Denton's Renewable Energy Plan: Can We Green It Up?

Next steps for Denton Municipal Electric, City Council, and future City Councils to make Denton a leader on clean energy

Photo by Cyrus Reed, Lone Star Chapter, Sierra Club

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Note: This short white paper is meant as a discussion piece as Denton Municipal Electric, citizens, and the current city council consider the implementation of the Renewable Denton Plan as adopted in September 2016.

INTRODUCTION

In 2016, Denton City Council approved the Denton Renewable Energy Plan, brought to them by Denton Municipal Electric (DME), the city's publicly owned electric utility. The plan has four main components:

1. Committing Denton to increase contracts with renewable energy providers, so that 70 percent of their annual energy use would be covered by those contracts by the end of 2019;
2. Ending their contract with the Gibbons Creek coal plant, which historically has provided up to 40 percent of Denton's energy use;
3. Purchasing 12 small natural gas plants (**Wärtsilä** Reciprocating Internal Combustion Engines (RICE)) to provide up to 220 MW of power, and placing them at a site within the DME service area with an expectation they be in service by the Summer 2018;
4. Setting a longer-term goal of meeting 100% of DME's needs by 2035 with renewable energy.

In many ways, Denton became one of the leaders in Texas and the U.S. with this decision to adopt a plan to meet the majority of its energy needs with resources that don't require water, don't produce emissions that impact our health, and do not produce the gases that are cooking our climate. Table 1 shows current renewable energy plans in Texas by municipal electric and electric cooperatives.

Table 1. Renewable Energy Goals in Texas for Selected Entities

Entity	Goal	Year	Long-Term Goal	Year
Georgetown Electric	100%	2016	100%	2016
Denton Electric	70%	2019	100%	2025
Austin Energy	55%	2025	100% Carbon-Free	2030 (1)
CPS Energy (San Antonio)	20%	2020	NA	
Pedernales Electric Cooperative	30%	2025	NA	
State of Texas	5,880 MW	2015	10,000 MW	2025 (2)

(1) Austin Energy's 100% 2030 goal is based on net-zero carbon and is subject to affordability parameters. The long-term goal of the city is to get to net zero-carbon emissions by 2050;
(2) Texas has already met both the 2015 and 2025 goal, as more than 18,000 MW of wind have already been installed in Texas.

So What's the Problem?

While Denton does become one of the current leaders on renewable energy with adoption of its Renewable Energy Plan in 2016, the decision was extremely controversial. Most of the Denton citizens who came to public meetings sponsored by DME, or to city council as it deliberated the plan, opposed the plan, and specifically opposed the idea of combining the goal of 70 percent renewables with the addition of 12 natural gas plants in the immediate area of Denton itself.

For one, Denton was the focal point of a movement of citizens concerned about the impacts of hydraulic fracturing within city limits to produce oil and gas., Many had supported a ban of fracking, which was approved through a referendum process. They felt it ironic that after getting a ban on fracking approved (which was later disallowed by the 84th Legislature) that the city utility would come forth with a plan to add additional natural gas infrastructure. In addition, because the proposed engines will burn natural gas within the Denton area, those plants will increase the amount of nitrogen oxide pollution that could lead to higher ozone levels in the Denton and larger Dallas-Fort Worth area. Ten counties of the DFW metro area, including Denton County, are currently classified as a Non-Attainment Area for the Environmental Protection Agency's health-based ozone standard. By combusting additional natural gas, Denton will be adding to its local pollution levels and exacerbating its air-quality issues. Finally, many Denton residents were simply concerned about the wisdom of taking on an additional $265 million in additional cost, approved through revenue bonds, which are ultimately paid by taxpayers. Though, in theory the natural gas plants might earn revenue by selling into the energy market, with low energy prices throughout Texas, it is unlikely that such plants would be large revenue generators, although there may be particular hours when the plants will generate some revenues.

Finally, many believed that Denton could do better, and either go to 100% renewable energy, or combine renewable energy with non-fossil fuel resources like energy storage, demand response, and local solar.

Because of these and other concerns, many citizens and some council members, including Mayor Chris Watts, believed that additional alternatives to the plan should have been explored. Ultimately, the plan was approved on a 4-3 divided vote.

What Alternatives Were Actually Explored?

Initially, the Renewable Denton Plan was put through a third-party "independent" study after citizens and city council members expressed concerns about adopting the DME proposal. The Brattle Group was hired as the third party to review the plan and also assess several alternatives, with the report released to the public on June 10, 2016. A copy of the report can be found here.

The report largely confirmed the DME analysis, and found that the DME Plan -- with either 9 or 12 **Wärtsilä** engines and contracts for 70 percent of renewable energy, would allow DME to keep rates stable, meet energy needs, and provide a hedge against any local price spikes within ERCOT's market.

In general, the Brattle Group independent report found that the combination of flexible, fast-acting natural gas engines would mesh well with long-term renewable contracts. In their words, the plan "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." A copy of the report can be found here.

While the Brattle Group is a respected energy consultant, unfortunately the full range of alternatives was not studied. Instead, the study only focused on three potential alternatives:

1. **Status Quo-Texas Municipal Power Agency** (This strategy assumed that no additional renewable energy contracts would be signed other than one existing wind contract and one solar contract that only provide about 10 percent of Denton's annual needs, and that the contract with TMPA to provide up to 100 MW of coal-fired power would continue).
2. **Status-Quo Market Strategy** This scenario would rely principally on market purchases, and the existing renewable contracts.
3. **The RDP Plan**, including the DEC (Denton Energy Center), i.e. the natural gas plants and the 70 percent renewable plan.

Thus, the Brattle Group essentially modeled the RDP-DEC plan against two different status quo plans and concluded that the RDP-DEC plan was superior. In fact, the Brattle Group found that the RDP-DEC plan was between $750 million and $975 million less in costs over a 20-year period.

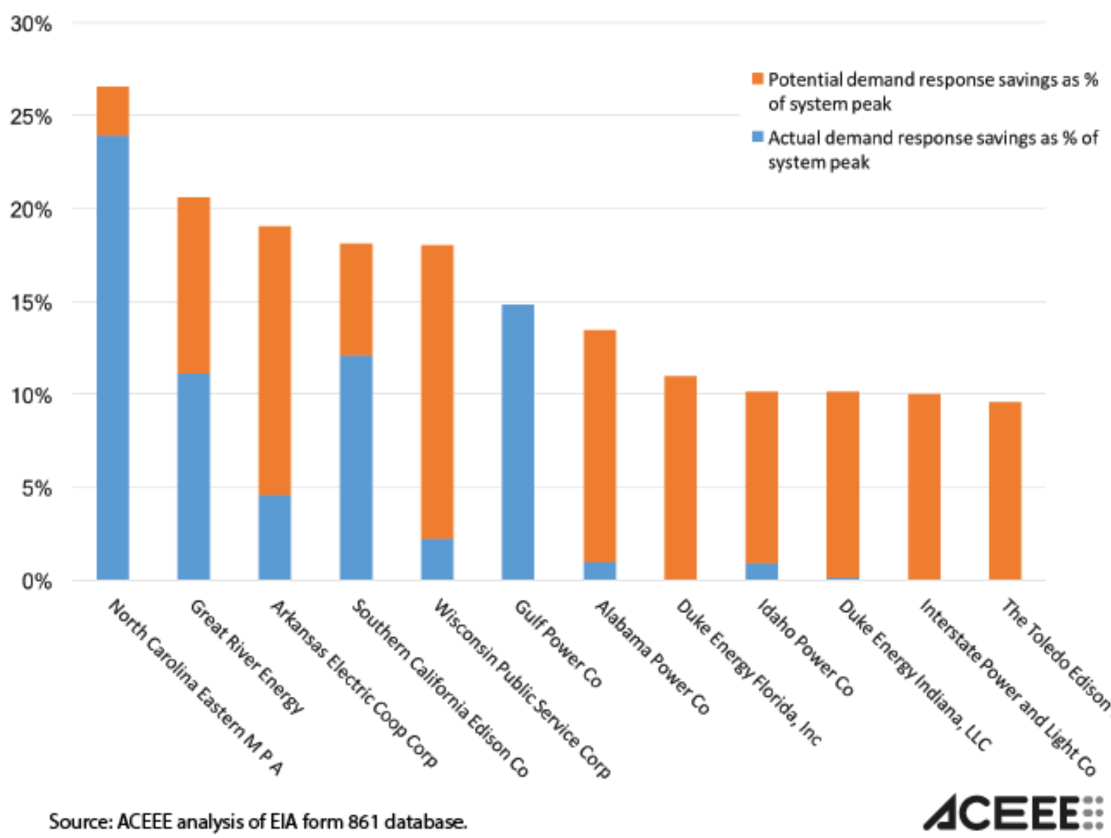
We partially agree. The RDP-DEC makes more economic sense than relying only on the market and not increasing the amount of renewables, or relying on an old inflexible coal plant for a significant amount of its power.

<u>However, the independent study did not actually accomplish what the City Council had instructed the DME and the Brattle Group to do: assess plans that would meet at least 70 percent renewable goals by 2019, but would not rely on new natural gas plants to get there.</u>

The Brattle Group did do a limited look at alternatives to the DEC natural gas engines, including looking at "firming contracts" with the renewable energy providers, where renewable contracts are increased and it is up to the contracts to find power when their solar or wind resources wane, but noted that the premium for firming contracts are about 66 percent higher than without firming.

The Brattle Group also stated that other technologies could provide hedging and firming functions such as “demand-side participation and storage.” However, they point out that demand response programs (working with customers to reduce energy needs at a time of peak needs) have limited capacity. Essentially, Brattle Group agreed that they could play some role to reduce demand when there is a spike, but are limited by capacity and by their ability to address “net load down events” (events where renewable contracts suddenly do not deliver enough electricity), and DME must find power quickly. They also rightly point out that DME would need to have contracts with customers so they would be willing to give up partial control of their energy use. Again, we agree that DME could not completely rely on demand response, but we believe some amount of demand response should be analyzed, such as 10% of the peak demand. This is a level that has been achieved by other utilities such as the Gulf Power Company, and recently, the organization ACEEE identified a 10% level of demand response as reasonable and achievable since some utilities have actually achieved as much as 25% (see graph). Thus, assuming the peak demand for the DME is 300 MW, an analysis should assess reaching agreements with industrial, commercial and residential customers to shave 10 percent of peak demand, or approximately 30 MW.

Potential and actual peak demand savings in 2015 for utilities with leading demand response programs.

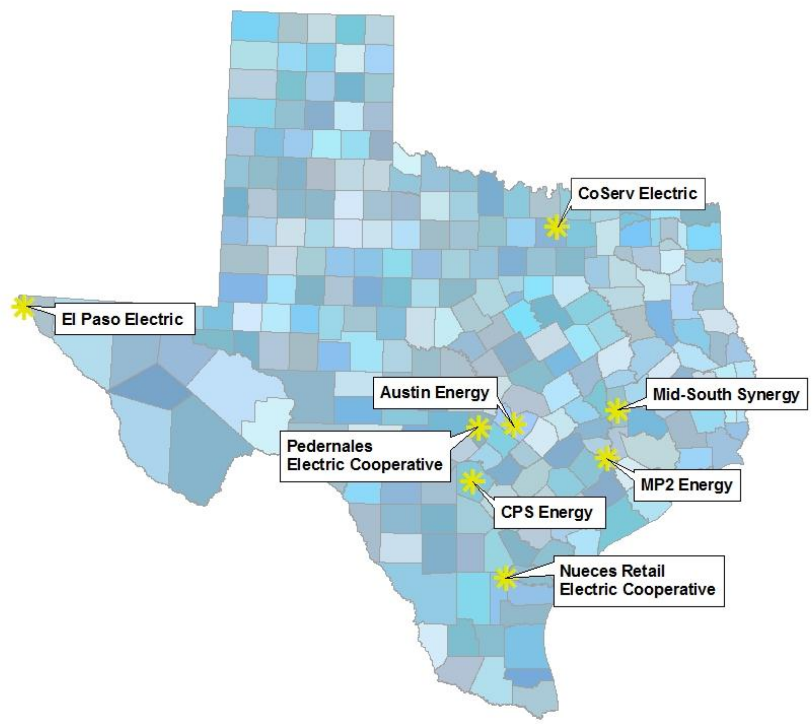


Source: ACEEE analysis of EIA form 861 database.

In terms of energy storage, the Brattle Group analysis simply stated, “Storage today is very expensive and is in the several thousands per kW range, compared with approximately $1,000/kW for RICE Units,” citing a study from 2013. To meet the 70 percent renewable goal, they would need more than 100 MW of battery storage, or more than was currently installed in the U.S. in mid-2016, according to the Brattle Group report. Again, however, the study relied on 2013 data. It did not actually compare *current* costs, and never presented a “storage” scenario. In fact, there are batteries systems today that are in the 800-$1,500/kW installation range, and other storage systems such as compressed air energy storage (CAES) are actually on par with the costs of some natural gas technologies. The report does point out that CAES relies on natural for some of its operation, yet the report never assessed CAES as an alternative, which uses approximately half as much natural gas as a traditional natural gas plant of a similar size. It also did not assess the use of alternatives like molten salt or hydrogen with a CAES plant, nor did it consider the advantages that battery and CAES storage can yield with respect to providing ancillary services, particularly “regulation up” and “regulation down” service.

The report also failed to assess a hybrid of local storage with community solar. That is, DME could authorize significant amounts of local solar, sell it to its customers as “community solar” where residents either lease or buy a section of the plant, and then add battery storage to make the electricity generated more “dispatchable.” In this way, DME could add local fossil fuel-free generation supported by the community. Currently, Austin Energy, CPS Energy, and Pedernales Electric, as well as Co-Serve Electric Cooperative just north of Denton have invested in community solar projects, with the first three actually adding batteries to their projects. And yet, DME and the Brattle Group study ignored this potential resource.

Texas Community Solar Projects



Source: North Texas Council of Governments, Go Solar Texas, gosolartexas.org.

Finally, the report states that achieving a 100 percent renewable energy goal would require DME to contract for at least twice its peak load to ensure that enough renewables were generated to meet its overall use. As an example, they noted that the City of Georgetown contracted for 294 MW of renewables to meet a peak use of 145 MW of demand. Thus, while their current plan calls for about 300 MW of renewable contracts, a 100% renewable commitment would need almost 600 MW of renewable contracts. Yet the report never actually ran any numbers on what such a plan would look like, or whether it would be a large cost long-term.

What Brattle Group Should Have Examined and What City Council Should Still Demand

Despite providing a few paragraphs on demand response and energy storage, and a short section on the expense of going to 100% renewable power, the city should have insisted on real detailed scenarios that would have adequately assessed these potential solutions. We believe that it is still possible, as the city moves forward with the contract on the new natural gas plants, to reexamine the following options:

- 100 percent renewable energy
- 70 percent renewable energy plus market purchases
- 70 percent renewable energy plus battery storage, community solar, and demand response;
- 70 percent renewable energy plus compressed energy air storage
- 70 percent renewable energy plus the most affordable combination of CAES, batteries, community solar, and demand response

In addition, DME and City Council could explore lowering the number of RICE engines and only installing 6 of the 12 engines laid out in the energy plan.

Table 2. Other Alternatives That Should Have Been Fully Examined by DME

	Renewables by 2019	Gas Resources by 2019	Coal	Demand Response	Community Solar	Battery Storage	CAES	Market Purchase
Council Directive 9/2016	70%	220 MW (13-15%)						13-15%
Scenario 1	100% to meet annual use							Only as needed
Scenario 2	70%							30%
Scenario 3	70%			30 MW	5-10 MW	30 MW		20%
Scenario 4	70%						150 MW	15%
Scenario 5	70%			30 MW	5-10 MW	20 MW	100 MW	15%
Scenario 6	70%	108 MW		30 MW	5-10 MW	20 MW		15%

Does It Matter? Isn't It Too Late?

The City has signed contracts with both Wartsilla (to provide the 12 natural gas engines) and with an EPC firm (equipment, procurement, and construction) to order, construct, and put the new natural gas plants into operation by the summer 2018. Indeed, the first payment of $23 million has already been made and designs have already been submitted. In addition, in December, the bonds were issued and were recently closed, so canceling or reducing these bonds could impact the City of Denton's bond rating.

However, if City Council were to decide, it can, like any contract, modify it or cancel it... for a price. Indeed, the contract actually does have a provision for termination by the city. The amount due at specific dates is set out in Schedule 13, but is redacted. Nonetheless, there is a specific right for the city to cancel the contract and pay a prorated amount.

If City Council were to decide not to proceed with the full implementation of the 12 natural gas engines, then the sooner that decision was made to cancel or reduce the number of engines the less money would be lost. As an example, they could choose to simply reduce the number of natural gas engines from 12 to 6.

In addition, the bonds can be repurchased through a tender offer at a market-clearing price, which would keep investors whole.

What Would an Alternative Analysis Show?

While a full alternative analysis would need to utilize a methodology similar to that employed by Brattle Group using U-Plan (which is used by ERCOT and Austin Energy) or a Power Systems Optimizer (PSO) used by Brattle Group, or similar software to analyze the benefits of choosing a different path than that selected by the present council, it is possible to do a simple analysis which indicates whether or not these alternatives would be as affordable or more affordable, based in part on available assumptions on future natural gas and other market prices. We suggest, based on this initial analysis, a fuller analysis should be examined.

What Do Different Energy Resources Cost?

In the Brattle Group's analysis, **they do not actually provide any examples of the current costs of different resources**, but only provide numbers on what the portfolios of different resources cost in combination, finding that the RDP-DEC plan was the most cost-effective. Thus, they make a conclusion without showing the actual inputs into the model (other than natural gas prices).

However, there are plenty of sources for the cost of different options, including Lazard, the Energy Information Administration, recent contracts in the ERCOT market, and other utilities that have been assessing resources. Based on recent Austin Energy, CPS Energy, and market prices in Texas, current solar contracts in West Texas are being contracted between $40 and $45 per MWh (with no extra "firming" capacity), while wind contracts are being obtained in the $20 to $40 per MWh range.

Because electric storage, including both batteries and CAES, are relatively new technologies without many MW installed, costs are less available, though both Austin Energy, which recently went through a study, and Lazard, have published recent estimates.

Costs on natural gas resources, including RICE engines, are fairly precise, because several utilities in Texas, including the South Texas Electric Cooperative, have been employing them.

Comparing the Alternatives

The tables below show expected overnight costs and a levelized costs for different resources, including battery storage, renewable power purchase agreements (PPAs), community solar, community solar plus storage, RICE engines, demand response, and a CAES system, similar to the one being built in East Texas by APEX, which when constructed could provide up to 300 MW of flexible generation using compressed air, and some natural gas to start up a turbine. While the system does utilize natural gas (about half as much as a traditional natural gas resource), the main compressor component can be run with renewable energy, and the turbine itself could be run with hydrogen gas or even by molten salts heated by solar resources, particularly as technology improves.

Table 3. Costs for Different Energy Resources, 2016-19 and Assumed Energy Output in 2019

	Overnight Cost ($/kW)	**Capacity and Expected Capacity Factor**	**Expected Energy per Year**	**Project Life (Years)**	**Levelized Cost (MWh)**
RICE Engines (Natural Gas)	$800/kW	30%	Up to 578,160 (1)	20	$75/MWh
Battery Storage, 30 MW (Lithium-Ion)	$1,500/kW	10%	26,280	10	$285/MWh
Compressed Energy Air Storage (150 MW)	$1,500/kW	40%	Up to 525,600 (2)	20	$100/MWh
Coastal Wind Power Purchase Agreements, 100 MW	PPA	40%	350,400	20	$35/MWh
West Wind, 100 MW	PPA	40%	350,400	20	$26/MWh
Solar PPA, 150 MW	PPA	33%	433,620	20	$40/MWh
Community Solar, 5 MW	$2,400/kW	22%	9,636	20	$90/MWh (with no storage)
Community Solar Plus Storage, 10 MW	$3,400/kW	32%	22,425	20 (some replacement needed at 10)	$120 (with 4-hour storage) MWh
Demand Response, 30 MW	$500/kW	As needed at peak	Bulky loads reduced at peak upon call (30 MW peak)	10	$30/MWh
Market Purchases			243,000 minimum		$25 off-peak, $50/MWh on-peak average in North Hub

Sources: Lazard, Lazard's Levelized Cost of Storage, Version 2.0 (December 2016); Lazard, Lazard's Levelized Cost of Energy Analysis - Version 10.0 (December 2016);
Austin Energy, Resource Plan Stakeholder Working Group, November 2016, Technology Costs; SNL Expected ERCOT Cost for North Hub in 2019.

(1) RICE engines would be dispatched based on market prices, ancillary needs, and energy demand. We assume that they would most likely be used for about 20 percent of their capacity.
(1) A CAES facility would also be used for ancillary services, and the actual "energy" output would probably be much lower for serving energy demand. We assume that roughly 60 percent of its capacity would be to provide ancillary services.

What Would Different Alternatives Look Like in Terms of Energy Used in 2019?

Table 4 shows the actual energy assumed to be generated by the different resources in 2019 (in MWh).

	Denton DME Current Plan	**Scen. 1 (100% Ren.)**	**Scen. 2 (70% Ren. plus Market)**	**Scen. 2 (Storage, Community Solar, Demand Response)**	**Scen. 3 (CAES)**	**Scen. 4 (All but RICE)**	**Scen. 5 (110 MW RICE, All Else)**
West Wind	350,000	700,000	350,000	350,000	350,000	350,000	350,000
Coastal Wind	350,000	700,000	350,000	350,000	350,000	350,000	350,000
Solar	433,000	866,000	433,000	433,000	433,000	433,000	433,000
RICE Engines	243,000						120,000
Market Purchases	243,000		487,000	324,000	255,000	243,000	243,000
Battery Storage				43,800		43,800	43,800
CAES					231,000	160,000	160,000
Community Solar				22,425		22,425	22,425
Demand Response				14,400		14,400	14,400
Total Energy	1,620,000	2,266,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000

What Would Be the Costs of These Different Approaches in 2019?

Each of the alternatives would create costs in 2019. Table 5 shows costs only. In other words, it does not consider the revenues that could be created by selling the energy into the market from these resources, or ancillary services earned from those resources. The table suggests that the DME Plan, the 70% plus market, and the 70% plus either CAES or 70% plus alternative dispatchable are the most cost effective. Because many of these resources are expected to be operating or contracted for at least 20 years, these annual totals would occur year after year. However, it is worth noting that in 2019, the most expensive annual costs would be about $15 million more than the least cost option. Over 20 years, assuming similar costs, that total is only about $300 million.

Table 5. "Costs" Only of Different Alternatives in Denton Plan in 2019 (in Millions)

	DEM - DCP Plan	**Scen. 1 (100% Renewable)**	**Scen. 2 (70% Renewable Plus Market)**	**Scen. 3 (Storage, Comm. Solar, Batteries, Demand Response)**	**Scen. 4**	**Scen. 5**	**Scen. 6**
West Wind	$9.1	$18.2	$9.1	$9.1	$9.1	$9.1	$9.1
Coastal Wind	$12.25	$24.5	$12.25	$12.25	$12.25	$12.25	$12.25
Solar	$17.32	$34.64	$17.32	$17.32	$17.32	$17.32	$17.32
RICE Engines	$18.22						$9.00
Market Purchase	$7.18		$14.37	$9.58	$7.45	$7.18	$7.18
Battery Storage				$7.49		$7.49	$7.49
CAES					$23.1	$16.2	$8.0
Comm. Solar (w/ Battery)				$2.69		$2.69	$2.69
Demand Response				$0.43		$0.43	$0.43
Total Cost	**$64.1**	**$77.34**	**$53.04**	**$58.86**	**$69.31**	**$72.67**	**$73.47**

Again, this only shows the **cost side** of the equation, not the **revenues**. Determining revenues depends on the individual market prices on a per-15- minute basis both where the energy is consumed in Denton, as well as the amount where the resource is actually generated, which is determined on a 5-minute basis, but settled on a 15-minute basis. As an example, if Denton were to contract for solar power in West Texas, it would pay the solar developer some amount -- such as $40/MWh of the energy produced -- whereas the qualified scheduling entity would earn whatever amount of money the solar earned at the local energy "node", presumably in West Texas. Thus, if the solar power plant earned an average of $20/MWh, the actual cost would be $40- $20/MWh, or $20/MWh, since Denton Electric must pay the solar developer the cost of the Power Purchase Agreement, but Denton Electric would earn whatever revenue the solar plant gets by selling into the market.

Similarly, while the average cost to run a RICE engine might be about $75/MWh, the engines presumably would only run when energy costs were high -- earning money at a higher price - and could also be used for ancillary services like responsive reserves or for regulation services. Presumably, DME would only offer them into the market when prices were above $75/MWh, so the actual revenue would be the money generated minus the operating costs.

The Brattle Group report made clear, one of the benefits of investing in RICE engines was precisely to earn money by providing ancillary services as well as earning energy prices during peak times. Those same benefits would also be available to battery storage, CAES facility, or community solar plus batteries. Even demand response could provide some ancillary services such as responsive reserves or providing Emergency Response Services (ERS) to meet emergency situations. Both Austin Energy and CPS Energy have contracted some of their loads with ERCOT to provide ERS, and thus earn money from those ERS contracts.

Table 6 provides some assumptions on West Texas, Coastal and North zone prices in 2019 based on future pricing available through SNL, an energy consulting company, as well as on ancillary service prices in 2019. Table 7 estimates the total costs of the plan assuming revenues from sales of energy and ancillary services are deducted from any costs to run the plants or pay solar or wind developers, and provides a more comparable total cost for each of the proposed alternatives. It does not consider bond payback, such as the expected 4-5 percent interest payments due on the RICE engines should they ultimately be built. Therefore, we think the actual revenues for the DME plan would likely be lower.

It is important to note on ancillary prices, the amount of money paid by a load serving entity like DME is an average for the percent of the market they represent, but the money earned is calculated in the day-ahead market, once settled in real-time. Thus, ERCOT essentially determines how much ancillary service it believes it will need on a daily basis, and the market then determines the actual price paid. The ancillary service costs are distributed to all load-serving entities.

Table 6. Expected Wholesale Price in West, Southern, and Northern Load Zones, 2019 (SNL Database)

Region	Off-Peak Price Average per MWh	On-Peak Price Average per MWh	Average Wholesale Price per MWh	Average Ancillary Service Price paid by Load	Average Ancillary Services Earned by Generator

				per MWh	per MWh (1)
Northern Load Zone	$21.98	$31.78	$26.88	$2.00	$20.00
North Zone	$21.73	$30.91	$26.00	$2.00	$20.00
Southern Load Zone	$21.72	$31.53	$26.625	$2.00	$20.00
West Zone	$19.20	$30.52	$24.86	$2.00	$20.00
ERCOT Wide	$20.25	$32.05	$26.15	$2.00	$20.00

(1) Based on average of expected ancillary service price for responsive reserves (2,800 MW) and regulation services (1,000 MW).

When the revenues are considered, this static model shows that all of the alternatives are fairly similar, costing $16 million-$25 million per year for energy costs and that all of the alternatives would meet the needs of Denton. In fact, the numbers suggest that going to 100% renewables may be the most cost-effective, although there could still be risks with this approach. For example, if prices were to spike in the Denton area, DME would still be responsible for purchasing that energy at the settled price, even though its demand was technically covered by the renewable contracts. ERCOT settles sales and purchases separately and unless DME were to purchase what are known as Point-to-Point Day Ahead purchases, they could be exposed to local price spikes in the North Zone Load Zone.

Table 7. Expected Cost Minus Revenue for Wholesale Costs for Alternatives, 2019 Estimate

	DEM Plan	**Scen. 1 (100% Ren.)**	**Scen. 2 (70% Ren. plus Market)**	**Scen. 3 (Storage, Comm. Solar & DR)**	**Scen. 4 (Renewables plus CAES)**	**Scen. 5 (Everything but Gas)**	**Scen. 6 (Everything plus 6 RICE Engines)**
West Wind	$1.18	$2.38	$1.19	$1.19	$1.19	$1.19	$1.19
Coastal Wind	$1.39	$2.77	$1.39	$1.39	$1.39	$1.39	$1.39
Solar	$5.65	$11.31	$5.65	$5.65	$5.65	$5.65	$5.65
RICE Engines	$3.91						$1.94
Market Purchase	$7.18		$14.37	$9.58	$7.45	$7.19	$7.19
Battery Storage				$5.97		$5.39	$5.39
CAES					$2.31	$1.62	$0.80
Comm. Solar (w/ battery)				$1.04		$1.04	$0.90

Demand Response				$0.14		$0.14	$0.14
Total Cost	**$19.30**	**$16.46**	**$22.60**	**$24.97**	**$18.08**	**$23.61**	**$24.51**

Some of the plans are riskier than others. Relying on the market to a great extent would assume that prices will not spike above a monthly average. In reality, prices vary greatly each day, hour, and season. Local price spikes could greatly impact the affordability of these plans. One of the benefits of owning local generation is being able to mitigate local price spikes with dispatchable local generation. RICE engines, demand response, community solar, community solar with storage, or storage alone all help mitigate local price spikes. The lowest cost option seems to be 100% renewables, renewables plus CAES, renewables plus RICE, and renewables plus market, but all of the options deserve more analysis over a 20-year time period.

Next Steps

As a first step, City Council should consider freezing the present contract for new natural gas power and look at alternatives. DME could invite other technologies to bid through an RFI or RFP for dispatchable technologies, including battery storage, CAES, solar plus storage, and demand response. DME should also expand its own energy efficiency, energy audit, and demand response programs. While Denton has several large commercial and industrial facilities, they appear to have no agreements to control loads and shift peak, when power is most expensive.

DME should also explore federal and state funding for new technologies like battery storage through the DOE and TCEQ. In recent years, Pedernales Electric Cooperative, CPS Energy, and Austin Energy have all received grants from the state and/or federal government that have lowered the total cost and allowed them to be leaders on clean energy.

Denton has significant local solar potential, and a community solar program could help those in Denton who cannot put solar on their own homes or businesses to invest in community solar, and help earn revenue for the city. While the costs and revenues only consider wholesale energy prices, designed correctly, the city could earn additional revenue by creating a community solar program.

Even if DME and City Council were to install all or some of new natural gas power, the City Council should direct DME to take the following steps:

- Require DME do more to promote their existing energy efficiency, energy audit, and solar programs
- Require DME to begin a community solar project, including community solar

with battery storage, to increase the use of local renewables

- Require DME to explore state and federal funding for storage technologies to add to their local system
- Consider requiring energy audits and disclosure at point-of-sale of certain residential and commercial properties
- Conducting a demand response and energy efficiency potential study to really build out those programs and beginning a process to contract 10% of their peak load with demand response programs
- Consider adding a “solar-ready” requirement to new construction as Houston and Lewisville have recently done so that it is less costly to add solar in the future.

Even if DME ultimately adds natural gas plants, taking steps to reduce local demand and increase energy provided by local solar and storage will help save money and decrease the need for using the gas plants.

Conclusion

The City Council and DME failed the citizens of Denton by not doing a full alternative study that looked at a 100 percent renewable option, a renewables plus market scenario, and a renewables plus local solar, storage (including CAES) and demand response. An introductory analysis finds that looking at these options might have led to City Council making a different decision than they made. The current city council should demand that a more full-scale analysis be made and if they fail to assess this, the next city council should demand that such a step be taken.