RENEWABLE, CARBON FREE AND BATTERY STORAGE STUDIES
# Table of Contents

1. **Executive Summary** .......................................................................................................................... 5  
2. **Introduction** ......................................................................................................................................... 8  
   2.1. **The 2027 Plan: Directives** ........................................................................................................ 8  
   2.2. **Approach to the Studies** ............................................................................................................. 8  
3. **Inputs to Studies** ................................................................................................................................. 9  
   3.1. **Current State of the ERCOT Market** .......................................................................................... 9  
   3.2. **ERCOT Market Resource Additions** .......................................................................................... 11  
   3.3. **Austin Energy Thermal and Renewable Resources** ................................................................. 12  
   3.4. **Austin Energy Historical Peak Demand and Energy** ................................................................. 13  
   3.5. **Austin Energy Forecasted Peak Demand and Energy** ................................................................. 13  
   3.6. **ERCOT Forecasted Peak Demand and Energy** ......................................................................... 16  
   3.7. **Fuel Price Forecast** .................................................................................................................... 17  
   3.8. **Transmission Considerations** .................................................................................................... 19  
   3.9. **Financial and Economic Assumptions** ..................................................................................... 19  
   3.10. **Renewables PTC/ITC Schedule** .............................................................................................. 19  
   3.11. **Renewables PPA & Storage Cost Assumptions** ..................................................................... 20  
4. **Analysis & Framework** ....................................................................................................................... 22  
   4.1. **Planning Models** ......................................................................................................................... 22  
   4.2. **Renewable Studies** ..................................................................................................................... 22  
   4.3. **Energy Storage System (ESS) Models** ..................................................................................... 22  
5. **Risk Analysis** ......................................................................................................................................... 29  
6. **Results** ............................................................................................................................................... 31  
   6.1. **PSA Rate Impact** ......................................................................................................................... 35  
7. **Summary** ........................................................................................................................................... 37  

**Appendices** ........................................................................................................................................... 38  

- Appendix A - City Council Adopted Resolution No. 20170817-061 .................................................. 39  
- Appendix B - Renewable Optimization Model..................................................................................... 42  
- Appendix C - Energy Storage Model..................................................................................................... 43  
- Appendix D - NPRR 863 ......................................................................................................................... 45  
- Appendix E - ERCOT Market Rules – FRRSUP and FRRSDN............................................................. 46
Table of Figures
Figure 3.1.1 - Announced Coal Plant Retirements and/or Mothball.........................................................9
Figure 3.2.1 - Expected Capacity Additions/Retirements ..............................................................................11
Figure 3.3.1 - Austin Energy Thermal and Renewable PPA Resources .........................................................12
Figure 3.5.1 - Austin Energy System Peak Demand Forecast ........................................................................14
Figure 3.5.2 - Austin Energy Annual Energy Forecast ..................................................................................14
Figure 3.5.3 - Austin Energy System Peak Demand Forecast Uncertainty .................................................15
Figure 3.5.4 - Austin Energy Annual Energy Forecast Uncertainty ..........................................................15
Figure 3.5.1 - ERCOT System Peak Demand Forecast ..............................................................................16
Figure 3.6.2 - ERCOT System Annual Energy Forecast .............................................................................17
Figure 3.7.1.1 - 2020 Resource Plan Natural Gas Price Forecast Range ....................................................18
Figure 3.7.2.1 - Coal and Nuclear Price Forecasts ......................................................................................18
Figure 3.11.1 - Battery Overnight Capital Cost and FO&M .......................................................................21
Figure 4.3.1 - Storage Ancillary Services and Operating Modes ..............................................................24
Figure 4.3.2 - 10 MW/20 MWh Battery Storage Energy, Ancillary Revenues and Charging Cost 2023 Installation Year .................................................................................................................27
Figure 5.1 - ERCOT Operating Reserve Demand Curve ...........................................................................29
Figure 6.1 - Renewable Studies PSA 20 Year NPV ..................................................................................33
Figure 6.2 - Renewable Studies PSA Average Annual Nominal Cost ..........................................................34
Figure 6.1.1 - Total Dollars above (below) the 2% Goal .............................................................................35
Figure 6.1.2 - Average System Rates above (below) the 2% Goal ............................................................36
Table of Tables

Table 3.1.1 - ERCOT Capacity and Demand Reserve Margin (2020-2024) – May 2019 .................10
Table 3.4.1 - Austin Energy Historical Peak Demand and Energy Requirements ..................13
Table 3.11.1 - ERCOT Renewable PPA Forecasts by Year Fuel Type and Zone .......................20
Table 4.3.1 - ERCOT Storage Capacity Existing and Projected .................................................25
Table 4.3.2 - Expected Net Revenue Inclusive of Capital Cost ..................................................26
Table 4.3.3 - 10 MW/20 MWh Battery Storage Energy, Ancillary Revenues and Charging Cost 2023 Installation Year .........................................................................................................................................................27
Table 4.3.4 - Sample Day Optimization Result ................................................................................28
Table 6.1 - Timing of Renewable Additions – 65%, 75% and 80% Studies ...............................31
Table 6.2 - Timing of Renewable Additions – 100% Study ..........................................................31
Table 6.3 - Renewable Additions to Meet Studies Goals .............................................................32
Table 6.4 - Renewable Studies PSA 20 Year NPV .......................................................................32
Table 6.5 - Renewable Studies PSA Average Annual Nominal Cost ..........................................33
Table 6.6 - Carbon Free 20 Year NPV PSA ..................................................................................34
Table 6.7 - Carbon Free Annual Average Nominal PSA .............................................................34
1. Executive Summary

In addition to meeting the goals of the Austin Climate Protection Plan, resource planning at Austin Energy is a continuous Strategic Initiative that supports several Strategic Goals for Austin Energy including Financial Health, Business Excellence and Environment.

Resource planning also sets high-level goals and strategies to manage customer demand. Reducing customer demand, especially during hours when prices are highest has the effect of lowering cost while lessening the environmental footprint of using energy. As a result, these programs allow the utility to maintain strategies that benefit all of our customers.

On August 17, 2017, the City Council approved Resolution No. 20170817-0611, adopting the Working Group recommendations and providing additional direction. The resolution further directed Austin Energy to perform different studies targeting different renewable and storage goals. The studies encompass a 10-year planning horizon within the ERCOT Nodal market framework. The studies help provide information to assess the opportunities and risks for serving AE electric customers over the longer term.

In addition to meeting the goals and objectives adopted in the 2027 Plan, the directives direct Austin Energy to perform the studies that includes:

- Construct a model that achieves both a 75% and an 80% renewable energy goal by 2027, including a consideration of the costs, benefits, risks and potential rate impacts
- Construct a model that achieves a 100% carbon-free energy goal by 2030, including a consideration of the costs, benefits, risks and potential rate impacts
- Assess the feasibility of achieving 100% renewable energy by 2035
- Study the costs, benefits, risks and potential rate impacts of achieving a more aggressive electric storage goal, such as 50 MW of electrical storage by 2027 and of achieving 100 MW of electrical storage by 2027

The studies considered renewable generation across different geographical regions in ERCOT using Optimization. Our studies recommend solar and to a lesser degree wind, ideally both located closer to the load centers. However, we note that Austin Energy renewable procurement is based on a request for proposals and considers prices, location and congestion amongst other factors and may deviate from the studies recommendations.

There are no questions that solar and wind have and will continue to benefit the ERCOT market in the form of lower emissions and prices; however, absent large scale storage there is operational risk in the near-term that needs to be addressed. To that aim, ERCOT identified some of the operational challenges associated with Intermittent Renewable Resources (IRR) as, intermittency in energy supply

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1 The full resolution is available in Appendix A.
making it difficult to predict available capacity for future hours and impacting regulation services, and large and sudden ramps for managing variance. In addition, renewable capacity may not coincide with peak demand (So called California Duck-Curve).

Studying or Planning for AE’s future needs is challenging. There is a great deal of challenges surrounding the studies including:

- Rapidly Changing Market Environment
- The future is uncertain and the model we use assumes we know everything we need to make the best choice, i.e. “perfect information” making model results less tenable
- The risks associated with intermittent resources
- Transmission limitations resulting in congestion with increased penetration of renewable resources
- Ramp issues and duck curve
- Future Market rule changes with the changing energy mix
- Future Federal policy changes
- Future PPA terms and costs

In short, there is a growing cone of uncertainty which is difficult to quantify. However, Austin Energy is able to provide a range and is confident the result can fall anywhere in the range under various uncertainties. The power supply adjustment cost (PSA) ranges as follows:

<table>
<thead>
<tr>
<th>Net Load Cost ($million)</th>
<th>65%</th>
<th>75%</th>
<th>80%</th>
<th>100%</th>
<th>Carbon_Free</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low (5th Percentile)</td>
<td>$4,170</td>
<td>$4,208</td>
<td>$4,227</td>
<td>$4,267</td>
<td>$4,224</td>
</tr>
<tr>
<td>High (95th Percentile)</td>
<td>$6,681</td>
<td>$6,667</td>
<td>$6,660</td>
<td>$6,658</td>
<td>$6,825</td>
</tr>
</tbody>
</table>

The following key themes have emerged from the Studies:

- When prices are low as in the 5th percentile, increasing the share of renewable resources increases the PSA
- When prices are high as in the 95th percentile, increasing the share of renewable resources is flat assuming that the resources are closer to the load centers and available during high price periods
- Retiring all gas generation increases the PSA in both High and Low cases.
- Storage seems to add cost to the portfolio and would require further reduction in the cost to make it economical

The intermittent nature of energy production from renewable resources, and the much wider geographic footprint of power generation resources than is usual for an electric utility, a daily supply portfolio and risk management process involving production forecasting, supply balancing
transactions, and seasonal, monthly and daily congestion (basis) hedging becomes paramount to the successful operation of a power supply portfolio of renewable resources. In conclusion, Austin Energy continues to remain the leader among its peer utilities in achieving a clean generation portfolio and providing for sound business decisions in a highly competitive electric market. Austin Energy will continue to strive to strike a balance between both objectives. Flexibility is key for achievement of the goals and maintenance of rate stability.
2. Introduction

2.1. The 2027 Plan: Directives
On August 17, 2017, the City Council approved Resolution No. 20170817-061², adopting the Working Group recommendations and providing additional direction. The Studies detailed in this report include:

**Renewable Energy**
- Construct a model that achieves both a 75% and an 80% renewable energy goal by 2027, including a consideration of the costs, benefits, risks and potential rate impacts.
- Construct a model that achieves a 100% carbon-free energy goal by 2030, including a consideration of the costs, benefits, risks and potential rate impacts.
- Assess the feasibility of achieving 100% renewable energy by 2035.

**Emerging Technology and Energy Storage**
- Study the costs, benefits, risks and potential rate impacts of achieving a more aggressive electric storage goal, such as 50 MW of electrical storage by 2027 and of achieving 100 MW of electrical storage by 2027.

2.2. Approach to the Studies

**75% and 80% renewable energy goal by 2027**
- Timing and capacity additions from optimization
- Ownership after PTC/ITC expires if economical

**100% Carbon free energy goal by 2030**
- Carbon free assumes no fossil generation
- Retire Sand Hill CC and Gas turbines in 2030
- Transmission upgrades with retirement of all the Gas units where known
- 65% renewable goal

**100% renewable energy goal by 2035**
- Timing and capacity additions from optimization
- In addition to 80% by 2027, equal increments are added in 2031, 2033 and 2035
- Ownership after PTC/ITC expires if economical

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² The full resolution is available in Appendix A.
3. Inputs to Studies

3.1. Current State of the ERCOT Market

Advances in hydraulic fracturing have made it possible to access some of the potential of gas shale production. In the near term, the impact on gas prices has been significant with prices in 2019 averaging in the range of $2.0-3.0/MMBtu. At these low natural gas prices, coal power plants are being displaced by gas-fired generation. Nevertheless, increased competition from renewable resources has resulted in energy prices that do not provide support for long-term investment in new gas plants. Recent announcements of coal and gas retirements and continued load growth raise concerns about ERCOT reserve margins expected to stand at 10%-11% or even less this summer. Figure 3.1.1 shows the location of recently announced coal retirements.

![Figure 3.1.1 - Announced Coal Plant Retirements and/or Mothball](image)

A total of 4,245 MW of coal generation retired at the end of December 2017 and early January 2018. Another coal plant at risk is the 470 MW Gibbons Creek 1 that was seasonally mothballed in 2018 and will participate in the ERCOT wholesale market only during the summer months June through September.

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3 Although coal plant retirements took place after completion of the resource plan, scenarios anticipating coal retirement of this magnitude were analyzed.

4 Coal plants in Texas - Source: [https://www.eia.gov/state/maps.php](https://www.eia.gov/state/maps.php)
In addition to announced coal retirements, 45 MW of biomass capacity was retired in 2017, and 823 MW of gas capacity was retired in early 2018.

As shown in Table 3.1.1 below, these retirements have a direct impact on the ERCOT Capacity, Demand, and Reserve Margin (CDR).

Table 3.1.1 - ERCOT Capacity and Demand Reserve Margin (2020-2024) – May 2019

<table>
<thead>
<tr>
<th>Load Forecast, MW:</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
</tr>
</thead>
<tbody>
<tr>
<td>Summer Peak Demand (based on normal weather)</td>
<td>76,645</td>
<td>78,824</td>
<td>80,390</td>
<td>82,506</td>
<td>84,121</td>
</tr>
<tr>
<td>plus: Energy Efficiency Program Savings Forecast</td>
<td>1,764</td>
<td>2,065</td>
<td>2,225</td>
<td>2,592</td>
<td>2,823</td>
</tr>
<tr>
<td>Total Summer Peak Demand (before Reductions from Energy Efficiency Programs)</td>
<td>78,409</td>
<td>80,889</td>
<td>82,615</td>
<td>85,098</td>
<td>86,943</td>
</tr>
<tr>
<td>less: Load Resources Providing Responsive Reserves</td>
<td>-1,173</td>
<td>-1,173</td>
<td>-1,173</td>
<td>-1,173</td>
<td>-1,173</td>
</tr>
<tr>
<td>less: Load Resources Providing Non-Spinning Reserves</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>less: Emergency Response Service (10- and 30-min ramp products)</td>
<td>-749</td>
<td>-749</td>
<td>-749</td>
<td>-749</td>
<td>-749</td>
</tr>
<tr>
<td>less: Energy Efficiency Program Savings Forecast</td>
<td>-1,764</td>
<td>-2,065</td>
<td>-2,225</td>
<td>-2,592</td>
<td>-2,823</td>
</tr>
<tr>
<td>File Peak Load, MW</td>
<td>74,705</td>
<td>76,865</td>
<td>78,390</td>
<td>80,366</td>
<td>81,981</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Resources, MW:</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capacity, Thermal/Hydro</td>
<td>65,207</td>
<td>65,286</td>
<td>65,286</td>
<td>65,286</td>
<td>65,286</td>
</tr>
<tr>
<td>Available mothballed Capacity, MW</td>
<td>3,514</td>
<td>3,514</td>
<td>3,514</td>
<td>3,514</td>
<td>3,514</td>
</tr>
<tr>
<td>Non-Coastal Wind, Peak Average Capacity Contribution (1% of installed capacity)</td>
<td>2,884</td>
<td>2,887</td>
<td>2,887</td>
<td>2,887</td>
<td>2,887</td>
</tr>
<tr>
<td>Coastal Wind, Peak Average Capacity Contribution (5% of installed capacity)</td>
<td>1,636</td>
<td>1,636</td>
<td>1,636</td>
<td>1,636</td>
<td>1,636</td>
</tr>
<tr>
<td>Solar Utility-Scale, Peak Average Capacity Contribution (7% of installed capacity)</td>
<td>1,377</td>
<td>1,377</td>
<td>1,377</td>
<td>1,377</td>
<td>1,377</td>
</tr>
<tr>
<td>Storage, Peak Average Capacity Contribution (0% of installed capacity)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>RMR Capacity to be under Contract</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total Capacity, MW</td>
<td>82,521</td>
<td>88,359</td>
<td>88,644</td>
<td>88,644</td>
<td>88,389</td>
</tr>
</tbody>
</table>

| Reserve Margin | 10.5% | 15.2% | 13.0% | 10.3% | 7.8% |

From the ERCOT system operator perspective, retirement of many large generators is bad news for grid dynamic stability. Generators are rotating mass capable of providing system inertia that can act to arrest frequency deviation and decay whenever there is a deviation in the power balance.

When load demand exceeds generation supplied, frequency drops below the target 60 Hz and conversely increases above the target 60 Hz when generation supplied exceeds load demand. Generators equipped with governor response are able to sense the change in frequency and automatically increase or decrease generation as may be required.

Since renewable resources do not have the same inertial response as gas and steam units, and as the share of renewable resources increases in the mix of generation, there is renewed interest in
understanding the relationship between inertial and frequency response. Chief among them are the following initiatives:

- Making frequency response services a requirement (e.g. an ancillary service)
- Developing control methods for wind and solar in support of grid frequency
- Coupling solar panels with energy storage systems such as batteries and take advantage of inverters’ fast response time to provide the needed solution to frequency control during periods of low grid inertia.
- The use of technology in modern wind generators to transfer kinetic energy stored in the generator and rotating blades to provide additional power under frequency excursion.

3.2. ERCOT Market Resource Additions

Twice a year ERCOT releases a report on Capacity, Demand, and Reserves (CDR), providing information about existing and planned resources for the upcoming years. The CDR from May 2019 is used as a starting point for future resource additions. Of the generation resources reported in the CDR, only those in an advanced stage of completion are included to the resource plan generation mix. Furthermore, wind and solar resources that are included are those with sufficient financial guarantee, as reported in ERCOT’s monthly Generation Interconnection Study (GIS) report.

In order to maintain economic reserve margin as well as to replace retiring resources, further capacity was added beyond what was announced in the CDR. This addition is composed primarily of natural gas, wind, solar and storage. Annual capacity additions and retirements by fuel type are shown in Figure 3.2.1 below.

![Figure 3.2.1 - Expected Capacity Additions/Retirements](image)
3.3. **Austin Energy Thermal and Renewable Resources**

Austin Energy’s generation portfolio currently consists of both conventional thermal power plants and renewable power plants.

Figure 3.3.1 below summarizes Austin Energy’s thermal and renewable Purchase Power Agreement (PPA) resources.

<table>
<thead>
<tr>
<th>Unit Name</th>
<th>Fuel Type</th>
<th>Summer Rated Capacity (MW)</th>
<th>Year Installed</th>
<th>Retire /Contract End</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Fayette Power Project</strong></td>
<td>Coal</td>
<td>302</td>
<td>1979</td>
<td>2022*</td>
</tr>
<tr>
<td>FPP Unit 1</td>
<td>Coal</td>
<td>300</td>
<td>1980</td>
<td>2022*</td>
</tr>
<tr>
<td><strong>Total Coal</strong></td>
<td></td>
<td>602</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Decker Creek Power Station</strong></td>
<td>Gas</td>
<td>315</td>
<td>1970</td>
<td>2020</td>
</tr>
<tr>
<td>Decker Unit 1</td>
<td>Gas</td>
<td>420</td>
<td>1977</td>
<td>2021</td>
</tr>
<tr>
<td>Decker Unit 2</td>
<td>Gas</td>
<td>192</td>
<td>1980</td>
<td>Undecided</td>
</tr>
<tr>
<td><strong>Total Natural Gas</strong></td>
<td></td>
<td>1497</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>South Texas Power Project</strong></td>
<td>Nuclear</td>
<td>218</td>
<td>1988</td>
<td>Undecided</td>
</tr>
<tr>
<td>STP Unit 1</td>
<td>Nuclear</td>
<td>218</td>
<td>1989</td>
<td>Undecided</td>
</tr>
<tr>
<td><strong>Total Nuclear</strong></td>
<td></td>
<td>436</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Biomass</strong></td>
<td></td>
<td>108</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tessman Road Landfill</td>
<td>Landfill Methane</td>
<td>7.8</td>
<td>2003</td>
<td>2019</td>
</tr>
<tr>
<td>Nacogdoches Power</td>
<td>Biomass</td>
<td>100</td>
<td>2012</td>
<td>Undecided</td>
</tr>
<tr>
<td><strong>Total Biomass</strong></td>
<td></td>
<td>108</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Solar</strong></td>
<td></td>
<td>1,194</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Webberville Solar Project</td>
<td>Solar</td>
<td>30</td>
<td>2011</td>
<td>2036</td>
</tr>
<tr>
<td>Roserock Solar</td>
<td>Solar</td>
<td>150</td>
<td>2016</td>
<td>2036</td>
</tr>
<tr>
<td>Bootleg Solar</td>
<td>Solar</td>
<td>170</td>
<td>2016</td>
<td>2031</td>
</tr>
<tr>
<td>Kingsbury Solar</td>
<td>Solar</td>
<td>2</td>
<td>2017</td>
<td>2042</td>
</tr>
<tr>
<td>Waymark Solar</td>
<td>Solar</td>
<td>170</td>
<td>2018</td>
<td>2043</td>
</tr>
<tr>
<td>STPX12B1 Solar</td>
<td>Solar</td>
<td>170</td>
<td>2017</td>
<td>2042</td>
</tr>
<tr>
<td>Aragorn Solar</td>
<td>Solar</td>
<td>180</td>
<td>2021</td>
<td>2036</td>
</tr>
<tr>
<td>Pflugerville Solar</td>
<td>Solar</td>
<td>144</td>
<td>2021</td>
<td></td>
</tr>
<tr>
<td>Pandora Solar</td>
<td>Solar</td>
<td>250</td>
<td>2024</td>
<td>2038</td>
</tr>
<tr>
<td><strong>Total Solar</strong></td>
<td></td>
<td>1,194</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Wind</strong></td>
<td></td>
<td>1,768</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Whirlwind Energy Center</td>
<td>Wind</td>
<td>60</td>
<td>2007</td>
<td>2027</td>
</tr>
<tr>
<td>Hackberry Wind Project</td>
<td>Wind</td>
<td>165</td>
<td>2009</td>
<td>2023</td>
</tr>
<tr>
<td>Los Vientos II Windpower Project</td>
<td>Wind</td>
<td>202</td>
<td>2013</td>
<td>2037</td>
</tr>
<tr>
<td>White Tail Wind Farm</td>
<td>Wind</td>
<td>91</td>
<td>2013</td>
<td>2037</td>
</tr>
<tr>
<td>Los Vientos III Windpower Project</td>
<td>Wind</td>
<td>200</td>
<td>2015</td>
<td>2040</td>
</tr>
<tr>
<td>Los Vientos IV Windpower Project</td>
<td>Wind</td>
<td>200</td>
<td>2016</td>
<td>2041</td>
</tr>
<tr>
<td>Jumbo Road Wind</td>
<td>Wind</td>
<td>300</td>
<td>2015</td>
<td>2033</td>
</tr>
<tr>
<td>Karankawa Wind</td>
<td>Wind</td>
<td>200</td>
<td>2020</td>
<td>2034</td>
</tr>
<tr>
<td>Gulf Wind</td>
<td>Wind</td>
<td>150</td>
<td>2020</td>
<td>2035</td>
</tr>
<tr>
<td>Raymond Wind</td>
<td>Wind</td>
<td>200</td>
<td>2021</td>
<td></td>
</tr>
<tr>
<td><strong>Total Wind</strong></td>
<td></td>
<td>1,768</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Rated Capacity (2020)</strong></td>
<td></td>
<td>4,831</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Effective Capacity (2020)</strong></td>
<td></td>
<td>3,746</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* - To begin the retirement of Austin Energy’s portion of the Fayette Power Project (FPP), beginning by the end of 2022
The effective capacity is based on ERCOT discount factors for renewable resources and location; solar reserve contribution is 74%, west wind 15%, and coastal wind 58%.

3.4. Austin Energy Historical Peak Demand and Energy

Austin Energy’s peak demand and energy requirements vary each year as a function of multiple factors such as weather, population growth, and economic activity as well as conservation programs. Table 3.4.1 below provides last seven years peak demand data.

<table>
<thead>
<tr>
<th>Calendar Year</th>
<th>Peak Demand (MW)</th>
<th>% Change</th>
<th>Energy Requirements (GWh)</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>2,714</td>
<td></td>
<td>13,500</td>
<td></td>
</tr>
<tr>
<td>2012</td>
<td>2,701</td>
<td>-0.5%</td>
<td>13,043</td>
<td>-3.4%</td>
</tr>
<tr>
<td>2013</td>
<td>2,588</td>
<td>-4.2%</td>
<td>13,056</td>
<td>0.1%</td>
</tr>
<tr>
<td>2014</td>
<td>2,584</td>
<td>-0.2%</td>
<td>13,072</td>
<td>0.1%</td>
</tr>
<tr>
<td>2015</td>
<td>2,735</td>
<td>5.8%</td>
<td>13,409</td>
<td>2.6%</td>
</tr>
<tr>
<td>2016</td>
<td>2,755</td>
<td>0.7%</td>
<td>13,465</td>
<td>0.4%</td>
</tr>
<tr>
<td>2017</td>
<td>2,654</td>
<td>-3.67%</td>
<td>13,564</td>
<td>0.74%</td>
</tr>
<tr>
<td>2018</td>
<td>2,878</td>
<td>8.43%</td>
<td>13,928</td>
<td>2.68%</td>
</tr>
</tbody>
</table>

3.5. Austin Energy Forecasted Peak Demand and Energy

Austin Energy employs a combination of models to forecast future peak and energy demand. The models build monthly forecasts by customer classes that are aggregated to generate system-wide forecasts. The Statistically Adjusted End-use\(^5\) (SAE) forecast models are used to forecast residential and commercial sales; the industrial energy forecast is based on an econometric model.

All forecast models are adjusted to reflect the expected Demand Side Management (DSM) program savings to reach the DSM goal of 800 MW by 2020. The peak demand forecast is based on a multivariate regression model that incorporates the effect of temperature variation on monthly peak demand. Figure 3.5.1 shows peak demand forecast for 2020-2030. Peak demand is projected to grow from 2,779 MW in 2020 to 2,916 MW in 2030. This represents an average growth rate of 0.4% a year for that period. Austin Energy’s all-time peak of 2,878 MW occurred during summer 2018.

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\(^5\) Further description about Austin Energy load Forecast Methodology is available in Appendix B.
Figure 3.5.2 below shows Austin Energy annual energy forecast for the same period. Total energy demand is forecasted to be 13,910 GWh at the end of 2020 and then grow 0.4% annually to total energy demand of 14,552 GWh in 2030.
Alternative scenarios are also modeled to address forecast uncertainties due to weather variability. The extreme summer weather scenario is a simulation of the base forecast scenario coupled with extreme weather forecast conditions. The mild weather scenario is a simulation of the current base forecast scenario coupled with mild weather forecast conditions. Figure 3.5.3 shows the forecasted peak demand, and Figure 3.5.4 shows forecasted energy for the period 2020-2030 for the base, extreme weather, and mild weather scenarios.
3.6. ERCOT Forecasted Peak Demand and Energy

In 2014, ERCOT moved away from using economic indicators, such as nonfarm employment, for forecasting load to using a model that relies on forecasted growth rates in customer accounts (or premises) to project future growth trends. This model better captures the relationship between premise counts and specific economic factors such as number of households, population, housing stock and regional trends, as well as the variations in energy use among residential, business and industrial consumers.

ERCOT’s long-term load forecast, which was released in December 2018, is used to build load profiles for the resource planning study. Figure 3.6.1 shows ERCOT-wide system peak demand forecast for the base, extreme and mild weather scenarios. Peak demand is projected to grow from 75,922 MW in 2020 to 90,712 MW by 2030. This represents a compounded annual growth rate of 1.8%.

![Figure 3.6.1 - ERCOT System Peak Demand Forecast](image)

Figure 3.6.2 below shows the forecasted total energy for the period 2020-2030. Forecasted energy is expected to grow from 393,572 GWh in 2020 to 496,388 GWh in 2030, representing a 2.4% compound growth rate.

![Figure 3.6.2 - Forecasted Total Energy](image)
3.7. Fuel Price Forecast

3.7.1. Natural Gas

For the first year of the resource planning study, natural gas price forecasts are based on the New York Mercantile Exchange (NYMEX) gas index. For the remainder of the study period, long-term price outlooks from Wood Mackenzie are used. Selection of NYMEX forecasts for the first year is based on the notion that NYMEX gas prices are good indicators of the short to mid-term natural gas forward curve. On the other hand, Wood Mackenzie’s integrated, bottom-up data modeling and analysis approach makes the forecast more suitable for long-term price outlooks.

Regional ERCOT price differences or basis costs are applied to the price forecasts to derive the ERCOT region’s gas prices. Price forecasts are then adjusted for delivery costs and input to the UPLAN model. Three gas price scenarios are considered; base, high and low. Figure 3.7.1 shows annual natural gas price forecast for all scenarios.
3.7.2. Coal & Nuclear

Figure 3.7.2.1 shows annual nuclear fuel prices for Austin Energy resources and nuclear resources in ERCOT. For coal resources in Texas, forecasts from SNL Financial are used. Coal price forecasts do not reflect adjustments for EPA regulations affecting coal plants. Nuclear prices are based on published contract costs.
3.8. Transmission Considerations
ERCOT Steady State Working Group (SSWG) whose members are representatives of ERCOT Transmission Service Providers (TSP) and the ERCOT staff, releases seasonal and future transmission system data and load-flow base cases. These cases span a period of one year for the seasonal cases to up to seven years for long-term planning. These cases form the basis for the transmission network in UPLAN. In addition, the ERCOT Transmission Project and Information Tracking (TPIT) database provides TSPs with expected network updates that have yet to be implemented in the SSWG models release. In addition to the transmission upgrades outside the AE load zone, we have also considered upgrades that might result with the retirement of Decker Steam Generation.

3.9. Financial and Economic Assumptions
- Capital
  - 30 year 80% debt financing
  - 4.5% interest rate (near term: 5 years)
  - 5.5% interest rate (beyond year 6)
  - Applies to Capital Improvement Projects (CIP) for current plants
- Economic parameters
  - General inflation at 2%
  - Discount Rate at 7.5% (Austin Energy Weighted Average Cost of Capital)

3.10. Renewables PTC/ITC Schedule
Currently, the federal government provides Production Tax Credits (PTC) and Investment Tax Credits (ITC) to incentivize renewable energy generation. The incentive amounts are set to decline according to the following schedule:

Wind
- Commence construction prior to January 1, 2017 – 100% PTC or 30% ITC
- Commence construction during 2017 – 80% PTC or 24% ITC
- Commence construction during 2018 – 60% PTC or 18% ITC
- Commence construction during 2019 – 40% PTC or 12% ITC
- PTC/ITC are subject to being placed in service within two years from date of construction

Solar
- Commence construction prior to January 1, 2020 – 30% ITC
- Commence construction during 2020 – 26% ITC
- Commence construction during 2021 – 22% ITC
- Commence construction during 2022 – 10% ITC
- PTC/ITC are subject to being placed in service within two years from date of construction
3.11. **Renewables PPA & Storage Cost Assumptions**

Austin Energy contracts its utility-scale wind and solar generation through PPAs to take advantage of tax credits and lower the cost of renewable energy to our customers. PPA costs have dropped significantly in the recent past, Table 3.11.1 below shows PPA forecasts for ERCOT region. The PPA costs are based on Wood Mackenzie levelized costs and Austin Energy 2018 Renewable RFP.

*Table 3.11.1 - Renewable PPA Forecasts by Year Fuel Type and Zone*

<table>
<thead>
<tr>
<th>Year</th>
<th>Pan Solar</th>
<th>West Solar</th>
<th>North Solar</th>
<th>South Solar</th>
<th>Pan Wind</th>
<th>West Wind</th>
<th>North Wind</th>
<th>South Wind</th>
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</thead>
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<td>$21.76</td>
<td>$24.87</td>
<td>$27.86</td>
</tr>
<tr>
<td>2030</td>
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<td>$27.99</td>
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<td>$22.07</td>
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<td>$24.69</td>
<td>$24.89</td>
<td>$26.99</td>
<td>$23.91</td>
<td>$23.91</td>
<td>$27.02</td>
<td>$30.01</td>
</tr>
</tbody>
</table>
Figure 3.11.1 below shows overnight battery capital cost and FO&M (Source: Wood Mackenzie).

![Graph showing battery overnight capital cost and FO&M](image-url)

*Figure 3.11.1 – Battery Overnight Capital Cost and FO&M*
4. **Analysis & Framework**

4.1. **Planning Models**

Austin Energy relies on several models in the course of its resource planning. The main planning model is UPLAN Network Power Model\(^6\) (UPLAN-NPM), referred to as the “market model” is a proprietary software developed by LCG consulting. The other models are developed in-house to address specific modeling details associated with renewable resources, energy storage systems, finance, and SAS\(^7\) based programming language for reporting purposes.

Specific in-house linear programming models are developed for the purpose of renewable optimization\(^8\) and Mixed Integer Programming (MIP) models to address the unique features of energy storage systems, such as utility-scale battery storage. In all applications, nodal prices are obtained from the UPLAN market model.

Several financial models are also applied in resource planning. The primary financial model is maintained by Austin Energy’s Finance department and is also used for utility budgeting and rate-making decisions. Another financial model is the revenue requirement model, used to assess the viability of recovering operating and fixed costs of an asset.

4.2. **Renewable Studies**

Decisions that involve the timing, size, and composition of renewable resources over a given period belong to a class of combinatorial problems that can be difficult to solve. In all cases, the nodal LMPs for renewable resources are obtained from the market model and input to this sub-process.

The expected cost and revenues over a contract period of 25 years are input to the model. The model incorporates Austin Energy renewable energy target levels and known constraints about the market such as the maximum amount of renewables that can be developed in specific ERCOT Zones. The outcome is a portfolio of renewable resources and associated net present value revenues. It is important to note the optimization model is constrained in order to specify different levels of targets to meet resource plan objectives; once the target levels and terminal dates are specified the decision variables are type and location of renewable resource.

4.3. **Energy Storage System (ESS) Models**

A Mixed-Integer Programming Model\(^9\) (MIP) is developed to calculate the potential energy and ancillary services revenues of a 10MW, 2 hour duration battery (10 MW/20 MWh).

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\(^6\) A full description of UPLAN is available in Appendix C.
\(^7\) SAS stands for “Statistical Analysis System”.
\(^8\) Provided in Appendix D
\(^9\) Provided in Appendix E
fundamental model is used to forecast energy and ancillary service prices which are then used as input to the model as the battery is assumed a price-taker.

Our results indicate that energy arbitrage provides limited opportunities for revenues while ancillary services provide the bulk of revenues for grid scale energy storage. These findings are consistent with the report published by Pacific Gas and Electric summarizing “real-world” experience and data from participation of energy storage in CAISO\textsuperscript{10}.

Timing of installation of energy storage is achieved via maximization of net revenues over 20-year period. Storage goals of 50 MW and 100 MW by 2027 are achieved by installing each year 10 MW and 20 MW of energy storage respectively in years 2023-2027.

Netting battery capital cost from energy and ancillary services revenues results in negative profit and indicating under current expected capital cost battery storage is not yet profitable.

**Assumptions:**

- Maximum energy capacity: 20MWh
- Minimum energy capacity: 2MWh
- Maximum Charge/Discharge rate: 10MW
- Charging/Discharging efficiency: 85%
- Battery life: 10years
- Study Period: 2020-2040
- Capital cost: Based on Fixed O&M data provided by Wood Mackenzie Overnight battery

Several West Texas storage locations were considered as a proxy location:

- Blue Summit Energy
- Inadale ESS
- Notrees Energy Facility
- Pyron ESS
- Castle Gap Energy

Under current nodal market structure energy storage can only provide Fast Regulation Service in the up and down directions (FRRSUP and FRRSDN); however, ERCOT has recently approved a Nodal Protocol Revision Request (NPRR) 863 expanding the provision of Responsive Reserve Service (RRS) to storage facilities. Appendix F NPRR 863 provides ERCOT current ancillary service framework and new expanded services. To align our model with NPRR 863, no restrictions are imposed on the

amount of RRS that can be provided by energy storage. Henceforth, 10 MW of energy storage can provide 10 MW of RRS.

**Ancillary Services from Battery Storage**

Figure 4.3.1 below illustrates the possible combination of ancillary services that can be provided under differing battery operating modes.

In off-line mode, when the energy storage is not charging or discharging, it can sell the capacity in day ahead and provide FRRSUP, FRRSDN and RRS. In charging mode, energy storage can only provide FRRSDN. In discharge mode, energy storage can provide RRS and FRRSUP.

**Energy Storage in Day-Ahead Market**

Energy storage can plan its real time operational activity in the day-ahead market by submitting offers or bids to sell or buy energy respectively. The day-ahead market provides opportunities for energy storage to plan and maintain the desired state of charge in real time. In our model in order to avoid cycling cost associated with maintaining battery life we maintain a daily State of Charge (SOC) of 50%.

Based on ERCOT rules we impose restrictions on the maximum amount of FRRSUP and FRRSDN that can be provided by energy storage. ERCOT market rules for these two services are provided in Appendix G ERCOT Market Rules - FFRSU and FFRSD.

Based on ERCOT market rules, 10 MW of energy storage can provide only 8 MW of FRRSUP and 5 MW of FRRSDN. These numbers are expected to decrease as more storage is installed in ERCOT.
**Energy Storage in Real-Time Market**

In real time, if the storage is selected to provide FRRSDN, it will incur energy cost since providing this service requires charging. If storage is selected to provide FRRSUP or RRS it will earn energy revenues. ERCOT Deployment methodology for FFRSU and FFRSDN is provided in Appendix H.

To incorporate the above real time operations, we assume a 14% probability that the capacity sold in day ahead as FRRSUP/FRRSDN will be utilized in real time. We also assume a 1% probability that the capacity sold in day ahead as RRS will be deployed in real-time.

Finally, we enforce all model constraints to prevent overselling capacity as ancillary services in day ahead and obey SOC limitations. The average hourly prices from resources listed in Table 4.3.1 provide a proxy hourly forecast price for storage.

<table>
<thead>
<tr>
<th>UNIT NAME</th>
<th>UNIT CODE</th>
<th>COUNT CDR ZONE</th>
<th>START YEAR</th>
<th>CAPACITY (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>BLUE SUMMIT BATTERY</td>
<td>BLSUMMIT_BATTERY</td>
<td>WILBAR WEST</td>
<td>2017</td>
<td>30</td>
</tr>
<tr>
<td>INADALE ESS</td>
<td>INDL_ESS</td>
<td>NOLAN WEST</td>
<td>2018</td>
<td>9.9</td>
</tr>
<tr>
<td>NOTREES BATTERY FACILITY</td>
<td>NWF_NBS</td>
<td>WINKLE WEST</td>
<td>2013</td>
<td>33.7</td>
</tr>
<tr>
<td>PYRON ESS</td>
<td>PYR_ESS</td>
<td>SCURRY WEST</td>
<td>2018</td>
<td>9.9</td>
</tr>
<tr>
<td>OCI ALAMO 1</td>
<td>DG_OCI_ALMO1_ASTROI</td>
<td>BEXAR SOUTH</td>
<td>2016</td>
<td>1</td>
</tr>
<tr>
<td>TOS BATTERY STORAGE</td>
<td>DG_TOSBATT_UNIT1</td>
<td>MIDLAN WEST</td>
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</tr>
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<td>CASTLE GAP BATTERY</td>
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<td>2018</td>
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</tr>
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<td>BEXAR SOUTH</td>
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<td>RABBIT HILL ENERGY STORAGE PROJECT</td>
<td>WILLAG_SOUTH</td>
<td></td>
<td>2019</td>
<td>9.9</td>
</tr>
</tbody>
</table>

Source: ERCOT - Seasonal Assessment of Resource Adequacy (SARA - Summer 2019)

Our model incorporates all operational constraints previously discussed and sets as an objective the maximization of revenue less storage cost, given the energy and ancillary service prices from UPLAN. The basic assumption is for storage to act as price taker in the ERCOT market with no feedback-loop. The study horizon spans the period 2020-2040.

In order to achieve the goal of 50 MW of storage by 2027, we install storage in increments of 10MW/20MWh. The timing of the installation is based on the year that yields the maximum NPV of net revenues over 20 years. Based on our analysis 2023-2027 is the optimal period to install energy storage in increments of 10 MW per year to reach 50MW storage by 2027.

Table 4.3.2 below shows the expected 20-year nominal net revenues inclusive of capital cost for storage installed between 2023 and 2027.
Table 4.3.2 - Expected Net Revenue Inclusive of Capital Cost

Table 4.3.2 shows that based on expected capital cost battery storage is currently uneconomical.

To achieve the 100 MW of storage goal by 2027, we plan to install storage in increments of 20 MW/40MWh for years 2023-2027.

Table 4.3.3 shows the expected hourly energy and ancillary service revenues and charging cost over the battery life for 10MW/20MWH energy storage installed in 2023.
Table 4.3.3 - 10 MW/20 MWh Battery Storage Energy, Ancillary Revenues and Charging Cost

2023 Installation Year

Figure 4.3.2 shows the ancillary services by energy revenue components and charging cost for a battery installed in 2023.

Table 4.3.3 and Figure 4.3.2 highlight the fact that Ancillary services provide the bulk of revenue for grid scale energy storage, whereas energy arbitrage provide limited revenues. Maximum revenue is achieved by selling FRRSUP and RRS combining for 70% of revenues, then energy revenue 20% and FRRSDN at 10% of revenues. This finding is consistent with a report published by PG&E.
summarizing the potential revenues of energy storage in the CAISO market. Charging cost includes the potential of deployment of storage in real time to provide regulation down.

Table 4.3.4 shows a sample day optimization result.

**Table 4.3.4 - Sample Day Optimization Result**

<table>
<thead>
<tr>
<th>Hour</th>
<th>SOC</th>
<th>Energy Charge (MW)</th>
<th>Discharge (MW)</th>
<th>FRRSDN (MW)</th>
<th>FRRS UP (MW)</th>
<th>RRS (MW)</th>
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<tbody>
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<td>1</td>
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<td>0.00</td>
<td>5.00</td>
<td>0.00</td>
<td>10.00</td>
</tr>
<tr>
<td>22</td>
<td>9.05</td>
<td>0.00</td>
<td>0.00</td>
<td>5.00</td>
<td>0.00</td>
<td>10.00</td>
</tr>
<tr>
<td>23</td>
<td>9.52</td>
<td>0.00</td>
<td>0.00</td>
<td>5.00</td>
<td>0.00</td>
<td>10.00</td>
</tr>
<tr>
<td>24</td>
<td>10.00</td>
<td>0.00</td>
<td>0.00</td>
<td>5.00</td>
<td>0.00</td>
<td>10.00</td>
</tr>
</tbody>
</table>
5. **Risk Analysis**

The ERCOT market is an energy only market in which prices are allowed to rise to an administratively set cap of 9,000 $/MWH. Under shortage pricing Energy prices are allowed to increase as a function of the available on line reserves. This pricing mechanism is design to impute a value to reserves\(^\text{11}\), more specifically, as the amount of reserves declines an adder to energy prices increases as a function of remaining reserves. When the total available on-line capacity reaches 2,000 MW energy prices will fully reflect the cap. Higher market prices are expected to attract over-time new investment in generation. This pricing mechanism is referred to as Operating Reserve Demand Curve (ORDC). Figure 5.1 below shows sample ORDC curves.

![Figure 5.1 - ERCOT Operating Reserve Demand Curve](image)

Figure 5.1 shows the outcome of the Public Utility Commission of Texas (PUCT) decisions to prop-up prices, resulting in faster increase (green curve) to the cap as on-line operating reserves dwindle and a steep incline at 2,000 MW.

\(^{11}\) As the amount of physical reserves dwindle the network becomes more susceptible to perturbations, and the probability of not serving load increases. This expected cost of not serving load is imputed to reserves in the form of an administratively set energy adder ($/MWH) to locational energy prices, and is charged to all of the loads. The Public Utility Commission of Texas opted for the energy-only market with shortage pricing effective June 1, 2014. The price cap is reviewed and adjusted periodically.
The relevance of ORDC is evident in the context of August 2019 when energy prices topped at 9,000 $/MWH for several intervals and multiple days; in part due to inaccurate forecasts for renewable resources, exacerbating tight reserve conditions. Situations experienced during August 12-16, 2019 will be more pronounced and prominent as the share of wind and solar generation increases in ERCOT generation mix.

There are no questions that solar and wind have and will continue to benefit the ERCOT market in the form of lower emissions and prices; however, absent large scale storage there are operational risks in the near-term that need to be addressed. To that aim, ERCOT identified some of the operational challenges\textsuperscript{12} associated with Intermittent Renewable Resources (IRR) as, intermittency in energy supply making it difficult to predict available capacity for future hours and impacting regulation services, and large and sudden ramps for managing variance. In addition, renewable capacity may not coincide with peak demand (So called California Duck-Curve).

In order to quantify the impact of tight reserve margins, higher market dependence on renewable generation and revised ORDC pricing; Austin Energy performed a sensitivity analysis. Under sensitivity analysis, a particular configuration of Austin Energy’s portfolio is subject to differing modes of inputs. Sensitivity analysis informs about the robustness of the portfolio when key variables are changed from expected values. For example, if natural gas prices are higher or lower than expected, what is the impact on the portfolio? Sensitivities provide a structured framework to consider and analyze various options in a way that provides decision makers with valuable information about the robustness of those decisions. In addition to the sensitivity analysis, to address some of the idiosyncratic risk of fast power output fluctuation, Austin Energy reviewed the historic performance of existing renewable resources associated with high price periods and assumed those conditions would persist during the planning horizon. Any capacity shortfall from renewable resources during peak hours in a given year and a period of ten hours would be purchased at the prevailing high market price.

\textsuperscript{12} ERCOT Market Education Intermittent Renewable Resources
6. Results

Table 6.1 provides a summary of renewable additions by study.

*Table 6.1 - Timing of Renewable Additions – 65%, 75% and 80% Studies*

<table>
<thead>
<tr>
<th>Renewable Studies</th>
<th>GWh Req</th>
<th>Total GWh Short</th>
<th>Tranches (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>65% by 2027</td>
<td>9,312</td>
<td>1,001</td>
<td>334 334 334</td>
</tr>
<tr>
<td>75% by 2027</td>
<td>10,745</td>
<td>2,434</td>
<td>811 811 811</td>
</tr>
<tr>
<td>80% by 2027</td>
<td>11,461</td>
<td>3,150</td>
<td>1,050 1,059 1,050</td>
</tr>
</tbody>
</table>

For the 100% renewable by 2035 study, in addition to 80% by 2027, equal increments are added in 2031, 2033 and 2035. This is shown in Table 6.2 below.

*Table 6.2 - Timing of Renewable Additions – 100% Study*

<table>
<thead>
<tr>
<th>GWh Req Incremental GWh Short from 80%</th>
<th>Tranches GWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>100% by 2035 14,884 3,423</td>
<td>2031 2033 2035</td>
</tr>
<tr>
<td></td>
<td>1,141 1,141 1,141</td>
</tr>
</tbody>
</table>

Table 6.3 shows renewable additions in order to meet studies goals.
### Table 6.3 - Renewable Additions to Meet Studies Goals

<table>
<thead>
<tr>
<th>Year</th>
<th>Type and Location</th>
<th>MW</th>
<th>MWh</th>
<th>MW</th>
<th>MWh</th>
<th>MW</th>
<th>MWh</th>
<th>MW</th>
<th>MWh</th>
<th>Year</th>
<th>MW</th>
<th>MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>2023</td>
<td>Panhandle Solar</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>2031</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>West Solar</td>
<td>0</td>
<td>0</td>
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<td>0</td>
<td>0</td>
<td></td>
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<td></td>
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<tr>
<td></td>
<td>North Solar</td>
<td>54</td>
<td>133,426</td>
<td>132</td>
<td>324,400</td>
<td>171</td>
<td>420,000</td>
<td>0</td>
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<tr>
<td></td>
<td>South Solar</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<td>0</td>
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<tr>
<td></td>
<td>Panhandle Wind</td>
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<td>West Wind</td>
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<td>South Wind</td>
<td>62</td>
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<td>150</td>
<td>486,600</td>
<td>194</td>
<td>630,000</td>
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<tr>
<td></td>
<td><strong>Total</strong></td>
<td>116</td>
<td>333,565</td>
<td>282</td>
<td>811,000</td>
<td>366</td>
<td>1,050,000</td>
<td>496</td>
<td>1,141,000</td>
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<tr>
<td>2025</td>
<td>Panhandle Solar</td>
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<td>0</td>
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<td>West Solar</td>
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<td>571</td>
<td>1,050,000</td>
<td>620</td>
<td>1,141,000</td>
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<td></td>
<td>Panhandle Wind</td>
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<td>West Wind</td>
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<td>North Wind</td>
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<tr>
<td></td>
<td><strong>Total</strong></td>
<td>181</td>
<td>333,564</td>
<td>441</td>
<td>811,000</td>
<td>571</td>
<td>1,050,000</td>
<td>620</td>
<td>1,141,000</td>
<td></td>
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<tr>
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<td>2035</td>
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<tr>
<td></td>
<td>West Solar</td>
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<td>0</td>
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<td>0</td>
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<tr>
<td></td>
<td>North Solar</td>
<td>109</td>
<td>266,851</td>
<td>265</td>
<td>648,800</td>
<td>342</td>
<td>840,000</td>
<td>186</td>
<td>456,400</td>
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<tr>
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<td>South Solar</td>
<td>36</td>
<td>66,713</td>
<td>88</td>
<td>162,200</td>
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<td>210,000</td>
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<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Panhandle Wind</td>
<td>0</td>
<td>0</td>
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<td></td>
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<td></td>
<td>South Wind</td>
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<td>0</td>
<td>0</td>
<td></td>
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<td></td>
</tr>
<tr>
<td></td>
<td><strong>Total</strong></td>
<td>145</td>
<td>333,564</td>
<td>353</td>
<td>811,000</td>
<td>457</td>
<td>1,050,000</td>
<td>397</td>
<td>1,141,000</td>
<td></td>
<td></td>
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</tr>
<tr>
<td></td>
<td><strong>Grand Total</strong></td>
<td><strong>442</strong></td>
<td><strong>1,000,693</strong></td>
<td><strong>1,076</strong></td>
<td><strong>2,433,000</strong></td>
<td><strong>1,393</strong></td>
<td><strong>3,150,000</strong></td>
<td><strong>1,513</strong></td>
<td><strong>3,423,000</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Renewable optimization selects resources from the best locations (North & South) closer to the load centers with the best mix (more Solar). Study assumes that the resources have zero offer curves owing to the ITC and PTC expiration, resulting in less negative prices in South and North Zones.

Table 6.4 Shows, 5th and 95th Power Supply Adjustment (PSA) calculated on a 20 year NPV basis.

### Table 6.4 - Renewable Studies PSA 20 Year NPV

<table>
<thead>
<tr>
<th>Net Load Cost ($million)</th>
<th>65%</th>
<th>75%</th>
<th>80%</th>
<th>100%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low (5th Percentile)</td>
<td>$4,170</td>
<td>$4,208</td>
<td>$4,227</td>
<td>$4,267</td>
</tr>
<tr>
<td>High (95th Percentile)</td>
<td>$6,681</td>
<td>$6,667</td>
<td>$6,660</td>
<td>$6,658</td>
</tr>
</tbody>
</table>

The above table shows the range of portfolio costs for each of the goals with risk premium due to intermittency of renewable resources. When prices are low as in the 5th percentile, increasing the share of renewable resources increases the PSA. However, when prices are high as in the 95th percentile,
increasing the share of renewable resources is flat assuming that the resources are closer to the load centers and available during high price periods.

Figure 6.1 depicts renewable studies PSA on a 20-year NPV basis.

![Figure 6.1- Renewable Studies PSA](image)

Table 6.5 and Figure 6.2 provide PSA annual average nominal cost.

**Table 6.5 - Renewable Studies PSA Average Annual Nominal Cost**

<table>
<thead>
<tr>
<th>Average Net Load Cost ($million)</th>
<th>65%</th>
<th>75%</th>
<th>80%</th>
<th>100%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low (5th Percentile)</td>
<td>$410</td>
<td>$414</td>
<td>$417</td>
<td>$423</td>
</tr>
<tr>
<td>High (95th Percentile)</td>
<td>$685</td>
<td>$683</td>
<td>$682</td>
<td>$681</td>
</tr>
</tbody>
</table>
Carbon Free Case
Tables 6.6 and 6.7 provide 20 year NPV PSA and annual average nominal PSA cost, respectively. Retiring all gas generation increases the PSA as gas generation dispatches when in the money.

<table>
<thead>
<tr>
<th>Net Load Cost ($million)</th>
<th>Carbon_Free</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low (5th Percentile)</td>
<td>$4,224</td>
</tr>
<tr>
<td>High (95th Percentile)</td>
<td>$6,825</td>
</tr>
</tbody>
</table>

Table 6.7 - Carbon Free Annual Average Nominal PSA

<table>
<thead>
<tr>
<th>Average Net Load Cost ($million)</th>
<th>Carbon_Free</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low (5th Percentile)</td>
<td>$418</td>
</tr>
<tr>
<td>High (95th Percentile)</td>
<td>$707</td>
</tr>
</tbody>
</table>
6.1. PSA Rate Impact

Figure 6.1.1 shows ranges of Electric revenue above or below the 2% affordability goal. From the 2% affordability goal measure, the studies seem to be affordable provided there is a 2% rate increase from 2012 rates. However, this result does not address the competitive measure of below 50th percentile from the rest of Texas, which is very difficult to quantify.

![Figure 6.1.1 - Total Dollars above (below) the 2% Goal (High/Low Scenarios)](image-url)
Figure 6.1.2 shows the system rates for all the studies under high and low cases.
7. Summary

Austin Energy is one of the leaders among the nation’s utilities with substantial investments in renewable energy, energy efficiency, distributed resources, and smart grid technology. In order to continue our environmental leadership, we continually manage the value proposition between renewable PPAs in our portfolio and the value to our customer of renewable project ownership. The cost of renewable energy continues to come down. This bodes well for achieving our 2027 goals as well as future goals. There is risk that exists in our customer’s portfolio as our renewable percentages increase along with the growing amount of renewable energy the ERCOT market experiences. By allowing the utility to achieve its renewable goals in a strategic responsible manner, the utility is provided the opportunity to better manage the intermittent risk inherently growing in its portfolio as well as the price risk this changing portfolio experiences in a market whose conventional assets are shrinking.

Due to the intermittent nature of renewable energy production, risk management processes that manage supply and demand in ERCOT’s wholesale market involving production forecasting, balancing transactions, and seasonal, monthly and daily congestion (basis) hedging become ever more paramount to the successful operation of a power portfolio which has a high concentration of renewable resources.

Austin Energy continues to remain the leader among its peer utilities in achieving a clean generation portfolio and provide for sound business decisions in a highly competitive electric market. Austin Energy will continue to strive to strike a balance between both objectives. Flexibility in timing and technology is key for achievement of the goals and maintenance of rate stability.
Appendices
RESOLUTION NO. 20170817-061

BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF AUSTIN:

City Council adopts the Electric Utility Commission Resource Planning Working Group's 2016-17 Recommendations for Resource Planning Update, a copy of which is attached as Exhibit A, subject to the other provisions of this Resolution.

BE IT FURTHER RESOLVED:

In addition to the Working Group's Recommendations on Transportation, the City Council adopts the following additional directives:

1. Support the deployment of EV charging infrastructure to enable the City Fleet Services electrification plan, which includes at least 330 new charging stations by 2020 and deployment of at least 8-10 Austin Energy owned and operated DCFast stations by FY 2018.
2. Support the City Fleet Services electrification plan by transitioning 65 Austin Energy retired internal combustion engine vehicles to new electric vehicles by 2020.
3. Complete the Austin SHINES project by FY 2019 that includes assessing the value and business case for integrating stationary distributed energy storage. Leverage findings to determine applicability to EV batteries. Before the FY 2019 generation plan update, Austin Energy should do an analysis of potential value streams for energy storage that may include Demand Charge Reduction, Peak Load Reduction, Energy Arbitrage, Price Responsive Opportunities, Voltage Support, and Congestion Management and evaluate open standards and business cases that could be applied to a future state of feasible and affordable EV distributed storage. Additionally, identify potential load and storage resulting from aggressive EV development.
4. Support growth of public and private charging station deployments by offering rebates, operational support, outreach, and special public charging rates to include support for low-income populations.
5. Leverage the residential EV time-of-use rate pilot "EV360," launched in 2017, to develop lessons learned and best practices in FY 2018 for consideration in a wider roll-out of this service.

BE IT FURTHER RESOLVED:

In addition to the Working Group's Recommendations on Energy Efficiency and Demand Response, the City Council adopts the following directive:
Commit to accelerate Plug-In Electric Vehicle (PEV) based demand response capabilities, including modifying the electric vehicle residential charging station rebate program to encourage the deployment of equipment that enables peak shaving for PEV’s similar to Austin Energy's existing Power Partners HVAC demand-response thermostat program.

BE IT FURTHER RESOLVED:

The City Council adopts the Working Group's Recommendations regarding Energy Efficiency and Demand Response subject to the following amendment to the third bullet of that section of the Recommendations:

Commit to directing at least 20% of total DSM budget to existing and potential programs for low-income and hard-to-reach markets in the multifamily and single-family areas along with small businesses. A minimum of 5 percent of the 20 percent will be dedicated to the low-income weatherization program per year.

BE IT FURTHER RESOLVED:

To clarify the recommendations endorsed by the Working Group, the City Council directs the City Manager to conduct the following and present the results to the Electric Utility Commission (EUC), Resource Management Commission (RMC), and the Austin Energy Utility Oversight Committee (AEUOC) no later than September 30, 2019:

1. Construct a model that achieves both a 75 percent and an 80 percent renewable energy goal by 2027, including a consideration of the costs, benefits, risks, and potential rate impacts.
2. Construct a model that achieves a 100 percent carbon-free energy goal by 2030, including a consideration of the costs, benefits, risks, and potential rate impacts.
3. Study and possibly pilot a utility managed rooftop solar program that requires no investment from customer participants.
4. Evaluate the Working Group's recommendation to achieve 1,000 MW of energy efficiency by 2027 upon completion of a measurement and verification consultant study, review of standards and technology, and an analysis of budget and progress-to-date. Reset the goal if necessary to reflect proportionate demand reduction savings given any new methodology implemented. Austin Energy will concurrently assess the potential to reach a higher goal of 1,100 MW of energy efficiency and demand response by 2027.
5. Using the lessons learned following completion and implementation of the SHINES project, develop a roadmap for implementation of electrical storage to achieve the existing goal of 10 MW of electrical storage by 2025.
6. Study the costs, benefits, risks and potential rate impacts of achieving a more aggressive electric storage goal, such as 50 MW of electrical storage by 2027 and of achieving 100 MW of electrical storage by 2027.
7. Study the technical and economic feasibility of emerging technologies, including dispatchable renewable energy technologies, battery storage, compressed air energy storage, aggregated demand response, and vehicle-to-grid.

8. Reassess the costs and benefits of raising the local solar goals from 200 MW by 2025 to 250 MW by 2025 and to 300 MW by 2027, following the first year of implementation of the commercial value of solar.

9. Assess the feasibility of achieving 100 percent renewable energy by 2035.

BE IT FURTHER RESOLVED:

That the City Council affirms its continued interest in achieving the city's climate protection goal of reducing emissions as quickly as possible.

ADOPTED: August 17, 2017

ATTEST: Jannette S. Goodall
City Clerk
Appendix B - Renewable Optimization Model

Formulation

Select solar and wind resources that are available from the different zones, so as to maximize the net present value of profit, subject to meeting the renewable study energy requirement, and limits on how much energy can come from any single zone.

Indices:
- \( t \) for time periods (\( t = t_1, t_2, \ldots, t_n \)).
- \( z \) for zones (\( z = z_1, z_2, \ldots, z_m \)).
- \( k \) for resource fuel type (\( k = \text{solar, wind} \)).

Variables:
- \( R_{kzt} \) Capacity of resource \( k \) located in zone \( z \) and selected in time period \( t \).
- \( EN_{kzt} \) Energy from resource \( k \) located in zone \( z \) and selected in time period \( t \).
- \( UR_{kzt} \) Unitized NPV revenue of resource \( k \) located in zone \( z \) and selected in time period \( t \).
- \( UC_{kzt} \) Unitized NPV cost of resource \( k \) located in zone \( z \) and selected in time period \( t \).
- \( UP_{kzt} \) Unitized NPV profit of resource \( k \) located in zone \( z \) and selected in time period \( t \).

Parameters:
- \( EN_t \) Renewable energy requirement in period \( t \).
- \( CF_{kz} \) Capacity factor of resource \( k \) located in zone \( z \).
- \( Disc \) Discount rate.
- \( hr \) Period hours.
- \( ES_{zs} \) Zone energy constraint.

\[
\text{Max } \sum_t \sum_z \sum_k UP_{kzt} \cdot (R_{kzt} \cdot CF_{kz})
\]

St:
\[
\sum_k \sum_z R_{kzt} CF_{kz} = EN_t \quad \forall t
\]
\[
\sum_k \sum_z \sum_t R_{kzt} CF_{kz} \leq ES_{zs}
\]
\[
R_{kzt} \geq 0 \quad \forall k, z, t
\]
Appendix C - Energy Storage Model

param first:=1; # First hour in time period
param last:=24; # Last hour in time period
set TP:=first..last; # Set of time period
set NP;

param SocMax:=20; # Reservoir maximum capacity 90% of 3 MWh
param SocMin:=2; # Reservoir minimum capacity 10% of 3 MWh

param MaxChrg:=10; # Maximum charging capacity
param MinChrg:=0; # Minimum charging capacity
param MaxDis:=10; # Maximum discharge capacity
param MinDis:=0; # Minimum discharge capacity

param MaxRegUp:=8; # Maximum regulation up FRRS up
param MaxRegDn:=5; # Maximum regulation down FRRS dn

param Etac:=0.85; # Charge efficiency
param Etad:=0.85; # Discharge efficiency

param enprice{k in NP}; # Price of energy in hour k

param freq:=0.14; # Freq for regulation up and regulation down
param spinfreq:=0.01; # Freq for spin reserve

#Ancillary Services Parameters Definition
param ruprice{k in NP}>=0; # Up regulation price in hour k
param rdprice{k in NP}>=0; # Down regulation price in hour k
param spprice{k in NP}>=0; # Spin price in hour k

#Continuous Variables Definition
var Chrg{t in first..last} >=0; # Battery charging in hour k
var Dis{t in first..last} >=0; # Battery discharge in hour k
var Soc{t in first..last} >=0; # State of charge in hour k
var ChrgRegdwn{t in first..last} >=0; # Down regulation in charging mode
var DisRegup{t in first..last} >=0; # Up regulation in discharging mode
var DisSpin{t in first..last} >=0; # Spin reserve in discharging mode

#Binary Variables Definition
var uc{t in first..last} binary; # Charging integrality variable
var ud{t in first..last} binary; # Discharging integrality variable
var uchrgreg{t in first..last} binary; # Charging regulation variable
var udisreg{t in first..last} binary; # Discharging regulation variable

#Components of Objective Function
var TotalChrgCst; # Total charging cost
var TotalDisRev; # Total discharge revenue
var TotalChrgAsRev; # Total AS revenue from charging
var TotalDisAsRev; # Total AS revenue from discharging

#Read Energy and Natural Gas Prices;
table tab_plant IN "CSV" "Battery_Spin\Base\BaseDat2026.csv";
NP<-[Hour], enprice, ruprice, rdprice, spprice;

#CONSTRAINTS DEFINITION
subject to uclb{t in first..last}:uc[t]=1;
subject to uclub{t in first..last}:uc[t]=0;
subject to uclub{t in first..last}:ud[t]=0;
subject to uclub{t in first..last}:ud[t]=1;
subject to udUb[t in first..last]:ud[t] <= 1;
subject to uchrgreglb[t in first..last]:uchrgreg[t] >= 0;
subject to uchrgregub[t in first..last]:uchrgreg[t] <= 1;
subject to udisreglb[t in first..last]:udisreg[t] >= 0;
subject to udisregub[t in first..last]:udisreg[t] <= 1;

#Storage Dynamics

subject to InitSoc:Soc[first]=10;   # Initial battery state of charge
subject to FinalSoc:Soc[last]=10;  # Final battery state of charge

#Storage flow constraints

subject to ResDyn[t in first+1..last]:Soc[t]=Soc[t-1] + Etac*(Chrg[t]+freq*ChrgRegdwn[t])-(1/ Etad)*Dis[t]+freq*DisRegup[t]*spinfreq*DisSpin[t];
subject to ResDynUb[t in first+1..last]:Soc[t]-ChrgRegdwn[t]*freq <= SocMax;
subject to ResDynLb[t in first+1..last]:Soc[t]-DisRegup[t]*freq-DisSpin[t]*spinfreq >= SocMin;

#Charging Upper and Lower Bounds

subject to ChrgUb[t in first+1..last]:Chrg[t]+ChrgRegdwn[t] <= MaxChrg*uchrgreg[t];
subject to ChrgLb[t in first+1..last]:Chrg[t]>=MaxChrg*uc[t];
subject to RegOnUb[t in first+1..last]:ChrgRegdwn[t] <= MaxRegOn*uchrgreg[t];

#Discharging Upper and Lower Bounds

subject to DisUb[t in first+1..last]:Dis[t] + DisRegup[t]*DisSpin[t] <= MaxDis*udisreg[t];
subject to DisLb[t in first+1..last]:Dis[t] = = MaxChrg*ud[t];
subject to RegUpUb[t in first+1..last]:DisRegup[t] <= MaxRegUp*udisreg[t];

#Single Operating Mode

subject to SimultOpMode[t in first+1..last]:uc[t]+ud[t] <= 1;

subject to SimultChrgRegDisReg[t in first+1..last]:udisreg[t]+uchrgreg[t] <= 2-uc[t]-ud[t];
subject to SimultChrgRegDisReg1[t in first+1..last]:udisreg[t] <= 1-uc[t];
subject to SimultChrgRegDisReg2[t in first+1..last]:uchrgreg[t] <= 1-ud[t];

#Charging Cost

subject to BatChrgCst:TotalChrgCst=sum{t in first+1..last} Chrg[t]*enprice[t];

#Discharging Revenues

subject to BatDisRev:TotalDisRev=sum{t in first+1..last} Dis[t]*enprice[t];

#AS Revenues from Charging

subject to BatChrgAsRev:TotalChrgAsRev=sum{t in first+1..last} (ChrgRegdwn[t]*rdprice[t]);

#AS Revenues from Discharging

subject to BatDisAsRev:TotalDisAsRev=sum{t in first+1..last} (DisRegup[t]*ruprice[t] + DisSpin[t]*spprice[t]);

#Objective Function

maximize obj: TotalDisRev + TotalDisAsRev + TotalChrgAsRev - TotalChrgCst;

solve;

table tab_result {t in first..last} OUT "C:\Battery_Spin\Base\2026\BaseResultsf_spin.csv";

table tab_result1 {t in 1..1} OUT "C:\Battery_Spin\Base\2026\SBaseResultsf_spin.csv";
TotalDisRev, TotalDisAsRev, TotalChrgAsRev, TotalChrgCst;

end;
Source: Electricity Market Design Evolution to Efficiently Integrate Wind and other Emerging Technologies – ERCOT
Kenneth Ragsdale, Principal, Market Design, ERCOT, May 22, 2019, AWEA.
Appendix E - ERCOT Market Rules – FRRSUP and FRRSDN

For FRRS-Up, ERCOT calculates each Resource’s obligation according to the following two-step methodology:

Step 1: If 13 or fewer Resources are participating, ERCOT will first allocate to each Resource a minimum of 5 MW or the offered capacity of the Resource, whichever is smaller. If more than 13 Resources are participating, ERCOT will determine the minimum capacity obligation for each Resource by dividing 65 by the number of participating Resources. ERCOT will allocate to each Resource this minimum capacity obligation or the offered capacity of the Resource, whichever is smaller.

Step 2: ERCOT will allocate any remainder of the 65 MW maximum among those Resources whose maximum capacity offered is greater than the amount allocated under the first step in proportion to the amount of capacity offered.

For FRRS-Down, ERCOT calculates each Resource’s obligation according to the following two-step methodology:

Step 1: If 7 or fewer Resources are participating, ERCOT will first allocate to each Resource a minimum of 5 MW or the offered capacity of the Resource, whichever is smaller. If more than 7 Resources are participating, ERCOT will determine the minimum capacity obligation for each Resource by dividing 35 by the number of participating Resources. ERCOT will allocate to each Resource this minimum capacity obligation or the offered capacity of the Resource, whichever is smaller.

Step 2: ERCOT will allocate any remainder of the 35 MW maximum among those Resources whose maximum capacity offered is greater than the amount allocated under this first step in proportion to the amount of capacity offered.

Appendix F - ERCOT Ancillary Services Deployment

Below are the deployment instructions as highlighted in the ERCOT and pertaining to deployment of FRRSUP or FRRSDN.

- **Deployment by Dispatch Instruction:** Each Resource must provide 100% of its deployed capacity within 60 cycles of receiving a Dispatch Instruction from ERCOT. ERCOT may deploy FRRS resources for up to two minutes when frequency reaches a deviation of more than +/- .03 Hz from the 60 Hz nominal system frequency.

- **Deployment by Trigger Frequency:** Each Resource must deploy 100% of its obligated capacity within 60 cycles of a frequency deviation of more than +/- .09 Hz from the 60 Hz nominal system frequency.
Appendix G - PPA/Levelized Cost Assumptions

PPA cost assumptions for solar, wind and battery storage are from Wood Mackenzie.