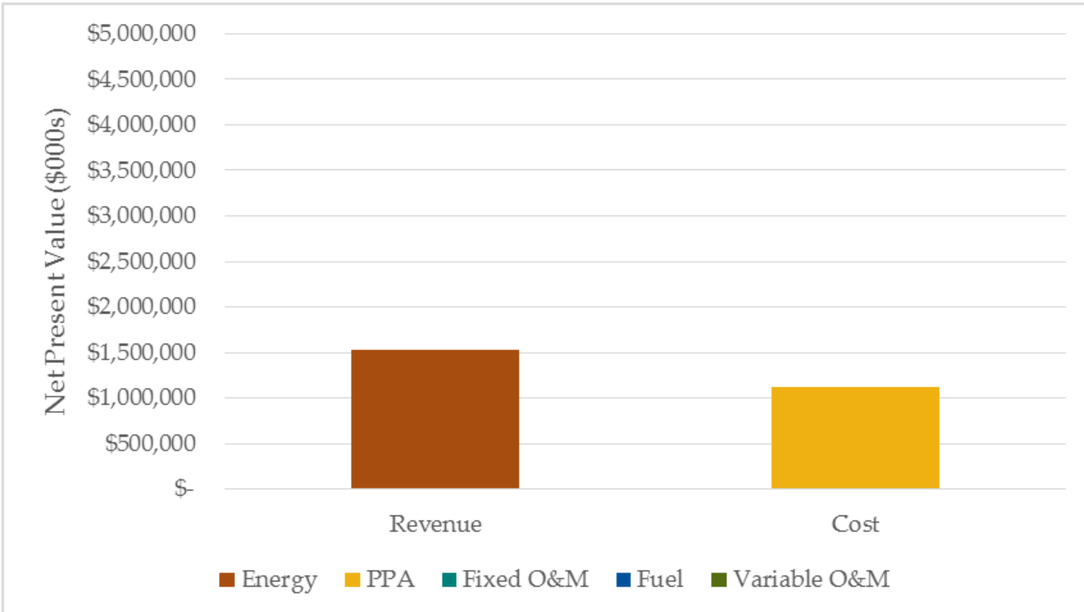
Source: Navigant

Figure 28. Cost and Revenue Comparison – C3 (500 MW Solar)



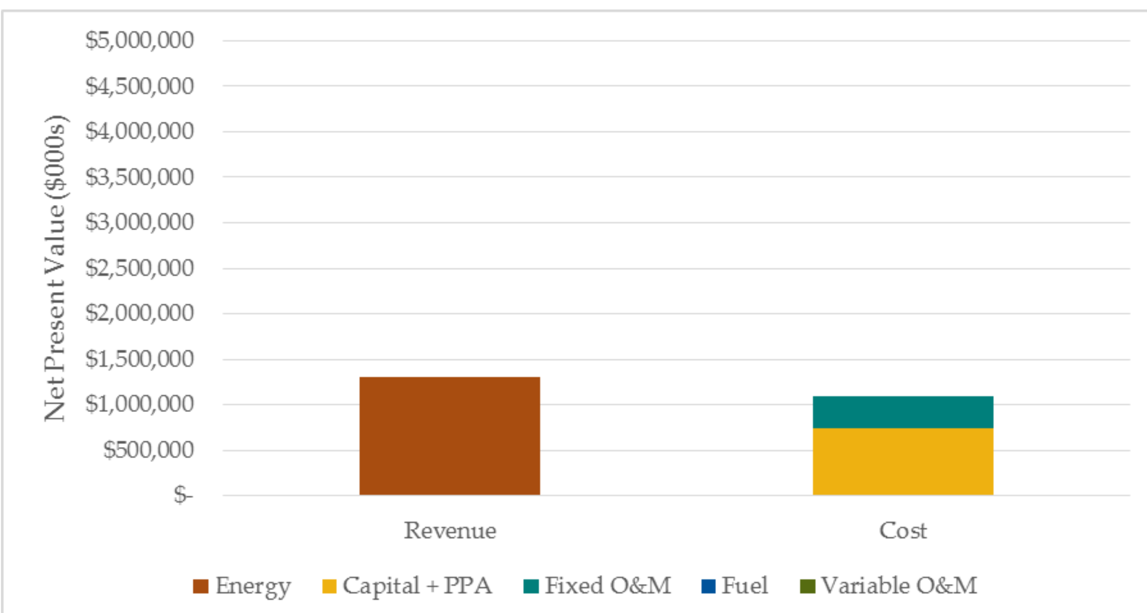
Source: Navigant

Figure 29. Cost and Revenue Comparison – C4 (500 MW Wind)



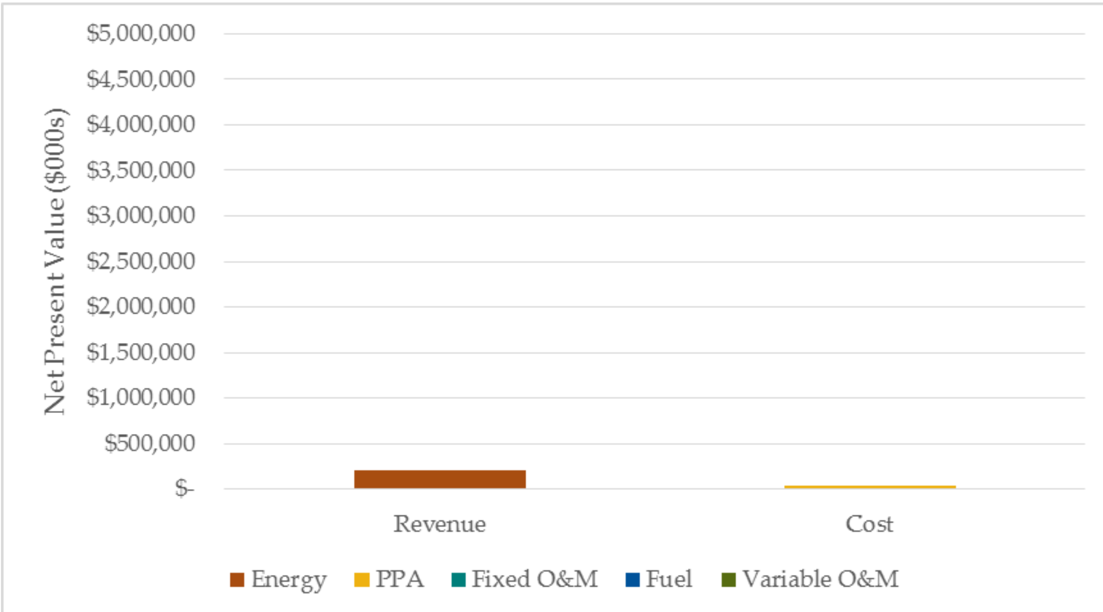
Source: Navigant

Figure 30. Cost and Revenue Comparison – C5 (Alternative Mix)



Source: Navigant

Figure 31. Cost and Revenue Comparison – C6 (Accelerated Solar)



Source: Navigant

4.1.3.1 What Is the Impact of Each Portfolio on Customer Rates?

A customer rate impact study is outside the scope of work of this report.

4.2 Renewable Generation

4.2.1 AE's Renewable Goals Are Met by All Portfolios in Every Scenario

AE plans to meet at least 55% of load with renewable power by 2025. Due to city goals to reduce carbon emissions, additional renewable power is preferred if the tradeoffs are not too impactful to rates. The renewable generation share of AE load that is met by renewables in 2025 is shown in Table 32. It is important to note that since the base assumption for this study is the 2025 Generation Plan except for the Gas Plant, the renewable goals are met by all portfolios in every scenario. Furthermore, in the three portfolios in which additional renewable power is procured, an even higher share of AE load is met with renewable power.

Table 32. Renewable Generation Share in 2025

Portfolio	Base Case	High Gas Case	Low Gas Case	High Solar Case
All Market	56%	58%	56%	56%
C1: Decker CC	56%	58%	56%	56%
C2: Sand Hill CC	56%	58%	56%	56%
C3: 500 MW Solar	64%	63%	64%	63%

C4: 500 MW Wind	70%	72%	69%	70%
C5: Alternative Mix	66%	68%	66%	66%
C6: Accelerated Solar	56%	58%	56%	56%

Source: Navigant

In terms of reducing carbon emissions, total renewable power over the study period matters more than the share in 2025. This value is shown in Table 33. The only change from the patterns of the 2025 renewable share is that, by looking at total renewable generation, the additional renewable power procured in the Accelerated Solar portfolio is counted.

Table 33. Total Renewable Generation (2016-2038) (GWh)

Portfolio	Base Case	High Gas Case	Low Gas Case	High Solar Case
All Market	191,997	196,328	190,341	191,501
C1: Decker CC	191,991	196,319	190,332	191,506
C2: Sand Hill CC	191,991	196,319	190,332	191,507
C3: 500 MW Solar	214,294	219,677	213,692	214,838
C4: 500 MW Wind	231,753	236,071	230,104	231,214
C5: Alternative Mix	222,219	226,518	220,537	221,700
C6: Accelerated Solar	196,945	201,276	195,288	196,455

Source: Navigant

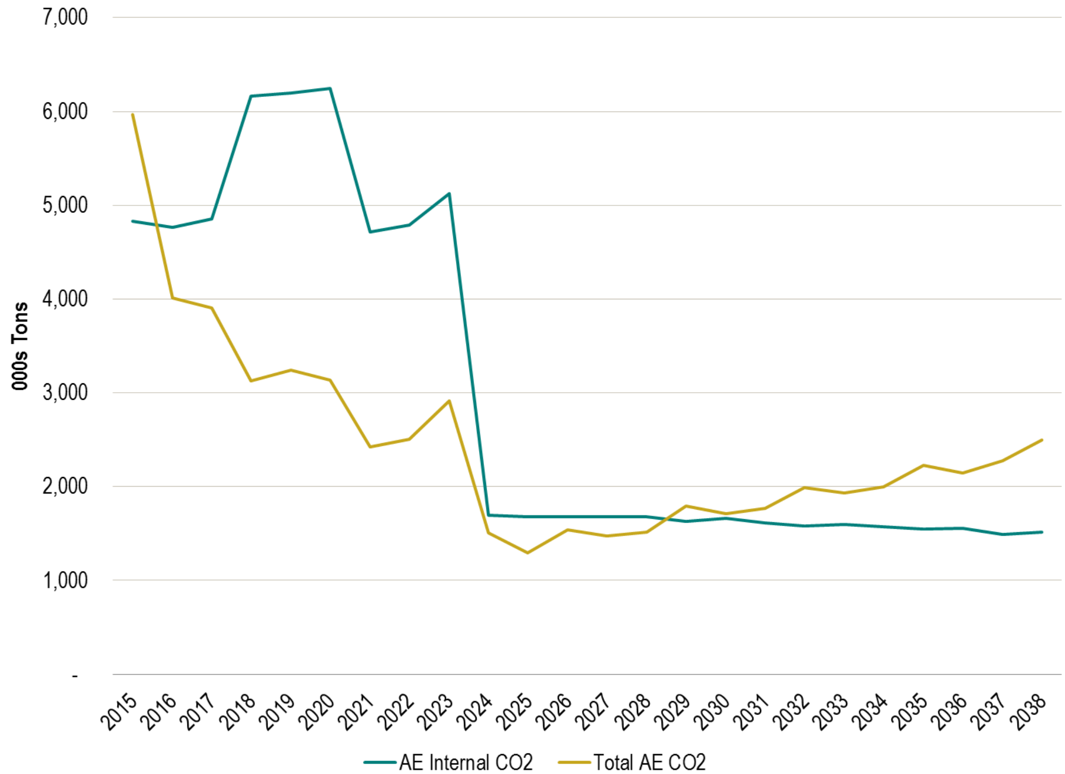
4.3 Emissions

AE and the City of Austin have emissions reductions goals, which are a key metric of this study. The city has the goal of zero net carbon emissions by 2050 or earlier if feasible. CO_2, NO_X, and SO_2 are global pollutants in the sense that it is a goal to reduce overall emissions, not just the local values. Hence, when calculating AE's emissions, we examined the impact of both (1) emissions associated with the power purchased from ERCOT to meet load requirements and (2) the emissions from the resources AE owns or for which it has contracted.

It is important to note that this is an accounting framework, and there are other methods for calculating the emissions that should be allocated to AE. Since AE is an integrated part of ERCOT, it is important to include the emissions from purchases and also to show the emissions reduction value of AE generation that is at a lower rate than the rest of ERCOT. In this study, this is calculated using average emissions rates but could also be calculated by looking at the total change in ERCOT emissions due to changes in AE's generation portfolio.

As an example, Figure 32 shows the comparison of internal AE emissions versus the total emissions attributed to the system. AE internal emissions are those that are directly emitted by AE-owned units. In years in which AE generation exceeds AE load, total emissions are lower than direct emissions, as the more carbon-efficient AE system helps lower overall ERCOT emissions.

Figure 32. AE Internal vs. Total AE Emissions with Gas Plant



Source: Navigant

4.3.1 CO_2 Emissions Are Reduced in Every Portfolio

The total AE CO_2 emissions over the forecast period are shown in Table 34. Somewhat counterintuitively, developing the Gas Plant reduces emissions significantly. This is because the Gas Plant is an advanced CC plant with high efficiency and emits CO_2 at a much lower rate than the overall ERCOT market. Therefore, as the addition of the Gas Plant reduces the amount of market purchases that AE will have to procure, there is a total reduction in CO_2 attributed to serving the AE load.

The 500 MW Solar portfolio has about the same emissions as the Gas Plant portfolios. The reason that emissions are not further reduced with the solar power is that, even though it is a zero-carbon technology, the capacity factor of the additional solar is much lower than the capacity factor of the Gas Plant, and so AE has higher ERCOT purchases with the additional solar. Had each portfolio been matched on an energy basis, the solar portfolio would have significantly more MW of solar and also significantly less CO_2 emissions. The 500 MW Wind portfolio has much lower emissions as the capacity factor of the wind is higher than the capacity factor of the solar.

Table 34. Total CO_2 Emissions Results (000s tons)

Portfolio	Base Case	High Gas Case	Low Gas Case	High Solar Case
All Market	71,925	69,540	72,431	72,522
C1: Decker CC	58,917	56,201	58,255	59,292
C2: Sand Hill CC	58,917	56,199	58,253	59,288
C3: 500 MW Solar	58,818	60,108	58,517	58,906
C4: 500 MW Wind	48,453	45,890	48,769	48,893
C5: Alternative Mix	54,992	51,563	54,472	54,541
C6: Accelerated Solar	69,013	66,443	69,335	69,421

Source: Navigant

The AE CO_2 emissions rate is show in Table 35. This value is important for Texas' compliance with the CPP. Under the CPP, Texas has to reduce its emissions rate to 1,042 lbs/MWh by 2030, so under all portfolios, AE is well under this target.

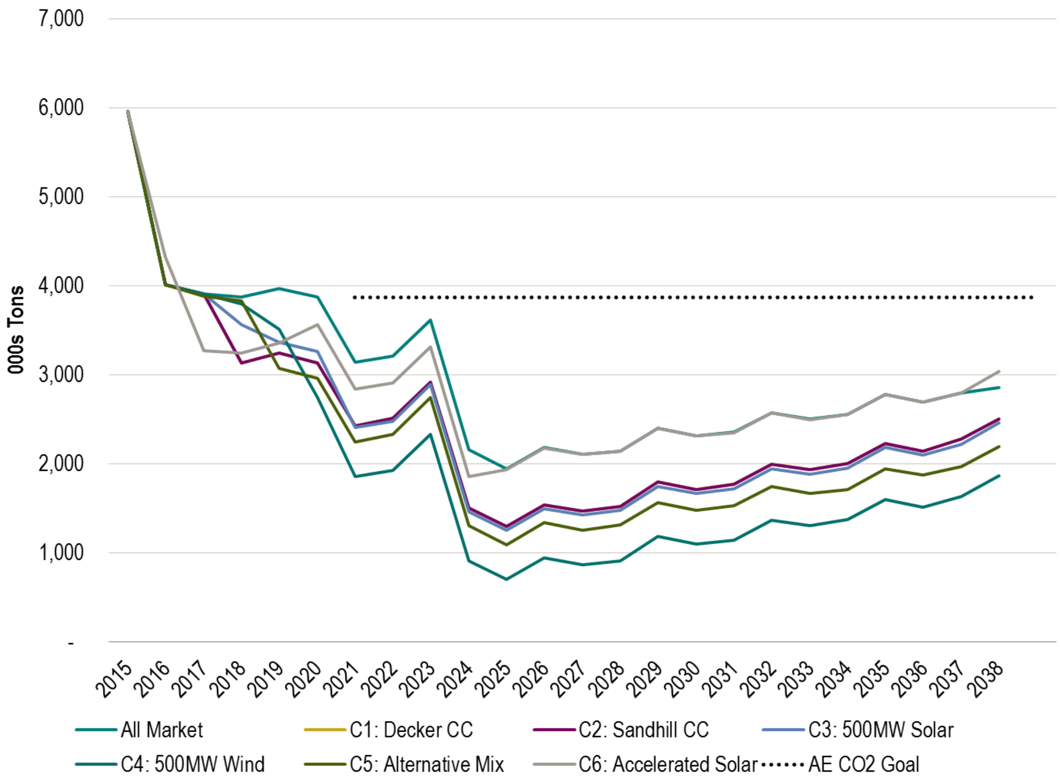
Table 35. CO_2 Emissions Rate (lbs/MWh)

Portfolio	Base Case	High Gas Case	Low Gas Case	High Solar Case
All Market	394	381	397	397
C1: Decker CC	323	308	319	325
C2: Sand Hill CC	323	308	319	325
C3: 500 MW Solar	322	329	321	323
C4: 500 MW Wind	265	251	267	268
C5: Alternative Mix	301	282	298	299
C6: Accelerated Solar	378	364	380	380

Source: Navigant

AE's CO_2 emissions by year are shown in Figure 33. In all cases, the Gas Plant cuts emissions by nearly two-thirds by 2025 before rising after that, since no new resources are added. In the portfolios with additional renewable resources, emissions are reduced even further. AE's current goal requires reduction of total CO_2 by 20% from 2005 levels (~4.8mil tons) by 2020 and this is met in all portfolios.

Figure 33. CO_2 Emissions by Year



Source: Navigant

4.3.2 NO_X and SO_2 Emissions Reductions Follow Similar Patterns

The total emissions for NO_X and SO_2 are shown in Table 36 and Table 37. The pattern of emissions is similar to that of CO_2 except that the gas generation has an even larger reduction than for CO_2 because gas generation is much less intensive in these pollutants than coal or the ERCOT system average.

Table 36. NO_x Emissions Results (000s tons)

Portfolio	Base Case	High Gas Case	Low Gas Case	High Solar Case
All Market	37	39	34	37
C1: Decker CC	20	22	16	20
C2: Sand Hill CC	20	22	16	20
C3: 500 MW Solar	30	35	28	30
C4: 500 MW Wind	25	28	23	26
C5: Alternative Mix	28	31	26	28
C6: Accelerated Solar	35	37	33	35

Source: Navigant

Table 37. SO_2 Emissions Results (000s tons)

Portfolio	Base Case	High Gas Case	Low Gas Case	High Solar Case
All Market	139	150	129	140
C1: Decker CC	90	100	76	91
C2: Sand Hill CC	90	100	76	90
C3: 500 MW Solar	123	138	112	124
C4: 500 MW Wind	110	121	101	111
C5: Alternative Mix	118	128	107	117
C6: Accelerated Solar	135	146	126	136

Source: Navigant

4.3.3 Resultant Impact on Local Criteria Pollutants

This analysis did not consider the economic impacts of other local pollutants, as it is beyond the capabilities of the models used here. For that type of analysis, it is prudent to use environmental analysis-specific models.

4.4 Water Usage

Local water usage is an important metric of this study. As explained in Section 3.2, power generation can be highly water intensive, particularly steam coal, steam gas, or nuclear generation. The Gas Plant uses relatively less water for generation of its type, but still requires access to significant water resources. As water is a local resource, this metric is calculated only for local, AE-owned resources.

The total water usage for each of the portfolios is shown in Table 38. Water usage is the same across all portfolios that do not add a new thermal unit and are about 15% higher in the portfolios with the Gas Plant. All of these levels of water usage are less than is used with the steam units that will retire under the approved 2025 Generation Plan.

Table 38. Water Usage Results (ACFT)

Portfolio	Base Case	High Gas Case	Low Gas Case	High Solar Case
All Market	228,425	228,786	231,305	225,121
C1: Decker CC	267,782	268,767	274,013	265,016
C2: Sand Hill CC	267,780	268,770	274,020	265,019
C3: 500 MW Solar	227,156	228,057	230,581	224,402
C4: 500 MW Wind	227,320	228,265	230,781	224,632
C5: Alternative Mix	227,163	228,159	230,750	224,948
C6: Accelerated Solar	227,705	228,711	231,102	225,018

Source: Navigant

4.5 Land Use Impacts

There are no identifiable land use impacts for the All Market option. For both of the Gas Plant build options (C1: Decker and C2: Sand Hill), the existing sites have more than adequate land available.

4.6 Local Economic Impacts

Although no detailed economic impact study or modeling has been performed, local impacts for gas CC construction and operation have been roughly estimated based on various information, including: cost and labor breakdowns in the AE engineer's report, recent/planned new builds in Texas and other U.S. locations, wage rate data for Travis County and the capital area (Texas), and assumptions. For a 500 MW CC natural gas plant built over a period of 2 years, total local/regional construction spending is estimated to be roughly $74 million, of which 75% is assumed to be labor ($55 million). This corresponds to about 400 full-time equivalent construction-related jobs (including support). Approximately 20 full-time jobs will be added for O&M after the Gas Plant begins commercial operation.

4.7 Gas Plant Economics

The Base case results of the Gas Plant economic analysis at an assumed capital cost of $800/kW are shown in Table 39 below. See Appendix C for complete results from all three capital cost scenarios: $700/kW, $800/kW, and $900/kW. The major analysis categories include discounting statistics, unit statistics (e.g., capacity rating and generation output), annual fixed charges (capacity charge, fixed O&M, insurance), variable non-fuel O&M, gas fuel costs, summary cost metrics (nominal, discounted, and levelized), and market revenue-related and net revenue metrics (annual NPV, total NPV).

Inputs and assumptions for all cases are identical except for the turnkey capital cost assumption, either $700/kW, $800/kW, or $900/kW. The assumption of $800/kW results in levelized costs of $74.70/MWh and a total NPV of $327 million.

Table 39. Financial Project Analysis Results, Decker CC Build, Base Capital Cost ($800/kW, Turnkey)

Calendar Year	Units	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11
Months in Service	Months	12	12	12	12	12	12	12	12	12	12	12
Discount Factor												
Utility Discount Rate and Annual Factor	5.00%	0.8227	0.7835	0.7462	0.7107	0.6768	0.6446	0.6139	0.5847	0.5568	0.5303	0.5051
Unit Statistics												
Capacity Rating	MW	500	500	500	500	500	500	500	500	500	500	500
Unit Output	MWh	3,056,108	3,107,410	3,130,577	3,185,512	3,285,994	3,257,616	3,280,174	3,287,602	3,264,405	3,250,488	3,252,943
Unit Capacity Factor	%	69.77%	70.95%	71.28%	72.73%	75.02%	74.37%	74.69%	75.06%	74.53%	74.21%	74.07%
Annual Fixed Charges												
Nominal Capacity Charge	$000	$ 43,308	$ 42,246	$ 41,494	$ 40,707	$ 39,882	$ 39,018	$ 38,113	$ 37,165	$ 36,172	$ 35,132	$ 34,042
Nominal Fixed O&M	$000	$ 6,571	$ 6,722	$ 6,877	$ 7,035	$ 7,197	$ 7,363	$ 7,532	$ 7,705	$ 7,882	$ 8,064	$ 8,249
Nominal Insurance	$000	$ 340	$ 349	$ 357	$ 366	$ 375	$ 385	$ 394	$ 404	$ 414	$ 425	$ 435
Nominal Total Fixed Charges	$000	$ 50,220	$ 49,317	$ 48,729	$ 48,108	$ 47,454	$ 46,765	$ 46,039	$ 45,274	$ 44,469	$ 43,620	$ 42,727
Nominal Total Fixed Charges Per kW-mo	$/kW-mo	$ 8.37	$ 8.22	$ 8.12	$ 8.02	$ 7.91	$ 7.79	$ 7.67	$ 7.55	$ 7.41	$ 7.27	$ 7.12
Discounted Total Fixed Charges	$000	$ 41,316	$ 38,641	$ 36,362	$ 34,189	$ 32,119	$ 30,145	$ 28,264	$ 26,471	$ 24,762	$ 23,133	$ 21,580
		$ 6,911.34	$ 7,070.98	$ 7,234.31	$ 7,401.41	$ 7,572.38	$ 7,747.29	$ 7,926.25	$ 8,109.34	$ 8,296.66	$ 8,488.32	$ 8,684.40
Variable O&M												
Nominal Non-Fuel Variable O&M	$000	$ 12,270	$ 12,429	$ 16,756	$ 24,151	$ 32,596	$ 33,109	$ 33,962	$ 36,453	$ 38,281	$ 39,230	$ 41,677
		$ 11,624	$ 12,067	$ 12,412	$ 12,895	$ 13,581	$ 13,747	$ 14,133	$ 14,462	$ 14,662	$ 14,906	$ 15,230
Total Fixed Charges and Non-Fuel VOM												
Nominal Total Fixed Charges & Non-Fuel VOM	$000	$ 62,490	$ 61,746	$ 65,484	$ 72,259	$ 80,050	$ 79,874	$ 80,000	$ 81,728	$ 82,750	$ 82,850	$ 84,403
Discounted Total Fixed Chrgs & Non-Fuel VOM	$000	$ 51,410	$ 48,380	$ 48,865	$ 51,353	$ 54,181	$ 51,487	$ 49,113	$ 47,784	$ 46,078	$ 43,937	$ 42,629
Sum Present Val Fixed Chrgs & Non-fuel VOM	$000	$ 875,814										
Other Utility Costs												
Nominal Annual Fuel Costs	$000	$ 90,870	$ 94,583	$ 104,263	$ 118,317	$ 131,760	$ 135,508	$ 140,199	$ 145,588	$ 153,276	$ 159,368	$ 173,265
Discounted Annual Fuel Costs	$000	$ 74,759	$ 74,108	$ 77,803	$ 84,085	$ 89,181	$ 87,350	$ 86,070	$ 85,122	$ 85,350	$ 84,516	$ 87,511
Summary Cost Metrics												
Nominal Average Total Fixed Charges (All)	$/kW-mo	$ 7.17										
Nominal Annual Costs (All)	$000	$ 153,360	$ 156,329	$ 169,747	$ 190,575	$ 211,811	$ 215,382	$ 220,200	$ 227,316	$ 236,026	$ 242,218	$ 257,669
Nominal Avg Costs Including Fuel, Var, & Fixed	$/MWh	$ 78.67										
Discounted Annual Costs (All)	$000	$ 126,169	$ 122,488	$ 126,668	$ 135,438	$ 143,362	$ 138,837	$ 135,183	$ 132,907	$ 131,428	$ 128,453	$ 130,140
Discounted Annual Output (All)	MWh	2,514,268	2,434,737	2,336,085	2,263,884	2,224,090	2,099,888	2,013,743	1,922,193	1,817,743	1,723,803	1,642,957
Levelized Costs Incl. Fuel, Variable, & Fixed (All)	$/MWh	$ 73.78										
Market Revenue Projections												
Nominal Realized Locational Marginal Prices	$/MWh	$ 41.18	$ 43.13	$ 51.36	$ 57.52	$ 69.20	$ 70.56	$ 82.02	$ 78.32	$ 75.81	$ 95.26	$ 95.48
Nominal Market-Based Revenue	$000	$ 125,847	$ 134,013	$ 160,789	$ 183,218	$ 227,380	$ 229,842	$ 269,034	$ 257,485	$ 247,487	$ 309,626	$ 310,593
Nominal Ancillary Services Revenue	$000	$ 3,775	$ 4,020	$ 4,824	$ 5,497	$ 6,821	$ 6,895	$ 8,071	$ 7,725	$ 7,425	$ 9,289	$ 9,318
Net Revenue Metrics												
Annual Net Present Value (Revenue Net of Cost)	$000	$ (19,529)	$ (14,336)	$ (3,085)	$ (1,323)	$ 15,155	$ 13,766	$ 34,935	$ 22,155	$ 10,516	$ 40,674	$ 31,436
Total Net Present Value (Revenue Net of Cost)	$000	$ 449,356										

Calendar Year	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22
Months in Service	12	12	12	12	12	12	12	12	12	12	0
Discount Factor											
Utility Discount Rate and Annual Factor	0.4810	0.4581	0.4363	0.4155	0.3957	0.3769	0.3589	0.3418	0.3256	0.3101	0.0000
Unit Statistics											
Capacity Rating	500	500	500	500	500	500	500	500	500	500	-
Unit Output	3,254,552	3,310,373	3,216,003	3,256,983	3,231,816	3,260,520	3,240,360	3,271,116	3,227,647	3,283,646	-
Unit Capacity Factor	74.30%	75.58%	73.42%	74.16%	73.79%	74.44%	73.98%	74.48%	73.69%	74.97%	0.00%
Annual Fixed Charges											
Nominal Capacity Charge	$ 32,901	$ 31,706	$ 30,453	$ 29,141	$ 27,766	$ 26,326	$ 24,817	$ 23,236	$ 22,395	$ -	$ -
Nominal Fixed O&M	$ 8,439	$ 8,633	$ 8,832	$ 9,035	$ 9,242	$ 9,455	$ 9,673	$ 9,895	$ 10,123	$ 10,355	$ -
Nominal Insurance	$ 446	$ 457	$ 469	$ 480	$ 492	$ 505	$ 517	$ 530	$ 544	$ 557	$ -
Nominal Total Fixed Charges	$ 41,786	$ 40,796	$ 39,753	$ 38,656	$ 37,501	$ 36,286	$ 35,007	$ 33,661	$ 33,061	$ 10,913	$ -
Nominal Total Fixed Charges Per kW-mo	$ 6.96	$ 6.80	$ 6.63	$ 6.44	$ 6.25	$ 6.05	$ 5.83	$ 5.61	$ 5.51	$ 1.82	$ -
Discounted Total Fixed Charges	$ 20,100	$ 18,689	$ 17,344	$ 16,062	$ 14,840	$ 13,676	$ 12,565	$ 11,507	$ 10,764	$ 3,384	$ -
	$ 8,885.01	$ 9,090.26	$ 9,300.25	$ 9,515.09	$ 9,734.90	$ 9,959.78	$ 10,189.87	$ 10,425.27	$ 10,666.11	$ 10,912.52	
Variable O&M											
Nominal Non-Fuel Variable O&M	$ 42,864	$ 46,442	$ 47,565	$ 49,225	$ 52,341	$ 53,501	$ 54,597	$ 58,103	$ 58,852	$ 61,492	$ -
	$ 15,558	$ 16,157	$ 16,026	$ 16,571	$ 16,788	$ 17,293	$ 17,547	$ 18,085	$ 18,220	$ 18,925	
Total Fixed Charges and Non-Fuel VOM											
Nominal Total Fixed Charges & Non-Fuel VOM	$ 84,650	$ 87,237	$ 87,318	$ 87,880	$ 89,842	$ 89,787	$ 89,603	$ 91,764	$ 91,914	$ 72,404	$ -
Discounted Total Fixed Chrgs & Non-Fuel VOM	$ 40,718	$ 39,964	$ 38,096	$ 36,516	$ 35,553	$ 33,840	$ 32,162	$ 31,369	$ 29,924	$ 22,450	$ -
Sum Present Val Fixed Chrgs & Non-fuel VOM											
Other Utility Costs											
Nominal Annual Fuel Costs	$ 187,284	$ 192,321	$ 193,815	$ 207,904	$ 214,553	$ 225,414	$ 227,852	$ 238,835	$ 243,614	$ 257,774	$ -
Discounted Annual Fuel Costs	$ 90,087	$ 88,104	$ 84,561	$ 86,389	$ 84,906	$ 84,956	$ 81,786	$ 81,646	$ 79,314	$ 79,928	$ -
Summary Cost Metrics											
Nominal Average Total Fixed Charges (All)											
Nominal Annual Costs (All)	$ 271,934	$ 279,558	$ 281,133	$ 295,785	$ 304,394	$ 315,201	$ 317,455	$ 330,599	$ 335,528	$ 330,179	$ -
Nominal Avg Costs Including Fuel, Var, & Fixed											
Discounted Annual Costs (All)	$ 130,805	$ 128,069	$ 122,657	$ 122,905	$ 120,459	$ 118,796	$ 113,948	$ 113,015	$ 109,238	$ 102,378	$ -
Discounted Annual Output (All)	1,565,495	1,516,520	1,403,131	1,353,344	1,278,939	1,228,856	1,163,103	1,118,230	1,050,829	1,018,153	-
Levelized Costs Incl. Fuel, Variable, & Fixed (All)											
Market Revenue Projections											
Nominal Realized Locational Marginal Prices	$ 92.65	$ 97.71	$ 108.92	$ 109.97	$ 122.06	$ 113.18	$ 123.08	$ 125.47	$ 125.76	$ 149.15	$ -
Nominal Market-Based Revenue	$ 301,549	$ 323,448	$ 350,282	$ 358,185	$ 394,465	$ 369,019	$ 398,836	$ 410,420	$ 405,893	$ 489,757	$ -
Nominal Ancillary Services Revenue	$ 9,046	$ 9,703	$ 10,508	$ 10,746	$ 11,834	$ 11,071	$ 11,965	$ 12,313	$ 12,177	$ 14,693	$ -
Net Revenue Metrics											
Annual Net Present Value (Revenue Net of Cost)	$ 18,597	$ 24,552	$ 34,754	$ 30,393	$ 40,327	$ 24,456	$ 33,506	$ 31,496	$ 26,873	$ 54,036	$ -
Total Net Present Value (Revenue Net of Cost)											

Source: Navigant

5. Recommendation

Navigant's analysis highlights the uncertainty in the ERCOT market, driven by market drivers such as natural gas pricing, environmental regulations, reserve margin, transmission congestion, real time price volatility, ancillary services costs and impact of increasing penetration of renewables such as solar and wind technologies.

A key finding from our assessment is that AE's policy of owning generation and in particular, local generation, mitigates ERCOT market price risks. Our results show that all portfolios assessed produce benefits for AE and its customers compared with the All Market portfolio which assumes no 500 MW resource(s) addition of any kind.

The results between the portfolios assessed are very close which is why it is important to consider the range of risks to AE and its customers that can be mitigated by the Gas Plant. The portfolios with the Gas Plant (at Decker or Sand Hill) resulted in the best mix of value and risk mitigation among the portfolios studied. The Gas Plant portfolios are the lowest-cost portfolio in two of the four scenarios and not catastrophic in any scenario. Our estimates of additional risks show that in the ERCOT nodal LMP market, location matters. With the planned retirement of ~1,300 MW of local generation in the AE load zone, we expect the locational costs and risks to AE's customers, principally transmission congestion, real time price volatility and ancillary services costs, to increase. As a part of the portfolio of Plan resources, the Gas Plant mitigates locational market risks while supporting goals such as 55% renewable portfolio by 2025, reduction of total CO2 by 20% from 2005 levels (~4.8mil tons) by 2020. The Gas Plant reduces water uses less water per megawatt hour than either Decker or FPP and the construction and operation of the plant provide positive local economic impacts.

Our recommendation to Council on the basis of the benefits and costs and impacts of each of the scenarios we assessed is that AE build the Gas Plant in the AE load zone to replace the Decker Creek Power Station's steam units when they are retired, and to support the planned retirement of FPP.

Additional Observations and Findings:

» **Selecting Solar Early Produces Benefits**: We ran a portfolio accelerating 600 MW of solar PPA selections to 2016 in order to estimate the benefits of selecting 600 MW now vs. over time. Subsequent to the start of our analysis 438MW was approved by the city. Our study results support this decision.

» **Pace of change in technology**: Given the pace of change in renewable and storage costs, AE should continue to monitor and consider these resources.

» **EE and DR resources are often highly valuable if they can be procured cost-effectively**: To the extent that AE can continue to develop additional programs to cost-effectively incentivize customers to participate in EE and DR and provide those resources, AE should continue to pursue these opportunities.

» **AE should consider other quick-starting generating technologies that were not in this scope of work:** This study finds the ERCOT market is evolving rapidly and technology costs are changing. These trends are likely to reward dispatchable quick-starting resources such as reciprocating engines, some combustion turbines, and storage. Installed locally, these technologies can also help mitigate local congestions risks. We recommend that AE, in its next generation plan, should consider this class of resource.

Appendix A. Detailed ERCOT Market Assumptions

Table A-1. Capacity Additions by Type by Year (MW)

	CC	CT Gas	IGCC	Wind	Solar	Other Renewable
2015	2,844	330	0	3,031	145	15
2016	0	592	0	1,587	0	0
2017	0	0	0	0	0	0
2018	900	0	0	0	38	0
2019	600	0	240	0	38	0
2020	600	0	0	0	37	0
2021	1,040	0	0	300	38	0
2022	600	0	0	300	37	0
2023	600	200	0	400	37	0
2024	1,800	200	0	400	38	0
2025	600	200	0	400	38	0
2026	1,200	200	0	400	37	0
2027	0	0	0	400	38	0
2028	1,200	200	0	400	38	0
2029	3,000	0	0	400	37	0
2030	0	200	0	400	38	0
2031	1,200	400	0	400	37	0
2032	2,400	200	0	400	38	0
2033	1,200	200	0	400	38	0
2034	1,200	800	0	400	37	0
2035	600	600	0	400	37	0
2036	0	1,800	0	400	38	0

Source: Navigant's PROMOD Reference Case Database, May 2015

Table A-2. Capacity Additions by Type by Zone (MW)

	CC	CT Gas	IGCC	Wind	Solar	Other Renewable
ERCOT Houston Zone	6,900	3,990	0	0	209	15
ERCOT North Zone	7,798	1,200	0	2,067	290	0
ERCOT South Zone	6,886	200	0	2,402	358	0
ERCOT West Zone	0	732	240	6,349	0	0

Source: Navigant's PROMOD Reference Case Database, May 2015

Table A-3. Retirements by Type by Year (MW)

	CT Gas	ST Coal	ST Gas	Wind
2015	0	0	0	64
2016	0	0	0	0
2017	0	0	0	0
2018	0	1,111	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	61	0	10	0
2022	0	0	291	0
2023	0	0	0	0
2024	0	0	872	0
2025	0	0	230	0
2026	368	0	460	0
2027	310	0	353	0
2028	0	0	0	0
2029	0	0	380	0
2030	0	0	0	0
2031	0	0	868	0
2032	0	0	294	0
2033	0	0	640	0
2034	0	0	983	0
2035	72	0	401	0
2036	0	0	1,534	0

Source: Navigant's PROMOD Reference Case Database, May 2015

Table A-4. Supply-Demand Balance

	Effective Summer Resource Capacity (MW)	Peak Summer Demand (MW)	Effective Summer Capacity Reserve (%)
2015	80,011	69,053	15.9%
2016	81,037	70,011	15.7%
2017	81,037	70,871	14.3%
2018	80,864	71,806	12.6%
2019	80,870	74,118	9.1%
2020	81,507	75,043	8.6%
2021	82,563	75,969	8.7%
2022	83,113	76,890	8.1%
2023	83,998	77,809	8.0%
2024	85,378	78,732	8.4%
2025	86,721	79,435	9.2%
2026	87,608	80,425	8.9%
2027	87,088	81,400	7.0%
2028	88,574	82,463	7.4%
2029	91,280	83,524	9.3%
2030	91,565	84,513	8.3%
2031	92,383	85,415	8.2%
2032	94,775	86,471	9.6%
2033	95,841	87,510	9.5%
2034	96,944	88,562	9.5%
2035	97,756	89,622	9.1%
2036	98,108	90,652	8.2%

Source: Navigant's PROMOD Reference Case Database, May 2015

Table A-5. Annual Average Natural Gas Prices, Base Case (2014$/MMBtu)

Year	Henry Hub	Houston Ship Channel	Texas Gas, Zone 1	Katy	Waha
2015	2.97	2.99	2.86	2.94	2.77
2016	3.82	3.84	3.66	3.78	3.59
2017	3.99	4.02	3.81	3.95	3.74
2018	4.11	4.13	3.90	4.07	3.80
2019	4.11	4.14	3.90	4.08	3.78
2020	4.40	4.44	4.15	4.37	4.03
2021	4.81	4.86	4.51	4.77	4.37
2022	5.06	5.10	4.72	5.01	4.56
2023	5.13	5.17	4.78	5.08	4.63
2024	5.14	5.19	4.80	5.10	4.65
2025	5.24	5.29	4.89	5.20	4.73
2026	5.44	5.49	5.08	5.40	4.91
2027	5.55	5.60	5.18	5.50	5.00
2028	5.89	5.93	5.51	5.83	5.31
2029	6.21	6.26	5.83	6.16	5.61
2030	6.13	6.18	5.75	6.08	5.53
2031	6.21	6.26	5.83	6.15	5.58
2032	6.44	6.48	6.06	6.37	5.79
2033	6.54	6.58	6.16	6.47	5.87
2034	6.66	6.69	6.27	6.58	5.96
2035	6.62	6.65	6.23	6.54	5.92
2036	6.70	6.74	6.32	6.63	6.03

Source: Navigant's Winter/Spring 2015 Fuel Forecast

Table A-6. Annual Average Natural Gas Prices, High Gas Case (2014$/MMBtu)

Year	Henry Hub	Houston Ship Channel	Katy	Texas Gas, Zone 1	Waha
2015	2.956	2.973	2.893	2.906	2.972
2016	3.260	3.284	3.174	3.191	3.317
2017	3.972	3.995	3.887	3.868	4.020
2018	4.401	4.419	4.340	4.235	4.290
2019	4.679	4.710	4.613	4.499	4.558
2020	5.433	5.475	5.355	5.211	5.300
2021	5.810	5.860	5.720	5.548	5.661
2022	6.193	6.239	6.097	5.906	6.032
2023	6.375	6.425	6.279	6.080	6.219
2024	6.603	6.658	6.507	6.301	6.446
2025	6.978	7.032	6.881	6.669	6.814
2026	7.366	7.419	7.268	7.050	7.190
2027	7.655	7.707	7.556	7.335	7.469
2028	8.258	8.306	8.154	7.937	8.048
2029	8.446	8.496	8.341	8.120	8.225
2030	8.275	8.327	8.169	7.949	8.047
2031	8.276	8.325	8.168	7.956	8.027
2032	8.467	8.511	8.358	8.156	8.191
2033	8.514	8.552	8.406	8.198	8.221
2034	8.696	8.730	8.588	8.381	8.389
2035	8.765	8.774	8.638	8.437	8.438
2036		8.866	8.729	8.521	8.546

Source: Navigant's Winter/Spring 2015 Fuel Forecast

Table A-7. Annual Average Natural Gas Prices, Low Gas Case (2014$/MMBtu)

Year	Henry Hub	Houston Ship Channel	Katy	Texas Gas, Zone 1	Waha
2015	2.527	2.544	2.464	2.477	2.543
2016	2.661	2.685	2.575	2.592	2.718
2017	3.053	3.076	2.967	2.949	3.101
2018	3.428	3.446	3.366	3.261	3.317
2019	3.755	3.785	3.689	3.574	3.634
2020	4.440	4.483	4.362	4.218	4.307
2021	4.627	4.676	4.536	4.364	4.478
2022	4.822	4.868	4.726	4.535	4.661
2023	4.807	4.857	4.712	4.513	4.651
2024	4.655	4.710	4.559	4.354	4.498
2025	4.520	4.574	4.423	4.211	4.356
2026	4.232	4.285	4.134	3.916	4.056
2027	4.077	4.128	3.977	3.756	3.890
2028	4.372	4.420	4.268	4.051	4.162
2029	4.473	4.522	4.367	4.146	4.251
2030	4.332	4.384	4.226	4.006	4.105
2031	4.371	4.420	4.263	4.051	4.121
2032	4.479	4.522	4.370	4.168	4.203
2033	4.507	4.545	4.399	4.191	4.215
2034	4.532	4.566	4.423	4.217	4.224
2035	4.480	4.510	4.374	4.173	4.174
2036		4.602	4.464	4.257	4.282

Source: Navigant's Winter/Spring 2015 Fuel Forecast

Table A-8. Annual Capacity-Weighted Coal Prices (2014$/MMBtu)

	Capacity-Weighted Coal Price
2015	1.87
2016	2.02
2017	2.06
2018	2.03
2019	2.02
2020	1.98
2021	2.02
2022	2.06
2023	2.07
2024	2.06
2025	2.06
2026	2.07
2027	2.07
2028	2.09
2029	2.12
2030	2.10
2031	2.09
2032	2.11
2033	2.11
2034	2.11
2035	2.09
2036	2.08

Source: Navigant – EVA

Table A-9. Annual Emissions Prices (2014$/ton)

Year	US National CO2	CSAPR Annual Nox	CSAPR Seasonal Nox	CSAPR Group 1 SO2	CSAPR Group 2 SO2
2015		$261	$25	$136	$226
2016		$209	$21	$70	$129
2017		$138	$21	$62	$123
2018		$120	$12	$50	$100
2019		$100	$10	$40	$80
2020	2.76	$80	$8	$30	$40
2021	7.37	$60	$6	$15	$20
2022	11.97	$40	$4	$10	$20
2023	11.97	$50	$5	$5	$10
2024	11.97	$40	$4	$5	$5
2025	12.89	$40	$4	$5	$5
2026	13.81	$40	$4	$5	$5
2027	13.81	$40	$4	$5	$5
2028	14.73	$40	$4	$5	$5
2029	14.73	$40	$4	$5	$5
2030	15.65	$40	$4	$5	$5
2031	16.57	$40	$4	$5	$5
2032	16.57	$40	$4	$5	$5
2033	17.49	$40	$4	$5	$5
2034	17.49	$40	$4	$5	$5
2035	17.49	$40	$4	$5	$5
2036	18.41	$40	$4	$5	$5

Source: Navigant

Table A-10. Transmission Assumptions

Project Name	Transmission Owner	Region	Voltage	Projected In-Service Date
*Lobo - North Edinburg 345-kV Circuit	AEP – TCC	South	345-kV	May-14
Lobo - Rio Bravo 345-kV Circuit	AEP – TCC	South	345-kV	May-14
Rio Bravo Bus A/Bus B Tie CB	AEP – TCC	South	345-kV	May-14
Rio Bravo - Del Sol 345-kV Circuit	AEP – TCC	South	345-kV	May-14
Del Sol Bus A/Bus B Tie CB	AEP – TCC	South	345-kV	Dec-15
Del Sol - North Edinburg 345-kV Circuit	AEP – TCC	South	345-kV	Dec-15
Loma - North Edinburg 345-kV Circuit	AEP – TCC	South	345-kV	Dec-15
*Big Lake - Friend 138-kV Circuit	AEP – TNC	West	138-kV	Dec-15
*Gilleland Creek - Tech Ridge 138-kV Circuit	Austin Energy - AE	South	138-kV	Dec-16
Gilleland Creek - Northeast 138-kV Circuit	Austin Energy - AE	South	138-kV	Dec-16
Northeast - Tech Ridge 138-kV Circuit	Austin Energy - AE	South	138-kV	Dec-16
Koppe Bridge - Wellborn 138-kV Circuit	Bryan Texas Utilities - BTU	South	138-kV	Sep-13
Thompson Creek - Snook 138-kV Circuit	Bryan Texas Utilities - BTU	South	138-kV	Dec-13
Koppe Bridge - Snook 138-kV Circuit	Bryan Texas Utilities - BTU	South	138-kV	Dec-13
Green Mountain - Stonegate 138-kV Circuit #2	CPS Energy	South	138-kV	Jun-15
Spruce - Skyline 345-kV Circuit #2	CPS Energy	South	345-kV	Jun-16
Menger Creek - Menger Creek Tap 138-kV Circuit	Lower Colorado River Authority - LCRA	South	138-kV	May-15
Bakersfield - Big Hill 345-kV Circuit	South Texas Electric Cooperative - STEC	West	345-kV	May-13
Bakersfield - North McCamey 345-kV Circuit	South Texas Electric Cooperative - STEC	West	345-kV	May-13
North McCamey - Odessa 345-kV Circuit	South Texas Electric Cooperative - STEC	West	345-kV	May-13
Doedyns - Sioux 138-kV Circuit	South Texas Electric Cooperative - STEC	South	138-kV	May-13
Alberta Switch - Doedyns 138-kV Circuit	South Texas Electric Cooperative - STEC	South	345-kV	May-13

Project Name	Transmission Owner	Region	Voltage	Projected In-Service Date
*Ricebird - Vanderbilt 138-kV Circuit	South Texas Electric Cooperative - STEC	South	138-kV	May-14
Ricebird - ETP 138-kV Circuit	South Texas Electric Cooperative - STEC	South	138-kV	May-14
ETP - Vanderbilt 138-kV Circuit	South Texas Electric Cooperative - STEC	South	138-kV	May-14
Loxley - Oaks 138-kV Circuit	South Texas Electric Cooperative - STEC	South	138-kV	May-14
Olinger - Elm Grove 138-kV Circuit	Texas Municipal Power Agency - TMPA	North	138-kV	May-15
Olinger - Firewheel 138-kV Circuit	Texas Municipal Power Agency - TMPA	North	138-kV	May-15
Olinger - Ben Davis 138-kV Circuit	Texas Municipal Power Agency - TMPA	North	138-kV	May-15
Shelby - Royse 138-kV Circuit	Texas Municipal Power Agency - TMPA	North	138-kV	May-15
*Olinger - Greenville 138-kV Circuit	Texas Municipal Power Agency - TMPA	North	138-kV	May-15
Olinger - Swindell 138-kV Circuit	Texas Municipal Power Agency - TMPA	North	138-kV	May-15
Swindell - Pruitt 138-kV Circuit	Texas Municipal Power Agency - TMPA	North	138-kV	May-15
Pruitt - Greenville 138-kV Circuit	Texas Municipal Power Agency - TMPA	North	138-kV	May-15
Greenville - Shelby 138-kV Circuit	Texas Municipal Power Agency - TMPA	North	138-kV	May-15

Source: Navigant

Appendix B. Detailed Gas Plant Assumptions

Independent Review of Austin Energy's Resource Plan
500 MW Combined Cycle Gas Plant
Prepared by Quality Power, LLC

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B.1 Methodology

Navigant Consulting, Inc. (Navigant) was hired by Austin Energy (AE) to provide an economic and financial assessment of the costs and benefits of a nominal 500 megawatt (MW) natural gas combined cycle (CC) plant (the "Gas Plant") to AE's portfolio. Quality Power, LLC (QP) is a subcontractor to Navigant for this project. Navigant requested that QP perform an independent review of the Gas Plant sites, design and assumptions.

The Gas Plant is to be constructed in the Austin area at either the Decker Creek plant site (Decker) or the Sand Hill Energy Center site (Sand Hill). The assessment also included the expected and high/low sensitivities for construction cost of the Gas Plant, including direct and financing costs. Other considerations for the operation and dispatchability of the Gas Plant include plant performance characteristics such as heat rates, ramp rates, and other operational limits.

Navigant requested and Austin Energy provided a study by Stanley Consultants, Inc. ("Stanley study") which Navigant provided to QP. AE systems operational information, Decker and Sand Hill site and existing infrastructure information, and other information related to the Gas Plant.

Navigant and Quality Power, LLC (QP) reviewed and analyzed the Stanley study, *500 MW Gas Fired Combined Cycle Power Generation Study*, dated July 2015. QP contacted three major CC plant manufacturers and obtained plant equipment data, capital cost, operations and maintenance (O&M) cost, plant performance data, emissions data, and other operational information for the Gas Plant. Navigant used the U.S. Energy Information Administration's (EIA's) website as a resource to obtain cost-related information to support our efforts. QP and Navigant relied on the data collected from AE and major vendors and our knowledge and experience to conduct this study and create this report.

Data Requested and Obtained from AE

Navigant requested and AE provided the following financial and site information, which Navigant provided to QP:

- Decker existing infrastructure and the spare capacity that can be reused for the Gas Plant:
    - Lake cooling water supply infrastructure and capacity
    - Natural gas supply pressure regulating station, gas availability, gas pressure, number of suppliers, etc.
    - Boiler water treatment facilities
    - Plant service and instrument air system
    - Existing power evacuation system including switchyard
    - Transmission system and line capacity
    - Land availability
    - Water rights
    - Maintenance shops

    - Warehouse
    - Office
- Decker steam units #1 and #2 are scheduled to retire by the end of 2018. Once these units are retired, the above existing infrastructure can be reused for the 500 MW CC plant if Decker is chosen as plant site.
- Sand Hill existing infrastructure and the spare capacity that can be reused for the Gas Plant:
    - Cooling water availability from Austin Water South Austin Wastewater Treatment Plant for the cooling tower
    - Transmission system and line capacity
    - Natural gas supply pressure stations, and gas availability, gas pressure, number of gas suppliers, etc.
    - Land availability
    - Water rights
    - Maintenance shops
    - Warehouse
    - Office

Navigant obtained the following financial and system operational information from AE and provide to QP:

- AE discount rate and bond rate
- System operational limits
- System operational rates

Stanley Study

In July 2015, Stanley Consultants, Inc. conducted a study for AE entitled *500 MW Gas Fired Combined Cycle Power Generation Study*. Navigant and QP obtained the copy of the study from AE and reviewed it. The Stanley study covers and compares various CC configurations, repowering of existing steam turbines, and reusing existing equipment, systems, and buildings. Since the focus of the study was to compare various technologies and repowering the power plant, very little information was used from the Stanley study in this study.

Vendor-Provided Information

At the request of Navigant, QP contacted three major CC plant equipment manufacturers and obtained capital cost for engineering, procurement, and construction (EPC) turnkey-type contract pricing for a nominal 500 MW natural gas-fired CC plant. QP also obtained from the vendors the O&M cost, cost for major overhaul, plant performance data, and other plant equipment-related information.

U.S. Energy Information Administration

QP also used EIA's website and obtained cost-related information to support our efforts.

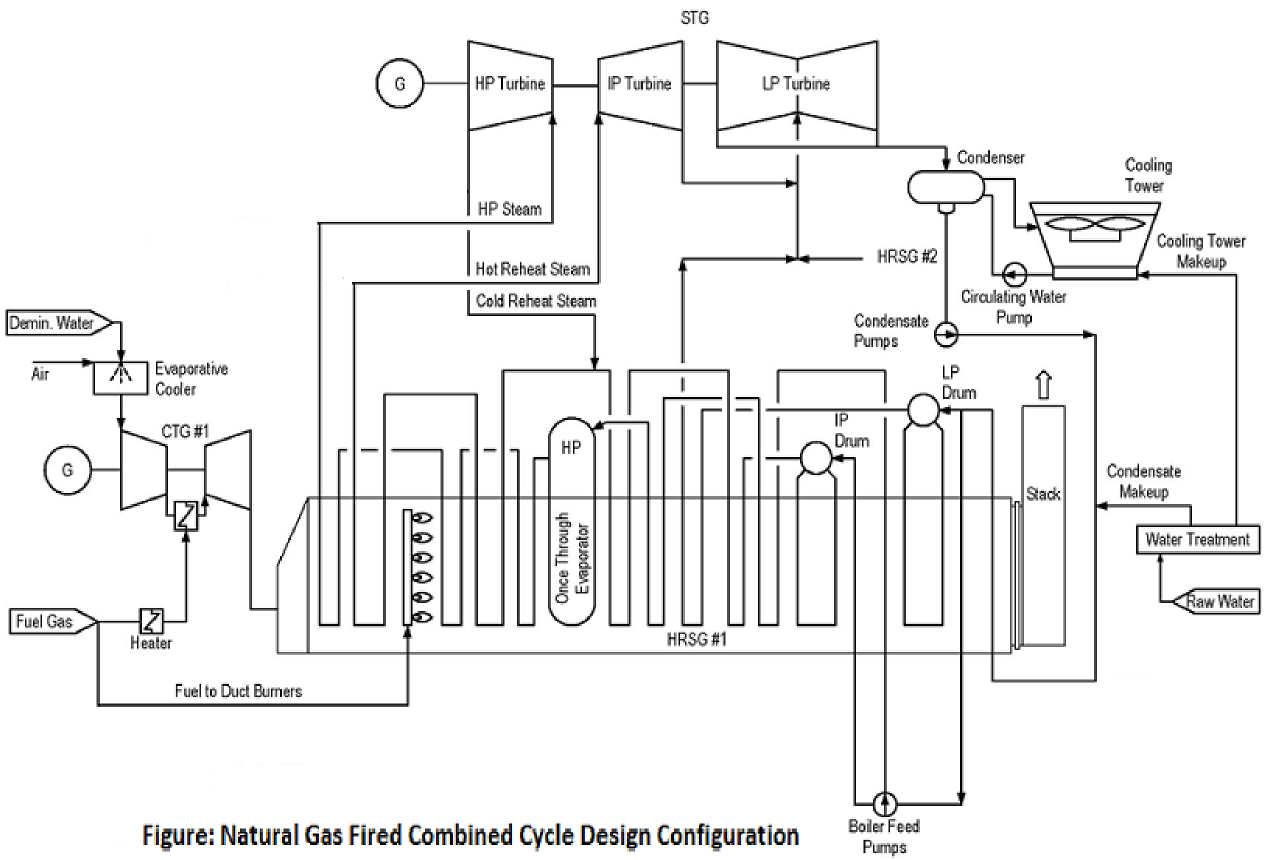
Assumptions
See Section B.3.

B.2 Gas Plant Assumptions

Technology
For the purpose of this study, Navigant and QP considered only advanced-class gas turbines for the 500 MW CC plant. The advanced-class gas turbine usually comes with a one-on-one (1x1) configuration. That means that the plant will have one gas turbine, one heat recovery steam generator (HRSG), and one steam turbine. This configuration is more efficient than a 2x2x1 configuration, as it has only one set of balance of plant equipment as opposed to two sets of balance of plant equipment, as in the case of a 2x2x1 configuration. The figure below shows the design configuration of 1x1 arrangements. QP obtained cost and plant information from three major gas turbine manufacturers:

- General Electric Power Systems
- Mitsubishi Electric
- Siemens Power Corporation

Figure 34. Natural Gas-Fired CC Design Configuration



Source: Quality Power, LLC

Scope of Supply

Capital Cost

All three vendors provided a summary base capital cost estimate based on the QP and Navigant scope of supply for EPC of a nominal 500 MW CC power plant at either Decker or Sand Hill.

A high-level scope of supply was provided by QP and Navigant to all three vendors to obtain the cost estimate:

- Plant size: 500 MW
- Configuration: 1x1 or 2x1
- Fuel: natural gas
- Type of supply: EPC - Turnkey
- Number of gas turbine(s): 1 or 2 (depending on supplier)

- Number of steam turbines: 1 (with LO systems and all auxiliaries, valves [stop, governor, etc.])
- Number of generators: 2 (1 gas turbine each and 1 steam turbine each)
- Number of generator excitation systems: 1
- Number of generator step-up transformers: 1 (also used as startup transformer)
- Number of HRSGs: 1 or 2 (depending on configuration)
- Number of condensers: 1
- Number of air evacuation systems: 1 with 2x100% pumps
- Number of condensate pumps: 2
- Number of feed pumps: 2x100%
- Number of cooling water pumps: 2+1
- Number of water treatment systems: 1
- Natural gas compressor: not required
- Steam turbine bypass: 100%
- Electrical equipment: switch gears, motors, enclosure, battery chargers, uninterruptible power supply (UPS), transformers, etc.
- Number of turbine control systems: 1
- Number of plant distributed control systems (DCSs): 1
- Number of emissions control equipment: 1
- Condenser cooling:
    - Include cooling tower and circulating water pumps
    - Include water treatment equipment
- Instrumentation and control equipment (including valves, instruments, analyzers, etc.)
- Supply and construct all necessary materials. The scope includes but is not limited to the following:
    - Piping, pipe hangers, and welding material
    - Labor
    - Concrete and structural steel
    - Power, control, and instrumentation communication cables
    - Duct banks, conduits, race ways, etc.
    - Erection of all plant equipment
    - Civil, mechanical, piping, electrical, and controls work

- Tools, cranes, welding equipment, test equipment, etc. and other as necessary
- Testing, startup, and commissioning services
- Land preparation, soil testing, etc.

- Supplied by the owner:
  - Land for the plant site
  - Plant cooling water: as alternate option, lake water, existing intake structure and pumps
  - Fuel supply available at site at 500 pounds per square inch gage (psig)
  - Power evacuation: existing switch yard has adequate capacity to export 500 MW to grid
  - ERCOT study
  - Permits (air and discharge)
  - Roadway: this 500 MW unit will be installed in an existing power plant that has an access road

EPC Cost

Based on the scope of supply for the Gas Plant, the capital cost for the EPC turnkey project is in the range of $700-$789 per kilowatt (kW) installed. Several factors affect the cost variations, including exchange rate, borrowing cost, nameplate rating of the equipment, and other supplier considerations.

The cost estimate assessing the cost differences for outdoor installation considerations, cooling tower issues, low water discharge issues, and air emissions issues pertained to Austin-area requirements.

The project indirect costs to the EPC contractor include engineering, distributable labor and materials, craft labor overtime and incentives, construction management, and startup and commissioning. The fees and contingency include contractor overhead costs, fees and profit, and construction contingency. Contingency in this category is considered contractor contingency, which would be held by a given contractor to mitigate its risk in the construction of a project.

The EPC cost estimate (see Table B-1 below) includes the project direct and indirect cost. It does not include owner's cost.

Table B-1. Indicative EPC Cost Estimate

Manufacturer/Model/Configuration	Net Output (MW)	Net Heat Rate – LHV Btu/kWh	Capital Cost – EPC ($ Million)	Cost per kW EPC ($/kW)
Mitsubishi 501 JAC (1x1)	495	5903	$386.4	$780
GE 7HA02 (1x1)	508	5956	$401.1	$789
Siemens SGT6 8000H(1x1)	500	5947	$350.0	$700

Source: Quality Power, LLC

Owner's Costs

Owner's costs (see Table B-2) include development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, project management, infrastructure interconnection costs (e.g., gas and water), owner's contingency, and cost of borrowing during construction. The electrical interconnection cost does not include an allowance for the plant switchyard, a subsequent interconnection to transmission lines and system upgrades.

Owner's engineer cost is estimated to be $5.0 million. The permitting cost is estimated to be $1.0 million. Based on AE's preliminary analysis, it would cost about $10.5 million to add necessary switchyard equipment and relocate some transmission lines if Decker is chosen as the plant site.

The cost of transmission line relocations and switchyard equipment is not included in the owner's cost, as ERCOT pays this cost.

Table B-2. Owner's Cost

Owner's Cost	Amount
Owner's engineer cost	$5.0 Million
Permit fees	$1.0 Million
Underwriter fees	$2.6 Million
Total owner's cost	**$8.6 Million**

Source: Quality Power, LLC

Total Project Cost

The total project cost includes the EPC contractor plus the owner's cost for the project, which is approximately $400 million, depending on the EPC contractor, detailed specification, and final negotiations.

Reuse of Existing Equipment
As Decker steam units 1 and 2 are scheduled to retire in 2018, it makes sense to reuse existing onsite equipment that is in good condition. The existing equipment is sized to support the larger existing gas units; they are capable of supporting the proposed Gas Plant. Following is the list of equipment that can be reused:

- Lake water intake infrastructure to provide cooling water for the condenser
- Boiler water treatment facility
- Air compressor systems
- Demineralized storage tanks
- Condensate storage tank
- Fuel gas pressure regulating station
- Warehouse
- Office building

Reusing existing plant equipment reduces the project capital cost, which is estimated to be $20.0 million.

O&M Expenses
O&M expenses consist of non-fuel O&M costs and fuel-related expenses. We focused on non-fuel O&M costs associated with the direct operation of the power plant. Power generation-related non-fuel O&M expenses span the following categories:

- Fixed O&M
- Variable O&M
- Major maintenance

Fixed O&M Costs
Fixed O&M expenses include the following categories:

- Staffing: Includes salaries, bonuses, and benefits such as insurance, leave, holiday pay, etc.
- Plant support equipment that consists of equipment rentals and temporary labor
- Plant-related general and administrative expenses (postage, telephone, office supply, etc.)
- Maintenance of structures and grounds
- Routine preventive and predictive maintenance expenses do not require an extended plant shutdown and include the following categories:
    - Maintenance of equipment such as feed pumps, main steam piping, and demineralizer systems
    - Maintenance of electric plant equipment, which includes service water, DCS, condensate system, air filters, and plant electrical

- Maintenance of miscellaneous plant equipment such as communications equipment, instrument and service air, and water supply system
- Plant support equipment that consists of tools, shop supplies and equipment rental, and safety supplies

The estimated fixed O&M cost is about $13.2/kW installed per year, which is equal to $6.6 million per year for a 500 MW CC plant.

Variable O&M Costs
Variable O&M expenses are generation-related costs that vary with electrical generation and include the following categories, as applicable to the given power plant technology:

- Raw water
- Waste and wastewater disposal expenses
- Chemicals, catalysts and gases
- Ammonia (NH_3) for selective catalytic reduction (SCR)
- Lubricants

The estimated variable O&M cost is $3.5/MWh.

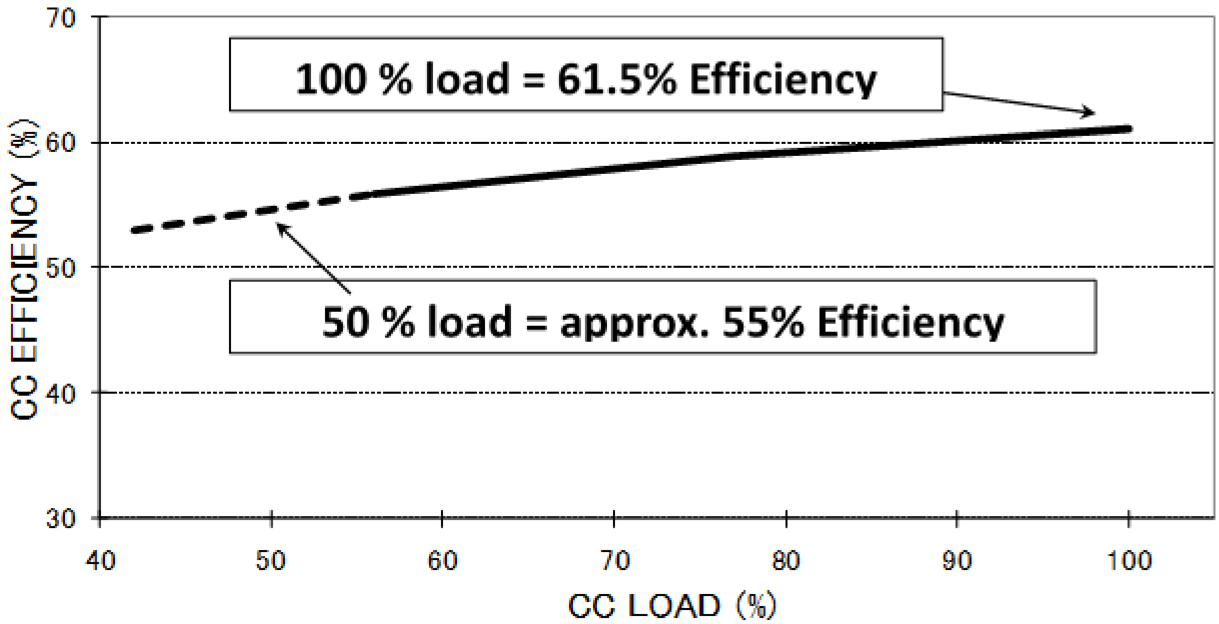
Major Maintenance Costs
Major maintenance expenses generally require an extended outage, are typically undertaken no more than once per year, and are assumed to vary with electrical generation or the number of plant starts based on the given technology and specific original equipment manufacturer recommendations and requirements. Major maintenance expenses include the following categories:

- Scheduled major overhaul expenses for maintaining the prime mover equipment
- Major maintenance labor
- Major maintenance spare parts costs
- Blowout preventer (BOP) major maintenance, which is major maintenance of the equipment at the given plant that cannot be accomplished as part of routine maintenance or while the unit is in commercial operation

Major maintenance expenses are included in the O&M expenses. These expenses may be in either the fixed or variable O&M rate, depending on the cost structure of the particular plant, considering such factors as capacity factor, hour and start cycling patterns, O&M contract structure (if applicable), and major maintenance timing triggers.

Operations and Performance
Heat Rate
The heat rate for the Gas Plant varies, as shown in Figure 35.

Figure 35. CC Efficiency vs. Load

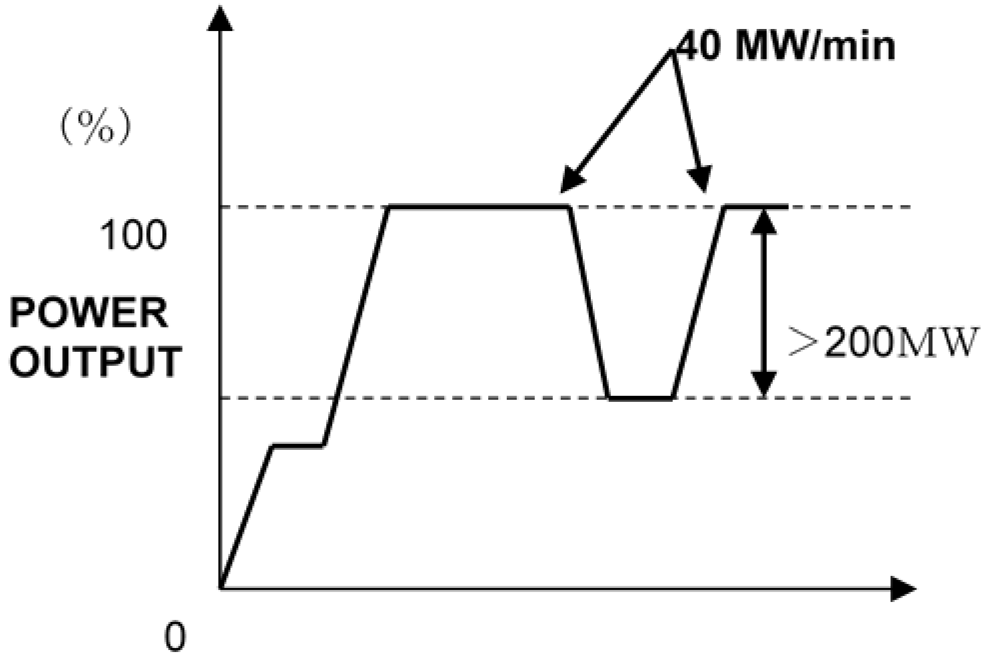


Source: Quality Power LLC

Ramp Rate

The ramp rate is the rate at which the Gas Plant's load will increase or decrease. It is measured in terms of MW per minute. For a nominal 500 MW CC plant, the ramp rate is expected to be 40 MW/min.

Figure 36. Ramp Rate



Source: Quality Power LLC

Water Use
Using lake water for condenser cooling is the most cost-effective cooling option, as it utilizes some of the existing cooling infrastructure and does not require any new, expensive cooling equipment. It also has the best plant efficiency because of the heat sink that the lake provides. This option is only possible at Decker, as this site is situated at Decker Lake.

Another option is the wet cooling tower option, which consumes the most water through evaporation and blowdown. It is more expensive than lake cooling. As Sand Hill is not located near a lake, a cooling tower is the only water-cooled option available for that site. Currently, Sand Hill uses cooling water from South Austin Regional Wastewater Treatment Plant and city water for cooling.

The costs provided in this report include this pipeline and associated infrastructure in the cooling tower costs.

The Gas Plant will have a heat rate of 6,631 British thermal units per kilowatt-hour (Btu/kWh) or less, compared to 10,000 Btu/kWh for a conventional gas-fired steam plant. A conventional steam unit is about 36% efficient, whereas the high-efficiency CC plant is about 60% efficient. To produce 500 MW of electricity, the Gas Plant uses only 150 MW of steam turbine capacity, compared to the 500 MW steam unit, which means that only 30% of steam will need to be cooled. In other words, the Gas Plant will use about 70% less water for cooling the condenser.

Emissions and Fuel Specifications

The Gas Plant efficiency is about 60%. It consumes 40% less fuel than a conventional gas-fired steam plant. Therefore, its emissions are at least 40% less. For emissions control, with use of best-available control technology (BACT), the following stack emissions are easily achievable.

Table B-3. Achievable Emissions

Stack Emission	Mitsubishi M501JAC	GE 7H	Siemens
NO_X abated ppmvd@15% O_2	2	n/a	2
CO abated ppmvd@15% O_2	3	n/a	2
VOC abated ppmvd@15% O_2	1	n/a	n/a
Particulate (PM_{10} total) lb/MMBtu HHV	0.00393	n/a	n/a

Source: Quality Power LLC

The Gas Plant's fuel specifications are shown below.

Table B-4. Fuel Specification

Components	Percentage by Volume
Methane CH_4	93.9
Ethane C_2H_6	3.2
Propane C_3H_8	0.7
n-Butane C_4H	0.4
Carbon dioxide CO_2	1.0
Nitrogen	0.8
Total	100.0

Source: Quality Power LLC

Table B-5. Heating Value of Gas

	LHV	HHV
Btu/lb	20,552	22,792
Btu/SCF	939	1040

Source: Quality Power LLC

Land Use

The 1x1 configuration uses one large CTG and HRSG pair, feeding steam to a steam turbine. The 1x1 plant configurations are the least expensive because of the overall net reduction in plant equipment and infrastructure. They also produce less power, and their minimum loads are limited, which provides less operational flexibility at reduced loads. Because of net reduction in the amount of balance of plant equipment, less land is required for the plant. Both Decker and Sand Hill have more than adequate land available for the Gas Plant.

B.3 Underlying Assumptions

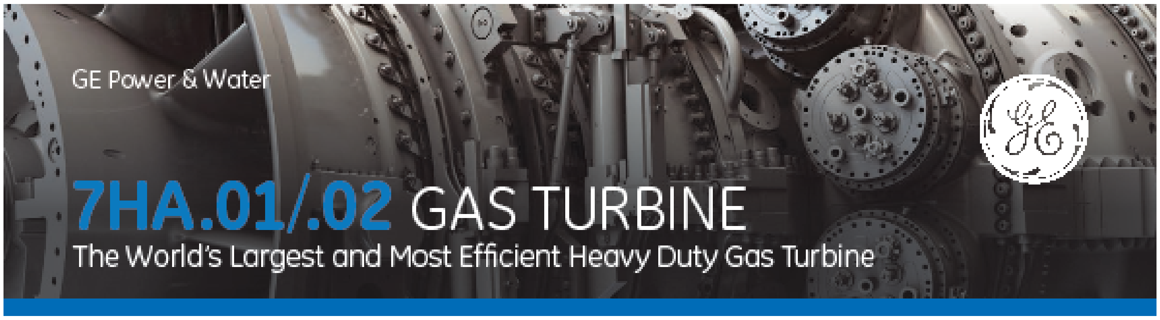
The following assumptions were made for purpose of this study:

- An ambient temperature of 85° F and 60% relative humidity at 600 feet above mean sea level is the design point for the heat balances.
- Utilize dry low NO_X emissions technologies only for combustion turbine NO_X control.
- The combustion turbines (CTs) and HRSG duct firing will only be fired on natural gas. Fuel oil will not be required as a backup fuel.
- For NO_X control, a SCR system will be required in the HRSG for post combustion turbine and duct.
- A carbon monoxide (CO) catalyst will be required for post combustion turbine and duct burner CO control.
- Inlet evaporative cooling (no chilling) is used for CT inlet cooling.
- Fuel gas performance heating is included for all CTs.
- Plant design is optimized around the unfired case, since this is where the plant will operate most of the time.
- There is no steam bypass. Adequate condenser cooling water and its infrastructure are available.
- The natural gas supply is available at site.
- Switchyard and transmission line cost will be pass-through.
- Natural gas is priced at $5.00 per million British thermal units (MMBtu).
- The discount rate is 3.0%.
- There is zero debt balance for Decker steam units #1 and #2.
- AE will pay cash for the plant; therefore, there is no impact on bond rating.
- The Gas Plant's emissions are 30% less than the steam units.
- The Gas Plant uses 65% less water than the current steam units.
- There is no added impact to the neighborhood.
- Land use is minimal.

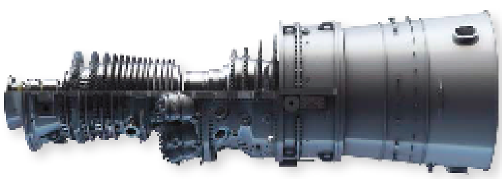
- Gas pressure is adequate.
- There are no hazardous or toxic wastes or archeological findings at the site.

B.4 Manufacturers and Equipment Information

The following pages provide equipment information supplied by the three manufacturers.



GE's 7HA gas turbine is the industry leader among H-class offerings and is available in two models—the 7HA.01 at 275 MW and the 7HA.02 at 337 MW. Thanks to a simplified air cooled architecture, advanced materials, and proven operability and reliability, the 7HA delivers the lowest life cycle cost per MW for 60 Hz applications. The economies of scale created by this high power density gas turbine, combined with its more than 61% combined cycle efficiency, enable the most cost effective conversion of fuel to electricity to help operators meet increasingly dynamic power demands.



Industry-Leading Operational Flexibility for Increased Dispatch and Ancillary Revenue

- Fast 10-minute ramp-up from start command to gas turbine full load.
- 50 MW/minute ramping capability within emissions compliance.
- Reaches turndown as low as 25% of gas turbine baseload output within emissions compliance.
- Fuel flexible to accommodate gas and liquid fuels with wide gas variability, including high ethane (shale) gas and liquefied natural gas.

Least Complex H-Class Offering

- A simpler configuration than GE's previous H-class fleet and one that does not require a separate cooling air system.
- The 7HA is now available with an air cooled generator for simplified installation and maintainability.
- Modular systems ease installation with 10,000 fewer man-hours than GE's 7F.03 gas turbine.
- Streamlined maintenance with quick-removal turbine roof, field-replaceable blades, and 100% borescope inspection coverage for all blades.
- Simplified dual fuel system uses less water, eliminates recirculation, and utilizes enhanced liquid purge for improved reliability and dependability.

Full-Load Validation

- At the heart of GE's heavy duty gas turbine validation program is the advanced full-scale, full-load test facility in Greenville, SC.
- Test stand enables GE to validate the 7HA gas turbine over an operating envelope larger than the variances an entire fleet of turbines would experience in the field, an approach that is superior to operating a field prototype for 8,000 hours.

275-337 MW Simple Cycle Output

>61% COMBINED CYCLE EFFICIENCY

	7HA.01	7HA.02
Frequency	60	60
SC Net Output (MW)	275	337
SC Net Heat Rate (Btu/kWh, LHV)	8,240	8,210
SC Net Heat Rate (kJ/kWh, LHV)	8,694	8,662
SC Net Efficiency (%, LHV)	41.4%	41.6%
Exhaust Energy (MM Btu/hr)	1,330	1,620
Exhaust Energy (MM kJ/hr)	1,403	1,709
GT Turndown Minimum Load (%)	25%	40%
GT Ramp Rate (MW/min)	50	50
NO_x (ppmvd) at Baseload (@15% O_2)	25	25
CO (ppm) at Min. Turndown w/o Abatement	9	9
Wobbe Variation (%)	+/-10%	+/-10%

Power Plant Configuration	1x1 MS 7HA.01	1x1 SS 7HA.02
CC Net Output (MW)	406	501
CC Net Heat Rate (Btu/kWh, LHV)	570	530
CC Net Heat Rate (kJ/kWh, LHV)	5,877	5,834
CC Net Efficiency (%, LHV)	61.3%	61.7%
Bottoming Cycle Type	3PRH	3PRH
Plant Turndown – Minimum Load (%)	33%	47%
Ramp Rate (MW/min)	50	50
Startup Time (Hot, Minutes)	<30	<30

Power Plant Configuration	2x1 MS 7HA.01	2x1 MS 7HA.02
CC Net Output (MW)	817	1,005
CC Net Heat Rate (Btu/kWh, LHV)	5,540	5,510
CC Net Heat Rate (kJ/kWh, LHV)	5,845	5,813
CC Net Efficiency (%, LHV)	61.6%	61.9%
Bottoming Cycle Type	3PRH	3PRH
Plant Turndown – Minimum Load (%)	16%	23%
Ramp Rate (MW/min)	100	100
Startup Time (Hot, Minutes)	<30	<30

H-Class High Performance Siemens Gas Turbine SGT-8000H series

Answers for energy.

H-Class High Performance Siemens Gas Turbine (SGT-8000H series)

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Contents

Abstract

This paper reviews design and validation of the advanced gas turbine SGT-8000H series and the associated combined cycle system SCC-8000H series, introduced by Siemens Energy. The new SGT-8000H series is the result of years of research and development within Siemens Energy. It is based on well proven features of the existing product lines combined with advanced technology.

The first SGT5-8000H gas turbine was fully tested and validated in 2008/2009 under field conditions in a real power plant environment at Irsching 4 Power Station (which is now renamed Kraftwerk Ulrich Hartmann), Bavaria/Germany, in a hosting agreement with E.ON. After extensive simple cycle testing, Irsching 4 was converted to a SCC5-8000H 1S single shaft combined cycle unit, and with the remarkable results demonstrated during commissioning and initial operation, it represents a milestone in fossil fired power plant technology.

Because the SGT6-8000H is scaled directly from the 50 Hz model, it will not require an extensive validation program. Nevertheless, an extensive engine test campaign with several configurations and off-design point testing is being conducted at the Berlin Test Facility to ensure product performance and integrity.

This comprehensive, rigorous approach ensures that subsequent "commercial" engines will be brought to market such that risk are controlled and with full validation based on extensive operating history. Initial commercial customer projects such as the 1200 MW Cape Canaveral and Riviera Clean Energy Centers of Florida Power & Light and the 410 MW unit Bugok III of GS EPS (GS Electric Power & Services, Ltd.,), Seoul represent the market introduction phase, with eight total current units.

Product Name	Grid Frequency	Gas Turbine Rated Power	Combined Cycle Rated Power (1x1)	Combined Cycle Rated Efficiency (1x1)
SGT5-8000H	50Hz	375 MW	570 MW	> 60%
SGT6-8000H	60Hz	274 M	410 MW	> 60%

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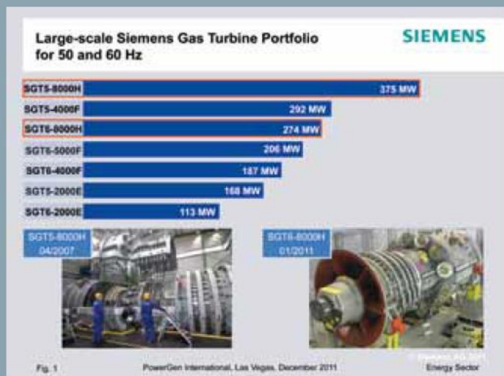

Fig. 1

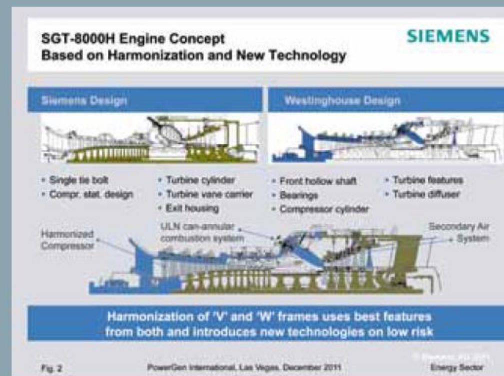

Fig. 2

Introduction

The worldwide need for energy is constantly rising while, at the same time, demand for reliable, affordable, efficient and environmentally-compatible power generation is increasing. In today's highly competitive business environment, customers and power plant operators expect an economical, state-of-the-art product. Increasingly, their purchasing decisions emphasize life-cycle cost analyses that span the entire lifetime of a power plant.

Siemens Energy developed its new generation H-class Siemens Gas Turbine (SGT™), the SGT-8000H series **(Fig. 1)**, taking both environmental protection as well as economical focus into consideration. Siemens Energy brought technical innovations in design and development, process engineering, materials and manufacturing and assembly processes together to transform these new requirements into reality.

The H-class gas turbine combines the best features of the established product lines with advanced technology. The functional and mechanical design of the new engine was built on the experience gained with the predecessor 50 Hz and 60 Hz engines. Proven design features were applied wherever possible, and "Design for Six Sigma" tools were used resolutely, to deliver a competitive product using proven design features wherever possible. **(Fig. 2)**.

Overview: SGT-8000H series Development Program

Following the merger of Westinghouse Power Generation with Siemens in August 1998, the decision was made to develop a Next Generation Family (NGF) of gas turbines. Siemens formally approved the H-technology development program in October 2000 and began basic engineering design in November 2001, almost four years before its public announcement in September 2005. Besides increasing output and efficiency, the intent of the NGF program was also to merge the existing V-engines, W501F and W501G product lines for a harmonized future product portfolio. The result of the NGF program are the advanced SGT5-8000H and SGT6-8000H gas turbines which utilize the experience and technology developed over decades by Siemens and the former Westinghouse **(Fig. 3)**.

Major cycle parameters such as compressor mass flow, firing temperature, exhaust temperature and corresponding combined cycle parameters such as steam temperatures and pressure levels had to be defined in order to meet the intended output and efficiency. One of the major concept decisions which had to be taken early in the program was the selection of the engine cooling method to ensure that hot gas path components withstand the increased temperatures, while maintaining and ensuring operational flexibility needed in today's fluctuating market environment. The SGT5-4000F and SGT6-5000F had purely air-cooled engine concepts, while the SGT6-6000G, a result of the Advanced Turbine System (ATS) program conducted by Westinghouse in conjunction with the Department of Energy of the United States (DOE), had a combined air and steam cooled approach. Based on operational experiences and feedback from customers regarding the growing need for operational flexibility, it was decided that a completely air-cooled concept would be developed for the SGT-8000H series.

4

Fig. 3

With the annular combustion system used on more than two hundred SGT-4000F turbines and the can-annular combustion system used on hundreds of engines in Westinghouse design, harmonization potential was identified for the combustion system. Based on operational experience and flexibility considerations, it was decided to develop a "Platform Combustion System" (PCS) based on the can-annular combustion system for the SGT-8000H series design. This combustion system went through extensive rig and engine testing beginning in 2005. Final validation was completed in full engine testing at Irsching.

The SGT-8000H series / SCC-8000H series is an integrated product line with common features based on the Siemens and Westinghouse product lines. The extensive fleet experience was used to develop the final feature of this design. The 50 Hz and 60 Hz SGT-8000H series concepts were developed concurrently to assure that validation testing from the first engine developed for the 50 Hz market provided significant proof for the 60 Hz design. The 50 Hz SGT5-8000H engine has been already successfully tested at Irsching 4 power station owned by E.ON Kraftwerke a German electric utility company. The 60 Hz SGT6-8000H utilizes the same (scaled) compressor, identical combustor (fewer number of cans) and a scaled turbine. Nevertheless, an extensive engine test campaign with several configurations and off-design point testing is being conducted at the Berlin Test Facility to ensure product performance and integrity.

Primary Objectives of the SGT-8000H series Program

Customer requirements resulting especially from today's liberalized energy markets and current trends in today's generation portfolio requirements for complementing the substantial market penetration of renewable power were the essential drivers for developing the new SGT-8000H series.

- Combined cycle net efficiency over 60%, resulting in approx. 3% of fuel savings for improved OPEX
- Significantly reduced emissions per kWh produced combined with the lower heat rate and 25 ppm NOx, 10 ppm CO and 330 g/kWh
- Increased turn-down for achievement of high efficiency and low emissions also in part-load operation from 100% – 50% load
- Quick start-up capability of less than 15 minutes and operational flexibility to meet immediate needs in power grids
- Lower specific investment costs (EUR/kW) for reduced specific CAPEX
- Reliability of over 99%, availability of over 94% and serviceability comparable to today's proven F-class technology
- Minimized life cycle costs for increased Net Present Value for the owner of at least 7 – 8%

The SGT5-8000H and SGT6-8000H gas turbine development team involved more than 250 engineers working in Erlangen, Berlin and Mülheim in Germany, as well as in Orlando and Jupiter in Florida. An additional 500 employees were involved in the manufacturing, assembly and preparations for testing the prototype engine. This new turbine was developed in strict compliance with the company's Product Development Process. The design effort incorporated previous lessons learned, applied proven design features wherever possible and "Design for Six Sigma" tools were used systematically to deliver a competitive product focused on life-cycle costs, performance, serviceability, flexibility, reliability, and low emissions.

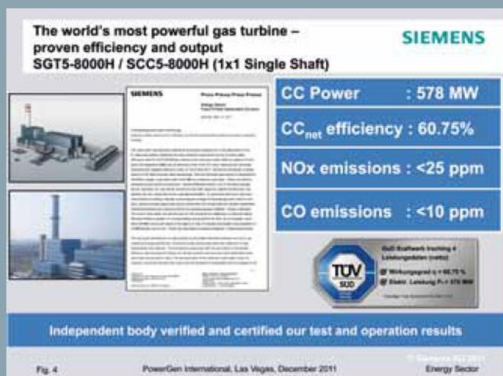

Fig. 4

Fig. 5

SGT-8000H series Main Design Features

The design is based on proven Siemens and Westinghouse technology.

- The engine has a single tie bolt rotor with interlocked discs using Hirth couplings. This design is used in the SGT5-4000F. Siemens has over 16,500,000 EOHs and 757 GTs operating with this type of rotor.
- The 13 stage compressor is Siemens harmonized design, which is offered on the SGT6-5000F as well as on the SGT-8000H series engines. This design has four variable guide vanes to improve part-load performance and blades can still be replaced without a rotor lift. The 50 Hz and 60 Hz versions – identical in design – are aerodynamically scaled.
- The can-annular combustion system design is based on the SGT6-5000F which has over 6 million operating hours. The 50 Hz and 60 Hz engines have the same baskets and burner assemblies.
- The fully air-cooled turbine airfoils use proven base materials. There are no single crystal components and no dependence on steam from the bottoming cycle for cooling. The 50 HZ and 60 Hz versions – identical in design – are aerodynamically scaled.

The SGT5-8000H is the largest operating gas turbine in the world, as noted by the Guinness Book of World Records. The 50 Hz and 60 Hz versions offer high efficiency and low emissions in base-load and part-load.

Operational Flexibility of the H-class Gas Turbine

The gas turbine power generation market has seen significant volatility in recent years due to climate change, changes in natural gas prices and the uncertain future of nuclear and coal power generation. In addition, the foreseeable demand for environmentally friendly power generation has convinced many power producers to integrate renewable generation capacities with environmentally clean gas-fired power plants. Keeping this key market driver in mind, the SGT-8000H series was designed for operational flexibility with the following key features:

- The engine is fully air-cooled, resulting in the ability to start fast and cycle quickly.
- Increased loading and acceleration rate reduces start-up time
  - Standard loading: 25 minutes to 375 MW
  - Fast Loading: 10 Minutes to 350 MW
- Increased turn-down to achieve high efficiency and low emissions in part-load operation down to 50% load
- Fast start-up capability of less than 15 minutes. Operational flexibility to meet immediate needs in power grids (>500 MW in less than 30 minutes, in combined cycle mode)
- Plant ramp down to minimum load at 100 MW (~20% combined cycle load) or shut down in less than 30 minutes
- Plant cycling operation with over 200 MW load change in less than 7 minutes

Test and Validation of the SGT5-8000H at Irsching 4 Power Station

By spring 2007, Siemens completed the assembly of the first 50 Hz engine at its Berlin plant. The unit was shipped to E.ON's Irsching 4 power station for performance validation under actual service conditions. It was first fired in December 2007 and synchronized to the grid shortly thereafter in March 2008. Full base load output was achieved on April 24, 2008. During the next 16 months the engine went through a rigorous in-service test and validation phase, including a comprehensive endurance test run, that ended on August 28, 2009.

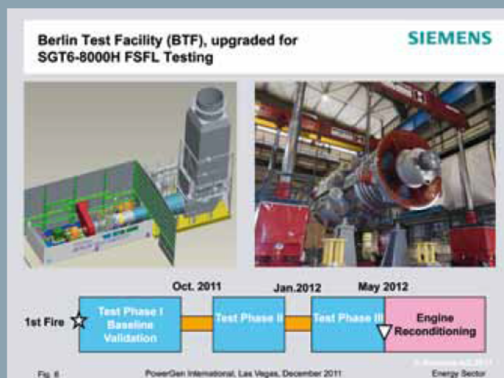

Fig. 6

Fig. 7

The total 18-month validation program consisted of multiple measurement campaigns, covering the full operating range starting from hot commissioning to a final endurance test in open cycle configuration. Although the SGT5-8000H has a commercial rating of 375 MW at ISO conditions, it was loaded to over 400 MW during open cycle testing at Irsching 4 in order to verify design integrity and exploit overall stability limits. During validation at Irsching 4, the unit accumulated 1525 hours of operation, of which 1243 hours were at base-load. Testing and validation were completed on August 28, 2009 and the unit was brought offline for a scheduled conversion to combined cycle.

Since then, the Irsching 4 plant has been converted into a single-shaft combined cycle power plant. After commissioning and initial combined cycle testing, the plant was turned over to E.ON for commercial operation in July 2011. The plant has been renamed Kraftwerk Ulrich Hartmann. The superior H-class performance of the new plant was demonstrated with 578 MW net output and 60.75% net efficiency in a world record testrun in spring 2011. **(Fig. 4)**

Increased operational flexibility was also demonstrated in reality, with optimized plant start-up times, less than 21 minutes at hot condition, ramp rates, grid code response times etc., representing a new and unprecedented level of advanced combined cycle technology **(Fig. 5)**.

Next Steps towards SGT6-8000H

The 60 Hz SGT6-8000H, rated at 274 MW, is a direct scale of the 50 Hz SGT5-8000H. The design of the SGT6-8000H is based exactly on Siemens proven aerodynamic scaling rules. A scaling factor of 1:1.2 is applied consistently across the entire cross section of the turbine.
The only exception is the combustion system, in which exactly the same components, such as burners and baskets, are used as in the 50 Hz model.

In order to reflect the reduced mass flow of approx. 1 : 1.44, 12 can-combustors are used on the 60 Hz model instead of 16. Based on this approach with many other proven examples, validation efforts for the SGT6-8000H can be based on the comprehensive information gained during the SGT5-8000H test program and only limited time and effort will be required to provide sufficient evidence for the integrity of the 60 Hz model.

Test and Validation Approach for SGT6-8000H

The first SGT6-8000H unit was recently installed in the test center of our Berlin manufacturing plant and is currently undergoing an eight month test program **(Fig. 6)**.

As of submission of this paper, detailed design, manufacturing, final assembly and commissioning of the SGT6-8000H have already been finalized and the production of the first commercial engines are in progress. The first of these engines will be tested at the Berlin Test Facility for validation before being shipped to the customer site in Florida.

Market Launch / First Commercial Orders Secured

The first commercial order was secured with Florida Power & Light (FPL). FPL selected the SGT6-8000H for modernization of its Cape Canaveral and Riviera Beach power plants based on the world class performance and operational flexibility demonstrated by the SGT-8000H series. Each of the new 1.200 MW combined cycle units will comprise of a 3 x 1 configuration, with three gas turbine-generator sets, three HRSGs and one steam turbine. The Cape Canaveral plant will commence commercial operation in 2013 and Riviera Beach will follow in 2014.

The first project in Asia is represented by the 410 MW single shaft combined cycle unit Bugok III of GS EPS (GS Electric Power & Services, Ltd.,), Seoul Korea **(Fig. 7)**, which will also start commercial operation in 2013.

Fig. 8

Summary

Overall, the SGT-8000H series program has reached all design targets and will serve as the basis for Siemens future advanced gas turbine and combined cycle:

- Increase of combined cycle net efficiency to over 60%
- Reduced emissions per produced kWh
- High efficiency and low emissions also in part-load operation
- Fast start-up capability and operational flexibility
- Reduced investment costs per kW
- High reliability and availability
- Lowest in lowest life cycle costs

While it seemed impossible at launch time, more than 60% combined cycle efficiency has been designed, manufactured, installed and proven during initial operation. Not only was efficiency and performance of gas fired generation technology shifted beyond existing borders, Siemens H-class technology has also added operational flexibility beyond existing F-class technology. It can be characterized as "Beyond 60% – Pioneering H-class Efficiency at world class flexibility".

Based on detailed evaluation of test data and comparison with design predictions, Siemens Energy is now able to offer the world class performance of the SGT-8000H series for full commercial application as follows:

Performance Rating	SGT5-8000H	SGT6-8000H
Gas Turbine Power Output	375 MW	274 MW
Gas Turbine Efficiency	40%	40%
Combined Cycle (1x1) Power Output	570 MW	410 MW
Combined Cycle (1x1) Efficiency	> 60%	> 60%

In conclusion, approximately 20 years after the introduction of today's F-class gas turbine and combined cycle technology, Siemens new advanced 8000H-class represents the most advanced and modern technology for economic and environmentally friendly gas fired power generation **(Fig. 8)**.

The new SGT-8000H product line and its implementation into a state-of-the-art combined cycle power plant is the result of a long term commitment during a multi-year program with significant financial and manpower investment. It shows Siemens commitment to meet customer expectations and continuing the successful partnership for improved customer value.

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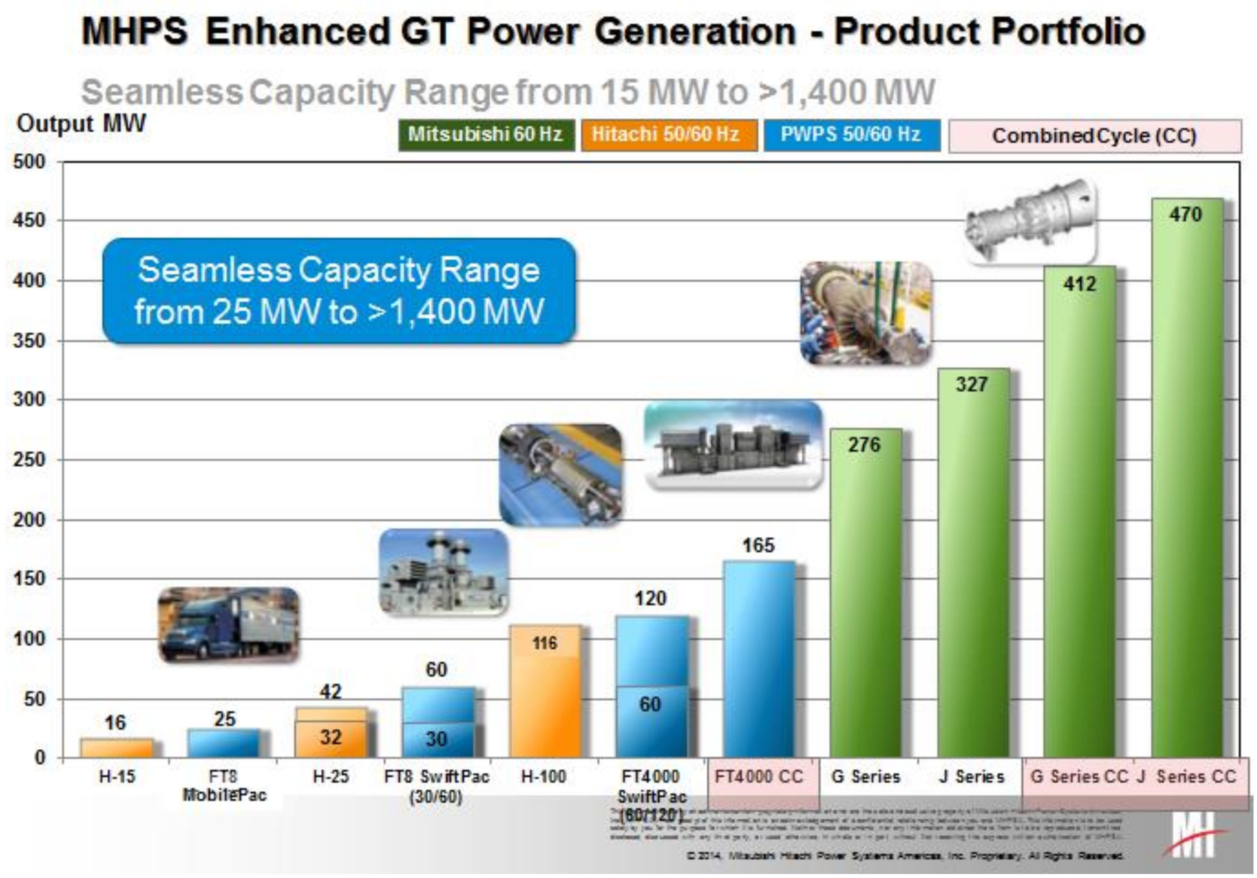
Mitsubishi Hitachi Power Systems
Advances Class Gas Turbine Information
M501GAC, GAC Fast, M501J, M501JAC
September 2015

MITSUBISHI HITACHI POWER SYSTEMS


MHPS Enhanced GT Power Generation - Product Portfolio
Seamless Capacity Range from 15 MW to >1,400 MW
Output MW
Mitsubishi 60 Hz
Hitachi 50/60 Hz
PWPS 50/60 Hz
Combined Cycle (CC)
Seamless Capacity Range from 25 MW to >1,400 MW
500
450
400
350
300
250
200
150
100
50
0
16
25
42
32
60
30
116
120
60
165
276
327
412
470
H-15
FT8 MobilePac
H-25
FT8 SwiftPac (30/60)
H-100
FT4000 SwiftPac (60/120)
FT4000 CC
G Series
J Series
G Series CC
J Series CC
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MHPSA Gas Turbine Fleet

MITSUBISHI HITACHI
POWER SYSTEMS

Gas Turbine and Combined Cycle Performance Specification

As of Aug 2015

Gas Turbine Frame		M501GAC	M501GAC-Fast	M501J	M501JAC
GT Power Output [MW]		276	270	327	310
GT Heat Rate [LHV, Btu/kWh]		8574 (39.8%)	8660 (39.4%)	8322 (41.0%)	< 8322 (Over 41.0%)
CC Power Output [MW]	1on1	412	405	470	450
	2on1	826	812	943	900
CC Heat Rate [LHV, Btu/kWh]	1on1	5735 (59.5%)	5785 (59.0%)	5549 (61.5%)	< 5595 (Over 61.0%)
	2on1	5726 (59.6%)	5764 (59.2%)	5531 (61.7%)	< 5595 (Over 61.0%)
Combustor Cooling Type		Air	Air	Steam	Air
Emission [@15% O_2, ppmvd]	NOx	15	15	25	25
	CO	10	10	10	10
	VOC	1	1	1	1
Turndown		50%	50%	50%	50%

ISO Standard Condition

MHPS Large Gas Turbine Global Experience

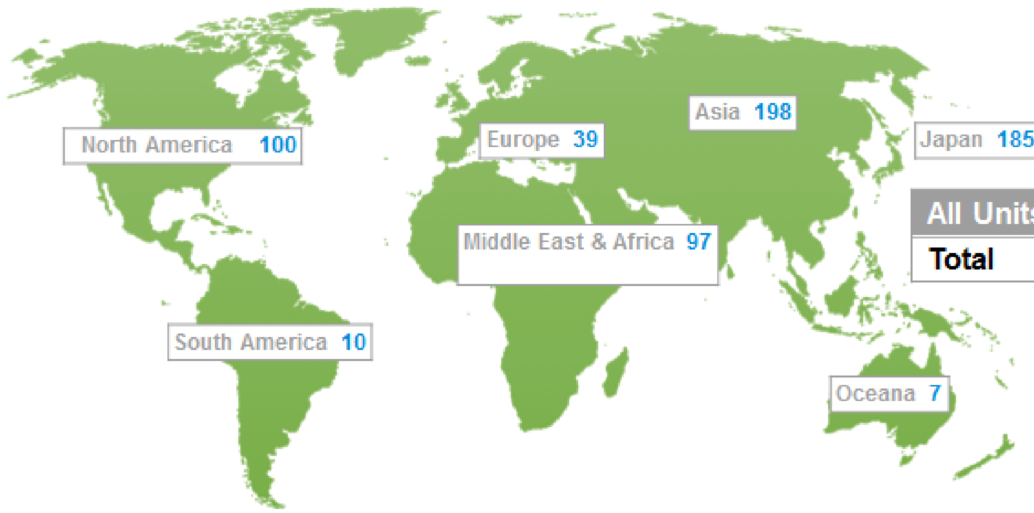
As of Aug 2015

J Series	
M501J	37
M701J	2
Total	**39**

G Series	
M501G	82
M701G	11
Total	**93**

F Series	
M501F	73
M701F	125
Total	**198**

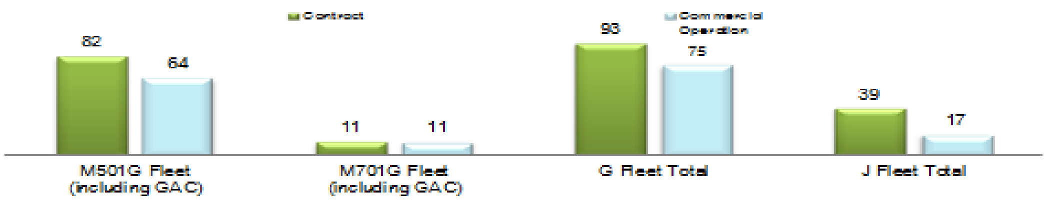
D Series	
M501D	25
M701D	93
Total	**118**



All Units	
Total	**637**

MHPS G & J Operation Record

Order/Operation Record as of Aug 2015 for G & J Fleet



	Contract	Commercial Operation	Start of operation	Operation hours	Start & Stops
M501G Fleet (including GAC)	82	64	1997	2,393,972 AOH	22,203 times
M701G Fleet (including GAC)	11	11	1999	581,577 AOH	1,159 times
G Fleet Total	93	75	1997	2,975,549 AOH	23,362 times
J Fleet Total	39	17	2011	155,614 AOH	2,251 times

1. *From 2014, MHPS signed the contract to Supply newly 12xM501J Gas Turbines in J Fleet total "39".*
   The accumulated operation of J Fleet exceeded 155,614AOH and 2,251 starts.
   Himeji No.2 PS, #6 GT started Commercial Operation on 25th March, 2015. Now Himeji No.2 PS is completed .

2. *In 2014, MHPS signed the contract to Supply newly7 x M501GAC Gas Turbine in G Fleet total "93".*
   The accumulated operation of G Fleet exceeded 2,975,549 AOH and 23,362 starts.

Slide 10

Appendix C. Background Data for Findings

Annual System Metric Outputs

Table 40: AE CO_2 Emissions (000s Tons)

Austin Energy CO2 Emissions (000s Tons)	All Market	C1: Decker CC	C2: Sandhill CC	C3: 500MW Solar	C4: 500MW Wind	C5: Alternative Mix	C6: Accelerated Solar
2015	5,968	5,968	5,968	5,968	5,968	5,968	5,968
2016	4,010	4,010	4,010	4,010	4,010	4,010	4,325
2017	3,909	3,908	3,908	3,909	3,909	3,881	3,273
2018	3,875	3,130	3,130	3,562	3,799	3,831	3,249
2019	3,970	3,244	3,244	3,362	3,509	3,074	3,356
2020	3,872	3,132	3,132	3,265	2,744	2,957	3,562
2021	3,143	2,425	2,425	2,406	1,855	2,242	2,838
2022	3,207	2,508	2,508	2,481	1,928	2,332	2,905
2023	3,617	2,918	2,919	2,895	2,334	2,741	3,313
2024	2,156	1,505	1,505	1,456	909	1,307	1,860
2025	1,939	1,291	1,291	1,249	698	1,090	1,937
2026	2,180	1,539	1,539	1,496	940	1,335	2,178
2027	2,103	1,472	1,472	1,428	867	1,253	2,102
2028	2,142	1,519	1,519	1,474	911	1,309	2,140
2029	2,403	1,792	1,792	1,748	1,180	1,563	2,402
2030	2,315	1,708	1,708	1,669	1,100	1,479	2,313
2031	2,353	1,772	1,772	1,716	1,144	1,530	2,352
2032	2,572	1,990	1,991	1,942	1,368	1,742	2,571
2033	2,500	1,935	1,935	1,881	1,306	1,667	2,498
2034	2,559	2,002	2,002	1,950	1,372	1,713	2,557
2035	2,783	2,227	2,227	2,180	1,594	1,942	2,782
2036	2,696	2,143	2,143	2,098	1,511	1,870	2,695
2037	2,800	2,275	2,275	2,215	1,631	1,966	2,798
2038	2,854	2,501	2,501	2,459	1,867	2,190	3,038

Table 41: AE Annual System Costs (000s 2014)

	C0 (Market Purchases)	C1 and C2 (500 MW CC)	C2 (Sand Hill CC)	C3 (500 MW Solar)	C4 (500 MW Wind)	C5 (Alternative Mix)	C6 (Accelerated Solar)
2015	345,063	345,063	345,063	345,063	345,063	345,063	345,063
2016	344,786	344,786	344,786	344,786	344,786	344,786	363,565
2017	348,926	348,496	348,496	348,926	348,895	349,121	351,907

2018	343,890	363,644	363,611	353,022	360,447	342,462	344,148
2019	344,342	357,332	357,371	361,034	396,051	368,934	343,474
2020	330,185	328,140	328,158	338,259	357,438	349,147	316,923
2021	373,539	370,716	370,478	377,481	379,352	388,342	358,011
2022	400,729	374,717	374,832	386,116	390,430	407,907	379,042
2023	411,162	387,696	388,087	399,663	399,890	417,999	390,728
2024	500,354	453,262	452,995	470,583	476,529	494,223	479,459
2025	482,615	455,557	455,616	455,578	459,078	474,448	469,650
2026	485,913	473,638	473,629	467,635	463,352	484,237	469,528
2027	540,385	485,569	485,507	495,680	502,804	519,843	521,749
2028	538,472	493,936	493,944	494,865	495,292	515,286	516,029
2029	537,473	504,319	504,026	503,373	493,279	519,952	519,837
2030	545,795	505,541	504,946	505,600	497,369	522,735	532,750
2031	579,748	515,727	515,492	526,564	525,164	537,249	571,317
2032	584,340	538,007	538,599	535,563	531,085	552,260	573,565
2033	600,592	534,694	534,642	526,923	529,459	551,505	587,032
2034	578,837	537,593	537,983	525,072	517,794	544,302	570,480
2035	624,129	568,046	568,180	567,694	558,757	584,053	615,773
2036	581,704	528,737	528,669	526,432	511,985	540,061	574,857
2037	607,492	558,993	558,891	553,530	544,246	564,163	599,761
2038	613,038	529,518	531,161	535,568	534,983	563,588	611,955

Gas Plant Financial Results

Navigant Consulting, Inc. (Navigant) has prepared a financial analysis of the Decker combined cycle (CC) natural gas plant new build. This explores cost and revenue metrics for the plant, considering capital cost, fixed operations and maintenance (O&M), interest cost, and other fixed and variable costs (including fuel). Revenue is based on projected realized locational marginal prices (LMPs) for energy from the plant. All analysis is done in nominal ("then-year") dollars and is then discounted to obtain present value summary statistics such as levelized cost and total net present value (NPV).

The modeling inputs and outputs described in the main body of the report provide the inputs for the financial analysis. For the new Decker CC, these include annual values from 2018 through 2038 for capacity, actual generation (energy), realized LMP, fuel (gas) cost, non-fuel operating cost, and fixed O&M. Real 2014$ values are converted to nominal using assumed 2.3% annual escalation.

The financial project analysis relies on a variety of assumptions in addition to inputs obtained from upstream PROMOD modeling. Key assumptions include the following:

- 2-year construction, with commercial operations starting on 1/1/2018
- Financing term and book life of 20 years, with operations over 21 years

- Debt ratio at 100% for both construction and permanent financing
- Turnkey capital construction cost of between $700 per kilowatt (kW) and $900/kW (excluding interest charges)
- Construction financing and project debt at 4.82% interest rate (nominal)
- Discount rate of 5.00% (nominal), with discounting back to year 2014
- Straight-line, 20-year depreciation
- No taxes

Interest during construction, depreciation, and annual capital recovery are estimated and used to obtain analysis results on an annual basis. Three results tables are incorporated in this appendix: base Decker analysis at $700/kW, base Decker analysis at $800/kW, and base Decker analysis at $900/kW. As can be seen in the tables, the major categories include discounting statistics, unit statistics (e.g., capacity rating and generation output), annual fixed charges (capacity charge, fixed O&M, insurance), variable non-fuel O&M, gas fuel costs, summary cost metrics (nominal, discounted, and levelized), market revenue-related, and net revenue metrics (annual net present values, total NPV).

Inputs and assumptions for all cases are identical except for the turnkey capital cost assumption, either $700/kW, $800/kW, or $900/kW. The lower-end assumption of $700/kW results in levelized costs of $73.23/MWh, payback (in discounted terms) in 6-7 years, and a total NPV of $379 million. The higher-end assumption of $900/kW results in levelized costs of $76.17/MWh, payback (in discounted terms) in 9-10 years, and a total NPV of $274 million. The assumption of $800/kW results in levelized costs of $74.70/MWh and a total NPV of $327 million.

Table C-1. Financial Project Analysis Results, Decker CC Build, Base Capital Cost ($800/kW, Turnkey)

Calendar Year	Units	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11
Months in Service	Months	12	12	12	12	12	12	12	12	12	12	12
Discount Factor												
Utility Discount Rate and Annual Factor	5.00%	0.8227	0.7835	0.7462	0.7107	0.6768	0.6446	0.6139	0.5847	0.5568	0.5303	0.5051
Unit Statistics												
Capacity Rating	MW	500	500	500	500	500	500	500	500	500	500	500
Unit Output	MWh	3,056,108	3,107,410	3,130,577	3,185,512	3,285,994	3,257,616	3,280,174	3,287,602	3,264,405	3,250,488	3,252,943
Unit Capacity Factor	%	69.77%	70.95%	71.28%	72.73%	75.02%	74.37%	74.69%	75.06%	74.53%	74.21%	74.07%
Annual Fixed Charges												
Nominal Capacity Charge	$000	$ 43,308	$ 42,246	$ 41,494	$ 40,707	$ 39,882	$ 39,018	$ 38,113	$ 37,165	$ 36,172	$ 35,132	$ 34,042
Nominal Fixed O&M	$000	$ 6,571	$ 6,722	$ 6,877	$ 7,035	$ 7,197	$ 7,363	$ 7,532	$ 7,705	$ 7,882	$ 8,064	$ 8,249
Nominal Insurance	$000	$ 340	$ 349	$ 357	$ 366	$ 375	$ 385	$ 394	$ 404	$ 414	$ 425	$ 435
Nominal Total Fixed Charges	$000	$ 50,220	$ 49,317	$ 48,729	$ 48,108	$ 47,454	$ 46,765	$ 46,039	$ 45,274	$ 44,469	$ 43,620	$ 42,727
Nominal Total Fixed Charges Per kW-mo	$/kW-mo	$ 8.37	$ 8.22	$ 8.12	$ 8.02	$ 7.91	$ 7.79	$ 7.67	$ 7.55	$ 7.41	$ 7.27	$ 7.12
Discounted Total Fixed Charges	$000	$ 41,316	$ 38,641	$ 36,362	$ 34,189	$ 32,119	$ 30,145	$ 28,264	$ 26,471	$ 24,762	$ 23,133	$ 21,580
		$ 6,911.34	$ 7,070.98	$ 7,234.31	$ 7,401.41	$ 7,572.38	$ 7,747.29	$ 7,926.25	$ 8,109.34	$ 8,296.66	$ 8,488.32	$ 8,684.40
Variable O&M												
Nominal Non-Fuel Variable O&M	$000	$ 12,270	$ 12,429	$ 16,756	$ 24,151	$ 32,596	$ 33,109	$ 33,962	$ 36,453	$ 38,281	$ 39,230	$ 41,677
		$ 11,624	$ 12,067	$ 12,412	$ 12,895	$ 13,581	$ 13,747	$ 14,133	$ 14,462	$ 14,662	$ 14,906	$ 15,230
Total Fixed Charges and Non-Fuel VOM												
Nominal Total Fixed Charges & Non-Fuel VOM	$000	$ 62,490	$ 61,746	$ 65,484	$ 72,259	$ 80,050	$ 79,874	$ 80,000	$ 81,728	$ 82,750	$ 82,850	$ 84,403
Discounted Total Fixed Chrgs & Non-Fuel VOM	$000	$ 51,410	$ 48,380	$ 48,865	$ 51,353	$ 54,181	$ 51,487	$ 49,113	$ 47,784	$ 46,078	$ 43,937	$ 42,629
Sum Present Val Fixed Chrgs & Non-fuel VOM	$000	$ 875,814										
Other Utility Costs												
Nominal Annual Fuel Costs	$000	$ 90,870	$ 94,583	$ 104,263	$ 118,317	$ 131,760	$ 135,508	$ 140,199	$ 145,588	$ 153,276	$ 159,368	$ 173,265
Discounted Annual Fuel Costs	$000	$ 74,759	$ 74,108	$ 77,803	$ 84,085	$ 89,181	$ 87,350	$ 86,070	$ 85,122	$ 85,350	$ 84,516	$ 87,511
Summary Cost Metrics												
Nominal Average Total Fixed Charges (All)	$/kW-mo	$ 7.17										
Nominal Annual Costs (All)	$000	$ 153,360	$ 156,329	$ 169,747	$ 190,575	$ 211,811	$ 215,382	$ 220,200	$ 227,316	$ 236,026	$ 242,218	$ 257,669
Nominal Avg Costs Including Fuel, Var, & Fixed	$/MWh	$ 78.67										
Discounted Annual Costs (All)	$000	$ 126,169	$ 122,488	$ 126,668	$ 135,438	$ 143,362	$ 138,837	$ 135,183	$ 132,907	$ 131,428	$ 128,453	$ 130,140
Discounted Annual Output (All)	MWh	2,514,268	2,434,737	2,336,085	2,263,884	2,224,090	2,099,888	2,013,743	1,922,193	1,817,743	1,723,803	1,642,957
Levelized Costs Incl. Fuel, Variable, & Fixed (All)	$/MWh	$ 73.78										
Market Revenue Projections												
Nominal Realized Locational Marginal Prices	$/MWh	$ 41.18	$ 43.13	$ 51.36	$ 57.52	$ 69.20	$ 70.56	$ 82.02	$ 78.32	$ 75.81	$ 95.26	$ 95.48
Nominal Market-Based Revenue	$000	$ 125,847	$ 134,013	$ 160,789	$ 183,218	$ 227,380	$ 229,842	$ 269,034	$ 257,485	$ 247,487	$ 309,626	$ 310,593
Nominal Ancillary Services Revenue	$000	$ 3,775	$ 4,020	$ 4,824	$ 5,497	$ 6,821	$ 6,895	$ 8,071	$ 7,725	$ 7,425	$ 9,289	$ 9,318
Net Revenue Metrics												
Annual Net Present Value (Revenue Net of Cost)	$000	$ (19,529)	$ (14,336)	$ (3,085)	$ (1,323)	$ 15,155	$ 13,766	$ 34,935	$ 22,155	$ 10,516	$ 40,674	$ 31,436
Total Net Present Value (Revenue Net of Cost)	$000	$ 449,356										

Calendar Year	Units	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22
Months in Service	Months	12	12	12	12	12	12	12	12	12	12	0
Discount Factor												
Utility Discount Rate and Annual Factor	5.00%	0.4810	0.4581	0.4363	0.4155	0.3957	0.3769	0.3589	0.3418	0.3256	0.3101	0.0000
Unit Statistics												
Capacity Rating	MW	500	500	500	500	500	500	500	500	500	500	-
Unit Output	MWh	3,254,552	3,310,373	3,216,003	3,256,983	3,231,816	3,260,520	3,240,360	3,271,116	3,227,647	3,283,646	-
Unit Capacity Factor	%	74.30%	75.58%	73.42%	74.16%	73.79%	74.44%	73.98%	74.48%	73.69%	74.97%	0.00%
Annual Fixed Charges												
Nominal Capacity Charge	$000	$ 32,901	$ 31,706	$ 30,453	$ 29,141	$ 27,766	$ 26,326	$ 24,817	$ 23,236	$ 22,395	$ -	$ -
Nominal Fixed O&M	$000	$ 8,439	$ 8,633	$ 8,832	$ 9,035	$ 9,242	$ 9,455	$ 9,673	$ 9,895	$ 10,123	$ 10,355	$ -
Nominal Insurance	$000	$ 446	$ 457	$ 469	$ 480	$ 492	$ 505	$ 517	$ 530	$ 544	$ 557	$ -
Nominal Total Fixed Charges	$000	$ 41,786	$ 40,796	$ 39,753	$ 38,656	$ 37,501	$ 36,286	$ 35,007	$ 33,661	$ 33,061	$ 10,913	$ -
Nominal Total Fixed Charges Per kW-mo	$/kW-mo	$ 6.96	$ 6.80	$ 6.63	$ 6.44	$ 6.25	$ 6.05	$ 5.83	$ 5.61	$ 5.51	$ 1.82	$ -
Discounted Total Fixed Charges	$000	$ 20,100	$ 18,689	$ 17,344	$ 16,062	$ 14,840	$ 13,676	$ 12,565	$ 11,507	$ 10,764	$ 3,384	$ -
		$ 8,885.01	$ 9,090.26	$ 9,300.25	$ 9,515.09	$ 9,734.90	$ 9,959.78	$ 10,189.87	$ 10,425.27	$ 10,666.11	$ 10,912.52	
Variable O&M												
Nominal Non-Fuel Variable O&M	$000	$ 42,864	$ 46,442	$ 47,565	$ 49,225	$ 52,341	$ 53,501	$ 54,597	$ 58,103	$ 58,852	$ 61,492	$ -
		$ 15,558	$ 16,157	$ 16,026	$ 16,571	$ 16,788	$ 17,293	$ 17,547	$ 18,085	$ 18,220	$ 18,925	
Total Fixed Charges and Non-Fuel VOM												
Nominal Total Fixed Charges & Non-Fuel VOM	$000	$ 84,650	$ 87,237	$ 87,318	$ 87,880	$ 89,842	$ 89,787	$ 89,603	$ 91,764	$ 91,914	$ 72,404	$ -
Discounted Total Fixed Chrgs & Non-Fuel VOM	$000	$ 40,718	$ 39,964	$ 38,096	$ 36,516	$ 35,553	$ 33,840	$ 32,162	$ 31,369	$ 29,924	$ 22,450	$ -
Sum Present Val Fixed Chrgs & Non-fuel VOM	$000											
Other Utility Costs												
Nominal Annual Fuel Costs	$000	$ 187,284	$ 192,321	$ 193,815	$ 207,904	$ 214,553	$ 225,414	$ 227,852	$ 238,835	$ 243,614	$ 257,774	$ -
Discounted Annual Fuel Costs	$000	$ 90,087	$ 88,104	$ 84,561	$ 86,389	$ 84,906	$ 84,956	$ 81,786	$ 81,646	$ 79,314	$ 79,928	$ -
Summary Cost Metrics												
Nominal Average Total Fixed Charges (All)	$/kW-mo											
Nominal Annual Costs (All)	$000	$ 271,934	$ 279,558	$ 281,133	$ 295,785	$ 304,394	$ 315,201	$ 317,455	$ 330,599	$ 335,528	$ 330,179	$ -
Nominal Avg Costs Including Fuel, Var, & Fixed	$/MWh											
Discounted Annual Costs (All)	$000	$ 130,805	$ 128,069	$ 122,657	$ 122,905	$ 120,459	$ 118,796	$ 113,948	$ 113,015	$ 109,238	$ 102,378	$ -
Discounted Annual Output (All)	MWh	1,565,495	1,516,520	1,403,131	1,353,344	1,278,939	1,228,856	1,163,103	1,118,230	1,050,829	1,018,153	-
Levelized Costs Incl. Fuel, Variable, & Fixed (All)	$/MWh											
Market Revenue Projections												
Nominal Realized Locational Marginal Prices	$/MWh	$ 92.65	$ 97.71	$ 108.92	$ 109.97	$ 122.06	$ 113.18	$ 123.08	$ 125.47	$ 125.76	$ 149.15	$ -
Nominal Market-Based Revenue	$000	$ 301,549	$ 323,448	$ 350,282	$ 358,185	$ 394,465	$ 369,019	$ 398,836	$ 410,420	$ 405,893	$ 489,757	$ -
Nominal Ancillary Services Revenue	$000	$ 9,046	$ 9,703	$ 10,508	$ 10,746	$ 11,834	$ 11,071	$ 11,965	$ 12,313	$ 12,177	$ 14,693	$ -
Net Revenue Metrics												
Annual Net Present Value (Revenue Net of Cost)	$000	$ 18,597	$ 24,552	$ 34,754	$ 30,393	$ 40,327	$ 24,456	$ 33,506	$ 31,496	$ 26,873	$ 54,036	$ -
Total Net Present Value (Revenue Net of Cost)	$000											

Source: Navigant

NAVIGANT

Table C-2. Financial Project Analysis Results, Decker CC Build, Lower-End Capital Cost ($700/kW, Turnkey)

Calendar Year	Units	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
		1	2	3	4	5	6	7	8	9	10	11
Months in Service	Months	12	12	12	12	12	12	12	12	12	12	12
Discount Factor												
Utility Discount Rate and Annual Factor	5.00%	0.8227	0.7835	0.7462	0.7107	0.6768	0.6446	0.6139	0.5847	0.5568	0.5303	0.5051
Unit Statistics												
Capacity Rating	MW	500	500	500	500	500	500	500	500	500	500	500
Unit Output	MWh	3,056,108	3,107,410	3,130,577	3,185,512	3,285,994	3,257,616	3,280,174	3,287,602	3,264,405	3,250,488	3,252,943
Unit Capacity Factor	%	69.77%	70.95%	71.28%	72.73%	75.02%	74.37%	74.69%	75.06%	74.53%	74.21%	74.07%
Annual Fixed Charges												
Nominal Capacity Charge	$000	$ 37,901	$ 36,972	$ 36,314	$ 35,624	$ 34,902	$ 34,146	$ 33,355	$ 32,525	$ 31,656	$ 30,746	$ 29,793
Nominal Fixed O&M	$000	$ 6,571	$ 6,722	$ 6,877	$ 7,035	$ 7,197	$ 7,363	$ 7,532	$ 7,705	$ 7,882	$ 8,064	$ 8,249
Nominal Insurance	$000	$ 298	$ 305	$ 313	$ 320	$ 328	$ 337	$ 345	$ 354	$ 362	$ 372	$ 381
Nominal Total Fixed Charges	$000	$ 44,770	$ 43,999	$ 43,503	$ 42,980	$ 42,428	$ 41,846	$ 41,232	$ 40,584	$ 39,901	$ 39,182	$ 38,423
Nominal Total Fixed Charges Per kW-mo	$/kW-mo	$ 7.46	$ 7.33	$ 7.25	$ 7.16	$ 7.07	$ 6.97	$ 6.87	$ 6.76	$ 6.65	$ 6.53	$ 6.40
Discounted Total Fixed Charges	$000	$ 36,832	$ 34,474	$ 32,463	$ 30,545	$ 28,717	$ 26,974	$ 25,313	$ 23,729	$ 22,219	$ 20,779	$ 19,406
Variable O&M												
Nominal Non-Fuel Variable O&M	$000	$ 12,270	$ 12,429	$ 16,756	$ 24,151	$ 32,596	$ 33,109	$ 33,962	$ 36,453	$ 38,281	$ 39,230	$ 41,677
Total Fixed Charges and Non-Fuel VOM												
Nominal Total Fixed Charges & Non-Fuel VOM	$000	$ 57,040	$ 56,428	$ 60,259	$ 67,131	$ 75,024	$ 74,954	$ 75,193	$ 77,037	$ 78,183	$ 78,412	$ 80,100
Discounted Total Fixed Chrgs & Non-Fuel VOM	$000	$ 46,927	$ 44,213	$ 44,966	$ 47,709	$ 50,779	$ 48,316	$ 46,162	$ 45,042	$ 43,535	$ 41,583	$ 40,456
Sum Present Val Fixed Chrgs & Non-fuel VOM	$000	$ 827,462										
Other Utility Costs												
Nominal Annual Fuel Costs	$000	$ 90,870	$ 94,583	$ 104,263	$ 118,317	$ 131,760	$ 135,508	$ 140,199	$ 145,588	$ 153,276	$ 159,368	$ 173,265
Discounted Annual Fuel Costs	$000	$ 74,759	$ 74,108	$ 77,803	$ 84,085	$ 89,181	$ 87,350	$ 86,070	$ 85,122	$ 85,350	$ 84,516	$ 87,511
Summary Cost Metrics												
Nominal Average Total Fixed Charges (All)	$/kW-mo	$ 6.45										
Nominal Annual Costs (All)	$000	$ 147,910	$ 151,011	$ 164,522	$ 185,447	$ 206,784	$ 210,462	$ 215,392	$ 222,626	$ 231,459	$ 237,779	$ 253,365
Nominal Avg Costs Including Fuel, Var, & Fixed	$/MWh	$ 77.41										
Discounted Annual Costs (All)	$000	$ 121,686	$ 118,321	$ 122,769	$ 131,794	$ 139,960	$ 135,666	$ 132,232	$ 130,165	$ 128,885	$ 126,100	$ 127,967
Discounted Annual Output (All)	MWh	2,514,268	2,434,737	2,336,085	2,263,884	2,224,090	2,099,888	2,013,743	1,922,193	1,817,743	1,723,803	1,642,957
Levelized Costs Incl. Fuel, Variable, & Fixed (All)	$/MWh	$ 72.43										
Market Revenue Projections												
Nominal Realized Locational Marginal Prices	$/MWh	$ 41.18	$ 43.13	$ 51.36	$ 57.52	$ 69.20	$ 70.56	$ 82.02	$ 78.32	$ 75.81	$ 95.26	$ 95.48
Nominal Market-Based Revenue	$000	$ 125,847	$ 134,013	$ 160,789	$ 183,218	$ 227,380	$ 229,842	$ 269,034	$ 257,485	$ 247,487	$ 309,626	$ 310,593
Nominal Ancillary Services Revenue	$000	$ 3,775	$ 4,020	$ 4,824	$ 5,497	$ 6,821	$ 6,895	$ 8,071	$ 7,725	$ 7,425	$ 9,289	$ 9,318
Net Revenue Metrics												
Annual Net Present Value (Revenue Net of Cost)	$000	$ (15,045)	$ (10,168)	$ 814	$ 2,322	$ 18,557	$ 16,937	$ 37,886	$ 24,898	$ 13,059	$ 43,028	$ 33,610
Total Net Present Value (Revenue Net of Cost)	$000	$ 497,708										

Calendar Year	Units	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
		12	13	14	15	16	17	18	19	20	21	22
Months in Service	Months	12	12	12	12	12	12	12	12	12	12	0
Discount Factor												
Utility Discount Rate and Annual Factor	5.00%	0.4810	0.4581	0.4363	0.4155	0.3957	0.3769	0.3589	0.3418	0.3256	0.3101	0.0000
Unit Statistics												
Capacity Rating	MW	500	500	500	500	500	500	500	500	500	500	-
Unit Output	MWh	3,254,552	3,310,373	3,216,003	3,256,983	3,231,816	3,260,520	3,240,360	3,271,116	3,227,647	3,283,646	-
Unit Capacity Factor	%	74.30%	75.58%	73.42%	74.16%	73.79%	74.44%	73.98%	74.48%	73.69%	74.97%	0.00%
Annual Fixed Charges												
Nominal Capacity Charge	$000	$ 28,795	$ 27,748	$ 26,652	$ 25,504	$ 24,301	$ 23,041	$ 21,721	$ 20,337	$ 19,599	$ -	$ -
Nominal Fixed O&M	$000	$ 8,439	$ 8,633	$ 8,832	$ 9,035	$ 9,242	$ 9,455	$ 9,673	$ 9,895	$ 10,123	$ 10,355	$ -
Nominal Insurance	$000	$ 390	$ 400	$ 410	$ 420	$ 431	$ 442	$ 453	$ 464	$ 476	$ 487	$ -
Nominal Total Fixed Charges	$000	$ 37,624	$ 36,781	$ 35,894	$ 34,959	$ 33,975	$ 32,938	$ 31,846	$ 30,696	$ 30,197	$ 10,843	$ -
Nominal Total Fixed Charges Per kW-mo	$/kW-mo	$ 6.27	$ 6.13	$ 5.98	$ 5.83	$ 5.66	$ 5.49	$ 5.31	$ 5.12	$ 5.03	$ 1.81	$ -
Discounted Total Fixed Charges	$000	$ 18,098	$ 16,850	$ 15,660	$ 14,526	$ 13,445	$ 12,414	$ 11,431	$ 10,493	$ 9,831	$ 3,362	$ -
Variable O&M												
Nominal Non-Fuel Variable O&M	$000	$ 42,864	$ 46,442	$ 47,565	$ 49,225	$ 52,341	$ 53,501	$ 54,597	$ 58,103	$ 58,852	$ 61,492	$ -
Total Fixed Charges and Non-Fuel VOM												
Nominal Total Fixed Charges & Non-Fuel VOM	$000	$ 80,487	$ 83,223	$ 83,459	$ 84,184	$ 86,315	$ 86,439	$ 86,442	$ 88,799	$ 89,049	$ 72,335	$ -
Discounted Total Fixed Chrgs & Non-Fuel VOM	$000	$ 38,716	$ 38,125	$ 36,413	$ 34,980	$ 34,158	$ 32,578	$ 31,028	$ 30,356	$ 28,992	$ 22,429	$ -
Other Utility Costs												
Nominal Annual Fuel Costs	$000	$ 187,284	$ 192,321	$ 193,815	$ 207,904	$ 214,553	$ 225,414	$ 227,852	$ 238,835	$ 243,614	$ 257,774	$ -
Discounted Annual Fuel Costs	$000	$ 90,087	$ 88,104	$ 84,561	$ 86,389	$ 84,906	$ 84,956	$ 81,786	$ 81,646	$ 79,314	$ 79,928	$ -
Summary Cost Metrics												
Nominal Annual Costs (All)	$000	$ 267,772	$ 275,544	$ 277,273	$ 292,088	$ 300,868	$ 311,853	$ 314,294	$ 327,634	$ 332,663	$ 330,109	$ -
Discounted Annual Costs (All)	$000	$ 128,803	$ 126,230	$ 120,974	$ 121,369	$ 119,064	$ 117,534	$ 112,814	$ 112,002	$ 108,306	$ 102,356	$ -
Discounted Annual Output (All)	MWh	1,565,495	1,516,520	1,403,131	1,353,344	1,278,939	1,228,856	1,163,103	1,118,230	1,050,829	1,018,153	-
Market Revenue Projections												
Nominal Realized Locational Marginal Prices	$/MWh	$ 92.65	$ 97.71	$ 108.92	$ 109.97	$ 122.06	$ 113.18	$ 123.08	$ 125.47	$ 125.76	$ 149.15	$ -
Nominal Market-Based Revenue	$000	$ 301,549	$ 323,448	$ 350,282	$ 358,185	$ 394,465	$ 369,019	$ 398,836	$ 410,420	$ 405,893	$ 489,757	$ -
Nominal Ancillary Services Revenue	$000	$ 9,046	$ 9,703	$ 10,508	$ 10,746	$ 11,834	$ 11,071	$ 11,965	$ 12,313	$ 12,177	$ 14,693	$ -
Net Revenue Metrics												
Annual Net Present Value (Revenue Net of Cost)	$000	$ 20,599	$ 26,391	$ 36,438	$ 31,929	$ 41,723	$ 25,718	$ 34,640	$ 32,509	$ 27,806	$ 54,057	$ -

Source: Navigant

NAVIGANT

Table C-3. Financial Project Analysis Results, Decker CC Build, Higher-End Capital Cost ($900/kW, Turnkey)

Calendar Year	Units	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11
Months in Service	Months	12	12	12	12	12	12	12	12	12	12	12
Discount Factor												
Utility Discount Rate and Annual Factor	5.00%	0.8227	0.7835	0.7462	0.7107	0.6768	0.6446	0.6139	0.5847	0.5568	0.5303	0.5051
Unit Statistics												
Capacity Rating	MW	500	500	500	500	500	500	500	500	500	500	500
Unit Output	MWh	3,056,108	3,107,410	3,130,577	3,185,512	3,285,994	3,257,616	3,280,174	3,287,602	3,264,405	3,250,488	3,252,943
Unit Capacity Factor	%	69.77%	70.95%	71.28%	72.73%	75.02%	74.37%	74.69%	75.06%	74.53%	74.21%	74.07%
Annual Fixed Charges												
Nominal Capacity Charge	$000	$ 48,716	$ 47,521	$ 46,675	$ 45,789	$ 44,861	$ 43,889	$ 42,871	$ 41,804	$ 40,687	$ 39,517	$ 38,292
Nominal Fixed O&M	$000	$ 6,571	$ 6,722	$ 6,877	$ 7,035	$ 7,197	$ 7,363	$ 7,532	$ 7,705	$ 7,882	$ 8,064	$ 8,249
Nominal Insurance	$000	$ 383	$ 392	$ 402	$ 412	$ 422	$ 433	$ 444	$ 455	$ 466	$ 478	$ 490
Nominal Total Fixed Charges	$000	$ 55,670	$ 54,636	$ 53,954	$ 53,236	$ 52,480	$ 51,684	$ 50,846	$ 49,964	$ 49,036	$ 48,059	$ 47,030
Nominal Total Fixed Charges Per kW-mo	$/kW-mo	$ 9.28	$ 9.11	$ 8.99	$ 8.87	$ 8.75	$ 8.61	$ 8.47	$ 8.33	$ 8.17	$ 8.01	$ 7.84
Discounted Total Fixed Charges	$000	$ 45,799	$ 42,809	$ 40,261	$ 37,834	$ 35,521	$ 33,316	$ 31,215	$ 29,213	$ 27,305	$ 25,487	$ 23,754
Variable O&M												
Nominal Non-Fuel Variable O&M	$000	$ 12,270	$ 12,429	$ 16,756	$ 24,151	$ 32,596	$ 33,109	$ 33,962	$ 36,453	$ 38,281	$ 39,230	$ 41,677
Total Fixed Charges and Non-Fuel VOM												
Nominal Total Fixed Charges & Non-Fuel VOM	$000	$ 67,940	$ 67,064	$ 70,710	$ 77,387	$ 85,076	$ 84,793	$ 84,808	$ 86,418	$ 87,317	$ 87,289	$ 88,707
Discounted Total Fixed Chrgs & Non-Fuel VOM	$000	$ 55,894	$ 52,547	$ 52,765	$ 54,997	$ 57,583	$ 54,658	$ 52,065	$ 50,527	$ 48,621	$ 46,291	$ 44,803
Sum Present Val Fixed Chrgs & Non-fuel VOM	$000	$ 924,166										
Other Utility Costs												
Nominal Annual Fuel Costs	$000	$ 90,870	$ 94,583	$ 104,263	$ 118,317	$ 131,760	$ 135,508	$ 140,199	$ 145,588	$ 153,276	$ 159,368	$ 173,265
Discounted Annual Fuel Costs	$000	$ 74,759	$ 74,108	$ 77,803	$ 84,085	$ 89,181	$ 87,350	$ 86,070	$ 85,122	$ 85,350	$ 84,516	$ 87,511
Summary Cost Metrics												
Nominal Average Total Fixed Charges (All)	$/kW-mo	$ 7.88										
Nominal Annual Costs (All)	$000	$ 158,810	$ 161,648	$ 174,973	$ 195,703	$ 216,837	$ 220,301	$ 225,007	$ 232,006	$ 240,593	$ 246,657	$ 261,972
Nominal Avg Costs Including Fuel, Var, & Fixed	$/MWh	$ 79.93										
Discounted Annual Costs (All)	$000	$ 130,653	$ 126,655	$ 130,567	$ 139,083	$ 146,764	$ 142,008	$ 138,135	$ 135,649	$ 133,971	$ 130,807	$ 132,314
Discounted Annual Output (All)	MWh	2,514,268	2,434,737	2,336,085	2,263,884	2,224,090	2,099,888	2,013,743	1,922,193	1,817,743	1,723,803	1,642,957
Levelized Costs Incl. Fuel, Variable, & Fixed (All)	$/MWh	$ 75.14										
Market Revenue Projections												
Nominal Realized Locational Marginal Prices	$/MWh	$ 41.18	$ 43.13	$ 51.36	$ 57.52	$ 69.20	$ 70.56	$ 82.02	$ 78.32	$ 75.81	$ 95.26	$ 95.48
Nominal Market-Based Revenue	$000	$ 125,847	$ 134,013	$ 160,789	$ 183,218	$ 227,380	$ 229,842	$ 269,034	$ 257,485	$ 247,487	$ 309,626	$ 310,593
Nominal Ancillary Services Revenue	$000	$ 3,775	$ 4,020	$ 4,824	$ 5,497	$ 6,821	$ 6,895	$ 8,071	$ 7,725	$ 7,425	$ 9,289	$ 9,318
Net Revenue Metrics												
Annual Net Present Value (Revenue Net of Cost)	$000	$ (24,012)	$ (18,503)	$ (6,984)	$ (4,967)	$ 11,753	$ 10,595	$ 31,984	$ 19,413	$ 7,973	$ 38,320	$ 29,263
Total Net Present Value (Revenue Net of Cost)	$000	$ 401,004										

Calendar Year	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22
Months in Service	12	12	12	12	12	12	12	12	12	12	0
Discount Factor											
Utility Discount Rate and Annual Factor	0.4810	0.4581	0.4363	0.4155	0.3957	0.3769	0.3589	0.3418	0.3256	0.3101	0.0000
Unit Statistics											
Capacity Rating	500	500	500	500	500	500	500	500	500	500	-
Unit Output	3,254,552	3,310,373	3,216,003	3,256,983	3,231,816	3,260,520	3,240,360	3,271,116	3,227,647	3,283,646	-
Unit Capacity Factor	74.30%	75.58%	73.42%	74.16%	73.79%	74.44%	73.98%	74.48%	73.69%	74.97%	0.00%
Annual Fixed Charges											
Nominal Capacity Charge	$ 37,008	$ 35,663	$ 34,254	$ 32,777	$ 31,231	$ 29,610	$ 27,913	$ 26,134	$ 25,192	$ -	$ -
Nominal Fixed O&M	$ 8,439	$ 8,633	$ 8,832	$ 9,035	$ 9,242	$ 9,455	$ 9,673	$ 9,895	$ 10,123	$ 10,355	$ -
Nominal Insurance	$ 502	$ 514	$ 527	$ 540	$ 554	$ 568	$ 582	$ 597	$ 611	$ 627	$ -
Nominal Total Fixed Charges	$ 45,949	$ 44,810	$ 43,612	$ 42,353	$ 41,027	$ 39,633	$ 38,167	$ 36,626	$ 35,926	$ 10,982	$ -
Nominal Total Fixed Charges Per kW-mo	$ 7.66	$ 7.47	$ 7.27	$ 7.06	$ 6.84	$ 6.61	$ 6.36	$ 6.10	$ 5.99	$ 1.83	$ -
Discounted Total Fixed Charges	$ 22,102	$ 20,528	$ 19,028	$ 17,598	$ 16,236	$ 14,937	$ 13,700	$ 12,520	$ 11,696	$ 3,405	$ -
Variable O&M											
Nominal Non-Fuel Variable O&M	$ 42,864	$ 46,442	$ 47,565	$ 49,225	$ 52,341	$ 53,501	$ 54,597	$ 58,103	$ 58,852	$ 61,492	$ -
Total Fixed Charges and Non-Fuel VOM											
Nominal Total Fixed Charges & Non-Fuel VOM	$ 88,812	$ 91,252	$ 91,177	$ 91,577	$ 93,368	$ 93,135	$ 92,764	$ 94,729	$ 94,778	$ 72,474	$ -
Discounted Total Fixed Chrgs & Non-Fuel VOM	$ 42,720	$ 41,803	$ 39,780	$ 38,052	$ 36,949	$ 35,101	$ 33,297	$ 32,383	$ 30,857	$ 22,472	$ -
Sum Present Val Fixed Chrgs & Non-fuel VOM											
Other Utility Costs											
Nominal Annual Fuel Costs	$ 187,284	$ 192,321	$ 193,815	$ 207,904	$ 214,553	$ 225,414	$ 227,852	$ 238,835	$ 243,614	$ 257,774	$ -
Discounted Annual Fuel Costs	$ 90,087	$ 88,104	$ 84,561	$ 86,389	$ 84,906	$ 84,956	$ 81,786	$ 81,646	$ 79,314	$ 79,928	$ -
Summary Cost Metrics											
Nominal Average Total Fixed Charges (All)											
Nominal Annual Costs (All)	$ 276,097	$ 283,573	$ 284,992	$ 299,481	$ 307,921	$ 318,549	$ 320,616	$ 333,563	$ 338,392	$ 330,248	$ -
Nominal Avg Costs Including Fuel, Var, & Fixed											
Discounted Annual Costs (All)	$ 132,807	$ 129,908	$ 124,341	$ 124,441	$ 121,855	$ 120,058	$ 115,083	$ 114,029	$ 110,171	$ 102,399	$ -
Discounted Annual Output (All)	1,565,495	1,516,520	1,403,131	1,353,344	1,278,939	1,228,856	1,163,103	1,118,230	1,050,829	1,018,153	-
Levelized Costs Incl. Fuel, Variable, & Fixed (All)											
Market Revenue Projections											
Nominal Realized Locational Marginal Prices	$ 92.65	$ 97.71	$ 108.92	$ 109.97	$ 122.06	$ 113.18	$ 123.08	$ 125.47	$ 125.76	$ 149.15	$ -
Nominal Market-Based Revenue	$ 301,549	$ 323,448	$ 350,282	$ 358,185	$ 394,465	$ 369,019	$ 398,836	$ 410,420	$ 405,893	$ 489,757	$ -
Nominal Ancillary Services Revenue	$ 9,046	$ 9,703	$ 10,508	$ 10,746	$ 11,834	$ 11,071	$ 11,965	$ 12,313	$ 12,177	$ 14,693	$ -
Net Revenue Metrics											
Annual Net Present Value (Revenue Net of Cost)	$ 16,594	$ 22,713	$ 33,071	$ 28,857	$ 38,932	$ 23,194	$ 32,371	$ 30,482	$ 25,941	$ 54,014	$ -
Total Net Present Value (Revenue Net of Cost)											

Source: Navigant