PREPARED BY GDS ASSOCIATES, INC.

FREMONT UTILITIES DEPARTMENT

Fremont, Nebraska

2023 Integrated Resource Plan

December 2023

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

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1 Integrated Resource Plan Methodology

1.1 FREMONT UTILITIES DEPARTMENT BACKGROUND

The City of Fremont, Department of Utilities provides gas, electric, water, and wastewater services to the City of Fremont, Nebraska, and surrounding areas. Fremont, a growing community located in eastern Nebraska, has a population of around 27,000 people. Fremont Utilities Department (FUD) owns and operates three coal/natural gas fired steam turbines, one dual fuel combustion turbine, and two community solar arrays. FDU also has a purchase power agreement (PPA) for 40.89 MW of wind resource and a 5 MW capacity agreement with the Western Area Power Administration (WAPA). FUD is a participant in the Southwest Power Pool and has three system interconnections and interconnection agreements with Omaha Public Power District (OPPD). Fremont has 20 MW of firm transmission from Cottonwood windfarm to Fremont, 5 MW firm transmission from OPPD to Fremont and 5 MW of firm transmission from WAPA to Fremont.

1.1.1 WAPA IRP Requirements

WAPA requires that the FUD develops an integrated resource plan (IRP), every five years. As such, FUD with the help of engineering and consulting firm GDS Associates, Inc. (GDS), completed an IRP study to act as a guide for the utility's future planning and development efforts to serve customer demand and energy requirements over the next 20 years.

1.2 IRP BUILDING BLOCKS

GDS's foundational approach to the IRP process includes the concept of addressing key elements of the project termed "building blocks". These elements are grouped into buckets of information that represent the overarching list of assumptions and processes which influence the IRP's strategic plan, modeling process, and evaluation of results. Each building block, and the elements which it is comprised of, is carefully contemplated to ensure a thorough analysis devoid of meaningful consideration gaps.

FIGURE 1.2.1: IRP BUILDING BLOCKS

1.3 PROCESS AND MODELING

At a high level, the IRP process is broken into three phases: an assessment of FUD's existing system operations and forecasting of future requirements, the development of study assumptions including the identification of stakeholder planning priorities and viable supply side alternatives, and an operational and economic stress-test of the IRP portfolios under the selected market sensitivities.

TABLE 1.3.1: IRP PROCESS OVERVIEW

Process Phase	Module
Phase 1 Existing System Operations & Future Requirements Assessment	Demand & Energy Requirements Forecasting
	Existing Resources Review
	Existing Purchased Power Arrangements Review
	EV Load Growth Potential Review
	EE/DSM Potential Review
	Historical Power Cost Review
	Transmission & System Operations Review
Phase 2 Derivation of IRP Modeling Assumptions	Future Market Outlooks Development
	Viable Supply Side Alternatives Review
	Portfolio Development
	Utility Stakeholder Priority Identification
Phase 3 Stress-test Evaluation	Hourly Dispatch Modeling
	Portfolio Incremental Cost Modeling
	Portfolio NPV Comparisons by Scenario
	Scorecard Evaluation & Recommendations

1.4 IRP SCENARIOS

The energy industry undergoes constant change, influenced by the countless variables that shape the world it exists within. Sweeping transformations within the industry have produced a far different planning environment today, than was the norm several decades ago. The national fuel mix continues to shift away from traditional coal-fired generation in place of cleaner alternatives including renewables and natural gas. From late 2021 throughout 2022, natural gas and electricity markets were severely strained, leading to extreme, and lasting, pricing volatility that was not seen for at least a decade prior. Wide-spread electrification, energy efficiency, and electric vehicle adoption efforts continue to impact the demand and energy requirements utilities must plan to serve the future needs of their customers. These are just a few examples of the market uncertainties which electric utilities must operate under. There are no guarantees for what tomorrow may hold, only that the industry is constantly evolving, and will continue to do so over the course of the IRP study term.

To that end, future planning measures must be evaluated under a variety of market outlook sensitivities to test the technical feasibility and power cost volatility under ungovernable external influences. This study tests each potential pathway against three market scenarios: 1) a base assumptions scenario, 2) an accelerated technology implementation, and 3) an increased regulatory scenario.

Base Case Scenario

The base case represents a future similar to the world as it exists today. This trajectory is marked by stable natural gas prices based on current futures prices. In the base case, environmental standards are largely voluntary, leading to slow and steady progress towards lower renewable prices and greater adoption of energy efficiency and electric vehicle rollout efforts.

Accelerated Technology Scenario

Accelerated Technology represents a future in which improved economic growth drives faster adoptions and higher penetrations of renewable generation, energy efficiency programs, and electric vehicle rollout. This trajectory is marked by higher natural gas prices and lower cost renewables, with environmental standards that are still largely voluntary.

Regulatory Scenario

The Regulatory Scenario represents a future that has been influenced by significant changes to electric industry regulation geared to address climate issues. Although driven by different catalysts, this scenario has similar assumptions with the Accelerated Technology scenario, such as higher natural gas prices, lower renewable prices, and higher levels of electric vehicle adoption. The most significant difference is that in this scenario, it is assumed that Congress passes legislation mandating a federal carbon tax.

A summary of the study assumptions across differing market scenarios is illustrated in Table 1.4.1.

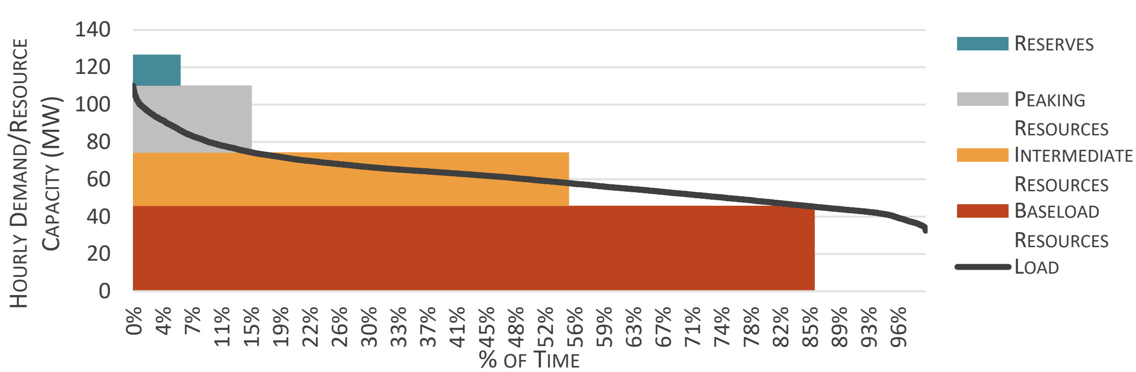
TABLE 1.4.1: MARKET OUTLOOK SCENARIO OVERVIEW

	Base Case	Accelerated Tech.	Regulatory
Load Growth	Base	Highest	High
Natural Gas Prices	Base	High	Highest
Coal Prices	Base	High	High
Market Energy Prices	Base	High	Highest
Market Capacity Prices	Base	High	High
Renewable Prices	Base	Low	Low
Carbon Tax	No	No	Yes

1.5 PORTFOLIOS

A primary objective of the IRP is to identify resource generation opportunities that will provide FUD a technically feasible and operationally reliable pathway to serve its future capacity and energy requirements in a manner that best aligns with its priorities. This is achieved via a comprehensive process of evaluating the qualitative and quantitative advantages and disadvantages of not only each individual generation alternative, but also the practicality of each as a contributor to a larger grouping of power supply assets. Portfolios represent the groups of supply- and demand-side resources utilized to meet load requirements. Each resource portfolio is designed based on FUD's load shape. Beyond ensuring the resource mix provides adequate capacity to meet the peak, each portfolio should reasonably align to the system load shape with an appropriate mix of baseload, intermediate, and peaking resources.

FIGURE 1.5.1: EXAMPLE LOAD DURATION CURVE



2 Demand and Energy Requirements

2.1 BASE DEMAND AND ENERGY FORECAST

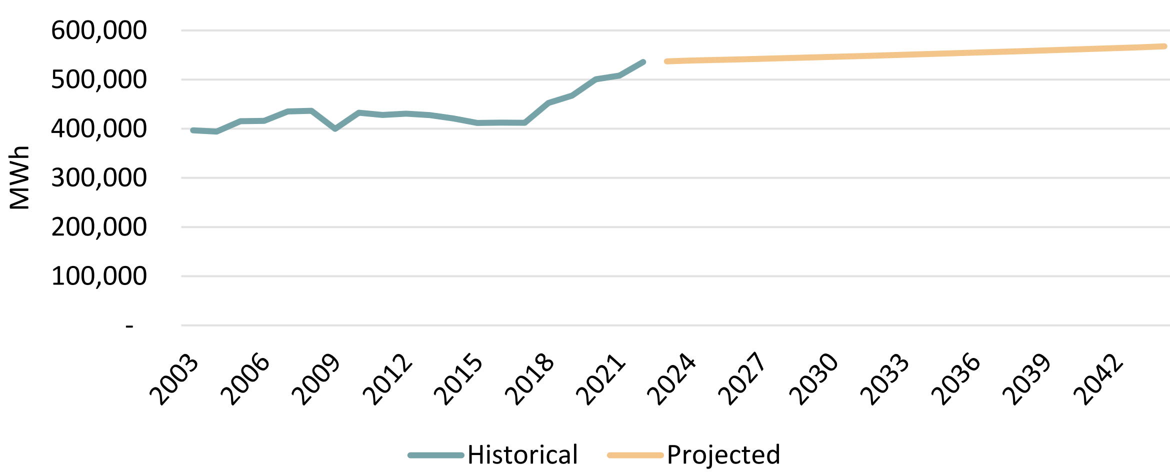
GDS developed a long-term load forecast as part of the IRP produced for the City of Fremont. Historical system load data by customer class, total system peak demand, and hourly system load was provided by Fremont for use in the development of the load forecast. Fremont also provided its most recently completed in-house load forecast for reference, which included detailed data on expectations of future load growth for several large volume customers.

After initial analysis and forecast development, GDS and Fremont determined that the large volume industrial customers should be forecasted separately from the rest of Fremont system load (Net system load). GDS developed an econometric model for Fremont net system load, incorporating local economic conditions and projections, and monthly heating and cooling degree days. The net system load projections were combined with the large volume customer load projections, resulting in a total system forecast. GDS developed both Summer and Winter system NCP demand forecast based on a load factor model. Fremont is a historically Summer peaking system and is projected to remain so for the duration of the forecast period.

As part of the forecast development, GDS consulted with Fremont staff regularly, ensuring that both parties were comfortable with the overall forecast methodology and results.

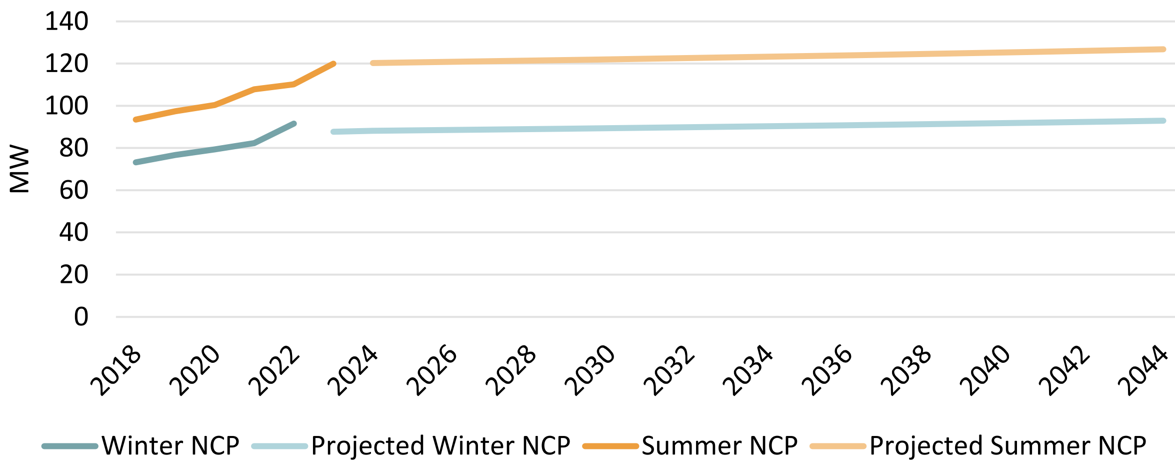
Overall Fremont system energy is projected to grow at a compound annual growth rate of 0.3% from 2023 through 2043. The very slow, steady growth of the system is indicative of a nearly saturated service territory. As there is not much room for additional homes or businesses within Fremont's service territory, load growth can be attributed to increasing consumer electronics within both homes and small businesses. While there is the possibility of further expansion from some of Fremont's large volume customers, it is considered unlikely in the near future so large volume customer sales was kept constant for the forecast period.

FIGURE 2.1.1: HISTORICAL AND FORECASTED ENERGY REQUIREMENTS



Fremont system peak demand has increased steadily over the most recent five years, however much of that growth can be attributed to the increasing demand of large volume customers. None of Fremont's large volume customers are expected to continue to grow at such a rapid pace in the future, resulting in a slower pace of growth for Fremont system demand for the forecast period.

FIGURE 2.1.2: HISTORICAL AND FORECASTED DEMAND REQUIREMENTS

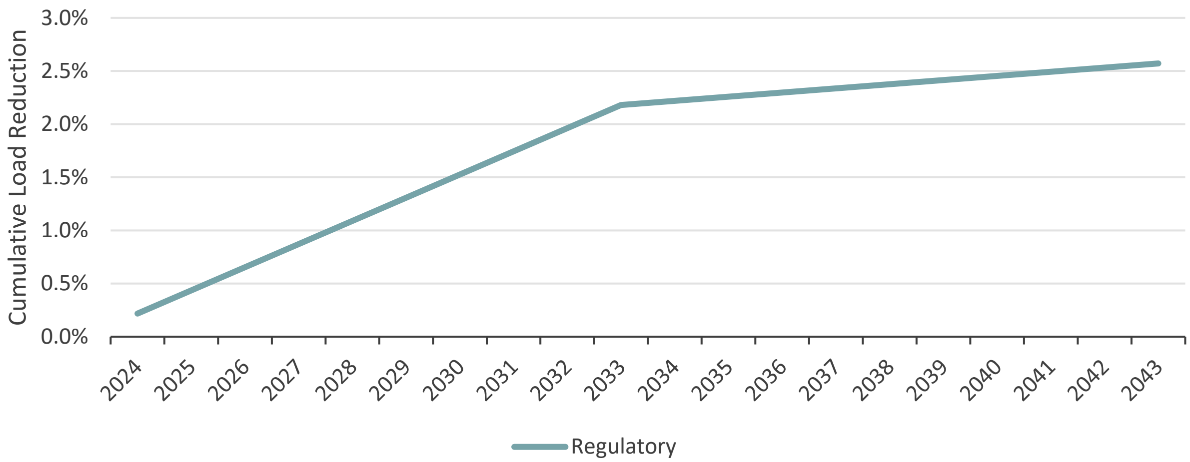


2.2 ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT FORECAST

Energy efficiency (EE) and demand-side management (DSM) programs have critical elements of utility planning efforts and enhanced customer experience. DSM is a broad definition that includes EE as well as demand response (DR). Generally speaking, DSM programs refer to the planning, design, implementation, and evaluation of activities engaged in by the utility to encourage their customers to modify the amount and timing of their consumption. Whether directly motivated by utility incentives, or taken by an individual consumer or business, some examples of these efforts include installation of higher efficiency electrical equipment and/or "smart" devices, building shell improvements such as ceiling or attic upgrades, or behavioral conservation changes to reduce consumption. This study considers one sensitivity in which elevated EE/DSM adoption is applied to the baseline forecast, contributing to lower annual sales and peak avoidance.

In the Regulatory scenario, energy savings are assumed to start at 0.22% annually, dropping over time as "low hanging fruit" options are pursued leading to diminishing returns. By the end of the study term in 2043, cumulative energy savings total roughly 2.6% which was applied to the base forecast on a load-weighted basis. Demand implications were determined based on the reduction coincident with the timing of FUD's peak.

TABLE 2.2.1: EE/DSM STUDY ASSUMPTIONS



2.3 ELECTRIC VEHICLE PENETRATION

The future of transportation is increasingly electric, as electric vehicles (EVs) become more common place in the United States as a viable substitute for traditional internal combustion engine (ICE) vehicles. As EV adoption rates grow, it is imperative that utilities anticipate and plan for the incremental demand and energy requirements that result from wide-spread EV charging within their territories. For this study, two potential levels of future EV penetration and the resulting impacts to FUD load are considered.

While substantial research on national EV projections exists, reliable and publicly available information on a local, city, or state level is far more difficult to attain, particularly considering the wide variety of the types of EVs that are present in today's market.

The following variables were utilized in the formation of both projected EV adoption roll-out curves:

1. Residential household count and customer growth (GDS Load Forecast)
2. Vehicles per residential household (US Census Data)
3. Vehicle lifespan (Bureau of Transportation Statistics)
4. Residential EV fuel economies and vehicle class breakdown (US DOE)
5. Annual vehicle miles traveled per EV (GDS)

The difference between the two projections results from the assumed market share of electric vehicles in Fremont's service territory. By the end of the study term, it is assumed that EV's make up 5% of new vehicle sales under the Accelerated Technology scenario, and 11% of new vehicle sales under the Regulatory scenario.

TABLE 2.3.1: PROJECTED MARKET SHARE FOR NEW RESIDENTIAL ELECTRIC VEHICLES

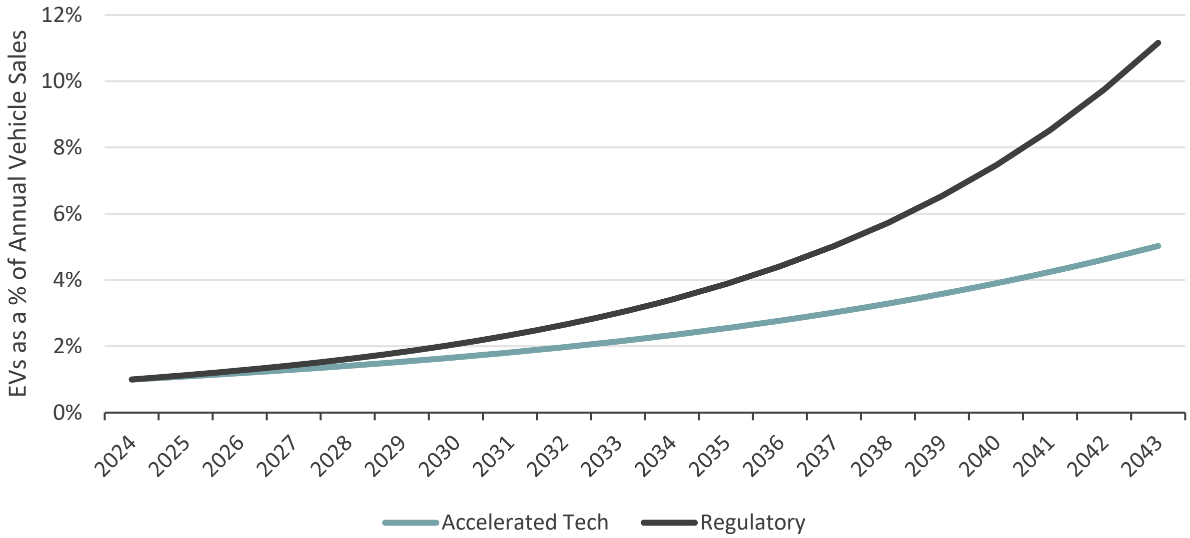
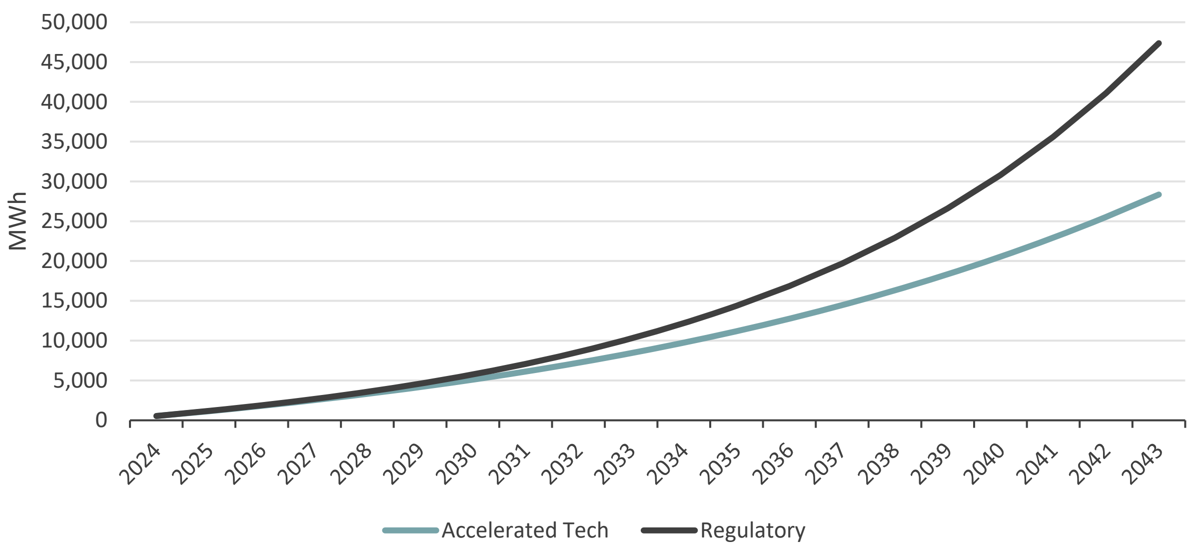


TABLE 2.3.2: INCREMENTAL ENERGY ASSOCIATED WITH EV CHARGING



2.4 RESULTING MARKET SCENARIO DEMAND AND ENERGY FORECASTS

The prior sections detail the load requirements assumed in this IRP study, in addition to the various load modifying assumptions around energy efficiency programs and EV growth projections. The future demand and energy requirements utilized in the study, are based on the combination of these projections which vary between the three market scenarios.

TABLE 2.4.1: RESULTING MARKET SCENARIO DEMAND REQUIREMENTS (MW)

	Base Case	Accelerated Tech	Regulatory
2025	120.5	120.7	120.1
2030	122.0	122.6	120.8
2035	123.5	124.8	122.4
2040	125.3	127.6	125.7

TABLE 2.4.2: RESULTING MARKET SCENARIO ENERGY REQUIREMENTS (GWH)

	Base Case	Accelerated Tech	Regulatory
2025	540	541	539
2030	546	551	544
2035	553	564	555
2040	561	582	578

3 Existing Resources and Power Supply Arrangements

TABLE 2.4.1: FUD EXISITNG POWER SUPPLY PORTFOLIO

Resource	Fuel	Nameplate Capacity
Lon D. Wright Power Plant	Coal (Primary)/Natural Gas	129.0 MW
Derril G. Marshall Generating Station	Natural Gas (Primary)/Diesel	40.0 MW
WAPA Hydro Allocation	Hydro	5.0 MW
Cottonwood Wind PPA	Wind	40.89 MW
City of Fremont Community Solar	Solar	2.31 MW

3.1 LON D. WRIGHT POWER PLANT

FUD has owned and operated the Lon D. Wright Power Plant (LDW) since 1958. LDW Power Plant is FUD's main power production facility and consists of three steam turbines, unit 6, 7, and 8. Although primarily coal-fired, LDW has dual fuel capability, also able to run off of natural gas. LDW units 6-8 have nameplate capacities of 16.5 MW, 21.0 MW, and 91.5 MW respectively and operate at a roughly 40-45% capacity factor, producing enough generation to account for 85-95% of FUD's annual energy requirements.

3.2 DERRIL G. MARSHALL GENERATING STATION

FUD has owned and operated the Derril G. Marshall (DGM) Generating Station since 2003. DGM is a 40 MW natural gas turbine that is used for reliability concerns and during peak demand. DJM typically operates at an annual capacity factor of up to 3%, serving approximately 0-1% of FUD's energy requirements.

3.3 WAPA HYDRO ALLOCATION

FUD has an ongoing 4.79 MWh max hydro allocation from Western Area Power Administration (WAPA) and a typical monthly supply of approximately 26,250 MWh energy and 5.0 MW capacity. WAPA markets and delivers federal hydroelectric power and energy to public bodies and cooperatives within the western region of the United States. The City of Fremont is located within WAPA's Upper Great Plains Region. WAPA generation is scheduled and has operated at a roughly a 60% capacity factor in recent years, serving roughly 5% of FUD's annual energy requirements.

3.4 COTTONWOOD WIND PURCHASE POWER AGREEMENT

Beginning in 2027, FUD entered into a 25-year power purchase agreement with NextEra for a 40.89 MW allocation of wind energy and capacity from the Cottonwood Wind facility. The Cottonwood wind facility is located in Blue Hill, Nebraska and operates at an annual capacity factor of approximately 55%, serving roughly 35% of FUD's annual energy requirements.

3.5 CITY OF FREMONT COMMUNITY SOLAR

In 2018, the City of Fremont launched a 1.32 MW community solar farm, located adjacent to the LDW power plant. Due to the initial customer response, the City of Fremont approved a second phase of the project consisting of an additional 1 MW. The community solar farms operate at roughly a 20% capacity factor and serve approximately 0-1% of FUD's annual energy requirements.

4 Viable Supply Side Alternatives

4.1 NATURAL GAS FIRED TECHNOLOGY

Reciprocating Internal Combustion Engine (RICE) units are quick-start units with minimal startup costs that can be operated for either short or extended periods of time to meet electric load requirements. RICE units are available in a variety of smaller capacities, typically 9 MW or 15 MW per unit, with a modular design that enables multiple unit configuration necessary to achieve a total capacity capable of meeting incremental generation gaps. RICE units operate by pressurizing fuel using pistons that alternatively move back and forth in a pattern of intake, compression, combustion, and exhaust to create rotating motion and produce electricity. While combustion turbines (CTs) typically have lower capital costs and significantly lower non-fuel O&M costs than RICE units, the lower heat rate of RICE units provides advantageous fuel costs, which can result in an overall lower levelized cost of electricity if annual operating hours are significant. RICE units have an additional advantage over CTs because individual units can be dispatched in various combinations, such that optimal heat rate is achieved over a much broader range of MW output.

Simple-cycle gas turbines are, as the name suggests, less complex than combined cycle turbines and have several relative benefits such as lower construction costs and quicker starts. However, in converting to a combined cycle, the same gas turbine could achieve a higher nameplate capacity and efficiency resulting in significant improvements in generation output at the same fuel cost. With the addition of a Heat Recovery Steam Generator (HRSG) waste heat from the gas turbine is then used to power a steam turbine to generate additional electricity.

At present, Fremont faces challenges preventing natural gas supply delivery at a volume necessary to ensure reliable and/or substantial output from any resources that rely on the fuel. For purposes of this study, capital costs have been incorporated into any portfolios that comprise primarily natural gas-fueled resources, to account for pipeline build, compressor stations, feed studies and other costs associated with improving natural gas supply.

4.2 RENEWABLE AND ZERO-CARBON TECHNOLOGY

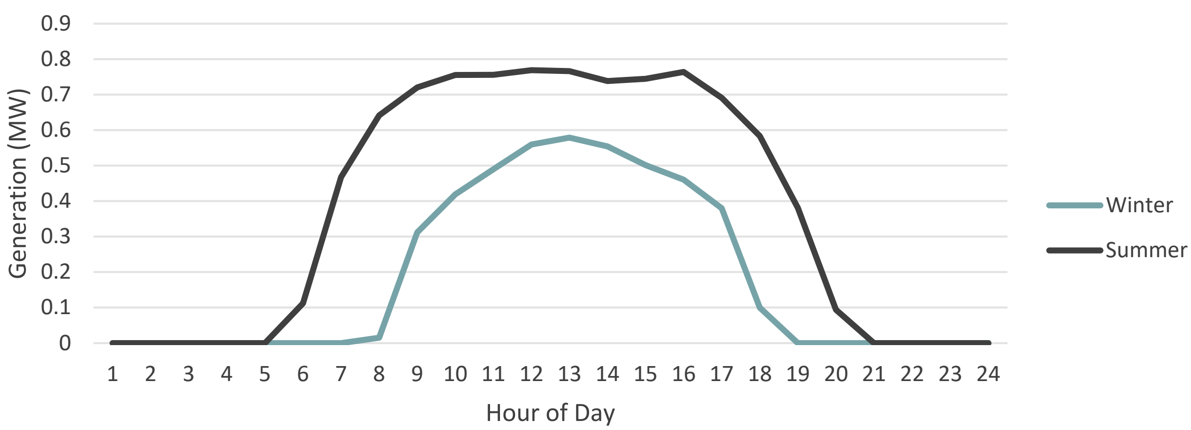
In recent years, the societal push for businesses and individuals to become more conscious of their impacts on the environment and make efforts to reduce their carbon footprints has been steadily increasing. This is particularly relevant to players in the electric utility industry who have the unique ability to directly implement these changes. As a result, demand for clean technologies has grown, leading to improvements in cost and efficiency. As with any generation technology, there are advantages and disadvantages to any resource, with renewable and zero-carbon resources holding no exception. Multiple IRP portfolios in this study incorporate a component of incremental clean capacity to test the economic and operational feasibility of such an addition to FUD’s portfolio.

4.2.1 Photovoltaic Solar & Energy Storage Systems

Both solar and battery energy storage systems (BESS) have been major sources of the clean energy capacity additions within the US over recent decades, with pricing and technological efficiency benefitting from significant investments from utilities, as well as individual players in the industrial, commercial, and even residential sectors. Given the incentives afforded by the Inflation Reduction Act (IRA), the growing possibility of clean-energy focused legislation, and the value of fuel-diversity highlighted by the volatility experienced in the natural gas and electricity markets over the last three years, solar and battery storage are becoming increasingly viable resource considerations, despite their inherent challenges.

To properly hedge load, the timing of electric generation needs to align to the timing of customer demand. Solar output is highly dependent upon the time of day, reaching its peak production mid-day, after which generation gradually diminishes, concurrent with rising energy consumption from electric customers. This challenge is only worsened as we get further from the summer months in which solar production is greatest. Heavy reliance on a resource that cannot produce sufficient and dispatchable generation under uncontrollable circumstances such as heavy cloud cover, can cause reliability issues for a system if these risks are not properly mitigated.

FIGURE 4.2.1: AVERAGE DAILY OUTPUT PER MW OF INSTALLED SOLAR



Although not without its own challenges, battery storage provides one solution to help mitigate the challenges tied to the intermittency of solar production. Present day battery systems are most commonly lithium-ion based, and are often used to store solar excess solar production until it later needed or to offset a utilities peak demand. Batteries can be a useful tool to bolster system reliability, particularly when renewables are incorporated into a supply mix. These systems do however have several practical limitations. Battery systems are only capable of shifting generation that has already been produced. While they have come a long way since their initial applications, they still often come at a price premium particularly for configurations that optimize flexibility of use.

4.2.2 Small Modular Nuclear Reactors

Since they first emerged in the United States over 60 years ago, nuclear power plants have produced clean, dispatchable, baseload, generation, standing out as the most reliable source of source of zero-carbon energy we have had available to serve load at a large scale. Despite these, and many other benefits including low operating costs and land requirements, high up-front capital costs and long construction timelines have led to a significant decline in traditional nuclear power plants which are instead being replaced with more cost-effective options such as new build natural gas combined cycle.

Recent legislation has allocated subsidies to existing nuclear plants, providing economic incentive to continue operations, however looking forward, the future of nuclear likely resides with new plant designs based on modular reactors of far smaller capacities. The base module of a small modular reactor (“SMR”) is typically around 50 MW, and at present, can be combined to achieve a plant of up to 600 MW. As each unit is factory produced, it is a far lower-cost option than traditional nuclear. Additionally, its modular design allows for more maintenance flexibility as a single unit can be taken offline while the others remain in operation. While SMR’s provide a promising option to re-invest in clean and reliable baseload generation with nuclear power, it is still likely that their economic feasibility will be dependent upon clean energy tax incentives and/or the introduction of carbon tax legislation.

4.3 BILATERAL MARKET SUPPLY

Several of the IRP portfolios include components of market-based energy and/or capacity. Alternative to hedging demand and energy requirements via long-term, owned or contracted resource investments, SPP market participants can enter into financial hedges by the use of a bilateral transaction in which a third party provides energy and/or capacity under mutually agreeable terms. This can take many forms including fixed volume or load following transactions, both of which require the determination of key terms such as delivery points, volumes, times of delivery, start and end dates, and product price.

One portfolio contains an energy-only block, which in Fremont’s case as a non-network integrated transmission service customer, requires the inclusion of additional point-to-point transmission costs to ensure delivery to Fremont.

For all portfolios in which Fremont’s peak demand, plus a reserve margin of 18%, exceeds its cumulative accredited resource capacity, it is assumed that the deficiency is cured via a bilateral transaction in which a secondary counterparty designates a volume of its excess capacity to Fremont, enabling it to comply with its SPP Resource Adequacy requirements.

5 IRP Resource Portfolios

The IRP evaluation was designed to capture the key costs associated with incremental changes to FUD's current power supply mix to help inform future planning efforts. An equally important objective is to capture the impacts of those incremental changes on the operational side to ensure that resource or purchase power investments are made in a way that aligns to FUD's load profile.

5.1 RESOURCE SIZING CONSIDERATIONS

The starting point for determining the necessary generation capacity for the IRP resource portfolios was to review how the current resource mix stacked up against anticipated load at the end of the study term, with the following questions in mind.

1. From an energy perspective, how does the volume of anticipated annual generation compare to the anticipated volume of energy required to serve customer need? If there is an excess or deficiency, to what degree is Fremont a net seller into or buyer from the market?

2. From a demand perspective, how does the cumulative volume of anticipated accredited capacity compare to the anticipated peak demand grossed up by a market reserve requirement? If there is an excess or deficiency, to what degree is Fremont over- or under- hedged on capacity?

The study assumed a capacity requirement of peak demand plus an 18% SPP Market Reserve margin, and that a maximum of 30% of the nameplate value of solar and 15% of the nameplate value of wind would be the longer term accreditation levels for these types of resources from a regional perspective. Even taking into consideration 20 years of anticipated load growth, a demand reserve margin, and the capacity devaluation of intermittent renewables, FUD's cumulative resource mix results in an anticipated excess from both a capacity and energy standpoint.

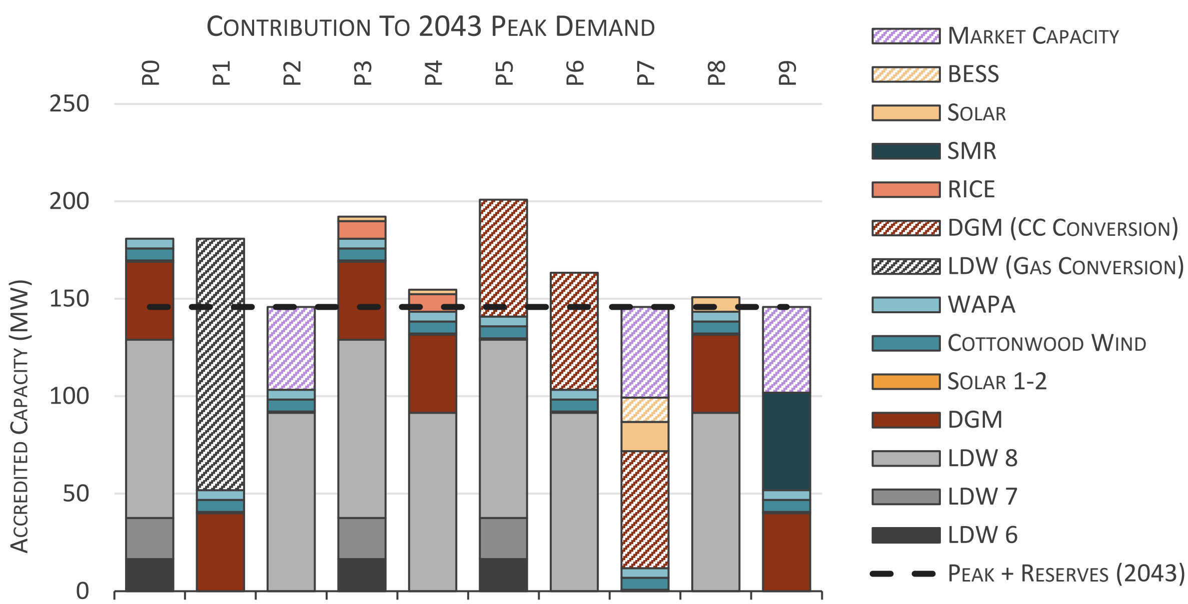
5.2 PORTFOLIO DESIGN APPROACH

Because the PO (Business-as-Usual) portfolio is already well aligned to both current and future needs, for many of the IRP portfolios, existing resource retirements were contemplated to maintain an appropriate volume of capacity and associated generation when adding in new resource alternatives. Some portfolios, however, featured no retirements to help illustrate the impact of incremental costs while avoiding any risk to reliability. Portfolio alternatives were developed with four main focuses in mind:

1. Minimal Investment/Marginal Variation
2. Internal Combustion Build
3. DGM Combined Cycle
4. Carbon Reduction Pathways

An illustration of the IRP study portfolios is shown in Table 5.2.1 on the following page. The resources within the portfolios are accredited as per an SPP resource adequacy outlook as previously described.

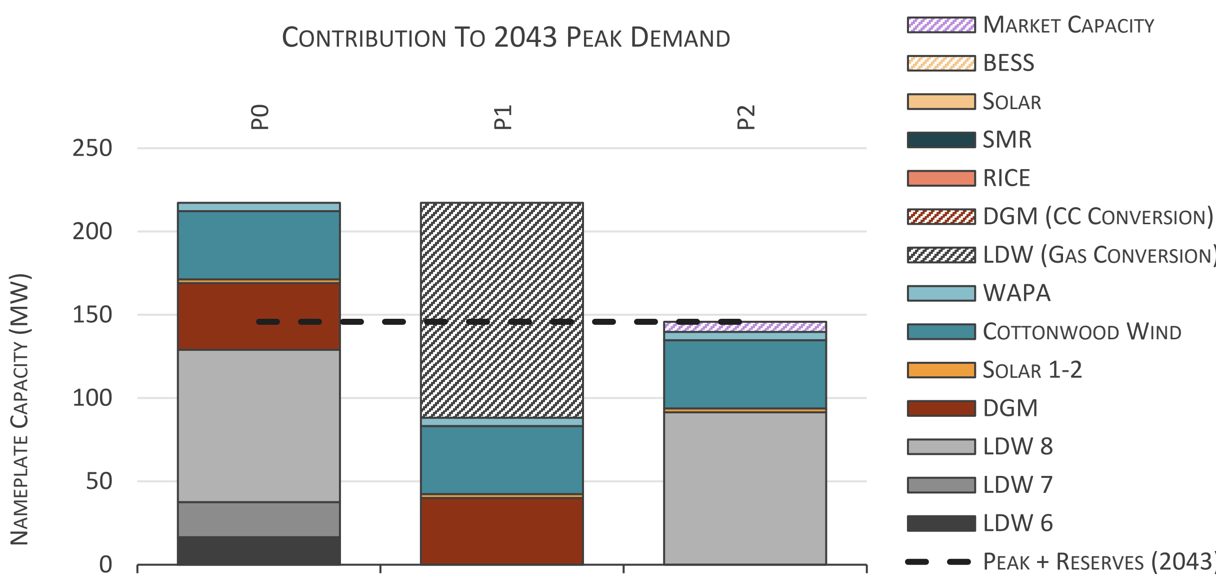
TABLE 5.2.1: IRP PORTFOLIO SUMMARY (SPP ACCREDITED CAPACITIES)



5.2.1 Minimal Investment/Marginal Variation Portfolios

The first category of portfolios focuses on alternative supply arrangements that largely mirror the existing mix, and/or require little investment to achieve. Three portfolios reside within this grouping.

FIGURE 5.2.1: MINIMAL VARIATION PORTFOLIOS (NAMEPLATE CAPACITY)



Portfolio 0 (P0), otherwise referred to as the Business-as-Usual portfolio, assumes no incremental change is made to the existing combination of owned resources and purchased power agreements. It assumes

that LDW Units 6-8, and DGM continue operating, and that the same contribution of distributed solar, PPA wind, and WAPA, remain in the mix.

Portfolio 1 (P1) assumes that LDW Units 6-8 remain in operation but are no longer fueled by coal, and instead run off natural gas, which they are already capable of. All other components to the existing portfolio remain constant, however this shift in primary fuel source does require capital investment to improve natural gas supply issues to the plant.

Portfolio 2 (P2) assumes partial retirement of LDW with Units 6-7, but does not incorporate the addition of any physical resources to fill in the small deficiency that is left as a result. Instead, this portfolio relies upon marginal bilateral, market-based, capacity and block energy purchases. As FUD is not an SPP Network Integrated Transmission Service (NITS) customer, the purchase of block energy assumes an equivalent capacity of point-to-point transmission must be contracted to ensure firm delivery.

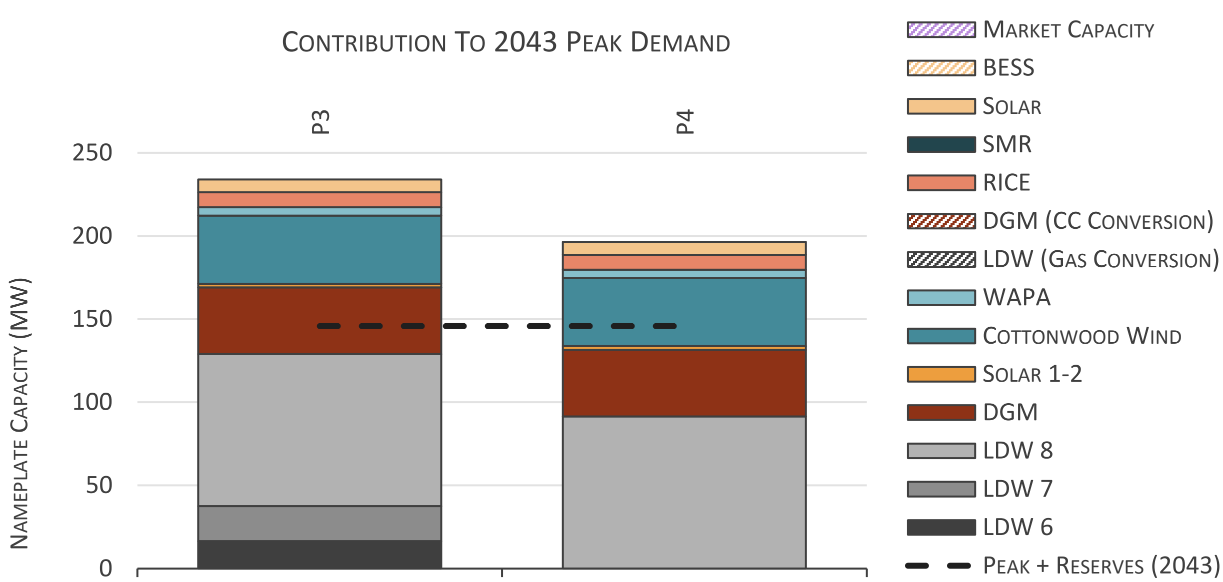
TABLE 5.2.2: MINIMAL INVESTMENT/MARGINAL VARIATION RETIREMENTS AND ADDITIONS

Portfolio	Resource Retirements	Resource Additions
P0: Business-As-Usual	• N/A	• N/A
P1: LDW Gas Conversion	• N/A	• N/A
P2: Bilateral Market-Based Supply	• LDW 6-7	• Annual ATC Energy Blocks

5.2.2 Internal Combustion Build Portfolios

The second category of portfolios focuses on alternative supply arrangements that incorporate the addition of a single Reciprocating Internal Combustion Engine (RICE). In both portfolios within this grouping, RICE is used to firm up the supply around incremental distributed solar capacity and to support system reliability.

FIGURE 5.2.2: INTERNAL COMBUSTION BUILD PORTFOLIOS (NAMEPLATE CAPACITY)



Portfolio 3 (P3) assumes only incremental resource additions relative to P0. In this portfolio, FUD supplements its existing distributed solar facilities to achieve a total nameplate capacity of up to 10 MW. In conjunction with the solar capacity addition, this portfolio assumes a new build RICE unit to shape around the intermittent generation. Similarly to P1, the incremental gas fired generation in this portfolio calls for capital investments to improve upon the natural gas supply issues FUD currently faces.

Portfolio 4 (P4) differs from P3 only in that LDW Units 6-7 are retired to lessen the capacity excess position and therefore reduce fixed operating costs. All other components of the portfolio remain consistent.

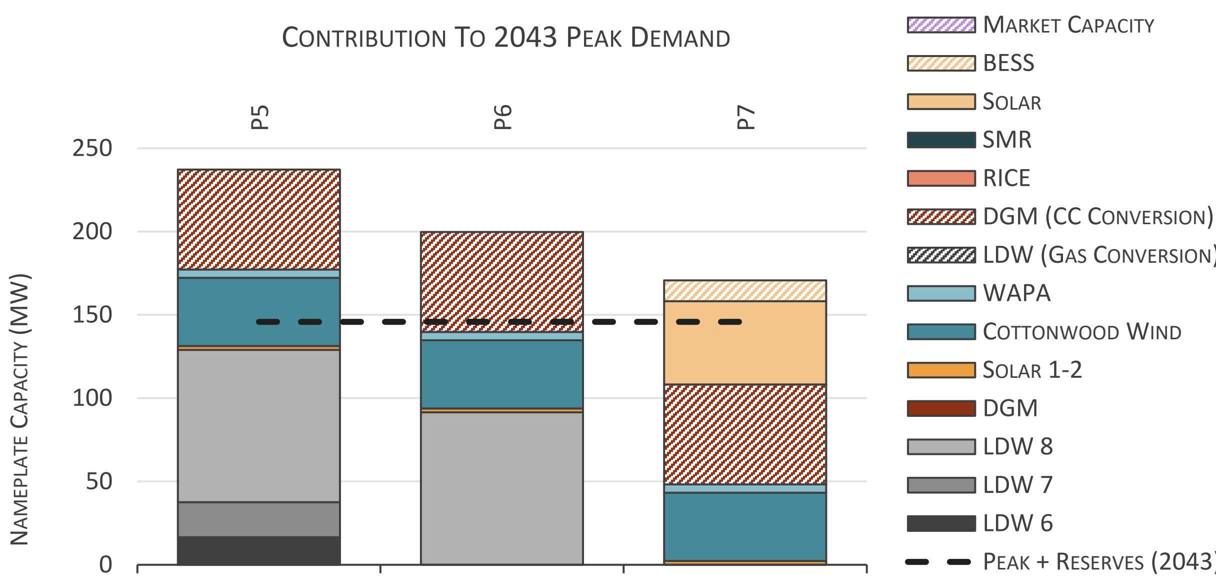
TABLE 5.2.3: INTERNAL COMBUSTION BUILD RETIREMENTS AND ADDITIONS

Portfolio	Resource Retirements	Resource Additions
P3: RICE + DG Solar (No Retirements)	• N/A	• RICE (9 MW) • Distributed Solar (7.7 MW)
P4: LDW Gas Conversion	• LDW 6-7	• RICE (9 MW) • Distributed Solar (7.7 MW)

5.2.3 DGM Combined Cycle Portfolios

The third category of portfolios focuses on alternative supply arrangements that include capital upgrades to convert DGM from a CT to a CC with the addition of a heat recovery steam generator (HRSG). Three portfolios reside within this grouping, all of which assume 20 MW of additional capacity (resulting in a total of 60 MW) are achieved from the upgrade.

FIGURE 5.2.3: DGM COMBINED CYCLE PORTFOLIOS (NAMEPLATE CAPACITY)



Portfolio 5 (P5) assumes no resource retirements or additions. The only difference that sets P5 apart from P0 is the incremental capacity and associated generation achieved by the addition of a HRSG at DGM, and the corresponding natural gas supply improvements necessary to fuel the plant.

Portfolio 6 (P6) differs from P5 only in that LDW 6-7 are retired to lessen the capacity excess position and therefore reduce fixed operating costs. All other components of the portfolio remain consistent.

Portfolio 7 (P7) features a total plant retirement of LDW, including Unit 8. To help lessen the capacity deficiency caused by the retirement, utility scale solar and supplemental battery storage are incorporated into the mix. Due to the lower capacity accreditation of solar from a resource adequacy standpoint, P7 does rely on bilateral capacity purchases to fulfill peak demand plus reserves.

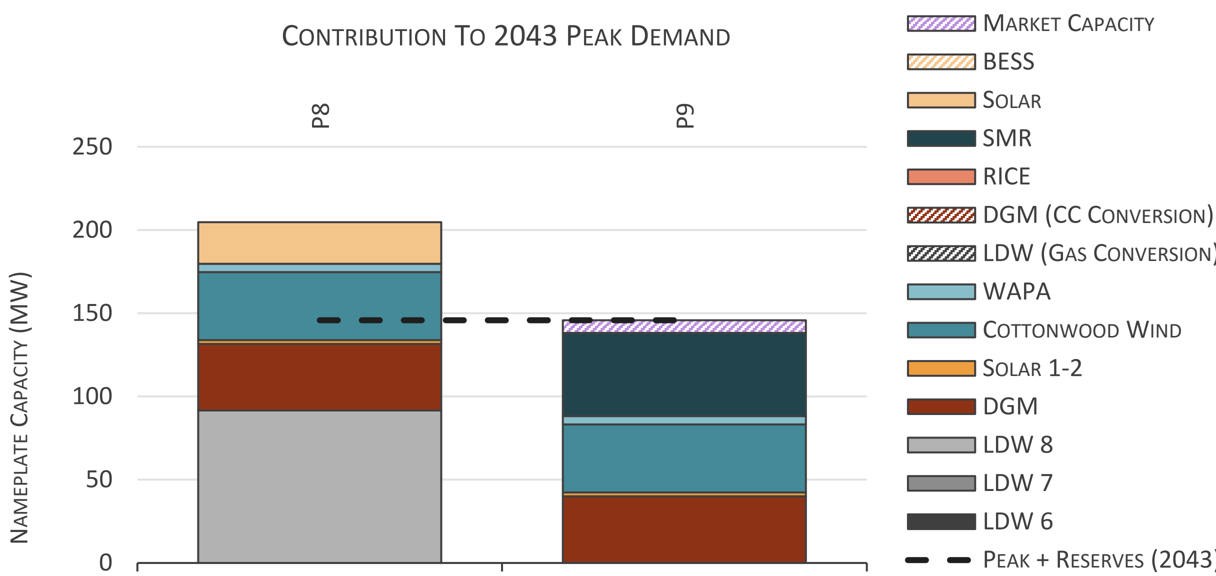
TABLE 5.2.4: DGM COMBINED CYCLE RETIREMENTS AND ADDITIONS

Portfolio	Resource Retirements	Resource Additions
P5: Small CC (No Retirements)	• N/A	• HRSG - 1x1, (DGM 60 MW CC)
P6: Small CC	• LDW 6-7	• HRSG - 1x1, (DGM 60 MW CC)
P7: Small CC + Hybrid Solar	• LDW 6-8	• HRSG - 1x1, (DGM 60 MW CC) • Solar (50 MW) + BESS (50 MWh)

5.2.4 Carbon Reduction Pathways Portfolios

The last category of portfolios focuses on incremental changes that reduce FUD's carbon emissions. Two portfolios reside in this category.

FIGURE 5.2.4: CARBON REDUCTION PATHWAYS PORTFOLIOS (NAMEPLATE CAPACITY)



Portfolio 8 (P8) takes an approach of lower resistance in which LDW Units 6-7 are retired while utility scale solar is added to the mix to further offset fossil fuel generation. In this portfolio, incremental solar capacity additions are kept at a level that are easily absorbed by load, avoiding the need for battery storage shaping.

Portfolio 9 (P9) takes a more aggressive approach in which coal is eliminated from the portfolio entirely with the retirement of LDW Units 6-8, and is replaced with a co-ownership allocation of small modular nuclear. While SMR's are currently in early developmental stages in the United States, in order to appropriately capture the anticipated costs associated with the resource, it is assumed as a resource addition throughout the term of the study. Due to the inherently high capacity factor of the resource, in replacing LDW with nuclear capacity, Portfolio 9 relies on bilateral capacity purchases to meet peak demand plus reserves.

TABLE 5.2.5: CARBON REDUCTION PATHWAYS RETIREMENTS AND ADDITIONS

Portfolio	Resource Retirements	Resource Additions
P8: Utility Solar	• LDW 6-7	• Solar (25 MW)
P9: SMR	• LDW 6-8	• SMR (50 MW)

6 IRP Scenarios and Key Assumptions

6.1 ESCALATION, FINANCING, AND DISCOUNT RATES

The IRP average general inflation rate is 2.5% per annum over the 20-year study period. It is based on the long-term inflation forecasts from Blue Chip Economic Indicators, the Congressional Budget Office, and the Federal Reserve Bank of Philadelphia. This inflation rate is used to escalate all capital construction costs, fixed and non-fuel variable O&M expenses, and capital cost of major environmental / maintenance expenditures during the 20-year study period.

The IRP study evaluation assumes that FUD will issue new bond debt to finance 100% of all new generation resources in the alternative resource portfolios, excluding PPA arrangements for solar, battery storage, and supplier block selections. The interest rate associated with new bond issuances was assumed to be 4.0% and was based on the Energy Information Administration's (EIA) 2023 Annual Energy Outlook (AEO23) macroeconomic projections for Long Term AA Utility Bond interest rates. The study also assumes the discount rate is 4.0%. The discount rate is used in all net present value calculations to bring all future cash flows during the term of the study to a present value basis. The table below provides a look into the capital cost requirements for the non-PPA installed portfolio assets. All these costs were assumed to be financed over the IRP's 20-year study period so that the study included all incremental resource decision costs within the study's NPV calculations.

TABLE 6.1.1: PORTFOLIO ASSET CAPITAL COST ASSUMPTIONS

Capital Expense	Plant Size (MW)	Nom. Rate ($/kW)	Nom. Cost ($M)
RICE	9 MW	$2,000	$18
HRSG (DGM CC)	60 MW	$900	$54
SMR	50 MW	$8,000	$400
Pipeline Upgrades	-	-	$9

6.2 FUEL PRICE PROJECTIONS

6.2.1 Natural Gas Price Projections

Three natural gas price curves were utilized for the analysis. The Base Case scenario natural gas assumptions reflect similar commodity pricing to that within the United States market over the past decade. While recent global events have had an impact on the stability and low-cost nature of natural gas prices that became the norm towards the late 2000's, this scenario assumes that the pressures that have driven volatility in the past (at times) are not present throughout most of the study term. With this in mind, the gas price projections were derived largely from a current market outlook of the NYMEX Henry Hub futures trading curve as of May 2023. Starting at approximately $4.16/MMBtu in 2025, the average natural gas price over the 20-year term comes to roughly $4.83/MMBtu.

TABLE 6.2.1: NATURAL GAS PRICE ASSUMPTIONS ($/MMBTU)

	Base Case	Accelerated Tech	Regulatory
2025	4.16	4.17	4.18
2030	4.32	4.88	6.03
2035	4.86	5.64	7.95
2040	5.36	6.86	9.03
2045	5.92	7.57	9.50

The Accelerated Technology and Regulatory assumptions were developed to represent the potential for a moderate to substantial increase in the pricing outlook due to unforeseen geopolitical events and/or changes in legislation. The basis of the Accelerated Tech price curve is a NYMEX Henry Hub futures trading curve as of January 2023. Starting at $4.17/MMBtu, the average natural gas price over the 20-year term comes to roughly $5.73/MMBtu. The basis of the Regulatory assumption is the EIA Annual Energy Outlook 2023, Low Oil & Gas Supply Case natural gas curve. Starting at $4.18/MMBtu in 2025, the average natural gas price over the 20-year term comes to roughly $7.42/MMBtu.

6.2.2 Coal Price Projections

Two coal price curves were utilized for the analysis. The first, used in the Base Case market scenario, is based on Powder River Basin coal price futures as of April 2023 which feature a slight dip between 2024-2025, then consistent escalation of roughly 2-3% on average. The second, used in the Accelerated Technology and Regulatory scenarios, assumes short-term market disruption causing coal prices to spike 25% per year, for the first two years, followed by escalation for the remainder of the study term. These assumptions result in a price forecast that averages approximately 50% higher than the Base Case market scenario.

TABLE 6.2.2: COAL PRICE ASSUMPTIONS ($/MMBTU)

	Base Case	Accelerated Tech/ Regulatory
2025	1.76	2.28
2030	2.08	3.25
2035	2.36	3.57
2040	2.70	4.08
2045	3.04	4.60

6.2.3 Carbon Tax Assumptions

Under the Regulatory Scenario, it is assumed that the federal government enacts a carbon tax that would be implemented prior to the start of the study term in 2025. This assumption impacts all thermal resources by increasing the cost to generate via a tax on emissions.

TABLE 6.2.3: CARBON TAX PRICE ASSUMPTIONS ($/TON)

	Regulatory
2025	31.50
2030	40.20
2035	51.31
2040	65.49
2045	83.58

In recent United States Congressional sessions, several bills have been proposed targeting the implementation of a carbon tax or cap and trade program. The IRP utilizes a mid-point of some of the more conservative proposals, to gauge the potential impact of such a tax without holding enough weight to completely overshadow the other variables that could influence the portfolios under this market scenario and to enable the economics associated with fuel switching. The latter of which is likely to be the underlying premise for any carbon tax curve that is implemented. Starting at $30.00/ton, the carbon tax assumption escalates at 5% annually, resulting in an average price of roughly $49.60/ton over the 20-year term.

6.3 SPP MARKET CAPACITY AND ENERGY PRICES

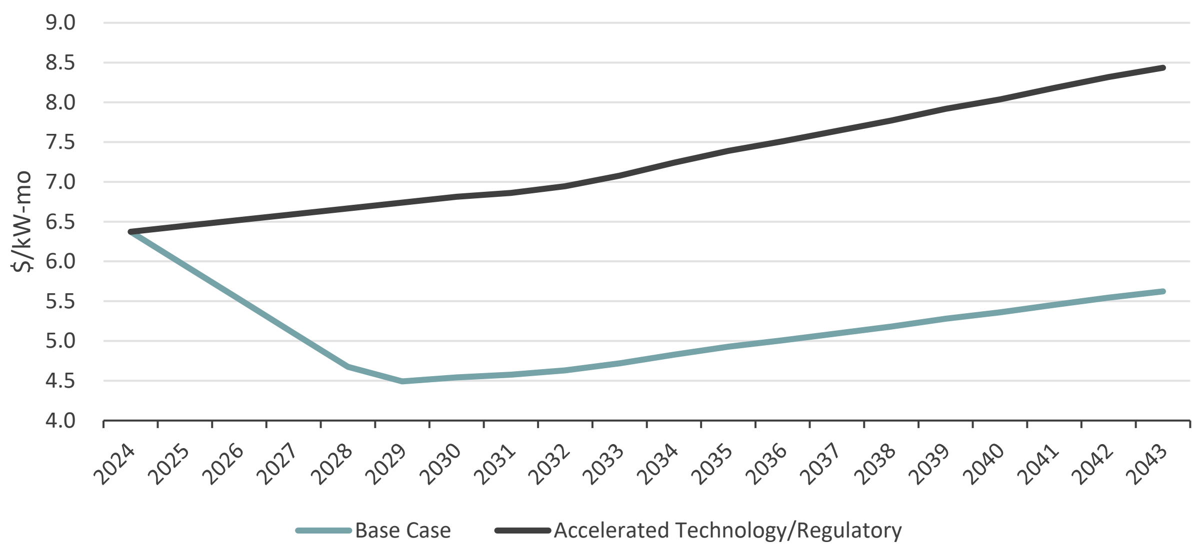
6.3.1 Bilateral Capacity Price Projections

Capacity price projections are necessary to determine the cost of incremental capacity necessary to meet FUD's load planning requirements. These projections are based on a fundamental approach using the estimated cost of incremental new capacity to the SPP region, something commonly referred to as "Cost of New Entry" (CONE), or the estimated cost of new generation. For the past several years, SPP capacity transaction prices have been low and recent market data from other long-term RFPs, coupled with SPP's projected planning reserve margin increases to the Summer season from its LOLE study through planning year 2029, suggest that capacity prices will be at or below CONE for the foreseeable future until the time further resource adequacy (RA) rules are modified.

The IRP considers two capacity price forecasts. The base case is characterized by a few years in which supply catches up to demand, but with the continued proliferation of renewable capacity within the footprint requiring flexible generation and continued plant retirements, prices are expected to increase relative to historical pricing which had been below the $3/kW-mo level. The high-capacity case is marked by an acceleration of the need for capacity due to higher load growth, higher EV adoption rates, even greater rollouts of renewables, and advanced regulatory policy amendments to market planning targets.

The average capacity price for the Base Case scenario is approximately $5.20/kW-mo over the course of the term, while the price for the Accelerated Technology and Regulatory Scenarios averages approximately $7.40/kW-mo. These projections served as a way to price the bilateral capacity transactions that were assumed to take place in some of the portfolios for the balance of capacity need.

FIGURE 6.3.1: IRP CAPACITY PRICE ASSUMPTIONS



The ongoing evolution of the SPP resource adequacy construct will have a direct impact on the outlook for these capacity price projections over the next 3 to 5 years and should be closely monitored. Not only has the Summer season planning reserve margin (PRM) been increased from 12% to 15% in the past couple of years, but also the preliminary results from the 2023 LOLE study suggest another 1-2% increase to the Summer season PRM will be necessary. More material impacts are projected from SPP seeking approval from the FERC, after working through a stakeholder engagement process over the past year, to revise the tariff to include a PRM requirement for the Winter season. This tariff language update will include a separate PRM determination for the Winter season and the preliminary results from the 2023 LOLE study suggest that the Winter season PRM should be set at an approximately 40% target.

Furthermore, there are a wide range of other RA policy developments that will impact market planning requirements and presumably the cost of capacity going forward. Performance based accreditation (PBA) of thermal generation resources, effective load carrying capability (ELCC) of renewable generation resources, and other market design initiatives will set performance and planning targets for the capacity accreditation for all resources in the region. These changes are likely to impact the need for capacity for all utilities and could produce seasonal scarcity of bilateral supply and/or cost increases associated with new self-build options. Table 6.3.1 below outlines the key target dates for a variety of these RA policy initiatives to illustrate further refinement is very much in progress at SPP and future IRP studies should include the impacts from these policy initiatives. Presumably more of the policy details and example data will be provided to market participants over the next couple of years.

TABLE 6.3.1: SPP RA POLICY TARGETS

RA POLICY TARGETS

Policy	MOPC target	Non-Binding	Binding
Improved outage policy	January 2024	Winter 2024/2025	Winter 2026/2027
Availability language policy	January 2024	Winter 2024/2025	Winter 2026/2027
Normalized EUE standard policy	April 2024	Summer 2025	Summer 2026
VOLL metric and usage policies*	April 2024	TBD	TBD
Outage Policy RR	April 2024	Winter 2024/2025	Winter 2026/2027
Availability RR	April 2024	Winter 2024/2025	Winter 2026/2027
Winter PRM RR	July 2024	Winter 2024/2025	Winter 2026/2027
Summer PRM RR	July 2024	Summer 2025	Summer 2026
Normalized EUE standard RR	July 2024	Summer 2025	Summer 2026
Fuel Assurance/OMC RR	July 2024	Winter 2024/2025	Winter 2026/2027
PRM stabilization/projection policies*	July 2024	TBD	TBD
Demand Response RR*	April/October 2024	Winter 2024/2025	Winter 2026/2027
Ramping RAR policy*	October 2024	Summer 2025	Summer 2027
Ramping RAR RR*	January 2025	Summer 2025	Summer 2027

*Denotes potential date modifications based on higher priority policy items

6.3.2 Energy Price Projections

The IRP study included assumptions for FUD's balance of energy needs from the SPP energy market. For modeling purposes, the IRP study largely assumed self-supply dispatch from its generation resources as described in Section 7; however, energy market economics were taken into account for the portfolio which included a defined bilateral energy transaction as well as the balance of dispatch energy as previously mentioned. A conservative approach was utilized to account for any potential "net margins" that were incurred due to these operating assumptions so as to not bias the study to seek arbitrage opportunities for this planning exercise. Serving load needs in an economic but also reliable manner was a primary focus for this study.

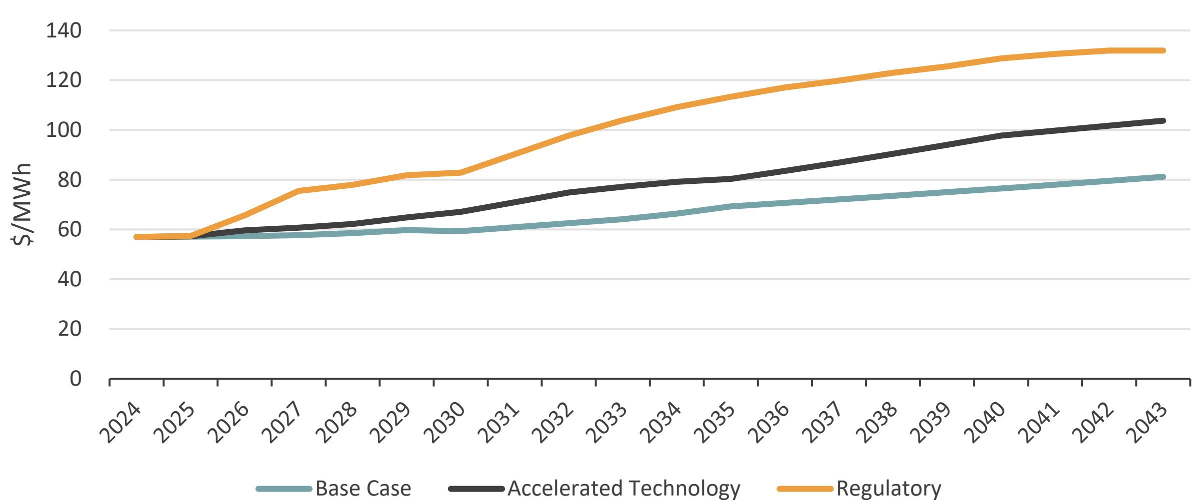
Hourly LMP projections are modeled as a part of the application of these market price assumptions. LMP pricing is a reflection of the energy cost from the incremental resource needed to serve the last MWh in the load curve – which results in a different LMP for every hour in a year. Of course, while the energy component is the biggest part of the LMP price, it is only one of three components, the other two include costs for losses and congestion.

An SPP market energy price curve, reflecting the annual average of the hourly LMPs, is summarized in Figure 6.3.2 for each of the three IRP scenarios: Base Case, High-Technology, and Adverse Regulatory Environment. The resulting market energy curves represent the underlying gas and coal fuel prices and amount of renewable resources for each IRP scenario, and in the case of the Adverse Regulatory Environment scenario, the inclusion of a carbon tax. To the extent this pricing information was utilized for bilateral energy blocks, additional price adders were layered in to model firm delivery of the energy product including transmission delivery costs and supplier product premiums.

TABLE 6.3.2: LMP INPUTS AND RESULTING MARKET PRICES

Market Scenario	Gas Assumption	Carbon Tax	Resulting Energy Price
Base Case	Base	No	Low
Accelerated Technology	High	No	Higher
Regulatory	High	Yes	Highest

FIGURE 6.3.2: IRP MARKET ENERGY ASSUMPTIONS (7X24 BLOCKS)

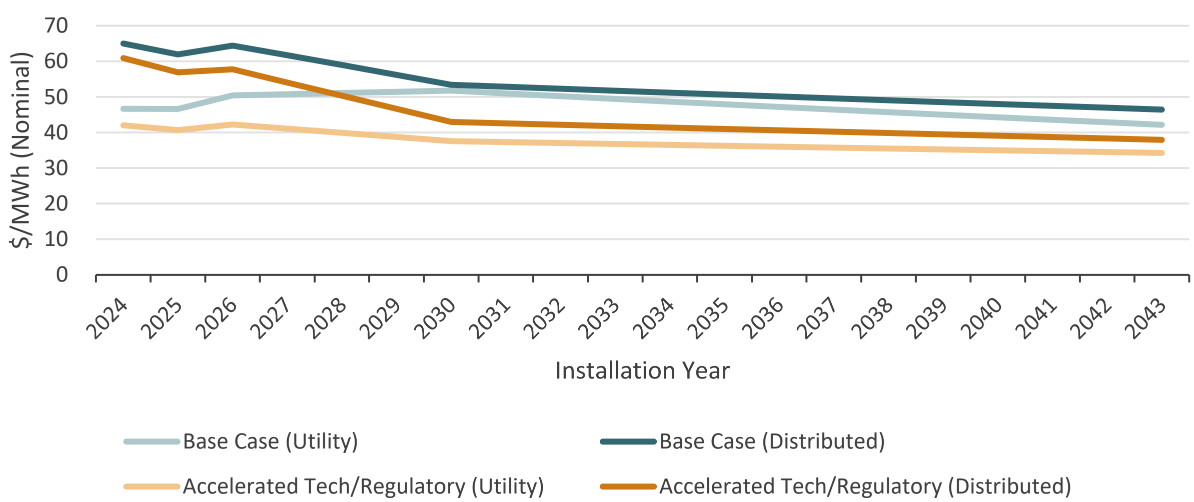


6.4 RENEWABLE AND ZERO-CARBON TECHNOLOGY COST PROJECTIONS

6.4.1 Solar PPA Cost Curves

Solar PPA pricing is based on NREL's 2023 Annual Technology Baseline (ATB) cost curves and current price trends in the PPA market. The ATB focuses on three pricing scenarios that are influenced by different levels of R&D investment and technological advancements. Recent PPA pricing has been at a premium relative to the ATB projections, in part due to ongoing supply chain issues. In the Accelerated Technology and Regulatory scenarios, renewable rollout adoption rates are fast-tracked, leading to lower prices earlier on which then plateau as incremental advancements/supply chain efficiencies become more difficult to achieve. PPA pricing is typically set at a fixed rate at the start of a contract term, which is consistent with the modeling assumptions of the IRP.

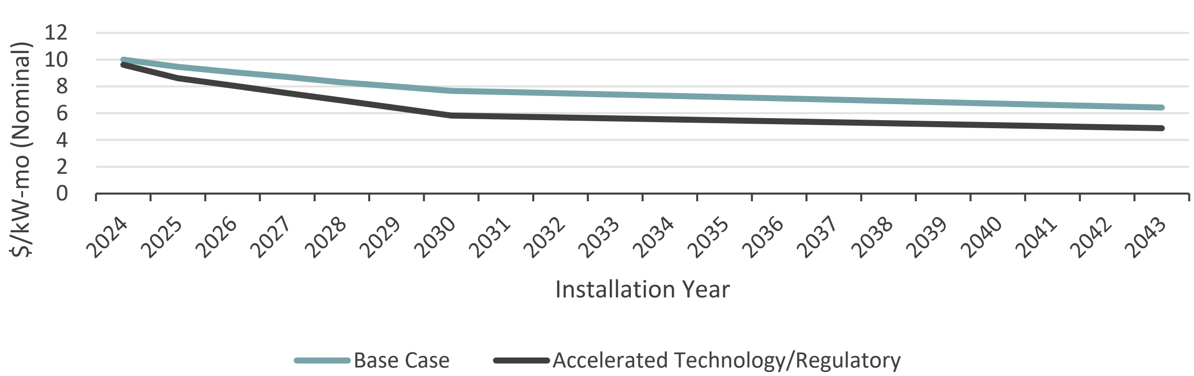
FIGURE 6.4.1: SOLAR PPA PRICING ASSUMPTIONS



6.4.2 Battery Storage ESSA Cost Curves

Battery Storage ESSA cost curves were also based upon a combination of projections from the 2023 NREL ATB and current ESSA pricing trends. Recently, pricing for a 4-hour system has regularly fallen around $10/kW-mo. Using NREL's ATB cost curves, the current price was de-escalated at a moderate and conservative rate to illustrate further technological advancements in the battery storage space.

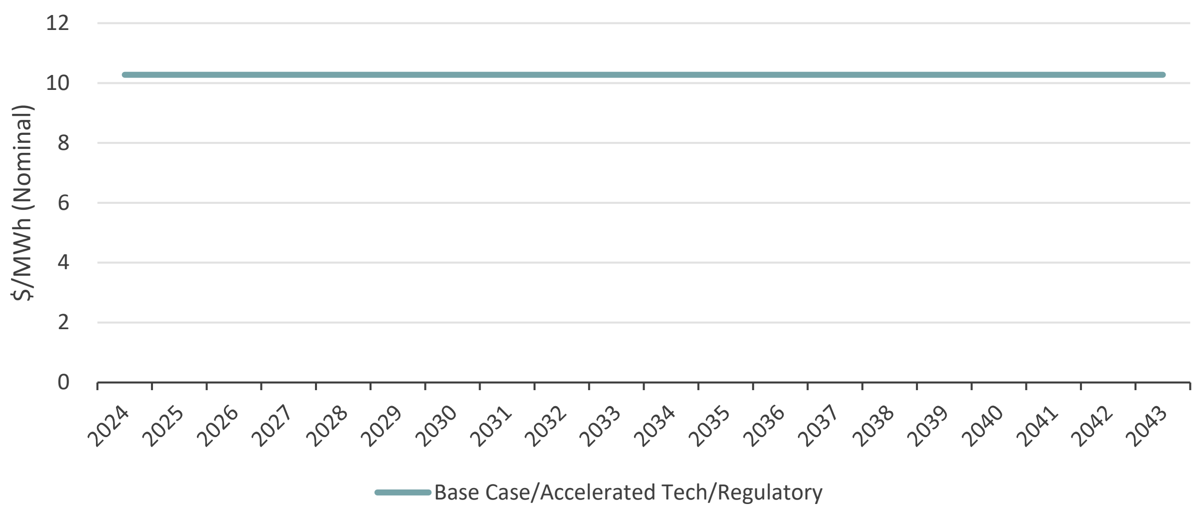
FIGURE 6.4.2: BATTERY STORAGE ESSA PRICING ASSUMPTIONS (4-HOUR DURATION)



6.4.3 Nuclear Operating Cost Projections

SMRs were assumed to operate at a steady, low, variable operating cost. Over the term, the nominal cost of fuel was assumed to be a flat $0.70/MMBtu. SMR's were assumed to operate at a 10,400 Btu/kWh, with variable operations and maintenance costs at $3.00/MWh.

FIGURE 6.4.3: NUCLEAR VARIABLE OPERATING COST ASSUMPTIONS



7 Dispatch Modeling Methodology

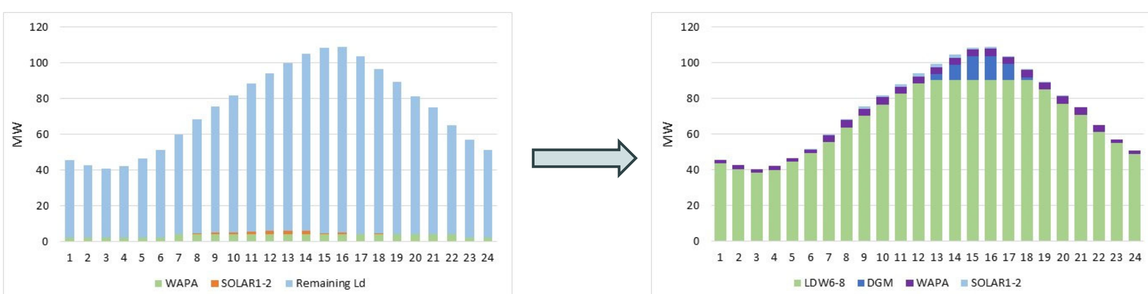
The IRP study utilized hourly economic resource dispatch models to evaluate the generation resource stack resulting from each of the portfolios under each of the market outlooks. The economic dispatch models incorporated FUD's load forecast information, to determine the optimal combination of owned and contracted resource generation to serve those requirements, as well as any SPP market interaction necessary to supplement the portfolio. Outputs analyzed from this platform included system production costs, dispatch volumes by resource, net market purchases and or sales volumes and associated costs, and carbon emissions estimates.

7.1 DISPATCH MODEL FUNCTIONALITY

The economic dispatch model conducts, on a daily and hourly basis, assessments as to whether a generation resource should or should not be dispatched as per its physical operating parameters, projected operational power costs, and the corresponding system load need.

Prior to being used the hourly dispatch model, the hourly load forecast is adjusted to net FUD's WAPA hydro allocation, solar generation, wind generation, and nuclear generation as appropriate for the relevant resource portfolios. This is done to reflect the zero, or very low, variable dispatch cost of these resources. In addition to the zero, low variable cost resources, for portfolios where FUD was purchasing blocks of energy, those energy quantities were also used to reduce FUD's load.

Once pre-dispatch resources were accounted for and netted against load requirements, the model compared hourly SPP market LMP prices with each generator's given variable cost profile and run time characteristics to determine when it was economical to run each resource recognizing there will be some periods of imbalance and ability to rely on partial transmission service solutions to deliver power as compared to a purely self-supply arrangement. Generators were modeled to include start fuel costs, minimum and maximum capacity states with corresponding heat rates, variable O&M expense, minimum run time, minimum down time, and a maximum number of starts per day.



In addition to adhering to generator operating constraints, the proprietary dispatch model also minimizes the arbitrage ability of generation to ramp up and down excessively to capture short hourly market LMP spikes as this is generally not the goal of prudent utility planning practices nor the primary reason for installing generation. The least cost dispatch solutions from the model were subsequently combined with the additional fixed cost considerations for each scenario to achieve a holistic view of the results in comparison with each other. The results of the analysis are further described in Section 9 of this report.

8 Scorecard Criteria and Metrics

One of the primary objectives of this study is to evaluate the economic feasibility of each of the study portfolios selected under each of the three IRP market scenarios. Estimated net present value power costs and their associated potential cost volatility are two important aspects in evaluating resource alternatives, however there are additional considerations for FUD that were identified as priorities to be contemplated when making any future planning decisions. Multiple stakeholder groups for the city voted upon six key criteria to be measured in the scoring process:

1. **Reliability (35%) –** The ability to provide a consistent and dependable system, capable of withstanding sudden electric disturbances.
2. **Economical/Cost Effectiveness (30%) –** The total cost of the system supply arrangements, including the degree of exposure to potential cost volatility.
3. **Environmental Impact (15%) –** The avoidance of greenhouse gas emissions and other air pollutants related to the burning of fossil fuels.
4. **Economic Growth Opportunity (10%) –** The benefit to the community by construction, operations, and maintenance careers.
5. **Fuel Diversity (5%) –** The utilization of supply resources in such a way to reduce the risk of adverse changes in fuel commodity prices.
6. **Market Exposure (5%) –** The ability to self-supply in such a way to diminish reliance on imports of external energy and/or capacity.

8.1 SCORING MATRIX

Before completing the analysis, a criteria rating system was determined upon which to quantify the results. The system assigns up to three quality points across the six key metrics. Points are determined based on a portfolio's degree of conformity to each of the criteria, with partial points in .50 increments awarded as necessary to distinguish between portfolios of similar, but unequal value. To the extent a portfolio's point value would differ between different market outlook scenarios, a weighting of 50% was applied to the base case, with the remaining 50% evenly distributed between the two sensitivities.

TABLE 8.1.1: SCORECARD MATRIX

	1 Point	2 Points	3 Points
Reliability	• Dispatchable capacity < NCP • Capacity excess of intermittent resources	• Dispatchable capacity < current mix, but >= reserve requirements • Capacity excess of intermittent resources	• Dispatchable capacity > current mix • Dispatchable capacity = current mix
Economical/ Cost-Effective	• NPV > one standard deviation of overall economic results	• NPV is within one standard deviation of overall economical results	• NPV < one standard deviation of overall economical results
Environmental Impact	• Current fuel-mix remains • Negligible improvement	• Coal gen is replaced with gas, and/or, • DG solar supplements current mix	• Zero-carbon baseload introduced, and/or, • Utility solar offsets fossil fuel gen
Economic Growth Opportunity	• Retirements with no replacement of local, dispatchable, resources • Requires solar installation, or local capital upgrades	• Maintains current or equivalent mix of local, dispatchable, resources • Requires solar installation, or local capital upgrades	• Local, dispatchable, resources additions
Fuel Diversity	• Worsened fuel diversity mix	• Maintains current fuel diversity mix	• Improved fuel diversity mix
Market Exposure	• Net market interaction > 10%, and/or, • Capacity purchases required to meet NCP	• Net market interaction of 5-10%, and/or, • Capacity purchases required to meet reserves	• Net market interaction of 0-5%, and/or, • Sufficient accredited capacity

9 Economic Evaluation

The combination of the economic hourly dispatch results and the fixed carrying cost, fixed O&M expenses, and other fixed purchased power related expenses produces the total incremental cost for each portfolio. The annual projected costs are discounted back to 2024 dollars at a discount rate of 4.0% for a net present value (NPV) comparison of all portfolios and across the various market scenarios. This process allows FUD to compare the most economically feasible alternatives and to determine the potential benefits of various portfolios under the specified market scenarios. Table 9.1.1 compares the net present value and the levelized rate of all the generation portfolios over the IRP study period, followed by figures that compare the resource portfolio economic valuations for each scenario and illustrate the ranking of the portfolios in relation to each other (i.e. a lower ranking means lower cost).

TABLE 9.1.1: NET PRESENT VALUE AND LEVELIZED RATE RESULTS

	Base Case		Accelerated Tech		Regulatory	
IRP Portfolio	NPV ($Millions)	Rate ($/MWh)	NPV ($Millions)	Rate ($/MWh)	NPV ($Millions)	Rate ($/MWh)
P0: Business-As-Usual	$380.3	$45.5	$466.0	$55.7	$869.9	$103.1
P1: LDW Gas Conversion	$634.1	$75.9	$717.4	$85.8	$1,024.3	$121.4
P2: Bilateral Market-Based Supply	$410.2	$49.1	$496.5	$59.4	$908.7	$107.7
P3: RICE + DG Solar (No Retirements)	$430.2	$51.5	$509.2	$60.9	$887.0	$105.2
P4: RICE + DG Solar	$402.5	$48.1	$476.4	$57.0	$865.2	$102.6
P5: Small CC (No Retirements)	$472.5	$56.5	$563.1	$67.4	$910.6	$108.0
P6: Small CC	$434.0	$51.9	$519.8	$62.2	$887.8	$105.3
P7: Small CC + Hybrid Solar	$625.2	$74.8	$652.6	$78.1	$831.9	$98.6
P8: Utility Solar	$361.3	$43.2	$433.2	$51.8	$795.5	$94.3
P9: SMR Nuclear	$1,050.3	$125.6	$1,055.8	$126.3	$1,062.4	$126.0

As described in detail in Sections 1.4, Section 2, and Section 6, the IRP market scenarios utilized varying assumptions for FUD's load requirements, fuel costs, environmental costs, and technological costs among the others detailed throughout those sections. Thus, the cost for any specific resource portfolio across the various market scenarios is going to differ, some differentials are more severe than others. The power cost volatility will be discussed in more detail in the latter half of this section. To make it easier to compare the economic benefits of the resource portfolios for each IRP market scenario, the following illustrations provide a summary of each portfolio's total incremental NPV cost and provide a ranking of those resource portfolios from lowest cost to highest cost, for the Base Case, Accelerated Technology, and Regulatory market scenarios, respectively.

TABLE 9.1.2: BASE CASE PORTFOLIO NET PRESENT VALUES

Rank	Portfolio	NPV ($Millions)	Rate ($/MWh)
1	P8: Utility Solar	$361.3	43.2
2	P0: Business-As-Usual	$380.3	45.5
3	P4: RICE + DG Solar	$402.5	48.1
4	P2: Bilateral Market-Based Supply	$410.2	49.1
5	P3: RICE + DG Solar (No Retirements)	$430.2	51.5
6	P6: Small CC	$434.0	51.9
7	P5: Small CC (No Retirements)	$472.5	56.5
8	P7: Small CC + Hybrid Solar	$625.2	74.8
9	P1: LDW Gas Conversion	$634.1	75.9
10	P9: SMR Nuclear	$1,050.3	125.6

The top three lowest incremental cost portfolios from the Base Case market scenario analysis include P8 (Utility Solar), P0 (Business-As-Usual), and P4 (RICE + DG Solar). These results indicate FUD's current asset mix is economically viable by way of comparison to the IRP study portfolios under Base Case market scenario assumptions. Incremental inclusion for some volume of solar capacity and energy as part of the resource mix with the potential retirement of LDW units 6 and 7 are also economically viable approaches to FUD's long term power supply planning efforts.

TABLE 9.1.3: ACCELERATED TECHNOLOGY PORTFOLIO NET PRESENT VALUES

Rank	Portfolio	NPV ($Millions)	Rate ($/MWh)	*Diff. w/Base ($/MWh)*
1	P8: Utility Solar	$433.2	51.8	8.6
2	P0: Business-As-Usual	$466.0	55.7	10.2
3	P4: RICE + DG Solar	$476.4	57.0	8.9
4	P2: Bilateral Market-Based Supply	$496.5	59.4	10.3
5	P3: RICE + DG Solar (No Retirements)	$509.2	60.9	9.4
6	P6: Small CC	$519.8	62.2	10.3
7	P5: Small CC (No Retirements)	$563.1	67.4	10.9
8	P7: Small CC + Hybrid Solar	$652.6	78.1	3.3
9	P1: LDW Gas Conversion	$717.4	85.8	9.9
10	P9: SMR Nuclear	$1,055.8	126.3	0.7

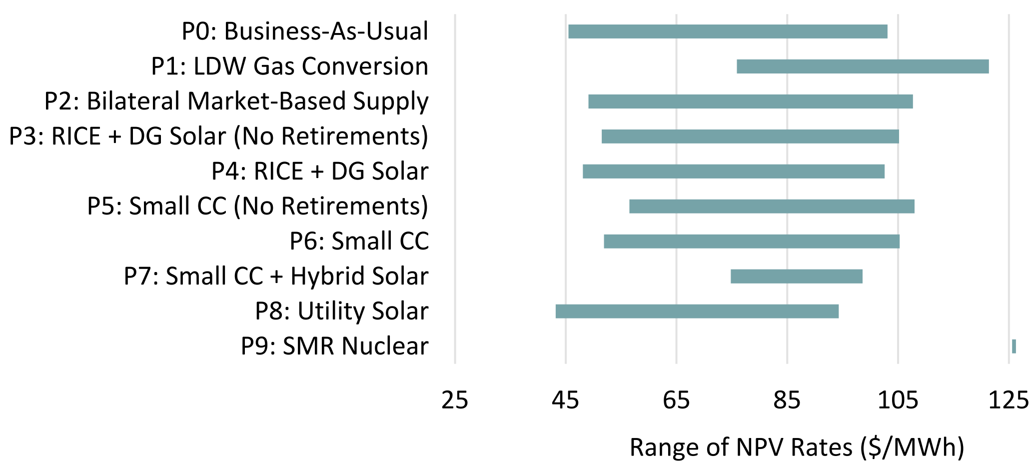
The top three lowest incremental cost portfolios from the Accelerated Technology market scenario are the same as the Base Case market scenario results. These results are interesting to note as they indicate that FUD does currently have a well-diversified resource portfolio with an ability to respond to differing market conditions. The incremental NPV costs increased by an average of approximately $9/MWh for the top three lowest cost portfolios as compared to the Base Case market scenarios. Some decreased variability in portfolios P8 (Utility Solar) and P4 (RICE + DG Solar) illustrate the benefits from diversifying FUD's portfolio further towards incremental solar additions.

TABLE 9.1.4: REGULATORY PORTFOLIO NET PRESENT VALUES

Rank	Portfolio	NPV ($Millions)	Rate ($/MWh)	*Diff. w/Base ($/MWh)*
1	P8: Utility Solar	$795.5	94.3	51.1
2	P7: Small CC + Hybrid Solar	$831.9	98.6	23.8
3	P4: RICE + DG Solar	$865.2	102.6	53.5
4	P0: Business-As-Usual	$869.9	103.1	57.6
5	P3: RICE + DG Solar (No Retirements)	$887.0	105.2	53.7
6	P6: Small CC	$887.8	105.3	53.4
7	P2: Bilateral Market-Based Supply	$908.7	107.7	58.6
8	P5: Small CC (No Retirements)	$910.6	108.0	51.5
9	P1: LDW Gas Conversion	$1,024.3	121.4	45.5
10	P9: SMR Nuclear	$1,062.4	126.0	0.4

In the Regulatory market scenario environment, financial mechanisms are in place encouraging a fundamental shift away from conventional fossil fuel generation sources to clean energy technologies primarily through the assumption of a carbon tax as described in Section 6.2.3. All portfolios incur increased costs; however, the portfolios that incorporate renewable energy as well as more efficient gas-fired generation, in terms of emissions rates, experience fewer cost increases than the others. While outside of the scope of this analysis, it would remain to be seen what financial products might be available in a "RECs" (Renewable Energy Credits) exchange were it to exist that might help to offset some of the emissions-related operating costs of a fossil fuel portfolio and be another avenue to manage overall portfolio costs.

FIGURE 9.1.1: PORTFOLIO NPV POWER COST VOLATILITY COMPARISON



Lastly, Figure 9.1.1 above illustrates the range of levelized power costs, in $/MWh, for the resource portfolios across all three market scenarios. Diversity of supply provides for an enhanced ability for FUD to respond to market price signals and to lower power cost differentials across the market scenarios. The portfolios with renewable resource selections increased FUD's supply diversity and provided for lower power cost volatility. The economic takeaways of this Section 9.1 are utilized as part of the overall portfolio scorecard and the recommendations contained in Section 10.

10 Conclusions and Recommendations

The IRP study's main purpose is to inform FUD on the value and benefits of alternative power supply constructs as compared to its existing resource mix. This IRP evaluation is not designed to specifically recommend an alternative power supply portfolio but simply to conclude whether an alternative resource mix(es) is a viable solution to hedging FUD from potential power costs under a variety of potential market scenarios.

Pairing the economic evaluation results from Section 9 with the scoring criteria and metrics described in Section 8 results in the following scorecard. The criteria scorecard results conclude that FUD's optimal resource mixes from the study are portfolios (P8, P3, P0, and then either P4 or P5) each having closely reached an optimal total average score of 2.3 points or higher using the scoring metric weightings. The top three portfolios include consideration for a utility scale solar installation, a distributed scale solar installation paired with a reciprocating engine, or remaining with the FUD's current asset mix.

TABLE 10.1.1: SCORECARD EVALUATION RANKINGS

	Reliability	Economical/Cost Effective	Environmental Impact	Economic Growth Opportunity	Fuel Diversity	Market Exposure	Weighted Score	Ranking
Weighting	**35%**	**30%**	**15%**	**10%**	**5%**	**5%**	**100%**	**-**
P0: Business-As-Usual	2.50	2.75	1.00	2.00	2.00	3.00	**2.30**	**3**
P1: LDW Gas Conversion	2.50	1.00	2.00	2.50	1.50	1.50	**1.88**	**9**
P2: Bilateral Market-Based Supply	2.00	2.50	1.50	1.00	2.50	2.00	**2.00**	**7**
P3: RICE + DG Solar (No Retirements)	3.00	2.00	2.00	2.50	3.00	3.00	**2.50**	**2**
P4: RICE + DG Solar	2.00	2.75	2.00	1.50	3.00	3.00	**2.28**	**5**
P5: Small CC (No Retirements)	3.00	1.75	1.75	2.00	2.25	3.00	**2.30**	**4**
P6: Small CC	2.00	2.00	2.25	2.00	3.00	3.00	**2.14**	**6**
P7: Small CC + Hybrid Solar	2.00	1.75	2.50	1.50	1.50	3.00	**1.98**	**8**
P8: Utility Solar	2.50	3.00	2.50	1.50	2.50	2.00	**2.53**	**1**
P9: SMR Nuclear	2.00	1.00	3.00	1.00	2.50	2.00	**1.78**	**10**

Taking all of the aforementioned information into context, the IRP report's recommendations are:

1. FUD's current resource mix does provide a good balance of diversity against a variety of potential market factors. Capacity for additional gas supply should continue to be a consideration, especially if major capital upgrade costs or market dynamics change significantly. For example, any advancements in carbon legislation will accelerate considerations for fuel switching in FUD's fleet. The "Business-As-Usual" portfolio scored in third place in the overall scorecard rankings.

2. Both the quantitative and qualitative analysis of the scorecard evaluation process demonstrate both economic and other perceived benefits for pursuing incremental changes to FUD's existing resource portfolio. Based on the scorecard evaluation process, GDS recommends two potential incremental resource pathways forward:

    a. FUD should consider the operational viability of adding up to 25 MW of utility-scale solar within its service territory with the potential for retirements of LDW units 6 and 7. The additional renewable energy will help to diversify FUD's supply mix and its value can be further defined by performing an RFP solicitation for detailed price discovery. Retirement of the LDW units would include further consideration for the operational needs of the FUD system with incorporation of the solar installation. The "P8" portfolio scored in first place in the overall scorecard rankings.

    b. FUD should consider the operational viability for adding up to 8 MW of distributed-scale solar within its service territory and to pair this addition with a 9MW RICE unit. Similar to item 2a above, increased diversity of the FUD system scored well with the variety of criteria utilized in this IRP process. The purposeful combination of a "right-sized" engine, capable of providing generation shaping around the smaller scale solar installation, affords FUD the ability to layer in another incremental resource solution to assist in meeting load need at comparatively reasonable projected power costs. Price discovery on the solar resources for both 2a and 2b could be conducted within the same RFP solicitation for further consideration at the same time. The RICE installation would require FUD to seek detailed EPC cost estimates and ownership costs to benchmark against the cost assumptions utilized in this IRP report. The "P3" portfolio scored in second place in the overall scorecard rankings.

These recommendations and resulting actions will establish the best course for FUD's immediate and long-term future resource considerations. This concludes the IRP study process, evaluation, and recommendations for this report.

PREPARED BY GDS ASSOCIATES, INC.

FREMONT UTILITIES DEPARTMENT

2023 Integrated Resource Plan

December 2023

GDS Associates, Inc.
ENGINEERS & CONSULTANTS