PACE

4401 Fair Lakes Court
Fairfax, VA 22033-3848 USA
Phone: 1.703.818.9100
Fax: 1.703.818.9108

2009 Integrated Resource Plan Report

Prepared for:

Midwest Energy Incorporated

December 17, 2009

TABLE OF CONTENTS

EXHIBITS

EXECUTIVE SUMMARY

Over the next couple of years, the bulk of Midwest Energy's ("MWE") energy supply must be replaced, as its Purchase Power Agreements ("PPAs") with the current supplier will expire in 2010 and 2013. Since MWE has limited amounts of its own generation, much of this supply will have to be negotiated in new or renegotiated power supply contracts. In this 2009 Long Range Resource Plan ("LRRP"), MWE identifies its preferred plan for satisfying its future electric power requirements. The plan consists of its existing generating units, the expansion of the Goodman Energy Center ("GMEC"), new peaking capacity similar to GMEC, additional wind capacity, and two types of contracts: unit-contingent baseload coal and Units Most Likely[1] ("UML") PPAs over the next twenty years. This Preferred Resource Plan best satisfies the multiple objectives of meeting MWE's long term electricity needs in a reliable, cost competitive, flexible, and environmentally conscious manner under a wide variety of market, regulatory, and economic conditions.

The Preferred Long Range Resource Plan updates MWE's 2005 LRRP and was designed to answer a number of critical questions:

1. What is the proper mix of baseload (coal-fired) generation to have in the energy supply portfolio?
2. What is the best term (length) of PPAs for baseload and UML power contracts?
3. How much wind or other renewable generation is economic beyond that required to meet Federal and Statewide Renewable Portfolio Standards?
4. Is expansion of the GMEC part of the preferred portfolio, and if so, when should expansion occur?
5. Should MWE build additional peaking capacity of the GMEC type, and if so, when?
6. How much Demand Response ("DR") is cost effective?
7. PPAs may carry restrictions with them that are related to requiring high load factors and resale limitations. How important are these factors in the decision of the amount of baseload and UML capacity to acquire?

The 2009 LRRP resulted from a structured, two-stage process. Phase I consisted of the screening of several technology (peaking, solar, and wind) options, and two types of PPAs. It evaluated the optimal mix of baseload versus UML contracts ranging from 0 to 100 percent, and evaluated over 100 portfolios, representing combinations of these technology additions and contract options over the planning horizon. The number of uncertainties considered in the Phase II "risk" stage of the process is measured in the thousands, as uncertainty in load, coal and gas prices, dispatch for technology choices, carbon prices, capital costs for technologies, and power prices for net purchases and sales were quantified and considered. Twenty portfolios were explicitly considered in the risk analysis. This not only included a representative range of baseload and UML PPAs, but also considered combinations of incremental peaking generation, expanding GMEC, as well as wind and solar additions in excess of those needed to comply with RPS.

[1] This type of contract is priced based on the marginal resource used to serve MWE's load. The capacity cost component is based on the supplier's estimate of the fixed costs associated with the units most likely to serve the contract throughout the year.

Pace also completed a high-level analysis of the cost-effective potential of DR options in the MWE service territory. The purpose of the analysis was to identify the amount of load reduction that is possible at a cost lower than a new peaking resource. The results presented in this report are focused on the recommended amount of peaking capacity compared to baseload and renewables. It is important to recognize, however, that the successful implementation of DR programs can substitute the need for some peaking capacity.

Quantum scenarios representing regulatory uncertainty regarding carbon legislation were also explicitly considered. The Phase II "risk analysis" reveals the strengths and risks associated with each portfolio by exposing them to a wide range of conditions. This allows for the evaluation of portfolios across a range of outcomes and under extreme conditions.

PREFERRED RESOURCE PLAN

The Preferred Resource Plan represents a slight reconfiguration of MWE's existing electricity portfolio over the next 20 years. The Preferred Resource Plan consists of enough wind resources to meet existing and planned RPS requirements and also includes 50 MW of additional economic wind generation between 2020 and 2025. The plan includes the expansion of the Goodman Energy Center by 25 MW around 2015 and 75 MW from a new local gas-fired peaking capacity similar to GMEC in the 2015-2020 time frame. The implementation of DR programs, however, could delay the need for new peaking capacity by a few years. The preferred contract mix is initially a roughly equal split between baseload and UML, although new peaking additions or DR programs would significantly reduce UML capacity amounts in the intermediate to longer term. Flexibility is inherent in this generation mix since there is little difference in expected costs between 45 and 60 percent of baseload capacity, though higher baseload capacity carries higher market risk and more exposure to carbon price volatility. Exceeding 60 percent baseload generation is uneconomic, particularly if there are restrictions on load factor or restrictions on resale that would restrict MWE's ability to sell excess baseload power in the SPP market.

Long term contracts for baseload generation are warranted, particularly if some flexibility (reopener provision) is built in over the course of the term to address carbon risk and the desire to add new renewable resources when economic. Through time, volatility of carbon related costs is expected to grow. On one hand, if carbon prices do not alter the overall cost-effectiveness of coal-based generation longer term contracts are clearly preferred. If allowance prices for carbon are highly volatile, however, pass-through mechanisms could make baseload contracts very expensive. Contractually, mechanisms that either limit cost pass-through, or at least require prudent carbon risk management, will limit the risk of a long-term PPA for baseload power. In addition, wind power is expected to become economic after 2020. Hence, reopeners should be considered in the baseload contract to reduce the generation level over time to accommodate economic wind purchases.

The minimum viable contract terms for both baseload and UML contracts is 5 years in order to ensure Midwest retains its so-called "rollover" rights to extend the transmission service as required to deliver the resource. By 2015, expanding GMEC, building additional peaking generation capacity, and implementing some DR programs are all economic options. Hence, MWE needs to either negotiate a series of five-year contracts or have a longer term contract with a reopener that will allow MWE as much flexibility as needed to reduce its volume of UML purchases and avoid unnecessarily high demand charges.

Key elements of the incremental changes to MWE's current portfolio in the Preferred Resource Plan include:

- **Renewable Energy Additions:** The Preferred Resource Plan adds 50 MW of wind generation after 2020, beyond the 50 MW required for meeting its RPS obligations by 2030.
- **New Owned Generation:** The Preferred Resource Plan adds a new 50 MW gas-fired peaking capacity similar to Goodman around 2015 and an additional 25 MW around 2020.
- **Upgrades of Existing Generation:** A 25 MW expansion of the GMEC is added around 2015.
- **Demand Response Programs:** Around 16 MW of load reduction are possible at a cost lower than a new peaker. If implemented successfully, this can reduce the need for new peaking capacity by 16 MW or delay the construction by a few years. It may also replace existing owned generating resources that are later determined to be candidates for retirement.

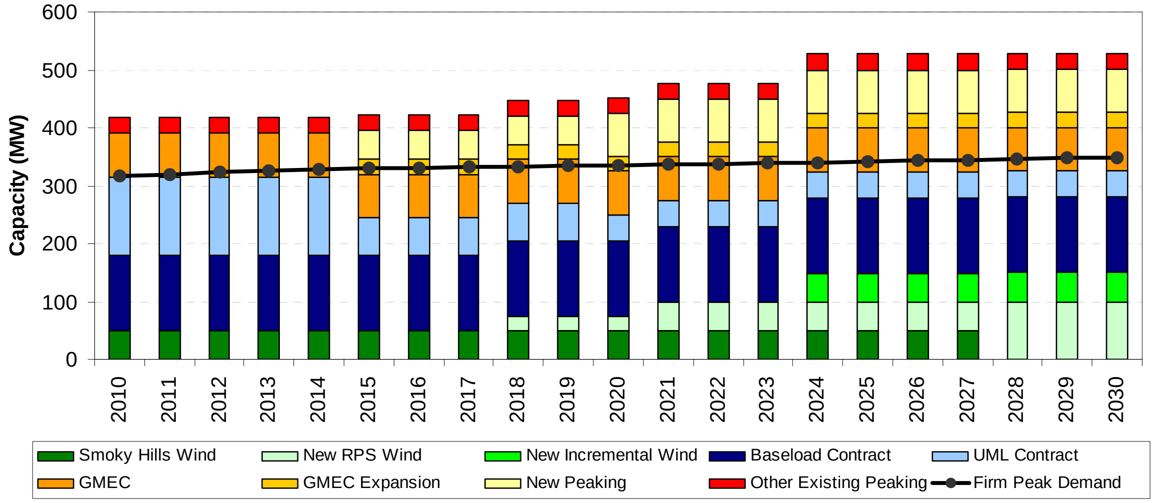
It is explicitly recognized that financing and permitting requirements, as well as the success of DR programs may impact the development schedule for the expansion at GMEC and/or the development of a new generating facility if it is determined that simultaneous development is not the most prudent course of action.

Exhibit 1 provides a summary of the Preferred Resource Plan as it is expected to evolve over time, with unit additions relative to the existing portfolio shown by installation date. The changes summarized in the table are incremental to the existing portfolio. This Exhibit 1 also shows the expected peak firm loads for the study period relative to the total resources expected to be available, including the non-dispatchable wind resources. As shown in Exhibit 2, cost-effective DR programs can substitute for peaking requirements.

Exhibit 3 illustrates the expected resource generation mix for MWE in 2016 and 2030 under the Preferred Resource Plan. No assumptions were included regarding the substitution of DR programs for new peaking resources. Exhibit 4 displays the generation mix in 2030 if the DR is included.

Exhibit 1: Summary of Preferred Resource Plan

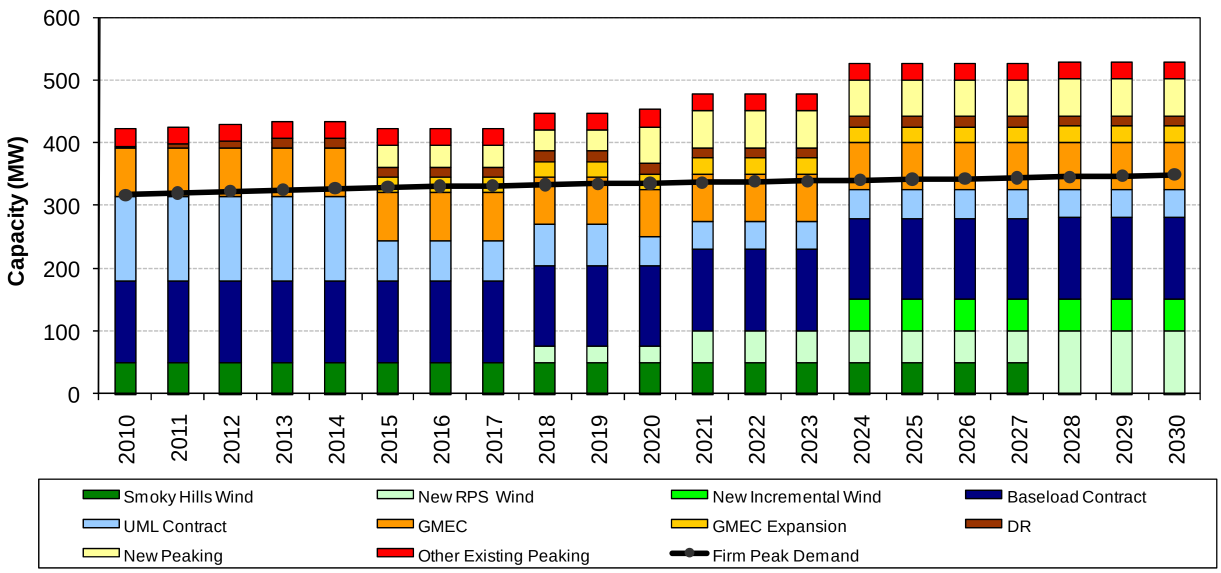
Portfolio Item	2010-2014	2015-2019	2020-2024	2025-2030
Baseload Contract	130 (20 years)			
UML	135 (5 years)	65 (5 years)	45 (10 years)	
GMEC Expansion		25		
New Peaking		50	25	
RPS Wind		25	25	50
Incremental Wind			50	



Baseload contract should consider reopeners for maximum volume flexibility
Source: Pace

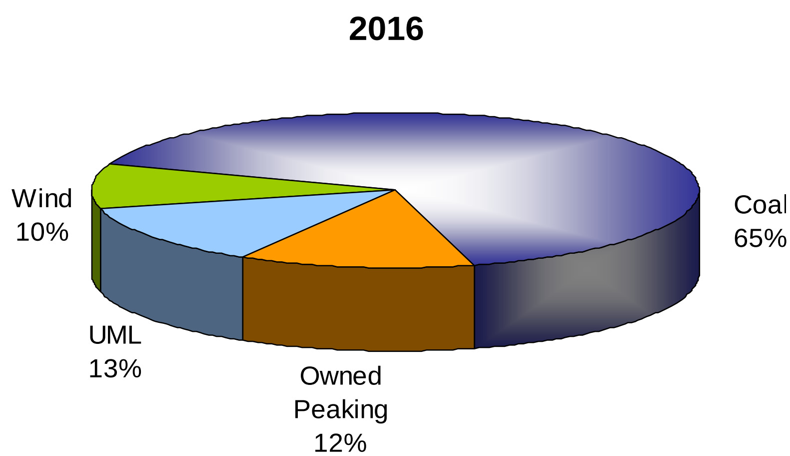
Exhibit 2: Summary of Preferred Resource Plan Including DR

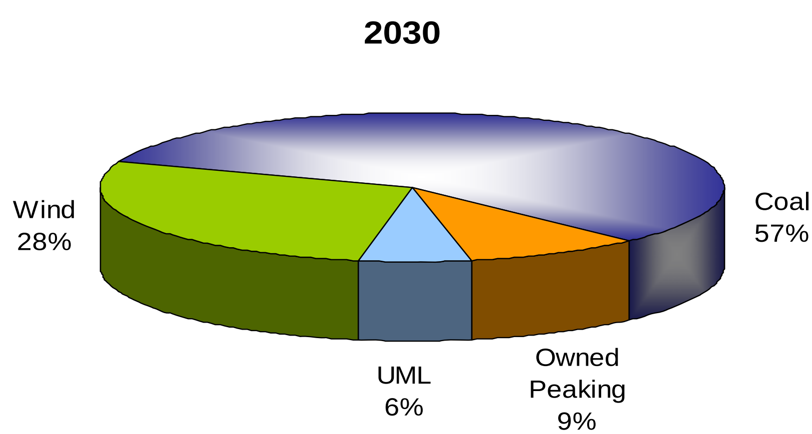
Portfolio Item	2010-2014	2015-2019	2020-2024	2025-2030
Baseload Contract	130 (20 years)			
UML	135 (5 years)	65 (5 years)	45 (10 years)	
GMEC Expansion		25		
DR	16			
New Peaking		35	25	
RPS Wind		25	25	50
Incremental Wind			50	



Baseload contract should consider reopeners for maximum volume flexibility
Source: Pace

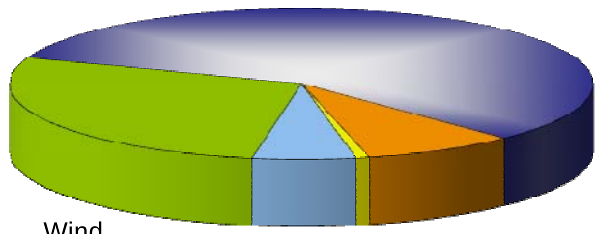
Exhibit 3: Energy Mix of the Preferred Resource Plan (2016 and 2030)





Source: MWE and Pace

Exhibit 4: Energy Mix of the Preferred Resource Plan Including DR (2030)



Source: MWE and Pace

IRP POLICIES AND ACTION PLAN

Development of the Preferred Resource Plan considered a wide range of potential options and was evaluated against two main criteria:

- Competitive Rates (measured in lowest present value of revenue requirements and levelized resource costs)
- Rate Stability (measured as the standard deviation in the range of costs)

The Preferred Resource Plan consists of a range of generation additions through PPAs, owned peaking capacity, and renewable wind generation. The recommended contract and resource mix:

- Will result in the lowest achievable cost;
- Achieves maximum flexibility to adapt to market and regulatory conditions and preserve negotiation leverage;
- Exceeds the expected goals for renewable generation and moderates exposure to carbon allowance prices, a risk that can be managed through contractual provisions.

The Preferred Resource Plan calls for several action items to meet the planning objectives. These can be summarized as follows:

- **Negotiate PPAs:** By the beginning of 2010, finalize negotiations of new PPAs for baseload and UML type contracts with the preferred supplier. Due to the attractiveness of owned peaking resources, UML contracts should be negotiated with the shortest lengths possible. The baseload contract should be negotiated for at least fifteen years but should include reopeners for maximum volume flexibility.
- **Implement Pilot Demand Response Programs:** Initiate further exploration of the cost-effectiveness of DR programs, particularly in the form of agricultural load shedding and interruptible rates, to better assess the potential of DR programs as a feasible substitute for new peaking capacity.

- **New Local Gas-Fired Generation:** By approximately 2015, expand GMEC and build 50 MW of new peaking capacity. Build an additional 25 MW by approximately 2020.
- **Renewable Energy:** Beyond 2015, increase the proportion of MWE's energy mix provided by renewable energy sources. By around 2018, a total of 50 MW of new wind is needed to meet RPS. In 2024 and beyond, add economic additional wind capacity on the order of 50 MW and replace the Smoky Hills contract when it expires. Throughout the planning horizon, continue to track the cost and efficiencies of wind and solar and take advantage of economic opportunities as they arise.
- **GHG Emissions Reductions:** Protect MWE as much as possible against imprudent risk management of carbon and fuel cost exposures. Prudent management language should be included in new contractual arrangements.

PLANNING ENVIRONMENT AND KEY DRIVERS

MWE has provided reliable and economical electric service in its service territory for over fifty years, but now faces critical new challenges as it makes plans to continue doing so well into the future:

- New and emerging laws will require MWE to reduce greenhouse gas emissions and increase its renewable portfolio associated with serving its customers' energy needs, although the exact reductions in GHG and increases in renewable requirements that ultimately will be required are still unknown.
- MWE is restricted by available transmission capacity from diversifying its portfolio by contracting with anyone other than a limited number of interconnected suppliers for a significant share of its current power supply. This could result in restrictions in new PPAs (on minimum load factors or resale restrictions) that can affect its options for minimizing costs and market risks.
- The costs of serving MWE's electricity requirements will inevitably increase in the future because new energy resources are more expensive than the current supply mix.

The manner in which MWE addresses each of these concerns could have a significant impact on the rates that MWE charges its customers and how well it achieves its environmental objectives. MWE has conducted a detailed assessment, known in the utility industry as an Integrated Resource Plan ("IRP") to identify a preferred approach for meeting all of these challenges. The IRP process included the following key steps:

- Assessing the critical trade-offs between costs and risks that are inherent in each resource strategy in order to appropriately balance these conflicting objectives;
- Choosing a recommended long-term resource strategy as well as a short-term action plan focusing on immediate steps MWE should take.

KEY DRIVERS AFFECTING MWE'S IRP OPTIONS

Integrated Resource Planning for electric utilities like MWE is a complex undertaking, accompanied by significant risk and uncertainty. Commitments made by utilities to specific resource options such as new power plants typically last 20 years or more, and PPAs may last anywhere from 5 to 20 years. At the same time, legal, regulatory, and market conditions that affect the apparent wisdom of those choices are changing constantly and require ongoing monitoring and adjustment. These considerations affect all electric utilities. The key issues driving the choices that MWE must make in its 2009 IRP are as follows:

- Volatile fuel and capital costs
- Rising Renewable Portfolio Standards
- Carbon constraints weighing on fossil fueled generation sources, including those associated with baseload contracts
- Significant exposure to potential cost increases
- Evolving regulatory and environmental challenges
- Ongoing technology advances opening new opportunities
- Contract leverage that suppliers may have with MWE, and that may restrict its options

- Limited contracting options and transmission access rights due to its geographic location

Each of these driving forces represents a key source of risk and uncertainty that must be considered in an IRP process. While these risk issues are discussed in greater detail in the body of this report, the following section highlights the evolving regulatory environment and environmental mandates that are driving MWE's resource planning needs.

Environmental Considerations

Senate leaders anticipate releasing their comprehensive climate and energy bill this fall after the House of Representatives passed The American Clean Energy and Security Act of 2009 ("ACES") on June 26, 2009. From these bills, MWE can begin to anticipate what their future challenges will be as a power provider under a carbon-regulated economy. The following is a brief summary of some of the issues MWE will face under carbon and clean energy regulation.

Federal Renewable Electricity Standard

A Renewable Electricity Standard ("RES") places an obligation on electricity suppliers requiring that a certain percentage of electricity sold be derived from alternative or renewable energy resources. Both the House (ACES) and the Senate have proposed Federal RES bills which, as drafted, would require electricity suppliers that deliver more than 4,000,000 MWhs annually to their retail customers to comply with renewable generation targets. Although there is still uncertainty around the standards and renewable energy levels, as currently drafted, MWE would be exempt from such federal obligation as its annual retail sales are well below 4,000,000 MWhs.

States such as Kansas with existing renewable standards will be permitted to continue to implement and administer their own standards, with the federal standard acting as the floor, requiring a minimum level of renewable generation.

Carbon Regulation: Cap-and-Trade

Regulated entities under a cap-and-trade regime are required to submit government-issued emissions allowances equal to the number of tonnes of $CO_{2(e)}$ that they emitted the previous year. The leading climate change bills over the past few years, including ACES, place the point of regulation at the point of fossil fuel combustion. MWE generates some of its own electricity from its gas-fired peaking units and will be required to retire emissions allowances from the emissions that result from those units. MWE will not be required to submit allowances for the emissions that result from the electricity that they purchase from any third-party generator, which is the source of the majority of MWE's delivered electricity.

MWE will, however, be subject to increases in costs for the electricity that they purchase. The leading bills, to a varying degree, provide protections against drastic electricity rate spikes in the form of free allowance allocations. ACES provides a pool of allowances for all Load Serving Entities ("LSEs") which would be divided based in part on historical emissions and in part on historical electricity deliveries. The method for distributing allowances to LSEs is a point of some contention. Suppliers who rely on high carbon generation technologies (coal) prefer allowances to be distributed based solely on historical emissions, and LSEs who rely on lower carbon generation technologies (nuclear) prefer heavier weighting based on electricity deliveries.

In addition to the allowances MWE would receive from the pool of LSEs, they may receive additional allowance allocations as a "Small LDC" as they fall under the "Small LDC" threshold of 4,000,000 MWh annual deliveries. All told, under ACES, MWE would receive a distribution of allowances that will cover approximately 85%-90% of their increased costs in the early years of the program. The allowances are to be used for the benefit of the retail ratepayer – what exactly constitutes a "benefit" would ultimately be determined by the state regulator.

It is safe to assume that the third-party generator with whom MWE contracts will pass through some or all of the carbon compliance costs to MWE. The ACES drafters presumed that carbon costs would be passed through from generator to LSE as evidenced by the fact that the point of regulation (the generator) is different from the point of free allowance allocation (the LSE). Moving forward, Midwest will need to specifically address carbon issues in their contracts in order to limit ambiguity and future litigation.

It should be noted that under ACES, merchant coal generators receive free allowance allocations designed to offset some of their emissions and subsequent compliance costs in the early years. Designed to lessen the cost impact from dispatching merchant coal under carbon regulation, the allocation scheme may apply to MWE's supplier and could potentially lessen the compliance costs that are passed through to MWE.

MIDWEST ENERGY SITUATION ASSESSMENT

MWE is an electric and natural gas cooperative utility serving parts of central and western Kansas. MWE owns and operates a small amount of generation capacity and therefore supplies the majority of its member's electrical capacity and energy needs through a portfolio of supply contracts. These contracts essentially expire between now and 2013 (beginning in 2010) and will need to be replaced in some form: either with new power purchase agreements, generation development, DR programs, ownership participation or alternative means in order to meet the capacity and energy requirements of its customers.

MWE is subject to the regulatory jurisdiction of the Kansas Corporation Commission in matters related to the provision of retail and wholesale electric service and the siting of transmission and generation facilities. MWE is a member of the Southwest Power Pool ("SPP") and relies on the transmission coordination and market rules of this regional transmission organization.

The SPP was approved by the FERC in 2004 as a Regional Transmission Organization ("RTO") in order to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale prices of electricity. The SPP RTO consists of 26 balancing authorities and manages transmission in eight states including, Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. Members consist of a mix of Investor Owned Utilities ("IOUs"), cooperatives, municipalities, state agencies, independent transmission companies, independent power producers and marketers. In 2008, three members based in Nebraska, which include Nebraska Public Power District ("NPPD"), the Omaha Public Power District ("OPPD"), and Lincoln Electric System ("LES") joined SPP.

MWE does not operate as an independent control area. Rather, control area services are purchased from another entity. However, MWE does operate and maintain its own transmission system, having interconnections with Westar Energy, Mid-Kansas Electric Cooperative, and Sunflower Electric. Furthermore, MWE independently contracts for and schedules all capacity and energy purchases, and also schedules operation of its owned generating resources as needed.

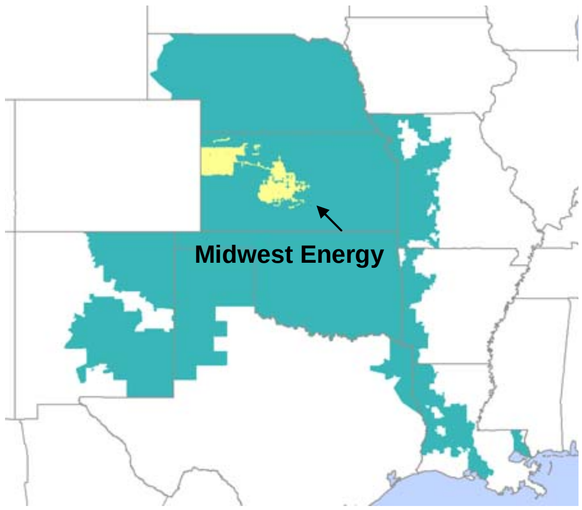
MWE is committed to proactively considering the implications of its resource decisions on member rate levels and rate stability and in maintaining its long term financial health. The electricity market and interrelated energy markets are uncertain and volatile owing to load growth variability, generating capacity availability, regional and localized transmission availability, and the increasing price volatility associated with natural gas and coal fuels, among other factors. It is prudent for MWE to proactively consider its resource supply options in advance of the expiration of its current supply portfolio as the resource choices that are made will underpin their rate stability and rate competitiveness well in to the future. In this regard, MWE has contracted Pace Global Energy Services ("Pace") to assist with development of a Long-Range Resource Plan (the "LRRP") to supply electric capacity and energy covering the period 2010 through 2030.

PACE

COMPANY PROFILE

MWE manages a service territory of nearly 80,000 electric and natural gas customers with an average retail load of slightly more than 150 MW and a peak load around 300 MW. MWE's service territory within the context of the SPP geographic footprint is shown in Exhibit 5.

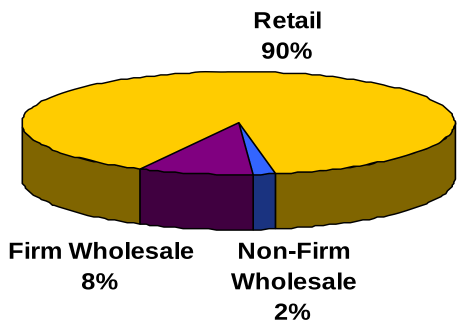
Exhibit 5: MWE's Service Territory



Source: MWE and Pace

MWE's load is composed of three separate segments: Retail Sales, Firm Wholesales, and Non-Firm Wholesales. Retail Sales are the largest component, accounting for approximately 90% of total energy. Retail Sales in combination with Firm Wholesales compose the load levels that set reserve requirements. Exhibit 6 displays MWE's expected customer energy sales mix for 2009.

Exhibit 6: MWE's Expected 2009 Customer Mix



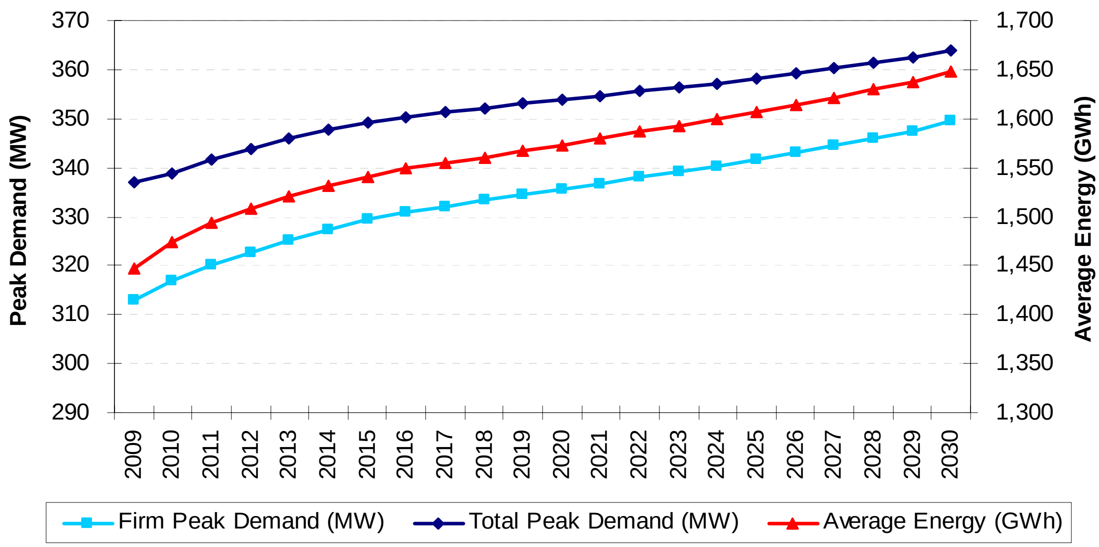
Source: MWE and Pace

LOAD GROWTH

MWE provided their long-term forecast of electricity sales to Pace. Average energy growth over the near term (2009-2015) has an estimated average annual rate of 1.05 percent, and long-term growth (2016-2030) has an estimated average annual rate 0.45 percent. Peak load is projected to grow at an average annual rate of 0.53 percent during the 2010-2030 period compared with sales growth of 0.62 percent during that period.

Exhibit 7 presents the forecasted average energy and peak load for MWE with and without non-firm wholesales.

Exhibit 7: MWE Peak Demand and Energy Forecast



Source: MWE and Pace

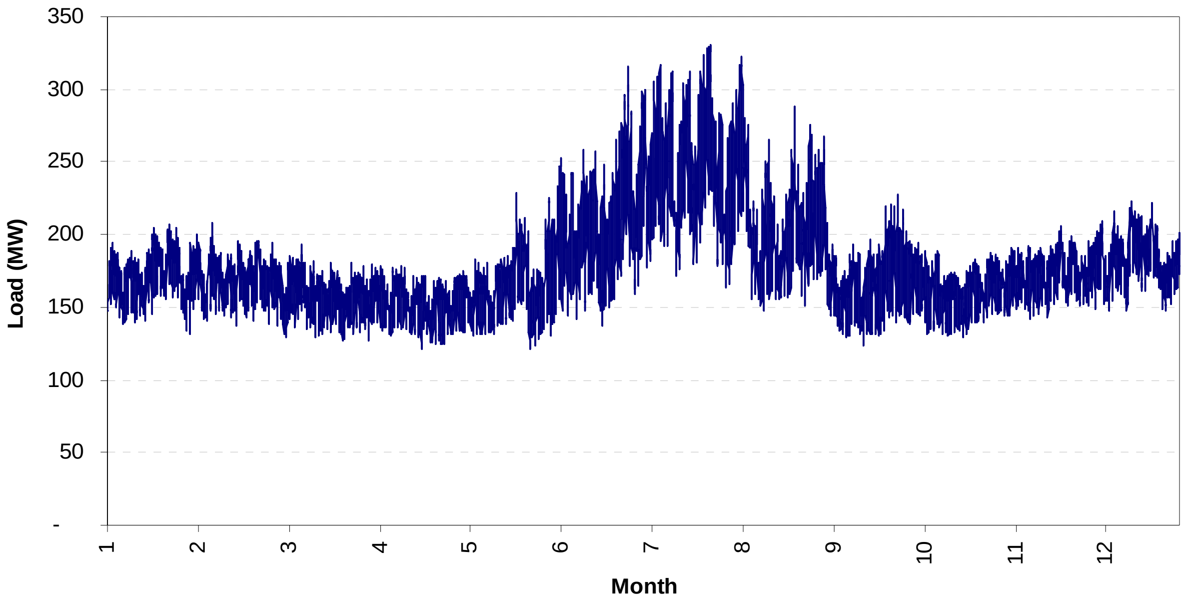
MWE's load forecast was used throughout the screening analysis described in later sections of this report. In addition, Pace developed stochastic bands around the energy and peak demand projections provided by MWE. Details on load uncertainty and stochastic methodology can be found in the appendix.

Hourly Load Projections

To arrive at the granularity of load growth projections needed for the analysis, Pace's methodology applies growth factors derived from the MWE peak demand and energy forecasts to the actual 8,760 hours of load occurring in a utility system. In this way, our market modeling system contains the highest level of detail to reflect not only the cost to serve certain levels of load but also how hourly changes impact the use of different types of generation units. Pace uses an Hourly Load Module, based on a historical year of actual reported hourly load within MWE (2008 for this simulation), to translate annual peak demand and energy growth factors into future hourly demand for a given Study Period.

The result of this process is an hourly demand shape that replicates actual market fluctuations and allows for representative dispatch patterns of the generating resources in the market. Exhibit 8 displays the hourly load profile for 2008. The MWE system is strongly summer peaking, with highest loads expected during the July-August time period.

Exhibit 8: 2008 Hourly Load Profile for MWE



Source: MWE and Pace

EXISTING SUPPLY RESOURCES

MWE owns a total of 102 MW of peaking capacity. 76 MW of this is from the new natural gas-fired generation at the Goodman Energy Facility. The capacity owned by MWE is detailed in Exhibit 9. For purposes of this study it is assumed that this owned capacity will remain in service throughout the study period.

Exhibit 9: MWE's Existing Generating Resources

Plant Name	Owned Capacity (MW)	Online Year	Ownership (%)	Fuel	Unit Type
Great Bend	9	1950	100	Gas/Oil	IC
Bird City	4	1965	100	Oil	IC
Colby	13	1970	100	Gas/Oil	GT
Goodman Energy Center	76	2008	100	Gas	IC

Source: MWE and Pace

Contract Summary

In addition to peaking capacity, MWE currently has four PPAs. The four PPAs are due to expire in 2010 and 2013. Any new contract negotiated with a supplier will supersede the existing contracts. In order to meet renewable portfolio standards, MWE entered into a contract for wind from Smoky Hills in 2008 for 49 MW. A summary of the existing contracts is shown in Exhibit 10. Additional detail is provided in the confidential appendices to this report.

Exhibit 10: MWE's Existing Contracts

Contract Name	Type	Capacity (MW)	Expiration
WPPA	Peaking	30	5/31/2013
PPA	Peaking	60	5/31/2013
WP	Baseload	40	5/31/2013
P	Baseload	125	5/31/2010
Smoky Hills	Wind	49	1/31/2028

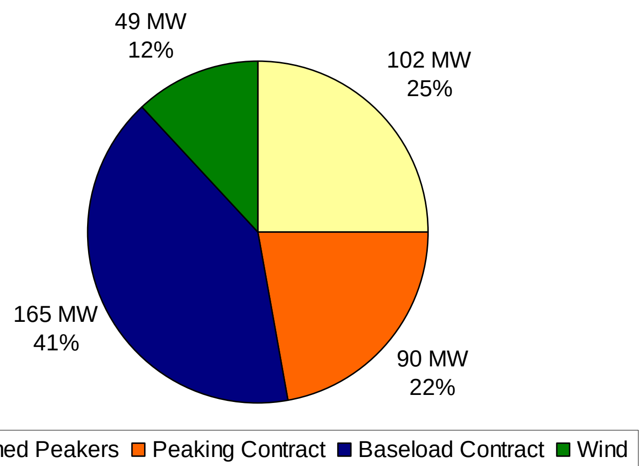
Source: MWE and Pace

Although MWE's owned capacity is all fueled by oil or natural gas, it purchases coal-fired power generation under its existing PPAs. This makes up over 45 percent of its capacity needs. Its peaking contracts represent about 25 percent of its capacity needs.

MWE's contracts with the existing supplier are all tied to specific plants or groups of units. Any new contract for baseload capacity negotiated between MWE and a supplier is expected to be similar in nature to the current contracts. A summary of the integrated portfolio, including contracts, is shown in Exhibit 11.

Exhibit 11: MWE Portfolio Summary by Capacity

Plant Name	Type	Primary Fuel	Start	End	Capacity (MW)
Great Bend	IC	Gas	1950		9
Bird City	IC	Gas	1965		4
Colby	GT	Gas	1970		13
Goodman Energy Center	IC	Gas	2008		76
WPPA	Peaking Contract	Gas		5/31/2013	30
PPA	Peaking Contract	Gas		5/31/2013	60
WP	Baseload Contract	Coal		5/31/2013	40
P	Baseload Contract	Coal		5/31/2010	125
Smoky Hill	Wind Contract	Wind		1/1/2028	49



Source: MWE and Pace

As MWE's contracts expire, one of the key questions facing MWE is whether to extend or replace these contracts, and if so, for how long and in what proportion. Many factors affect the evaluation of the future mix:

- Baseload contracts may require a high load factor: By imposing a high load factor requirement, the supplying party could force MWE to take energy even when not required to meet load. Since load and market prices are uncertain, this can result in having to pay for power that MWE cannot use.
- Restrictions on reselling power under the contracts: Supplying parties could also prohibit the resale of excess power from the negotiated contracts. In combination with a high load factor requirement, this can constitute a significant risk to MWE when load is low.
- Carbon legislation can impact the economic viability of baseload coal relative to other options over time.

- Renewable technology development will have an impact on the proper mix. Although solar technology is not currently economic, it is expected to become more economic by the end of the Study Period. As market prices increase, wind generation economics will also improve.
- Additional owned peaking capacity may provide value as a hedge against market conditions and some types of contracts.
- The successful implementation of DR programs may reduce the need for new peaking capacity.

Current negotiations with suppliers will replace peaking contracts with a "Units Most Likely" contract ("UML"). Instead of linking the energy charge to a single unit or a group of units, the UML contract charges MWE the cost of the incremental unit used to meet MWE's load after the third party's load and other obligations have been served.

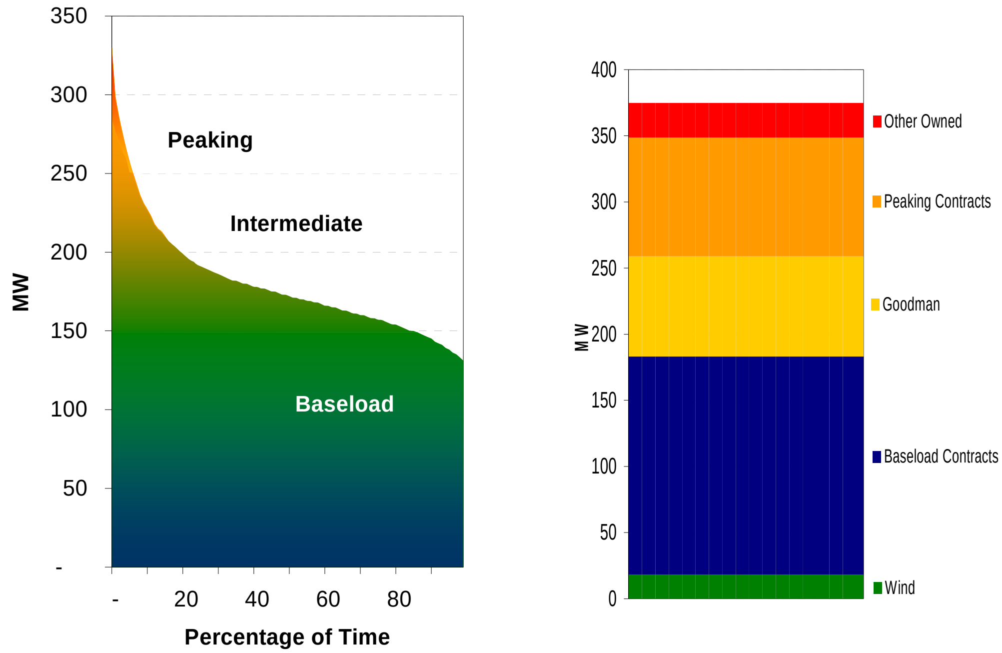
The UML contract currently under negotiation is based upon the dispatch of the third party's generating capacity. The energy component of the contract is determined by the variable cost of the marginal unit that serves MWE. The capacity component is determined by the third party's estimate of the units that will most likely be dispatched to serve MWE's load. The structure of the UML contract requires some modeling of the supplier's system. Details on the assumptions and simulation analyses relevant to this contract type can be found in the confidential appendices to this report.

SUPPLY AND DEMAND BALANCE

Exhibit 12 presents the 2008 load duration curve for MWE alongside their current existing resources and contracts. The full capacity of all resources and contracts is assumed, unless the resource is wind. In that case, average annual capacity factors were used to display average generation levels over the course of a year. Current generating capacity under four contracts, totaling 255 MW, are due to expire over the next few years.

The evaluation of new contracts and capacity additions will aim to optimize the energy and capacity cost profile of each option against MWE's load profile.

Exhibit 12: Business as Usual Long Term Supply and Demand Balance

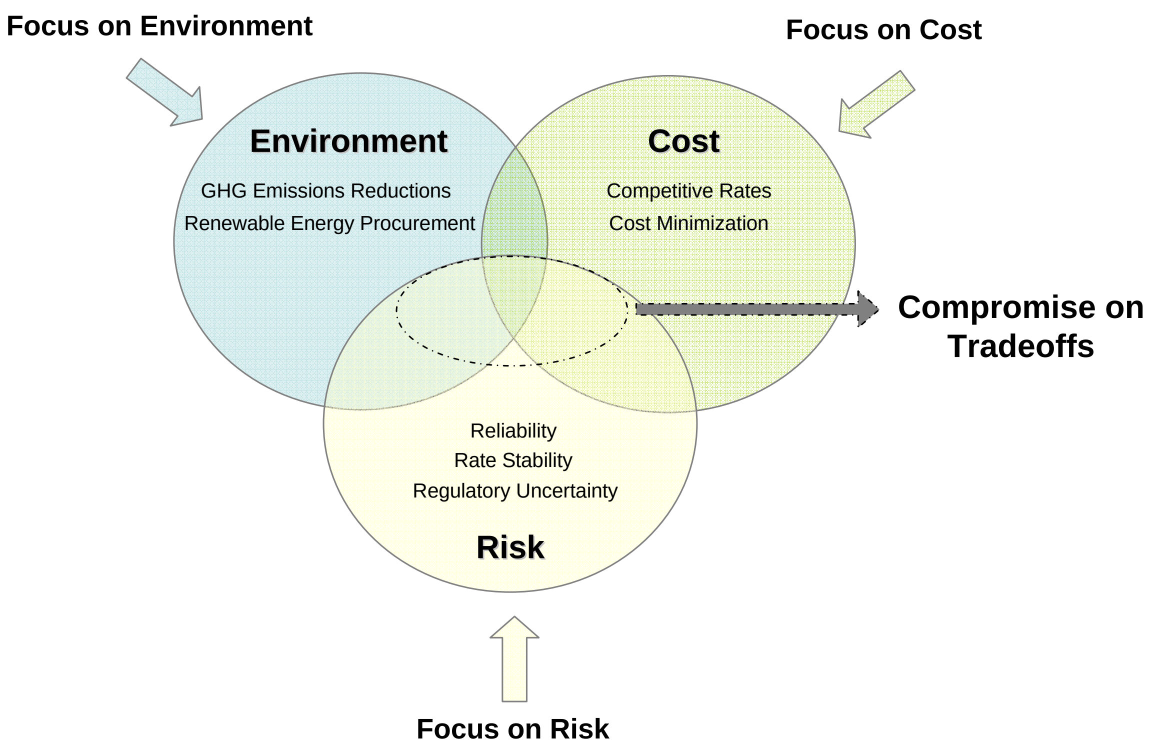


Source: MWE and Pace

PLANNING OBJECTIVES AND METRICS

To properly evaluate resource decisions, the planning objectives were identified early in the resource planning process. Even with the appropriate metrics identified for each planning objective, the tradeoffs associated with resource decisions represent a big challenge for resource planning. Exhibit 13 displays three commonly competing objectives. As is shown, focus on any one objective can move the resource plan away from focus on the others.

Exhibit 13: Competing Planning Objectives



Source: Pace

The following section describes the list of planning objectives that were identified for the current IRP and defines the metrics used throughout the analysis to evaluate the performance of the different portfolio options.

PRIMARY PLANNING OBJECTIVES, CONSTRAINTS, AND METRICS

Preserve Competitive Rates (Cost)

Preserving competitive rates is a common objective for utilities. For comparison purposes, different portfolio options were evaluated based on the levelized net present value of all generation-related costs associated with serving the utility's load (2008$/MWh). Pace's cost metric includes the variable cost of generation, fixed costs, capital costs investments, and the cost of net market transactions (purchases minus sales).

Maintain Stable Rates (Price Risk)

Fuel and power price volatility, as well as uncertainty around energy demand and capital costs, can result in significant changes in portfolio cost. Portfolios that can mitigate significant market swings can also achieve higher rate stability. Rate stability can be measured by different metrics like standard deviation or probability bands.

Portfolios were evaluated against statistically derived distributions on key market drivers, like natural gas prices, energy demand, power market prices, and capital costs. Rather than record portfolio costs under one set of assumptions, costs were measured under a distribution of the key assumptions drivers. In this context, portfolios were evaluated based on the standard deviation of the NPV of costs (or each year's cost where appropriate). This represents a metric of how wide the distribution of costs can get for each portfolio. The lower the standard deviation, the less exposed the portfolio is to market volatility.

Provide Reliable Service (Reliability)

System reliability is a primary concern for any load-serving entity, and long-term utility planning is usually done using a reserve margin criterion, such as the 13.6% planning reserve margin used by MWE.

CO_2 Emission Liability

An increasing concern regarding global climate change has put specific emphasis on the carbon intensity associated with different power generating resource options. Although coal-fired generation remains one of the most efficient sources of power generation, its potential environmental impacts pose a growing concern to the public and utility planners alike. Moreover, the potential advent of significant costs associated with CO_2 emissions constitutes a major risk for coal plant owners.

Renewable Generation

Specific regulations concerning both federal and statewide RPS standards for utilities in Kansas will drive renewable resource additions. MWE is committed to meeting these requirements. Increasing generation from renewable resources will also directly result in reduced CO_2 emissions for the portfolio.

Manage Contract Risks on Sales

In the case of MWE, an important consideration is whether its PPAs will allow them to re-sell excess power back into the market. If sales from contracted energy are restricted and load is less than anticipated, MWE might be in a position where it is paying for power it cannot use or re-sell. Restrictions on load factor and resales are considered in the construction of portfolios and analyzed directly in the analysis.

ANALYSIS OF BASELOAD VS. UML TRADEOFFS (PHASE I SCREENING ANALYSIS)

The resource planning approach taken in this 2009 LRRP consists of two major phases. The first phase is designed to screen all feasible contract and resource options that meet MWE's energy requirements. The screening process includes a representation of all expected market conditions and planning constraints (RPS standards, existing resources, contract requirements and minimum lengths). These options are evaluated based on MWE's objectives, energy and regulatory requirements, as well as specific contract options offered by the preferred supplier. A number of portfolios are then selected to be further evaluated during the "risk" phase of the analysis.

The goals of the screening analysis are to:

1. Eliminate technologies that are not economically feasible for MWE during the planning horizon;
2. Identify capacity additions required to meet expected RPS standards;
3. Concentrate on the most cost-effective mix of Baseload and UML contracts over time;
4. Provide insight into the timing of generation or PPA additions for consideration in the risk analysis;
5. Provide guidance into the implications of PPA restrictions that might affect the construction of a limited number of portfolios in the risk analysis.

SCREENING ANALYSIS

Screening analyses were performed with a customized screening tool in a deterministic rather than probabilistic or stochastic framework. The screening analysis is able to rapidly evaluate key metrics for all contract combinations and a variety of technology combinations within the framework of MWE's operations.

Screening Process

The screening process was performed in accordance with Exhibit 14. As is noted, the screening analysis incorporated a detailed representation of portfolio resources, MWE demand (load), and all relevant costs such as fuel prices, power prices, environmental compliance costs, and fixed and variable operating charges. The screening analysis evaluated different contract options from the preferred supplier as well as alternative resources for ownership or contract.

The key elements of the process can be summarized as follows:

1. Reference case assumptions for load, costs of existing capacity, capacity additions, and contract and fuel costs were developed (these are described in detail in the Appendices)

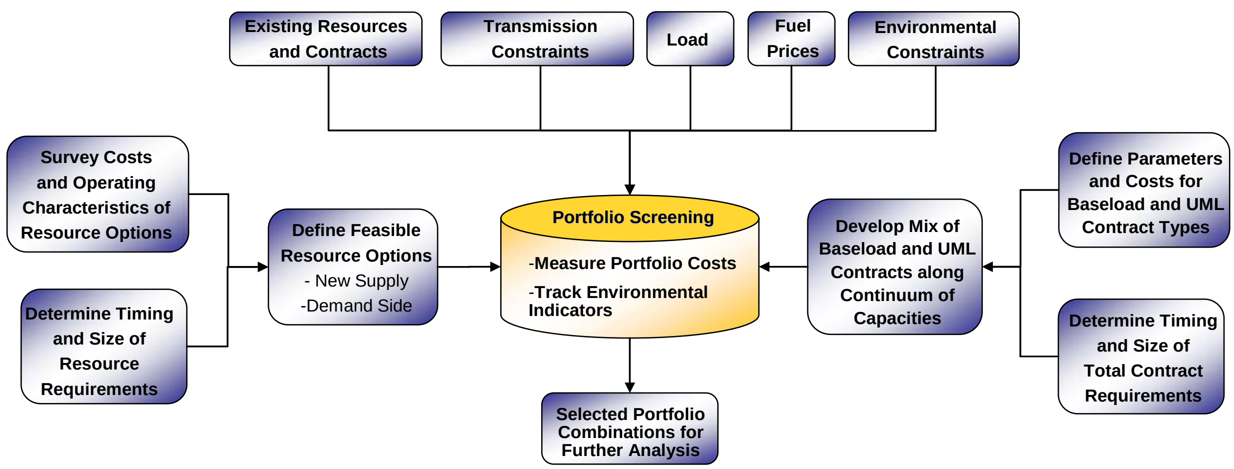
2. Contract options were evaluated across a continuum of capacity mixes for baseload and "units most likely" ("UML") based on Reference Case conditions. The full range of

contract options from 100% of UML to 0 percent baseload (and corresponding 0% to 100% baseload) was assessed.

3. Incremental wind, solar and peaking combinations during each of three time periods (2010-2015, 2015-2020 and 2020-2025) were assessed to see which reduced portfolio costs in comparison to the optimal baseload/UML generation mix and during which time periods.
    a. Based on operational profiles, wind replaced baseload contract capacity, while solar and new (GEC type) peaking capacity replaced UML capacity.

4. Candidate portfolio combinations were selected for evaluation in the full risk analysis.

Exhibit 14: Process Diagram for Screening Analysis



Source: Pace

Contract Options

Two types of contracts were evaluated:

- Baseload Unit-Contingent Coal-Fired Generation: MWE currently has baseload, unit-contingent coal-based contracts. These contracts contain a fixed capacity charge, with variable costs associated with actual costs of plant generation. Using existing baseload contracts as a guide, Pace evaluated a representative coal-fired plant within the preferred supplier's fleet to track operations and costs associated with this contract.
- Units Most Likely ("UML") Generation: This type of contract allows MWE to purchase energy from the preferred supplier at their marginal cost of serving MWE's load, after the supplier's native load requirements and other obligations are met. Analysis of this contract type requires full simulation of the supplier's portfolio mix and load requirements in order to simulate the hourly cost of energy.

Resource Options

In order to analyze new resource options, an assessment of costs and operating characteristics was performed for a range of feasible technologies. The following options were evaluated:

- Wind (considered a baseload but intermittent supply option)
- Solar photovoltaic
- Goodman Energy Center ("GMEC") Expansion (a peaking option)
- Additional peaking capacity similar to GEC (a peaking option)

Capital cost estimates and operating profiles were developed for these resource options from a combination of information from Pace technology assessments from consulting projects and public reports, as shown in Exhibit 15. These estimates were combined with financing assumptions and tax rules summarized in Exhibit 16 to develop appropriate cost comparisons. The gas-fired peaking options were structured assuming ownership by MWE, while the renewable options were assumed to be constructed by a private developer and contracted through a power purchase agreement. Operational parameters were applied and specified at the hourly level, where appropriate.

Exhibit 15: Operating and Cost Parameters for New Resource Options

Technology	Early Capital Cost	Mid Capital Cost	Late Capital Cost	VOM	FOM	Heat Rate	Block Size
	2008$/kW	*2008$/kW*	*2008$/kW*	*2008$/MWh*	*2008$/kW-yr*	*Btu/kWh*	*MW*
GMEC Expansion	755	722	714	4.00	13.20	8,600	25
New Peaker (Wartsila)	795	760	751	4.00	13.20	8,600	25
Wind	2,103	2,080	2,052	0	20.45	na	25
Solar PV - Si	5,096	3,625	2,594	0	5.99	na	30

Source: Pace

Exhibit 16: Reference Case Financing and Tax Benefit Assumptions

Technology	Equity/ Debt Ratio	Return on Equity	Interest Rate	WACC (ROR)	PTC	ITC	Levelized Recovery Requirement	Levelized Recovery Requirement
	%	%	%	%	$/MWh	$/kW-year	$/MWh	$/kW-year
Expansion Peaker	40	11.31	5.25	7.67	-	-	59*	77
New Peaker	40	11.31	5.25	7.67	-	-	62*	81
Wind	50	15	8.25	11.63	20	-	57**	184
Solar PV - Si	50	15	8.25	11.63	-	22.5	126 (2021) 99 (2026)***	222 (2021) 175 (2026)

* 15% capacity factor assumption
** 37% capacity factor assumption
*** 20% capacity factor assumption

Source: Pace

SCREENING RESULTS

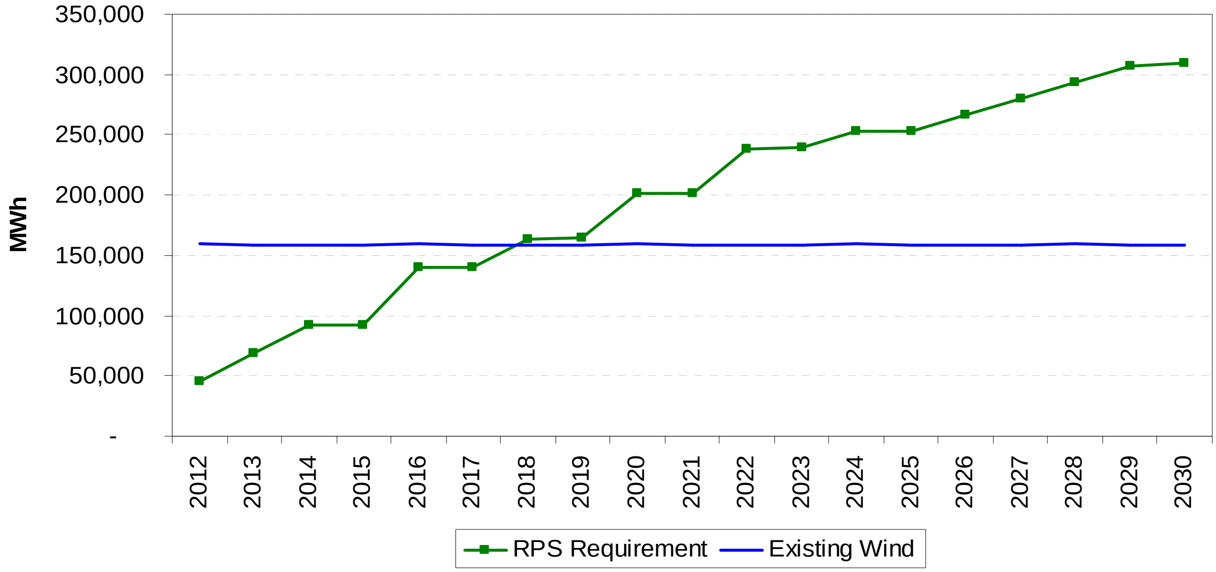
The key conclusions of the initial resource screening were:

- In order to meet projected federal Renewable Portfolio Standard requirements by 2030, MWE will need to add about 50 MW of wind capacity (at a 37% capacity factor) to its portfolio (in addition to replacing the current Smoky Hills contract at expiration).
- The lowest cost mix of baseload versus UML type contracts is between 40 and 60 percent baseload.
- Additional peaking capacity at the Goodman Energy Center or elsewhere is cost effective early in the Study Period.
- New wind additions beyond RPS requirements should be delayed beyond 2020, but may be cost effective thereafter, as price expectations for natural gas prices and carbon compliance costs increase.
- New solar additions do not appear cost-effective during the Study Period.

RPS Requirements

Exhibit 17 shows that expected Federal RPS requirements of 25 percent by 2030 will require additional renewable generation beyond the existing Smoky Hills wind contract by 2018. Although MWE is long renewable capacity at the moment, a gap between the expected requirements is expected to develop and grow over time. By 2030, a total of about 50 MW of new wind capacity (at a 37% capacity factor) is required to meet this expected standard (which includes an option that 25% of the requirement could be met by energy efficiency). As a result, Pace has included incremental 25 MW wind additions in 2018 and 2021 in its portfolio development.

Exhibit 17: Expected Renewable Generation Requirements vs. Existing Supply



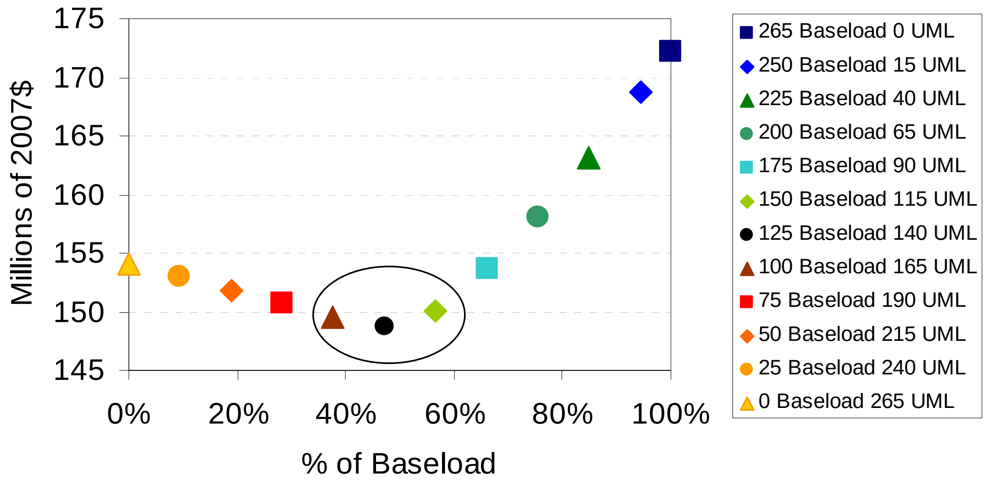
Source: Pace

Baseload vs. UML Mix

Pace evaluated the most cost-effective mix of baseload and UML capacity by testing a continuum of options from 100 percent of capacity requirements served by baseload and 0 percent UML to 0 percent baseload and 100 percent UML. It was determined that a mix containing between 40 percent and 60 percent baseload capacity (100 to 150 MW) is the most cost-effective, with 50 percent being the preferred option in the screening analysis. This is displayed in Exhibit 18.

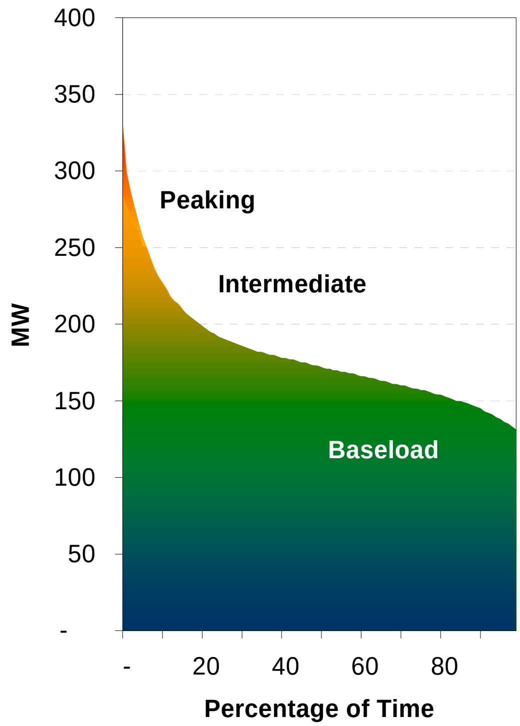
This mix of contract types is the most effective and efficient way to meet MWE's load profile, which is shown in load duration form in Exhibit 19. Too much baseload capacity with high fixed capacity charges would result in an oversupply for many hours of the year, leading MWE to pay for energy and capacity that it does not need. Too little baseload capacity would force MWE to pay for the UML supplier's marginal gas-fired resources at a higher variable cost than coal-fired baseload resources when loads are low.

Exhibit 18: Baseload vs. UML (2026-2030)



Source: Pace

Exhibit 19: Load Duration Curve

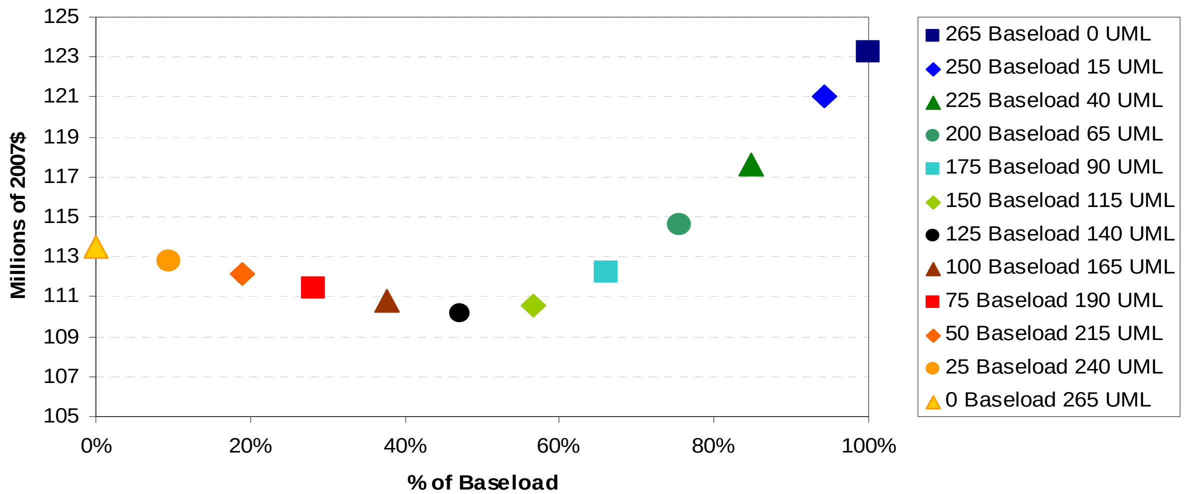


Source: Pace

Certain restrictions may be introduced in negotiations that could either require high load factors on the baseload contracts or restrict sales. In the screening analysis, we considered how one or the other of these types of restrictions might affect the targeted level of baseload generation relative to UML generation.

Higher Load Factor Requirement: A high load factor requirement means that MWE must take energy from the baseload contract every hour at a level close to available output. Under such an arrangement, MWE may be able to sell some of the excess generation to an off-taker at a discount to cost. When analyzing this scenario, Pace has credited MWE with the ability to sell 80% of its excess power at 80% of its cost. A PPA that requires a commitment to high (98 percent) load factors but allows limited re-sales (at a discount to market) results in optimal baseload portfolio percentages of around 50 percent, as displayed in Exhibit 27.

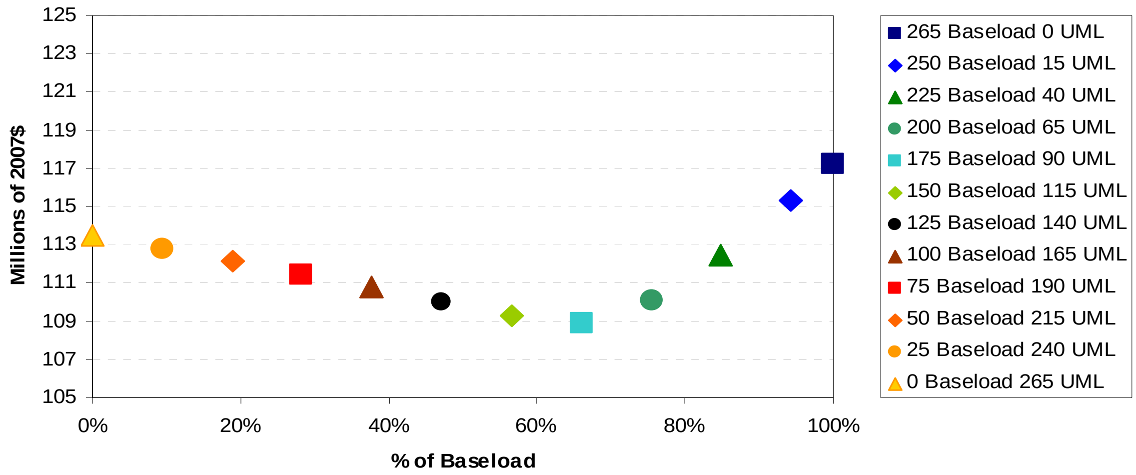
Exhibit 20: Impact on Reference Case of High Load Factor



Source: Pace

Restricting Resales: In analyzing a total restriction of sales, Pace has simulated a scenario where MWE would be required to take only 90 percent of the baseload energy (90% load factor), but be unable to sell any of it back. This means that excess energy beyond load requirements in any hour would be paid for even if unused. Under these conditions, the optimal baseload percentage increases to a number closer to 70 percent. This is shown in Exhibit 21. As discussed later, uncertainty in load and market conditions can change these findings.

Exhibit 21: Impact on Reference Case of Sales Restriction



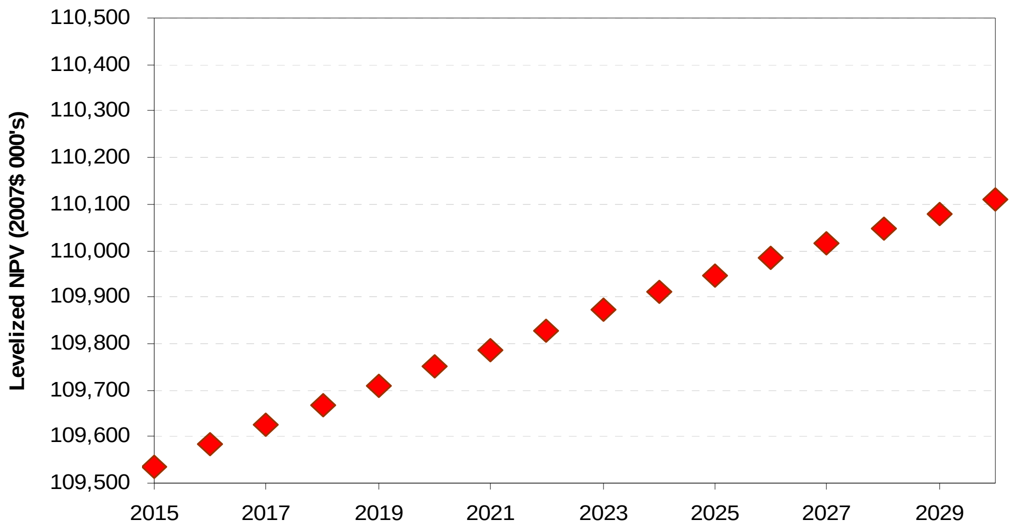
Source: Pace

Incremental Capacity Additions

Pace examined the cost-effectiveness of additional natural gas-fired peaking capacity additions to MWE's portfolio. The analysis tested the costs and ideal timings for expanding the Goodman Energy Center and adding more peaking power plants. All additional peaking capacity was simulated through replacement of an equal amount of UML capacity. It was concluded that additions of gas-fired peaking capacity (both expansion of GEC and additional capacity of a similar nature) or DR programs provide an effective hedge against potential high costs of UML generation, reducing generation costs.

Pace's analysis indicates that the best timing is as early as feasible, since peaking capacity additions are lower cost than projected UML contract costs throughout the entire Study Period. Exhibit 22 summarizes the total net present value of portfolio costs for different scenarios that add incremental peaking capacity for each of the years between 2015 and 2030. As can be seen, the scenario that adds peaking capacity earliest is most cost-effective. This suggests that the length of the UML contract should be structured around the time needed to expand the current peaking capacity or construct a new plant.

Exhibit 22: NPV of Additional MWE Owned Peaking Capacity over Time

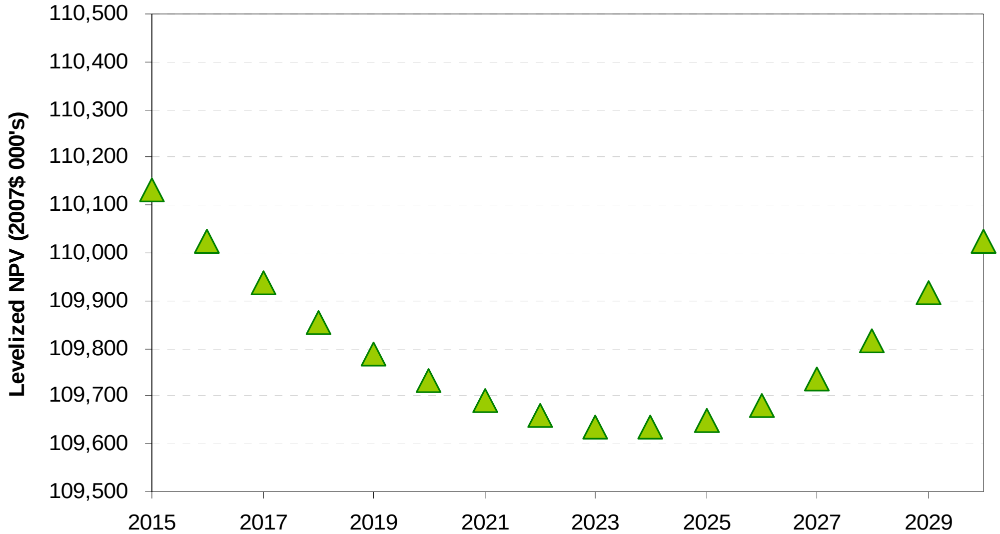


Source: Pace

Pace also examined the cost-effectiveness of adding renewable capacity additions above and beyond those required to meet expected RPS targets. Similar to the tests for additional peaking capacity, the analysis examined the effects on cost of new wind or solar PV expansion over time, from 2015 to 2030. Incremental wind additions replaced baseload contract capacity on a firm reserve credit basis, while incremental solar additions replaced UML capacity. This is due to the expected operational profiles of these two renewable types.

Although solar additions become more economic over time, they are never expected to result in a net benefit in total portfolio costs over the planning horizon. Incremental wind capacity additions (between 25 and 50 MW) beyond that required to meet Federal RPS standards ("economic wind additions"), however, may reduce portfolio costs. Exhibit 23 displays the net present value of total portfolio costs for different scenarios with wind additions in each of the years between 2015 and 2030. This shows that the optimal timing for new economic wind additions is between 2021 and 2025. Low initial gas and coal costs make wind cost-prohibitive in the near term versus MWE's current portfolio and contract options, but rapidly rising cost expectations for both natural gas and carbon compliance make wind more economic after 2020.

Exhibit 23: NPV of Additional Wind Capacity over Time

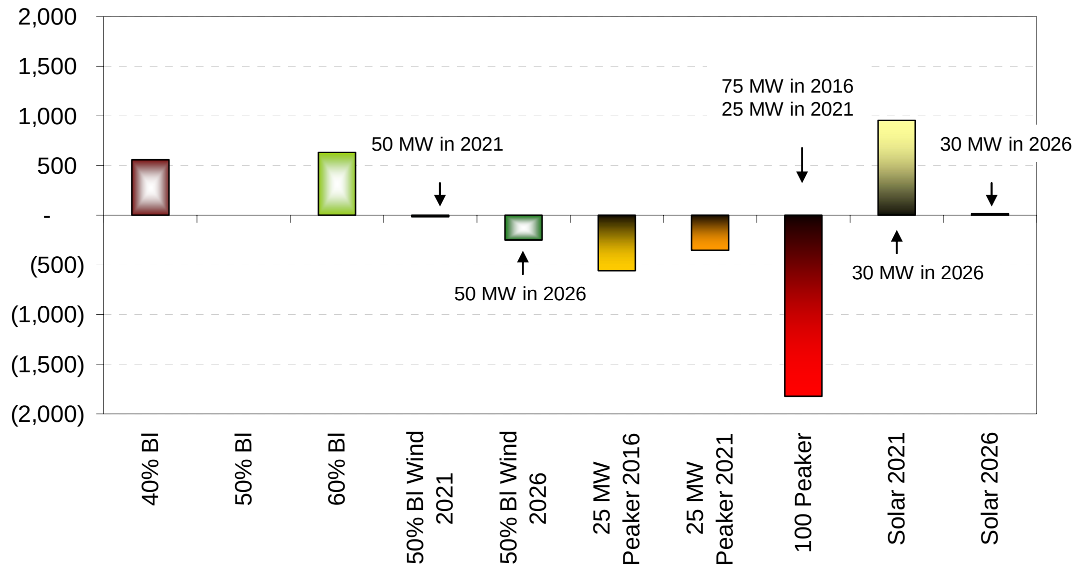


Source: Pace

Screening Conclusions

Pace's screening analysis concluded that the optimal mix between baseload and UML contracts is around 50 percent each, depending on load factor and sales restriction considerations. Incremental natural gas-fired peaking capacity additions are likely to reduce costs as soon as they can be brought into service. New economic wind additions are not cost-effective until after 2020 and new solar additions are not cost-effective throughout the Study Period. To display these results and compare their magnitude on a net present value basis, Pace has shown the relative portfolio cost outcomes for a variety of capacity mixes against a reference scenario with 50 percent baseload and 50 percent UML in Exhibit 24. In this display, positive values indicate additional portfolio costs, while negative values indicate lower costs and a benefit to the portfolio.

Exhibit 24: Screening Analysis Results (NPV in $000)



Source: Pace

CANDIDATE PORTFOLIOS FOR RISK ANALYSIS

With the resource screening analysis conclusions guiding portfolio development, specific details regarding MWE's projected supply/demand balance and required reserve margins were analyzed in order to develop practical timing and size (capacity addition) parameters for resource additions.

The Phase I analysis resulted in the creation of twenty distinct portfolios that examine different baseload and UML capacity mixes, various sales and load factor restrictions, and different timing and capacities for incremental additions. The twenty selected portfolios are summarized in Exhibit 25 as incremental additions to the existing MWE portfolio.

The details of each of the incremental portfolio options referenced in Exhibit 25 are as follows:

- The first 5 portfolios consider only baseload and UML supply options for meeting MWE's load using 40%, 50%, 60% and 70% baseload capacity. High load factors (98%) with some limitations to the ability to re-sell excess baseload energy were used in the 40-60% cases. Lower load factors (90%) with a complete prohibition to sell back excess baseload energy were used for the 60-70% baseload cases, consistent with the screening analysis results.
- The next five cases focus on the 50% baseload option with high load factors and resales but backed down the contract capacities for increments to wind (in either 2021 or 2024), GMEC expansion, incremental peakers in 2015 and 2020 or solar (in 2027).
- The final ten cases focused on the 60% baseload option under two different load factor/resale combinations and the same increments to wind or peakers (including the GMEC expansion).

As mentioned before, although not explicitly simulated in the Risk Analysis, effective DR programs can displace the need for some peaking capacity.

Exhibit 25: Phase II Portfolios (Incremental to Existing Peaking and RPS Generation)

Portfolio Number	Portfolio Name	Baseload %	Load Factor	Sale Back	Wind	GMEC Expansion	New Peaker	Solar
1	40% Baseload	40%	98%	80% at 80%				
2	50% Baseload	50%	98%	80% at 80%				
3	60% Baseload	60%	90%	None				
4	60% Baseload	60%	98%	80% at 80%				
5	70% Baseload	70%	90%	None				
6	50% Bl Wind 2021	50%	98%	80% at 80%	50 MW in 2021			
7	50% Bl Wind 2024	50%	98%	80% at 80%	50 MW in 2024			
8	50% Bl Peaker 2015	50%	98%	80% at 80%		25 MW in 2015		
9	50% Bl 100 MW Peaker	50%	98%	80% at 80%		25 MW in 2015	50 MW in 2015/ 25 MW in 2020	
10	50% Bl Solar 2027	50%	98%	80% at 80%				Solar 2027
11	60% Bl Wind 2021	60%	90%	None	50 MW in 2021			
12	60% Bl Wind 2024	60%	90%	None	50 MW in 2024			
13	60% Bl Peaker 2015	60%	90%	None		25 MW in 2015		
14	60% Bl 100 MW Peaker	60%	90%	None		25 MW in 2015	50 MW in 2015/ 25 MW in 2020	
15	60% Bl Solar 2027	60%	90%	None				Solar 2027
16	60% Bl Wind 2021	60%	98%	80% at 80%	50 MW in 2021			
17	60% Bl Wind 2024	60%	98%	80% at 80%	50 MW in 2024			
18	60% Bl Peaker 2015	60%	98%	80% at 80%		25 MW in 2015		
19	60% Bl 100 MW Peaker	60%	98%	80% at 80%		25 MW in 2015	50 MW in 2015/ 25 MW in 2020	
20	60% Bl Solar 2027	60%	98%	80% at 80%				Solar 2027

Source: Pace

OUTSTANDING RISK FACTORS FOR FURTHER CONSIDERATION

The Phase I analysis highlighted several key risks that cannot be accounted for in a screening exercise reliant on single point estimates for key market drivers. As a result, further evaluation of the following key risks was determined to be required as part of the Phase II analysis:

- Load is highly uncertain. Hence, the PPA restrictions evaluated in Phase I could be greatly influenced by the possibility that load could be less than expected, which would potentially make both high load restrictions and restricting resales more expensive.
- Fuel market volatility and carbon legislation on coal-based generation costs through high allowance values could affect the optimal mix of baseload generation or at least the timing and term of the baseload PPAs.
- The evaluation of wind, solar, and owned peaking capacity additions is affected by uncertainties in capital costs relative to the contracting options, as well uncertainties in market drivers that affect the contract costs.

For all of these reasons, we evaluated the list of portfolio combinations around the following uncertainties.

- Evaluation of the exposure of all of the portfolio options to statistically quantifiable risk factors:
    - Customer demand and regional load
    - Coal and Natural gas prices
    - Power market prices
    - Capital costs for resource additions (peaking natural gas turbines, wind, and solar)
    - Capacity costs for the baseload and UML contracts

- Evaluation of certain portfolio options in the context of quantum events through scenario analysis that explore the:
    - Emerging state/regional/federal carbon policy constraints and valuation

QUANTITATIVE AND RISK ASSESSMENT OF PROPOSED PORTFOLIOS (PHASE II)

RISK INTEGRATED RESOURCE PLANNING APPROACH

MWE, just like most electric utilities, has to make resource decisions under a great deal of uncertainty. A resource decision that meets all objectives when judged only under current or best guess forecasted conditions may prove to be a future financial burden on the utility over time if the forecasts are wrong. Fuel market volatility, capital cost uncertainty, load uncertainty, emission regulations, and regulatory changes will all affect how resources and contracts perform throughout their operational lives. Understanding the range of potential market volatility and the severity of impending regulatory changes on alternative generation portfolios is crucial to make the appropriate portfolio choices. The least expensive resource addition may not be the best if it also exposes MWE to severe market volatility or severe negative effects associated with an impending regulatory change. The tradeoffs between costs, risks, and other utility objectives need to be quantified for each portfolio and need to inform the selection of the portfolio that performs best according to those objectives the utility ranks as its highest priorities.

As introduced in the previous chapter, the 2009 LRRP took a risk-based approach to resource planning.[2] The first phase screened all the feasible resource and contract options through an analysis that included a representation of all expected market conditions and planning constraints (RPS standards, reliability requirements, and feasible contract parameters). These options were evaluated based on cost performance and were developed around minimum requirements for RPS and reserve margin.

The portfolios in Phase I were constructed to capture a broad spectrum of baseload and UML contract mixes, as well as owned versus contracted supply resources. The portfolios included additional economic natural gas-fired peakers and renewables when appropriate and factored in different timing possibilities. This allows MWE to evaluate all viable resource options and identify the resource characteristics and combinations that constitute a good portfolio. Phase II of the 2009 IRP process focuses on the quantification of risks and the impact of different uncertainties on the performance of all portfolios selected from the screening process. Exhibit 26 illustrates the details of the Phase I and Phase II components of the 2009 IRP process.

Objectives for Review in Risk Analysis

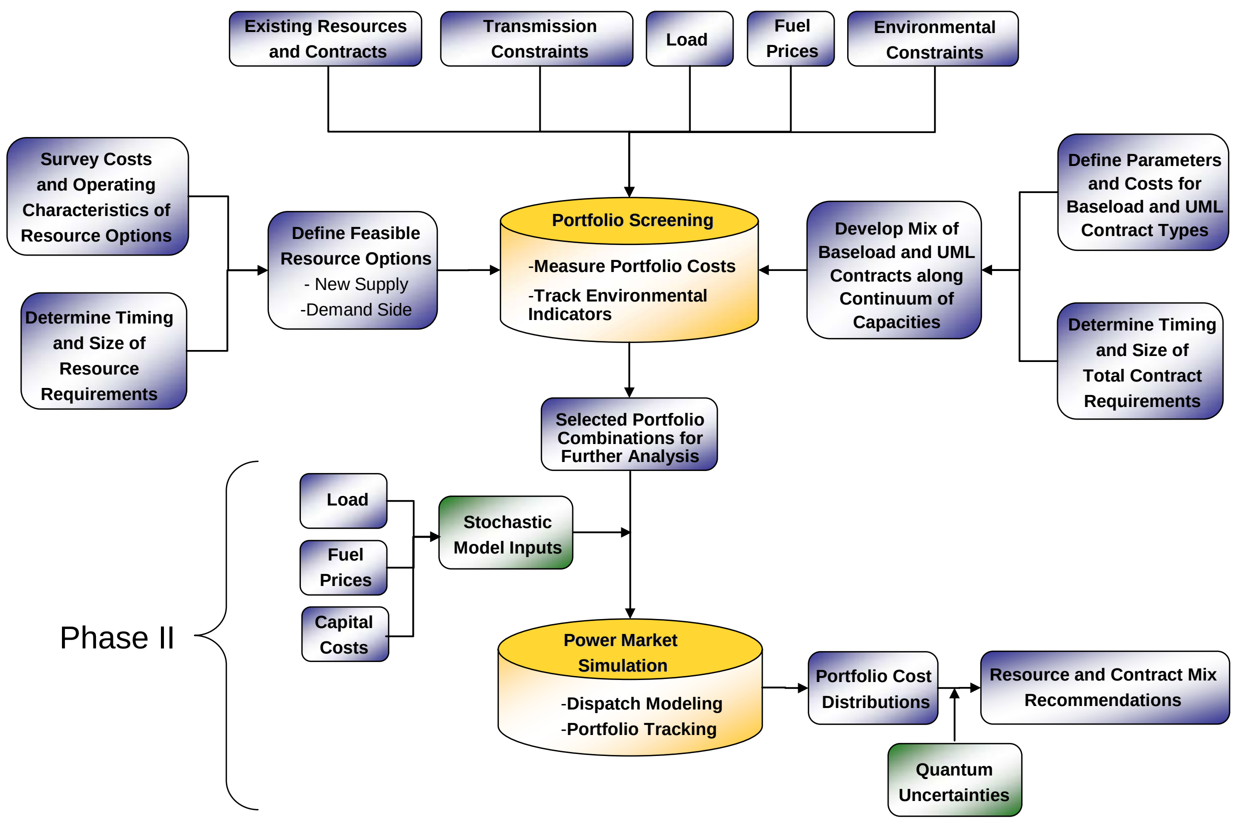
The Phase II process is intended to re-examine several analyses from the screening phase to test the robustness of the preliminary conclusions under an uncertain environment. This will lead to selection of a portfolio (or range of portfolios) that best meets MWE's objectives across a range of market and regulatory outcomes. The major objectives of the Phase II analysis include:

- Re-evaluation of the proper mix of baseload versus UML generation, without additional renewables beyond required for meeting RPS requirements.

[2] Pace employed its Risk Integrated Resource Planning ("RIRP") approach in analyzing feasible portfolio options in the context of a variety of uncertainties in order to measure performance under multiple planning objectives.

- o Consideration of whether adding renewables beyond RPS requirements is cost-effective (adding wind in either 2020 or 2025 and reducing baseload coal PPA)
- o Consideration of expanding GMEC by 25 MW in 2015 (Reducing UML PPA)
- o Consideration of additional increments of owned peaking capacity in 2015 and 2020 (reducing UML PPA)
- o Evaluation of portfolio performance under a high carbon scenario

Exhibit 26: Risk Integrated Resource Planning Process



Source: Pace

The Phase II process focuses on the quantification of uncertainty, which can be measured through different methodologies. Uncertainty was evaluated using two main methods: statistically-driven stochastic analyses and scenario (quantum) analyses. Stochastic simulations are generally deemed appropriate for variables that have a wide and continuous range of potential outcomes that can be quantified based on historical relationships and volatilities. In this analysis, load, fuel, and capital cost uncertainty were evaluated using stochastic inputs. Discrete events that result in significant or quantum changes for portfolio performance or market outcomes were evaluated through scenario analyses.

Uncertainty is measured as a distribution of the aggregation of all potential costs (capital, O&M, fuel, etc.) of the incremental generation portfolio decisions over time. By quantifying the costs over a wide range of potential market and regulatory outcomes, we can get an accurate picture of the full range of risks associated with any portfolio over the entire planning horizon. Additional detail on the Phase II process and tools can be found in the appendix.

STOCHASTIC (QUANTIFIED RISK) PORTFOLIO ANALYSES

Stochastic inputs used in Phase II were based on a combination of historic volatility, observed relationships between key market drivers and outcomes, and expectations for future market and technological change trends. Pace's market insight is used to develop a view on future market trends; statistical and modeling tools are then employed to quantify the uncertainty around the expected trends and evaluate the performance of each portfolio under different uncertainties.

The effects of fuel, load, and capital cost uncertainty on the portfolios were quantified by simulating the hourly operations of all portfolio resources over the study horizon under 500 different load, fuel, and capital cost combinations. As stated previously, these distributions were based upon historical statistical analyses of load, fuel prices, and capital costs. Fuel price uncertainty was primarily quantified through evaluation of historical volatility in natural gas and coal market prices. Energy and peak demand uncertainty was evaluated through regression analysis around key determinants of load and uncertainty analysis around energy efficiency and demand side measures. Capital cost uncertainty was evaluated by defining stochastic bands around the capital costs of each resource addition in the portfolio for each year of the Study Period, based on historical commodity cost volatility and breakdowns of capital costs for different generating technologies. Technology change and uncertainty was also accounted for, by representing expected declines in capital costs for solar technology and to a lesser degree peaking and wind capacity over time. Details on the construction of these distributions are provided in an appendix.

SCENARIO ANALYSES

For any given portfolio, there are significant sources of uncertainty that cannot be quantified using stochastic simulations. Quantum cases developed around discrete assumptions changes have been analyzed through separate scenario analyses. In this study, the portfolio risks evaluated using scenario analyses included:

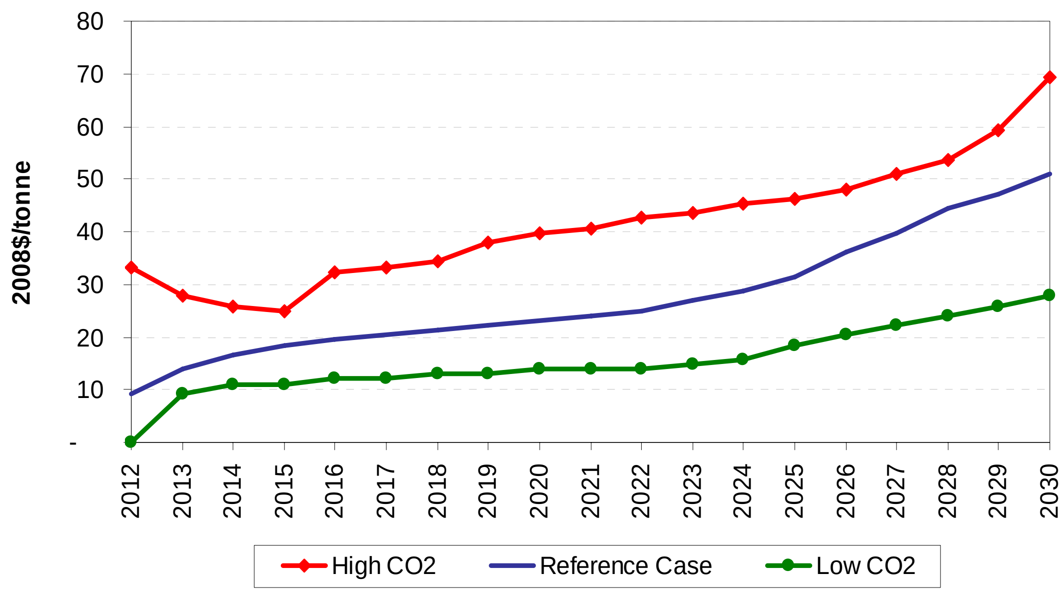
- High CO_2 Cost Scenario
- Low CO_2 Cost Scenario

Regulatory Risk Associated with Higher and Lower CO_2 Allowance Prices

Significant CO_2 emission compliance costs are expected over the Study Period. The uncertainty surrounding the timing and pricing level of such costs represents a big risk for any CO_2-intensive portfolio or contract. Pace's analysis included the evaluation of all portfolio costs under a high and low CO_2 case. Exhibit 27 displays the annual CO_2 compliance costs assumed in the reference, high, and low CO_2 case. Portfolios with a larger share of coal-intensive generation will face a relatively greater cost impact than those with less reliance on coal. Pace evaluated the relative impact of CO_2 on costs based on the NPV of portfolio costs under the different CO_2 scenarios.

To place the concept of higher and lower CO_2 costs into its proper context, the scenarios were developed around a consistent set of market factors, including gas prices, load and other capacity expansion considerations. For example, legislation that results in higher carbon costs will also likely result in more coal plant retirements, higher near term gas demand and prices, and eventually lower overall demand for gas as more renewables are able to be placed in the generation mix. Additional detail on these assumptions can be found in the appendix to this report.

Exhibit 27: CO_2 Costs for Reference Case and High Case



Source: Pace

PORTFOLIO RISK ASSESSMENT RESULTS

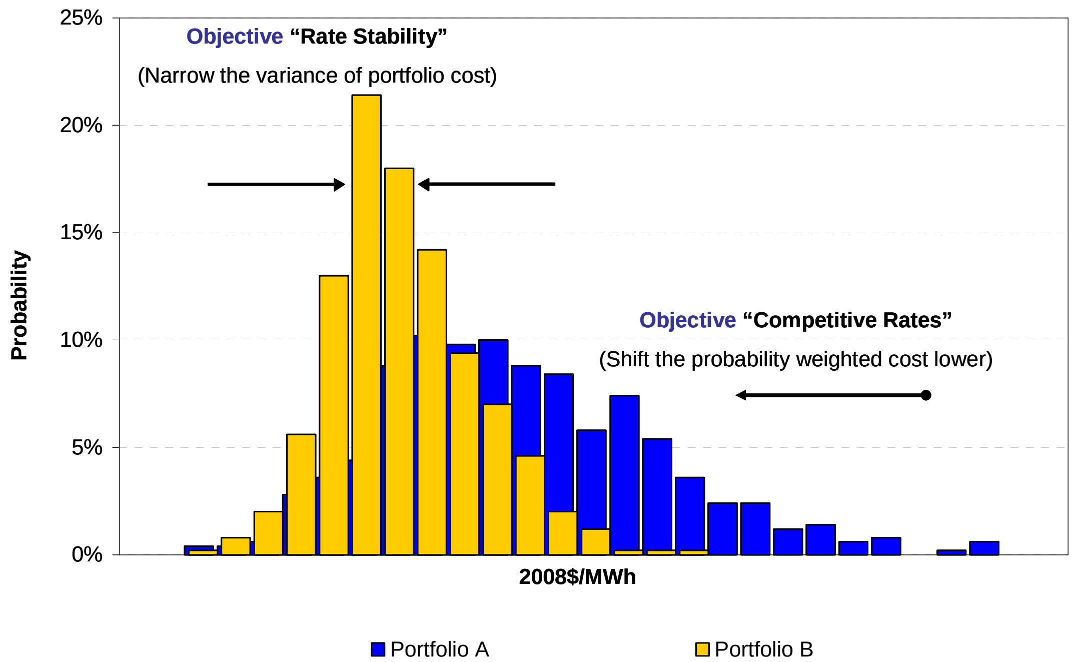
The quantification of risks within the Phase II analysis was performed first through stochastic analysis. This analysis quantified distributions around the total costs of each of the portfolios. Key result metrics included the net present value of portfolio costs (computed as a levelized annuity price per MWh) and the width of the distribution (the standard deviation). Additional scenario analyses were then performed to measure the exposure of each of the portfolios to other risk factors, such as major regulatory changes or uncertainties around particular aspects or components of the portfolio. Where appropriate, the impact of these scenarios on the total portfolio costs was measured as an increment to the mean of the portfolio distributions.

Cost Distributions

Whereas traditional "base case" approaches quantify the effects of one set of fuel price, load, and capital cost assumptions, the stochastic simulation of these variables results in distributions around the "reference case." Portfolio cost distributions convey information regarding the general cost level of different portfolios, but also provide valuable insight into the risks associated with each portfolio.

Exhibit 28 presents two illustrative portfolio distributions. In the example, Portfolio B's distribution is centered further to the left. This implies that the mean of the costs for Portfolio B are lower than the mean of the costs for Portfolio A. As shown, Portfolio B also has a tighter distribution than Portfolio A. This means that there is more risk associated with Portfolio A since the uncertainty around its costs is bigger.

Exhibit 28: Portfolio Cost Distributions



Source: Pace

As the different portfolio distributions were evaluated throughout this analysis, portfolio costs were compared based on the mean of the distribution; the market risks associated with the portfolio were evaluated based on the width of the distribution, which is a measure of how costly the portfolio can get (enumerated as the standard deviation of the distribution).

Key Findings

The key findings of the risk analysis are:

- The optimal baseload percentage mix is between 50 and 60 percent (125 to 150 MW), maintaining some ability to sell excess power;
- The expansion of GMEC is warranted, as is additional natural gas-fired peaking capacity;
- The economic addition of wind generation in or around 2024 is favorable, but only depending on resale provisions for the baseload contract;
- Solar additions are not cost-effective incremental additions to the portfolio.

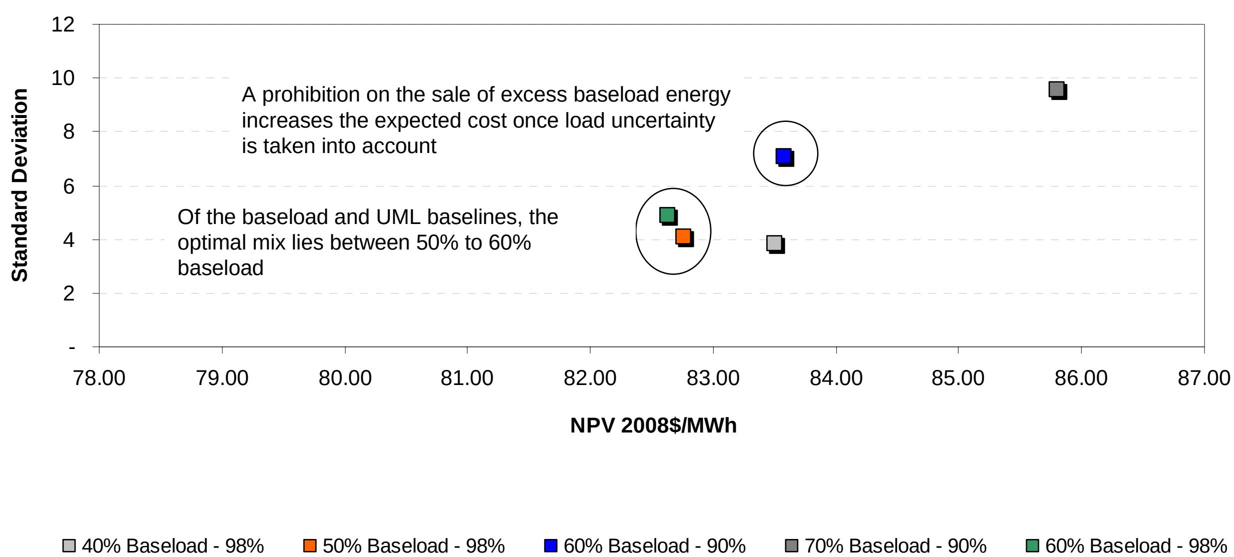
- The impact of higher carbon costs raises the costs of all portfolios substantially, but doesn't change the optimal portfolio combination. In fact, due to less baseload, the 50 percent portfolio is less exposed to higher CO_2 prices than those portfolios with 60 percent baseload.

Baseload-UML Mix and Sales Restrictions

The risk analysis indicates that the optimal baseload percentage mix is between 50 and 60 percent, as long as some ability to sell excess power is retained. Exhibit 29 displays the expected costs and standard deviation of the targeted range of baseload and UML mixes. The horizontal axis displays the net present value of total portfolio costs from 2015 to 2030 in 2008$/MWh, and the vertical axis shows the standard deviation, the key measure of risk.

As can be seen, the least cost portfolio option (the one furthest to the left in Exhibit 29) has a baseload percentage at about 60 percent. However, the 50 percent portfolio option has only a slightly higher expected cost (slightly to the right) with a slightly lower risk profile (slightly lower). Lower baseload percentages (40%) are clearly higher costs. The prohibition to sell back any excess energy assumed for the higher baseload percentages result in both higher expected costs and higher risk.

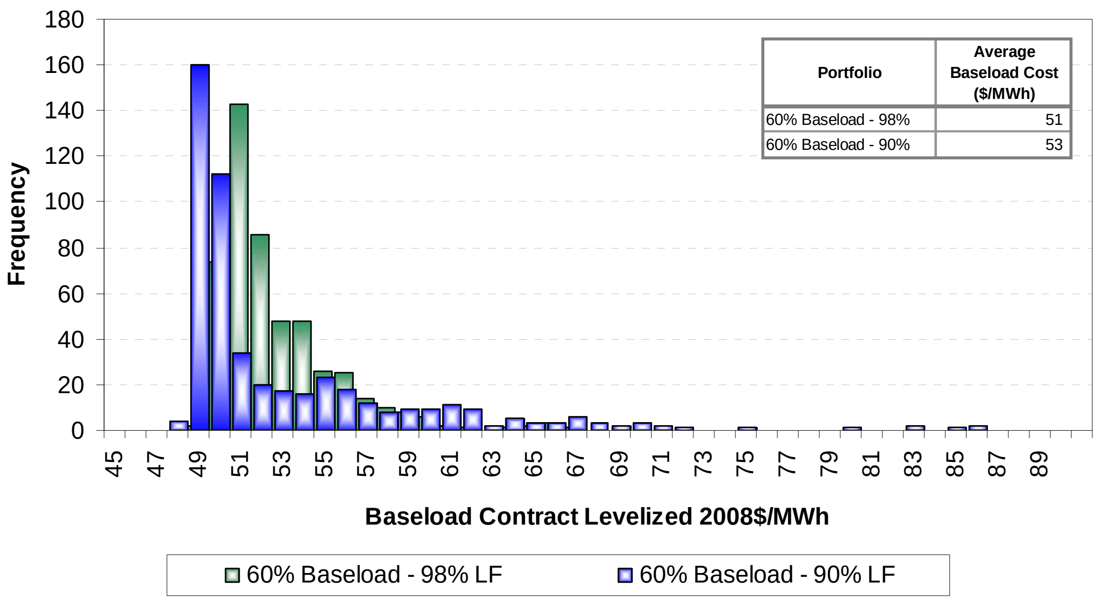
Exhibit 29: Cost vs. Risk for Different Baseload-UML Portfolio Options



Source: Pace

Increasing the baseload percentage increases portfolio risk for two primary reasons. First of all, increasing baseload generation results in more excess supply for MWE under low-load conditions. This excess supply must be sold for a loss or not sold at all. As load uncertainty is included in the Phase II risk analysis, Pace has found that larger amounts of baseload capacity put the portfolio at greater risk of having excess energy that must be sold at a discount or lost completely. Therefore, the inability to resell any excess baseload power can result in higher cost, if load growth is lower than expected. This is the case for the 60 percent baseload case with a prohibition on sales and a 90 percent load factor requirement, which in Exhibit 29 is to the right (higher cost) and above (higher risk) the 60 percent baseload case with resales and a 98 percent load factor requirement. This increase in the width of the distribution when resales are prohibited is shown in Exhibit 30.

Exhibit 30: Baseload Energy Cost Distributions for 60% Baseload with and without Resale



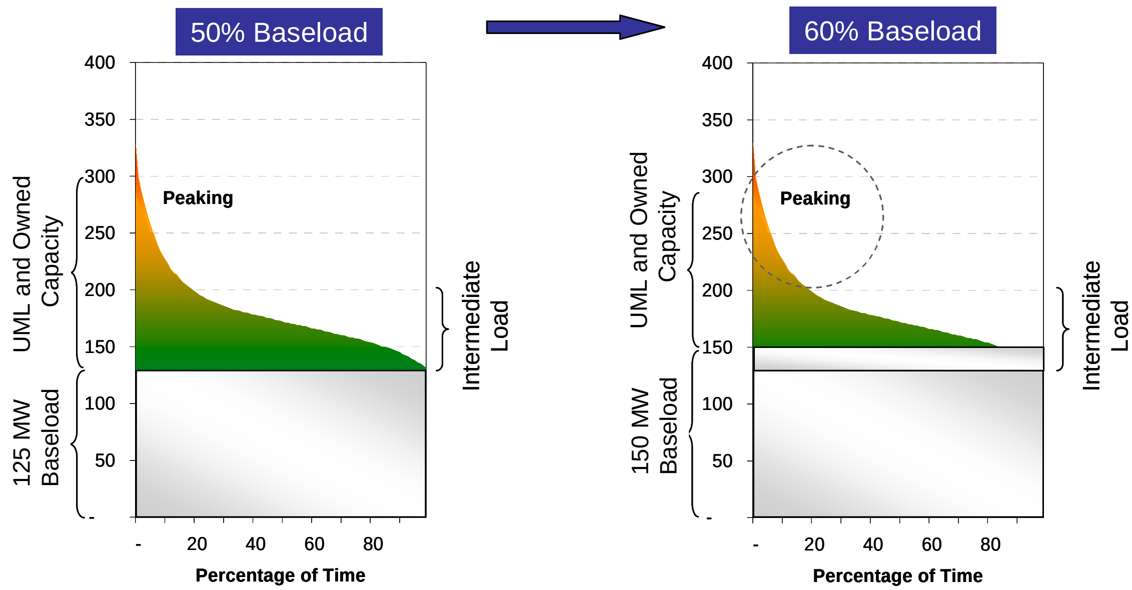
Source: Pace

Second, portfolios with additional baseload capacity are also more risky because they reduce the UML share. A reduction in the UML percentage effectively pushes the capacity mix of the UML contract towards a higher-cost and more volatile section of the counterparty's supply curve. Exhibit 31 illustrates the underlying drivers of the increase in UML energy cost volatility.

As an example, if 50 percent of the contracted capacity requirements for MWE are served with the UML contract (the other 50 percent with a baseload contract), MWE would likely use UML energy to serve intermediate and peaking load requirements. If the percentage of contracted baseload was increased, however, the UML contract would be used to serve less of the intermediate load requirements. In its place, the additional baseload energy would be used for some intermediate load hours. The remaining UML energy would, therefore, be composed of a larger percentage of peaking hours. Because peak energy prices are often more volatile, the risks associated with the UML contract are also greater, at least in regard to overall average cost, when it is relied upon only during peak periods. Exhibit 32 shows the distribution of the resulting $/MWh of the contracted UML energy for the 50 percent and 60 percent baseload portfolios.

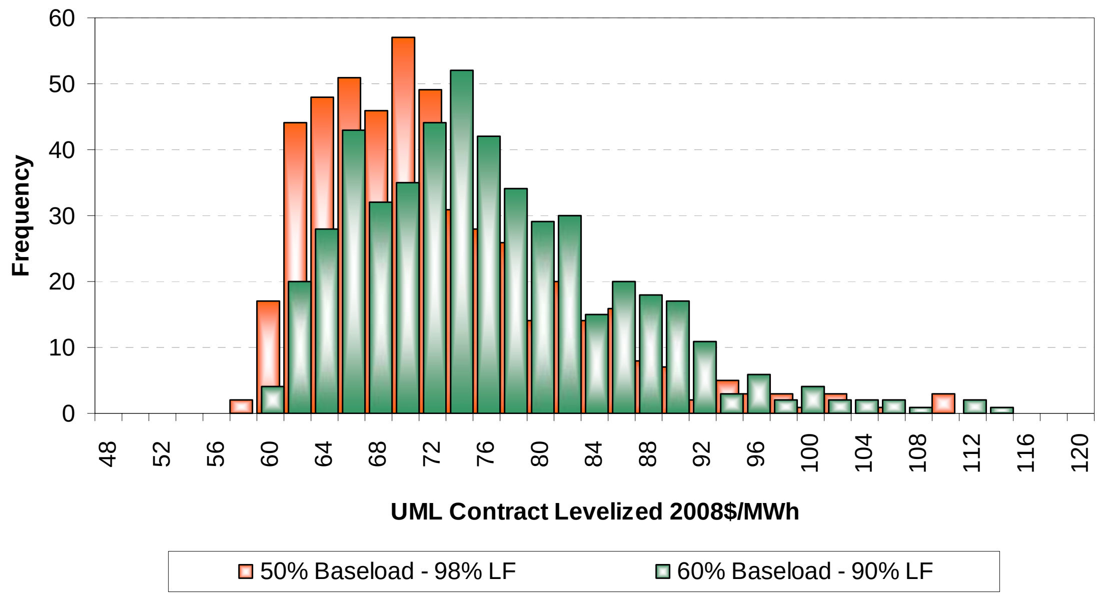
Exhibit 31: Underlying Drivers of the Increase in Risk Associated with UML Energy

1. If the baseload contract is increased by 25 MW, the UML contract is reduced by 25 MW
2. More of the intermediate load hours that were before supplied by the UML contract will now be supplied by the baseload contract
3. This results in the use of the UML contract for a larger percentage of peaking hours and a smaller percentage of intermediate load hours
4. Because peaking energy is more volatile, and this now constitutes a bigger percentage of the UML energy, this increases the risk associated with the UML contract



Source: Pace

Exhibit 32: UML Energy Cost Distributions for 50 and 60 Percent Baseload Portfolios



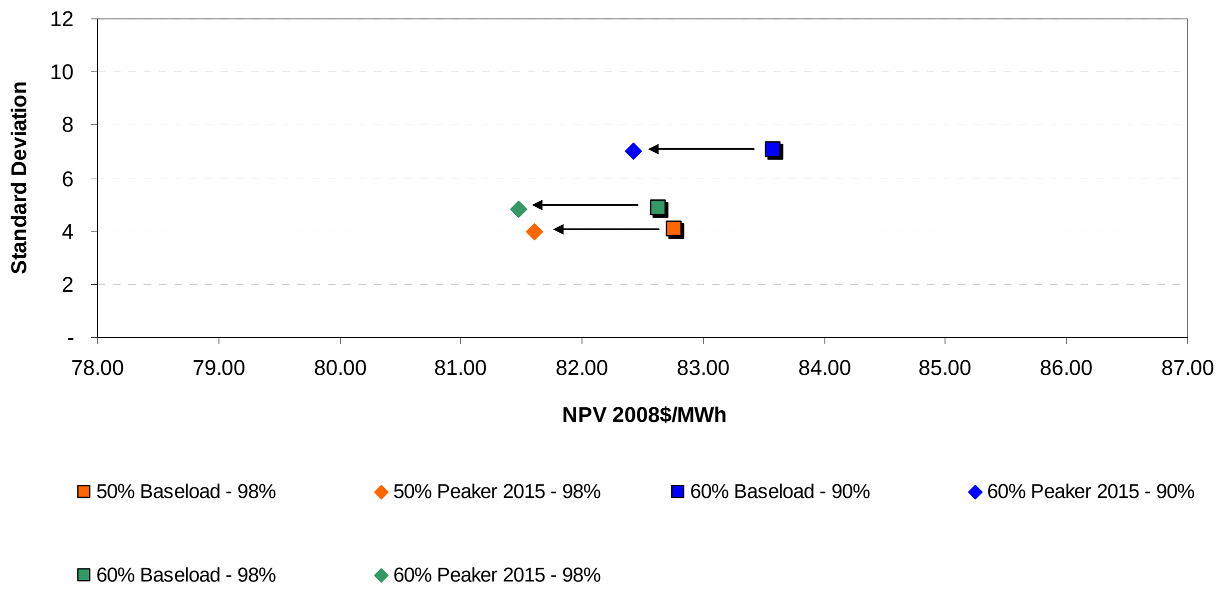
Source: Pace

Natural Gas Peaking Expansion

The expansion of GMEC is warranted, as is additional natural gas-fired peaking capacity. As shown in Exhibit 33, the expansion of GMEC reduces portfolio costs by just over $1/MWh on a levelized basis. It does this with no appreciable increase in risk. This is because additional owned peaking capacity reduces the portfolio's reliance on the UML contract during the most volatile peak periods, as well as the more stable intermediate times. Furthermore, capital cost uncertainty associated with new construction is offset by the market uncertainty from the UML that is avoided, as well as the avoided uncertainty around capacity charges in the UML contract.

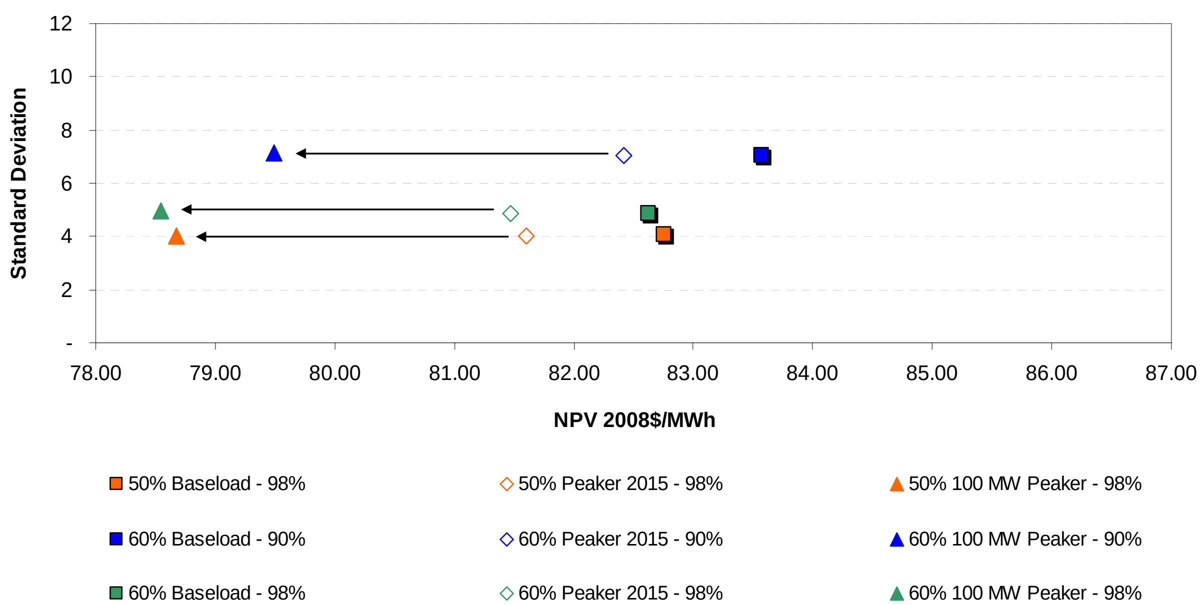
Additional natural gas peaking capacity beyond the GMEC expansion is more cost-effective than UML contract capacity. This is true with new capacity additions as early as 2015 and with total incremental additions beyond GMEC of 75 MW (a total of 100 MW of new gas-fired peaking capacity). GMEC-type generation is more efficient than the likely capacity available from system power at nearby interconnected utilities after they meet their own load. Exhibit 34 displays the cost and risk impact on the portfolios of adding a total of 100 MW of new peaking capacity to each of three baseload-UML combinations. The impact on the net present value of total portfolio costs is around $4/MWh when compared to the reference points.

Exhibit 33: Cost vs. Risk for Portfolios that Include GMEC Expansion



Source: Pace

Exhibit 34: Cost vs. Risk for Portfolios that Include Additional Peaker Expansion



Source: Pace

Demand Response Programs

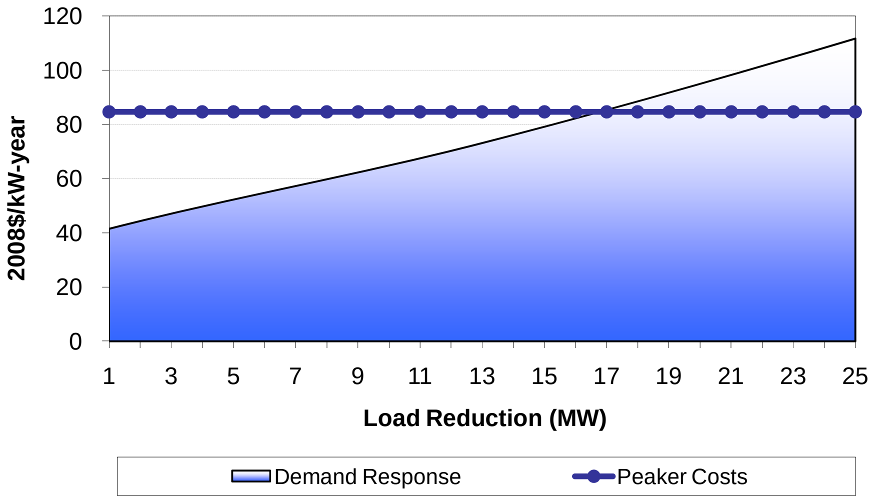
The successful implementation of DR programs can reduce a utility's need for peaking generation. To assess the cost-effectiveness of DR, it is pertinent to compare its levelized costs to the costs of a new peaking unit. Pace performed a high-level analysis of the effectiveness of DR programs to displace or delay some of the need for new peaking capacity. Given MWE's customer base and load profile for each customer class, Pace considered five types of DR programs in its analysis:

1. Agricultural Load Shedding
2. Thermostat Control – Residential
3. Thermostat Control – Small Commercial and Industrial
4. Direct Load Control/Advanced Metering Infrastructure ("AMI") – Residential
5. Direct Load Control/AMI – Small Commercial and Industrial

To estimate the costs and expected kW savings for each of these programs, Pace relied on publicly available information from several sources. The details of this analysis are shown in the confidential appendices to this report.

Exhibit 35 illustrates the costs associated with achieving different levels of load reduction compared to the costs of a new peaking plant. Under the simulated reference case conditions, the analysis indicates that roughly 16 MW of load reduction could be achieved at a cost lower than a new peaker built by MWE. This indicates that there is potential to further decrease utility costs by implementing some DR programs and delaying the need for new peaking capacity.

Exhibit 35: Levelized Cost Comparison of Demand Response vs. Peaking Capacity



Source: Pace

The composition of the cost-effective mix of DR programs (16 MW) is shown in Exhibit 36. In summary:

- The agricultural load shedding program accounts for roughly 8 MW of the mix

- An additional 8 MW of load reduction are the result of a combination of residential and small commercial and industrial thermostat control
- Direct load control and price response through AMI does not account for a significant amount of load reduction in a cost-effective mix

Exhibit 36: Composition of 16 MW of Cost-Effective Demand Response

Program	Customer Class	Eligible Customers	Per Customer Reduction	Per Customer Cost	Customer Participation Rate	Total Utility Savings	Cost to Utility		
Name	*Name*	*#*	*kW*	*Total $*	*%*	*MW*	*$*	*$/kW*	*$/kW-year (10 years)*
Agricultural Load Shedding Program	Irrigation	680	22.4	6,080	66%	8.0	4,025,405	501	**74**
Thermostat Control - Residential	Res	29,719	0.5	515	26%	3.8	2,435,192	641	**94**
Thermostat Control - Small C/I	SmCI	12,423	0.8	545	42%	4.1	2,429,569	595	**87**
Direct Load Control/AMI - Residential	Res	29,719	0.3	370	0%	0.0	82	923	**136**
Direct Load Control/AMI - Small C/I	SmCI	12,423	0.4	400	2%	0.1	71,721	888	**130**

Source: Pace

Due to MWE's customer composition, an irrigation load shedding program is expected to yield the most cost-effective demand reductions. Consistent with these results, MWE is moving forward with a pilot load shedding irrigation program. The program will be rolled out in 2009 and should constitute a good basis for the further evaluation of the cost effectiveness of other DR programs.

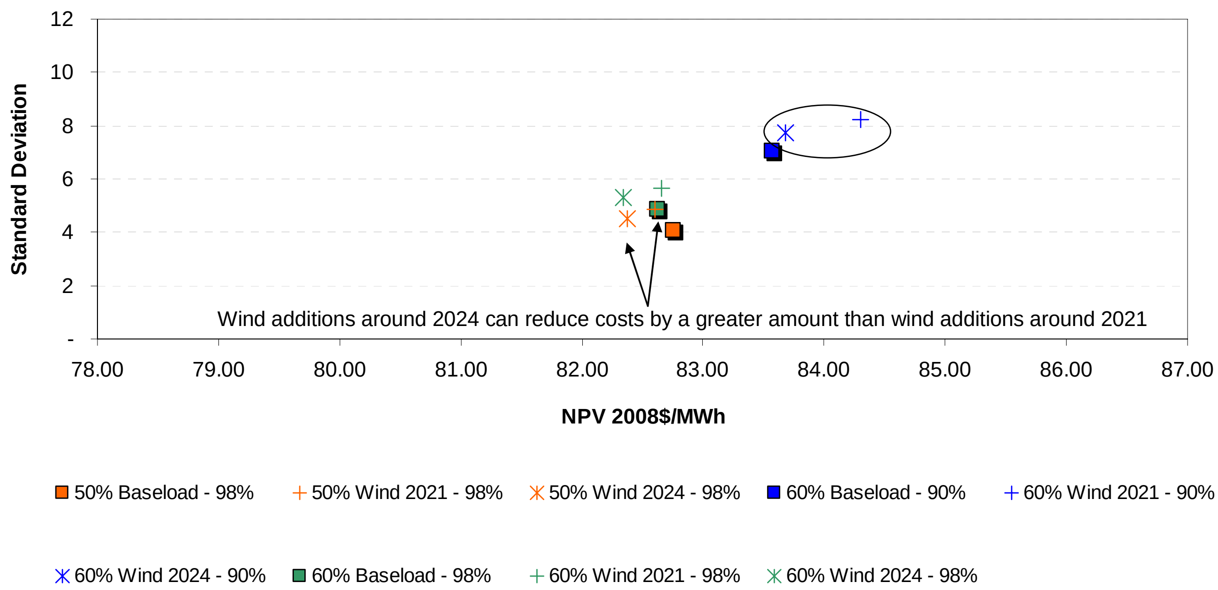
The amount of load reduction achieved through DR programs does not invalidate the results of the screening and risk analysis in any way. It can, however, delay the need for new peaking capacity, result in a smaller-size peaker, or replace existing generating resources that may be retired.

Wind Expansion

The economic addition of wind generation in or around 2024 is favorable, depending on resale provisions for the baseload contract. Adding wind capacity in 2024 reduces portfolio costs with an insignificant increase in risk relative to a coal-based baseload PPA. Adding wind in 2021 exhibits both higher expected cost and risk to adding wind in 2024. This is due to the fact that the cost-effectiveness of wind is dependent on increasing natural gas and carbon compliance costs. The one exception to this result is under conditions where resales are not available. This is because a greater percentage of coal baseload can result in too much excess energy when wind is blowing and under conditions where demand levels are low. Without the ability to sell back excess energy, additional wind capacity can increase the risk and associated cost of wind portfolios.

Exhibit 37 summarizes these results by showing the comparative cost outcomes of adding wind in 2024 versus 2021 for each of three Baseload-UML contract combinations. In addition, as can be seen in the case with 90% load factor and no ability to resell power, the addition of extra wind capacity can actually lead to increased costs and significantly higher risks.

Exhibit 37: Cost vs. Risk for Portfolios that Include Wind Additions

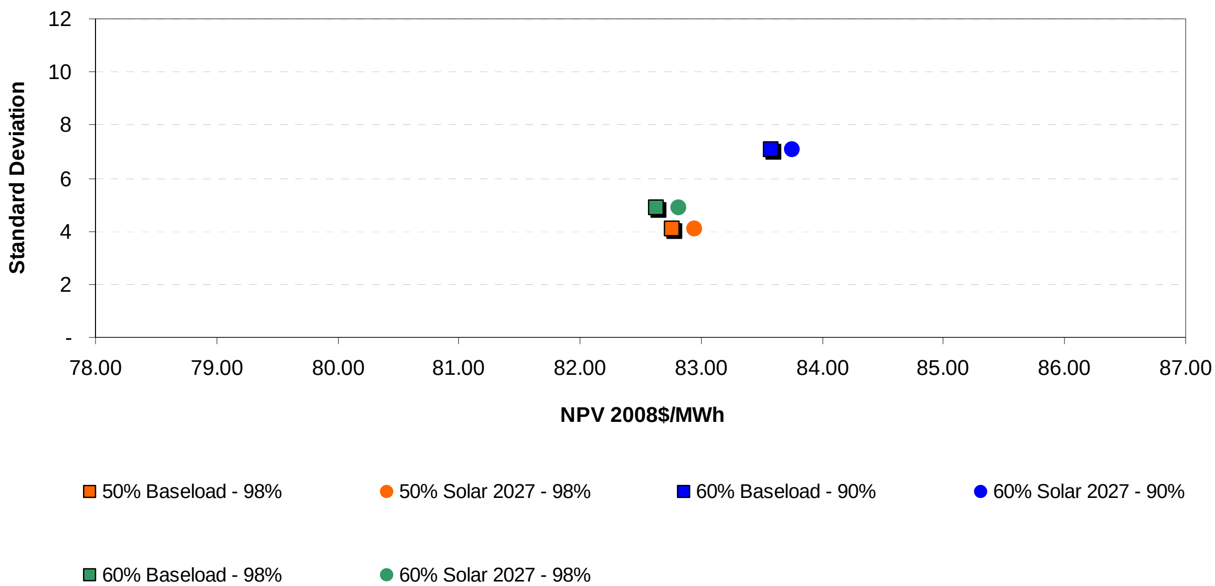


Source: Pace

Solar Expansion

Solar additions are not cost-effective incremental additions to the portfolio. Adding solar capacity, even in the out years of the Study Period, does not serve to lower the expected value of portfolio costs. Although solar generation could provide a hedge against uncertain natural gas prices and UML contract costs and although the capital costs associated with solar installations are expected to decline over time, the relatively high costs and associated uncertainty serve to make portfolios with solar additions more costly. Exhibit 38 shows that solar additions serve to increase portfolio costs under each of the baseload-UML capacity mix scenarios.

Exhibit 38: Cost vs. Risk for Portfolios that Include Solar Additions



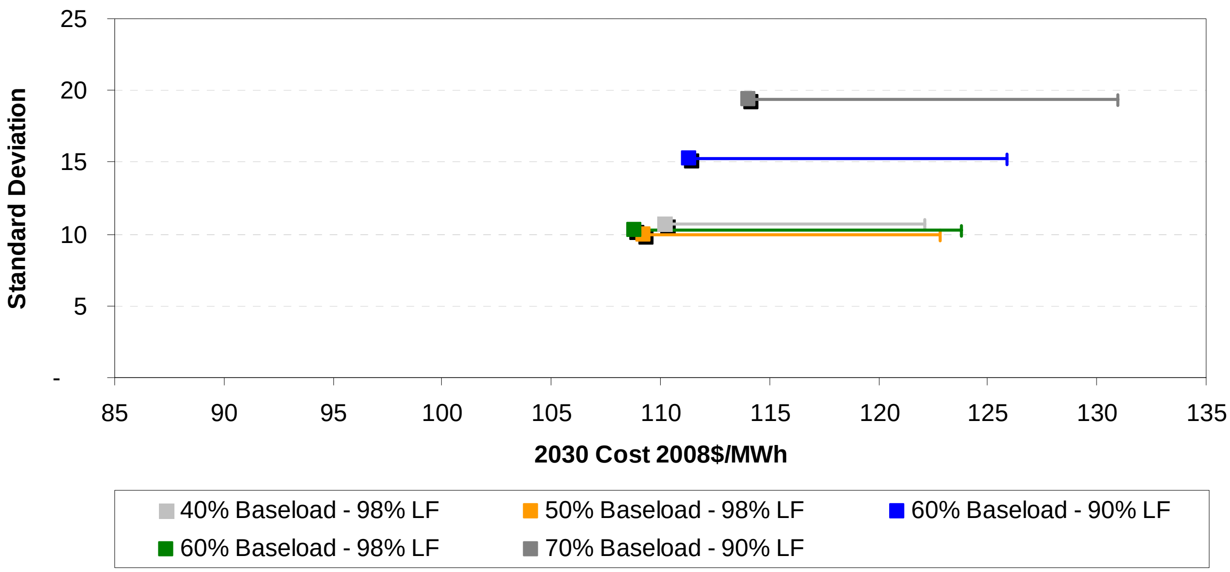
Source: Pace

High CO_2 Scenario Analyses Results

As mentioned before, Pace evaluated the exposure of all portfolios to risks associated with several quantum scenarios. The impact of higher carbon costs raises the costs of all portfolios substantially, but doesn't change the optimal portfolio combination. In fact, due to less baseload, the 50 percent portfolio is less exposed to higher CO_2 prices than those portfolios with more baseload.

Exhibit 39 shows the impact on costs for each of the baseload-UML combinations under high CO_2 prices in the year 2030. The risks associated with high CO_2 prices are directly related to the amount of coal in the portfolio (the amount of baseload contract share). Portfolios that contain less coal-intensive baseload limit their exposure to high CO_2 prices, while portfolios that have more baseload coal face a more significant cost risk if CO_2 prices are higher than anticipated.

Exhibit 39: Impact of High CO_2 Scenario on Different Baseload Options



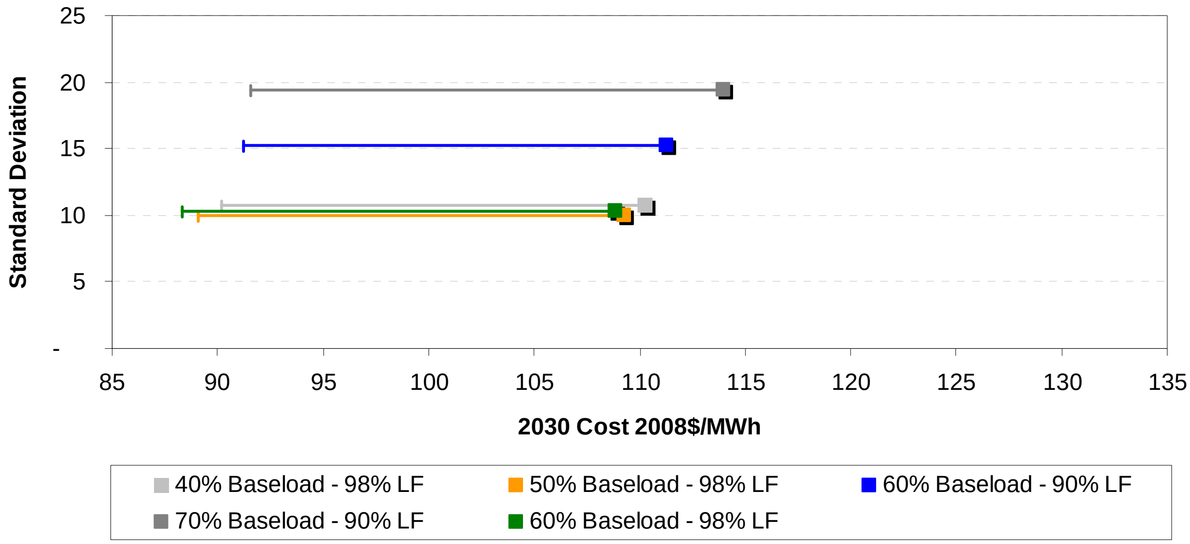
Source: Pace

Low CO_2 Scenario Analyses Results

The impact of lower carbon costs decreases the costs of all portfolios substantially, but, like the high CO_2 case, doesn't affect the optimal portfolio combination. Under lower CO_2 prices, the 60 percent portfolio is less exposed to higher CO_2 prices and is slightly preferable to the other options.

Exhibit 39 shows the impact on costs for each of the baseload-UML combinations under low CO_2 prices in the year 2030. As with the high CO_2 case, the risks associated with high CO_2 prices are directly related to the amount of coal in the portfolio. Portfolios that contain more coal-intensive baseload will benefit more from reduced CO_2 prices.

Exhibit 40: Impact of Low CO_2 Scenario on Different Baseload Options



Source: Pace

Summary and Conclusions

- The risk analysis confirms that a baseload contract share between 50 and 60 percent is the most cost-effective portfolio option for MWE. The analysis also indicates that there are some cost and risk tradeoffs between the 50 percent and 60 percent baseload options, especially with regard to the ability to resell excess energy. The risk analysis concludes that the more cost-effective and less risky baseload contracts contain provisions to resell energy, even at the expense of a higher load factor.

- The addition of around 100 MW of peaking capacity results in cost savings from both the 50 percent and the 60 percent baselines.

  - Effective DR programs can further reduce these costs by displacing or delaying the need for some incremental peaking capacity.

- As an increment to required renewable capacity expansion, the addition of wind during the last few years of the Study Period can also reduce costs when compared to the baseline, but only if sales restrictions are not prohibitive.

- High CO_2 costs expose 60 percent baseload portfolios to slightly higher cost outcomes than portfolios with only 50 percent baseload.

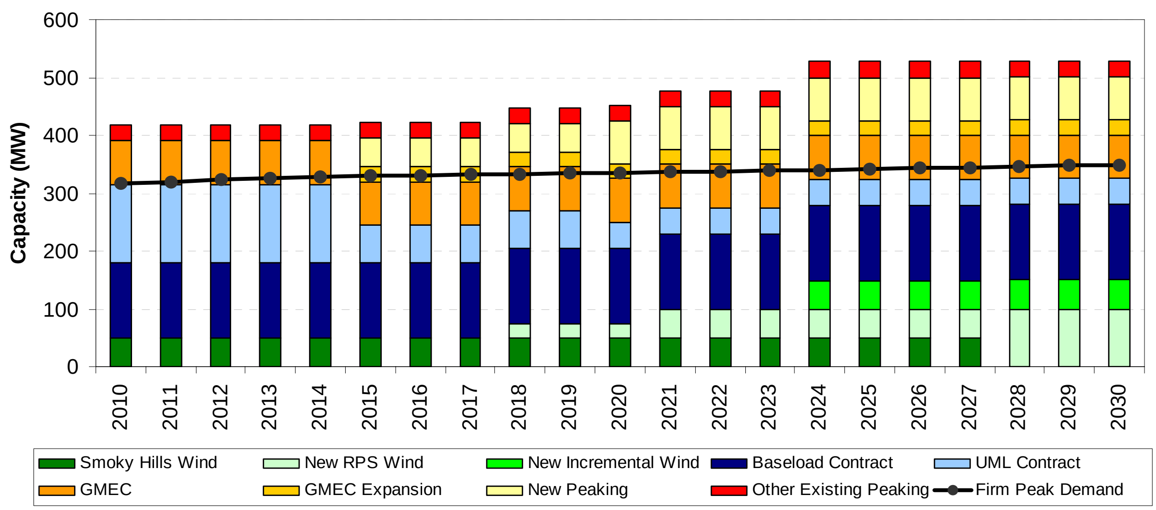
- In all cases examined, the increase in risk associated with procuring a higher percentage of baseload capacity outweighs any potential cost savings of going to 60% baseload. Based on the risk analysis, a 50% baseload option with peaking capacity additions during the next few years and wind additions to meet RPS requirements and during the last few years of the Study Period is the preferred portfolio.

ACTION PLAN

Exhibit 41 summarizes the recommended portfolio action plan by time period as well as the projected annual capacity mix of the entire portfolio over time. The table indicates timing of incremental capacity or contract additions with contract length, where appropriate. This recommended resource plan maintains a significant measure of flexibility to adapt to market conditions and future regulations. Exhibit 42 illustrates the wind generation from the recommended plan against the simulated RPS compliance targets for MWE.

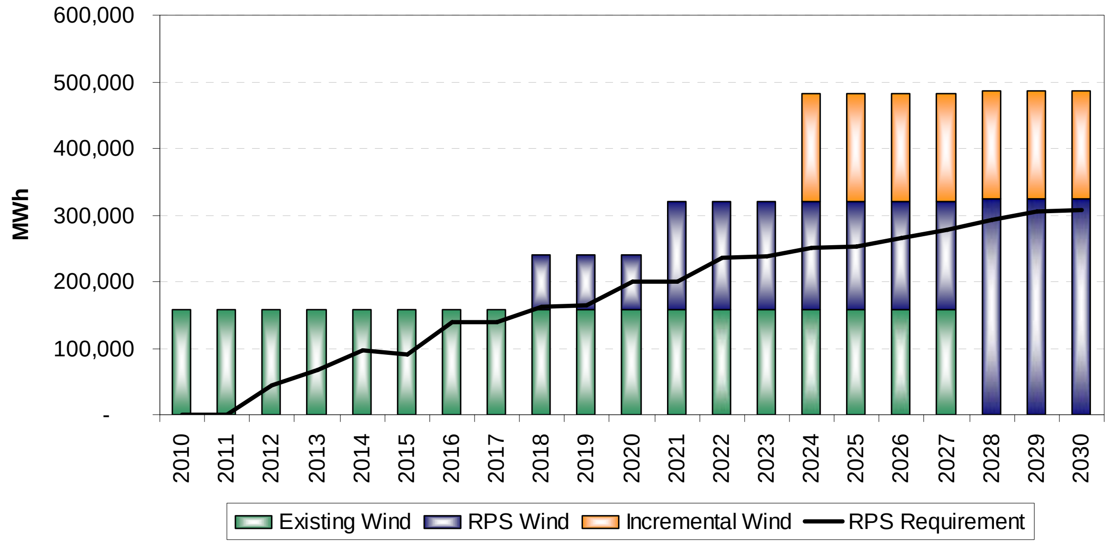
Exhibit 41: Recommended Portfolio Action Plan and Resulting Capacity Mix

Portfolio Item	2010-2014	2015-2019	2020-2024	2025-2030
Baseload Contract	130 (20 years)			
UML	135 (5 years)	65 (5 years)	45 (10 years)	
GMEC Expansion		25		
New Peaking		50	25	
RPS Wind		25	25	50
Incremental Wind			50	



Source: Pace

Exhibit 42: RPS Compliance vs. Targets



Source: Pace

The recommended plan includes the following key elements, which will require MWE to take specific actions to begin reconfiguring its existing portfolio over the next several years:

- **Negotiate PPAs:** By the beginning of 2010, finalize negotiations of new PPAs for baseload and UML type contracts with the preferred supplier. Due to the attractiveness of owned peaking resources, UML contracts should be negotiated with the shortest lengths possible. The baseload contract should be negotiated for at least fifteen years.
- **New Local Gas-Fired Generation:** By approximately 2015, expand GMEC and build 50 MW of new peaking capacity. Build an additional 25 MW by approximately 2020. Lead times will require that approvals, permits, and construction schedules be in development in 2011 for the early expansions. Successful implementation of DR programs can result in less or delayed need for new peaking capacity.
- **Demand Response Programs:** There is evidence that some amount of load reduction can be achieved cost-effectively. Pace recommends pursuing the implementation of the agricultural load shedding pilot program and interruptible rates.
- **Renewable Energy:** Beyond 2015, increase the proportion of MWE's energy mix provided by renewable energy sources to meet likely RPS requirements. By 2021, a total of 50 MW of new wind is needed. In 2024 and beyond, add economic additional wind capacity on the order of 50 MW and replace the Smoky Hills contract when it expires. Throughout the planning horizon, continue to track the cost and efficiencies of wind and solar and take advantage of economic opportunities as they arise.
- **GHG Emissions Reductions:** Protect MWE as much as possible against imprudent risk management of carbon and fuel cost exposures. Prudent management language should be included in new contractual arrangements.