# Review of the Renewable Denton Plan

## Final Report

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*Acknowledgement:* We acknowledge the valuable contributions of many individuals to this report and to the underlying analysis, including members of The Brattle Group for peer review.

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# I. Executive Summary

## A. Overview

The City of Denton asked The Brattle Group ("Brattle") to review Denton Municipal Electric's ("DME"'s) proposed Renewable Denton Plan ("RDP"), which calls for increasing the renewable generation in DME's portfolio (mostly wind and solar resources) from the current 40% of energy served to 70% by 2019. This report reviews the RDP and alternative options analyzed by DME, and performs an independent economic feasibility assessment of the RDP.

DME currently has two sources of power supply besides market purchases – a 100 MW power sales agreement with the Gibbons Creek Steam Electric Station ("Gibbons Creek") operated by the Texas Municipal Power Agency ("TMPA") and a wind power purchase agreement ("PPA") with NextEra. A 30 MW solar PPA is scheduled to start in 2019 (together with the NextEra wind PPA, "existing renewable PPA"). Therefore, under the status quo portfolio ("Status Quo" or "SQ") DME will have multiple PPAs with the balance being purchased from the ERCOT market in 2019. The Gibbons Creek power sales agreement will expire in the next few years and DME must decide whether to extend it.

DME designed the RDP to increase Denton's renewable generation without creating additional costs for ratepayers. The RDP is designed to lower costs relative to Status Quo. The RDP calls for DME to sign long-term renewable PPAs and make an investment in the new Denton Energy Center ("DEC"), which will consist of two separate plants with six reciprocating engines ("RICE" or "RICE units") at each site. By design, the PPAs and the DEC will complement each other. The PPAs will lower emissions and reduce costs, while the DEC will "firm" the intermittent renewable power supply.

The term "firm" describes power supply sources that dependably generate a pre-determined amount of energy. Quick responding dispatchable units can "firm" intermittent renewables by providing back-up generation when renewable output falls. "Firm" power insures that DME physically matches supply and demand in real time and limits customers' exposure to the volatile Electric Reliability Council of Texas ("ERCOT") Real-Time energy market. The physical balancing requirement is particularly important for DME and its customers. As an ERCOT

qualified scheduling entity ("QSE"), DME shares ERCOT's obligation to maintain system reliability and faces financial penalties if it fails to perform as required, or as directed by ERCOT.

The RDP is time sensitive for several reasons. First, the Gibbons Creek power sales agreement renewal is approaching. Second, the newly extended federal tax incentives for renewable resources (production tax and investment tax credits) will be phased out starting in 2017. These favorable government policies, combined with low natural gas prices, and low interest rates have pushed prices for renewable PPAs to historic lows. DME has concluded that it can sign long-term renewable PPAs on terms that will fix energy prices below both current energy prices and expected future energy prices. Finally the current exchange rate (US dollar against the Euro) is favorable for purchasing the Euro-denominated RICE units.

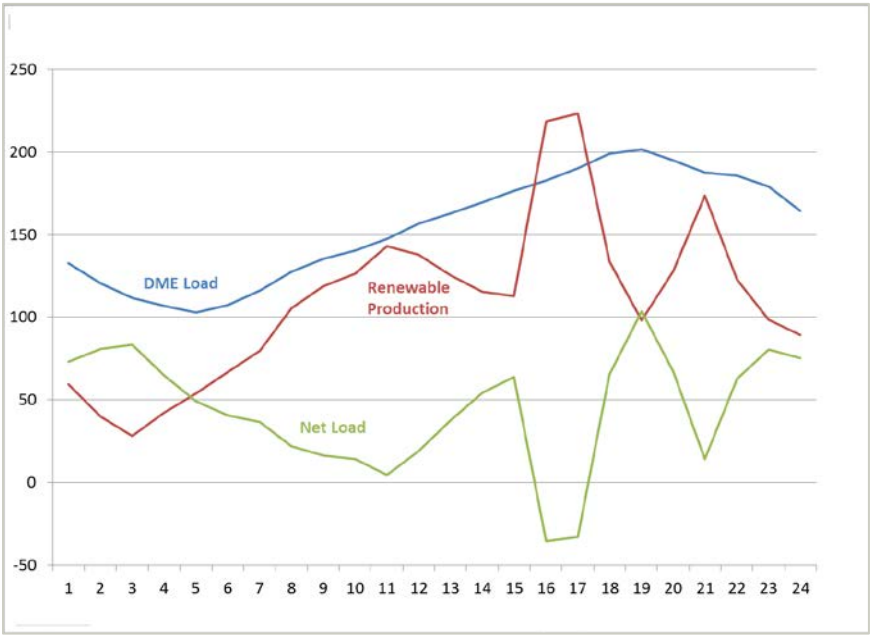
## B. THE DEC IS AN INTEGRAL PART OF THE RDP

Approximately 10% of Denton's current physical power supply comes from intermittent renewable resources.[1] Raising the share of physical power from intermittent renewable resources to 70% by 2019 will make it significantly more challenging for DME to maintain the physical supply-demand balance.

Figure ES-1 (Hourly Net Load and Ramping Needs) shows the estimated DME load (blue line), production from renewable resources (red line), and the resulting net load (green line) for a day in May 2019.

[1] Renewable Energy Credits ("RECs") increase the renewable portion of DME's portfolio to 40%.

**Figure ES-1: Hourly Net Load and Ramping Needs**




The net load (green line) variation of over 100 MW in less than two hours illustrates the difficulty of balancing the system. The variability of DME's renewable resources (and hence net load) will be highly correlated with the variability in ERCOT's renewable energy resources as a whole. While the increasingly large portfolio of ERCOT wind resources has some geographic diversity, the overall net load variability has increased with wind penetration. When wind resources drop off suddenly, the overall supply becomes short and prices tend to rise, at times sharply.

When wind resource output is low, DME will be more likely to experience a physical imbalance between its supply and demand, and will need to purchase energy on the ERCOT wholesale market. In other words, DME is most likely to need to buy energy from the ERCOT market during times when prices are expected to be high.

We understand from DME that not having the firming capability inherent in the DEC, or the equivalent provided by a third party would put DME's QSE status in jeopardy.

## C. ALTERNATIVES TO THE DEC

To firm its power supply, DME must either pay a premium to purchase flexible power products from the market, or it can develop its own flexible power supply (the DEC).

If DME firms its renewable portfolio through market purchases, it will need to pay a premium for flexible power throughout the duration of the PPAs. By developing the DEC, DME will have access to a flexible power supply (each RICE unit can provide its full capacity in 5 minutes and can ramp at 15 MW/minute) that will firm DME's entire renewable portfolio. While the DEC requires upfront debt financing, it will significantly reduce DME's future costs associated with firming renewables. Moreover, potential revenue from market sales of energy and ancillary services will help pay the DEC's debt service charges.

DME has alternatives to the DEC for firming its power supply by obtaining flexible power from a third party. Currently, we are not aware of any contracting options that match the flexibility of the physical hedge provided by the DEC. A fixed quantity firming contract for renewable resources would provide a less flexible, but an otherwise similar hedge. However, pricing on existing firm arms-length contracts indicate such costs would be very high. Going without any hedging mechanisms will create financial risks and further may lead to unwanted consequences, such as jeopardizing the QSE status of DME.[2]

## D. WHAT WILL THE RDP LIKELY COST?

The Brattle analysis compares three potential power supply *Strategies*: an *RDP-DEC Strategy* and two *Status Quo Strategies*. In the *RDP-DEC Strategy*, the RDP with DEC is implemented to achieve 70% renewable penetration. In the *SQ-TMPA Strategy*, the DME generation portfolio remains Status Quo including Gibbons Creek. Finally, in the *SQ-Market Strategy*, Gibbons Creek is no longer part of the DME portfolio and DME purchases the needed additional power from the ERCOT market. Under the two *Status Quo Strategies,* DME's renewable penetration level remains at the current 40% level, enabled by existing renewable PPAs and RECs.

An economic analysis was performed using two different natural gas scenarios. Both scenarios use natural gas price forecasts from the latest ERCOT Long Term System Assessment ("LTSA"). The Base Scenario uses the LTSA reference natural gas price forecast and the Low Gas Scenario uses the LTSA low gas forecast, which effectively assumes that current low gas prices prevail in real terms for the foreseeable future. Figure ES-2 (Historical and Forecasted Natural Gas Prices)

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[2] DME serving as its own QSE and managing its own energy portfolio has saved the City of Denton several million dollars per year. For example, the savings in the first year of serving as its own QSE was around $13.5 million.

and Figure ES-3 (Forward Power Price Curves) show the natural gas prices and power prices derived for the two scenarios. [3]

**Figure ES-2: Historical and Forecasted Natural Gas Prices**

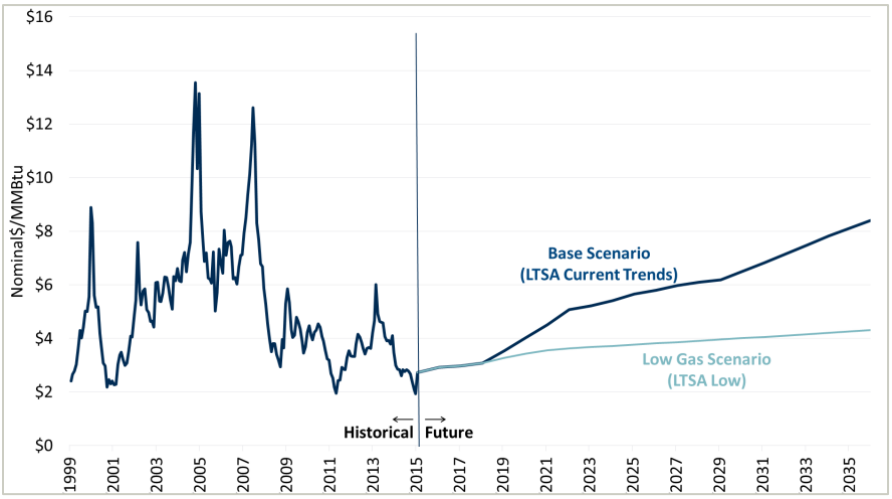
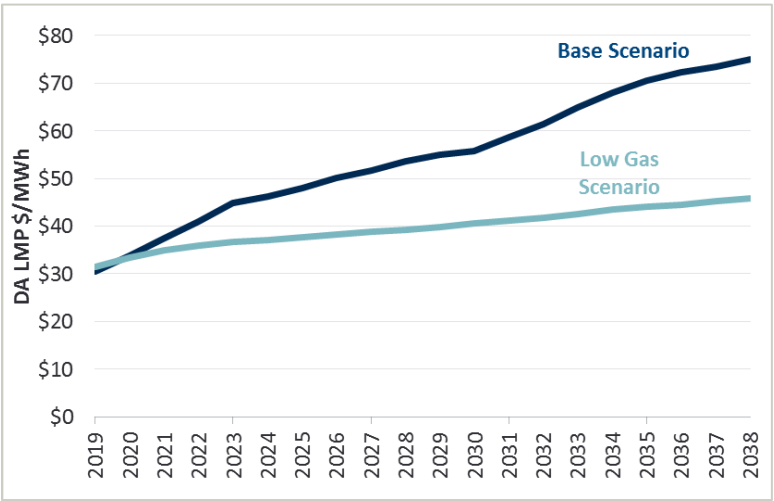



**Figure ES-3: Forward Power Price Curves**




The Brattle analysis confirms that the *RDP-DEC Strategy* is the most cost efficient option among the three *Strategies.* Figure ES-4 (Base Scenario Cost Comparison) and Figure ES-5 (Low Gas Scenario Cost Comparison) show the estimated cost for DME to serve its customers under the

[3] The electricity price projections were derived from a recent Brattle analysis of the ERCOT market. http://www.brattle.com/system/publications/pdfs/000/005/292/original/Exploring_Natural_Gas_and_Renewables_in_ERCOT__Part_IV_-_The_Future_of_Clean_Energy_in_ERCOT.pdf?1464026626

two scenarios. Costs for the *RDP-DEC Strategy* fall further in 2036 after the full repayment of DEC's outstanding debt.

**Figure ES-4: Base Scenario Cost Comparison**

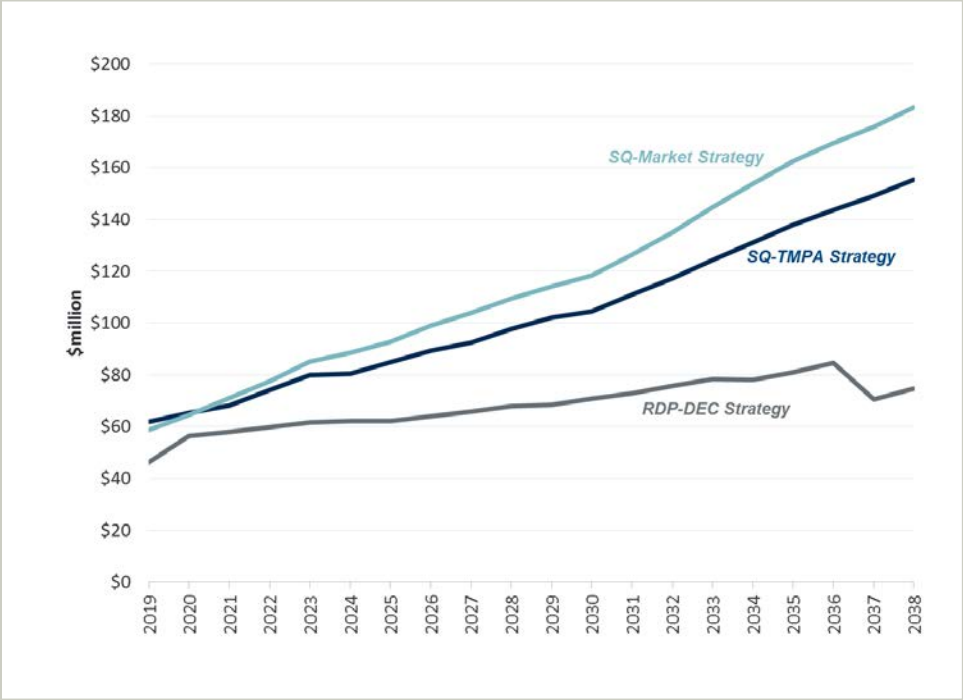
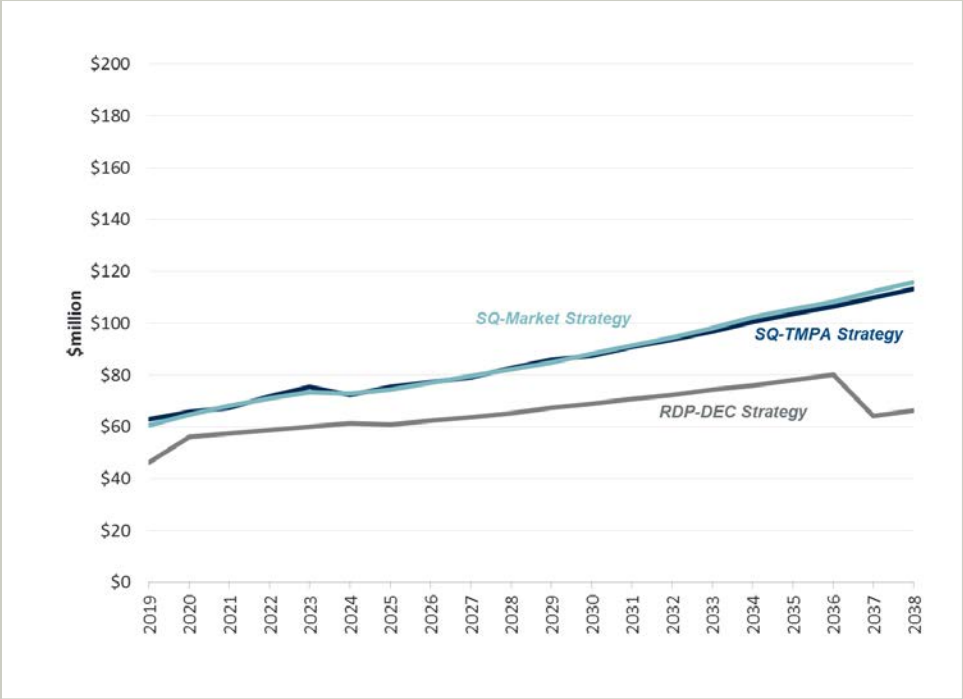



**Figure ES-5: Low Gas Scenario Cost Comparison**



Both the renewable PPAs and the DEC are integral parts of the RDP. The DEC physically hedges the variability brought by the increased renewable resources, while maintaining DME's QSE status, and is therefore necessary to implement the *RDP-DEC Strategy*.

In the Base Scenario, the *RDP-DEC Strategy* costs approximately $975 million less than the *SQ-Market Strategy* over 20 years and $750 million less than the *SQ-TMPA Strategy*. In the Low Gas Scenario, the *RDP-DEC Strategy* costs approximately $410 million less over 20 years than either *Status Quo Strategies*. These results show that even at current natural gas prices the *RDP-DEC Strategy* will reduce DME's costs. Furthermore the *RDP-DEC Strategy* acts as a hedge against rising natural gas prices, likely yielding even greater savings when gas prices rise.

Savings from the renewable PPAs drive the lower DME customer costs. Figure ES-6 (Base Scenario Cumulative Cost ($000) Difference by Components) and Figure ES-7 (Low Gas Scenario Cumulative Cost ($000) Difference by Components) compare the *RDP-DEC Strategy* to the *SQ-Market Strategy* and break down the components of the cumulative savings of the *RDP-DEC Strategy*. These Figures show that in both scenarios, Energy Market/PPA cost (the green portion of the bars) is the dominant contributor to the cost savings. Other Portfolio Savings enabled by the DEC include avoided REC purchases and optimization of DME's purchases in the Day-Ahead and Real-Time markets. In addition to these savings, DEC can offset the DME cost through market sales. Under current market protocols, DEC will sell energy and ancillary services to the ERCOT market. DME will then buy back from the market the amount needed to serve its load. The net revenue of the amount DEC sold and DME bought back will offset DME's cost to serve load. In the Base Scenario, the Total Portfolio Savings (solid blue line) is higher than the combined savings of Energy Market/PPA and Other Portfolio Savings because this net revenue from market sales exceeds DEC's financing costs (the red portions of the bars in the negative direction). The Low Gas Scenario shows similar observations, although the Total Portfolio Savings (solid blue line) is slightly lower than the combined savings of Energy Market/PPA and Other Portfolio Savings. Note that this analysis only extends 20 years. The DEC is able to provide additional benefits to DME customers well beyond 20 years.

**Figure ES-6: Base Scenario Cumulative Cost ($000) Difference by Components**

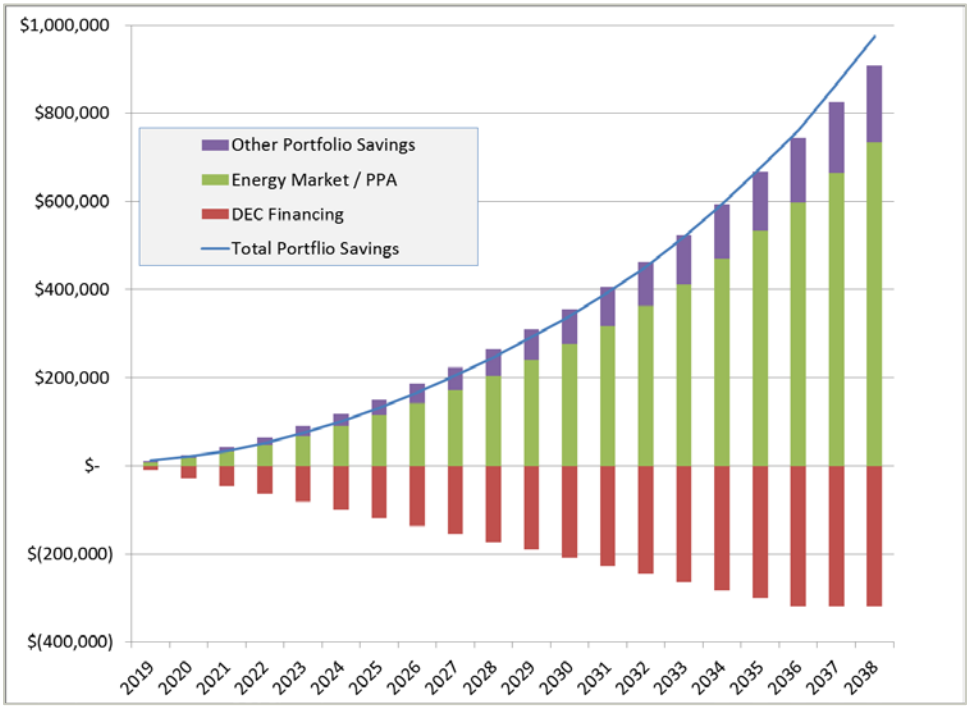
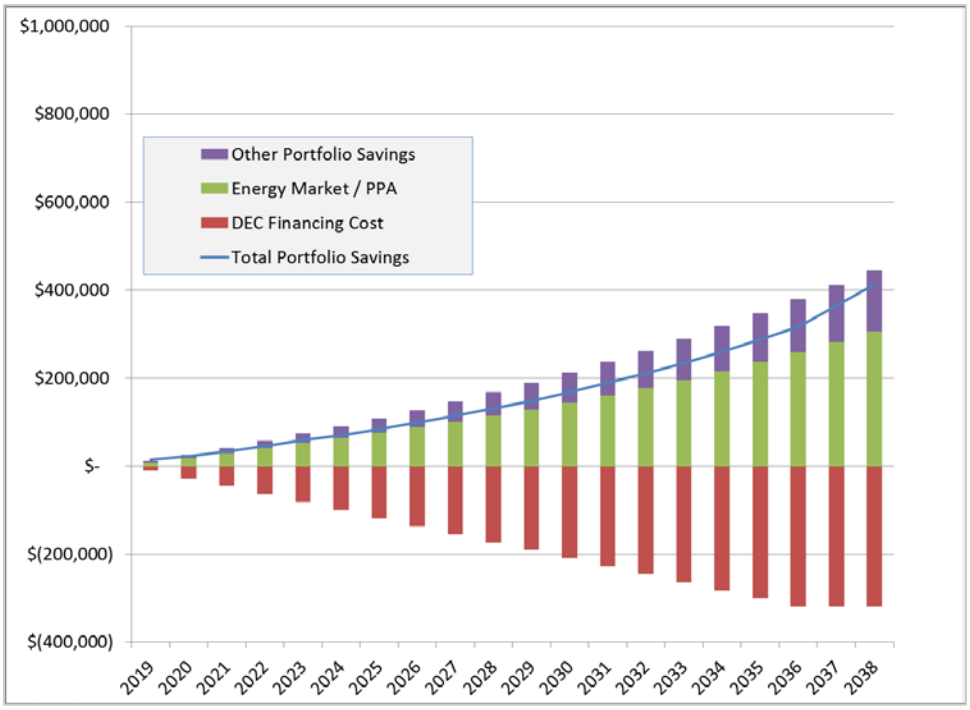



**Figure ES-7: Low Gas Scenario Cumulative Cost ($000) Difference by Components**



In addition to providing these economic benefits, the *RDP-DEC Strategy* will lower fossil fuel usage and associated air emissions. If the DEC operates at a 20% capacity factor (averaging approximately 33,000 MWh of power generated per RICE unit), it will reduce approximately 325 tons of $SO_2$, 180 tons of NOx, 120 tons of VOC, and over 40,000 tons of $CO_2$ per year compared to purchasing power from the ERCOT market.

## E. How Big Should the DEC Be?

The net-load analysis in Figure ES-1 (Hourly Net Load and Ramping Needs) shows that a minimum of nine RICE units are required. This is based on one year of projected data (for 2019) and not assuming future load growth or forecast deviations of the renewable resources. Under the RDP, DME will have nearly 500 MW of variable renewables and greater net-load ramps are certainly probable. In addition, individual RICE units will at times be out for planned and forced outages. These two factors indicate that 12 RICE units provide a good balance from an operational perspective.

Each of the DEC stations is planned to have six units to provide added reliability. The two major cost components of a station are the engines themselves and the "balance of plant." The balance of plant consists of the land, gas pipeline, transmission to the plant and the substation, the building and controls. Having more or less units at a site does not change the balance of plant costs. Thus in going from 9 to 12 units (in total) the cost will not increase by 33%. Quotes DME received indicate that building six units rather than 12 will only lower the cost by 35%, not 50%.

Thus, based on operational need and cost, we conclude 12 units to be appropriate for DME's needs as part of the RDP.

The *RDP-DEC Strategy* provides other benefits that are not quantified, such as minimal water usage compared with other thermal capacity. Overall, the *RDP-DEC Strategy* appears to be the lowest cost and most reliable option for achieving the City of Denton and DME's goal of higher renewable penetration. It is important to note that DME needs to make changes to the ongoing electricity delivery services to customers without any disruption—both physically and financially—and having physical options to hedge the renewable variability is important.

The remainder of this report is organized as follows: Section II (Background) provides an overview and background of DME, the RDP, and DEC; Section III (Assessing the Economic Feasibility of the Renewable Denton Plan Metrics) discusses the modeling methodology,

assumptions, and analysis results; and Section IV (Conclusion) summarizes the findings once again. Further details of the study analysis and assumptions are included in the Appendices.

All monetary values in this report are shown in nominal dollars, unless specified otherwise.

# II. Background

## A. Today's System

The City of Denton, located on the north end of the Dallas–Fort Worth metroplex in North Texas, has grown rapidly in recent years. Between 2010 and 2011, it was the seventh fastest-growing city with a population over 100,000 in the United States. Today, the estimated population of approximately 140,000 continues to grow.

### 1. The Generation Portfolio

Denton Municipal Electric ("DME"), owned by the City of Denton, has been the provider of reliable and affordable energy for the greater Denton area since 1905. DME maintains competitive and stable rates and is recognized as a national leader in public power.[4] Denton's current peak load is anticipated to grow at approximately 2% per year for the foreseeable future, and its peak is expected to exceed 380 MW by 2019. Today, the industrial customers (approximately 12% of the customer base) provide 60% of DME's revenues with the remaining 88% (mostly residential customers) providing the balance. The generation portfolio serving Denton's load includes 100 MW from the 473 MW coal–fueled Gibbons Creek Steam Electric Station ("Gibbons Creek"), a "firmed" Wind Power Purchase Agreement ("PPA") with NextEra (i.e., DME receives a constant amount of power regardless of the wind conditions), and purchases from the Electric Reliability Council of Texas ("ERCOT") markets.[5] DME can choose to cease the firming provision in the NextEra Wind PPA, which will lower the PPA cost, at any time.[6] With this portfolio and through purchases of Renewable Energy Credits ("REC"s), DME achieves a 40% renewable penetration level today.

The current Gibbons Creek power sales agreement is scheduled to expire in the next few years and DME must decide if it wants to renew. A new Solar PPA starts in January of 2019. Therefore,

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[4] DME is also designated as a Reliable Public Power Provider by the American Public Power Association and received the U.S. Department of Energy 2011 Wind Power Award.

[5] The Gibbons Creek Steam Electric Station, also known as the Texas Municipal Power Agency ("TMPA"), was first put in service in October 1983. It is currently jointly operated by the four cities of Bryan (21.7% ownership), Denton (21.3% ownership), Garland (47% ownership), and Greenville (10% ownership). The four cities need to decide on their intentions of extending the Gibbons Creek agreement for an additional two years by September 2016 and TMPA has issued an RFP to sell its ownership. Gibbons Creek provides about 140 full time jobs to the local community.

[6] If firming is no longer needed, the PPA price will drop by approximately 40%.

under the status quo ("Status Quo" or "Status Quo world"), DME's generation portfolio in 2019 will consist of power from various PPAs (Gibbons Creek, the NextEra Wind PPA, and the new solar PPA). DME will need to purchase the balance of its energy needs from the ERCOT market.[7] DME's vision is to increase the renewable penetration level to 70%. The comprehensive Renewable Denton Plan ("RDP") was developed for this purpose.

### 2. Qualified Schedule Entity Services

As an ERCOT market participant, DME must either contract for Qualified Scheduling Entity ("QSE") services or provide them on its own.[8] With the goal of lowering ongoing operational costs, DME has created the Energy Management Organization ("EMO") to function as its own QSE and optimize power purchases. Creating the EMO to act as its QSE has produced significant economic benefits, saving the City of Denton a net of $13.5 million during its first year of operations alone. The EMO also gives DME flexibility to increase renewable penetration through PPAs.

To maintain its QSE status, DME must follow strict operational guidelines set by ERCOT and the Public Utility Commission of Texas ("PUCT"). DME must maintain the supply and demand balance schedule at all times and manage the supply uncertainty associated with its intermittent renewable PPAs. Expanding DME's renewable energy portfolio, as called for under the RDP, will create new operational challenges for the EMO. As discussed later in this report, the Denton Energy Center ("DEC") will help the EMO address the operational challenges created by the new renewable portfolio.

## B. The Renewable Denton Plan

DME estimates that in 2019 approximately 1,150,000 MWh of energy (out of the estimated 1,620,000 MWh of energy served) will come from renewable resources. The goal of the RDP is to increase the physical renewable penetration level to 70% by 2019 without increasing costs to customers. Under the RDP, DME will further increase the renewable portion of its portfolio to account for future load growth. Associated goals include reducing fossil fuel usage, water consumption and air emissions. These goals are achieved through signing multiple PPAs with renewable resources and developing the DEC facilities. The RDP calls for Denton's energy supply

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7 Denton is located near ERCOT's Northern Hub.

8 Generators and customers cannot interact directly with ERCOT. A QSE acts as the intermediary.

to come from 52% wind, 17% solar, and 1% landfill gas, thus bringing the renewable share of the portfolio to 70%. The remaining 30% of the city's energy needs will come from the DEC and purchases from the ERCOT market, whichever is cheaper.

### 1. Renewable PPAs

Current market and regulatory conditions are very favorable for signing renewable energy PPAs. Interest rates are generally low (although expected to rise in the near future) and lead to lower capital costs for developing renewable resources. The production tax credit ("PTC") and investment tax credit ("ITC") for renewable resources have been extended but benefits begin to decline in 2017.[9] [10] Therefore, renewable resource developers have strong incentives to build now rather than later and the potential over-supply puts downward pressure on PPA prices.[11] Furthermore, historically low natural gas prices provide low cost power alternatives that further suppress PPA prices.

Wind PPA costs are approximately 20% lower than the average ERCOT Northern Hub energy price observed over the past three years. As a coarse indication, with 200 MW of Wind PPAs producing about 700,000 MWh per year (roughly a 40% capacity factor, which is lower than the developers' projected capacity factors), DME will save about $4.2 million per year in energy costs, compared to the alternative of purchasing from the ERCOT market. In reality, 200 MW of Wind PPAs will likely provide more power but wind produces more during off-peak hours and therefore the savings from these PPAs may differ from this illustrative calculation.

However, it is important to recognize that the renewable resource PPAs come with challenges caused by the variability and intermittency of power production. Operators cannot dispatch

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[9] Congress extended the PTC and ITC in December 2015. Solar ITC will continue at the current 30 percent rate through 2019, after which it will fall to 26 percent in 2020, 22 percent in 2021, and 10 percent in 2022. An additional commence-construction clause will extend the credit to any project in development before 2021 (as long as the project is in service before the end of 2023). The wind PTC will be retroactively applied to units that started construction in 2015 and extended through 2016, after which it will decline each year by 20% per year until it fully expires in 2020.

[10] DME is a tax exempt municipality and cannot take advantage of these tax incentives or accelerated depreciation. Therefore signing PPAs for renewable resources becomes the practical option for DME.

[11] Texas provides an excellent ground for developing renewable resources. The state has some of the best wind and solar resources in the country. The Competitive Renewable Energy Zone ("CREZ") transmission system enables wind from west Texas and the Panhandle to reach load centers such as Dallas-Fort Worth. The CREZ system might also enable solar resources in the future.

wind and solar facilities; the output depends on weather patterns. During periods when the forecast shows renewables resources generating at low output levels, operators must obtain back-up power supply from other resources. Further complicating operations, wind and solar forecasts do not perfectly predict actual operations. To ensure reliability in real-time, back-up to cover forecast error (i.e., the difference between the forecast and actual operations) is needed. Thus, operators must overcome the dual challenges of matching supply from intermittent resources with demand and the scheduling difficulties associated with forecast uncertainty.

Adding significant renewable resources to a system, as intended under the RDP, will increase the challenges associated with variability. The current DME portfolio relies in part on Gibbons Creek to balance the supply and demand. The flexibility—i.e., ramping provided by Gibbons Creek—of only 1 MW per minute is just enough to address the current load variability, but would not be sufficient to address the flexibility needs created by the RDP. Load variations are fairly predictable and are not very rapid or large. However, the output of renewables can vary dramatically from minute to minute as wind speed and cloud coverage changes.[12]

### 2. The Denton Energy Center

The variability of DME's renewable resources (and hence net load) will be highly correlated with the variability in ERCOT's renewable energy resources as a whole. The growing portfolio of ERCOT wind resources has some geographic diversity, but overall system net load variability has risen as wind generation has increased. Prices tend to rise when wind resources drop off sharply. This is especially true when the decreased wind output is not expected. At these times DME would be most exposed to the physical imbalance of supply and demand and also to the ERCOT wholesale market to augment the supply shortage. Therefore, DME would be exposed to the need to buy significant quantities of power at high prices from the ERCOT market. The planned DEC provides a solution—both physically and financially—to this variability issue.

The DEC consists of two natural gas fired power plants that have access to multiple natural gas pipelines at each plant site. Each plant will have six quick-start capable reciprocating engines ("RICE" or "RICE units") with 18.75 MW of capacity per unit, adding up to a total capacity of

[12] Solar has a large morning ramp (up) and evening ramp (down) that makes for operational challenges as well. But these ramps are at least somewhat predictable.

225 MW (112.5 MW per plant).[13] Each RICE unit will have a minimum operating level of 3.75 MW (20% of full capacity) and is capable of providing Energy, Responsive Reserve ("RRS"), Non-Spinning Reserves ("NSRS"), and Regulation Up ("RUS") services to the ERCOT market within a minute's notice when the units are synchronized.[14] Regulation Down ("RDS") service can also be provided if any RICE units are dispatched for energy above a certain level. The operational flexibility provided by the RICE units is a hedge against the variability/intermittency of power generated by the renewable resources.

In addition to providing flexibility, the RICE units will contribute to reducing fossil fuel usage and air emissions. The RICE units have full load heat rates of approximately 8,300 Btu/kWh, which is lower than ERCOT's current implied market heat rate of about 9,000 Btu/kWh, as shown in Table 1 (ERCOT Northern Hub Implied Market Heat Rate).[15] Therefore, at a macro level, generation from the RICE units will be more efficient and thus consume less fossil fuel than the average generator that sells into the ERCOT market.[16]

**Table 1: ERCOT Northern Hub Implied Market Heat Rate**

| Year | ERCOT Northern Hub Implied Market Heat Rate (Btu/kWh) |
|---|---|
| 2011 | 10,200 |
| 2012 | 9,376 |
| 2013 | 8,216 |
| 2014 | 8,451 |
| 2015 | 9,080 |
| Average | 9,065 |

[13] The analysis performed simulates use of Wärtsilä 50SG engines.

[14] Regulation Up and Down services respond every four seconds, either increasing or decreasing as necessary to fill the gap between energy produced by generators and actual system load. Responsive and Non-Spinning Reserves are to protect the system against unforeseen contingencies, such as unplanned generator, transmission, and substation outages, and ensure that the system frequency can quickly be restored to appropriate levels following the contingency event. Responsive Reserves must be provided within ten minutes while Non-spinning Reserves can be provided from slower responding generation capacity within 30 minutes.

[15] Table 1 (ERCOT Northern Hub Implied Market Heat Rate) was calculated using historical ERCOT Northern Hub Real-Time prices and daily Henry Hub natural gas prices.

[16] The marginal fuel type in the ERCOT market is predominantly natural gas. Typically, approximately 90% of the variable cost of a thermal generator is fuel cost and therefore variable costs will be correlated highly with heat rates of the thermal generators. Under this assumption, when ERCOT dispatches the RICE units, they are reducing fossil fuel usage by displacing higher cost generators that will likely burn more fuel.

Environmentally, the RICE units use minimal water (approximately 12 gallons a week) and have very low air emission rates compared to other thermal generators.[17] Detailed characteristics of the RICE units are included in Appendix-A (Denton Energy Center Characteristics).

While the current RDP with DEC will likely achieve the goals discussed earlier, the 225 MW DEC does require a $220 million investment, which DME plans to finance through municipal bonds. The schedule assumes DEC to be constructed during the first two years and start commercial operation in the third year.

We address two questions: 1) Can the City of Denton go to 70% renewables and maintain DME's competitive retail rates; and 2) is the RDP a good way to achieve the 70% goal?.

### 3. Timing of Decision

The timing of the RDP decision cannot be delayed. The Gibbons Creek power sales agreement will expire in the next few years and DME must decide soon if they want to extend it. Denton's current load growth (at approximately 2% per year) requires DME to secure more energy sources in the immediate to near future, either by purchasing from the market, signing PPAs, or developing its own resources. Options include extending the Gibbons Creek power sales agreement, building the DEC, and signing new PPAs. These options will take time to finalize and implement and will be directly impacted by the decisions regarding the DEC investment. Market conditions are favorable —including the aforementioned opportunities to secure low cost renewable PPAs and the current exchange rate between Euros and US dollars for purchasing the RICE units—indicates a prompt decision to be beneficial.

The choice that the City of Denton must make is whether to pursue the RDP, or remain as today. The next section discusses the benefits and costs associated with each of these options. We then discuss alternatives for achieving 70% renewables.

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[17] Emissions accounted for 30% of the decision criteria for the Denton Energy Center RFP issued by DME.

# III. Assessing the Economic Feasibility of the Renewable Denton Plan

The economic feasibility of DME pursuing the RDP with the DEC can be assessed by comparing the cost of serving the DME load against the anticipated future system if that system were to remain at "Status Quo" (as of today). This section compares the various options available to DME today, then quantifies the comparative net benefits where possible using a production simulation model. We will then address the various options that may be available for pursuing the RDP. Finally, we will discuss qualitative assessments of these options.

## A. The Renewable Denton Plan vs Status Quo

As discussed earlier, the RDP goal is to increase renewable penetration and reduce fossil fuel usage and associated air emissions while maintaining both financial and physical reliability, and without increasing customer costs. DME believes that the RDP does exactly this. The first question is how RDP compares to the Status Quo. To assess this question, we compared the costs and benefits of the Status Quo with the RDP.

### 1. Potential Benefits of RDP and DEC

The renewable PPAs allow DME to provide power at a likely lower cost than the Status Quo while simultaneously reducing fossil fuel usage and associated air emissions. The DEC allows DME to hedge market and operational risks that emerge from a large reliance on renewable resources with variable outputs.

Power from renewable resources is variable. The DEC can provide a back-up option for power and firm this variability. The alternative is to purchase it from the ERCOT energy and ancillary service markets or sign contracts that provide services similar to what the DEC would provide. This back-up option is beneficial in both the scheduling timeframe (Day-Ahead when one decides on unit commitment and the amount to purchase from the market etc.) and in the operational timeframe (Real-Time when one faces the consequence of forecast deviations, including those for renewable resources). It is particularly valuable when production from wind resources is over-forecasted in the Day-Ahead timeframe (i.e. actual production from wind resources in Real-Time is less than what was forecasted Day-Ahead) when DME makes irreversible (in general) decisions for the next day operation. Over-forecast of wind often results in price spikes (because the lack of generation in Real-Time requires ERCOT to call on expensive units) and purchasing from the ERCOT Real-Time energy market under such conditions can be expensive. In addition to the market prices they may be subject to Reliability Unit Commitment

charges. Forecast deviation on solar resources will have similar effects. DEC can hedge such risks because the RICE units effectively provide a "firming" service to the renewable PPAs. This back-up option also allows DME to lower the current NextEra wind PPA cost. The NextEra wind PPA is firmed and NextEra provides a constant amount of power regardless of the wind conditions. However, if the firming through the PPA is no longer needed, the PPA price can be reduced by approximately 40%.

In addition, owning and operating the flexible RICE units can provide DME with the following additional benefits:

1. Potential Revenue Streams

   DEC can sell energy and ancillary services to the ERCOT market. It is important to note that when the RICE units are generating (i.e., dispatched by ERCOT), they are likely reducing both the ERCOT-wide fossil fuel consumption (they have lower heat rates, otherwise they would not be dispatched) and air emissions (they have a lower emission rate than most thermal generators) on a macro level (looking at the entire ERCOT generation portfolio), thereby augmenting the RDP's goals.

2. Day-Ahead and Real-Time Market Optimization

   Historical observations of the ERCOT market indicate that Day-Ahead energy prices are higher than Real-Time energy prices. Figure 1 (Day-Ahead and Real-Time Price Spreads for All-Hours) shows the monthly average of historical differences between Day-Ahead and Real-Time prices. As this Figure shows, the price difference for all hours averaged around $2/MWh. However, the Real-Time price is much more volatile than the Day-Ahead. Figure 2 (Day-Ahead and Real-Time Positive Price Spreads) shows the average price difference between Day-Ahead and Real-Time when the difference is positive, i.e., when the Real-Time price is higher (teal dotted line) and when the Day-Ahead price is higher (dark blue line). These two Figures show that while on average the Day-Ahead prices are higher than Real-Time, when the Real-Time prices do become higher than Day-Ahead, the magnitude of the difference becomes much larger because the Real-Time prices are much more volatile. To hedge against this high Real-Time price volatility (such as those caused by wind forecast deviation discussed above), risk-averse entities including DME usually secure most of the power in the Day-Ahead market. The DEC will allow DME to increase the purchase from the generally lower-priced but more volatile Real-Time energy market because the DEC provides insurance against any Real-Time energy

market price spikes. As an illustrative estimate, if DME procures 10% of its energy needs for 2019 (estimated annual energy is around 1,620,000 MWh) from the market and most of that is from the Day-Ahead market, there can be over $300,000 in potential savings per year (assuming $2/MWh difference in Day-Ahead and Real-Time market prices) by optimizing the Day-Ahead and Real-Time procurement. In reality, the potential savings will be larger because the $2/MWh difference is the average differences for all hours, including hours when the Real-Time prices are higher than Day-Ahead.

**Figure 1: Day-Ahead and Real-Time Price Spreads for All-Hours**

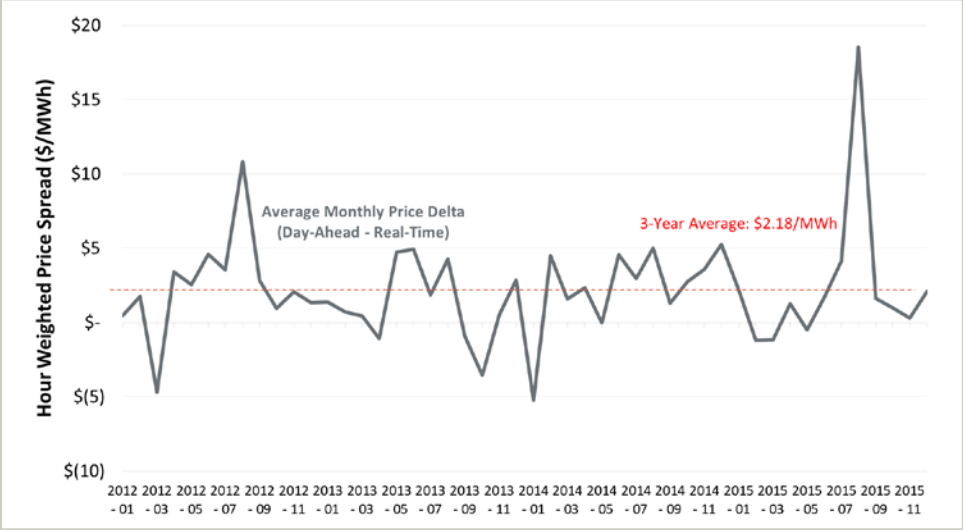
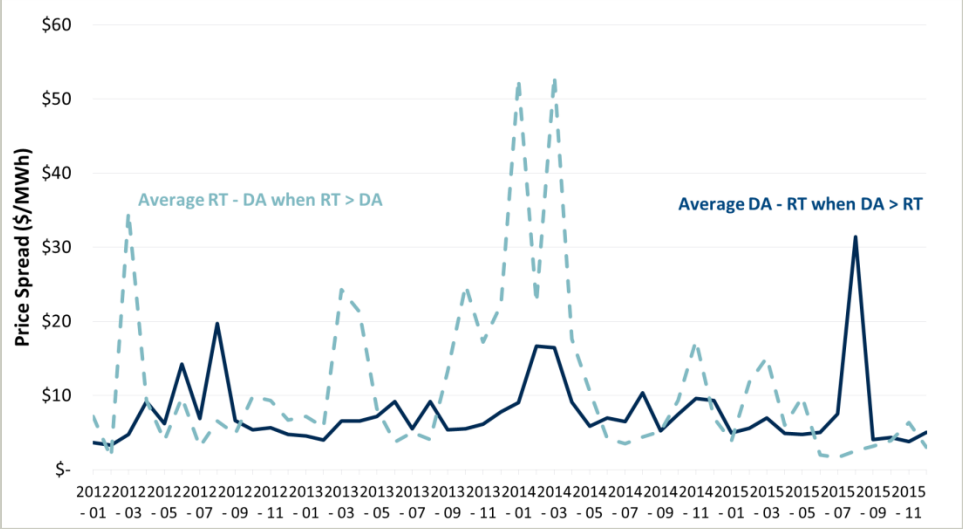



**Figure 2: Day-Ahead and Real-Time Positive Price Spreads**



These potential benefits are quantified in the following sections and compared with the $220 million investment that is not needed in the Status Quo. Therefore, we compare the net economic benefits of the RDP including these benefits against the Status Quo.

## 2. Method for Quantifying the Comparative Economic Benefits

The first step in assessing the comparative economic benefits of RDP is to define the Status Quo. With the Gibbons Creek power sales agreement scheduled to expire in 2018 or later, there are potentially two Status Quo views in 2019—one that includes Gibbons Creek as part of the generation portfolio, and another without Gibbons Creek. Therefore, we looked at the following three *Strategies*:

- *SQ-TMPA Strategy*: This Strategy represents Status Quo (same as today) with Gibbons Creek (TMPA) continuing as part of the portfolio. No additional renewable PPAs are signed (other than the solar PPA that starts in 2019).
- *SQ-Market Strategy*: This is the same strategy as *SQ-TMPA Strategy* but without Gibbons Creek as part of the portfolio. It relies more heavily on purchases from the ERCOT market.
- *RDP-DEC Strategy:* This Strategy represents RDP with various renewable PPAs enabled by the DEC that are signed to achieve the 70% renewable target.

DME prepared an Excel-based model to analyze these *Strategies*. While the Excel-based model produced similar results and was analytically sound, it was limited in its ability to optimize the DEC's operations. Therefore, we felt it important to perform an independent assessment of the economic benefits of the three *Strategies* using production simulation tools. This assessment was performed in the following two-steps.

1. Prepare a forward price curve for power.
2. Assess the cost of serving DME customers under the different *Strategies*.

Details of each step are discussed next.

### *Prepare a forward price curve for power*

In the ERCOT market power prices are highly correlated to natural gas prices. For this assessment, we created two scenarios using the natural gas price forecast from the 2016 ERCOT Long-Term System Assessment ("LTSA") report. The first scenario, the Base Scenario, uses the LTSA's current trend forecast that represents a reasonable view of future natural gas prices. The second scenario, the Low Gas Scenario, uses the LTSA's low forecast. In the Low Gas Scenario,

the natural gas price does not change from today's price in real terms (in other words prices only grow by future inflation).

Figure 3 (Historical and Forecasted Natural Gas Prices) below shows these two natural gas price forecasts. Figure 4 (Forward Power Price Curves) shows the corresponding power price forecasts developed using these natural gas prices for this assessment. The method and tools used for developing the forward price curves are discussed in Appendix-B (Analyses Assumptions and Methods).

**Figure 3: Historical and Forecasted Natural Gas Prices**

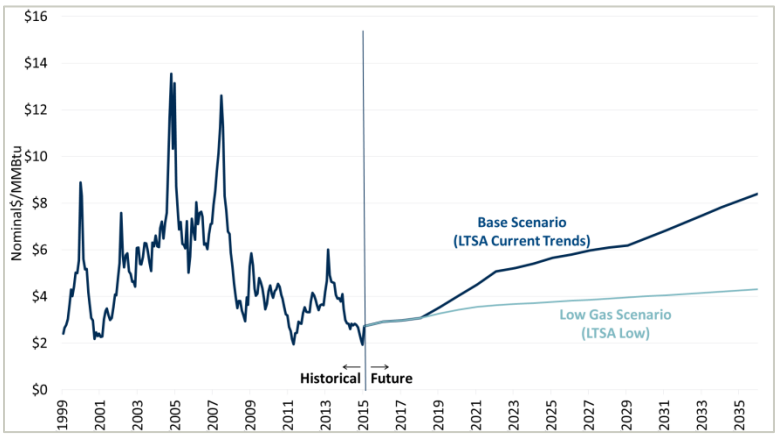
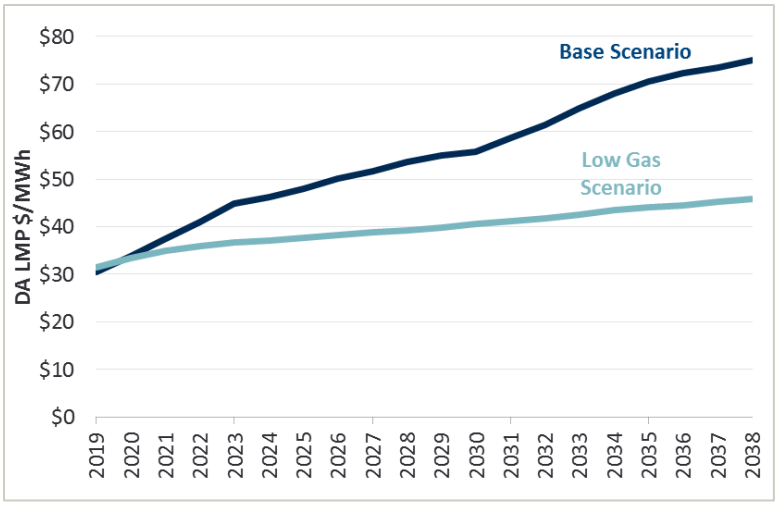



**Figure 4: Forward Power Prices Curves**



### *Assess the cost of serving energy under the different options*

The second step is to use the forward price curves and existing/future PPAs to assess and compare the cost of serving energy under the three *Strategies* listed above (*SQ-TMPA, SQ-Market,* and *RDP-DEC Strategies*).

To address varying system conditions, this two-step analysis is repeated under varying assumptions derived from historical (2012 through 2015) market observations. Based on historical prices from these four years, we prepared four distinct hourly Day-Ahead and Real-Time energy price forecasts. Price forecasts for ancillary services (RRS, NSRS, RUS, and RDS) were also developed, using price ratios of each ancillary service and energy from the historical years. Differences in the prices developed reflect variations in market conditions, load, wind and solar output, generator and transmission outages, and other various factors that a deterministic model cannot easily capture. Table 2 (Historical Energy and Ancillary Service Prices) below shows the annual average price for energy and ancillary services and the ratios derived (and applied to energy price forecasts). As a general trend, using later year profiles (2014 or 2015) resulted in a higher ancillary service to energy price ratio.

**Table 2: Historical Energy and Ancillary Service Prices**

| Average Prices | | Profile Years | | | |
|---|---|---|---|---|---|
| | | 2012 | 2013 | 2014 | 2015 |
| Historical Energy Prices | Day-Ahead | $ 27.58 | $ 31.86 | $ 38.13 | $ 25.34 |
| | Real-Time | $ 25.19 | $ 30.45 | $ 36.26 | $ 22.87 |
| Historical Ancillary Services Prices | RRS | $ 8.72 | $ 8.13 | $ 11.27 | $ 9.96 |
| | NSRS | $ 3.63 | $ 3.43 | $ 5.18 | $ 6.35 |
| | RUS | $ 4.23 | $ 4.89 | $ 9.74 | $ 5.35 |
| | RDS | $ 8.94 | $ 8.57 | $ 12.43 | $ 10.25 |
| Derived Ratio of Ancillary Services and Energy Price | RRS | 31.6% | 25.5% | 29.6% | 39.3% |
| | NSRS | 13.2% | 10.8% | 13.6% | 25.1% |
| | RUS | 15.3% | 15.3% | 25.5% | 21.1% |
| | RDS | 32.4% | 26.9% | 32.6% | 40.4% |

We also varied the RICE units' capability to provide regulation. The RICE units are technically capable of providing regulation up to its full capacity (i.e., 15 MW per unit) when

synchronized.[18] However, today's ERCOT regulation market size is only about 600 MW. Allowing all 12 RICE units to provide regulation up to their full capability would potentially result in a combined 180 MW of capability, and can result in market saturation where prices fall. To address this concern, we modeled the RICE units with three varying capabilities of providing regulation services (i.e., 100% Regulation Capability, 20% Regulation Capability, and 0% Regulation Capability) and used the 20% Regulation Capability as our default assumption.

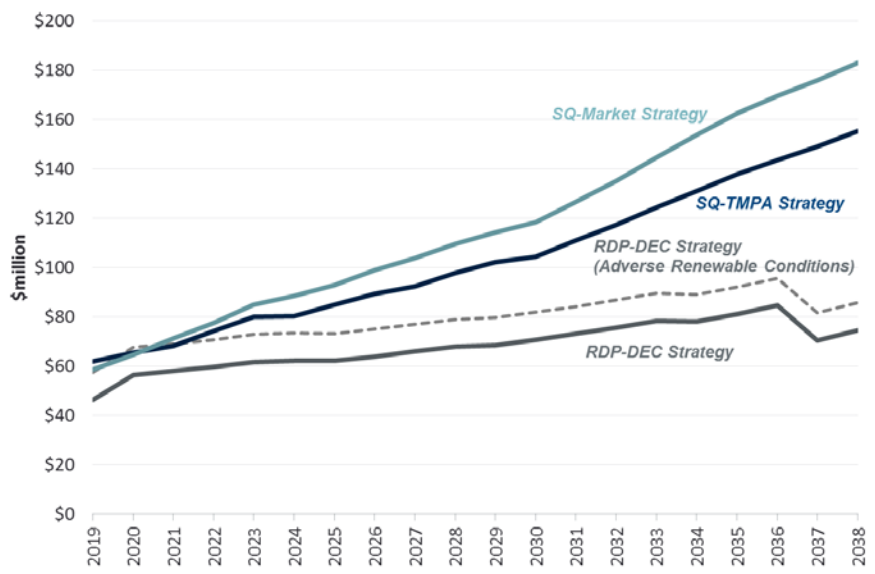
Detailed methodology and assumptions used for this two-step analysis are also discussed in Appendix-B (Analyses Assumptions and Methods). Values presented in this report are the average values of the four historical profiles and assumes 20% Regulation Capability for the RICE units. We indicate the potential range of the results presented by observing all the different sensitivities (profile years and RICE unit characteristics) later.

### 3. Quantified Comparative Economic Benefits

By using the aforementioned approach, we observed that the *RDP-DEC Strategy* to cost less to the DME customers than the *SQ-TMPA Strategy* or *SQ-Market Strategy*. Figure 5 (Base Scenario Cost Comparison) and Figure 6 (Low Gas Scenario Cost Comparison) below compares the net cost of serving energy among the three *Strategies* for the two scenarios (Base Scenario and Low Gas Scenario) discussed above.

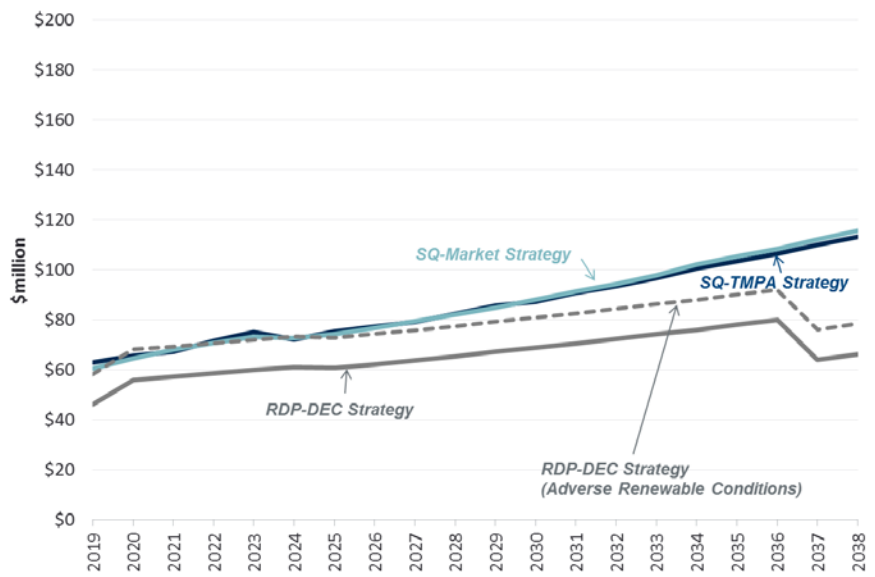
[18] The minimum generation level of the RICE units is 20% of its full capacity of 18.75 MW, or 3.75 MW. Therefore the operational range where a RICE unit can provide regulation would be between 3.75 MW and 18.75 MW, allowing each unit to provide up to 15 MW of regulation.

**Figure 5: Base Scenario Cost Comparison**




The adverse renewable conditions shown here illustrate the downside potential for years with lower production from renewable resources. These conditions may occur sporadically and would not continue over the 20 year period analyzed here.

**Figure 6: Low Gas Scenario Cost Comparison**




The adverse renewable conditions shown here illustrate the downside potential for years with lower production from renewable resources. These conditions may occur sporadically and would not continue over the 20 year period analyzed here.

As these figures show, the *RDP-DEC Strategy* (solid grey line) shows the lowest cost compared to the *SQ-TMPA Strategy (dark blue line)* and *SQ-Market Strategy (teal line)* in both Scenarios. The comparative benefits grow even larger after 2036 when the DEC debt is paid off. In the Base Scenario, the RDP-DEC Strategy costs approximately $975 million less than the SQ-Market

Strategy over 20 years and $750 million less than the SQ-TMPA Strategy. The Low Gas Scenario shows a much smaller difference of approximately $410 million between the *RDP-DEC Strategy* and either of the *Status Quo Strategies*. Note that the impact of extending the Gibbons Creek power sales agreement diminishes with lower gas prices. The Low Gas Scenario, which assumes the natural gas price to be roughly constant at today's level in real dollar terms, represents a reasonable "down-side case" Scenario for the DEC investment. These results show that even at current natural gas prices the *RDP-DEC Strategy* will reduce DME's costs. Furthermore, the comparative benefit of the *RDP-DEC Strategy* increases with higher gas prices indicating that this *Strategy* effectively provides a hedge against rising gas prices. This is because the *RDP-DEC Strategy* utilizes fixed price renewable PPAs while the cost for the two *Status Quo Strategies* that rely heavily on the ERCOT market increase with natural gas prices.

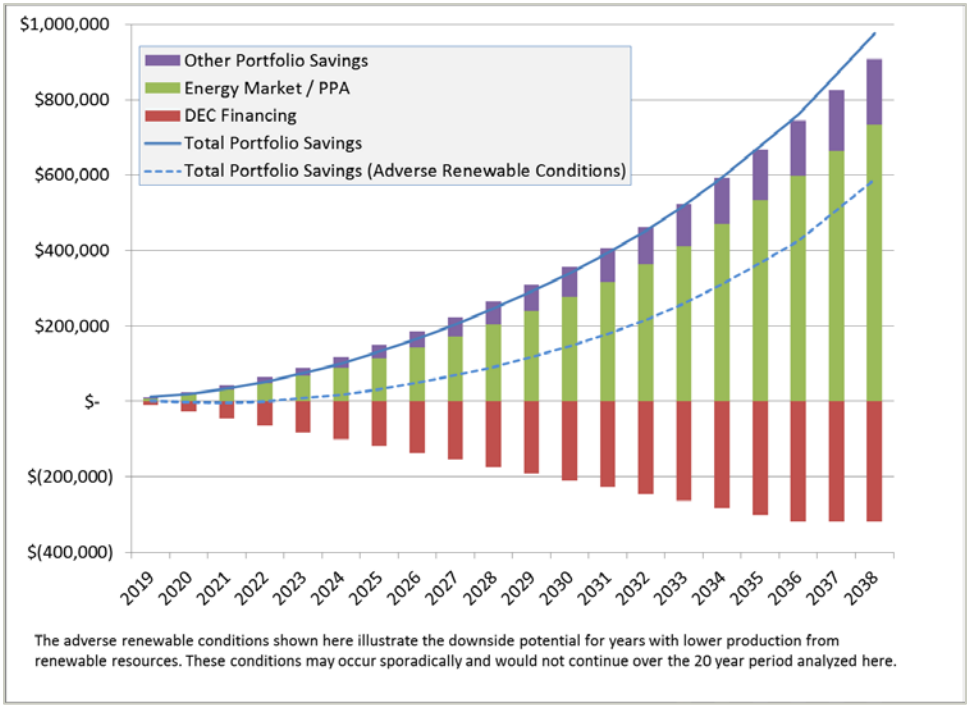
Both the renewable PPAs and the DEC are integral parts of the RDP. The DEC physically hedges the variability brought by the increased renewable resources and is therefore necessary to implement the *RDP-DEC Strategy*. In addition, the DEC can offset DME's cost through market sales. Under current market protocols, DEC will sell energy and ancillary services to the ERCOT market and DME buys back what is needed to serve its load. Any net revenue from these transactions (i.e., the difference between what DEC sold and what DME bought back, or "net-sales") will help the *RDP-DEC Strategy* further offset their cost. The amount DME needs will depend on the renewable resource profile that varies year to year.

In the future, there may be years with adverse renewable conditions when production from renewable resources are lower or the variability is higher. Under such conditions, DME may need to buy back more power from ERCOT and the net revenue of the net-sales may potentially drop to zero in some hours. It is important to note that such adverse conditions occur sporadically and would not be sustained for a longer period, such as over a full year. The dotted grey lines in Figure 5 (Base Scenario Cost Comparison) and Figure 6 (Low Gas Scenario Cost Comparison) represents extreme cases with adverse renewable conditions that lead to zero profits from net-sales. It should be viewed as the potential down-side case that may occur in any given year, but not through the entire 20 year period. Even under the extremely unlikely future where these adverse conditions are sustained, the *RDP-DEC Strategy* costs approximately $710 million less than the *SQ-Market Strategy* over 20 years and $490 million less than the *SQ-TMPA Strategy* under the Base Scenario. In the Low Gas Scenario, the *RDP-DEC Strategy* costs approximately $170 million less over 20 years than either *Status Quo Strategies*. The actual

comparative benefit will vary by year and likely lie closer to the solid grey lines of Figure 5 (Base Scenario Cost Comparison) and Figure 6 (Low Gas Scenario Cost Comparison).

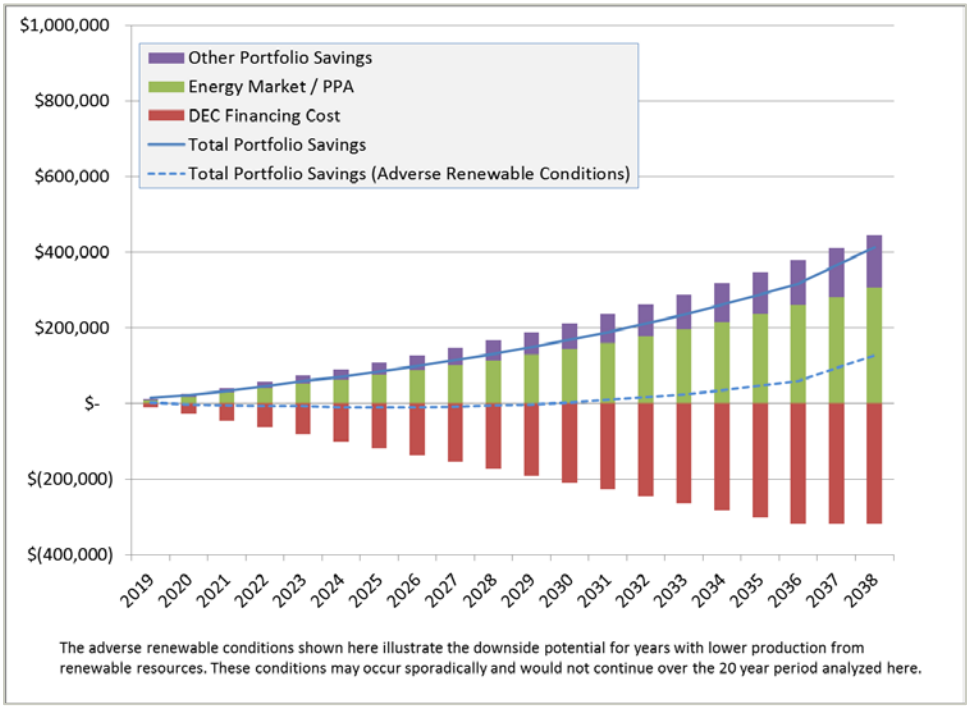
Figure 7 (Base Scenario Cumulative Cost and Savings ($000) Comparison) and Figure 8 (Low Gas Scenario Cumulative Cost and Savings ($000) Comparison) compare the *RDP-DEC Strategy* to the *SQ-Market Strategy* and break down the components of the cumulative savings of the *RDP-DEC Strategy*.[19]

**Figure 7: Base Scenario Cumulative Cost and Savings ($000) Comparison**




[19] Under the Base Scenario, the *SQ-Market Strategy* shows higher costs than the *SQ-TMPA Strategy*. The comparative benefit of the *SQ-TMPA Strategy* over the *SQ-Market Strategy* is in excess of $230 million over twenty years. However, it is important to note that the *SQ-TMPA Strategy* cost may be higher than what is represented here. Given the uncertainty surrounding coal assets, the remainder of this section will compare the *RDP-DEC Strategy* to the *SQ-Market Strategy*. An example of such uncertainty is discussed in Appendix-C (Uncertainty for the *SQ-TMPA Strategy*).

**Figure 8: Low Gas Scenario Cumulative Cost and Savings ($000) Comparison**




These figures show that in both scenarios, Energy Market/PPA cost (the green portion of the bars) is the dominant contributor to the cost savings. Other portfolio savings enabled by the DEC include avoided REC purchases and optimization of DME's purchases in the Day-Ahead and Real-Time markets. Details of REC savings are included in Appendix-B (Analyses Assumptions and Methods).

Under the Base Scenario, the Total Portfolio Savings (solid blue line) is higher than the combined savings of Energy Market/PPA and Other Portfolio Savings because the net-sales offsets are larger than the DEC's Financing Costs (the red portions of the bars in the negative direction). The Low Gas Scenario shows similar observations, although the net-sales offset does not fully cover the DEC Financing Cost. Under adverse renewable conditions, the Total Portfolio Savings (dotted blue line) becomes lower but the cumulative value is still positive and covers the DEC Financing Costs (the red portions of the bars in the negative direction) in both the Base and Low Gas Scenarios. Note that this analysis only extends 20 years. The DEC is likely to be in service and providing additional benefits to DME customers well beyond that point in time.

Figure 9 (Base Scenario DEC Market Sales ($000) by Product) and Figure 10 (Low Gas Scenario DEC Market Sales ($000) by Product) show the revenues and profits from selling energy and ancillary services to the ERCOT market, and associated operating costs of DEC.

**Figure 9: Base Scenario DEC Market Sales ($000) by Product**

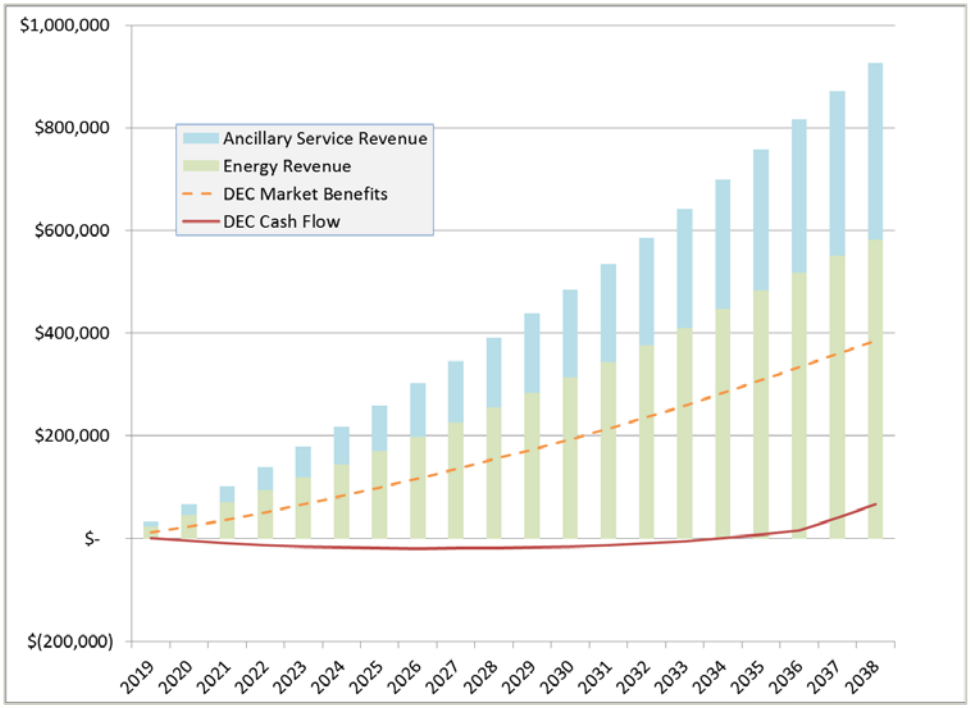
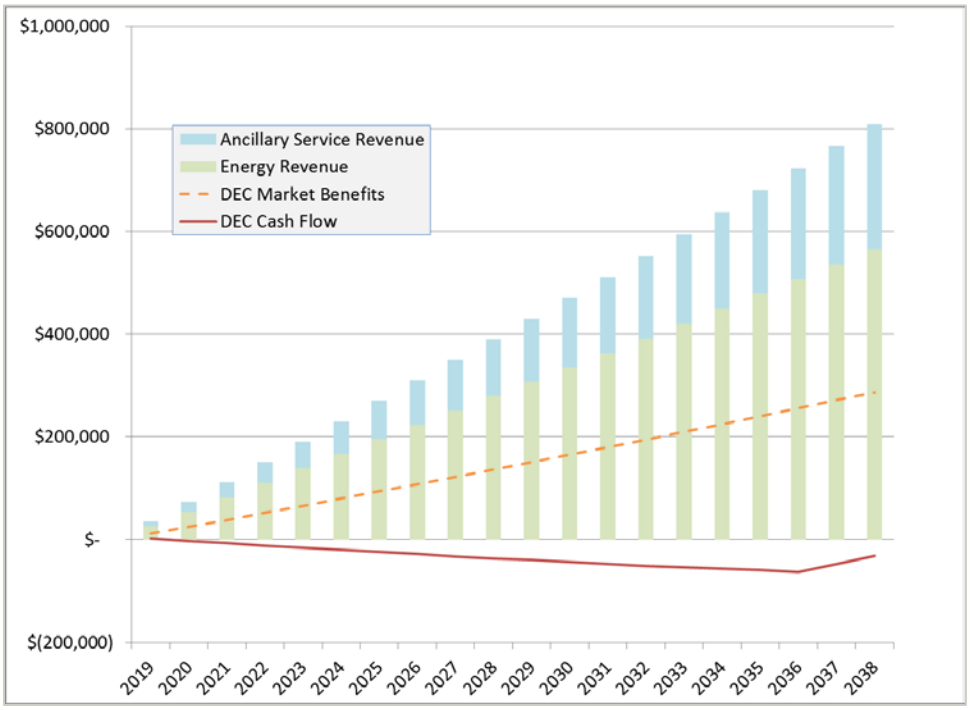



**Figure 10: Low Gas Scenario DEC Market Sales ($000) by Product**




Ancillary services include RRS, NSRS, RUS, RDS, and Black-Start services. Energy, RRS, NSRS, RUS, and RDS were optimized using the production simulation. Energy revenues (light green bars) include energy sold Day-Ahead and any conversion from NSRS converted to Energy in

Real-Time when the market price is higher than $75/MWh. The dotted orange line shows the combined profit from both energy (light green bar) and ancillary services (light blue bar) after subtracting DEC operating costs, which include fuel and operating and maintenance costs. The dotted orange line of Figure 9 (Base Scenario DEC Market Sales ($000) by Product) would equal the difference between the dotted blue line and solid blue line of Figure 7 (Base Scenario Cumulative Cost and Savings ($000) Comparison). Similarly, the dotted orange line of Figure 10 (Low Gas Scenario DEC Market Sales ($000) by Product) would equal the difference between the dotted blue line and solid blue line of Figure 8 (Low Gas Scenario Cumulative Cost and Savings ($000) Comparison).

Finally, the red line compares the net revenue (dotted orange line) against the principal and interest that DME must pay for the DEC. Under the Base Scenario, the cumulative value becomes positive indicating that DEC can show a net positive cash flow even as a standalone plant with the potential net-sales. This is not the case for the Low Gas Scenario, as we observed in Figure 8 (Low Gas Scenario Cumulative Cost and Savings ($000) Comparison).

The benefits discussed above are for the average conditions for our default assumptions. Table 3 (Base Scenario Total Portfolio Benefits ($000) by Profile Year) and Table 4 (Low Gas Scenario Total Portfolio Benefits ($000) by Profile Year) below show the potential range of the comparative benefits of the *RDP-DEC Strategy* (compared to the *SQ-Market Strategy*) with net-sales. Assuming the historical four years' conditions, the comparative benefit of the *RDP-DEC Strategy* portfolio can vary by 10% or so in the Base Scenario and by nearly 18% in the Low Gas Scenario. The maximum downside variations in both Scenarios are about 75% of the potential upside. If more weight is put on recent years, estimated benefits become larger. Regardless, the observation that the *RDP-DEC Strategy* is the lowest cost option for DME remains intact.

## Table 3: Base Scenario Total Portfolio Benefits ($000) by Profile Year

| Year | Profile Year | | | | |
|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | Average |
| 2019 | $ 11,019 | $ 10,166 | $ 12,876 | $ 15,234 | $ 12,324 |
| 2020 | $ 6,589 | $ 5,991 | $ 8,908 | $ 11,281 | $ 8,192 |
| 2021 | $ 11,271 | $ 10,767 | $ 13,628 | $ 16,831 | $ 13,124 |
| 2022 | $ 15,662 | $ 15,258 | $ 18,283 | $ 21,804 | $ 17,752 |
| 2023 | $ 21,136 | $ 20,450 | $ 23,910 | $ 27,720 | $ 23,304 |
| 2024 | $ 24,050 | $ 23,364 | $ 27,119 | $ 30,686 | $ 26,305 |
| 2025 | $ 28,229 | $ 27,754 | $ 31,284 | $ 35,306 | $ 30,643 |
| 2026 | $ 32,540 | $ 31,955 | $ 35,571 | $ 39,859 | $ 34,981 |
| 2027 | $ 35,485 | $ 34,813 | $ 38,640 | $ 43,070 | $ 38,002 |
| 2028 | $ 39,128 | $ 38,238 | $ 42,447 | $ 46,667 | $ 41,620 |
| 2029 | $ 42,985 | $ 42,297 | $ 46,423 | $ 50,991 | $ 45,674 |
| 2030 | $ 44,810 | $ 44,116 | $ 48,364 | $ 52,983 | $ 47,568 |
| 2031 | $ 50,562 | $ 49,725 | $ 54,533 | $ 59,201 | $ 53,505 |
| 2032 | $ 56,295 | $ 55,168 | $ 60,674 | $ 64,978 | $ 59,279 |
| 2033 | $ 62,698 | $ 62,018 | $ 67,382 | $ 72,394 | $ 66,123 |
| 2034 | $ 71,927 | $ 71,539 | $ 77,288 | $ 82,395 | $ 75,787 |
| 2035 | $ 78,074 | $ 77,049 | $ 82,819 | $ 88,174 | $ 81,529 |
| 2036 | $ 81,595 | $ 80,093 | $ 86,630 | $ 91,628 | $ 84,986 |
| 2037 | $ 101,763 | $ 100,688 | $ 106,486 | $ 112,357 | $ 105,323 |
| 2038 | $ 105,014 | $ 103,948 | $ 109,630 | $ 115,758 | $ 108,587 |
| Total | $ 920,834 | $ 905,396 | $ 992,894 | $ 1,079,317 | $ 974,610 |
| Dev. from Avg. | -5.5% | -7.1% | 1.9% | 10.7% | 0.0% |

## Table 4: Low Gas Scenario Total Portfolio Benefits ($000) by Profile Year

| Year | Profile Year | | | | |
|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | Average |
| 2019 | $ 13,031 | $ 12,186 | $ 14,768 | $ 16,981 | $ 14,242 |
| 2020 | $ 7,293 | $ 6,304 | $ 9,297 | $ 11,344 | $ 8,559 |
| 2021 | $ 9,382 | $ 8,409 | $ 11,348 | $ 13,807 | $ 10,737 |
| 2022 | $ 10,807 | $ 9,801 | $ 12,825 | $ 15,571 | $ 12,251 |
| 2023 | $ 11,718 | $ 10,668 | $ 13,780 | $ 16,597 | $ 13,191 |
| 2024 | $ 10,010 | $ 8,971 | $ 12,384 | $ 14,834 | $ 11,550 |
| 2025 | $ 12,050 | $ 11,089 | $ 14,268 | $ 17,110 | $ 13,629 |
| 2026 | $ 12,995 | $ 12,008 | $ 15,201 | $ 18,140 | $ 14,586 |
| 2027 | $ 14,149 | $ 13,158 | $ 16,354 | $ 19,371 | $ 15,758 |
| 2028 | $ 15,222 | $ 14,128 | $ 17,564 | $ 20,346 | $ 16,815 |
| 2029 | $ 15,804 | $ 14,963 | $ 18,222 | $ 21,305 | $ 17,573 |
| 2030 | $ 17,555 | $ 16,614 | $ 19,971 | $ 23,144 | $ 19,321 |
| 2031 | $ 19,025 | $ 18,043 | $ 21,456 | $ 24,676 | $ 20,800 |
| 2032 | $ 20,179 | $ 19,200 | $ 22,731 | $ 25,671 | $ 21,945 |
| 2033 | $ 21,756 | $ 20,835 | $ 24,268 | $ 27,565 | $ 23,606 |
| 2034 | $ 24,385 | $ 23,531 | $ 27,018 | $ 30,291 | $ 26,306 |
| 2035 | $ 25,368 | $ 24,540 | $ 28,059 | $ 31,407 | $ 27,343 |
| 2036 | $ 26,375 | $ 25,332 | $ 29,138 | $ 32,264 | $ 28,277 |
| 2037 | $ 46,189 | $ 45,248 | $ 48,782 | $ 52,411 | $ 48,157 |
| 2038 | $ 47,460 | $ 46,419 | $ 50,016 | $ 53,656 | $ 49,388 |
| Total | $ 380,753 | $ 361,447 | $ 427,451 | $ 486,489 | $ 414,035 |
| Dev. from Avg. | -8.0% | -12.7% | 3.2% | 17.5% | 0.0% |

Table 5 (Base Scenario DEC Market Sales and Cash Flow ($000) by Profile Year) and Table 6 (Low Gas Scenario DEC Market Sales and Cash Flow ($000) by Profile Year) below show the potential range of the DEC cash flow of the *RDP-DEC Strategy* (compared to the *SQ-Market Strategy*). The red lines in Figure 9 (Base Gas Scenario DEC Market Sales ($000) by Product) and Figure 10 (Low Gas Scenario DEC Market Sales ($000) by Product) show the average numbers of the last column. Under the Base Scenario the cash flow for DEC including the DEC financing cost is mostly positive while the Low Gas Scenario shows a potential to drop by nearly $50 million from the average prediction. The total cash flow over 20 years can potentially drop to negative $80 million, although this is much smaller than the Portfolio-wide benefits. Furthermore, the cash flow does not include any scarcity payment, which is a feature of the ERCOT market that enables the market participants to collect their investment costs. Should such revenues be included, the net cash flow for DEC as a standalone would likely be positive for both the Base and Low Gas Scenario. However, as previously mentioned, the DEC and the PPAs are complementary and the combined net benefits are estimated in the $400 million to almost $1 billion range, depending on gas prices.

**Table 5: Base Scenario DEC Market Sales and Cash Flow ($000) by Profile Year**

| Year | Profile Year | | | | |
|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | Average |
| 2019 | $ 216 | $ (210) | $ 2,602 | $ 4,780 | $ 1,847 |
| 2020 | $ (8,088) | $ (8,122) | $ (5,187) | $ (2,818) | $ (6,054) |
| 2021 | $ (7,178) | $ (7,098) | $ (4,132) | $ (1,148) | $ (4,889) |
| 2022 | $ (6,399) | $ (6,132) | $ (2,997) | $ 288 | $ (3,810) |
| 2023 | $ (5,197) | $ (5,106) | $ (1,528) | $ 2,030 | $ (2,450) |
| 2024 | $ (4,830) | $ (4,769) | $ (1,017) | $ 2,634 | $ (1,995) |
| 2025 | $ (4,377) | $ (4,097) | $ (470) | $ 3,382 | $ (1,390) |
| 2026 | $ (3,553) | $ (3,298) | $ 408 | $ 4,526 | $ (479) |
| 2027 | $ (3,121) | $ (2,887) | $ 1,027 | $ 5,283 | $ 75 |
| 2028 | $ (2,563) | $ (2,384) | $ 1,803 | $ 6,126 | $ 745 |
| 2029 | $ (2,094) | $ (1,968) | $ 2,220 | $ 6,720 | $ 1,220 |
| 2030 | $ (2,084) | $ (1,937) | $ 2,365 | $ 6,920 | $ 1,316 |
| 2031 | $ (1,121) | $ (1,049) | $ 3,800 | $ 8,405 | $ 2,509 |
| 2032 | $ (336) | $ (326) | $ 5,061 | $ 9,673 | $ 3,518 |
| 2033 | $ 801 | $ 1,184 | $ 6,589 | $ 11,531 | $ 5,026 |
| 2034 | $ 1,593 | $ 1,997 | $ 7,755 | $ 12,996 | $ 6,085 |
| 2035 | $ 3,002 | $ 2,809 | $ 8,571 | $ 14,094 | $ 7,119 |
| 2036 | $ 3,004 | $ 2,569 | $ 8,814 | $ 14,531 | $ 7,229 |
| 2037 | $ 21,017 | $ 20,869 | $ 26,612 | $ 32,711 | $ 25,302 |
| 2038 | $ 21,211 | $ 21,149 | $ 26,778 | $ 33,119 | $ 25,564 |
| Total | $ (98) | $ 1,192 | $ 89,074 | $ 175,784 | $ 66,488 |
| Diff. from Avg. | $ (66,586) | $ (65,296) | $ 22,586 | $ 109,296 | $ - |

**Table 6: Low Gas Scenario DEC Market Sales and Cash Flow ($000) by Profile Year**

| Year | Profile Year | | | | |
|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | Average |
| 2019 | $ 1,255 | $ 925 | $ 3,613 | $ 5,623 | $ 2,854 |
| 2020 | $ (7,013) | $ (7,352) | $ (4,342) | $ (2,339) | $ (5,261) |
| 2021 | $ (6,541) | $ (6,876) | $ (3,828) | $ (1,595) | $ (4,710) |
| 2022 | $ (6,367) | $ (6,692) | $ (3,556) | $ (1,045) | $ (4,415) |
| 2023 | $ (6,321) | $ (6,646) | $ (3,422) | $ (845) | $ (4,309) |
| 2024 | $ (6,261) | $ (6,604) | $ (3,218) | $ (713) | $ (4,199) |
| 2025 | $ (6,251) | $ (6,556) | $ (3,280) | $ (605) | $ (4,173) |
| 2026 | $ (6,246) | $ (6,535) | $ (3,248) | $ (481) | $ (4,127) |
| 2027 | $ (6,164) | $ (6,407) | $ (3,120) | $ (279) | $ (3,992) |
| 2028 | $ (6,209) | $ (6,414) | $ (3,008) | $ (181) | $ (3,953) |
| 2029 | $ (6,185) | $ (6,352) | $ (3,015) | $ (27) | $ (3,895) |
| 2030 | $ (6,059) | $ (6,280) | $ (2,849) | $ 225 | $ (3,741) |
| 2031 | $ (5,899) | $ (6,116) | $ (2,631) | $ 487 | $ (3,540) |
| 2032 | $ (5,956) | $ (6,015) | $ (2,557) | $ 530 | $ (3,499) |
| 2033 | $ (5,719) | $ (5,785) | $ (2,299) | $ 899 | $ (3,226) |
| 2034 | $ (5,210) | $ (5,346) | $ (1,810) | $ 1,471 | $ (2,724) |
| 2035 | $ (5,362) | $ (5,425) | $ (1,867) | $ 1,489 | $ (2,791) |
| 2036 | $ (5,526) | $ (5,638) | $ (1,955) | $ 1,463 | $ (2,914) |
| 2037 | $ 12,847 | $ 12,764 | $ 16,322 | $ 19,970 | $ 15,476 |
| 2038 | $ 12,877 | $ 12,753 | $ 16,365 | $ 20,022 | $ 15,504 |
| Total | $ (76,311) | $ (80,595) | $ (13,703) | $ 44,070 | $ (31,635) |
| Diff. from Avg. | $ (44,676) | $ (48,960) | $ 17,932 | $ 75,704 | $ - |

Table 7 (DEC Market Sales and Cash Flow ($000) by RICE Regulation Capability) below shows the potential range of the DEC cash flows when we change the RICE units' regulation capability assumptions. Obviously being allowed to provide up to full capacity provides a more preferred cash flow. It should be noted that the impact to cash flow with the 0% Regulation Capacity is relatively small and the potential downside risk of the regulation market saturation is mitigated.

**Table 7: DEC Market Sales and Cash Flow ($000) by RICE Regulation Capability**

| Scenario | Regulation Capability | Profile Year | | | | |
|---|---|---|---|---|---|---|
| | | 2012 | 2013 | 2014 | 2015 | Average |
| Base Scenario | 0% | $ (8,163) | $ (6,906) | $ 78,751 | $ 163,265 | $ 56,737 |
| | 20% | $ (98) | $ 1,192 | $ 89,074 | $ 175,784 | $ 66,488 |
| | 100% | $ 47,520 | $ 49,002 | $ 150,026 | $ 249,701 | $ 124,062 |
| | Average | $ 13,086 | $ 14,430 | $ 105,950 | $ 196,250 | $ 82,429 |
| Low Gas Scenario | 0% | $ (82,445) | $ (86,621) | $ (21,423) | $ 34,886 | $ (38,901) |
| | 20% | $ (76,311) | $ (80,595) | $ (13,703) | $ 44,070 | $ (31,635) |
| | 100% | $ (40,089) | $ (45,014) | $ 31,880 | $ 98,291 | $ 11,267 |
| | Average | $ (66,282) | $ (70,744) | $ (1,082) | $ 59,082 | $ (19,756) |

Overall, the RICE units by themselves are roughly at break-even and if more weight is put on recent years, the cash flow could be estimated to become more positive. Regardless of the cash flow for DEC as a standalone, the *RDP-DEC Strategies* is the least cost option for DME with the renewable PPAs being the largest contributor, as shown in Figure 7 (Base Scenario Cumulative

Cost and Savings ($000) Comparison) and Figure 8 (Low Gas Scenario Cumulative Cost and Savings ($000) Comparison).

In addition to providing comparative economic benefits discussed above, the *RDP-DEC Strategy* reduces fossil fuel consumption and air emissions compared to the alternative of purchasing from the market. Table 8 (DEC Average Emissions) below compares the estimated RICE units' average emissions for the 20 year period (2019 – 2038) simulated by profile years (2012, 2013, 2014, and 2015) against the actual historical average of ERCOT for 2012 through 2015. The RICE units produce a significantly lower amount of air emission compared to purchasing from the ERCOT market. For example, if one RICE unit generates 33,000 MWh (approximately 20% capacity factor) in a given year, the corresponding reduction of air emission will be approximately 27 tons of $SO_2$, 15 tons of NOx, 10 tons of VOC, and over 3,300 tons of $CO_2$.

**Table 8: DEC Average Emissions**

| Year/Pollutant | 2012 | 2013 | 2014 | 2015 | Average |
|---|---|---|---|---|---|
| SO2 - RICE (lbs/MWh) | 0.005 | 0.005 | 0.005 | 0.005 | 0.005 |
| SO2 - ERCOT (lbs/MWh) | 2.000 | 1.800 | 1.800 | 1.600 | 1.800 |
| NOx - RICE (lbs/MWh) | 0.081 | 0.081 | 0.082 | 0.083 | 0.082 |
| NOx - ERCOT (lbs/MWh) | 1.100 | 1.000 | 1.100 | 1.000 | 1.050 |
| VOC - RICE (lbs/MWh) | 0.151 | 0.151 | 0.151 | 0.153 | 0.151 |
| VOC - ERCOT (lbs/MWh) | 0.891 | 0.782 | 0.864 | 0.843 | 0.845 |
| CO2 - RICE (lbs/MWh) | 1065.0 | 1065.1 | 1067.5 | 1082.0 | 1069.9 |
| CO2 - ERCOT (lbs/MWh) | N/A | 1299.0 | 1307.0 | 1279.0 | 1295.0 |

Finally, the comparative economic benefit values discussed above assumes that DEC enables the renewable PPAs. However, DEC does require a $220 million investment and that raises the question of alternatives to the DEC as part of the RDP.[20] The next section will discuss the necessity of DEC and potential alternatives to DEC and their indicative costs.

## B. Alternatives to The Denton Energy Center

The largest benefit of RDP is from the renewable PPAs enabled by the DEC. DEC hedges the largest risk DME faces with the RDP—the variability of renewable resources. Can the variability be hedged through alternative means, such as through contracts or by simply relying on the ERCOT market to provide the needed flexibility through Real-Time energy and ancillary

[20] There are risks associated with investing $220 million. Potential risks include short-term changes in exchange rates, and in municipal bond rates for financing the DECs. In the longer-term, DME faces the risk that market revenues may not be as high as projected.

services? We address these questions by first assessing the quantity of flexibility needed, then review the DEC and alternative options.

### 1. Flexibility Needed for the RDP and DEC Capabilities

Table 9 (Net Load Variability) below compares the estimated net load (i.e., load minus renewable generation) variability for 2019 between Status Quo and the RDP plan. This metric measures the combined effect of load variation and variable renewable output that DME must plan for. We see that adding the various renewable resources will increase the flexibility needs by more than three times.[21]

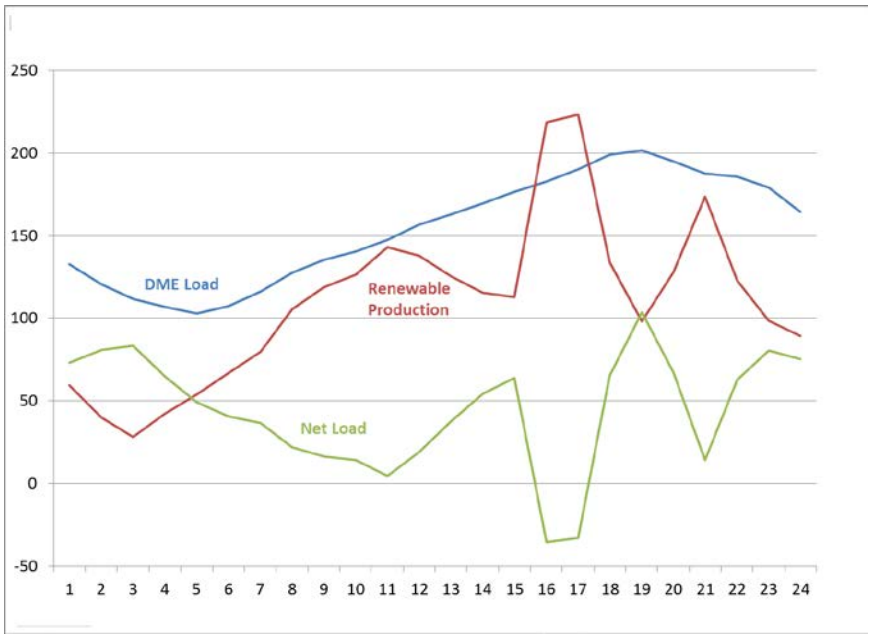
**Table 9: Net Load Variability**

| Assumed 2019 Conditions | Max Hour-to-Hour Net Load Variability (MW) |
|---|---|
| Status Quo | 39 |
| With RDP and Renewable PPAs | 123.2 |

Figure 11 (Hourly Net Load and Ramping Needs) below shows the estimated hourly DME load (blue line), production from the various renewable resources (red line), and DME's effective net load (green line) for May 21st, 2019.

[21] Table 9 (Net Load Variability) is calculated based on hourly profiles (estimated hourly load and production from renewable resources for 2019 provided by DME), and therefore the maximum net load variability on a minute-by-minute basis will likely be higher than what is shown here.

**Figure 11: Hourly Net Load and Ramping Needs**




This figure shows several contiguous hours of ramping needs, starting around hour ending 15 when production from renewable resources surge and net load drops to be negative, followed by around hour ending 17 when the production from renewable resources drop and the net load surges. These events are followed by another surge in production from renewable resources around hour ending 21. These ramping events, which in this example fluctuate by over 120 MW, need to be addressed by DME in both planning and operation as the generation portfolio changes to include large amounts of renewable resources. In the Day-Ahead timeframe, DME needs to schedule its operation for the next day based on this estimated net load (green line in Figure 11). In the Real-Time timeframe, DME needs to respond to any deviations of renewable production (red line in Figure 11) from its forecast and resulting change in net load (green line in Figure 11).

DEC's ability to provide power quickly when needed allows DME to address these flexibility needs. This Back-up Power option provides a physical hedge against the variability of the renewable resources in both the Day-Ahead and Real-Time. If DME wishes to secure all the flexibility needs as indicated in Table 9 (Net Load Variability) from DEC, DEC will need at least nine RICE units assuming the full range of flexibility is available from all units when needed. A

larger number of units may be preferable to account for the fact that some units' flexibility may be restricted because it is providing energy or experiencing outages at any given time.[22]

### 2. Alternative Options

There are several alternative options including seeking contracts or simply relying on the ERCOT market without any hedging.

Having no new hedge—an extreme alternative to DEC—ties the City of Denton and DME to Gibbons Creek—the primary source of generation flexibility today. However, the flexibility from Gibbons Creek is limited and is just enough to cover today's net load variability. In the future, when net load variability increases with increased renewable resources, having no hedge is not a viable option. It immediately exposes DME to the more volatile Real-Time market that can result in higher rates for DME customers. Figure 12 (ERCOT High Price Hours) below shows the prices for the top 5% hours from 2011 through 2014 and the frequency of high priced hours during these years.[23] The Operating Reserves Demand Curve implemented by ERCOT in June 2014 allows energy prices to jump up to $9,000/MWh at any given time when operating reserves become scarce, indicating that future energy prices may be more volatile than what was observed in the past.[24] Furthermore, DME's QSE status, which has produced savings of several million dollars a year ($13.5 million in its first year and less in the following years), can be jeopardized. ERCOT can revoke DME's QSE status if DME cannot meet operating criteria. If QSE status were lost, realizing the RDP goals (increasing renewables, reducing fossil fuel usage and air emissions, while not raising customer rates) would become more difficult and costlier because DME will have to pay an external QSE to manage the generation portfolio.

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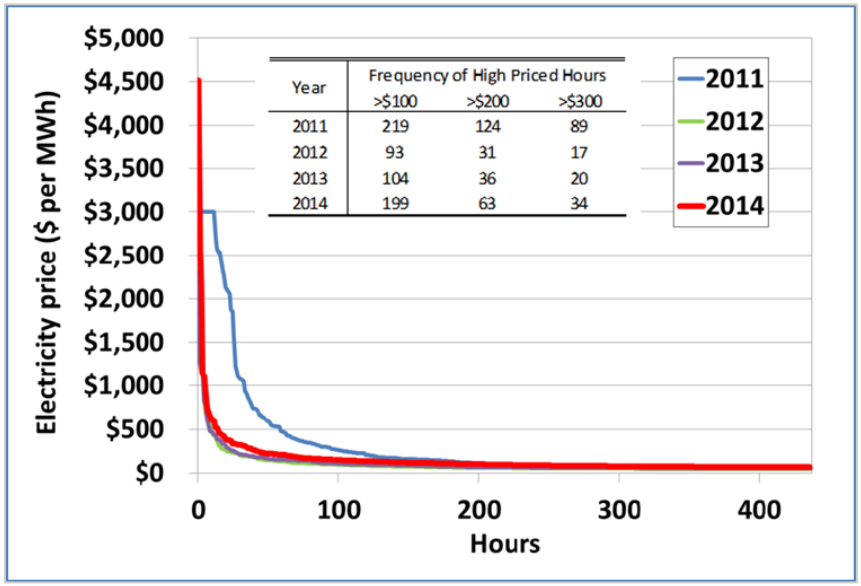
22 Each RICE unit can provide about 15 MW (80% of its 18.75 MW capacity) of flexibility. Although the net load variation can go up or down, we anticipate that downward variability can also be controlled by curtailing some renewable resources and therefore not need to double the flexible capacity.

23 With the exception of 2011—a year with extreme temperature variations —we see that the number of high priced hours increasing between 2012 and 2014, with 2014 being significantly larger than 2012 or 2013. Source: Potomac Economics, LTD., 2014_ERCOT_State_of_the_Market_Report, available at https://www.potomaceconomics.com/uploads/ercot_documents/2014_ERCOT_State_of_the_Market_Report.pdf

24 The ERCOT market is designed to have these high priced hours so generators can collect their investment costs. Without the high priced hours, the market may not be sustainable in the long-run.

**Figure 12: ERCOT High Price Hours**




| Year | Frequency of High Priced Hours | | |
|---|---|---|---|
| | >$100 | >$200 | >$300 |
| 2011 | 219 | 124 | 89 |
| 2012 | 93 | 31 | 17 |
| 2013 | 104 | 36 | 20 |
| 2014 | 199 | 63 | 34 |

Currently there are no real hedging mechanisms that are provided directly through the ERCOT markets and therefore the valuation of such hedge needs to rely on arms-length contracts of similar kinds. Firming contracts of renewable resources can potentially replace part of the hedging functions provided DEC. However, most firming contracts are for a fixed quantity and do not provide the load following capabilities provided by DEC. Only if the load served by DME is a fixed quantity for all hours (i.e., flat load), could firming contracts entirely replace the hedges provided by DEC.

DME has an ongoing contract with NextEra that firms the power from wind resources. This contract supplies DME with a constant quantity of power, regardless of the wind conditions. The premium for firming is approximately 66% higher than without firming (without firming is about 40% cheaper than with firming). This premium equates to the actual power procured for firming purposes to be priced above $60/MWh, illustrating how expensive the back-up power is. By comparison the marginal production cost of the RICE units are approximately between $25/MWh and $40/MWh today, depending on the operation level (full load is more efficient than at partial load) and natural gas prices (assumed to be in the $3/MMBtu–$4/MMBtu range today).

The NextEra contract indicated firming renewable power costs about 66% more (i.e., without firming the cost goes down by 40%). If we conservatively assume the future cost of firming

renewables to be about 40% more, the RDP energy from renewables per year would cost over $17 million per year for the firming premium alone.[25] Note that the NextEra type of firming contracts will not provide all of the additional benefits of owning the DEC discussed earlier. These benefits include the Day-Ahead/Real-Time optimization benefits ranging from nearly $3 million to over $10 million a year totaling $130 million in 20 years under the Base Scenario, the potential net revenues from the RICE units that is about half of the Day-Ahead/Real-Time optimization benefits over 20 years, and the reduction of emissions that are not monetized and discussed in Table 8 (DEC Average Emissions). The firming contracts will also be for a fixed quantity so DME will still need other means to follow the load, which changes hour by hour, and day by day. Therefore contracting for flexibility will likely cost much more than DEC.[26]

Other technologies can also provide hedging. Potential technologies include demand-side participation and storage. Demand-side resources can provide Regulation services (many thermal loads can provide this service) and have some capability to deal with net load uncertainty, but only limited capacity is available. The experience of many jurisdictions indicates that 10% of peak load would be a very large penetration level of demand-side resources. All demand-side resources programs reduce but only a few increase demand. Thus these resources could partially address net load ramp up events (output from generators need to increase rapidly to balance demand) but would have limited ability to address net load down events. Finally, there are many demand-side measures, each with different characteristics. Many are voluntary actions taken by participants.[27] DME would need direct control of these resources in order for them to provide the same services as the DEC and customers would have to be willing to give partial control of their

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[25] This is not extremely expensive. If the counter-party needs to provide firming through physical generators similar to the RICE units, the cost of providing firming would be in the $75/MWh to $90/MWh range. This assumes $25/MWh to $40/MWh variable cost ($3/MMBtu - $4/MMBtu natural gas prices with 8,300 Btu/kWh heat rate) and a $50/MWh fixed cost (assuming the RICE units carrying charge is $100/kW-year, or $100,000/MW-year, and operate at 23% capacity factor, which is roughly equivalent to running at full capacity for 2000 hours. Note that firming to follow load that changes over time will cost more than simply firming against a nominal quantity, as is the case with the NextEra wind contract. It is also questionable if such contracts are readily available at arms-length.

[26] The firming contract counter-party will likely have a higher cost of capital than DME and therefore any contract that requires physical assets, including firming power, will likely cost more than DEC.

[27] Demand response programs are usually implemented by contracts between a utility and demand response aggregators.

devices to DME and to ERCOT. Thus, demand resources are at best a very limited source of hedging what DME needs.

Storage today is very expensive. For example, battery technologies are still in the several thousand dollars per kW range, compared with approximately $1,000/kW for RICE units.[28] The longevity of batteries will depend on how and how often they are charged and discharged but are typically much shorter than the lifespan of the RICE units. In actual operation, storage must be charged—ideally with excess wind or solar because charging with fossil fuels is counterproductive. Charging by fossil fuel resources will simply increase fossil fuel usage and air emissions by roughly 20%–25% because of round-trip efficiency (losses in the charge-discharge cycle). Furthermore, batteries have limited energy storage capability–typically in the three to four hours range, and that may not be enough for DME with the large renewable portfolio. Even if these operational limitations are not an issue, DME will likely need over 100 MW of storage capacity to address the variability brought by the renewable resources. To put this quantity into perspective, the total capacity of utility-scale batteries with storage capacities of 2-hours or more in the U.S. that is currently online or under construction is about 65 MW.[29] Battery storage at the levels needed by DME is not practical or economic today.[30]

## C. Can Denton Move to 100% Renewables?

A few cities around the country have targeted 100% renewables. This can mean one of two things: 1) having renewables under contract equal to expected average annual customer demand; or 2) having sufficient renewables under contract to meet customer demand in every hour so that no fossil fueled-generation is ever used. Option 1 is less restrictive than option 2 because option 1 allows fossil-fueled plants to provide energy when renewable output is low.

Two of the cities seeking to be 100% renewable are Georgetown, TX and Burlington, VT. We will discuss Georgetown later in this section. Burlington has a very different resource base than

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28 DOE/EPRI 2013 Electric Storage Handbook in Collaboration with NRECA. Battery costs vary greatly by size, technology and storage capacity.

29 DOE Global Energy Storage Database, accesses June 1, 2016.

30 Many Compressed Air Energy Storage or Liquid Air Energy Storage technologies ultimately use natural gas as a fuel in the discharge cycle. These technologies therefore have carbon emissions even if they are charged with renewable energy. If they are charged with fossil-fired generation, the charge-to-discharge cycle losses can result in significant carbon emissions in addition to the direct carbon emissions from the use of natural gas in the discharge cycle.

Denton or Georgetown. It has hydro, biomass and wind.[31] Hydro output can be controlled to match load. Hydro can also be used for storage. Biomass is dispatchable like a gas plant. Thus, Burlington has only a limited amount of variable output resources in its portfolio; while all of Denton's renewable power will be variable.

The only way to have 100% renewable power from wind and solar with no fossil-fueled generation while maintaining reliability is to contract for a great deal more capacity than is actually needed to serve customers' expected demand. For DME to have no reliance on anything but renewable power, it would need to contract for many times its peak load to ensure that under the most adverse wind and solar conditions that can occur, the portfolio of PPAs would still provide enough power to meet the citizens' of Denton's demand.

Figure 11 shows the hourly output of the proposed 300 MW renewable PPAs and DME's expected hourly load over the course of a day in May 2019. During hour ending 19, when load reaches its peak level of 200 MW, PPA output is only 100 MW. During hour ending 3, when PPA output falls to its nadir of 25 MW, DME load is 110 MW. A simple calculation shows that to have enough power to cover demand during every hour of the day, DME would need several times more renewable power under PPA. During its peak demand hour (hour ending 19), DME would need 600 MW of PPA capacity under contract. To meet demand when PPA output is lowest (hour ending 3), DME would need more than 1,300 MW under contract. Of course, this analysis would have to be done for every 5- or 10-minute interval of the year with a scaled up portfolio to determine how much power might be needed. In addition, a wide range of weather patterns would have to be evaluated.

Under this hypothetical situation, DME would have much more energy than DME's demand. DME would become a very large seller in the ERCOT real time market. The EMO would not be able to sell forward under contract or in the Day-Ahead market. It would need to reserve all of its power for Denton's citizens until Real-Time, when it would either sell excess power into the Real-Time market or refuse to take excess purchased PPA power.

Large quantities of storage would allow DME to store some of the excess power for later use. To ensure the storage system only relies on renewable energy, energy would need to be stored when PPA output exceeded DME load, as opposed to when storing was least expensive. Since the

[31] Burlington is 50% hydro, 30% biomass and 20% wind. Source: SNL.

storage system would be charged with renewable power, it would use no fossil fuel.[32] The amount of storage required and the required hours of storage capability would need to be designed in conjunction with an analysis of DME's future load and the set of PPAs. If battery storage technologies become cost-effective and available in large scale systems, which they are not today, a true 100% renewable strategy will become feasible. Until then, a reliable 100% renewable strategy using this approach is simply not feasible.

To achieve 100% renewables in terms of expected total energy (and rely on fossil generation to keep costs under control and maintain expected reliability standards) would still require DME to have much more power under contract than 70%. To reach a 70% renewable level, DME plans to sign PPAs for 300 MW of renewable capacity, which is at about 80% of the 2019 expected peak load. Based on the experience of Georgetown, TX, to achieve 100%, DME might need to contract for twice as much renewable capacity as its expected peak load.[33] At that level, the firming requirements using RICE units or contracts will also be greater.

While we have not analyzed the cost, a recent study found that reaching 100% renewable penetration can cost twice as much as achieving an 80% renewable target.[34]

## D. Other Qualitative Considerations

In addition to the economic benefits identified above, there are other factors that should be considered qualitatively. The objective of this section is to assess these factors that were not analyzed quantitatively in the balance of this study. The analysis herein is primarily qualitative. The qualitative analysis considered includes the following:

- Water Usage Limitations and Draught Risks
- Hedging Market Operations/Execution Related Risks
- Optionality Value for PPAs
- Optimal Capacity of DEC

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32 As noted above, many Compressed Air Energy Storage or Liquid Air Energy Storage technologies use natural gas as a fuel and could not be used as part of a 100% plan.

33 Georgetown's goal is 100% renewable energy. Details are limited but Georgetown plans to have about 294 MW of renewable PPAs for their 145 MW peak. https://gus.georgetown.org/renewable-energy-faqs/

34 Flexibility mechanisms and pathways to a highly renewable US electricity future, Bethany A. Frew, Sarah Becker, Michael J. Dvorak, Gorm B. Andresen, and Mark Z. Jacobson, Energy, 2016.)

### 1. Water Usage Limitations and Drought Risks

In recent years, the ERCOT market has experienced moderate to rather severe drought conditions.[35] In 2011, 98% of the state of Texas was in moderate to worse drought conditions, followed by 2012 when 85% of the state was in moderate to worse drought conditions. While the drought conditions occurred in these years had limited impact on power production from thermal generators, it did flag the potential of up to 3,000 MW of thermal resources potentially becoming impacted and raised concerns over the long-run, especially as the resource adequacy margin in ERCOT get tighter. The RICE units require very little water for operations (around 12 gallons a week for DEC, compared to more than 20 million gallons per week for a typical combined cycle plant) and will likely not be impacted even if severe drought conditions last for multiple years, as it has back in 1950 – 1957.[36]

### 2. Hedging Market Operations and Execution Related Risks

Owning and operating DEC relieves DME from potential risks related to market operations and execution. For example, the forward curve for the upcoming season (especially the summer peak period when the prices are typically highest) may be in excess of what DME believes it to be. There is a risk of paying too much by accepting that high priced forward curve. The DEC would allow DME to stay limit forward purchases under these circumstances by using the DEC to limit exposure to potential high prices.

In the future where the total variability of net load becomes higher with the increased renewable resources (as Figure 11 (Hourly Net Load and Ramping Needs) illustrates), having no other means to provide flexibility can potentially jeopardize DME's QSE status. ERCOT can revoke DME's QSE status if DME cannot maintain its Generation Resource Energy Deployment Performance. If DME's QSE status were to be lost, realizing the RDP goals (increasing renewables, reducing fossil fuel usage and air emissions, while not raising customer rates) will become a harder and costlier challenge because DME will have to pay an external QSE to manage the generation portfolio.

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35 Source: http://www.ercot.com/content/news/presentations/2014/ERCOT-DroughtHearing-06-26-14.pdf

36 Source: http://www.ercot.com/content/committees/other/lts/keydocs/2013/ERCOT_Water_Use_and_Availability_-_DrtRpt_1DF.pdf

### 3. Optionality Value for PPAs

As discussed earlier, the Gibbons Creek power sales agreement is scheduled to expire in 2018 and the four owners (cities of Bryan, Denton, Garland, and Greenville) can express their intent of extension or termination starting September 2016. Having DEC will provide DME with the optionality value regarding Gibbons Creek but also for other contracts including the renewable PPAs. Without DEC, the termination date of Gibbons Creek and starting day of other PPAs must be adjusted so that no gap exists. Furthermore, in the case that Gibbons Creek power sales agreement is extended, the current unfavorable regulatory policy surrounding coal units will likely lead the plant to retirement, requiring DME to seek alternative power sources again.

### 4. Optimal Capacity of DEC

The optimal capacity of DEC needs to be considered. As discussed earlier, a high level analysis of flexibility needs based on net load fluctuation indicates at least nine RICE units (and perhaps 10 or 11 if outages are accounted for). However, this analysis only looks at hourly data for a single year of 2019 and future load growth is not considered. The highest net load variability may also occur within an hour. And the analysis did not consider forecast deviations for the renewable resources. Furthermore, the net load variability will depend on the resource type and location, and vary by season and year. These factors suggest that nine units may not be enough to cover DME's operational needs. Also installing additional units in the future will necessarily disturb the operations of the existing (in the future) units.[37] 12 RICE units provide a good balance from an operational perspective.

At the same time, there are economies of scale for purchasing 12 RICE units compared to nine units. Two major cost components of the DEC are the RICE units by themselves and the "balance of plant." The balance of plant consists of land, gas pipelines, transmission lines to the plant and substations, buildings and controls, among other common equipment and facilities needed. The change in the number of RICE units does not significantly change the balance of plant costs. Quotes DME received from the vendor indicate that reducing the number of RICE units from 12 to six would only reduce the total price by 35%. Similarly, the incremental cost reduction from changing the total number of units by three (from the currently planned 12 to nine units) will only be around $30 to $35 million, rather than $55 million—a quarter of the $220 million

[37] Gas pipeline interconnection needs are such examples.

investment. This $30 to $35 million may only pay for one or two units if installed at a later time.[38] These factors indicate that 12 RICE units provide a good balance from an economic perspective as well.

Reducing the number of RICE units by three will impact two factors. First, the net-sales benefit (margins from the energy and ancillary services sold to the ERCOT market) will be reduced by approximately 25% (three out of 12 units). This indicates foregoing margins of approximately $70 (under the Low Gas Scenario) to $95 million (under the Base Scenario) generated by the RICE units over 20 years. Secondly, nine units may not be enough to keep up with changing future system conditions. The RDP includes additional renewable PPAs to be signed every five years as the DME demand grows. Table 10 (RICE Unit Count and Estimated Renewable Penetration Level) shows the estimated renewable level for the proposed RDP. The renewable penetration level for the RDP with 12 RICE units, shown in the second column, increases every five years (2024, 2029, and 2034) as new renewable PPAs are added ("post-2019 PPAs") to account for DME's growing demand. Increases in renewables through post-2019 PPAs and load growth will lead to more variability. It is unclear whether nine RICE units can adequately hedge such increased variability. If that uncertainty precludes signing the post-2019 PPAs, ratepayers will lose the expected savings associated with those PPAs. We estimate the PPAs would result in savings as high as $80 million over 20 years. Furthermore, Denton will not be able to achieve the 70% renewable goal in the long-term. The last column in Table 10 (RICE Unit Count and Estimated Renewable Penetration Level) below shows the estimated renewable level for Denton, if it is decided that 9 units cannot accommodate any post-2019 PPAs.

[38] The average per-unit cost is slightly higher than $18 million when 12 units are installed (i.e. $220 million / 12 units = $18.3 million per unit).

**Table 10: RICE Unit Count and Estimated Renewable Penetration Level**

| Year | Renewable Level (%) | |
|---|---|---|
| | Current Plan (12 RICE Units) | Reduced Plan (9 RICE Units) |
| 2019 | 77.9% | 77.9% |
| 2020 | 76.4% | 76.4% |
| 2021 | 74.9% | 74.9% |
| 2022 | 73.4% | 73.4% |
| 2023 | 72.0% | 72.0% |
| 2024 | 77.6% | 70.4% |
| 2025 | 75.5% | 68.4% |
| 2026 | 74.0% | 67.1% |
| 2027 | 72.6% | 65.8% |
| 2028 | 71.2% | 64.5% |
| 2029 | 76.3% | 63.2% |
| 2030 | 74.8% | 62.0% |
| 2031 | 73.3% | 60.7% |
| 2032 | 71.9% | 59.6% |
| 2033 | 70.5% | 58.4% |
| 2034 | 76.2% | 57.2% |
| 2035 | 74.7% | 56.1% |
| 2036 | 73.3% | 55.0% |
| 2037 | 71.8% | 53.9% |
| 2038 | 70.4% | 52.9% |

In short, developing only nine RICE units will reduce upfront capital costs by $30 to $35 million. However, we estimate that without the additional three RICE units, DME risks losing between $70 million and $175 million in future savings and potentially not achieving the RDP goals.

# IV. Conclusion

Brattle has reviewed the City of Denton's plan to increase its reliance on renewable energy. The proposed RDP increases the City's physical renewable energy portfolio to 70% of energy served and significantly reduces costs relative to the status quo. DME achieves these outcomes under the RDP by entering long-term PPAs for low priced renewable energy, while developing the DEC to "firm" the power supply from these intermittent renewable resources.

Contracting for renewable capacity will lower energy costs, but integrating a high level of intermittent resources creates operational challenges. As an ERCOT QSE, DME shares ERCOT's obligation to maintain system reliability. If it fails to do so, DME risks losing its current QSE status (estimated to be saving Denton's ratepayers several million dollars a year) and could face further financial penalties. To avoid risking its QSE status while increasing its intermittent renewable energy purchases, DME must either contract for responsive, dispatchable capacity or develop its own.

The DEC would provide the sort of highly flexible capacity that DME needs to "firm" the intermittent renewable PPAs. Although the DEC requires substantial debt financing, profits from the sale of energy and ancillary services will likely cover most or all of the debt service. DME could contract for similar capacity from the market, but based on data from existing "firm" renewable PPAs that would likely cost more than the DEC over the 20 year study horizon. This makes the DEC an integral part of the RDP to provide cleaner, lower-cost power for the citizens of Denton.

In analyzing the economic benefits of the RDP, this report compares three future *Strategies*: the *RDP-DEC Strategy* in which the RDP with DEC achieves 70% renewable penetration, the *SQ-TMPA Strategy* in which the DME generation portfolio remains the same as the status quo including Gibbons Creek, and the *SQ-Market Strategy* in which Gibbons Creek is no longer part of the DME portfolio and DME purchases additional power from the ERCOT market. In both *Status Quo Strategies*, DME's renewable penetration level remains at the current 40% level, enabled by existing renewable PPAs and RECs. The report analyzes the *Strategies* using two different natural gas prices forecast from ERCOT's LTSA. The Base Scenario uses the LTSA reference case natural gas price forecast, and the Low Gas Scenario uses the LTSA low gas forecast, which effectively assumes the current low gas prices prevail in real terms for the foreseeable future.

The analyses confirm the *RDP-DEC Strategy* is the most cost efficient option among the three *Strategies.* In the Base Scenario, the *RDP-DEC Strategy* costs $975 million less over 20 years than the *SQ-Market Strategy* and $750 million less than the *SQ-TMPA Strategy*. In the Low Gas Scenario, the *RDP-DEC Strategy* costs approximately $410 million less over 20 years than either *Status Quo Strategy*. These results show that even at current natural gas prices, the *RDP-DEC Strategy* will reduce DME's costs. The *RDP-DEC Strategy* acts as a hedge against rising natural gas prices and yields even greater savings when gas prices rise.

Both the renewable PPAs and the DEC are integral parts of the RDP. The DEC physically hedges the net load variability caused by the increased renewable resources that bring about the cost savings shown in the *RDP-DEC Strategy*. Without the DEC, or comparable flexible capacity, incorporating large amounts of intermittent resources would expose rate payers to the price volatility of the ERCOT wholesale energy market and jeopardize DME's economically important QSE status. An existing arms-length firming contract indicates the cost of obtaining comparable capacity from the market would be high. Based on this observation, the DEC is the lowest cost option for "firming" the renewable energy.

Overall, the *RDP-DEC Strategy* appears to be the lowest cost and most reliable option for achieving the City of Denton and DME's goal of higher physical renewable penetration. It is important to note that DME needs to make changes to its ongoing electricity delivery services to customers without any disruption—either physical or financial—and therefore having physical options to hedge the renewable variability is important. Both the physical and financial factors indicate that the investment decision should not be delayed. Physically, DME needs generation resources in the near future, as the load grows (by approximately 2% per year) and the Gibbons Creek power sales agreement approaches its renewal time. Financially, the extended tax incentives for renewable resources and the historically low gas prices provide a favorable opportunity for signing renewable PPAs. These tax incentives will phase out starting in 2017 and various natural gas price forecasts indicate prices may begin to rise. Finally, the current exchange rate (US dollars against Euros) is favorable for purchasing the Europe-made RICE units.

With all these factors considered, we find that the RDP is an effective strategy to increase Denton's clean, physical renewable energy while reducing its electricity costs. Because it is the cheapest option to "firm" the renewable PPAs, the DEC is an integral component of implementing the RDP while keeping costs at a minimum and complying with ERCOT's reliability standards.

# V. Appendices

Appendix-A: Denton Energy Center Characteristics

Appendix-B: Analyses Assumptions and Methods

Appendix-C: Uncertainty for the *SQ-TMPA Strategy*

## A. DENTON ENERGY CENTER CHARACTERISTICS

The RICE units were assumed to have a minimum generation level of 3.75 MW (20% of full capacity). For future years, we assumed a heat rate degradation of 0.5% per year, which totals to 10% degradation over the 20 year period analyzed. This is higher than the 0.3% per year suggested by the manufacturer, making the results conservative.

For ancillary services, consistent with the ERCOT market rules of today, we assumed that each RICE unit could provide 3.75 MW (20% of full capacity) of RRS and up to full capacity of NSRS. For regulation (RUS and RDS), we modeled the RICE units using three varying capabilities:

- 100% Regulation Capability: The RICE units can provide regulation up to 100% of its capability (15 MW).
- 20% Regulation Capability: The RICE units can provide regulation up to 20% of its capability (3.75 MW).
- 0% Regulation Capability: The RICE units cannot provide any regulation (0 MW).

The 100% Regulation Capability best represents the actual capability of the RICE units. However, the ERCOT regulation market is limited—it only requires 600 MW of regulation today. DEC's 12 RICE units can provide a combined 180 MW of regulation services (15MW * 12 units). Offering this amount in the relatively small regulation market may have impacts to market clearing prices. Therefore we assumed that on average, a RICE unit can only provide up to 20% of its capacity (3.75 MW) into the regulation market. This limits the total regulation services being provided by the 12 RICE units to 45 MW, and therefore assumes minimal price impacts.

## B. Analyses Assumptions and Methods

This Appendix summarizes the various assumptions and models used for the economic feasibility analyses. The economic feasibility analyses prepared hourly forward price curves from the natural gas forwards to assess the comparative benefits of the *Status Quo Strategies* and *RDP-DEC Strategy*, then further used the hourly forward curves to assess the performance of the RICE units. The RICE units' performance was assessed by dispatching the RICE units against the forward price curves. This was done through the PSO model, a production simulation tool.

### 1. Creating Forward Power Curves from Natural Gas Price Forecasts

The forward natural gas price forecast from the ERCOT LTSA was used as an input to the Xpand model to produce a long term power price curve.

Xpand is a linear programming model that simulates electric generation system expansion over multi-decade time horizons. Its objective function minimizes the present value of total system costs, including capital cost, fixed O&M, variable O&M, fuel and emission costs while meeting electricity demand and complying with environmental policy limits, operating reserve constraints and reserve margin constraints (where applicable). It is designed to operate as if all generation decisions are market-driven. As part of the cost-minimizing solution, Xpand produces forecasts of short-term and long-term decisions such as new capacity additions, retirements, generation and fuel mix levels, and energy prices.

Table APP-B1 (Natural Gas Price Forecast) below shows the natural gas prices used and shown in Figure 3 (Historical and Forecasted Natural Gas Prices).

**Table APP-B1: Natural Gas Price Forecast**

| Year | Scenarios | |
|---|---|---|
| | Base | Low Gas |
| 2017 | $ 2.930 | $ 2.930 |
| 2018 | $ 2.981 | $ 2.981 |
| 2019 | $ 3.075 | $ 3.075 |
| 2020 | $ 3.534 | $ 3.277 |
| 2021 | $ 4.043 | $ 3.444 |
| 2022 | $ 4.520 | $ 3.564 |
| 2023 | $ 5.070 | $ 3.631 |
| 2024 | $ 5.220 | $ 3.676 |
| 2025 | $ 5.405 | $ 3.722 |
| 2026 | $ 5.650 | $ 3.769 |
| 2027 | $ 5.800 | $ 3.816 |
| 2028 | $ 5.975 | $ 3.863 |
| 2029 | $ 6.095 | $ 3.912 |
| 2030 | $ 6.195 | $ 3.961 |
| 2031 | $ 6.505 | $ 4.010 |
| 2032 | $ 6.830 | $ 4.060 |
| 2033 | $ 7.155 | $ 4.111 |
| 2034 | $ 7.500 | $ 4.162 |
| 2035 | $ 7.820 | $ 4.214 |
| 2036 | $ 8.130 | $ 4.267 |
| 2037 | $ 8.430 | $ 4.320 |
| 2038 | $ 8.725 | $ 4.374 |

## 2. Shaping Forward Price Curves

The power price forecast from Xpand corresponds to Day-Ahead prices, which we shaped using historical hourly prices for both Day-Ahead and Real-Time.

Xpand operates on a seasonal basis using load duration curves and provides projected prices for 72 tranches per future year; these prices reflect the average across all the hours that are in a particular tranche. We calculated the historic average Day-Ahead price for the hours in each tranche. We then multiplied the historic Day-Ahead price for each particular hour by the ratio of the projected average tranche price and the historic average tranche price. We further adjust this price by inflation to get a final Day-Ahead price. We then applied the historical Real-Time and Day-Ahead price ratio to this final Day-Ahead price to derive the Real-Time price.

## 3. Varying Assumptions (Profile Years and RICE Characteristics)

To account for varying market conditions, we prepared four distinct hourly power price forecasts using price profiles from 2012, 2013, 2014, and 2015. Differences in these shapes reflect changes in market conditions, load, wind and solar output, generator and transmission outages, and other various factors. For each of the four power price forecasts, the Day-Ahead Xpand forward prices remain the same for each tranche, but the hour by hour Day-Ahead energy prices (largely driven by load conditions), the difference between Day-Ahead and Real-Time prices, and the difference between the various ancillary services prices (derived from the relationship with the energy prices), vary based on differences in the hourly price profiles from the four historical years (2012, 2013, 2014, and 2015). We also analyzed sensitivities based on the quantity of ancillary service the RICE units can provide, as discussed in Appendix-A (Denton Energy Center Characteristics). This is because assuming that all the 12 RICE units can provide their full capability of ancillary services to the market may over-estimate the benefits of DEC.

Table APP-B2 through Table APP-B5 below lists the monthly average Day-Ahead and Real-Time power prices derived using the four different historical years' profiles for the two Scenarios, as shown in Figure 4 (Forward Power Price Curves).

**Table APP-B2: Base Scenario Forecasted Day-Ahead Price (Annual Average)**

| Years | Profile Years | | | | |
|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | Average |
| 2019 | $ 30.49 | $ 30.49 | $ 30.49 | $ 30.49 | $ 30.49 |
| 2020 | $ 33.79 | $ 33.80 | $ 33.83 | $ 33.78 | $ 33.80 |
| 2021 | $ 37.53 | $ 37.53 | $ 37.53 | $ 37.53 | $ 37.53 |
| 2022 | $ 40.94 | $ 40.94 | $ 40.94 | $ 40.94 | $ 40.94 |
| 2023 | $ 44.93 | $ 44.93 | $ 44.93 | $ 44.93 | $ 44.93 |
| 2024 | $ 46.24 | $ 46.26 | $ 46.28 | $ 46.24 | $ 46.26 |
| 2025 | $ 47.93 | $ 47.93 | $ 47.93 | $ 47.93 | $ 47.93 |
| 2026 | $ 50.21 | $ 50.21 | $ 50.21 | $ 50.21 | $ 50.21 |
| 2027 | $ 51.79 | $ 51.79 | $ 51.79 | $ 51.79 | $ 51.79 |
| 2028 | $ 53.60 | $ 53.62 | $ 53.64 | $ 53.59 | $ 53.61 |
| 2029 | $ 54.95 | $ 54.95 | $ 54.95 | $ 54.95 | $ 54.95 |
| 2030 | $ 55.76 | $ 55.76 | $ 55.76 | $ 55.76 | $ 55.76 |
| 2031 | $ 58.70 | $ 58.70 | $ 58.70 | $ 58.70 | $ 58.70 |
| 2032 | $ 61.48 | $ 61.48 | $ 61.53 | $ 61.46 | $ 61.49 |
| 2033 | $ 64.89 | $ 64.89 | $ 64.89 | $ 64.89 | $ 64.89 |
| 2034 | $ 68.01 | $ 68.01 | $ 68.01 | $ 68.01 | $ 68.01 |
| 2035 | $ 70.63 | $ 70.63 | $ 70.63 | $ 70.63 | $ 70.63 |
| 2036 | $ 72.34 | $ 72.34 | $ 72.42 | $ 72.31 | $ 72.35 |
| 2037 | $ 73.56 | $ 73.56 | $ 73.56 | $ 73.56 | $ 73.56 |
| 2038 | $ 75.10 | $ 75.10 | $ 75.10 | $ 75.10 | $ 75.10 |

## Table APP-B3: Base Scenario Forecasted Real-Time Price (Annual Average)

| Years | Profile Years | | | | |
|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | Average |
| 2019 | $ 28.73 | $ 29.28 | $ 28.66 | $ 29.39 | $ 29.01 |
| 2020 | $ 31.85 | $ 32.45 | $ 31.76 | $ 32.63 | $ 32.17 |
| 2021 | $ 35.34 | $ 36.03 | $ 35.26 | $ 36.18 | $ 35.70 |
| 2022 | $ 38.53 | $ 39.29 | $ 38.46 | $ 39.46 | $ 38.94 |
| 2023 | $ 42.26 | $ 43.11 | $ 42.20 | $ 43.31 | $ 42.72 |
| 2024 | $ 43.49 | $ 44.39 | $ 43.44 | $ 44.65 | $ 43.99 |
| 2025 | $ 45.07 | $ 46.00 | $ 45.02 | $ 46.19 | $ 45.57 |
| 2026 | $ 47.19 | $ 48.19 | $ 47.15 | $ 48.38 | $ 47.73 |
| 2027 | $ 48.66 | $ 49.69 | $ 48.63 | $ 49.90 | $ 49.22 |
| 2028 | $ 50.41 | $ 51.45 | $ 50.34 | $ 51.74 | $ 50.99 |
| 2029 | $ 51.69 | $ 52.74 | $ 51.61 | $ 52.95 | $ 52.25 |
| 2030 | $ 52.48 | $ 53.52 | $ 52.38 | $ 53.75 | $ 53.03 |
| 2031 | $ 55.27 | $ 56.33 | $ 55.16 | $ 56.58 | $ 55.84 |
| 2032 | $ 57.91 | $ 59.01 | $ 57.79 | $ 59.37 | $ 58.52 |
| 2033 | $ 61.14 | $ 62.29 | $ 61.00 | $ 62.57 | $ 61.75 |
| 2034 | $ 64.16 | $ 65.29 | $ 63.95 | $ 65.60 | $ 64.75 |
| 2035 | $ 66.67 | $ 67.82 | $ 66.43 | $ 68.16 | $ 67.27 |
| 2036 | $ 68.35 | $ 69.46 | $ 68.08 | $ 69.94 | $ 68.96 |
| 2037 | $ 69.51 | $ 70.64 | $ 69.22 | $ 71.02 | $ 70.09 |
| 2038 | $ 70.96 | $ 72.14 | $ 70.67 | $ 72.51 | $ 71.57 |

## Table APP-B4: Low Gas Scenario Forecasted Day-Ahead Price (Annual Average)

| Years | Profile Years | | | | |
|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | Average |
| 2019 | $ 31.37 | $ 31.37 | $ 31.37 | $ 31.37 | $ 31.37 |
| 2020 | $ 33.32 | $ 33.32 | $ 33.35 | $ 33.31 | $ 33.33 |
| 2021 | $ 34.91 | $ 34.91 | $ 34.91 | $ 34.91 | $ 34.91 |
| 2022 | $ 35.98 | $ 35.98 | $ 35.98 | $ 35.98 | $ 35.98 |
| 2023 | $ 36.66 | $ 36.66 | $ 36.66 | $ 36.66 | $ 36.66 |
| 2024 | $ 37.17 | $ 37.18 | $ 37.21 | $ 37.16 | $ 37.18 |
| 2025 | $ 37.69 | $ 37.69 | $ 37.69 | $ 37.69 | $ 37.69 |
| 2026 | $ 38.22 | $ 38.22 | $ 38.22 | $ 38.22 | $ 38.22 |
| 2027 | $ 38.82 | $ 38.82 | $ 38.82 | $ 38.82 | $ 38.82 |
| 2028 | $ 39.32 | $ 39.32 | $ 39.35 | $ 39.30 | $ 39.32 |
| 2029 | $ 39.89 | $ 39.89 | $ 39.89 | $ 39.89 | $ 39.89 |
| 2030 | $ 40.56 | $ 40.56 | $ 40.56 | $ 40.56 | $ 40.56 |
| 2031 | $ 41.26 | $ 41.26 | $ 41.26 | $ 41.26 | $ 41.26 |
| 2032 | $ 41.74 | $ 41.75 | $ 41.78 | $ 41.73 | $ 41.75 |
| 2033 | $ 42.57 | $ 42.57 | $ 42.57 | $ 42.57 | $ 42.57 |
| 2034 | $ 43.60 | $ 43.60 | $ 43.60 | $ 43.60 | $ 43.60 |
| 2035 | $ 44.10 | $ 44.10 | $ 44.10 | $ 44.10 | $ 44.10 |
| 2036 | $ 44.49 | $ 44.50 | $ 44.54 | $ 44.48 | $ 44.50 |
| 2037 | $ 45.29 | $ 45.29 | $ 45.29 | $ 45.29 | $ 45.29 |
| 2038 | $ 45.82 | $ 45.82 | $ 45.82 | $ 45.82 | $ 45.82 |

**Table APP-B5: Low Gas Scenario Forecasted Real-Time Price (Annual Average)**

| Years | Profile Years | | | | |
|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | Average |
| 2019 | $ 29.45 | $ 30.11 | $ 29.45 | $ 30.18 | $ 29.80 |
| 2020 | $ 31.27 | $ 31.98 | $ 31.28 | $ 32.10 | $ 31.66 |
| 2021 | $ 32.75 | $ 33.50 | $ 32.77 | $ 33.57 | $ 33.15 |
| 2022 | $ 33.76 | $ 34.52 | $ 33.77 | $ 34.60 | $ 34.16 |
| 2023 | $ 34.39 | $ 35.17 | $ 34.40 | $ 35.25 | $ 34.81 |
| 2024 | $ 34.89 | $ 35.68 | $ 34.90 | $ 35.81 | $ 35.32 |
| 2025 | $ 35.37 | $ 36.17 | $ 35.38 | $ 36.25 | $ 35.79 |
| 2026 | $ 35.86 | $ 36.68 | $ 35.87 | $ 36.76 | $ 36.29 |
| 2027 | $ 36.42 | $ 37.26 | $ 36.44 | $ 37.34 | $ 36.86 |
| 2028 | $ 36.89 | $ 37.74 | $ 36.91 | $ 37.87 | $ 37.35 |
| 2029 | $ 37.43 | $ 38.29 | $ 37.44 | $ 38.36 | $ 37.88 |
| 2030 | $ 38.06 | $ 38.94 | $ 38.08 | $ 39.01 | $ 38.52 |
| 2031 | $ 38.71 | $ 39.60 | $ 38.73 | $ 39.68 | $ 39.18 |
| 2032 | $ 39.18 | $ 40.07 | $ 39.21 | $ 40.22 | $ 39.67 |
| 2033 | $ 39.95 | $ 40.86 | $ 40.00 | $ 40.94 | $ 40.44 |
| 2034 | $ 40.91 | $ 41.85 | $ 40.96 | $ 41.93 | $ 41.41 |
| 2035 | $ 41.38 | $ 42.33 | $ 41.42 | $ 42.41 | $ 41.88 |
| 2036 | $ 41.76 | $ 42.71 | $ 41.81 | $ 42.86 | $ 42.29 |
| 2037 | $ 42.51 | $ 43.48 | $ 42.56 | $ 43.57 | $ 43.03 |
| 2038 | $ 43.00 | $ 43.99 | $ 43.05 | $ 44.07 | $ 43.53 |

Prices for ancillary services, nominally RRS, NSRS, RUS, and RDS, were assumed to be proportional to the energy prices for any historical profile. Figure APP-B1 through Figure APP-B4 compares the energy prices and various ancillary service price ratios against the energy prices.

**Figure APP-B1: Historical Price Ratio – RRS/Energy**

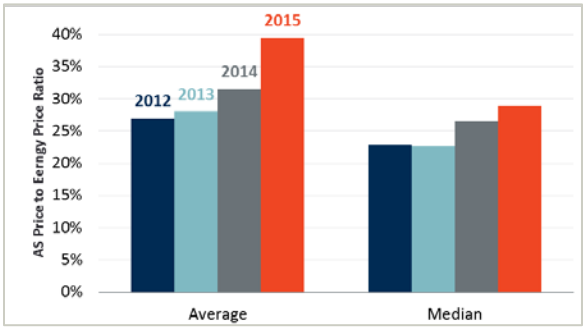


**Figure APP-B2: Historical Price Ratio – NRS/Energy**

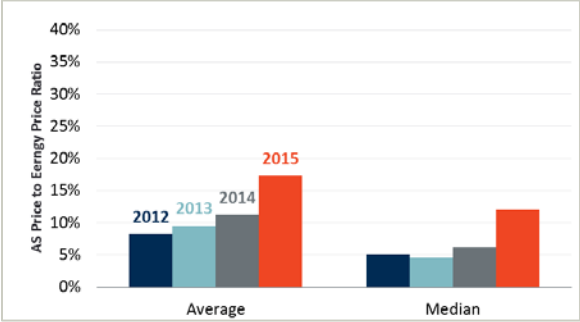



**Figure APP-B3: Historical Price Ratio – RUS/Energy**

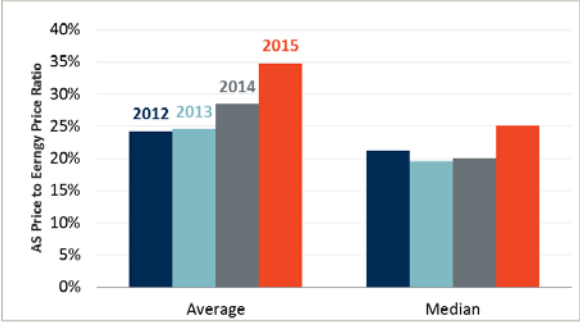



**Figure APP-B4: Historical Price Ratio – RDS/Energy**

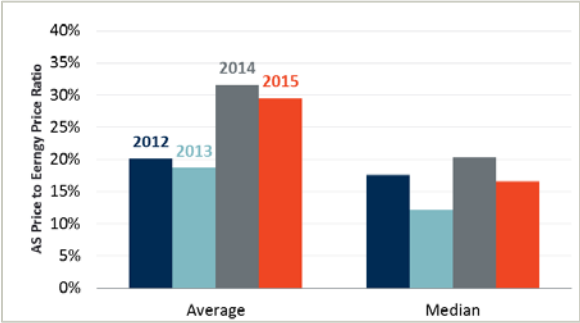



Table APP-B6 (Historical Price Ratio – Ancillary Services/Energy) shows the statistics of the various ancillary service values, including those in the Figures above. These figures and table indicate that on average ancillary service prices were lowest (compared to energy prices) in 2012 and highest in 2015. 2013 overall showed the largest volatility although 2014 had higher volatility for RUS.

**Table APP-B6: Historical Price Ratio – Ancillary Services/Energy**

| Ancillary Service Type | Profile Year | Min | Max | Average | Median |
|---|---|---|---|---|---|
| RRS | 2012 | 2% | 813% | 27% | 23% |
| | 2013 | 4% | 14313% | 28% | 23% |
| | 2014 | 0% | 310% | 32% | 27% |
| | 2015 | 5% | 1867% | 39% | 29% |
| NSRS | 2012 | 0% | 98% | 8% | 5% |
| | 2013 | 1% | 14313% | 10% | 5% |
| | 2014 | 0% | 614% | 11% | 6% |
| | 2015 | 1% | 190% | 17% | 12% |
| RUS | 2012 | 0% | 292% | 24% | 21% |
| | 2013 | 0% | 14315% | 25% | 20% |
| | 2014 | 0% | 19029% | 29% | 20% |
| | 2015 | 0% | 1433% | 35% | 25% |
| RDS | 2012 | 0% | 929% | 20% | 18% |
| | 2013 | 0% | 873% | 19% | 12% |
| | 2014 | 0% | 1383% | 32% | 20% |
| | 2015 | 0% | 1746% | 30% | 17% |

Finally, Table APP-B7 (Average Prices for the Four Profile Years) shows the average prices for energy, RRS, NSRS, RUS, and RDS for the four profiles.

**Table APP-B7: Average Prices for the Four Profile Years**

| Profile | Energy | | Ancillary Services | | | |
|---|---|---|---|---|---|---|
| Years | Day-Ahead | Real-Time | RRS | NSRS | RUS | RDS |
| 2012 | $ 27.58 | $ 25.19 | $ 8.72 | $ 3.63 | $ 4.23 | $ 8.94 |
| 2013 | $ 31.86 | $ 30.45 | $ 8.13 | $ 3.43 | $ 4.89 | $ 8.57 |
| 2014 | $ 38.13 | $ 36.26 | $ 11.27 | $ 5.18 | $ 9.74 | $ 12.43 |
| 2015 | $ 25.34 | $ 22.87 | $ 9.96 | $ 6.35 | $ 5.35 | $ 10.25 |

## 4. The PSO Model

Power Systems Optimizer ("PSO") is an advanced production cost simulation tool developed by Polaris Systems Optimization, Inc. Traditional production cost models were designed to model controllable thermal generation and focus on the energy markets. PSO was built to focus on the variability needs of the current and future electrical system. The model is able to simultaneously optimize energy and multiple ancillary services markets on a sub-hourly timeframe. PSO also allows for the modeling of forecast uncertainty and uses mixed-integer programming techniques

to solve the commitment and dispatch problem. The model is designed to mimic market operations software and market outcomes in competitive energy and ancillary services markets.

Given PSO's unique features, we first analyzed the RICE units' performance by modeling the Day-Ahead market on an hourly basis and Real-Time market on a 5 minute basis for historical years of 2012, 13, 14, and 15. We also modeled the historical years' Real-Time on an hourly basis to see if the results were significantly different. This is because simulating 5 minute interval significantly increases the computational complexity and time required. Table APP-B8 (Real-Time Simulation Results Comparison) below compares the two results for the four different historical profiles. As this table shows, modeling Real-Time on an hourly basis provides a slightly lower revenue outlook, mostly because it does not fully capture the units' capability of releasing NSRS and selling energy in Real-Time when the energy price is above $75/MWh, as ERCOT rules allow today. Given the small deviations showing conservative, we modeled the Real-Time on an hourly basis rather than on 5-minute basis for all future years (2019 through 2038). As discussed earlier, the PSO simulations were repeated using four different historical year profiles to account for the variability in system conditions.

**Table APP-B8: Real-Time Simulation Results Comparison**

| Profile Years | 2012 | 2013 | 2014 | 2015 | Total All Years |
|---|---|---|---|---|---|
| Total Annual Energy Revenues with Hourly Average RT Prices ($000): | $ 2,082 | $ 1,914 | $ 2,929 | $ 1,057 | $ 7,983 |
| Total Annual Energy Revenues with 5-Minute RT Prices ($000): | $ 2,140 | $ 1,947 | $ 2,998 | $ 1,078 | $ 8,164 |
| Delta Hourly-5 Min ($000) | $ (58) | $ (33) | $ (69) | $ (21) | $ (181) |
| Percent Delta | -2.7% | -1.7% | -2.3% | -1.9% | -2.2% |
| Total RT adjustment for NS release with Hourly Average RT Prices ($000): | $ 18 | $ 163 | $ 139 | $ 87 | $ 407 |
| Percentage of Annual Energy Revenues: | 0.9% | 8.5% | 4.7% | 8.2% | 5.1% |
| Total RT adjustment for NS release with 5-min Average RT Prices ($000): | $ 76 | $ 197 | $ 208 | $ 108 | $ 589 |
| Percentage of Annual Energy Revenues: | 3.6% | 10.1% | 6.9% | 10.0% | 7.2% |

## 5. REC Payments

Table APP-B9 (REC Payments) below shows the REC payment schedule for the two Status Quo Strategies (*SQ-TMPA Strategy* and *SQ-Market Strategy*) and the *RDP-DEC Strategy*. REC

purchases for the two *Status Quo Strategies* extend beyond 2024 when the current REC purchase agreement expires. REC payments do not change by Scenario.

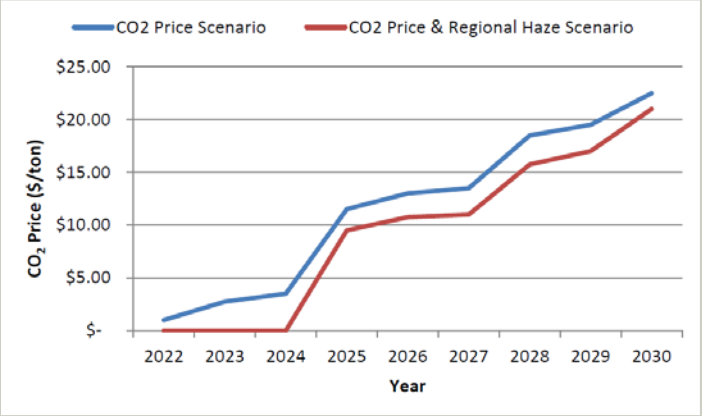
**Table APP-B9: REC Payments**

| Year | Status Quo Futures | RDP-DEC Future |
|---|---|---|
| 2019 | $ (1,593,590) | $ (1,382,328) |
| 2020 | $ (1,904,631) | $ (1,382,328) |
| 2021 | $ (1,933,473) | $ (1,382,328) |
| 2022 | $ (1,962,892) | $ (1,382,328) |
| 2023 | $ (1,992,900) | $ (1,382,328) |
| 2024 | $ (2,023,507) | $ (1,382,328) |
| 2025 | $ (1,910,638) | $ - |
| 2026 | $ (1,948,851) | $ - |
| 2027 | $ (1,987,828) | $ - |
| 2028 | $ (2,027,585) | $ - |
| 2029 | $ (2,068,137) | $ - |
| 2030 | $ (2,461,082) | $ - |
| 2031 | $ (2,510,304) | $ - |
| 2032 | $ (2,560,510) | $ - |
| 2033 | $ (2,611,720) | $ - |
| 2034 | $ (2,663,955) | $ - |
| 2035 | $ (2,717,234) | $ - |
| 2036 | $ (2,771,579) | $ - |
| 2037 | $ (2,827,010) | $ - |
| 2038 | $ (2,883,550) | $ - |

## C. UNCERTAINTY FOR THE *SQ-TMPA STRATEGY*

Under the Base Scenario, the *SQ-Market Strategy* shows higher costs than the *SQ-TMPA Strategy*. The comparative benefit of the *SQ-TMPA Strategy* over the *SQ-Market Strategy* is in excess of $230 million over twenty years. However, it is important to note that the *SQ-TMPA Strategy* cost may be higher than what is represented here. For example, Gibbons Creek may have to go comply with future environmental policies that are likely to be put in place. The most significant policy is likely to be a carbon policy. A recent study ERCOT study of EPA's Final Clean Power Plan examines two scenarios with carbon prices as shown in Figure APP-C1 (ERCOT CO2 Price Assumptions) below.[39]

**Figure APP-C1: ERCOT $CO_2$ Price Assumptions**




Under the Low Gas Scenario—the down-side case—the *RDP-DEC Strategy* will provide a positive cash flow of over $400 million over twenty years, or over $200 million in net present value, when compared against either *Status Quo Strategies*. Again, the *SQ-TMPA Strategy* may face higher costs as discussed above.

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39 ERCOT Analysis of the Impacts of the Clean Power Plan - Final Rule Update, dated October 16, 2015, available at: http://www.ercot.com/content/news/presentations/2015/ERCOT_Analysis_of_the_Impacts_of_the_Clean_Power_Plan-Final_.pdf