Hoosier Energy
2023 Integrated Resource Plan
Volume II: Technical Appendices

April 2024

Hoosier Energy – Technical Appendices to 2023 Integrated Resource Plan

- Appendix A – Integrated Resource Plan Executive Summary
- Appendix B – Quanta Report – System Reliability Assessment of Hoosier Energy's 2023 IRP Portfolios

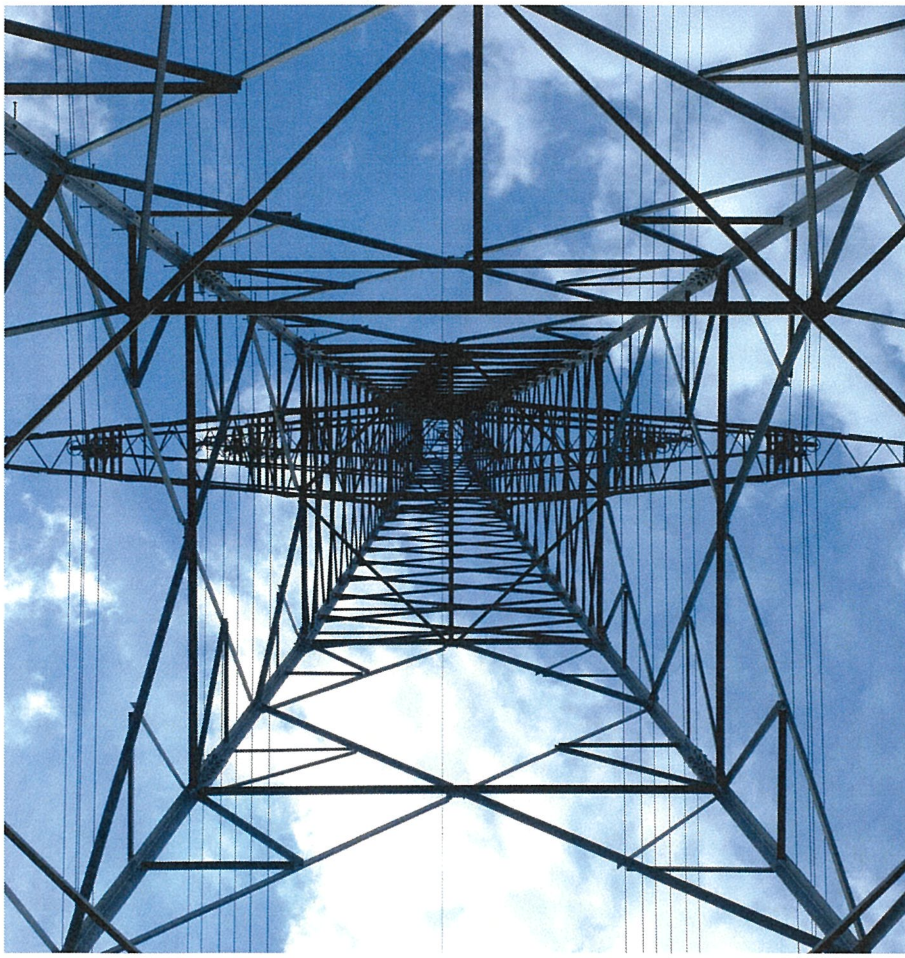
Appendix A

Integrated Resource Plan Executive Summary

HOOSIERENERGY

2023 Integrated Resource Plan

Executive Summary



Contents

What is Resource Planning?

Key Features

The resource planning process projects future consumer needs and comprehensively evaluates options for meeting those needs.

Resource plan inputs include:

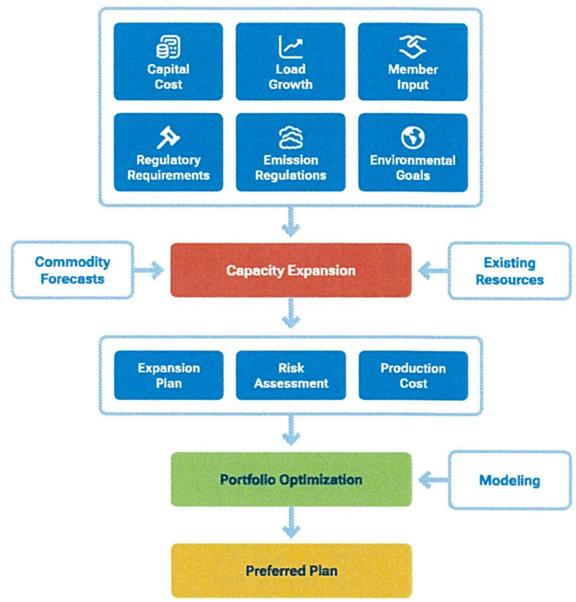
- Energy, peak demand and customer forecasts
- Resource strategies and regulatory policies
- Cost estimates and availability for current and future resources including capital, fixed and variable operating and maintenance costs
- Market projections for commodities

Risk Analysis

Inputs for the resource planning process are not absolute. Variables are stressed to understand the implications and interaction of inputs and impacts on costs and rates.

Uncertain Future

Resource plans will change over time. Course adjustments will reflect input from members and regulators, changes in growth patterns and financial considerations.



Power Network

Peak Demand

Member peak demand is projected to increase 10% by 2043.

2023	1,585 MW
2043	1,738 MW

Energy Requirements

Member energy needs are projected to increase 11% by 2043.

2023	8,400,000 MWh
2043	9,300,000 MWh

Number of Meters

The number of meters are expected to increase 8% by 2043.

2023	314,000
2043	338,000

4,100

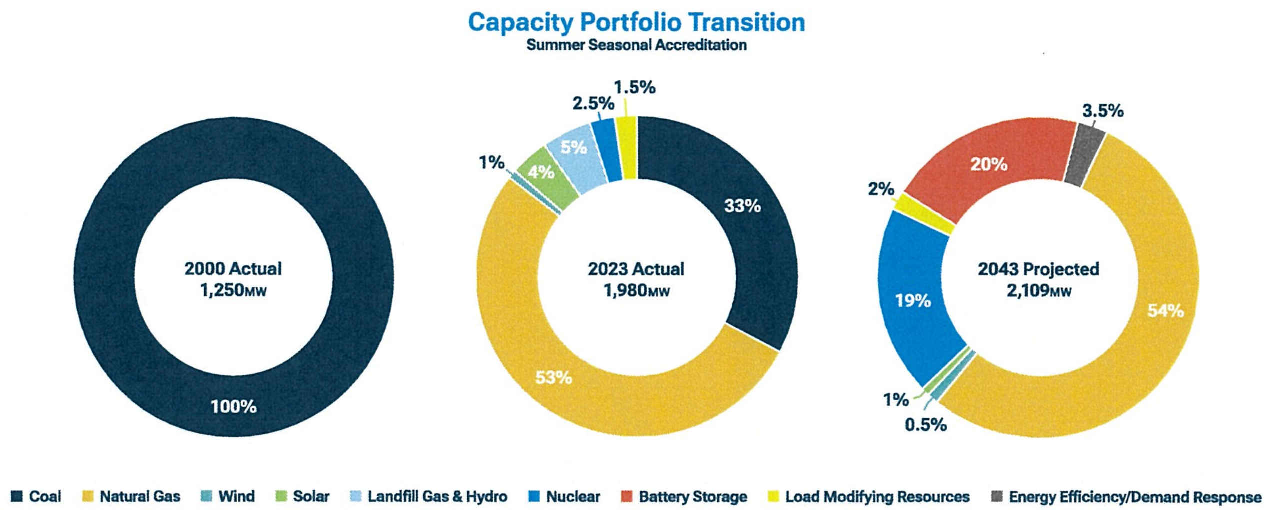
The estimated count of residential consumers having a plug-in hybrid or electric vehicle is 4,100. 8% of the surveyed residential consumers intend to acquire this particular type of car during the next 5 years.

5,600

There are 5,600 residential consumers who have renewable generation. Within the next 5 years, around 8% of residential users intend to implement renewable generation.

1.8%

The industrial energy sector is now having the highest energy growth rate among all energy sectors, with a compound annual growth rate of 1.8%.



Meeting Member Needs

Changes from 2020 to 2023

- Increased portfolio size (in MW) approximately 11% between 2020 and 2023.
- Added 200 MW of solar to the portfolio in 2022 via the Riverstart Solar project.
- Diversified counterparties from four in 2020 to 10 in 2023.
- Signed agreements to participate in the Palisades Nuclear re-powering.
- Added natural gas resources to lessen coal dependency.
- Added purchased power agreements (PPAs) to shift operating risk.
- Board decided in Jan. 2020 to pursue a more diverse resource mix, which included stepping away from Merom ownership.
- Board approved ownership transfer of the Merom plant to Hallador Energy in 2022.

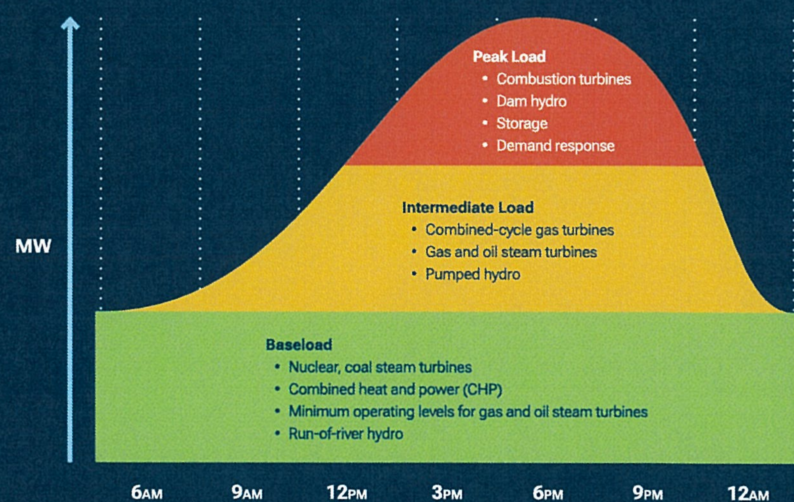
Expected changes from 2023 to 2043

- Replacement resources are expected to include a combination of natural gas, nuclear, wind, solar, and battery storage, both owned and purchased.
- Adapt to MISO's evolving reliability regulations by prioritizing stable, firm resources in order to meet load requirements during periods of high risk.
- Mitigate environmental regulatory risk by diversifying resources to include wind, solar and battery storage.
- Enhance risk and opportunity analysis to understand and mitigate vulnerabilities without compromising possibility.

Intermediate Load

Intermediate load represents electricity demand that falls between base load and peak load levels. While base load denotes the minimum demand that remains constant over time, typically occurring during periods of low consumption, and peak load refers to maximum demand experienced during high-consumption periods, intermediate load occurs during moderate demand times, such as weekdays when commercial and industrial activities are ongoing but residential usage is not at its peak.

Power plants catering to intermediate load must be flexible to adjust output quickly, such as natural gas-fired plants, combined cycle plants and certain renewable sources like hydroelectric or geothermal plants. Managing intermediate load efficiently ensures grid stability, reliability and optimal utilization of electricity generation and distribution systems, preventing shortages or excess capacity while supporting consistent delivery of electricity to consumers.



Available Resources

Natural Gas Combined Cycle (NGCC)

NGCCs provide both capacity and energy for extended periods of the day. The Holland plant, which is a 613 MW plant jointly owned with Wabash Valley Power Alliance, is an example within Hoosier's resource mix. Holland is an important component of the portfolio and has an excellent operating history.

Combustion Turbines (CTs)

CTs are usually natural gas-fired and sometimes have fuel-oil backup. CTs are generally quick start and can provide energy on short notice. CTs are designed to operate during peak demand periods but are generally available all hours of the year except during planned maintenance outages. Lawrence and Worthington generating stations are both examples of this technology within Hoosier's resource mix.

Wind

Federal production and investment tax credits have made wind resources economically appealing for energy portfolio diversification. Despite intermittent operation and lower capacity value during peak periods, wind resources, accounting for 15% of nameplate capacity in MISO's assessment, may require additional resources for planning reserve fulfillment. Hoosier Energy currently purchases 100 MW of wind through two separate PPAs and anticipates future additions based on Integrated Resource Plan projections.

Solar

Tax incentives, public policy requirements and growing consumer support have driven widespread solar project construction nationwide. Hoosier Energy's commitment to renewables is evident by the recent addition of 200 MW of solar generation with the Riverstart Solar PPA in 2022. This expansion aims to efficiently meet member load while signaling a shift toward cost-effective, reliable and sustainable energy sources, reflecting a broader trend toward a cleaner energy future.

Market Purchases

The forward power market remains a viable option for assistance in meeting member needs. Recent factors like low natural gas and renewables additions have reduced market power prices, challenging coal-fired generation. Continued downward pressure can provide opportunities to benefit from additional market participation, but it does not come without risk. Recent and expected future market volatility reinforce the importance of insuring long-term market exposure through strategic short-term hedging activity, owned assets, and purchased power agreements.

Other Generation

Other generation sources include nuclear, hydro, biomass and future technologies that have yet to mature. The current portfolio contains nuclear, hydro and biomass which all assist in the carbon neutrality transition. As technologies like battery storage continue to become more proven and cost-effective, Hoosier will be diligent in its analysis and understanding of these resources in order to capitalize on future opportunities.

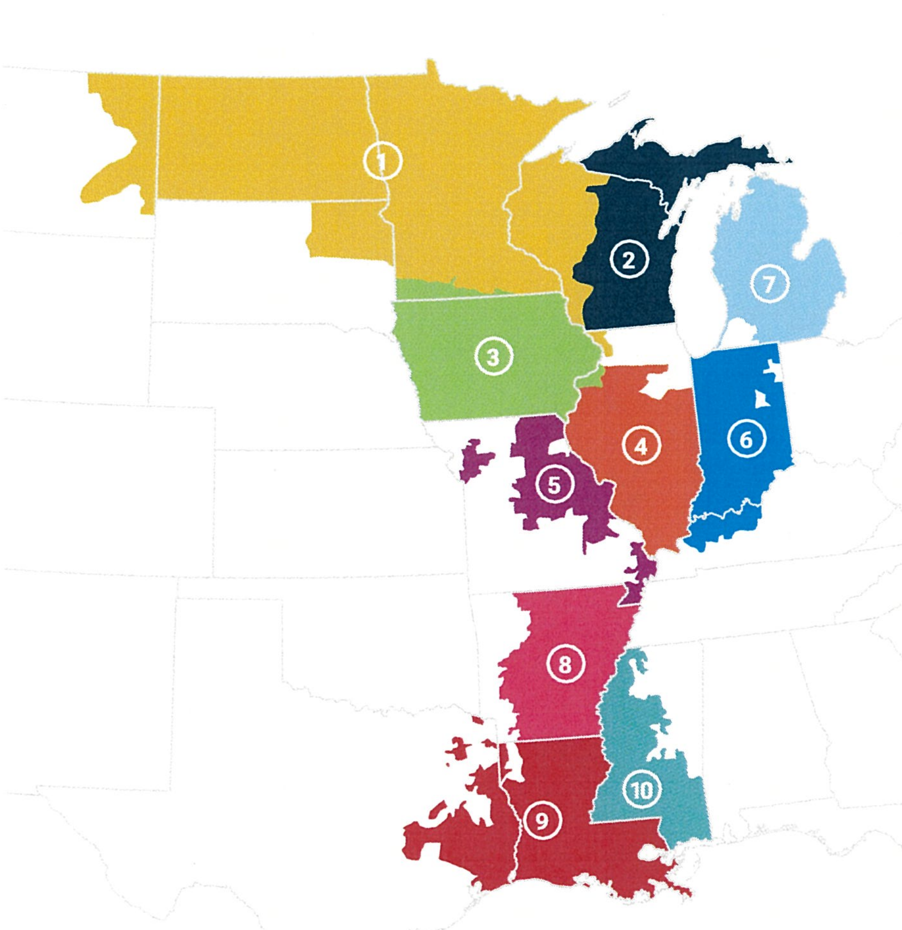
Demand Response

Demand response refers to requests for retail customers to reduce or interrupt load during times of peak usage and/or emergency events. Demand response requires coordination between Hoosier Energy, the member cooperative and the retail customer. Hoosier Energy recently implemented a demand response program consistent with MISO's rules. The program has successfully registered 10 customers with a total of roughly 30 MW of seasonal capacity.

Energy Efficiency

Consumers can help manage system demand through energy efficiency. When consumers use new strategies, products and technologies to reduce consumption, the effect can be equivalent to adding generation.

In 2022, annual savings from the demand-side management programs totaled 6,937 MWh. Summer demand was reduced by 3.14 MW and winter demand was reduced by 7.2 MW.



Key Risks

MISO Transitions

Hoosier Energy's service territory is part of the broader Midcontinent Independent System Operator (MISO) footprint. MISO is an independent not-for-profit, member-based organization responsible for reliably and cost-effectively managing power flows across the region. MISO's footprint includes 15 U.S. States and one Canadian province. It is one of the world's largest energy markets facilitating more than $40 billion in annual transactions.

The MISO footprint is divided into 10 zones for resource adequacy purposes. The purpose of the zones is to reflect transmission capability between the zones and ensure reliability during peak conditions. Hoosier Energy has load in two zones – Zone 6 (Indiana) and Zone 4 (Illinois) and resources in three zones – Zones 6, 4 and 7 (Michigan) with the addition of the Palisades PPA.

At peak times, Hoosier Energy's current forecast projects a capacity deficit in Zone 6 that is offset by capacity excess in other zones. ACES recently issued its annual Capacity Outlook which concludes that separation between the three zones is unlikely over the next few years. One of the goals of MISO's efforts to build additional transmission is to increase transfer capability between zones. Therefore, the price differential between the zones is expected to remain manageable. However, these projections may change especially if load growth is different than expected and/or due to unanticipated resource retirements.

The results of a recent MISO Survey indicate that, based on current assumptions, there are sufficient resources to serve expected load through the 2025/26 Planning Year. This means that short-term capacity should be available in the near term. However, the same report shows a projected mid- to long-term need for additional generation in order to meet demand across the footprint, all within the midst of baseload retirements and replacement generation with less reliability.

In addition to the seasonal construct that was approved by FERC in August of 2022 and implemented beginning in PY 2023-24, MISO continues to analyze changes to the capacity construct with the stated goal of further enhancing long-term resource adequacy. These changes include MISO's reliability-based demand curve (aka sloped demand curve) and changes to capacity accreditation methodology.

MISO has also developed a list of generation resource attributes that are deemed necessary to operate the system. These attributes include: availability, fuel assurance, ramp up capability, voltage stability, rapid startup, and long-duration energy at a high output. MISO's current timeline for implementation of these additional requirements is later this decade.

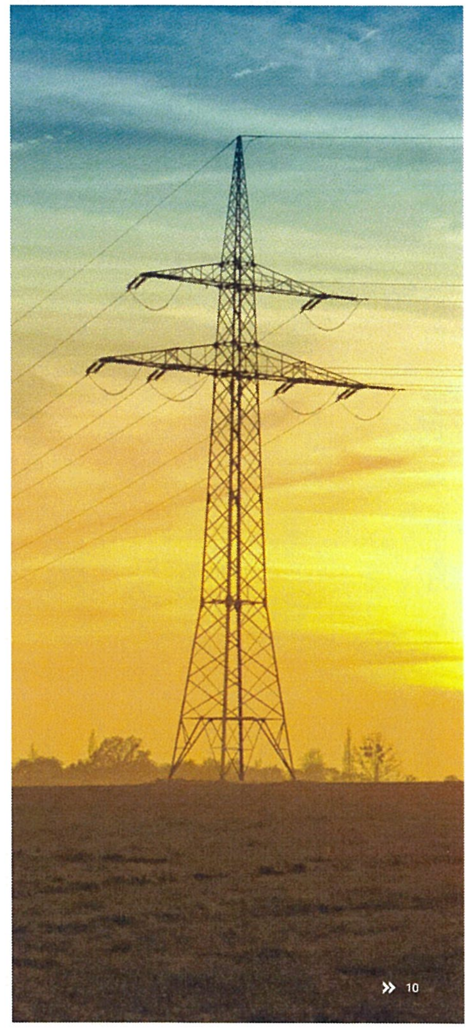
Market Volatility & Price Risk

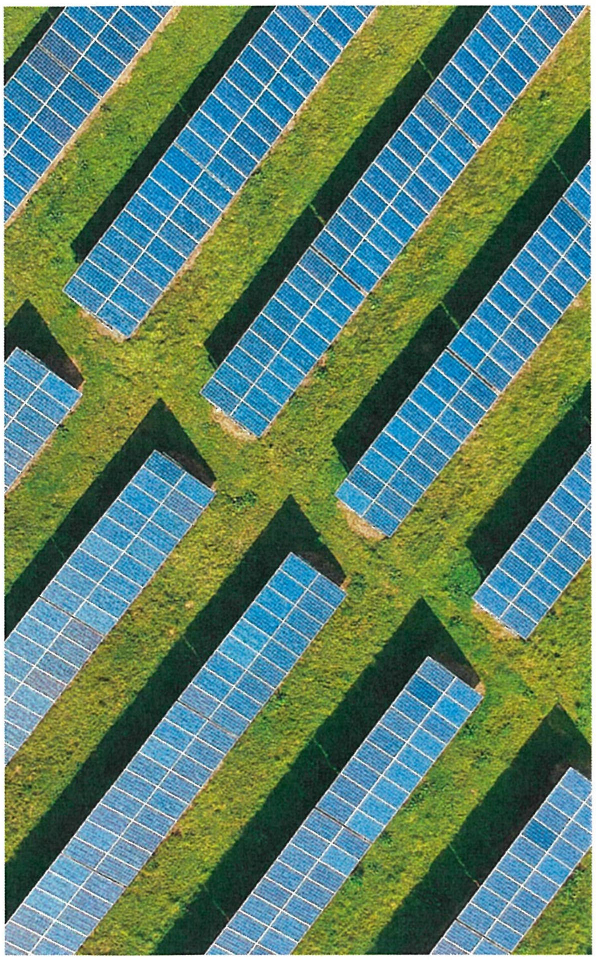
The resource planning process includes market price forecasts for power, natural gas, capacity and other commodities. These forecasts will change over time. Dramatic changes, such as price spikes from severe weather or an economic recession, will have material impact on expected outcomes.

While several market price scenarios are incorporated into the portfolio modeling to attempt to recognize a variety of market futures, it is impossible to capture all variability. Therefore, the Integrated Resource Plan should be viewed as a snapshot in time based upon current market forecasts and economic assumptions. The resources selected as part of the IRP process are highly dependent upon market price and will change over time, requiring additional hedging strategies such as managing market position and exposure, fixedprice energy contracts, a balance of owned assets, and a proactive formal hedging program.

Environmental Rules & Regulations

The EPA 111(b) and 111(d) rules pose significant challenges to a reliability portfolio. This ruling would require additional energy-producing resources in order to fill the gap from reduced natural gas generation. Other federal regulations such as a carbon tax could put additional cost pressure on a future resource strategy that does not add additional renewables and battery storage. This ruling also includes technology that needs additional time for development and infrastructure whose pricing is difficult to incorporate into modeling scenarios. Hoosier works with regulatory counsel and consultants within the cooperative network to navigate an accelerated regulatory environment with very few paths to success.





Transmission Price Constraints

Congestion is a significant cost risk. Congestion results from the locational marginal pricing (LMP) market methodology, which reflects the value of energy at specified locations throughout the electrical footprint. If the same priced electricity can reach all locations throughout the grid, then LMPs are the same. Transmission congestion, which can be caused by changes in consumer load requirements, generation outages, stress on the transmission system, etc., results when energy cannot flow either from or to other locations. This requires more expensive and/or more advantageously located electricity to flow in order to meet the demand. As a result, the LMP is higher in the constrained locations.

Hoosier Energy works with both ACES and outside consultants to analyze congestion between generation resources and load. This forward-looking analysis includes MISO-approved transmission expansion generation resource additions and retirements. In general, the analysis projects improved congestion impacts even though construction of new lines may impact dispatchability of existing generating units. Therefore, long-term congestion impacts appear to be a low risk at this time.

Counterparties & Resource Cost

Hoosier Energy members are well served by maintaining a mix of owned and purchased resources. Hoosier uses PPAs to acquire a mix of generation types including gas, nuclear, wind, solar and hydro. Future and current resource options include additional partnerships with existing or new counterparties to meet capacity and energy requirements. In addition to traditional PPAs, options may include shared ownership or Hoosier Energy taking a partial interest in generation resources owned by other companies. The increase and diversification of counterparties has opportunity but also includes risk with counterparty credit, reduction of negotiation position during times of scarcity or high pricing, and execution risk in an environment where new generation is increasingly more difficult to build.

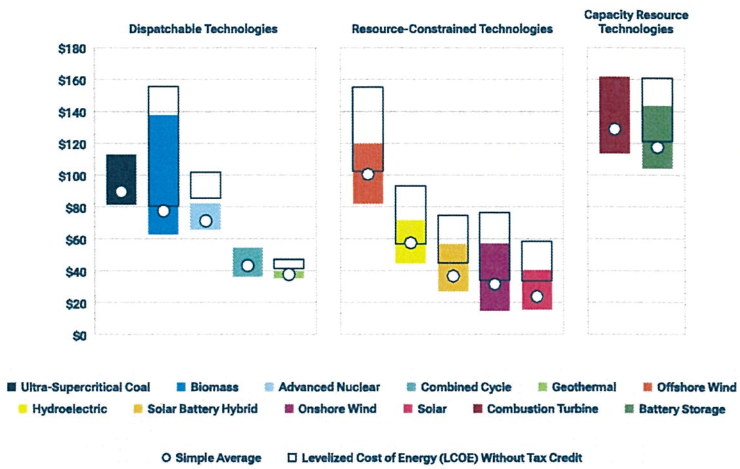
It has also been extremely difficult to bring new generation online due to supply chain obstructions, construction costs, significant ISO interconnection delays, and inflationary interest rates. These setbacks exist whether contracting or self-building and drive the cost of the resource (and therefore it's capacity and energy) higher, impacting overall power supply costs. Some of these costs can be avoided by contracting with existing resources, pursuing federal funding for resource development assistance, extending existing agreements, and participating more actively in the market. However, the risks of those efforts have to be measured and compared in order to make prudent resource decisions in an uncertain and volatile environment.

Energy Cost of New Generation

The chart on the the right reflects the U.S. Energy Information Administration's forecasted ranges of levelized cost of electricity for new generation resources entering service in 2028 (in 2022 dollars). This chart indicates that gas-fired, wind, solar and battery storage generation will be the most economic alternatives as portfolio additions. While wind and solar generation may be less expensive on a levelized cost basis than some alternatives, they are intermittent energy sources and only contribute a fraction of their nameplate capacity toward Hoosier's load obligation. The future development of economic utility-scale storage is expected to increase the value of intermittent resources.

Data source: U.S. Energy Information Administration, Annual Energy Outlook 2023

2022 Dollars Per Megawatt Hour (MWh)



Ownership vs. Purchased Power Agreements

Hoosier Energy members benefit from a balanced approach of owned assets and purchased power agreements (PPAs), which encompass coal, wind, solar, natural gas, nuclear, and hydro resources. PPAs enable risk mitigation, particularly operational risks, while leveraging counterparties' expertise to diversify the generation portfolio. Hoosier Energy strategically acquires a mix of solely and jointly owned facilities to further mitigate specific risks associated with owned generation resources. Future resource acquisitions will consider both ownership and PPA structures, with the preference determined by resource type, availability and counterparties' capabilities. Alongside traditional PPAs, alternatives such as shared ownership or partial interest in other companies' generation resources are under consideration, taking into account Hoosier Energy's advantageous capital structure, characterized by lower-cost debt and equity requirements. Ownership may prove economically favorable and suitable in appropriate circumstances.

2023 IRP Framework

Hoosier Energy used a portfolio matrix scenario design that evaluated seven hypothetical portfolio strategies. The seven strategies included:

- **Reference (Base) Case** – Currently projected commodity and resource costs (most likely future) with no new environmental regulation
- **EPA Rule** – Reference Case gas and power price capacity factor limitations for new and existing resources per EPA's CAA 111(b) and 111(d), as well as Reference Case technology costs
- **Carbon Tax** – Reference Case natural gas prices, higher power prices as a result of a federal carbon tax of $21/ton of CO2 starting in 2028 and increasing to $62/ton of CO2 by 2050, and Reference Case technology costs
- **EPA Rule + Carbon Tax** – Reference Case natural gas price capacity factor limitations plus a carbon tax which drives power prices higher, essentially combining the second and third scenarios, as well as Reference Case technology costs
- **Aggressive Environmental** – Low renewables and storage costs from additional federal incentives, high natural gas prices with the addition of upstream regulations, the full EPA Rule as well as a carbon tax driving power prices higher, and low technology costs
- **High-Price Environment** – High natural gas and power prices, and a high cost of replacement resources offset slightly by IRA benefits
- **Low-Price Environment** – Low cost of replacement resources, low natural gas and power prices, no environmental regulation, and low technology costs, basically a best-case-scenario

	Affordability & Stability			Environmental Sustainability				Risk & Opportunity					
	Reference Case 20-Year PVRR	10-Year Avg. Supply Cost	20-Year Avg. Supply Cost	Reference Case Cumulative Carbon Emissions	Avg. Carbon Emissions Across Scenarios	% Zero-Carbon Generation		Lowest PVRR Across Scenarios	Highest PVRR Across Scenarios	Avg. Market Interaction		Max % Generation from Single Resource Type	
	$MM	$/MWh	$/MWh	Tons	Tons	2030	2040	$MM	$MM	Purchases	Sales	2030	2040
Reference Case	$7,792	$64.29	$72.08	56,516,882	54,379,730	42%	45%	$6,896	$10,205	17%	5%	48%	37%
EPA Rule	$7,970	$65.94	$73.72	48,531,016	47,350,905	53%	59%	$7,150	$9,042	16%	9%	38%	35%
CO2 Tax	$7,925	$64.59	$73.29	46,729,713	44,838,013	46%	70%	$7,102	$9,218	16%	10%	43%	33%
EPA + CO2 Tax	$8,038	$66.25	$74.35	45,926,685	44,456,416	57%	70%	$7,241	$8,941	16%	11%	36%	33%
Aggressive Environmental	$8,082	$66.61	$74.76	46,218,628	44,617,299	56%	70%	$7,300	$8,897	15%	12%	37%	33%
High-Price	$8,122	$66.37	$75.11	47,305,607	46,708,489	57%	62%	$7,320	$9,255	16%	10%	36%	34%
Low-Price	$7,759	$64.18	$71.77	60,897,317	56,939,664	42%	40%	$6,838	$11,397	17%	5%	48%	48%

Scorecard Evaluation & Results Summary

In partnership with ACES, Hoosier Energy performed an extensive Scorecard Analysis of the various Portfolio Scenarios to select the Preferred Path with action steps.

In the Scorecard Analysis, Hoosier compared evaluations of the chosen hypothetical portfolios using three primary categories that address important risks and impacts for resource considerations: Affordability & Stability, Environmental Sustainability and Risk & Opportunity. These categories include several elements illustrated in the Five Pillars of Electric Service as defined by the State of Indiana's 21st Century Energy Policy Development Task Force of Affordability, Sustainability, Reliability, Resiliency and Stability. Although not included in the formal Scorecard, Hoosier also partnered with Quanta Technologies to asses the hypothetical portfolios' reliability properties, including during extreme weather events.

Affordability & Stability

The Scorecard Analysis revealed that, outside of an extremely low-price environment, the Reference Case provides the most affordable strategy for Hoosier Energy members. This is illustrated by the metric of 20-Year Present Value of Revenue Requirements (PVRR) which represents the total expected future revenue requirements, or revenue collections to cover costs, associated with a particular resource portfolio. Additional Affordability metrics include a 10-year and 20-year average of supply costs. These amounts are not finite or guaranteed, simply representations of the potential cost implications of future decision making.

Environmental Sustainability

Although the Scorecard Analysis did not demonstrate that the Reference Case results in the largest reduction of Cumulative Carbon Emissions, a balance must be struck in order to provide affordability and reliability to our members. Regulatory risk, which may eventually translate as cost risk, can be mitigated by investing in high-efficiency gas as an intermediate load resource replacement for coal, contracting for capacity-only products to create flexibility in order to diversify energy from non-carbon intensive generation, and beginning to layer in wind, solar and battery storage in the late 2020s/early 2030s.

Risk & Opportunity

The Scorecard Analysis also evaluated the portfolios for the risk and opportunity associated with cost exposure ranges in shifting environments, market interaction and exposure, and generation diversity. While the Reference Case had the lowest PVRR across all scenarios, it also had the widest range of costs if conditions significantly change from the 'most likely' conditions that were assumed for that capacity expansion. The Reference Case also had the largest concentration of a single resource type by 2030, but it evens out significantly in the next decade.

Reliability

Although reliability is not included on the Scorecard, it was important to understand the portfolios' potential impacts on operational reliability. While reliability and resource adequacy are not holistically the same, there is a significant impact between available and reliable generation and the ability to assess:

1. Ability to balance energy (ramping, dispatchability, flexibility)
2. Ability to control frequency (inertial response, primary response)
3. Ability to provide adequate short circuit strength to integrate inverter-based resources and mitigate their flicker-induced concerns
4. Ability to supply the dynamic reactive power required by loads to avoid motor stalling and ensure rapid transient voltage recovery

Their analysis demonstrated that all scenarios scored relatively similar with a demonstrated need of geographic proximity of generation to load.

Preferred Path & Short-Term Action Plan

Hoosier Energy's 2023 Integrated Resource Plan was created in an environment of uncertainty, volatility and unprecedented market and industry changes that create continuous challenges for long-range planning. Through changes in EPA regulations, MISO's resource adequacy approach, volatility in commodity prices, and inflated costs for replacement resources, the process of long-range planning has shifted from a long-distance view to a recurring, constant analysis as the industry continues to transition. All of these elements have influenced, and will continue to influence, Hoosier Energy's strategy and process for this IRP.

Hoosier Energy's Preferred Resource Portfolio and Short-Term Action Plan will:

Add reliable intermediate load resources through the changing dynamics of MISO's generation mix.

Capacity additions in the 2029-2035 timeframe will be critical for Hoosier to meet MISO capacity obligations and ensure member load is met through the increased winter seasonal need. As the IRP shows, natural gas resources and battery storage are currently the two best technologies for meeting winter firm capacity needs, but they need to be balanced with affordability. Capacity needs can also be met by taking advantage of demand response programs that allow load adjustments to consumption in order to save costs and maintain stability.

Balance market opportunities to meet short-term needs.

In the near-term, Hoosier still has a need to enhance the balance between risk and opportunity through a robust hedging program, advantageous short-term contracts, and monitoring markets for opportunities in order to hedge capacity between MISO zones and external ISOs. By staying informed about market trends and forecasts, Hoosier can better anticipate price fluctuations and help to mitigate events that are nearly impossible to anticipate by protecting against severe price exposure through various hedging approaches.

Create a balance between affordability and stability in order to mitigate regulatory risk exposure.

Expected changes to the portfolio mix may include the addition of low-to-zero carbon resources in order to mitigate potential future regulatory risks. This includes taking advantage of existing and future incentives to reduce costs of resources that may only provide sporadic value. This also includes monitoring emerging technologies for inclusion in future planning that could serve as viable clean energy options for future IRP planning. If/when these technologies are deemed cost-effective and viable, Hoosier will include them as replacement options in future Integrated Resource Plans.

Strategic Partners

Hoosier Energy worked alongside ACES, Quanta Technology, GDS Associates and others to inform and execute an analysis of hypothetical portfolio performance under differing economic and regulatory scenarios. The analysis consisted of a 20-year forward assessment of the member load forecast and resources required to achieve an affordable and reliable portfolio profile. The preferred strategy is to bolster Hoosier's baseload capacity while diversifying energy sources to avoid fuel, development and regulatory risk. Flexibility should also be created to take advantage of an evolving technology landscape as new advancements are made in energy storage and grid management.

ACES Power Marketing navigates energy risk management with precision and excellence, partnering closely with members and customers to deliver comprehensive services. Positioned as a trusted leader, they prioritize inclusivity, innovation and community support, ensuring every transaction serves clients' best interests. With a hands-on approach and unique agency model, ACES fosters success and integrity every step of the way.

GDS Associates, established in 1986, is a multi-service consulting and engineering firm with over 175 professionals across seven U.S. locations. Specializing in utilities and offering additional services such as information technology and market research, GDS stands as a reliable choice for engineering and energy consulting services.

Quanta Technology leads in infrastructure, focusing on electric power, renewables and engineering. They excel in constructing and maintaining global power grids, offering transmission and distribution line construction, EPC and emergency restoration. In renewables, Quanta leads with solar and wind power EPC, battery storage and hydrogen pipeline installation. Their utility solutions and engineering division provide expertise in professional engineering, surveying, environmental consulting and project management, shaping the future of energy infrastructure.

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Appendix B

Quanta Report – System Reliability Assessment of Hoosier Energy's 2023 IRP Portfolios

QUANTA TECHNOLOGY
A QUANTA SERVICES COMPANY

EXECUTIVE SUMMARY

System Reliability Assessment of Hoosier Energy's 2023 IRP Portfolios

PREPARED FOR

HOOSIER ENERGY

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February 17, 2024

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VERSION HISTORY

VERSION	DATE	DESCRIPTION
1.0	**17-FEB-2024**	Initial submission

Acronyms and Abbreviations

The following acronyms and abbreviations are used in this report:

CAP	Capacity credit of all resources, including existing, planned, and portfolio
DRP	Dynamic Reactive Power
ELCC	Effective Load Carrying Capacity
ESCR	Effective Short Circuit Ratio
ESS	Energy Storage System
FFR	Fast Frequency Response
GFM	Grid Forming
IBR	Inverter-Based Resource
ICAP	Installed Capacity
IEC	International Electrotechnical Commission
IRP	Integrated Resource Plan
LOLH	Loss of Load Hours
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability
PFR	Primary Frequency Response
PST	Phase Shifting Transformer
RoCoF	Rate of Change of Frequency
RTO	Regional Transmission Organization
SCR	Short Circuit Ratio
SE	Short-Term Emergency rating
VER	Variable Energy Resource

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Executive Summary

Background

Quanta Technology was retained by Hoosier Energy to provide an independent assessment, a scoring methodology, and metrics for the reliability attributes of seven resource portfolios that have been studied in its 2023 IRP. Hoosier Energy has evolved its IRP process to include measures of resource reliability contributions to ensure meeting its reliability and affordability obligations.

Key Findings

The study analyzed eight reliability attributes of each portfolio during normal and extreme conditions, and Table 1 summarizes the key findings.

Table 1. Summary of Key Findings

ANALYSIS AREA	KEY FINDINGS
Resource Adequacy	• All seven portfolios have adequate capacity. However, the location of resources is mostly outside Hoosier Energy's Area 207, which makes the area highly dependent on tie-lines. Without tie-lines, Area 207 is capacity-deficient for all portfolios. • The reserve margin in 2023 is excessive and will decrease substantially for all portfolios. • Capacity will depend highly on solar and storage (and their ELCCs) instead of the current dependence on thermal-backed resources. This dependence will introduce risk as MISO revises downward the ELCC credits as penetration levels of renewable and storage increase.
Energy Adequacy	• All portfolios can meet the energy requirements of Hoosier Energy's load inside and outside Area 207 even at the extreme load forecast (i.e., 90/10) if the tie-line import capability of 1463 MW does not drop below the 550 MW level. • Area 207 depends on imports for almost 4000-6000 hours in a year and 10-15% of its energy consumption, depending on portfolio, after accounting for the four solar projects in the MISO queue.
Energy Balancing (Ramping, Dispatchability, Flexibility)	• All seven portfolios have adequate energy balancing capability in 2030 due to having adequate energy storage and gas turbine ramping capability in Area 207.

Frequency Response (Inertial and Primary Responses)	• Area 207 has adequate inertial and primary frequency response if the tie-lines are in operation.
	• For islanded operation, to sustain the loss of the largest contingency (190 MW):
	  • 158 MW of energy storage should be equipped with GFM inverters to maintain a RoCoF below 1 Hz/s.
	  • 235 MW of energy storage on 1% droop control will be required to maintain frequency nadir below 0.5 Hz.

Short Circuit Strength	• Adequate short circuit strength to reliably maintain ESCR at all four solar sites if Hoosier Energy's area is connected to MISO. • If Hoosier Energy's area is islanded, the short circuit strength is insufficient to operate the four solar sites reliably without mitigations. A potential mitigation is the installation of a 325 MVA synchronous condenser.
Flicker	• Adequate short circuit strength to mitigate flicker concerns.

Dynamic VAR Deliverability	• Hoosier Energy's area has sufficient VAR deliverability if:
	  • Hoosier Energy's area is connected to MISO, and
	  • The four solar plants in Hoosier Energy's territory are designed to provide dynamic VAR support.
	• A deficiency will be expected if the solar plants do not provide dynamic VARs or Hoosier Energy is islanded.

Grid and Resource Portfolios

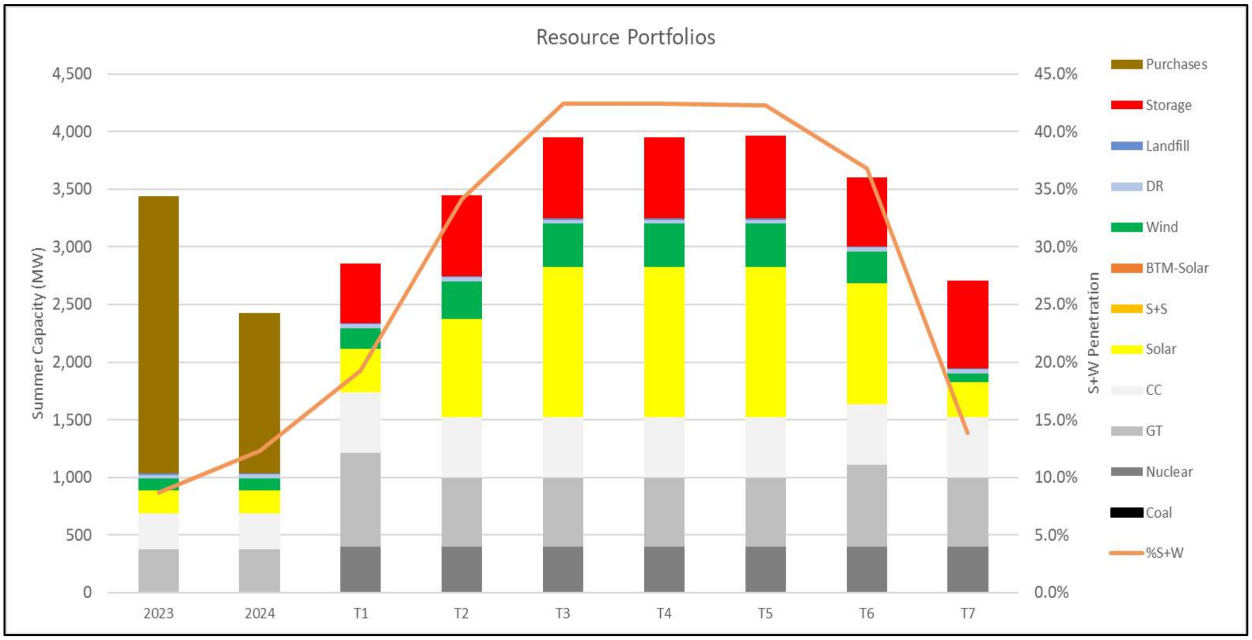
Hoosier Energy serves more than 760,000 customers through 18-member electric cooperatives across a 15,000-square-mile area in Indiana and Illinois. For this work, the Indiana study focused on the reliability assessment. Hoosier Energy owns and contracts about 3,445 MW of generation assets to serve its territory as of 2023. Hoosier Energy is part of the MISO grid and represents a small fraction of the grid's total makeup.

Electric power systems require several reliability services from installed resources that meet mandatory industry requirements (embodied in several NERC standards) to function properly and deliver reliable and safe electricity to consumers. Some reliability services, such as reserves, can be procured from the RTO. In contrast, others, such as voltage control and short circuit strength, have traditionally been assumed to be innately provided by the local resources. Integrating high levels of intermittent renewable resources (e.g., solar, wind) and other IBRs (e.g., energy storage) into the power grid brings a clear opportunity to realize a clean energy future. However, it also brings significant concerns about the preparedness of the electric grid to operate reliably.

A careful assessment of the essential grid services that the various IRP portfolios can provide is required to ensure continued safe and reliable operation of the power system following industry standards and, where applicable, the provision of additional reliability services and enforcement of interconnection standards to assure the successful implementation of the IRP objectives in a timely and affordable manner.

The 2023 IRP considered and optimized seven portfolio strategies. This reliability study analyzed all these portfolios. A range of solar, storage, wind, energy efficiency, demand response, gas, and nuclear resources is incorporated across the portfolios.

The seven portfolios analyzed in this study explored a wide range of resource strategies, as shown in Figure 1 and Table 2 where the IBRs reached 1.7 GWs and the renewable penetration 29.5% by 2040. This study focused all its analysis on 2030 as an interim year within the 20-year horizon and as a year when significant portfolio temporal changes have taken place. A distinct feature of Hoosier Energy's portfolios is that much of the planned resources will be outside its service territory. This common aspect across all IRP portfolios demonstrates Hoosier Energy's reliance on tie line connections to external systems. The system reliability assessment will describe and quantify this reliance. Furthermore, when considering the portfolio's resource locations, Hoosier Energy will not own or contract for solar or wind resources within its service territory. However, it plans on building significant energy storage resources within its territory in addition to the expected buildout of 682 MW of solar plants by third parties, as evidenced by the interconnection applications in the MISO queue.



2040 PORTFOLIO	T1: REFERENCE CASE	T2: PHASE 1 EPA RULE	T3: CO_2 TAX SCENARIO	T4: EPA AND CO_2 TAX	T5: AGG ENVIRO	T6: HIGH PRICE SCENARIO	T7: LOW PRICE SCENARIO
Dispatchable %	81%	66%	58%	58%	58%	63%	86%
Solar and Wind %	19.3%	34.1%	42.4%	42.4%	42.2%	36.8%	13.9%
Renewable Penetration %	8.5%	19.3%	29.5%	29.5%	29.5%	23.9%	6.8%

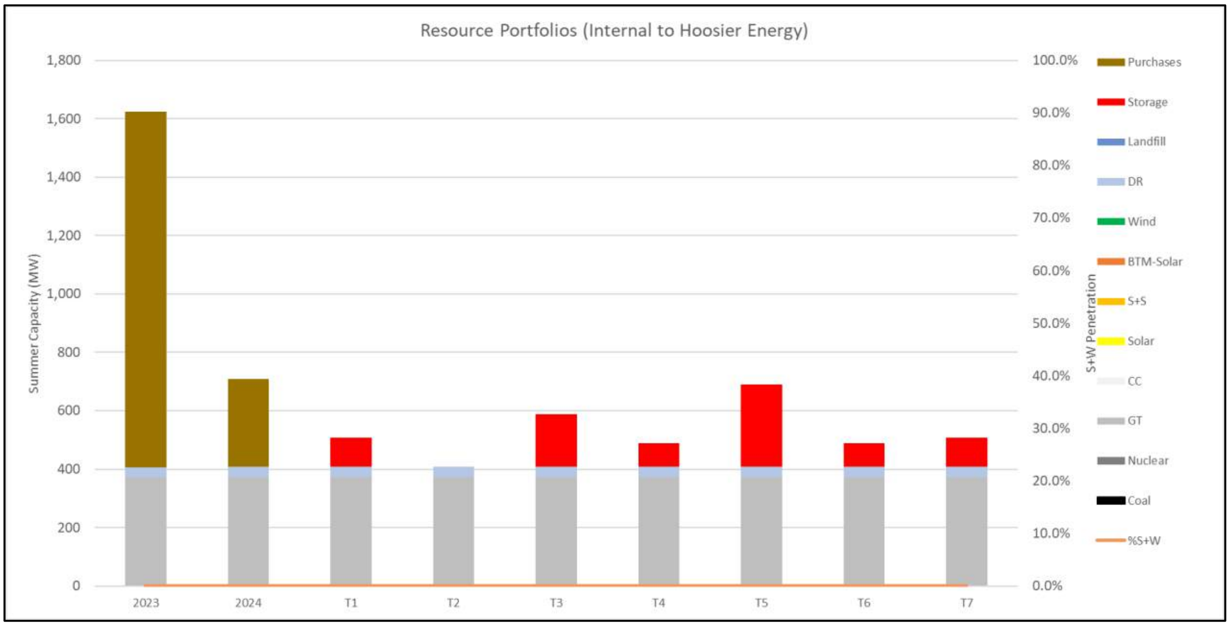


Figure 1. Resource Mix in each of the Portfolios in the Year 2030

Table 2. Resources Inside and Outside Hoosier Area 207

	IBRS (MW)	SOLAR + WIND (% OF ALL RESOURCE ICAP)	RENEWABLE PENETRATION (%)
2023	300	8.7%	9.9%
2030	475 - 1255	15% - 33%	7% - 20%
2040	1070 - 2395	14% - 42%	7% - 30%

MW	2023	2030	2040
Inside Hoosier Area 207			
Thermal	374	374	0–216
Purchases	1217	0	0
Solar/Wind	0	0	0
Storage	0	0–280	520–720
DR	33	35	35
Subtotal - Resources	**1,624**	**409 - 689**	**735 – 795**
Subtotal – Load	**757**	**817**	**828**
Outside Areas (Duke Energy)			
Thermal	331	1088–1388	1536
Purchases	1190	320	0
Solar/Wind	300	375–1050	375–1675

Storage	0	0	0
Subtotal - Resources	**1,821**	**1,983-2,658**	**1,911-3,231**
Subtotal - Load	**758**	**818**	**828**
Total Resources	**3,445**	**2,492 - 3,147**	**2,706 - 3,966**
Peak Load	**1,515**	**1,635**	**1,656**

Notes:
1. Hoosier Energy relies on a mix of resources within and outside its control area to serve its load. Only half the served load is within Hoosier Energy's area, while the rest is integrated within Duke Energy's grid.
2. The seven IRP resource scenarios call for the following strategies:
   a. Within Hoosier Energy's area: Reducing or eliminating thermal generation resources and increasing energy storage.
   b. Outside Hoosier Energy's area: Increasing thermal and solar/wind resources.
   c. Loads within Hoosier Energy's area rely on the transmission tie-line import capability of 1463 MW to offset the area's supply deficit.
3. Unrelated to the IRP: Renewable developers have interconnection queue requests in Hoosier Energy's area for up to 682 MW of solar projects at four sites.

Reliability and Performance Requirements

Grid reliability and security standards require grid planners and operators to adhere to numerous performance requirements[1], including the ones abbreviated and summarized in Table 3.

Table 3. Selected Grid Reliability and Security Requirements

RELIABILITY/SECURITY CATEGORY	REQUIREMENT / GUIDANCE	CONSEQUENCE
Steady-State Voltages	Voltages 138 kV and above, facilities to remain within 92-105% of rated levels.	Equipment insulation failure or heating and fire hazard.
Steady-State Frequency	Maintain system frequency within -/+0.5% of 60 Hz.	Affects 1) voltage level and magnetizing currents of transformers, 2) speed of motors, and 3) power-sharing between interconnecting areas.
Thermal Limits Pre-Contingency	Electric current flows on all bulk power facilities should not exceed 100% of their normal rating limits.	Exceeding grid equipment ratings causes equipment loss of life or catastrophic failure.
Thermal Limits Post-contingency	Electric current flows on all bulk power facilities should not exceed 100% of emergency (SE) rating limits after any P1*, P2-1, and P3 contingency and 100% of SE after any P4-P7 category contingencies.	Exceeding grid equipment ratings causes equipment loss of life or catastrophic failure.
Voltage Stability Limits Post-contingency	Voltages on 138 kV and above facilities should not exceed -10%/+5% of rated levels after any contingency of P1-P7 categories.	Exceeding grid equipment ratings leading to loss of life and failure.
Stability Limits Post-contingency	The power system should not lose synchronism following any P1-P7 category contingency and should not drop load. There should be an acceptable transient voltage recovery where the voltage following fault clearing shall recover to an allowable steady state condition after 5 seconds. Following the disturbance, the oscillations of the monitored parameters should display positive damping. The damping ratio should reach 3% or better for inter-area oscillations and 4% or better for local mode oscillations.	Cascading outages.
RoCoF	Following the loss of the largest generator, the RoCoF should not exceed 1.0Hz/s.	Reduced synchronizing torques may 1) cause generators to trip, 2) exceed the speed of operation of protective equipment, and 3) damage generators.
Power Quality – Harmonics	Connecting equipment should not inject harmonics exceeding allowable levels. The harmonic content of grid voltages should not exceed allowable levels.	Heating of equipment, audible noise, mis-operation of electronic devices, and deterioration of insulation in cables.

[1] NERC standards such as TPL-001-4.

RELIABILITY/SECURITY CATEGORY	REQUIREMENT / GUIDANCE	CONSEQUENCE
Power Quality – Flicker (Voltage Fluctuations)	The power output variability of connecting equipment should not rise to a level that irritates customers.	Visible irritation to customers, lost productivity, and damage to sensitive electronic equipment.
Short Circuit Ratio	The connecting equipment power injection level should be limited to a level commensurate with the strength of the grid at the point of common coupling.	Grid voltages become very sensitive, resulting in large voltage deviations beyond acceptable limits in response to renewable power fluctuations. This results in the malfunction of inverters' controls. Inverter manufacturers do not guarantee the proper operation of equipment under these conditions. It becomes difficult to energize large power transformers.
Protection System Operation	Short circuit currents should be high enough to properly operate protection systems.	Protection system mis-operation resulting in equipment failure, cascading outages, and human safety concerns.

*Contingency classification per NERC TPL-001-4 standard. P0 is intact system (N-0); P1 is single element failure (circuit, generator, transformer, shunt device); P2 is also single element failure (line section, bus, breaker); P3 is loss of a second element after a period of losing a generator (N-1-1), P4 is multiple element loss (stuck breaker), P5 is also multiple element loss (delayed fault clearing due to relay failure); P6 is a loss of single element (line, transformer, shunt) followed by a loss of another single element (N-1-1), and P7 is loss of multiple elements (common structure).

Being part of the MISO grid, Hoosier Energy relies on the market to provide many of the required reliability services, as shown in Figure 2, such as the dispatch of its resources, balancing its energy requirements, and frequency control. However, some reliability services, such as frequency responsive reserves, voltage support, and short circuit strength, are local and not procured through the markets. Other services, such as blackstart and restoration, are planned by Hoosier Energy and approved by MISO. Most of the time, the regional markets work as planned and provide the required reliability services to all participants. However, the available resources in the market are severely restricted during extreme weather or emergency operation events, such as "max gen" events. Thus, the ability of Hoosier Energy to continue serving its baseload customer needs should be assessed.

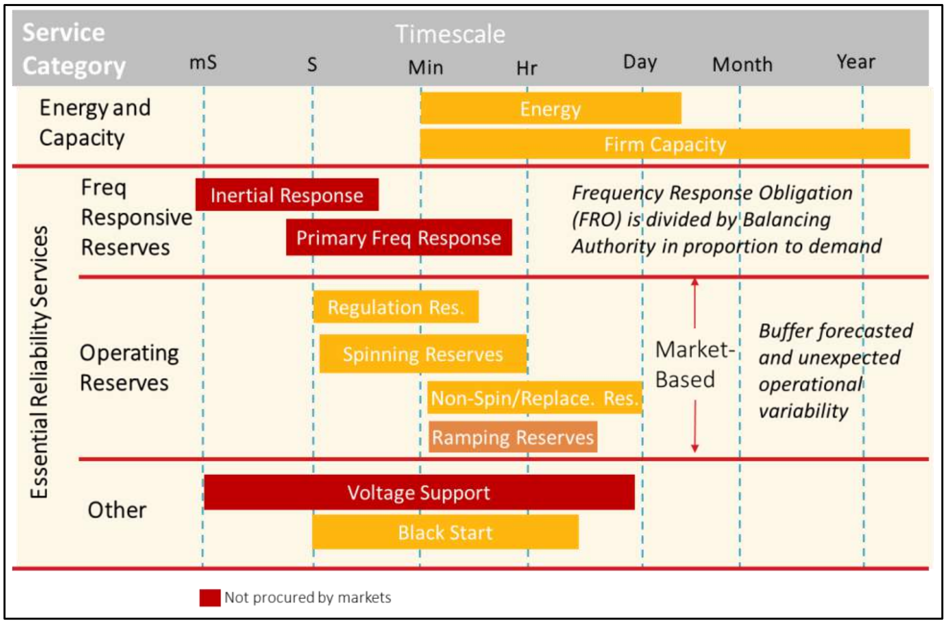


Figure 2. Essential Reliability Services

Study Methodology

The reliability assessment study (Figure 3) started by gathering and collating data characterizing the existing and planned resources, locations, retirement schedules, portfolio resource additions, and transmission grid power flow and dynamic models.

The study then reviewed, refined, and augmented the initial set of reliability metrics and the measures that will be used to quantify the performance of each portfolio against each metric.

Then the study conducted a series of system analyses quantifying the performance of each of the seven portfolios against each measure and, where appropriate, determining the required mitigations to address any performance gaps. The nature of the study is akin to a series of analysis filters. Passing one analysis filter does not guarantee the ability to integrate IBRs and operate reliably. However, limits imposed or flagged by any analysis filter represent a reliability concern that should be mitigated.

A matrix is organized with acceptable performance thresholds to provide a quantifiable score for each reliability measure. These scores are aggregated for each metric and, eventually, for each portfolio. Mitigations are quantified for each portfolio to address its reliability shortcomings.

Figure 3. Reliability Study Methodology

Reliability Metrics

Table 4 summarizes the nine metrics selected to assess the reliability attributes of each portfolio.

Table 4. Reliability Metrics

	METRIC	DESCRIPTION	RATIONALE
1	Resource Adequacy	Adequate resources should be available and ready to supply the capacity needs at peak demand levels, plus reserves each season.	The utility must have reliable resources whose capacity exceeds the peak load plus reserves.
2	Energy Adequacy	Resources can meet the energy and capacity duration requirements. Portfolio resources can supply customers' energy demands during normal and emergency max gen events and supply the energy needs of critical loads during islanded operation events.	The utility must have long-duration resources to serve the needs of its customers during emergency and islanded operation events.

	METRIC	DESCRIPTION	RATIONALE
3	Operational Flexibility and Frequency Support	Ability to provide an inertial energy reservoir or a sink to stabilize the system. Additionally, resources can adjust their output to provide frequency support or stabilization in response to frequency deviations with a droop of 5% or better.	Regional markets and/or control centers balance supply and demand under different time frames according to the prevailing market construct during normal conditions. However, local control centers should be able to maintain operation during under-frequency conditions in emergencies.
4	Short Circuit Strength Requirement	Ensure the system's strength enables stable integration of all IBRs within a portfolio.	The retirement of synchronous generators within the utility footprint and replacements with increasing levels of IBRs will lower the short circuit strength of the system. Resources that can operate at lower levels of SCR and those that provide higher short circuit current provide better future proofing without expensive mitigation measures.
5	Power Quality (Flicker)	The "stiffness of the grid" affects the sensitivity of grid voltages to the intermittency of renewable resources. Ensuring the grid can deliver power quality following IEEE standards is essential.	The retirement of large thermal generation plants lowers the strength of the grid. It increases its susceptibility to voltage flicker due to the intermittent nature of renewable resources unless properly assessed and mitigated.
6	Dynamic VAR Support	To avoid stalling, customer equipment driven by induction motors (e.g., air conditioning or factories) requires dynamic reactive power after a grid fault. The ability of portfolio resources to provide this service depends on their closeness to the load centers.	The utility must retain resources electrically close to load centers to provide this attribute following NERC and IEEE Standards.
7	Dispatchability and Automatic Generation Control	Resources should respond to directives from system operators regarding their status, output, and timing. Resources that can be ramped up and down automatically to respond immediately to changes in the system contribute more to reliability than resources that can be ramped only up or down, and those, in turn, are better than ones that cannot be ramped.	The ability to control frequency is paramount to the stability of the electric system and the quality of power delivered to customers. Control centers (regional or local) provide dispatch signals under normal conditions and emergency restoration procedures or other operational considerations.
8	Predictability and Firmness of Supply	Ability to predict/forecast the output of resources and to counteract forecast errors.	The ability to predict resource output from day-ahead to real-time is advantageous to minimize the need for spinning reserves. In places with an active energy market, energy is scheduled with the market in the day-ahead hourly market and the real-time 5-minute market. Deviations from these schedules have financial consequences, and thus, the ability to accurately forecast the output of a resource up to 38 hours ahead of time for the day-ahead market and 30 minutes for the real-time market is advantageous.

Table 5 shows the reliability metrics assessed using one or multiple measures.

Table 5. Reliability Measures for Each Metric

	METRIC	MEASURE
1	Resource Adequacy	Additional Reserve Margin Required
2	Energy Adequacy	LOLH - Normal System, 50/50 Forecast
		Expected Energy not Served (GWh) - Normal System 50/50 Forecast
		Max MW Short (MW) - Normal System 50/50 Forecast
		Max MW Short - Loss of 50% of Tie-Line Capacity, 50/50 Forecast
		Max MW Short (Islanded, 50/50 Forecast)
		Max MW Short (Normal System, 90/10 Forecast)

METRIC		MEASURE
3	Operational Flexibility and Frequency Support	Inertia MVA-s
		Inertial Gap FFR MW (% CAP)
		Primary Gap PFR MW (% CAP)
4	Short Circuit Strength	Inverter MWs Passing ESCR Limits (%) - Connected System
		Inverter MWs Passing ESCR Limits (%) - Islanded System
		Required Additional Synch Condensers MVA (% peak load) – Connected
		Required Additional Synch Condensers MVA (% peak load) – Islanded
5	Flicker	Compliance with Flicker Limits when Connected (GE Flicker Curve or IEC Flicker Meter)
		Compliance with Flicker Limits when Islanded
		Required Synchronous Condensers MVA to Mitigate Flicker
6	Dynamic VAR Support	Dynamic VAR to load Center Capability (% of Peak Load)
7	Dispatchability	Dispatchable (% CAP)
		Unavoidable VER Penetration %
		Increased Freq Regulation Requirements (% Peak Load)
		1-min Ramp Capability (MW)
		10-min Ramp Capability (MW)
8	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) (%VER MW)

Scope of Reliability Analysis

Operating a power system with high levels of IBRs requires careful analysis of the resource reliability attributes to ensure a safe and reliable system operation during normal, emergency, and islanded system conditions. This study evaluated seven portfolios across eight reliability metrics involving 24 measures. The study focused on the year 2030 for all quantitative analyses, an interim year within the 20-year horizon and a year when significant portfolio temporal changes have already occurred. The reliability studies focused on Hoosier Energy's service territory (Area 207) only since the rest of Hoosier Energy's load and resources are integrated within Duke Energy's much larger neighboring system. Table 6 summarizes the reliability assessments that have been conducted in this study.

Table 6. Reliability Assessments

	SELECTED RELIABILITY STUDY AREAS	NORMAL (50/50, CONNECTED)	MAX-GEN (90/10, IMPORT LIMITED)	ISLANDED
1	Resource Adequacy	X		X
2	Energy Adequacy	X	X	X
3	Operational Flexibility and Frequency Support	X		X
4	Short Circuit Strength Requirement	X		X
5	Power Quality (Flicker)	X		
6	Dynamic VAR Deliverability	X		
7	Dispatchability and Automatic Generation Control	X		
8	Predictability and Firmness of Supply	X		

This study assesses several of the mandatory reliability requirements for the year 2030. It is based on the IRP resource portfolios and schedules of retirements and additions along with third-party solar plants and the existing transmission grid. . It.

Prudent assumptions were made in the study. For instance, operating renewable resources economically requires them to generate all the time at their maximum potential power levels as allowed by solar irradiance and wind speeds. This mode of economic operation precludes these resources from providing frequency response in the upward direction, as will be required when a generator or import is suddenly lost. Reducing the power output to enable participation in frequency response in the upward direction is very expensive. However, the speed of control of the IBRs makes them perfectly suited for participating in frequency response in the downward direction (i.e., curtailment), as will be required when a large load or export is suddenly lost.

Due to time and data availability constraints, screening-level quantitative studies were conducted for a few reliability standards, including inertial response, primary frequency response, secondary frequency response, short circuit strength, system ramping requirements, dynamic reactive support, flicker, and energy adequacy. Other reliability assessment areas are outside this study's scope and include system protection and control interactions. Detailed system studies will be required to ascertain the system's reliability once a portfolio is selected and all portfolio resources' location, size, and technology are available.

Study Results

This study identified potential reliability gaps for each of the seven IRP portfolios and suggested potential mitigations to these gaps. The mitigations include grid-forming inverter technology, additional fast power resources such as battery storage, supercapacitors, combustion turbines, and synchronous condensers.

Table 7 summarizes the key findings of the performance measures under each of the nine metrics of the current trends future..

Table 7. Study Results of the Reliability Performance of Seven Portfolios

	Year 2030		T1	T2	T3	T4	T5	T6	T7
1	Resource Adequacy	Additional Reserve Margin Required - Summer (MW)	232	279	194	241	146	241	232
2	Energy Adequacy	Loss of Load Hours (LOLH) - normal system, 50/50 forecast	0	0	0	0	0	0	0
		Expected Energy not Served (GWh) - normal system 50/50 fcst	0	0	0	0	0	0	0
		max MW Short (MW) - normal system 50/50 forecast	0	0	0	0	0	0	0
		max MW Short - loss of 50% of tieline capacity, 50/50 fcst	0	0	0	0	0	0	0
		max MW Short (islanded, 50/50 forecast)	274	172	330	251	409	251	510
		max MW Short (normal system, 90/10 forecast)	0	0	0	0	0	0	0
3	Operational Flexibility and Frequency Support	Inertia MVA-s	2,185	2,185	2,185	2,185	2,185	2,185	2,185
		Inertial Gap FFR MW	158	158	158	158	158	158	158
		Primary Gap PFR MW	135	236	54	155	0	155	135
4	Short Circuit Strength	Inverter MWs passing ESCR limits (%) - Connected System	100%	100%	100%	100%	100%	100%	0%
		Inverter MWs passing ESCR limits (%) - Islanded System	0%	0%	0%	0%	0%	0%	0%
		Required Additional Synch Condensers MVA (when Connected)	0	0	0	0	0	0	0
		Required Additional Synch Condensers MVA (when Islanded)	325	325	325	325	325	325	0
5	Power Quality (Flicker)	Compliance with Flicker limits when Connected (GE Flicker Curve or IEC Flicker Meter)	100%	100%	100%	100%	100%	100%	100%
		Compliance with Flicker limits when Islanded	100%	100%	100%	100%	100%	100%	100%
		Required Synchronous Condensers MVA to mitigate Flicker	0	0	0	0	0	0	0
6	Dynamic VAR Support	Dynamic VARs that can be delivered to select load centers (% of Load) at peak	25%	25%	25%	25%	25%	25%	25%
7	Dispatchability and Automatic Generation Control	Dispatchable (%CAP)	68%	65%	70%	68%	72%	68%	68%
		Unavoidable VER Penetration %	38%	50%	28%	40%	16%	40%	38%
		Increased Freq Regulation Requirements (MW)	14	14	14	14	14	14	14
		1-min Ramp Capability (MW)	139	39	219	119	319	119	139
		10-min Ramp Capability (MW)	362	262	442	342	542	342	362
8	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) MW	199	99	279	179	379	179	199

Quantitative assessment of each measure was calculated using resource technology, size, location within each portfolio, resource production profiles, and grid data. Table 8 summarizes potential mitigation measures to address the reliability concerns and their estimated costs.

Table 8. Summary of Proposed Mitigations of Seven Portfolios

YEAR 2030	T1	T2	T3	T4	T5	T6	T7
Equip Stand-Alone ESS with GFM Inverters (MW)	158	158	158	158	158	158	158
Additional Synchronous Condensers (MW)	325	325	325	325	325	325	0
Additional Power Mitigation (MW)	135*	236	54*	155*	0	155*	135*
Increased Freq. Regulation	14	14	14	14	14	14	14

Address Inertial Response Gaps**	58	158	0	78	0	78	58
Address Primary Response Gaps	135	236	54	155	0	155	135
Firm up Intermittent Renewable Forecast	0	0	0	0	0	0	0

*Additional energy storage is required to be added to the portfolio by 2030 to operate reliably in island mode.
** Requires fast frequency response within 100 ms. It can be in battery storage, supercapacitors, or appropriately upsized combustion engines or gas turbines.

Observations and Comments

1. Reliability concerns were identified for each portfolio, especially under emergency and islanded conditions, and mitigation measures were identified as follows:
   a. Stand-alone energy storage FFR should have GFM with additional capabilities, including blackstart and GFM inverters. It is not widely used in the US market, but the technology is available and recommended for portfolios with high penetration of IBRs.
   b. The provision of additional fast power resources is required in each portfolio. These resources have been quantified for energy storage technology. However, supercapacitors or combustion turbines can also provide the same function, but the size should be determined for these technologies.
   c. Specifications of equivalent SCR of inverters not to exceed 3.5.
   d. Additional power mitigations should be utilized to address primary and inertial response gaps. When the Hoosier system is installed, primary response gaps are present, which drives the importance of maintaining Hoosier Energy systems' connection to external systems to provide support.
2. This study covered several areas of reliability assessment. However, it is not exhaustive. Areas that have not been covered include the following:
   a. The study assumed that any required grid upgrades would be implemented as part of the MISO interconnection process and thus excluded the analysis of portfolio deliverability.
   b. The study assumed the IRP process produced portfolios with sufficient capacity to meet the loss of load expectation target of 0.1 days/year, thus excluding the resource adequacy analysis.
   c. All reliability assessments in this study applied screening-level indicative analyses. Detailed system studies are essential and should be conducted to properly assess the system reliability of the short-listed Portfolios.

Scoring Methodology and Performance Thresholds

Table 9 summarizes the thresholds used in this study to score the reliability assessment of each measure, along with the rationale for setting the threshold values. Measures that exceed the upper threshold are deemed satisfactory (pass) and scored 1. Measures below the lower threshold are deemed potentially problematic and scored 0 (problem). Measures in between are cautionary and given a score of .5 (caution). The scores of measures within each of the eight metrics are averaged to yield a single score for each metric. Metric scores are then added for each portfolio and compared. The maximum score of each portfolio is eight.

Table 9. Scoring Thresholds

	YEAR 2031		1 (PASS)	2 (CAUTION)	3 (PROBLEM)	RATIONALE
1	Resource Adequacy	Additional Reserve Margin Required (MW)	1%	1% - 5%	5%	
2	Energy Adequacy	LOLH - Normal System, 50/50 Forecast	<2.4 hrs	2.4-4.8 hrs	>4.8 hrs	Expected number of hours in a year the portfolio is energy short and relies on imports (2.4hrs = 1 day in 10 years).
		Expected Energy Not Served (GWh) - Normal System 50/50 Forecast	<2.4*Peak	2.4-4.8*Peak	>4.8*Peak	The energy consumption is not supplied due to insufficient capacity resources within the portfolio to meet the demand.

YEAR 2031			1 (PASS)	2 (CAUTION)	3 (PROBLEM)	RATIONALE
		Max MW Short (MW) - Normal System 50/50 Forecast	<0%	0-10%	>10%	The maximum hourly power shortage in the portfolio that must be supplied by imports (% of tie-line import limits).
		Max MW Short - Loss of 50% of Tie Line Capacity, 50/50 Forecast	<0%	0-5%	>5%	The energy consumption is not supplied due to insufficient resources and imports to meet the demand when tie line import capacity is halved.
		Max MW Short (Islanded, 50/50 Forecast)	<70%	70-85%	>85%	The ability of resources to serve critical loads is estimated at 15% of the total load. Adding other important loads brings the total to 30%.
		Max MW Short (Normal System, 90/10 Forecast)	<5%	5-20%	>20%	The ability of portfolio resources to serve unanticipated growth in load consumption during MISO emergency max-gen events.
3	Operational Flexibility and Frequency Support	Inertia MVA-s	>4.2 *Peak	2.6-4.2 *Peak	<2.6 *Peak	The synchronous machine has an inertia of 2-5 x MVA rating. Conventional systems have inertia that exceeds 2-5x (peak load x 1.3).
		Inertial Gap FFR MW (% CAP)	0	0-10% of CAP	>10% of CAP	The system should have enough inertial response, so the gap should be 0. Inertial response of synch machine ≈ 10% of CAP.
		Primary Gap PFR MW (% CAP)	0	0 - 2% of CAP	>2% of CAP	The system should have enough primary response, so the gap should be 0. The primary response of synch machine ≈ 3.3% of CAP/0.1Hz (droop 5%).
4	Short Circuit Strength	Inverter MWs Passing ESCR Limits (%) - Connected System	95%	80-95%	80%	Grid following inverters require short circuit strength at the point of connection to operate properly (ESCR threshold of 3.5).
		Inverter MWs Passing ESCR Limits (%) - Islanded System	0	0-20%	>20%	Grid following inverters require short circuit strength at the point of connection to operate properly (ESCR threshold of 3.5).
		Required Additional Synch Condensers MVA (% Peak Load)	0	0-500	>500	The portfolio should not require additional synchronous condensers. 500 MVARs is a threshold.
5	Flicker	Compliance with Flicker Limits when Connected (GE Flicker Curve or IEC Flicker Meter)	>95%	80-95%	<80%	The percentage of system load buses likely to experience flicker (>100% of the borderline of irritation or Pst>1).
		Compliance with Flicker Limits when Islanded	>80%	50-80%	<50%	The percentage of system load buses likely to experience flicker (>100% of the borderline of irritation or Pst>1).
		Required Synchronous Condensers MVA to Mitigate Flicker	0%	0-500	>500	Size of synchronous condensers required to mitigate flicker. 500 MVARs is a threshold.
6	Dynamic VAR Support	Dynamic VAR to Load Center Capability (% of Peak Load)	≥85%	55-85%	<55%	DRP should exceed 55-85% of the peak load served by the load centers. The DRP requirement to prevent induction motor stalling is 2.5x the steady-state reactive consumption. Assuming a PF=0.9, Induction motors account for 50-80% of the load.
7	Dispatchability	Dispatchable (%CAP)	>60%	50-60%	<50%	Dipatchable resources are essential for system operation.
		Unavoidable VER Penetration %	<60%	60-70%	>70%	Intermittent power penetration above 60% is problematic when islanded.
		Increased Freq Regulation Requirements (% Peak Load)	<2% of Peak Load	2-3% of Peak Load	>3% of Peak Load	Regulation of conventional systems ≈1%.
		1-min Ramp Capability (MW)	>15% of CAP	10-15% of CAP	<10% of CAP	10% per minute was the norm for conventional systems. Renewable portfolios require more ramping capability.
		10-min Ramp Capability (MW)	>65% of CAP	50-65% of CAP	<50% of CAP	10% per minute was the norm for conventional systems. However, with 50% min loading, that will be 50% in 10 min. Renewable portfolios require more ramping capability.
8	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) (%VER MW)	≥ 0	-10% - 0% of CAP	<-10% of CAP	Excess ramping capability to offset higher intermittent resource output variability levels is desired.

The study results from Table 7 are normalized following the threshold definitions in Table 10.

Table 10. Normalized Study Results

	Year 2030		T1	T2	T3	T4	T5	T6	T7
1	Resource Adequacy	Additional Reserve Margin Required	0	0	0	0	0	0	0
2	Energy Adequacy	Loss of Load Hours (LOLH) - normal system, 50/50 forecast	1	1	1	1	1	1	1
		Expected Energy not Served (GWh) - normal system 50/50 fcst	1	1	1	1	1	1	1
		max MW Short (MW) - normal system 50/50 forecast	1	1	1	1	1	1	1
		max MW Short - loss of 50% of tieline capacity, 50/50 fcst	1	1	1	1	1	1	1
		max MW Short (islanded, 50/50 forecast)	1	1	1	1	1	1	1
		max MW Short (normal system, 90/10 forecast)	1	1	1	1	1	1	1
3	Operational Flexibility and Frequency Support	Inertia MVA-s	1/2	1/2	1/2	1/2	1/2	1/2	1/2
		Inertial Gap FFR MW (% CAP)	0	0	0	0	0	0	0
		Primary Gap PFR MW (% CAP)	0	0	0	0	1	0	0
4	Short Circuit Strength	Inverter MWs passing ESCR limits (%) - Connected System	1	1	1	1	1	1	0
		Inverter MWs passing ESCR limits (%) - Islanded System	0	0	0	0	0	0	0
		Required Additional Synch Condensers MVA (when Connected)	1	1	1	1	1	1	1
		Required Additional Synch Condensers MVA (when Islanded)	0	0	0	0	0	0	1
5	Power Quality	Compliance with Flicker limits when Connected (GE Flicker Curve or IEC Flicker Meter)	1	1	1	1	1	1	1
		Compliance with Flicker limits when Islanded	1	1	1	1	1	1	1
		Required Synchronous Condensers MVA to mitigate Flicker	1	1	1	1	1	1	1
6	Dynamic VAR Support	Dynamic VAR to load Center Capability (% of Peak Load)	1	1	1	1	1	1	1
7	Dispatchability and Automatic Generation Control	Dispatchable (%CAP)	1	1	1	1	1	1	1
		Unavoidable VER Penetration %	1	1	1	1	1	1	1
		Increased Freq Regulation Requirements (% Peak Load)	1	1	1	1	1	1	1
		1-min Ramp Capability (MW)	1	0	1	1	1	1	1
		10-min Ramp Capability (MW)	1/2	0	1	1/2	1	1/2	1/2
8	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) (%VER MW)	1	1	1	1	1	1	1

Ranking of Resource Portfolios

Table 11 shows the reliability scores of each portfolio for the eight metrics.

Table 11. Scores and Ranking of Portfolios

	YEAR 2030	T1	T2	T3	T4	T5	T6	T7
1	Resource Adequacy	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	Energy Adequacy	1.00	1.00	1.00	1.00	1.00	1.00	1.00
3	Operational Flexibility and Frequency Support	0.17	0.17	0.17	0.17	0.50	0.17	0.17
4	Short Circuit Strength	0.50	0.50	0.50	0.50	0.50	0.50	0.50
5	Power Quality	1.00	1.00	1.00	1.00	1.00	1.00	1.00
6	Dynamic VAR Support	1.00	1.00	1.00	1.00	1.00	1.00	1.00
7	Dispatchability and Automatic Generation Control	0.90	0.60	1.00	0.90	1.00	0.90	0.90
8	Predictability and Firmness	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Cumulative Core (out of Possible Eight)		**5.57**	**5.27**	**5.67**	**5.57**	**6.00**	**5.57**	**5.57**
Percent Score		**70%**	**66%**	**71%**	**70%**	**75%**	**70%**	**70%**
Ranking		**3**	**7**	**2**	**3**	**1**	**3**	**3**

Reliability Analysis of IRP Portfolios

Final Report

February 12, 2024

Team Introductions

- Quanta Technology

Salvador Palafox

PM and Technical Lead
Hisham Othman

SMEs
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Ajit Kulkarni

Technical Writer
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Project Engineers
Rahul Anilkumar
Khaled Al-Dahdouh
Geoffrey Kan

- Hoosier Energy
  - Mike Mooney (Corporate Planning)
  - Rick Gillingham (Resource Planning Analyst)
  - Christy Langley (Director of Power Supply)
  - Josh Cisney (Mgr Portfolio Optimization)
  - Patrick Maguire (ACES)

Project Schedule

Task #	Description	Start Date	End Date	Status
1	Customization of Reliability Metrics and Measures	ARO	ARO + 1 week	Completed
2	Data Collection and Configuration of Analysis Tools	ARO	ARO + 3 week	Completed
3	Energy Adequacy Assessment	Task 2 Completion	ARO + 6 weeks	Completed
4	Additional Reliability Assessments and Mitigations	Task 2 Completion	ARO + 9 weeks	Completed
5	Score and Rank Portfolio(s)	Tasks 3, 4 Completion	ARO + 13 weeks	Completed
6	Stakeholder Engagement	TBD	TBD	TBD

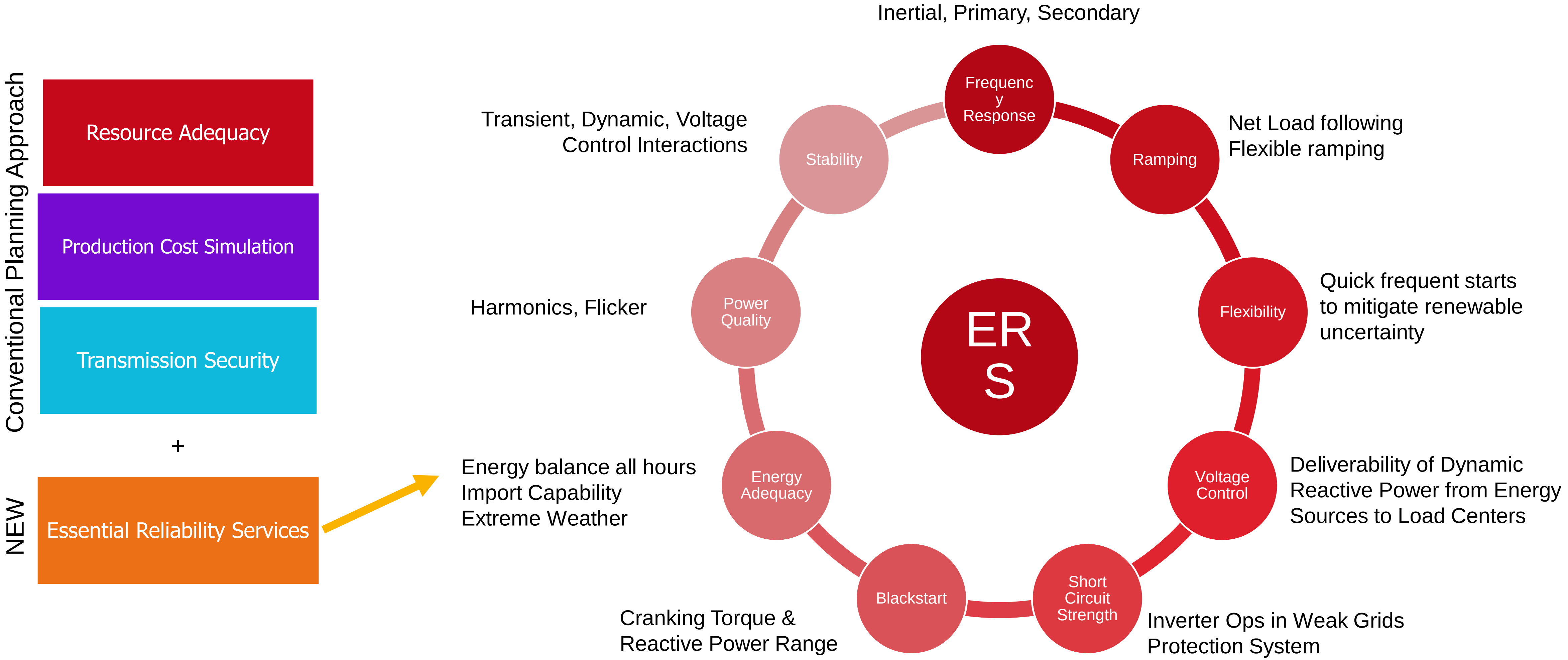
ARO: After Receipt of Signed and Acceptable Order and PO

Target Dates:

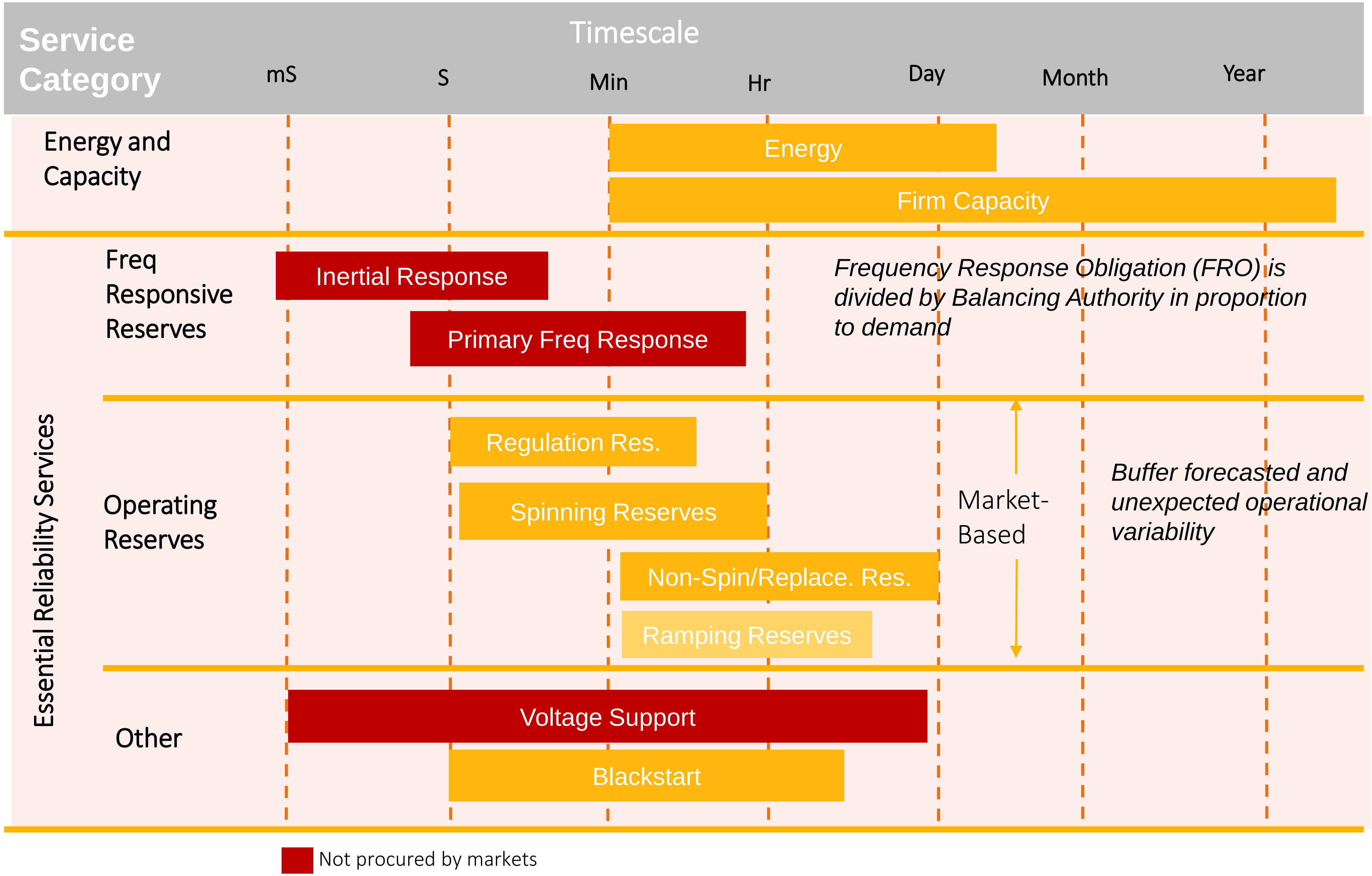
- Portfolio data received December 18, 2023
- Draft Final Report mid-late Feb 2024
- Final Report March 2024
- Update Calls/Meetings Weekly

Essential Reliability Services

The conventional planning paradigm is not sufficient to assure operational reliability with increasing retirements and dependance on solar/wind/storage resources, both distributed and utility-scale



Essential Reliability Services - Time and Sourcing



- **Regulation Reserves:**

  Rapid response by generators used to help restore system frequency. These reserves may be deployed after an event and are also used to address normal random short-term fluctuations in load that can create imbalances in supply and demand.

- **Ramping Reserves:**

  An emerging and evolving reserve product (also known as load following or flexibility reserves) that is used to address "slower" variations in net load and is increasingly considered to manage variability in net load from wind and solar energy. MISO, for example, sets the MW level based on the sum of the forecasted change in net load and an additional amount of ramp up/down (575 MW for now).

Key ERS Study Areas

1. Analyze system drivers:
   - Transmission grid and Area import limits
   - load and renewable profiles
   - Resource Portfolios/Scenarios

2. Resource Capacity & Energy Adequacy

3. Energy Balance
   - Ramping
   - Flexibility
   - Load following / dispatchability

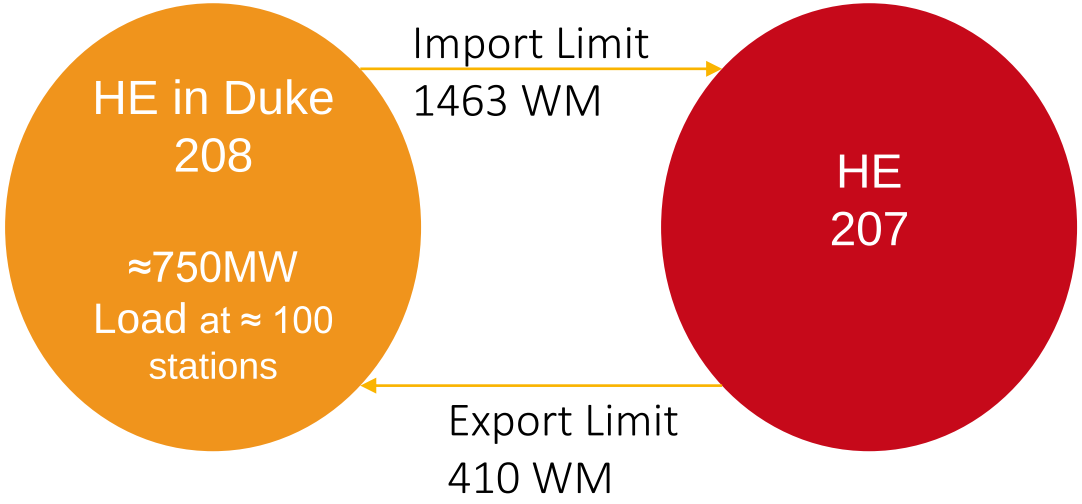
4. Frequency Response and System Stability
   - Inertial response
   - Primary frequency response
   - System Stability

5. Voltage Response and System Strength
   - Dynamic VAR support
   - System short circuit strength

Study Approach

	Selected Reliability Study Areas	Normal (50/50, Connected)	Max-Gen (90/10, Import Limited)	Islanded (Critical Load)
1	Resource Adequacy	X		
2	Energy Adequacy	X	X	X
3	Operational Flexibility and Frequency Support	X		X
4	Short Circuit Strength Requirement	X		X
5	Power Quality (Flicker)	X		
6	Dynamic VAR Deliverability	X		
7	Dispatchability and Automatic Generation Control	X		
8	Predictability and Firmness of Supply	X		

Hoosier System - Description



MW	2023	2030	2040
Inside Hoosier Area 207			
Thermal	374	374	0–216
Purchases	1217	0	0
Solar/Wind	0	0	0
Storage	0	0–280	520–720
DR	33	35	35
Subtotal - Resources	**1,624**	**409 - 689**	**735 - 795**
Subtotal – Load	**757**	**817**	**828**
Outside Areas (DE, ..)			
Thermal	331	1088–1388	1536
Purchases	1190	320	0
Solar/Wind	300	375–1050	375–1675
Storage	0	0	0
Subtotal - Resources	**1,821**	**1,983-2,658**	**1,911-3,231**
Subtotal - Load	**758**	**818**	**828**
Total Resources	**3,445**	**2,492 - 3,147**	**2,706 - 3,966**
Peak Load	**1,515**	**1,635**	**1,656**

- Hoosier Energy (HE) relies on a mix of resources within and outside its control area to serve its load. Only half the served load is within HE's area while the rest is integrated within Duke Energy's grid.
- The 7 IRP resource scenarios call for:
  - Within HE's area, reducing or eliminating thermal generation resources and increasing energy storage.
  - Outside HE's area, increasing thermal and solar/wind resources.
  - Loads with HE's area rely on the transmission tie-line import capability of 1463MW to offset for the area's supply deficit.
- Unrelated to the IRP, renewable developers have interconnection queue requests in HE's area for up to 682 MW of solar projects at four sites

Reliability Investigation Areas – Inside vs Outside

- Assess the resource and energy adequacy of each portfolio to ensure the ability to provide the capacity and energy requirements of all HE's load inside and outside HE's control area.

- Investigate the following reliability aspects of HE's control area:
  - Ability to balance energy (ramping, dispatchability, flexibility)
  - Ability to control frequency (inertial response, primary response).
  - Ability to provide adequate short circuit strength to integrate inverter-based resources (IBRs) and mitigate their flicker-induced concerns.
  - Ability to supply the dynamic reactive power required by loads to avoid motor stalling and ensure rapid transient voltage recovery (TRV).

- Note: Reliability of supply to HE's load outside its control area is dependent on Duke's system reliability and thus are excluded from further evaluation in this study.

Summary of Findings (1/5)

- **Resource Adequacy**:
  - All 7 portfolios have adequate capacity. However, location of resources mostly outside HE's Area 207 makes the area highly dependent on tie-lines. Without tie-lines, Area 207 is capacity deficient for all portfolios.
  - Reserve margin in 2023 is excessive and will decrease substantially for all portfolios.
  - Capacity will be highly dependent on solar and storage (and their ELCCs) instead current dependance on thermal-backed resources. This will introduce risk as MISO revises downward the ELCC credits as penetration levels of renewable and storage increase.

- **Energy Adequacy**:
  - The portfolio is able to meet the energy requirements of HE's load inside and outside of Area 207 even at the extreme load forecast (i.e., 90/10) **IF** the tie-line import capability of 1463MW does not drop below the 550 MW level.
  - Area 207 is dependent on imports almost 4000-6000 hours in a year and 10-15% of its energy consumption, depending on portfolio, after accounting for the 4 solar projects in the MISO Queue.

Summary of Findings (2/5)

- **Energy Balancing (Ramping, Dispatchability, Flexibility) – Analysis of Area 207**:
    - All 7 portfolios have adequate energy balancing capability in Y2030 due to having adequate energy storage and gas turbine ramping capability.

- **Frequency Response (Inertial and Primary Responses):**
    - If the tie-lines are in operation, Area 207 has adequate inertial and primary frequency response.
    - For islanded operation, to sustain the loss of the largest contingency (190MW):
        - 158MW of energy storage should be equipped with Grid-Forming Inverters (GFM) in order to maintain RoCoF below 1Hz/s.
        - 235MW of energy storage on 1% droop control will be required to maintain frequency Nadir below 0.5Hz.

Summary of Findings (3/5)

- **Short Circuit Strength**:
  - Adequate short circuit strength to reliability maintain ESCR at all four solar sites if HE area is connected to MISO.
  - If HE area is islanded, the short circuit strength is not sufficient to reliably operate the four solar sites without mitigations. A potential mitigation is the installation of 325MVA synchronous condenser.
- **Flicker:**
  - Adequate short circuit strength to mitigate flicker concerns.
- **Dynamic VAR Deliverability**:
  - HE area has sufficient VAR deliverability if:
    - HE area is connected to MISO, and
    - The four solar plants in HE territory are designed to provide dynamic VAR support.
  - If the solar plants do not provide dynamic VARs or HE is islanded, a deficiency will be expected.

Summary of Findings (4/5)

- Screening studies indicate the potential need for the following reliability mitigations:

	T1	T2	T3	T4	T5	T6	T7
Equip Stand-alone ESS with GFM inverters (MW)	**158**	**158**	**158**	**158**	**158**	**158**	**158**
Additional Synchronous Condensers (MVA)	**325**	**325**	**325**	**325**	**325**	**325**	**0**
Additional Power Mitigations (MW)	**135**[1]	**236**	**54**[1]	**155**[1]	**0**	**155**[1]	**135**[1]
Increased Freq Regulation	14	14	14	14	14	14	14
Address Inertial Response Gaps[2]	58	158	0	78	0	78	58
Address Primary Response Gaps	135	236	54	155	0	155	135
Firm up Intermittent Renewable Forecast	0	0	0	0	0	0	0

[1] Can utilize existing portfolio storage to provide frequency regulation. No need for additional storage.

[2] Requires fast frequency response within 100ms. Can be in the form of battery storage, super capacitors, or appropriately upsized combustion engines or gas turbines. Blackstart will require long duration for the energy component (4 hours or higher).

Summary of Findings (5/5)

Portfolio Reliability Ranking

	Year 2030	T1	T2	T3	T4	T5	T6	T7
1	Resource Adequacy	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	Energy Adequacy	1.00	1.00	1.00	1.00	1.00	1.00	1.00
3	Operational Flexibility and Frequency Support	0.17	0.17	0.17	0.17	0.50	0.17	0.17
4	Short Circuit Strength	0.50	0.50	0.50	0.50	0.50	0.50	0.50
5	Power Quality	1.00	1.00	1.00	1.00	1.00	1.00	1.00
6	Dynamic VAR Support	1.00	1.00	1.00	1.00	1.00	1.00	1.00
7	Dispatchability and Automatic Generation Control	0.90	0.60	1.00	0.90	1.00	0.90	0.90
8	Predictability and Firmness	1.00	1.00	1.00	1.00	1.00	1.00	1.00

	T1	T2	T3	T4	T5	T6	T7
Cumulative core (out of possible 8)	5.57	5.27	5.67	5.57	6.00	5.57	5.57
Percent Score	70%	66%	71%	70%	75%	70%	70%
Ranking	**3**	**7**	**2**	**3**	**1**	**3**	**3**

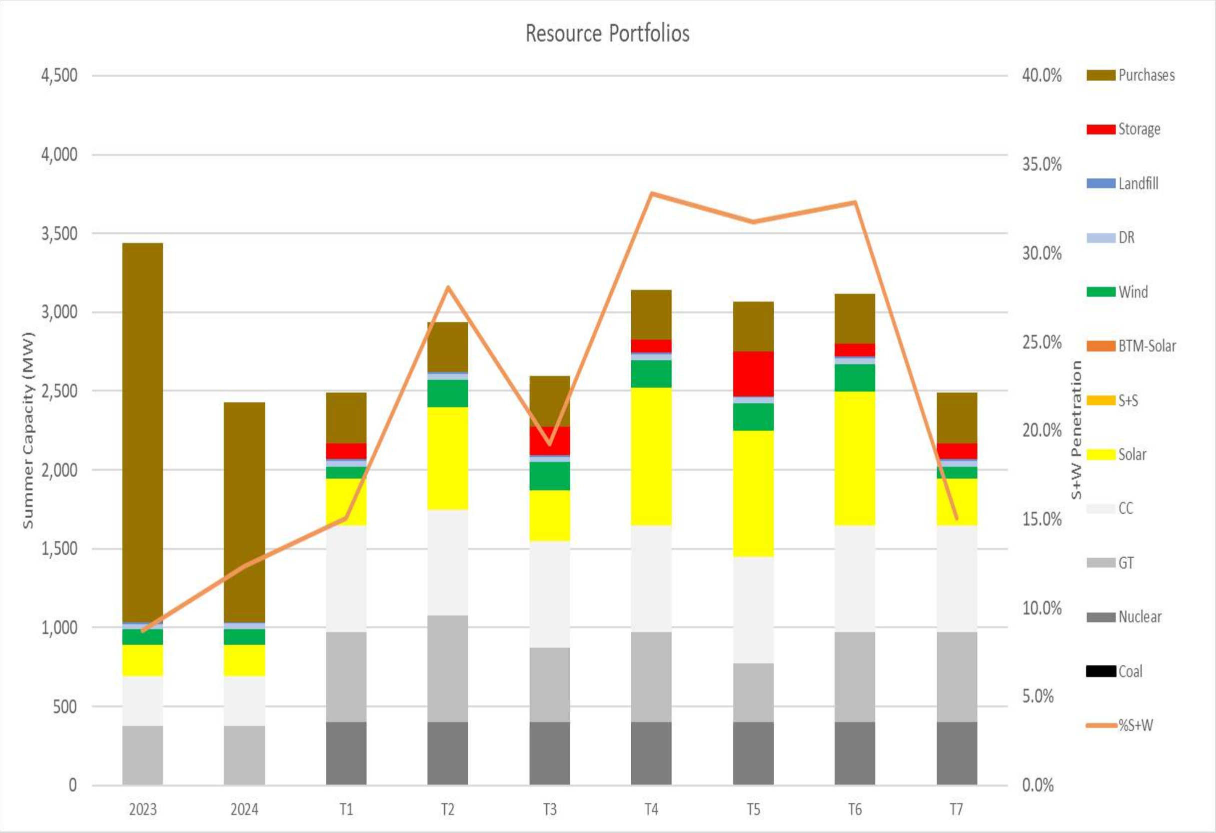
Portfolios:

- T1: Reference Case
- T2: Phase 1 EPA Rule
- T3: CO2 Tax Scenario
- T4: EPA and CO2 Tax
- T5: Aggressive Enviro
- T6: High Price Scenario
- T7: Low Price Scenario

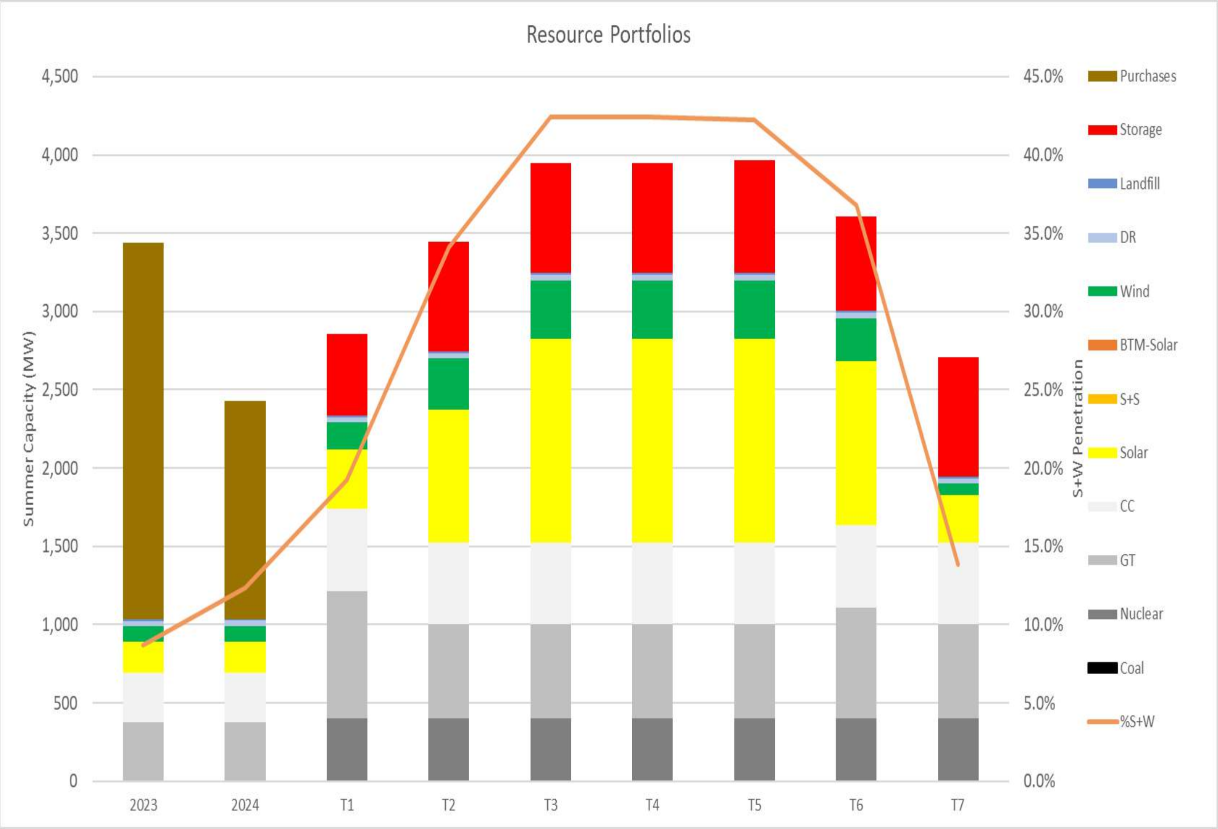
Resource Capacity Check

Portfolios (T1-T7)

Y2030



Y2040



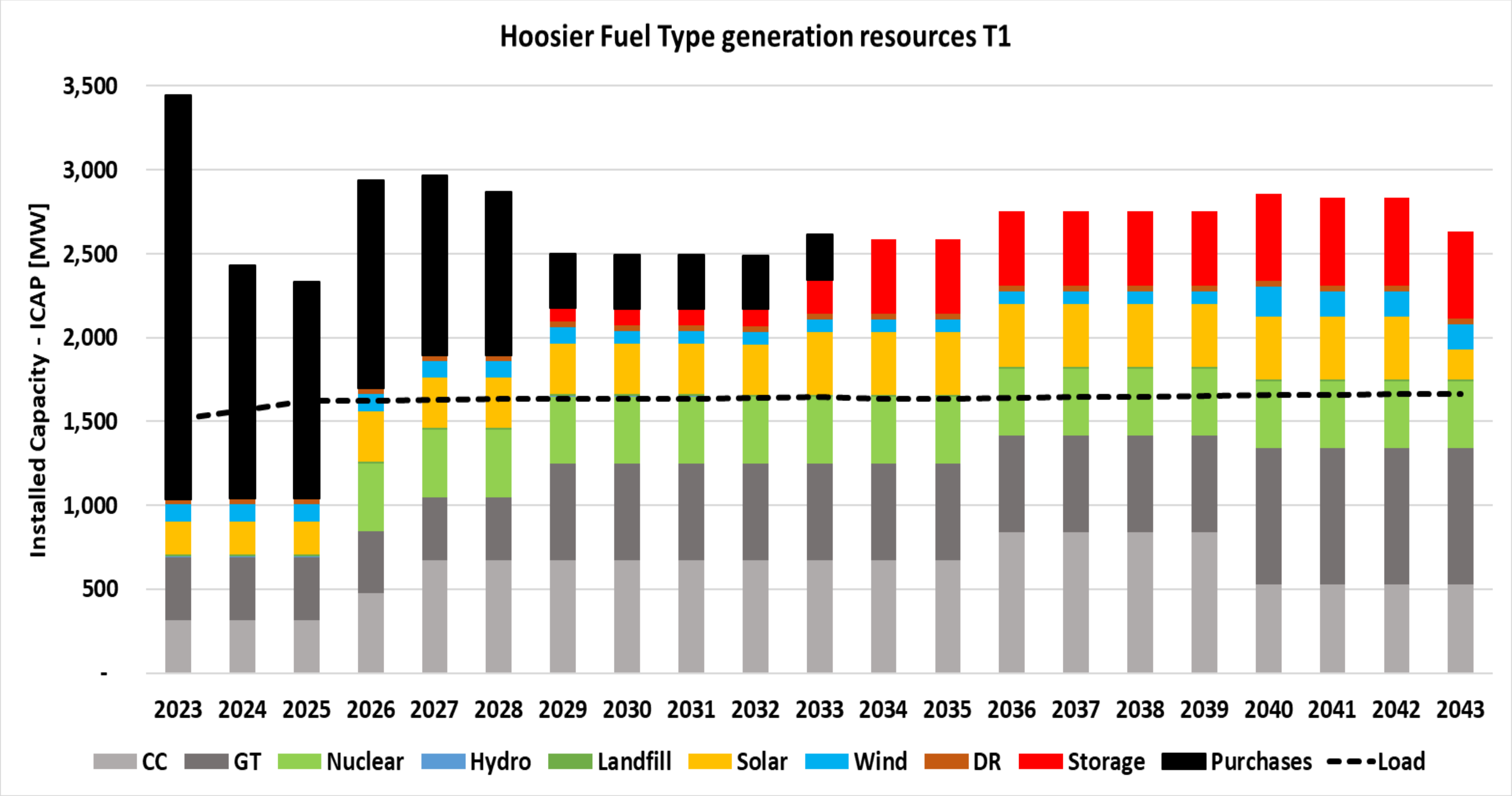
2030 Portfolio	T1 - Reference Case	T2 - Phase 1 EPA Rule	T3 -CO2 Tax Scenario	T4 - EPA and CO2 Tax	T5 - Agg Enviro	T6 - High Price Scenario	T7 - Low Price Scenario
Disp%	85%	72%	81%	67%	68%	67%	85%
S&W%	15.0%	28.0%	19.3%	33.4%	31.7%	32.8%	15.0%
RE Penetration %	6.9%	15.0%	7.5%	20.1%	18.4%	19.6%	6.9%

Portfolios:

- T1: Reference Case
- T2: Phase 1 EPA Rule
- T3: CO2 Tax Scenario
- T4: EPA and CO2 Tax
- T5: Aggressive Enviro
- T6: High Price Scenario
- T7: Low Price Scenario

2040 Portfolio	T1 - Reference Case	T2 - Phase 1 EPA Rule	T3 -CO2 Tax Scenario	T4 - EPA and CO2 Tax	T5 - Agg Enviro	T6 - High Price Scenario	T7 - Low Price Scenario
Disp%	81%	66%	58%	58%	58%	63%	86%
S&W%	19.3%	34.1%	42.4%	42.4%	42.2%	36.8%	13.9%
RE Penetration %	8.5%	19.3%	29.5%	29.5%	29.5%	23.9%	6.8%

Resource Portfolios (all Hoosier resources and load)



Gas Turbines plus Combined Cycle capacity increases from 690 MW in 2023 to 1415 MW in 2036.

CAPACITY CREDITS (Using ELCC and EFOR factors)

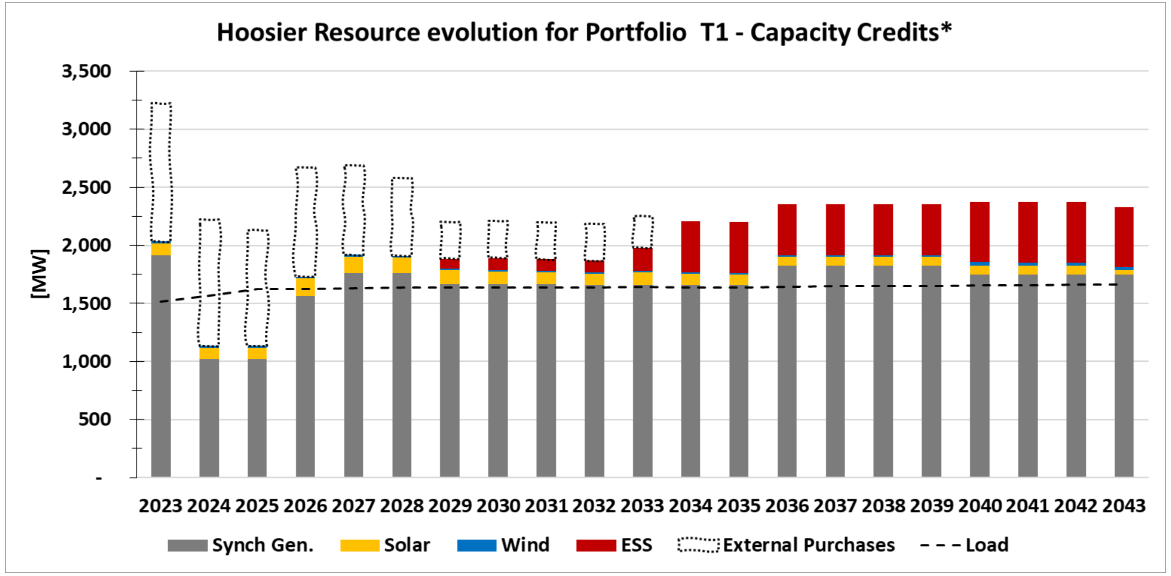
Effective Load Carrying Capability (ELCC)

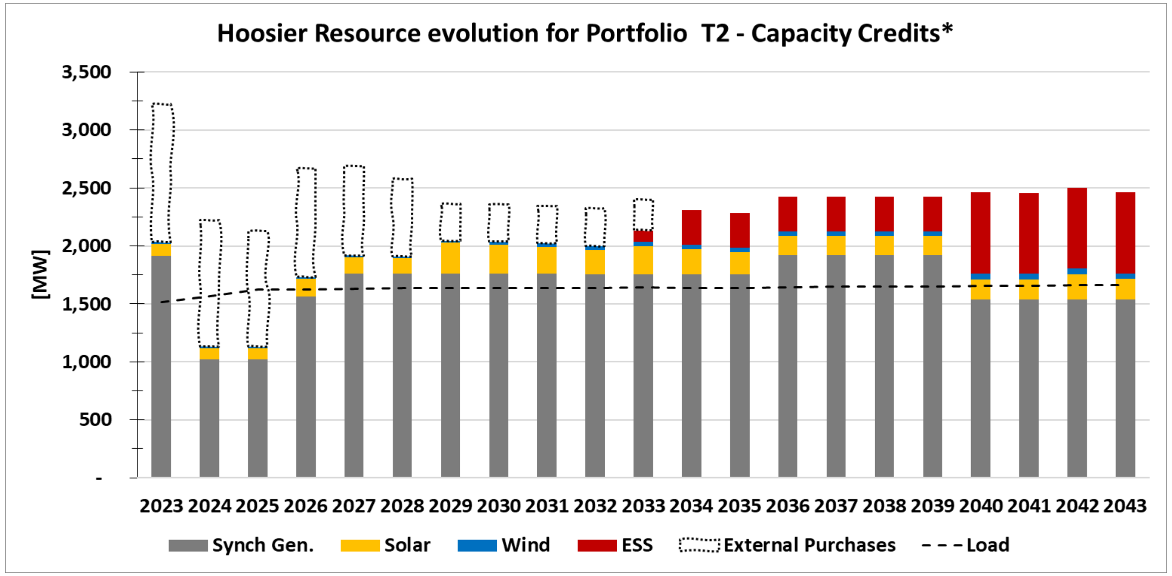
Technology	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Solar_ Winter	5.0%	5.0%	5.0%	5.0%	4.7%	4.4%	4.1%	3.8%	3.5%	3.2%	2.9%	2.6%	2.3%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Solar_ Other Seasons	50.0%	50.0%	50.0%	50.0%	47.0%	44.0%	41.0%	38.0%	35.0%	32.0%	29.0%	26.0%	23.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
Wind_ Summer	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%
Wind_ Fall	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%	18.9%
Wind_ Winter	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%	29.2%
Wind_ Spring	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%	24.9%

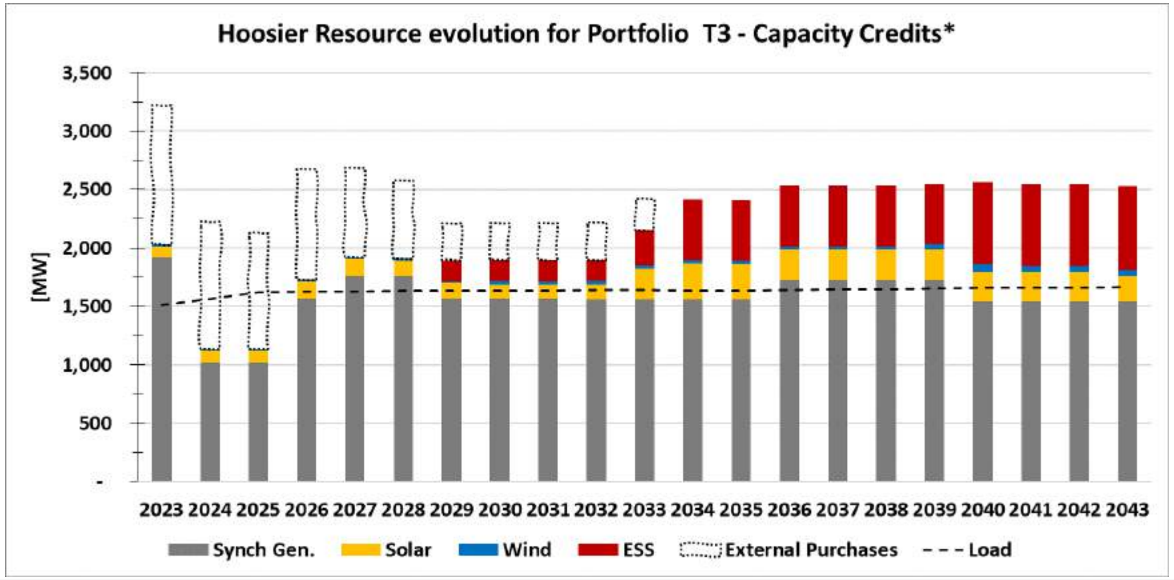
Equivalent Forced Outage Rate (EFOR)

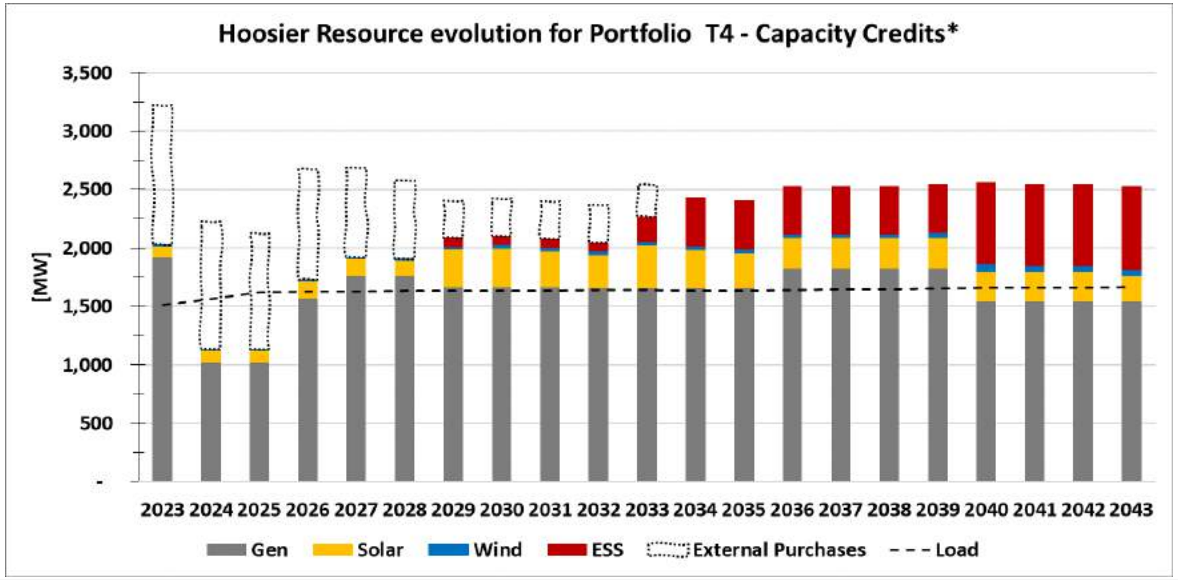
Technology	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Thermal Summer	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Thermal Fall	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Thermal Winter	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Thermal Spring	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%

Resource portfolios – Summer cases

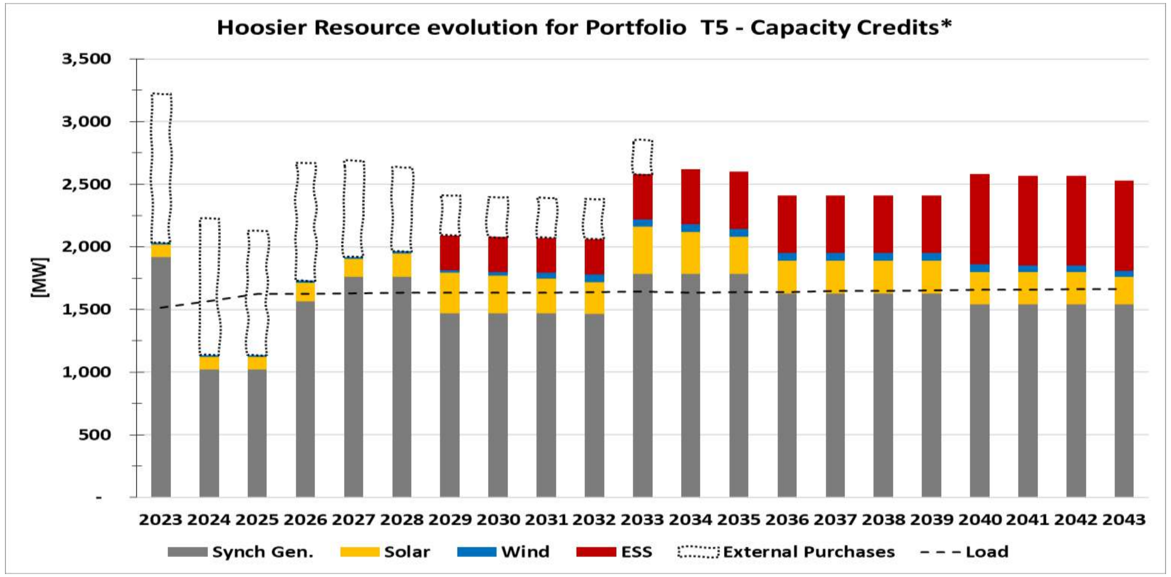


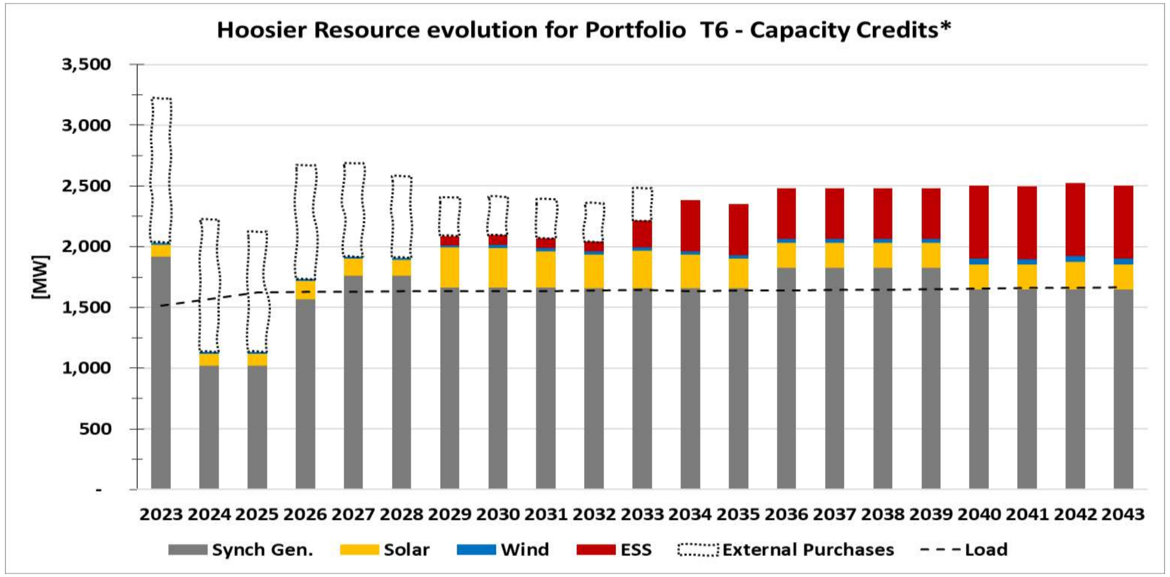


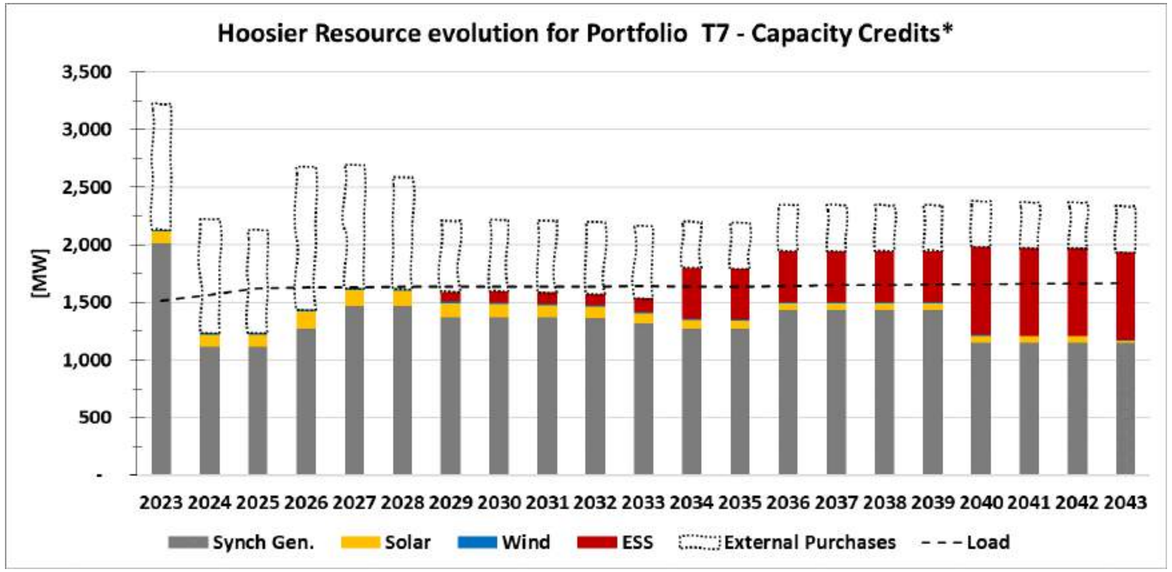




Resource portfolios – Summer cases



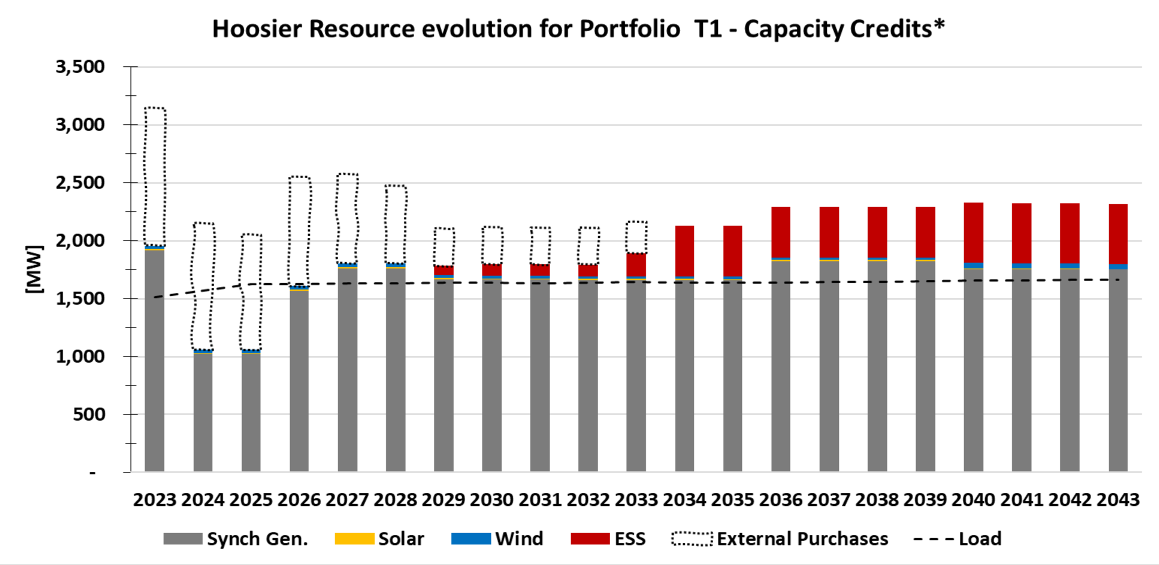


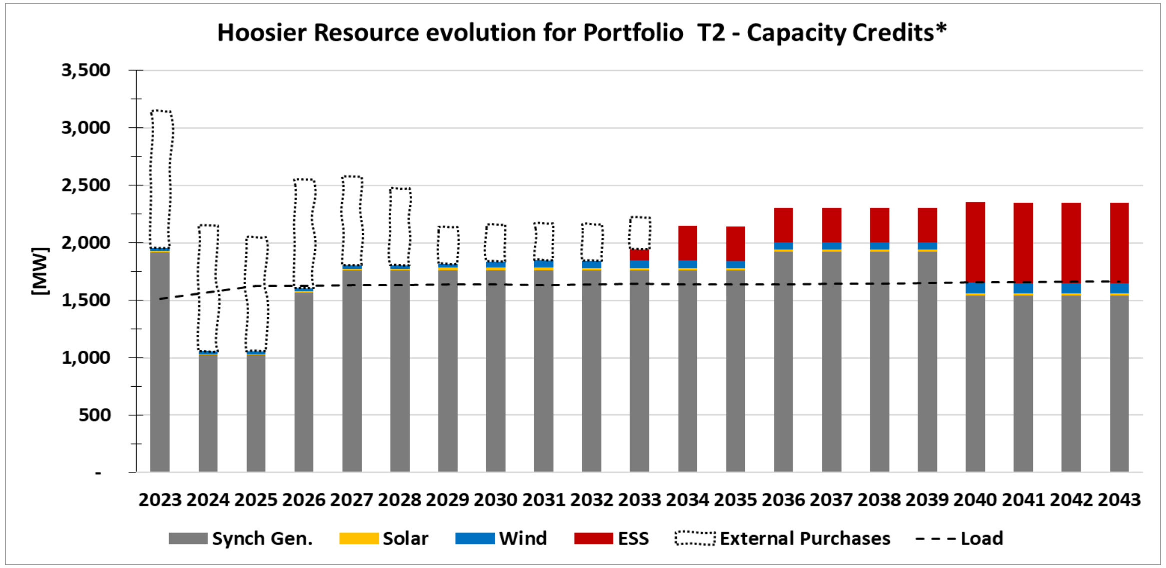


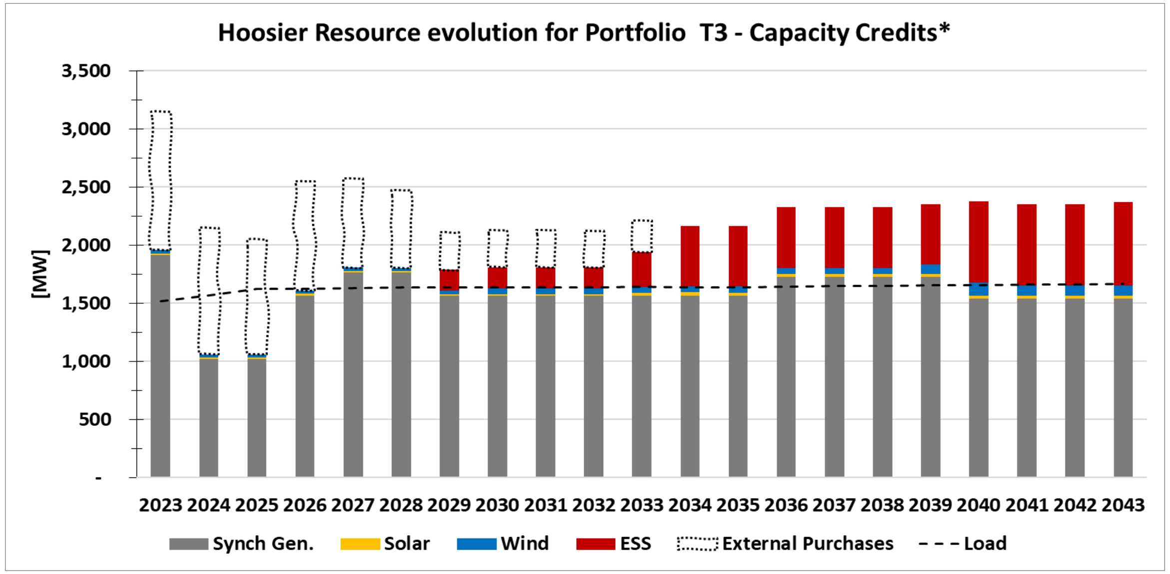
Summer peak load increases by 6.7% between 2023 and 2025, and after 2026 increases by 0.18% every year.

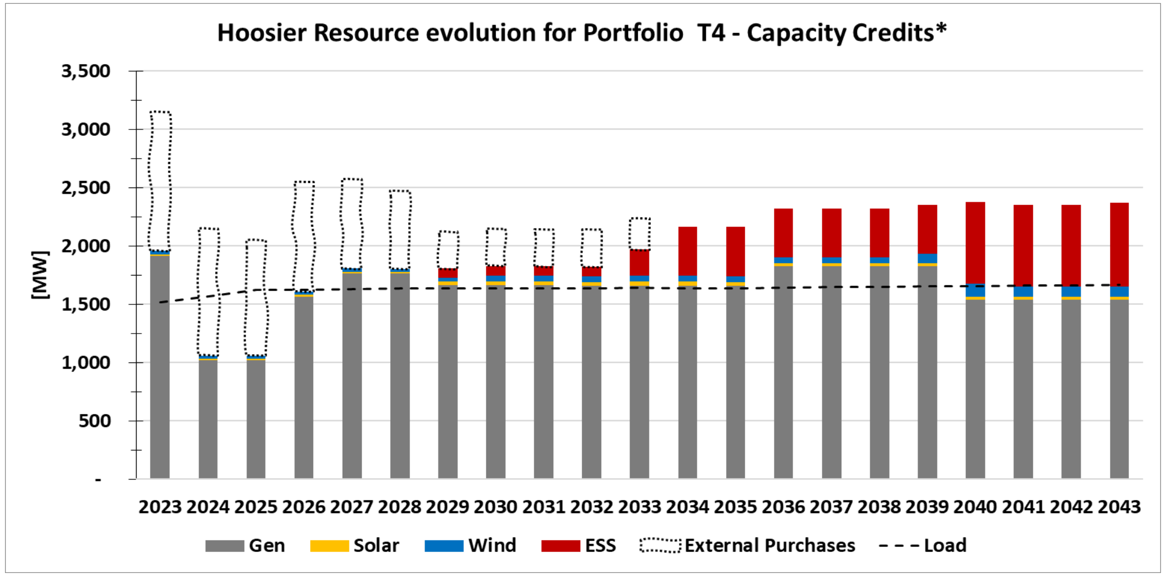
* Capacity credit calculation. Considers the use of ELCC and EFOR factors

Resource portfolios – Winter cases

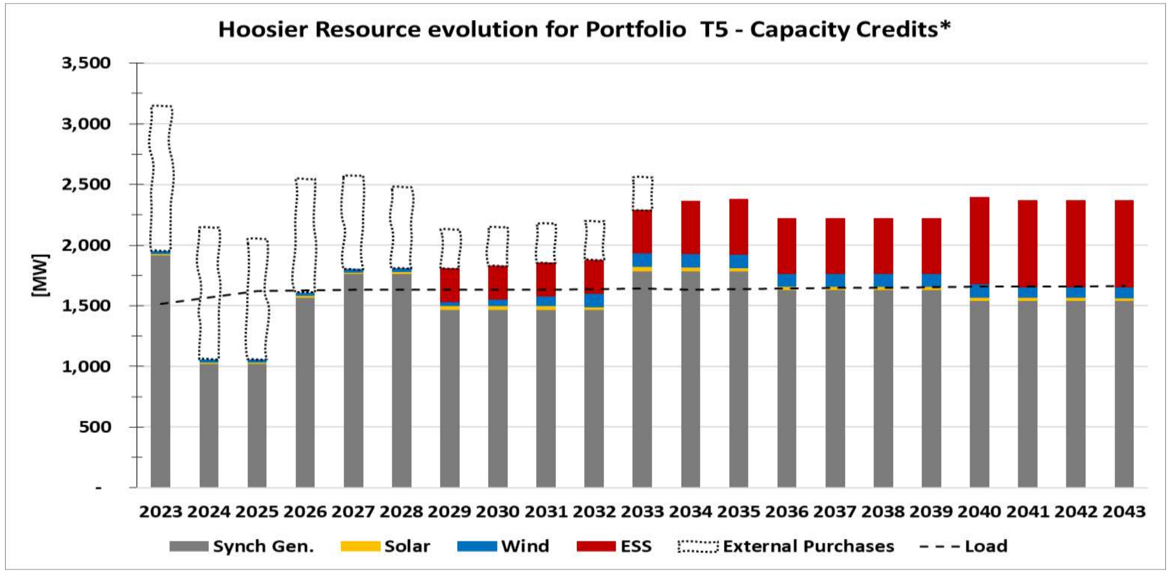


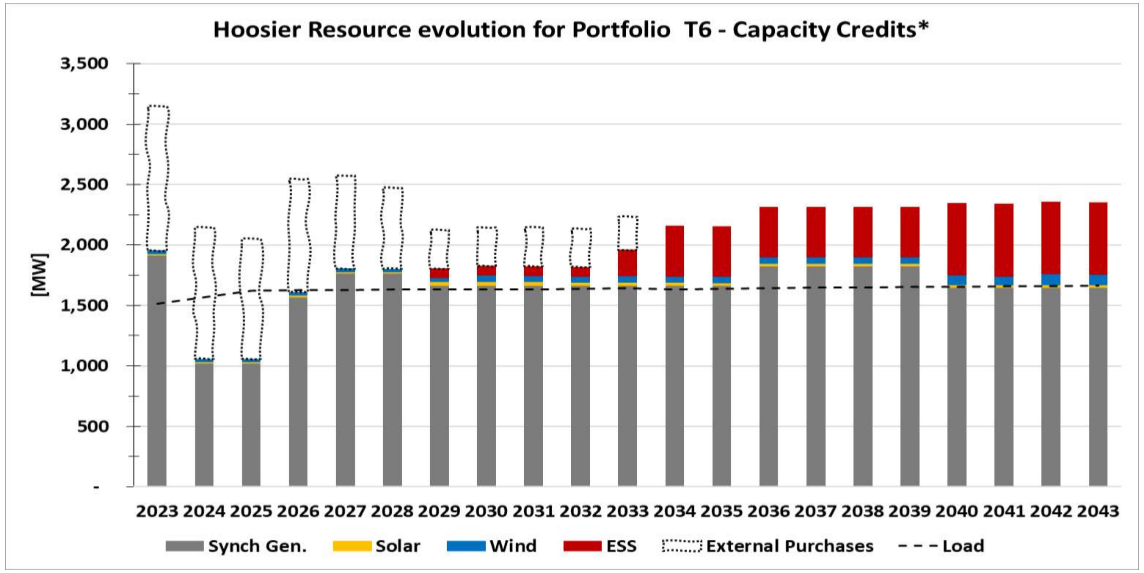


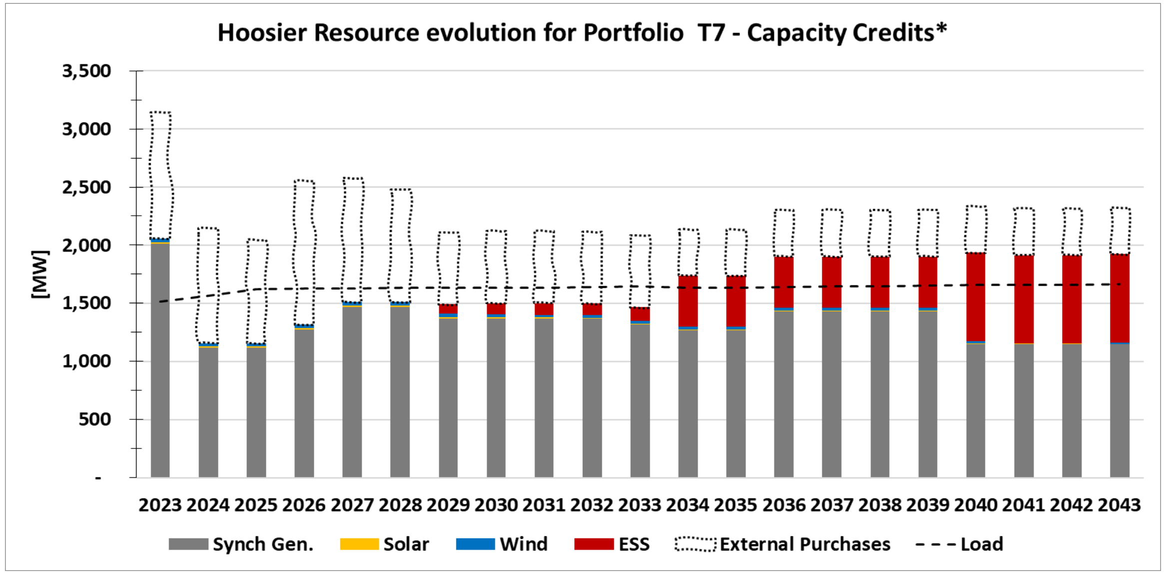




Resource portfolios – Winter cases

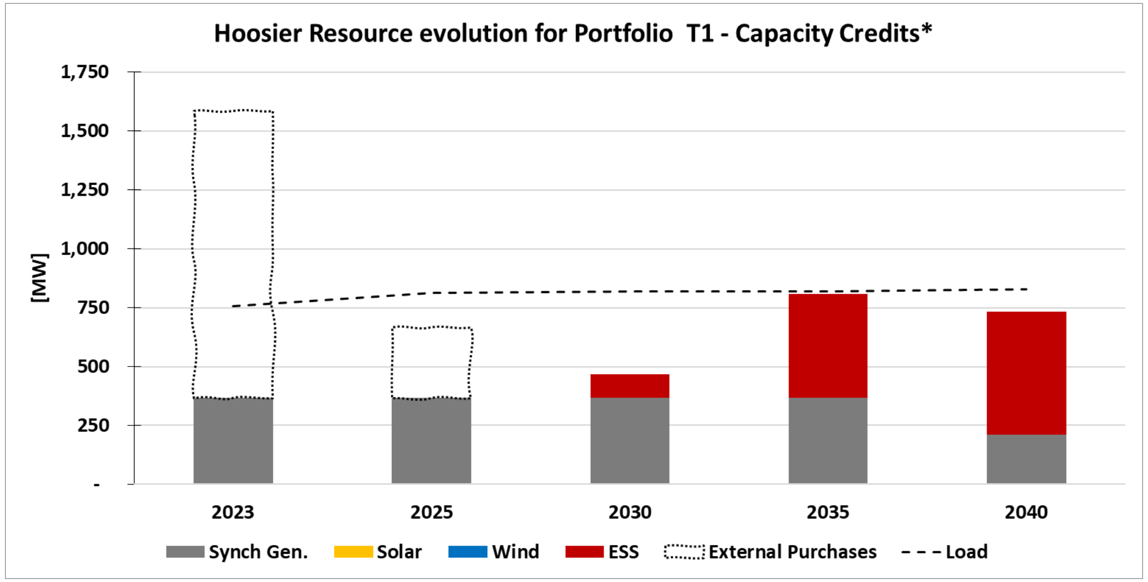


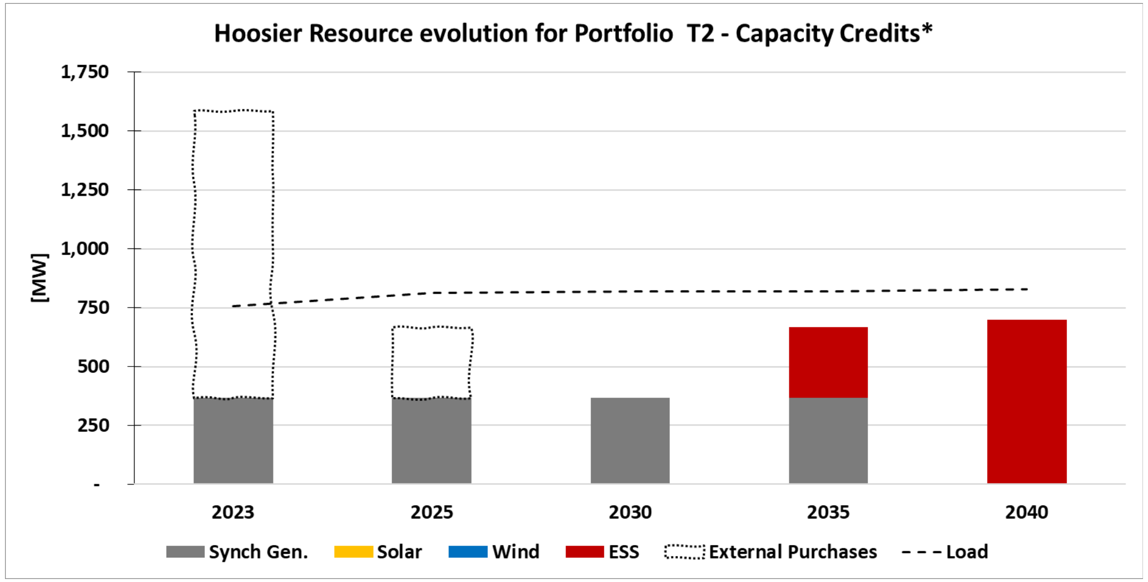


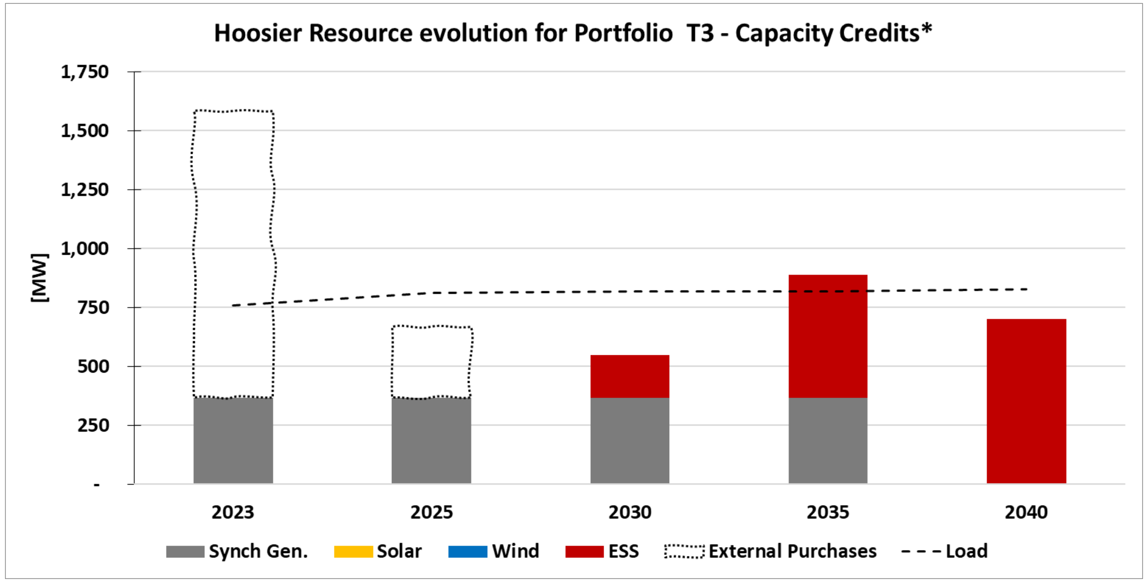


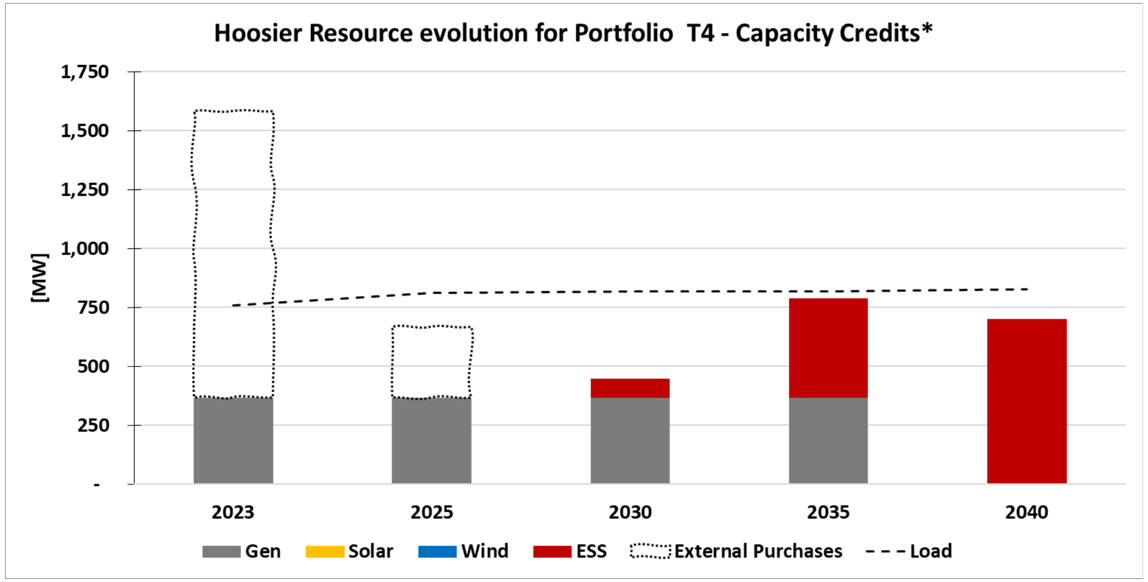
* Capacity credit calculation. Considers the use of ELCC and EFOR factors

Resource portfolios inside HEPN Territory – Area 207 (Summer and Winter)

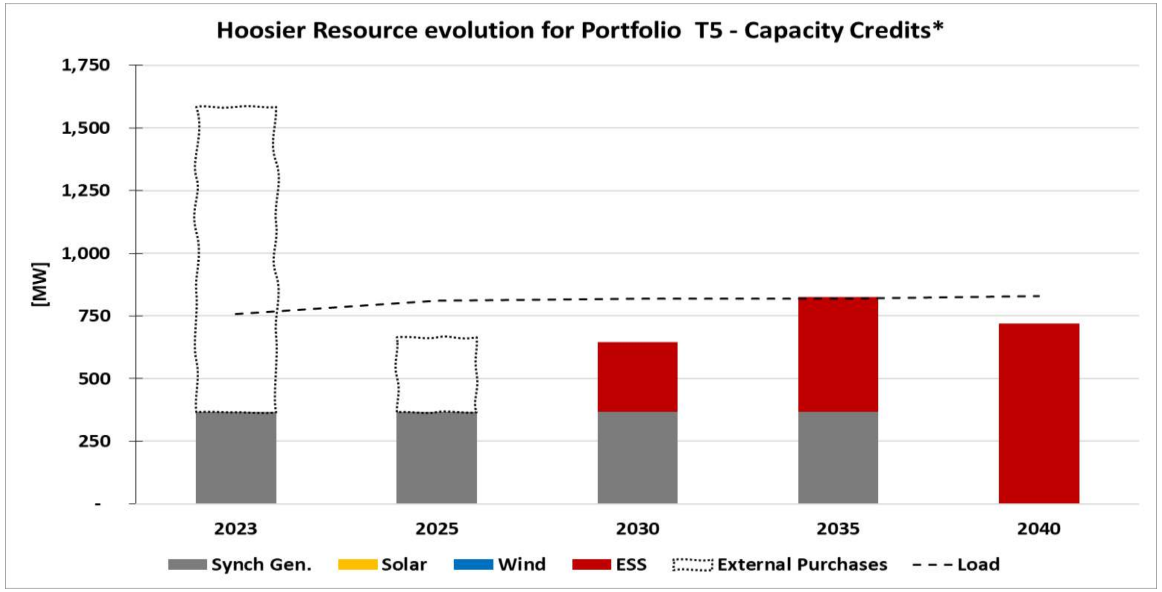


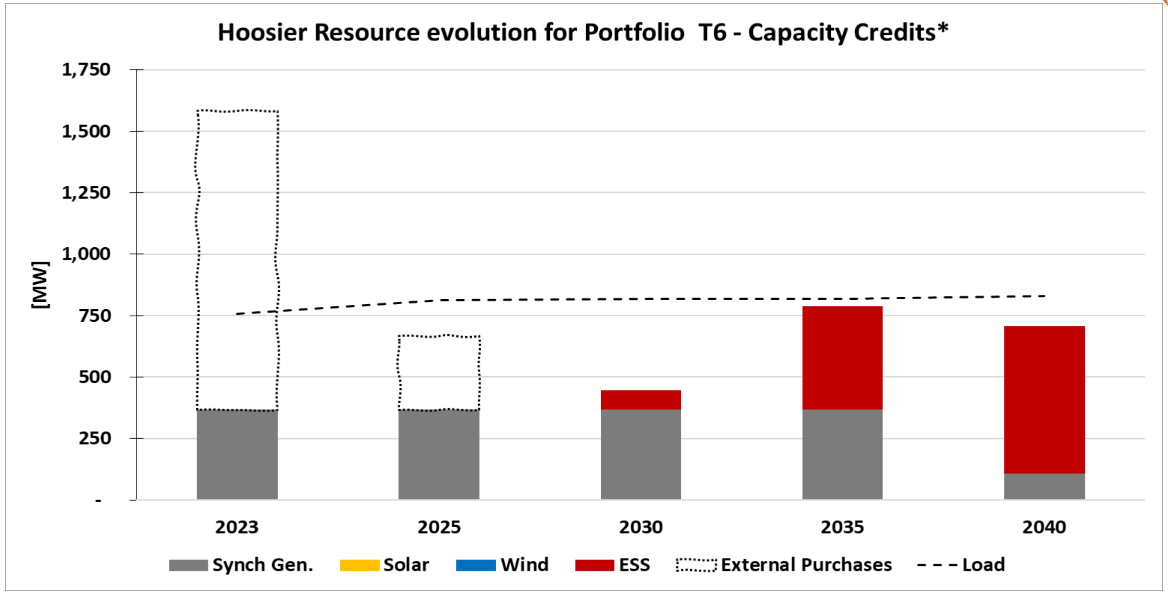


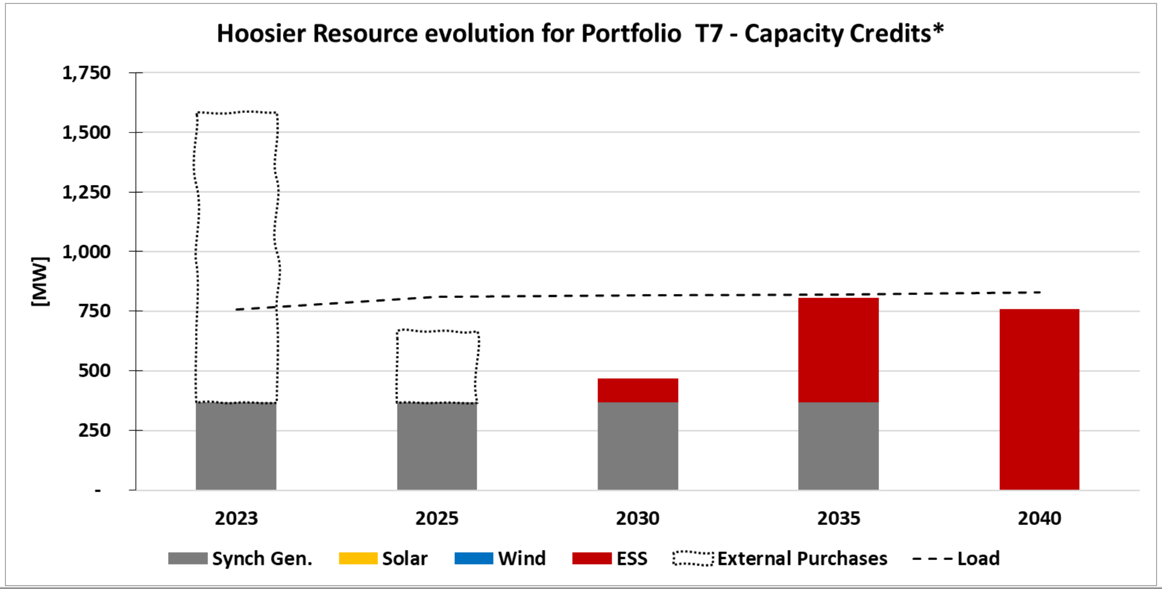




Resource portfolios inside HEPN Territory – Area 207 (Summer and Winter)







Observations and Comments

- The IRP portfolios replace purchases with a mix of thermal resources (nuclear, combined cycle, gas turbines), solar, and storage.
- All 7 portfolios have adequate capacity. However, location of resources mostly outside HE's Area 207 makes the area highly dependent on tie-lines. Without tie-lines, Area 207 is capacity deficient for all portfolios.
- Reserve margin in 2023 is excessive and will decrease substantially for all portfolios.
- Capacity will be highly dependent on solar and storage (and their ELCCs) instead of current dependance on thermal-backed resources. This will introduce risk as MISO revises downward the ELCC credits as penetration levels of renewable and storage increase.

Energy Adequacy Analysis

Metrics for Scoring Energy Adequacy

METRIC	DESCRIPTION	REFERENCE
LOLH	Number of Loss of Load Hours	LOLH <= 2.4 hours per year for the threshold 1-in-10 years
Outage Duration (days in 10 years)	Expected duration of outages (days in 10 years)	Days in 10 years = LOLH*24/10
LOLP	Loss of Load Probability	LOLP = LOLH/8760
EUE	Expected Unserved Energy	Total energy not served in a year (GWh)
LOLE (days in 10 years)	Expected number of days of interruption events in 10 years	Expected number of days in a year with load interruptions regardless of magnitude * 10
Max MW Short	Max Power Shortage (MW)	Max MW shortage at any hour in a year
Avg MW Short	Average Power Shortage (MW)	Average MW shortage during shortage hours
Min RM – Summer	Minimum reserve margin in Summer months	Lowest reserve margin for all hours in June-Aug
Min RM – Winter	Minimum reserve margin in Winter months	Lowest reserve margin for all hours in Dec-Feb

Note: “Min RM Summer” should be compared to the FPR target of **8.94%** in the Summer since it used UCAP instead of ICAP to calculate the reserve margins. Similarly, the “min RM – Winter” should be compared to the 21-27% target in Winter minus 5% or (**16**-22%).

Import Analysis of Area 207

	# Import Hrs																							
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	31	30	28	28	28	29	30	30	25	23	14	9	10	6	7	13	12	22	31	31	31	30	31	31
2	27	27	24	24	25	26	27	28	19	11	7	5	3	3	2	2	6	10	26	28	28	28	28	28
3	23	23	21	22	23	24	27	24	18	11	6	2	1	1	1	1	1	3	9	26	25	20	20	23
4	6	6	6	6	6	9	12	7	0	0	0	0	0	0	0	0	0	0	1	14	13	5	6	6
5	8	1	0	0	0	1	2	3	1	1	0	0	0	0	0	0	0	3	9	12	21	12	12	13
6	26	19	10	9	11	13	6	5	3	3	2	1	3	1	1	1	3	7	23	26	30	30	28	29
7	30	26	17	15	17	18	10	6	3	2	2	2	2	2	2	3	4	11	29	29	31	31	31	31
8	31	25	14	13	17	22	19	9	4	3	2	2	4	0	2	1	2	6	31	31	31	30	31	31
9	17	9	5	5	7	12	14	8	4	4	2	2	3	4	3	5	5	8	25	29	25	20	24	25
10	19	12	11	11	16	18	24	13	4	2	1	0	0	0	0	0	1	5	25	25	15	15	25	25
11	26	24	21	21	23	26	26	27	17	14	10	7	4	4	4	5	9	16	26	26	27	29	29	28
12	31	31	29	29	30	30	30	31	28	20	16	11	11	6	7	12	17	29	31	31	30	31	31	31

Year	2030	
Peak Load MW	817	
Annual Load GWh	4,366	
# Import Hrs	4,128	47.1%of time
# Export-Capable Hrs	4,592	52.4%of time
Import GWhs	483	11.1%of Load
Max Import MW	440	

Area 207 depends on imports to meet the energy needs of its load during 47% of the hours up to 440MWs, even after accounting for 4 solar sites not in HE's portfolios rated at 682MWs in 2030

Energy Adequacy Results – Portfolio T1

Energy Adequacy Metrics for Import 100%

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	753	807	813	813	823	
Annual Load GWh	3,948	4,232	4,261	4,266	4,317	
Avg MW Short	0	0	0	0	0	
Max MW Short	0	0	0	0	0	
Avg shortage GWhs	0	0	0	0	0	
Avg Interruption Duration (Days in 10 years)	0	0	0	0	0	
LOLE (#Interruption Days in 10 years)	0	0	0	0	0	
LOLP	0	0	0	0	0	
Min RM - Summer	314%	174%	149%	193%	180%	
Min RM - Winter	300%	162%	136%	177%	165%	
LOLH per year	0	0	0	0	0	

Energy Adequacy Metrics for Import 50%

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	753	807	813	813	823	
Annual Load GWh	3,948	4,232	4,261	4,266	4,317	
Avg MW Short	0	0	0	0	0	
Max MW Short	0	0	0	0	0	
Avg shortage GWhs	0	0	0	0	0	
Avg Interruption Duration (Days in 10 years)	0	0	0	0	0	
LOLE (#Interruption Days in 10 years)	0	0	0	0	0	
LOLP	0%	0%	0%	0%	0%	
Min RM - Summer	211%	78%	54%	98%	87%	
Min RM - Winter	203%	72%	47%	88%	77%	
LOLH per year	0	0	0	0	0	

Energy Adequacy Metrics for Import 0%

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	753	807	813	813	823	
Annual Load GWh	3,948	4,232	4,261	4,266	4,317	
Avg MW Short	0	203	454	455	615	
Max MW Short	0	281	523	524	658	
Avg shortage GWhs	0	39	1,294	1,298	2,601	
Avg Interruption Duration (Days in 10 years)	0	360	3,356	3,352	3,649	
LOLE (#Interruption Days in 10 years)	0	1,064	3,650	3,650	3,650	
LOLP	0%	10%	92%	92%	100%	
Min RM - Summer	108%	-18%	-55%	-55%	-74%	
Min RM - Winter	104%	-19%	-56%	-56%	-75%	
LOLH per year	0	864	8,055	8,046	8,757	

Energy Adequacy Metrics for 90/10 Load Forecast

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	850	911	917	918	929	
Annual Load GWh	4,167	4,467	4,497	4,502	4,556	
Avg MW Short	0	0	0	0	0	
Max MW Short	0	0	0	0	0	
Avg shortage GWhs	0	0	0	0	0	
Avg Interruption Duration (Days in 10 years)	0	0	0	0	0	
LOLE (#Interruption Days in 10 years)	0	0	0	0	0	
LOLP	0%	0%	0%	0%	0%	
Min RM - Summer	284%	154%	131%	172%	160%	
Min RM - Winter	254%	132%	109%	146%	135%	
LOLH per year	0	0	0	0	0	

Energy Adequacy Results – Portfolio T2

Energy Adequacy Metrics for Import 100%

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	753	807	813	813	823	
Annual Load GWh	3,948	4,232	4,261	4,266	4,317	
Avg MW Short	0	0	0	0	0	
Max MW Short	0	0	0	0	0	
Avg shortage GWhs	0	0	0	0	0	
Avg Interruption Duration (Days in 10 years)	0	0	0	0	0	
LOLE (#Interruption Days in 10 years)	0	0	0	0	0	
LOLP	0	0	0	0	0	
Min RM - Summer	314%	174%	136%	175%	175%	
Min RM - Winter	300%	162%	124%	160%	161%	
LOLH per year	0	0	0	0	0	

Energy Adequacy Metrics for Import 50%

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	753	807	813	813	823	
Annual Load GWh	3,948	4,232	4,261	4,266	4,317	
Avg MW Short	0	0	0	0	0	
Max MW Short	0	0	0	0	0	
Avg shortage GWhs	0	0	0	0	0	
Avg Interruption Duration (Days in 10 years)	0	0	0	0	0	
LOLE (#Interruption Days in 10 years)	0	0	0	0	0	
LOLP	0%	0%	0%	0%	0%	
Min RM - Summer	211%	78%	41%	80%	82%	
Min RM - Winter	203%	72%	35%	71%	73%	
LOLH per year	0	0	0	0	0	

Energy Adequacy Metrics for Import 0%

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	753	807	813	813	823	
Annual Load GWh	3,948	4,232	4,261	4,266	4,317	
Avg MW Short	0	203	454	455	823	
Max MW Short	0	281	523	524	828	
Avg shortage GWhs	0	39	1,306	1,299	4,316	
Avg Interruption Duration (Days in 10 years)	0	360	3,438	3,353	3,649	
LOLE (#Interruption Days in 10 years)	0	1,064	3,650	3,650	3,650	
LOLP	0%	10%	94%	92%	100%	
Min RM - Summer	108%	-18%	-55%	-55%	-100%	
Min RM - Winter	104%	-19%	-56%	-56%	-100%	
LOLH per year	0	864	8,252	8,047	8,758	

Energy Adequacy Metrics for 90/10 Load Forecast

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	850	911	917	918	929	
Annual Load GWh	4,167	4,467	4,497	4,502	4,556	
Avg MW Short	0	0	0	0	0	
Max MW Short	0	0	0	0	0	
Avg shortage GWhs	0	0	0	0	0	
Avg Interruption Duration (Days in 10 years)	0	0	0	0	0	
LOLE (#Interruption Days in 10 years)	0	0	0	0	0	
LOLP	0%	0%	0%	0%	0%	
Min RM - Summer	284%	154%	119%	155%	156%	
Min RM - Winter	254%	132%	98%	131%	131%	
LOLH per year	0	0	0	0	0	

Energy Adequacy Results – Portfolio T5

Energy Adequacy Metrics for Import 100%

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	753	807	813	813	823	
Annual Load GWh	3,948	4,232	4,261	4,266	4,317	
Avg MW Short	0	0	0	0	0	
Max MW Short	0	0	0	0	0	
Avg shortage GWhs	0	0	0	0	0	
Avg Interruption Duration (Days in 10 years)	0	0	0	0	0	
LOLE (#Interruption Days in 10 years)	0	0	0	0	0	
LOLP	0	0	0	0	0	
Min RM - Summer	314%	174%	172%	196%	178%	
Min RM - Winter	300%	162%	158%	180%	164%	
LOLH per year	0	0	0	0	0	

Energy Adequacy Metrics for Import 50%

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	753	807	813	813	823	
Annual Load GWh	3,948	4,232	4,261	4,266	4,317	
Avg MW Short	0	0	0	0	0	
Max MW Short	0	0	0	0	0	
Avg shortage GWhs	0	0	0	0	0	
Avg Interruption Duration (Days in 10 years)	0	0	0	0	0	
LOLE (#Interruption Days in 10 years)	0	0	0	0	0	
LOLP	0%	0%	0%	0%	0%	
Min RM - Summer	211%	78%	77%	100%	85%	
Min RM - Winter	203%	72%	69%	91%	75%	
LOLH per year	0	0	0	0	0	

Energy Adequacy Metrics for Import 0%

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	753	807	813	813	823	
Annual Load GWh	3,948	4,232	4,261	4,266	4,317	
Avg MW Short	0	203	454	455	823	
Max MW Short	0	281	523	524	828	
Avg shortage GWhs	0	39	1,294	1,298	4,316	
Avg Interruption Duration (Days in 10 years)	0	360	3,351	3,352	3,649	
LOLE (#Interruption Days in 10 years)	0	1,064	3,650	3,650	3,650	
LOLP	0%	10%	92%	92%	100%	
Min RM - Summer	108%	-18%	-55%	-55%	-100%	
Min RM - Winter	104%	-19%	-56%	-56%	-100%	
LOLH per year	0	864	8,042	8,045	8,758	

Energy Adequacy Metrics for 90/10 Load Forecast

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	850	911	917	918	929	
Annual Load GWh	4,167	4,467	4,497	4,502	4,556	
Avg MW Short	0	0	0	0	0	
Max MW Short	0	0	0	0	0	
Avg shortage GWhs	0	0	0	0	0	
Avg Interruption Duration (Days in 10 years)	0	0	0	0	0	
LOLE (#Interruption Days in 10 years)	0	0	0	0	0	
LOLP	0%	0%	0%	0%	0%	
Min RM - Summer	284%	154%	153%	174%	158%	
Min RM - Winter	254%	132%	129%	148%	133%	
LOLH per year	0	0	0	0	0	

Energy Adequacy Results – Portfolio T6

Energy Adequacy Metrics for Import 100%

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	753	807	813	813	823	
Annual Load GWh	3,948	4,232	4,261	4,266	4,317	
Avg MW Short	0	0	0	0	0	
Max MW Short	0	0	0	0	0	
Avg shortage GWhs	0	0	0	0	0	
Avg Interruption Duration (Days in 10 years)	0	0	0	0	0	
LOLE (#Interruption Days in 10 years)	0	0	0	0	0	
LOLP	0	0	0	0	0	
Min RM - Summer	314%	174%	146%	190%	176%	
Min RM - Winter	300%	162%	134%	175%	162%	
LOLH per year	0	0	0	0	0	

Energy Adequacy Metrics for Import 50%

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	753	807	813	813	823	
Annual Load GWh	3,948	4,232	4,261	4,266	4,317	
Avg MW Short	0	0	0	0	0	
Max MW Short	0	0	0	0	0	
Avg shortage GWhs	0	0	0	0	0	
Avg Interruption Duration (Days in 10 years)	0	0	0	0	0	
LOLE (#Interruption Days in 10 years)	0	0	0	0	0	
LOLP	0%	0%	0%	0%	0%	
Min RM - Summer	211%	78%	51%	95%	83%	
Min RM - Winter	203%	72%	44%	86%	74%	
LOLH per year	0	0	0	0	0	

Energy Adequacy Metrics for Import 0%

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	753	807	813	813	823	
Annual Load GWh	3,948	4,232	4,261	4,266	4,317	
Avg MW Short	0	203	454	455	719	
Max MW Short	0	281	523	524	743	
Avg shortage GWhs	0	39	1,294	1,298	3,459	
Avg Interruption Duration (Days in 10 years)	0	360	3,361	3,352	3,649	
LOLE (#Interruption Days in 10 years)	0	1,064	3,650	3,650	3,650	
LOLP	0%	10%	92%	92%	100%	
Min RM - Summer	108%	-18%	-55%	-55%	-87%	
Min RM - Winter	104%	-19%	-56%	-56%	-87%	
LOLH per year	0	864	8,067	8,046	8,758	

Energy Adequacy Metrics for 90/10 Load Forecast

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	850	911	917	918	929	
Annual Load GWh	4,167	4,467	4,497	4,502	4,556	
Avg MW Short	0	0	0	0	0	
Max MW Short	0	0	0	0	0	
Avg shortage GWhs	0	0	0	0	0	
Avg Interruption Duration (Days in 10 years)	0	0	0	0	0	
LOLE (#Interruption Days in 10 years)	0	0	0	0	0	
LOLP	0%	0%	0%	0%	0%	
Min RM - Summer	284%	154%	129%	170%	157%	
Min RM - Winter	254%	132%	107%	144%	132%	
LOLH per year	0	0	0	0	0	

Energy Adequacy Results – Portfolio T7

Energy Adequacy Metrics for Import 100%

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	753	807	813	813	823	
Annual Load GWh	3,948	4,232	4,261	4,266	4,317	
Avg MW Short	0	0	0	0	0	
Max MW Short	0	0	0	0	0	
Avg shortage GWhs	0	0	0	0	0	
Avg Interruption Duration (Days in 10 years)	0	0	0	0	0	
LOLE (#Interruption Days in 10 years)	0	0	0	0	0	
LOLP	0	0	0	0	0	
Min RM - Summer	314%	174%	149%	193%	183%	
Min RM - Winter	300%	162%	136%	177%	168%	
LOLH per year	0	0	0	0	0	

Energy Adequacy Metrics for Import 50%

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	753	807	813	813	823	
Annual Load GWh	3,948	4,232	4,261	4,266	4,317	
Avg MW Short	0	0	0	0	0	
Max MW Short	0	0	0	0	0	
Avg shortage GWhs	0	0	0	0	0	
Avg Interruption Duration (Days in 10 years)	0	0	0	0	0	
LOLE (#Interruption Days in 10 years)	0	0	0	0	0	
LOLP	0%	0%	0%	0%	0%	
Min RM - Summer	211%	78%	54%	98%	90%	
Min RM - Winter	203%	72%	47%	88%	80%	
LOLH per year	0	0	0	0	0	

Energy Adequacy Metrics for Import 0%

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	753	807	813	813	823	
Annual Load GWh	3,948	4,232	4,261	4,266	4,317	
Avg MW Short	0	203	454	455	823	
Max MW Short	0	281	523	524	828	
Avg shortage GWhs	0	39	1,294	1,298	4,316	
Avg Interruption Duration (Days in 10 years)	0	360	3,356	3,352	3,649	
LOLE (#Interruption Days in 10 years)	0	1,064	3,650	3,650	3,650	
LOLP	0%	10%	92%	92%	100%	
Min RM - Summer	108%	-18%	-55%	-55%	-100%	
Min RM - Winter	104%	-19%	-56%	-56%	-100%	
LOLH per year	0	864	8,055	8,046	8,758	

Energy Adequacy Metrics for 90/10 Load Forecast

METRIC / Year	2023	2025	2030	2035	2040	Trend
Peak Load MW	850	911	917	918	929	
Annual Load GWh	4,167	4,467	4,497	4,502	4,556	
Avg MW Short	0	0	0	0	0	
Max MW Short	0	0	0	0	0	
Avg shortage GWhs	0	0	0	0	0	
Avg Interruption Duration (Days in 10 years)	0	0	0	0	0	
LOLE (#Interruption Days in 10 years)	0	0	0	0	0	
LOLP	0%	0%	0%	0%	0%	
Min RM - Summer	284%	154%	131%	172%	163%	
Min RM - Winter	254%	132%	109%	146%	138%	
LOLH per year	0	0	0	0	0	

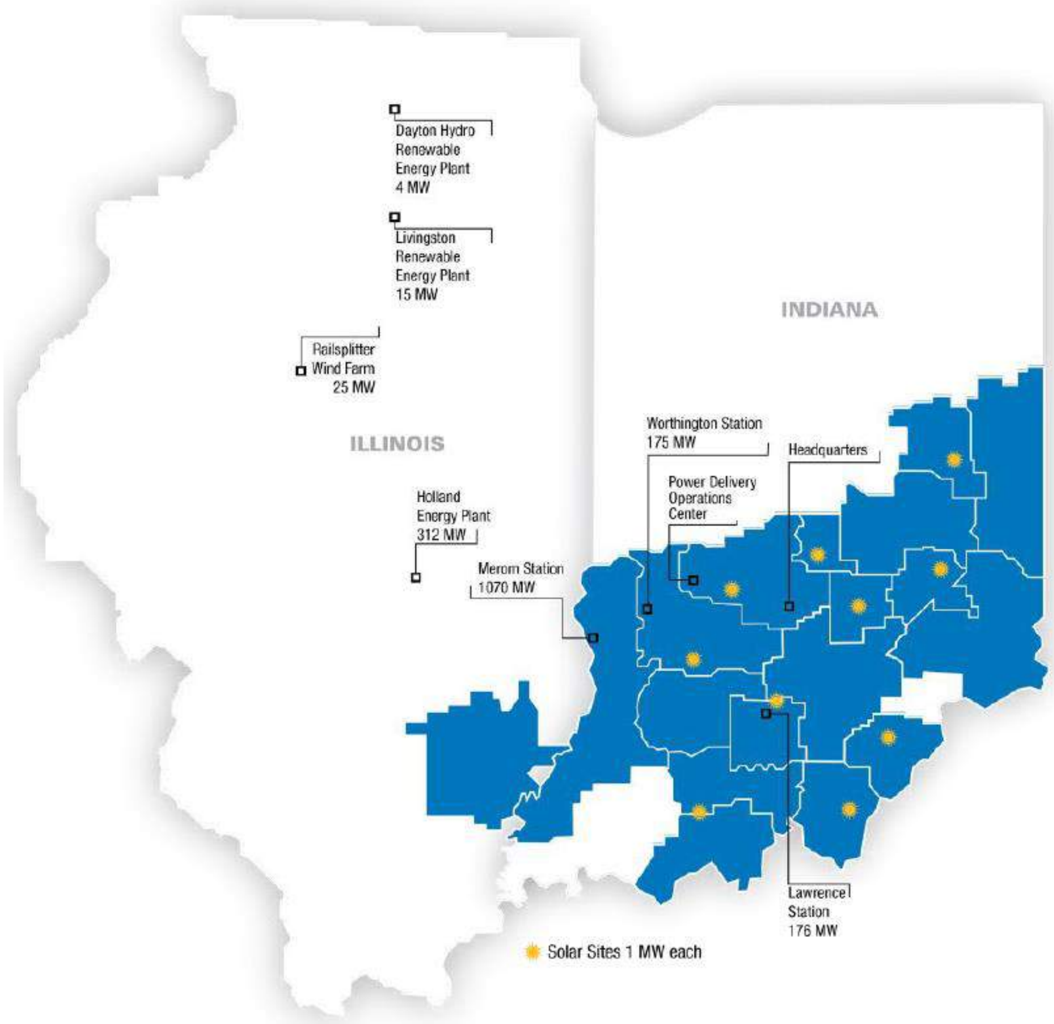
Observations and Comments

- The portfolio is able to meet the energy requirements of HE’s load inside and outside of Area 207 even at the extreme load forecast (i.e., 90/10) **IF** the tie-line import capability of 1463MW does not drop below the 550 MW level.
- Area 207 is dependent on imports almost 4000-6000 hours in a year and 10-15% of its energy consumption, depending on portfolio, after accounting for the 4 solar projects in the MISO Queue.
- Hoosier's total load in the area 207 can be met by transmission imports from neighboring systems (between 177% and 193% of total load).
- Between 177% and 242% of the peak load can be satisfied with Synchronous Generation plus Transmission imports, with an average of 219% among the 7 portfolios. Considering this external support, no energy adequacy problem could be identified in the system with 100% or 50% import capacity or with the 90/10 load forecast.
- The case of Import 0 % or area 207 in island operation is only secure for year 2023, considering the internal purchases. For the following years, the violation in the energy adequacy metrics occurs for all the portfolios:
    - The number of Interruption days in 10 years - LOLE surpasses the limit value of 1. Starts with 36 days in 2025 and reaches 365 days for the year 2040.
    - The maximum MW shortage is 828 MW and can occur in the year 2040.
    - The required reserve margin for safe operation is violated starting from 2025 for all the portfolios.

Grid – Demand – Profiles - Resources

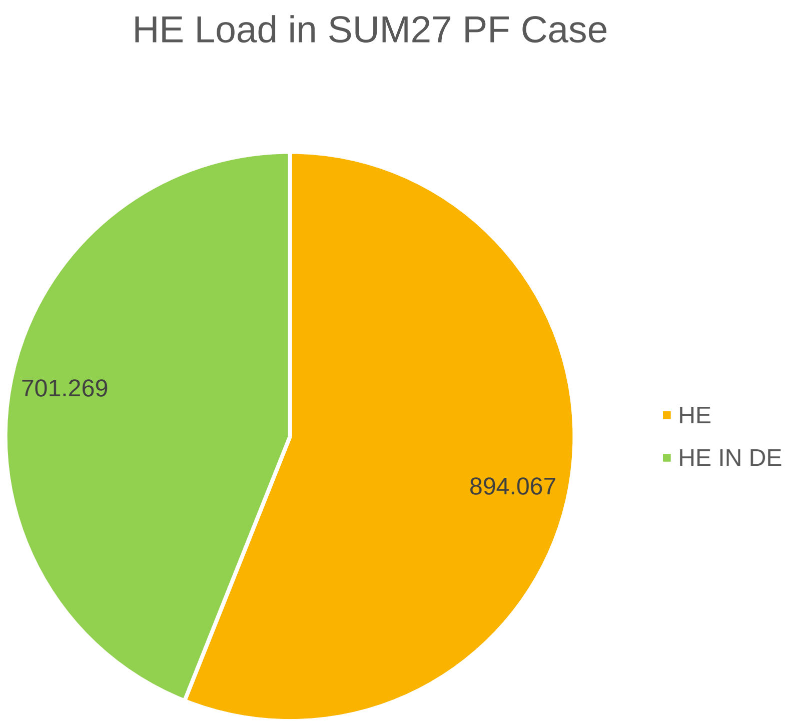
Hoosier Energy Territory and Electrical System Review

- Hoosier Energy serves load in Indiana and Illinois
- About 900MW of load is served by HE transmission system and 700MW is served by Duke Energy, based on the SUM27 PF case
- The remainder of the HE load is served off the following systems:
  - 5% off Ameren transmission system,
  - about 1% each off IPL, Vectren, LGE (not in MISO) and AEP (in PJM).
- HE generation assets are mostly in Indiana within the HE system (1760MW), and in Illinois (roughly 350MW).



Hoosier Energy Territory and Electrical System Review (Cont.)

- The HE load in the Duke Territory is scattered and not concentrated in one load pocket
- The Duke Energy system is large enough that serving HE's 700 MW is not at risk
- The HE system is capable of exporting about 400 MW to the DE system
- The HE system can import about 1463 MW from interconnected neighboring systems



Area Import Limits

- Thermal Limits:

Monitored Facility	TrLim	Cont Name
254638 16PETE 138 248428 07RATTAP 138 Z1	1463.3	P23:138:DEI-HE:HE WORTHINGTON 572_Dup1

- Voltage Limits:

Cont Name	MW Transfer at Vlow Limit	Bus # (Vmag Vio)	Bus Name	Base Volt	Cont Volt
13:230:GRE:SPARE_MN_GRE_2	3253.13	248888	07LCPROJ	0.7817	0.7811

Area Export Limit to Duke Energy

- Thermal Limits:

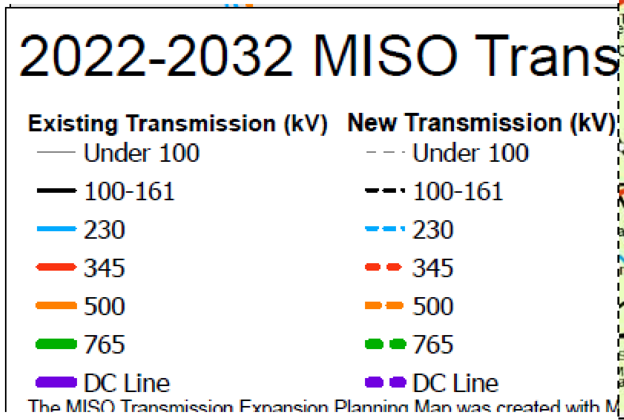
Monitored Facility	TrLim	Cont Name
248793 07BLOMNG 345 249640 08BLOOM2 230 2	410.6	P13:345-230:HE:07BLOMNG:1

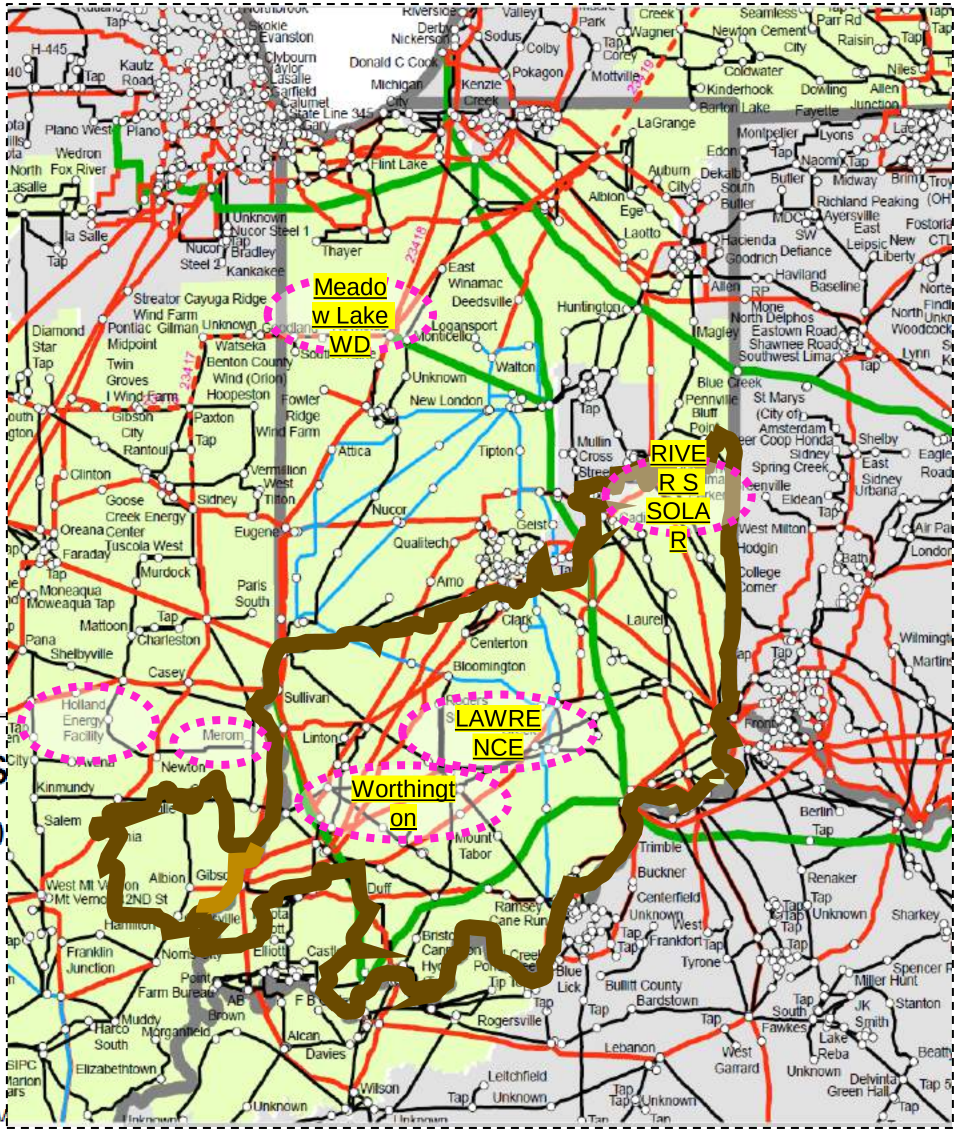
- Voltage Limits:

Cont Name	MW Transfer at Vlow Limit	Bus # (Vmag Vio)	Bus Name	Base Volt	Cont Volt
13:230:GRE:SPARE_MN_GRE_2	1006.25	248794	07CRTLND	0.9332	0.933

Hoosier Energy Service Territory

Hoosier Energy territory connected internally and with surrounding areas with a 765, 345, 230, 138, 69 and 34.5 kV network.





Hoosier Energy Power Balance

Loads per area 207 (HE) and 208 (HE in DE)

- Hoosier Energy loads in Area 207 sum 894 MW (PSS/E model for 2027)
- 701 MW are 99 Hoosier Loads served in area 208 by Duke Energy.
- 143 MW in 19 HE loads that share Buses with DEI in Area 208

kV	HE	HE IN DE	Total
13.8	25		25
22.8	67		67
34.5		35	35
69.0	613	493	1,106
138.0		174	174
161.0	188		188
Total	**894**	**701**	**1,595**

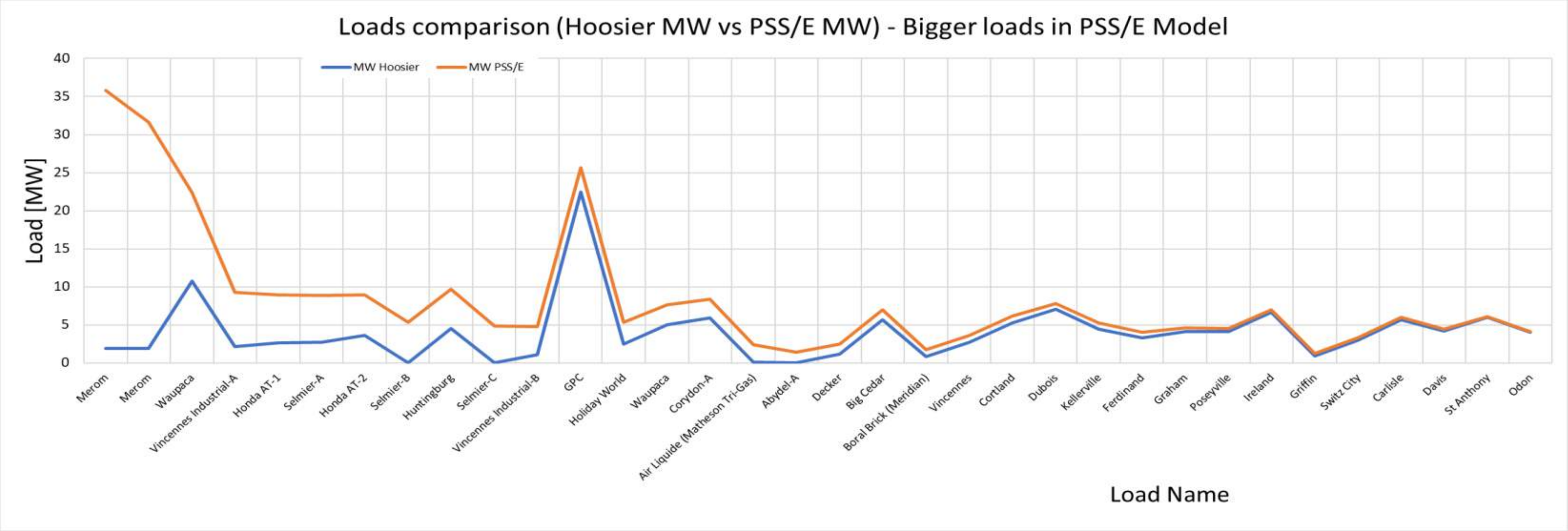
Area 207: Comparing Mapped loads in Hoosier Model and PSS/E Model

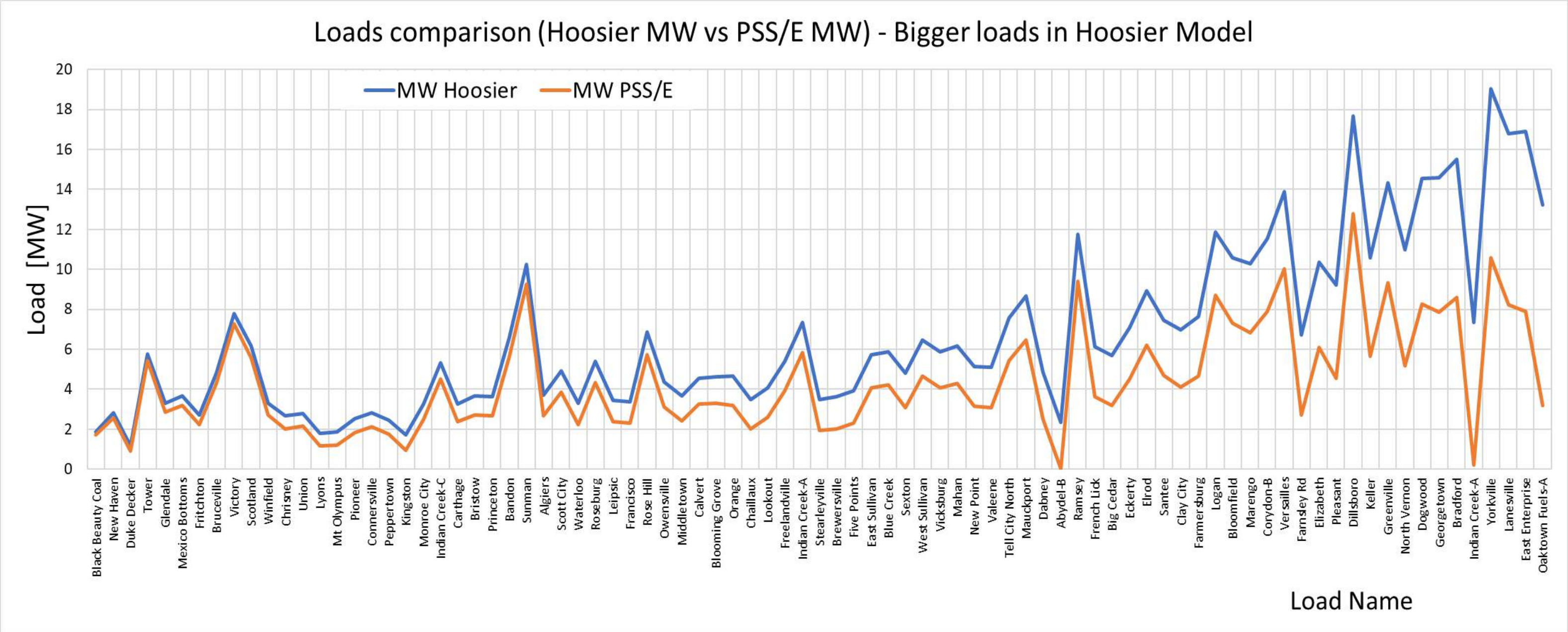
Hoosier Name	MW Hoosier	MW PSS/E	PSS/E Name
Merom	1.89	35.80	07MEROM1
Merom	1.89	31.60	07MEROM2
Waupaca	10.72	22.37	07WAP_HE
Vincennes Industrial-A	2.11	9.26	07VINSIP
Honda AT-1	2.60	8.95	07HONDA3
Selmier-A	2.69	8.88	07SELMIR
Honda AT-2	3.60	8.98	07HONDA4
Selmier-B	0.02	5.33	07SELMIR
Huntingburg	4.55	9.70	07HUNTBG
Selmier-C	0.03	4.87	07SELMIR
Vincennes Industrial-B	1.10	4.77	07VINSIP
GPC	22.49	25.67	07GPC
Holiday World	2.47	5.37	07HDYWD
Waupaca	5.02	7.62	07WILBUR
Corydon-A	5.88	8.38	07CORYDN
Air Liquide (Matheson Tri-Gas)	0.10	2.43	07AIRLIQ
Abydel-A	0.02	1.40	07ABYDEL
Decker	1.16	2.46	07DECKER
Boral Brick (Meridian)	0.85	1.77	07BORALB
Vincennes	2.71	3.60	07VINCEN
Cortland	5.27	6.15	07CRTLND
Dubois	7.04	7.84	07DUBOIS
Kellerville	4.43	5.22	07KLLRVL
Ferdinand	3.29	4.02	07FERDND
Graham	4.12	4.61	07GRAHAM
Poseyville	4.12	4.53	07POSYVL
Ireland	6.63	7.01	07IRELND
Griffin	0.91	1.26	07GRIFIN
Switz City	2.98	3.32	07SWTZ_C
Carlisle	5.70	6.01	07CARLIL
Davis	4.19	4.47	07DAVIS
Odon	4.04	4.09	07ODON
Buechler	6.63	6.68	07BUECLR
Cumback	4.00	4.03	07CUMBAC
Black Beauty Coal	1.87	1.70	07DEI_BLCKB
New Haven	2.80	2.55	07NW_HAV
Duke Decker	1.16	0.89	07DEI_DCKRE
Tower	5.76	5.43	07DEI_TOWER
Glendale	3.30	2.87	07GLENDL
Mexico Bottoms	3.65	3.19	07MEX_BM

Hoosier Name	MW Hoosier	MW PSS/E	PSS/E Name
Fritchton	2.70	2.23	07FRICTN
Bruceville	4.81	4.30	07BRUCVL
Victory	7.78	7.26	07VICTRY
Scotland	6.16	5.58	07SCTLND
Winfield	3.30	2.70	07WINFLD
Chrisney	2.65	2.03	07CHRNEY
Union	2.77	2.14	07UNION
Lyons	1.80	1.17	07LYONS
Mt Olympus	1.86	1.19	07MTOLYMPS
Pioneer	2.52	1.83	07PIONEER
Connersville	2.82	2.11	07CONVIL
Peppertown	2.46	1.74	07PEPRTN
Kingston	1.72	0.95	07KNG_SW
Monroe City	3.26	2.49	07MNRO_C
Indian Creek-C	5.34	4.50	07INDCRK
Carthage	3.27	2.37	07CARTHA
Bristow	3.67	2.73	07BRISTW
Princeton	3.63	2.68	07PRNCTN
Bandon	6.62	5.66	07BANDON
Sunman	10.23	9.24	07SUNAMN
Algiers	3.69	2.68	07ALGIER
Scott City	4.90	3.86	07SCT_CY
Waterloo	3.29	2.24	07WATRLO
Roseburg	5.38	4.32	07ROSEBG
Leipsic	3.45	2.37	07LEIPSIC
Francisco	3.38	2.29	07FRNCSC
Rose Hill	6.87	5.72	07ROSHIL
Owensville	4.38	3.12	07OWNVIL
Middletown	3.67	2.41	07MIDLTN
Calvert	4.54	3.27	07CALVRT
Blooming Grove	4.61	3.31	07BLMGRV
Orange	4.64	3.20	07ORANGE
Chaillaux	3.48	2.02	07CHAILX
Lookout	4.07	2.58	07LOKOUT
Freelandville	5.41	3.92	07FRELND
Indian Creek-A	7.33	5.83	07INDCRK
Stearleyville	3.47	1.94	07STRYVL
Brewersville	3.61	2.01	07BRWRVL
Five Points	3.92	2.30	07FVEPTS
East Sullivan	5.73	4.08	07ESLVIN_TP

Hoosier Name	MW Hoosier	MW PSS/E	PSS/E Name
Blue Creek	5.87	4.21	07BLU_CK
Sexton	4.79	3.07	07SEXTON
West Sullivan	6.47	4.67	07WSLVIN
Vicksburg	5.89	4.08	07VCKSBG
Mahan	6.16	4.30	07MAHAN
New Point	5.14	3.13	07NEW_PT
Valeene	5.09	3.06	07VALEEN
Tell City North	7.57	5.44	07TEL_CY
Mauckport	8.68	6.45	07MCKPRT
Dabney	4.83	2.50	07DABNEY
Abydel-B	2.36	0.02	07ABYDEL
Ramsey	11.76	9.40	07RAMSY
French Lick	6.12	3.64	07FRN_LK
Big Cedar	5.69	3.18	07BG_CDR
Eckerty	7.10	4.51	07ECKRTY
Elrod	8.91	6.19	07ELROD
Santee	7.45	4.71	07SANTEE
Clay City	6.96	4.11	07CLY_CY
Farmersburg	7.63	4.66	07FRMBRG
Logan	11.88	8.69	07LOGAN
Bloomfield	10.57	7.30	07BLMFLD
Marengo	10.27	6.81	07DEI_MARNG
Corydon-B	11.54	7.89	07CORYDN
Versailles	13.89	10.03	07VERSLJ
Farnsley Rd	6.72	2.69	07FARNSLEY
Elizabeth	10.37	6.10	07ELIZBH
Pleasant	9.23	4.53	07PLSANT
Dillsboro	17.66	12.79	07DILBOR
Keller	10.57	5.66	07KELLER
Greenville	14.31	9.31	07GRENVL
North Vernon	10.99	5.17	07N.VERN
Dogwood	14.55	8.26	07DOGWOD
Georgetown	14.59	7.84	07GRG_TN
Bradford	15.49	8.59	07BRDFRD
Indian Creek-A	7.33	0.20	07INDCRK
Yorkville	19.03	10.57	07YRKVIL
Lanesville	16.81	8.22	07LANVIL
East Enterprise	16.89	7.89	07E.ENTR
Oaktown Fuels-A	13.21	3.19	07OAKTN_P2
Big Cedar	5.69	6.99	07DEI_L_CDR
St Anthony	5.97	6.05	07S.ANTY
TOTAL	**714.98**	**659.46**	

Area 207: Comparing Loads comparison Hoosier and PSS/E models





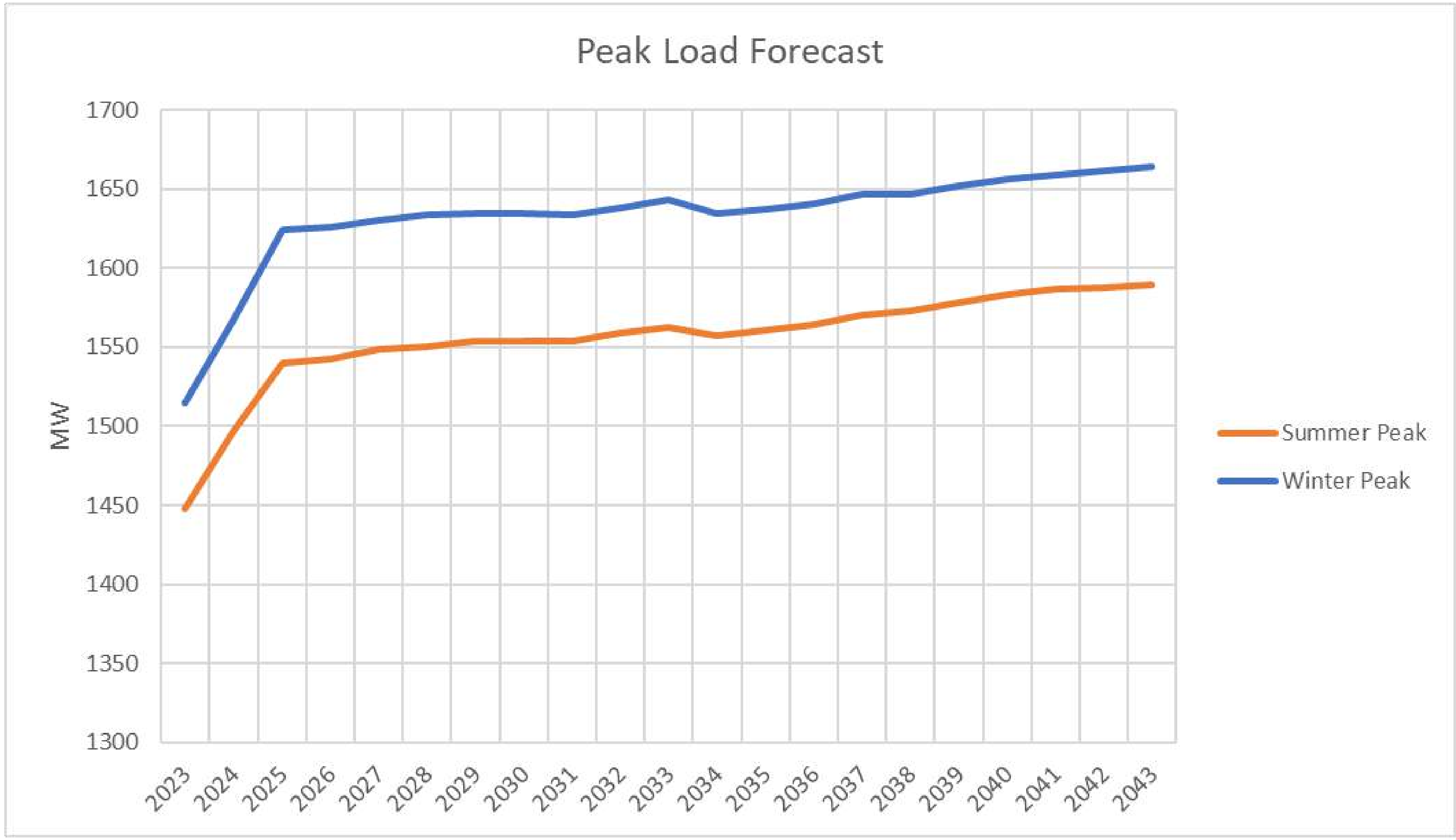
Not mapped load names

Hoosier Name	MW Hoosier	MW PSS/E	PSS/E Name
Bridgeport	3.90	4.99	07DEI_BECHW
Brookville Little Cedar	6.09	1.32	07DEI_MAPCO
Butlerville MP	0.00	6.78	07EASTMAD
Crane	0.00	0.00	07ESEX_W
Gibson Co Logistics	0.16	14.61	07FAIRFIELD
Gibson South Mine	9.46	0.00	07FVSTAR
Holton MP	0.00	5.74	07HARTLAKE
Honey Creek	9.86	0.00	07LYLESTATN
Mullinix	7.24	13.10	07MOORES
North Greenville	0.00	2.32	07MRM_D
Osprey Point - 102A	0.00	3.20	07NELSON
Osprey Point - 103A	0.15	10.10	07OWENSOUTH
Patoka Valley	2.24	6.80	07PRYCTY
Perry Co Ind	1.39	18.59	07SIG_OAKTN
Portal 2 Oaktown	1.35	0.15	07SUNCOL
Sunrise Carlisle	0.89	0.00	07TROY
Whitewater River MP	0.00	1.46	07WORTH1
		1.46	07WORTH1
		1.80	07WORTH2
		1.80	07WORTH2
		0.16	G084_07LAW1
		0.16	G084_07LAW1
		0.17	G084_07LAW2
		0.17	G084_07LAW2
		0.16	G084_07LAW3
		0.16	G084_07LAW3
TOTAL	42.72	95.21	

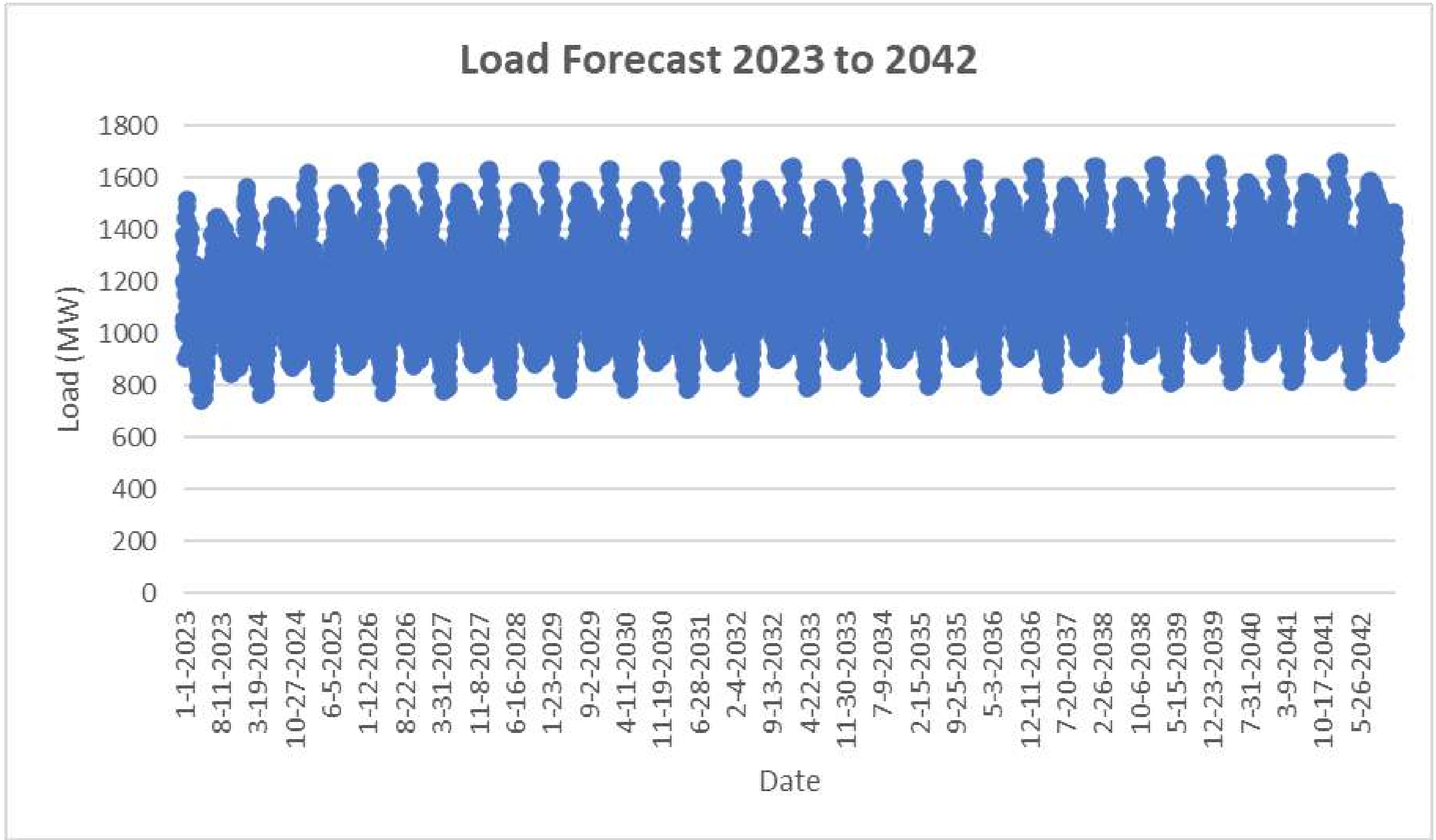
	MW Hoosier	MW PSS/E
Total mapped Loads	714.98	659.46
Total unmapped Loads	42.72	95.21
TOTAL MW	**757.70**	**754.67**

Total loads for area 207 sum between 755 and 758 MW for both models

Load Forecast

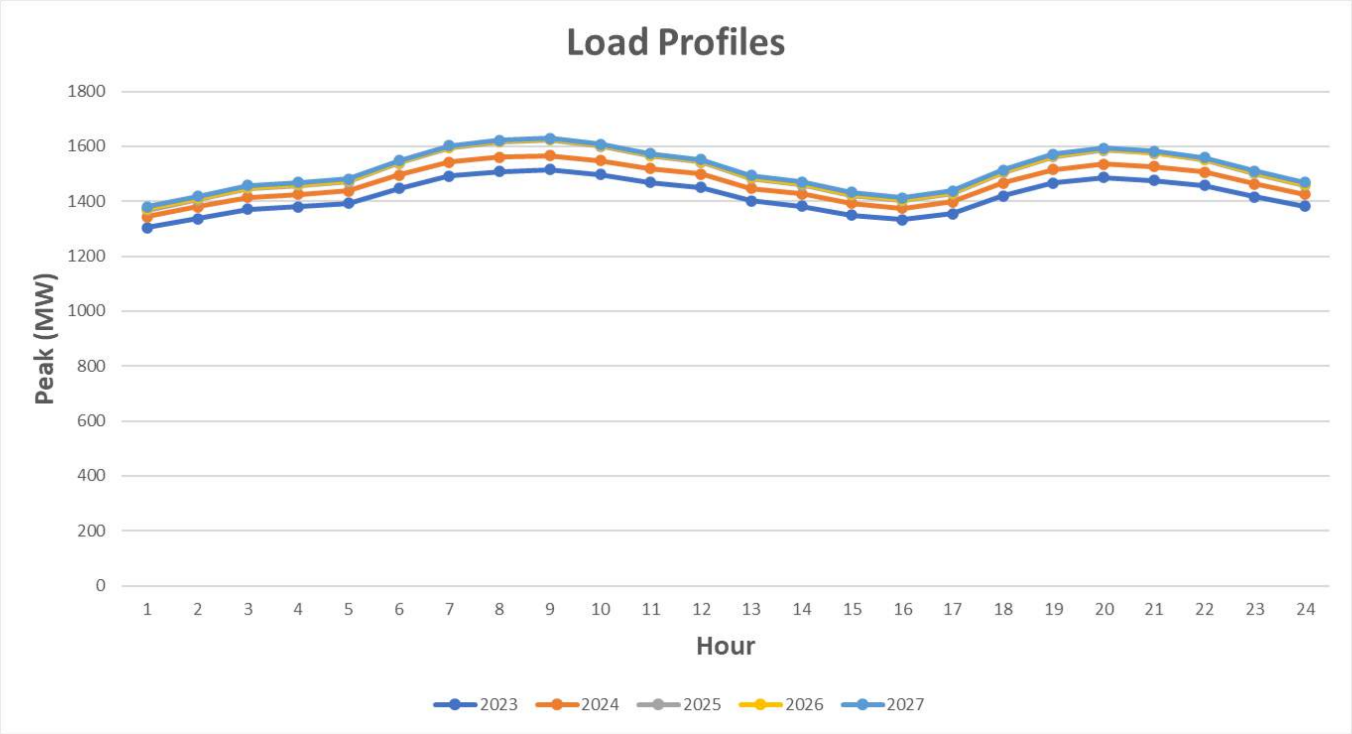


Forecasted Load Profiles



- Annual Peak Load forecasted between 1500 MW to 1662 MW

Load Profiles – 2023 to 2027



Year	Peak MW	Month	Day	Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2023	1515	1	16	9	1304	1337	1371	1380	1392	1447	1492	1509	1515	1497	1469	1450	1402	1383	1350	1333	1354	1419	1467	1486	1476	1457	1416	1381
2024	1567	1	15	9	1345	1379	1415	1425	1437	1495	1542	1561	1567	1548	1518	1499	1447	1427	1393	1375	1397	1466	1516	1536	1526	1506	1463	1426
2025	1624	1	13	9	1367	1406	1446	1457	1471	1539	1594	1616	1624	1601	1566	1543	1483	1460	1421	1401	1426	1505	1563	1587	1574	1551	1501	1458
2026	1626	1	19	9	1372	1410	1450	1461	1475	1542	1597	1618	1626	1603	1569	1546	1487	1464	1425	1405	1430	1508	1566	1589	1577	1554	1504	1462
2027	1598	1	19	9	1380	1418	1457	1468	1481	1547	1601	1622	1630	1608	1574	1551	1493	1471	1432	1413	1437	1514	1571	1594	1582	1560	1510	1469

Winter Peaking Profiles

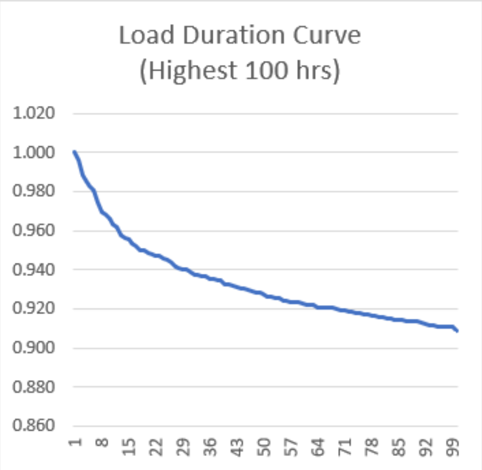
Load Profile

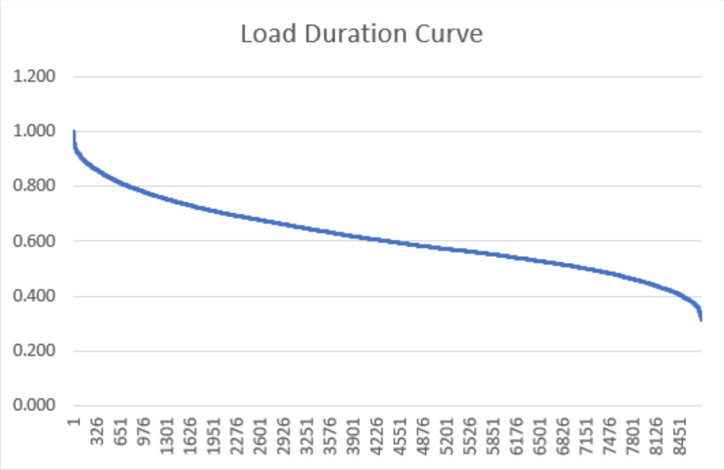
pu-h)

Demand (pu) Hour Ending

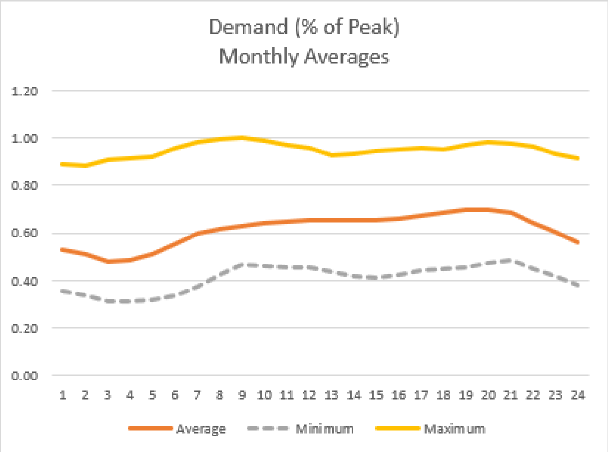
Month/Hr	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0.65	0.63	0.60	0.61	0.63	0.67	0.74	0.77	0.77	0.76	0.75	0.72	0.70	0.68	0.67	0.66	0.68	0.72	0.77	0.78	0.77	0.75	0.71	0.68
2	0.62	0.60	0.58	0.58	0.60	0.64	0.70	0.73	0.72	0.71	0.70	0.68	0.66	0.65	0.63	0.62	0.63	0.66	0.70	0.72	0.72	0.70	0.67	0.64
3	0.53	0.52	0.50	0.52	0.55	0.60	0.65	0.66	0.65	0.64	0.62	0.61	0.59	0.58	0.56	0.55	0.57	0.58	0.61	0.64	0.63	0.60	0.57	0.54
4	0.43	0.42	0.41	0.42	0.46	0.52	0.56	0.56	0.56	0.55	0.55	0.54	0.53	0.52	0.51	0.51	0.52	0.54	0.55	0.57	0.57	0.53	0.49	0.46
5	0.43	0.41	0.38	0.39	0.42	0.47	0.50	0.52	0.53	0.55	0.56	0.58	0.58	0.59	0.60	0.60	0.62	0.63	0.62	0.62	0.62	0.57	0.52	0.47
6	0.51	0.48	0.44	0.44	0.45	0.49	0.52	0.56	0.59	0.63	0.66	0.69	0.72	0.73	0.75	0.76	0.77	0.77	0.76	0.73	0.71	0.67	0.61	0.56
7	0.55	0.51	0.46	0.45	0.47	0.50	0.53	0.57	0.61	0.66	0.71	0.75	0.78	0.81	0.83	0.84	0.85	0.85	0.83	0.80	0.77	0.71	0.65	0.60
8	0.53	0.49	0.46	0.45	0.47	0.52	0.55	0.57	0.60	0.64	0.68	0.72	0.75	0.78	0.79	0.81	0.83	0.83	0.81	0.78	0.75	0.68	0.63	0.57
9	0.48	0.45	0.42	0.42	0.44	0.49	0.52	0.53	0.56	0.58	0.61	0.64	0.67	0.69	0.71	0.72	0.73	0.73	0.72	0.71	0.67	0.61	0.56	0.51
10	0.47	0.46	0.44	0.45	0.48	0.52	0.56	0.57	0.57	0.58	0.58	0.58	0.58	0.58	0.58	0.59	0.60	0.60	0.62	0.62	0.59	0.56	0.53	0.50
11	0.55	0.53	0.51	0.51	0.54	0.58	0.64	0.67	0.67	0.66	0.64	0.63	0.61	0.59	0.58	0.58	0.59	0.63	0.67	0.67	0.66	0.64	0.60	0.57
12	0.63	0.62	0.59	0.60	0.61	0.64	0.69	0.72	0.73	0.72	0.71	0.70	0.68	0.66	0.65	0.64	0.66	0.70	0.73	0.73	0.73	0.71	0.68	0.66
Average	*0.53*	*0.51*	*0.48*	*0.49*	*0.51*	*0.55*	*0.60*	*0.62*	*0.63*	*0.64*	*0.65*	*0.65*	*0.66*	*0.66*	*0.65*	*0.66*	*0.67*	*0.69*	*0.70*	*0.70*	*0.68*	*0.64*	*0.60*	*0.56*
Minimum	*0.35*	*0.34*	*0.31*	*0.31*	*0.32*	*0.34*	*0.37*	*0.43*	*0.47*	*0.46*	*0.46*	*0.45*	*0.44*	*0.42*	*0.41*	*0.42*	*0.44*	*0.45*	*0.46*	*0.47*	*0.48*	*0.45*	*0.41*	*0.38*
Maximum	*0.89*	*0.88*	*0.91*	*0.91*	*0.92*	*0.96*	*0.98*	*1.00*	*1.00*	*0.99*	*0.97*	*0.96*	*0.93*	*0.94*	*0.95*	*0.95*	*0.96*	*0.95*	*0.97*	*0.98*	*0.97*	*0.96*	*0.93*	*0.91*

Month	Daily Consump. Avg	Daily Consump. Min
1	*17.87*	*12.42*
2	*15.88*	*12.73*
3	*14.06*	*10.81*
4	*12.27*	*10.42*
5	*12.76*	*10.37*
6	*14.99*	*12.99*
7	*16.07*	*13.91*
8	*15.68*	*13.44*
9	*14.18*	*11.81*
10	*13.21*	*11.59*
11	*14.52*	*11.59*
12	*16.18*	*12.47*
	14.81	
	12.27	
	17.87	





Month	Monthly Consumption (% of Max)
1	100%
2	89%
3	79%
4	69%
5	71%
6	84%
7	90%
8	88%
9	79%
10	74%
11	81%
12	91%



Annual Consumption pu-h 5,374

Load Factor 61.3%

Hoosier Solar Profile (utility-Scale)

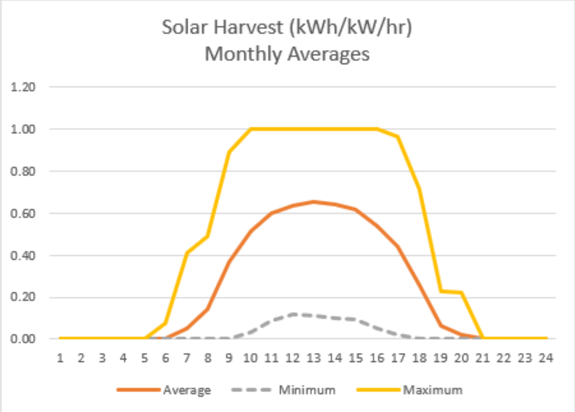
Average Solar Irradiance (kWh/kWac) Hour Ending

Month/Hr	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.31	0.46	0.55	0.57	0.59	0.54	0.40	0.29	0.08	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.22	0.44	0.60	0.68	0.68	0.66	0.63	0.56	0.43	0.22	0.01	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.29	0.50	0.57	0.62	0.68	0.63	0.60	0.54	0.46	0.29	0.06	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.23	0.52	0.65	0.68	0.67	0.66	0.66	0.68	0.65	0.54	0.35	0.08	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.01	0.15	0.26	0.50	0.61	0.68	0.68	0.72	0.73	0.70	0.63	0.56	0.39	0.12	0.05	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.02	0.18	0.26	0.54	0.66	0.71	0.74	0.75	0.71	0.68	0.62	0.56	0.42	0.15	0.09	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.01	0.14	0.24	0.52	0.64	0.70	0.70	0.73	0.73	0.72	0.64	0.60	0.40	0.14	0.08	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.20	0.46	0.58	0.65	0.68	0.66	0.73	0.74	0.69	0.62	0.44	0.13	0.04	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.20	0.45	0.53	0.64	0.65	0.67	0.68	0.65	0.56	0.48	0.29	0.05	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.46	0.61	0.71	0.72	0.74	0.71	0.66	0.54	0.40	0.14	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.23	0.38	0.44	0.49	0.50	0.49	0.46	0.36	0.21	0.03	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.27	0.38	0.44	0.46	0.41	0.36	0.25	0.13	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Average	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.05*	*0.14*	*0.37*	*0.52*	*0.60*	*0.64*	*0.65*	*0.64*	*0.62*	*0.54*	*0.44*	*0.26*	*0.06*	*0.02*	*0.00*	*0.00*	*0.00*	*0.00*
Minimum	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.03*	*0.09*	*0.12*	*0.11*	*0.10*	*0.10*	*0.05*	*0.02*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Maximum	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.08*	*0.41*	*0.49*	*0.89*	*1.00*	*1.00*	*1.00*	*1.00*	*1.00*	*1.00*	*1.00*	*0.97*	*0.71*	*0.23*	*0.22*	*0.00*	*0.00*	*0.00*	*0.00*

Month	Daily Energy Avg	Daily Energy Min	Daily Energy Max
1	*4.89*	*1.02*	*8.58*
2	*5.12*	*1.52*	*9.27*
3	*5.30*	*1.81*	*9.79*
4	*6.44*	*1.94*	*9.66*
5	*6.79*	*2.51*	*10.32*
6	*7.08*	*2.76*	*9.75*
7	*7.01*	*3.00*	*9.86*
8	*6.69*	*3.06*	*10.05*
9	*5.88*	*2.31*	*9.43*
10	*5.84*	*2.04*	*9.16*
11	*3.61*	*0.77*	*8.45*
12	*2.84*	*1.12*	*7.00*
	5.63		
	2.84		
	7.08		

- Solar Profile was provided from Hoosier Energy.
- Capacity Factor: 23.09%
- Avg Annual Solar Harvest 2023 kWh/kWac.

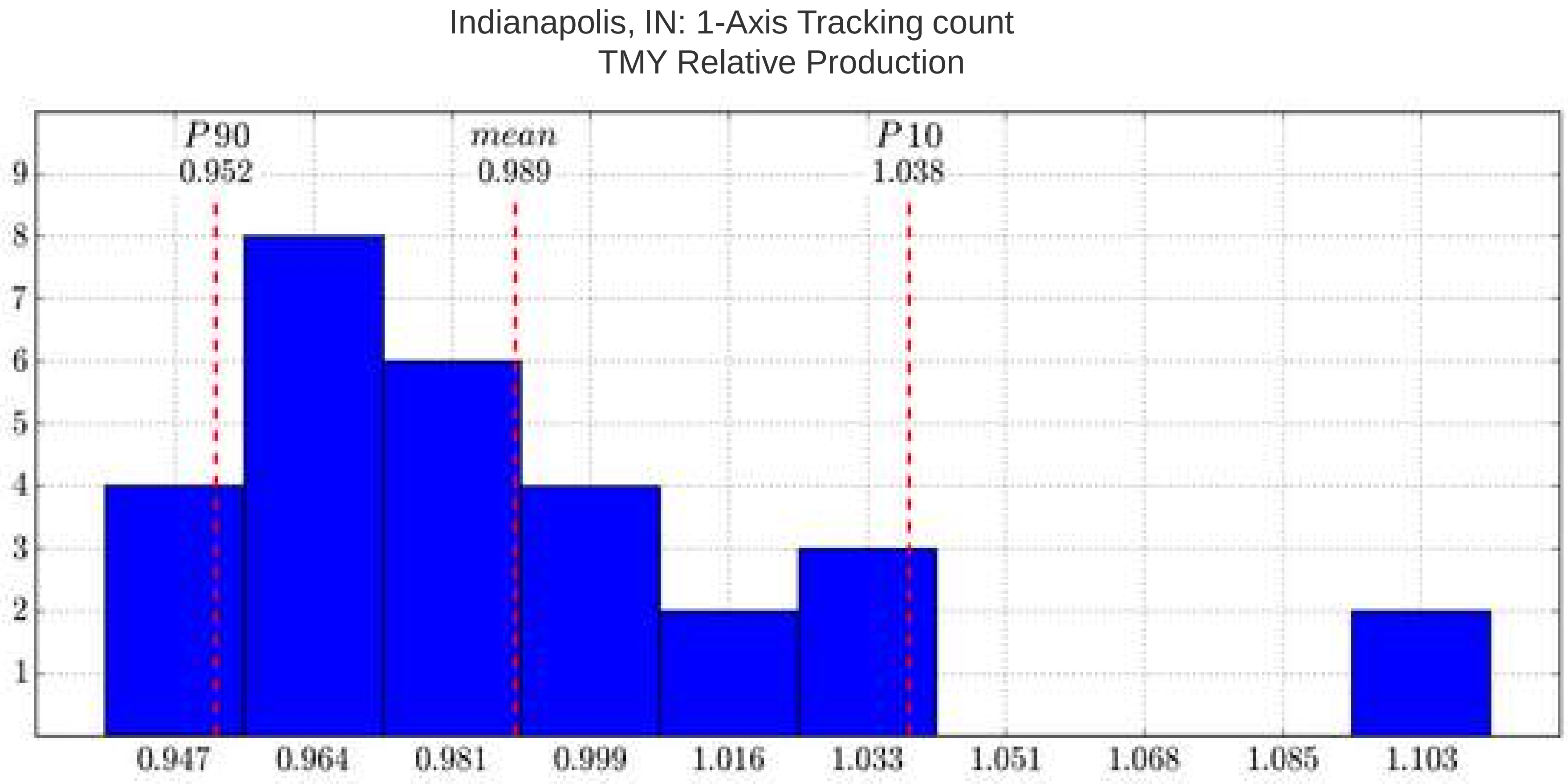
Month	Monthly Harvest (% of Max)
1	69%
2	72%
3	75%
4	91%
5	96%
6	100%
7	99%
8	95%
9	83%
10	83%
11	51%
12	40%



Annual Harvest kWh/kWac/Yr 2,023

Capacity Factor 23.09%

PV Watt's – Interannual Variability



- 10% probability that solar harvest will exceed 103.8% of average level.
- 90% probability that solar harvest will exceed 95.2% of average level.

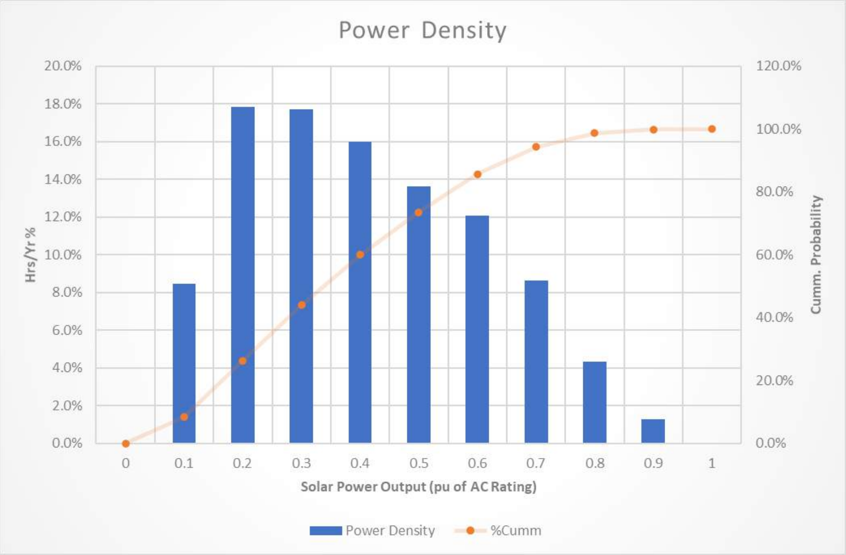
Wind Profiles Hoosier

Average Wind Power (kWh/kWac)

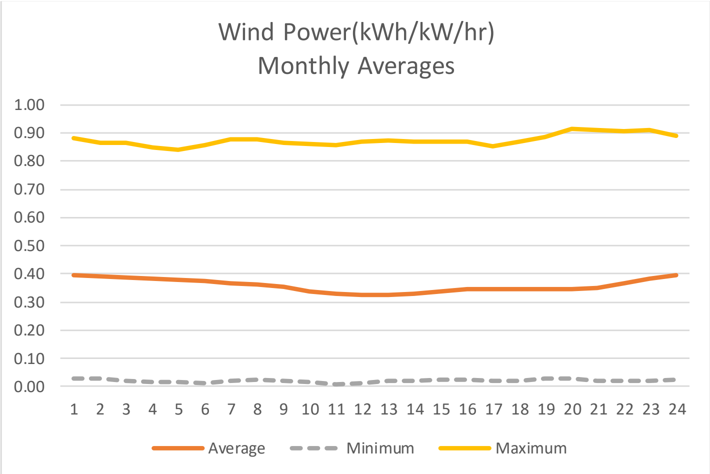
Hour Ending

Month/Hr	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0.41	0.40	0.40	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.38	0.37	0.36	0.37	0.37	0.37	0.37	0.38	0.39	0.41	0.42	0.42	0.41
2	0.39	0.37	0.37	0.36	0.35	0.34	0.33	0.33	0.32	0.33	0.32	0.31	0.31	0.31	0.31	0.32	0.33	0.34	0.34	0.35	0.37	0.39	0.39	0.39
3	0.48	0.47	0.46	0.45	0.45	0.44	0.44	0.43	0.43	0.42	0.40	0.38	0.37	0.37	0.37	0.39	0.39	0.40	0.40	0.41	0.42	0.45	0.47	0.49
4	0.45	0.45	0.44	0.44	0.43	0.43	0.42	0.42	0.42	0.40	0.40	0.41	0.43	0.44	0.45	0.46	0.46	0.46	0.46	0.44	0.42	0.44	0.45	0.46
5	0.38	0.38	0.38	0.37	0.37	0.37	0.37	0.37	0.35	0.33	0.33	0.33	0.33	0.32	0.31	0.31	0.30	0.30	0.31	0.30	0.31	0.32	0.34	0.36
6	0.31	0.32	0.31	0.30	0.29	0.28	0.28	0.26	0.23	0.20	0.21	0.23	0.26	0.27	0.28	0.29	0.29	0.29	0.29	0.27	0.25	0.24	0.26	0.29
7	0.27	0.27	0.28	0.28	0.27	0.27	0.27	0.26	0.23	0.19	0.18	0.20	0.20	0.22	0.23	0.23	0.24	0.24	0.23	0.22	0.20	0.19	0.21	0.25
8	0.25	0.25	0.25	0.25	0.25	0.24	0.23	0.22	0.21	0.16	0.15	0.16	0.17	0.18	0.18	0.18	0.18	0.18	0.18	0.17	0.16	0.18	0.21	0.24
9	0.39	0.39	0.39	0.37	0.37	0.37	0.36	0.36	0.35	0.32	0.30	0.29	0.29	0.31	0.33	0.34	0.34	0.34	0.33	0.32	0.33	0.37	0.39	0.41
10	0.46	0.45	0.45	0.45	0.44	0.44	0.44	0.44	0.44	0.42	0.41	0.40	0.41	0.42	0.44	0.45	0.46	0.46	0.44	0.43	0.45	0.46	0.47	0.47
11	0.47	0.46	0.45	0.45	0.45	0.45	0.44	0.43	0.44	0.43	0.41	0.39	0.38	0.39	0.41	0.42	0.43	0.42	0.41	0.43	0.44	0.46	0.47	0.47
12	0.50	0.48	0.48	0.47	0.46	0.46	0.46	0.46	0.46	0.45	0.45	0.42	0.39	0.37	0.37	0.37	0.37	0.38	0.40	0.44	0.46	0.48	0.50	0.50
Average	*0.40*	*0.39*	*0.39*	*0.38*	*0.38*	*0.37*	*0.37*	*0.36*	*0.35*	*0.34*	*0.33*	*0.32*	*0.33*	*0.33*	*0.34*	*0.34*	*0.35*	*0.35*	*0.35*	*0.35*	*0.35*	*0.37*	*0.38*	*0.39*
Minimum	*0.03*	*0.03*	*0.02*	*0.02*	*0.02*	*0.01*	*0.02*	*0.03*	*0.02*	*0.02*	*0.01*	*0.01*	*0.02*	*0.02*	*0.03*	*0.02*	*0.02*	*0.02*	*0.03*	*0.03*	*0.02*	*0.02*	*0.02*	*0.02*
Maximum	*0.88*	*0.86*	*0.87*	*0.85*	*0.84*	*0.86*	*0.88*	*0.88*	*0.86*	*0.86*	*0.86*	*0.87*	*0.87*	*0.87*	*0.87*	*0.87*	*0.85*	*0.87*	*0.88*	*0.92*	*0.91*	*0.91*	*0.91*	*0.89*

Month	Daily Energy Avg	Daily Energy Min	Daily Energy Max
1	*10.33*	*1.40*	*18.16*
2	*8.27*	*1.93*	*17.79*
3	*10.18*	*2.62*	*18.64*
4	*10.49*	*4.93*	*16.29*
5	*8.13*	*2.64*	*15.92*
6	*6.50*	*0.90*	*13.22*
7	*5.60*	*2.24*	*11.33*
8	*4.82*	*1.77*	*12.38*
9	*8.36*	*2.40*	*14.62*
10	*10.61*	*4.03*	*18.23*
11	*10.39*	*4.37*	*17.84*
12	*10.58*	*2.84*	*18.13*
	8.69		
	4.82		
	10.61		



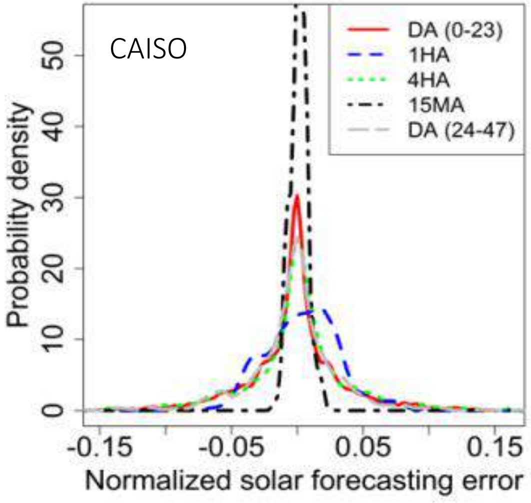
Month	Monthly Harvest (% of Max)
1	97%
2	78%
3	96%
4	99%
5	77%
6	61%
7	53%
8	45%
9	79%
10	100%
11	98%
12	100%



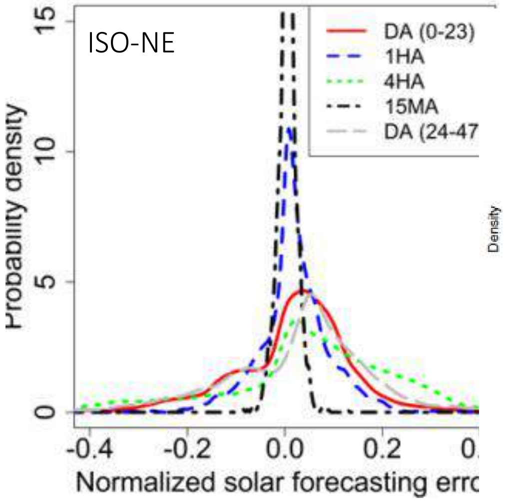
Annual Harvest kWh/kWac/Yr	3,141
Capacity Factor	35.86%

Forecast Errors

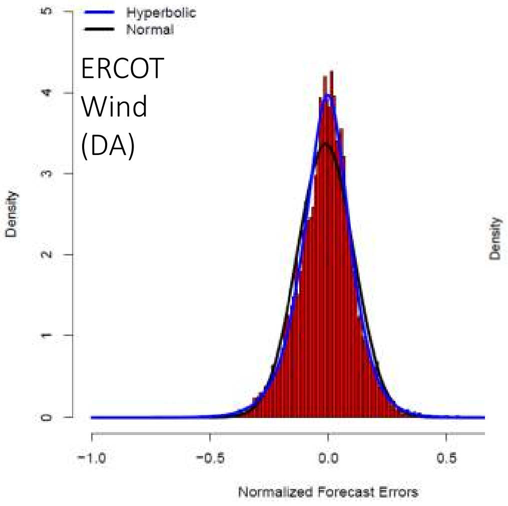
NREL Study 2014



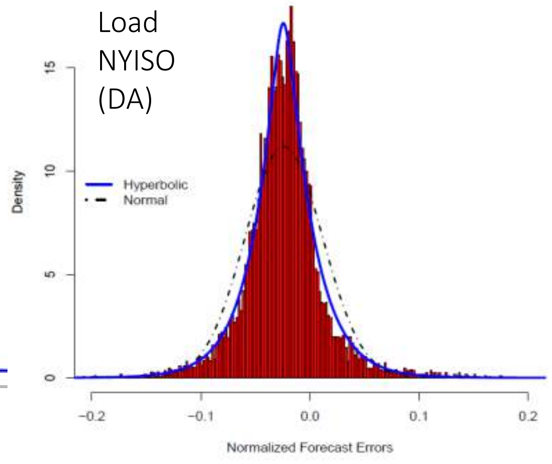
NREL Study 2014



NREL Study 2012



NREL Study 2012



- NREL studies show:

Forecast Error % 3-sigma	Solar in CAISO	Solar in ISO-NE	Wind in ERCOT	Load in NYISO
1-Day Ahead	15%	40%	45%	10%
4-Hour Ahead	10%	30%		
1-Hour Ahead	10%	20%		
15-min Ahead	2%	5%		

Industry Research on Wind Variability

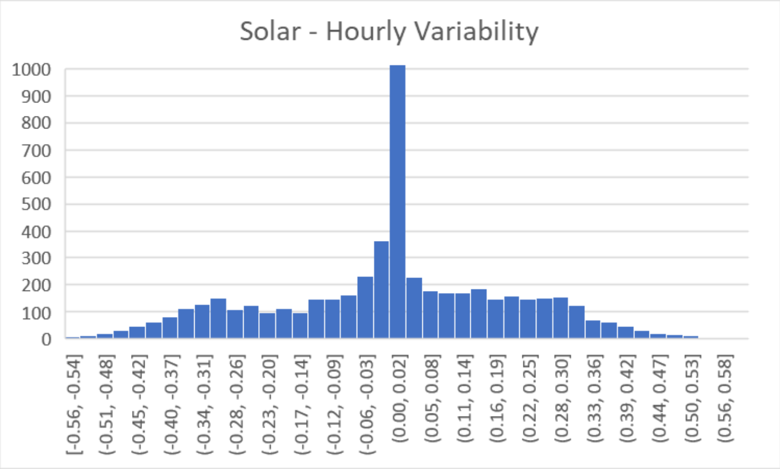
Time Interval	Statistical Metric	14 Turbines		61 Turbines		138 Turbines		250+ Turbines	
		(kW)	(%)	(kW)	(%)	(kW)	(%)	(kW)	(%)
1 (one) Second	Average	41	0.4	172	0.2	148	0.1	189	0.1
	Standard Deviation	56	0.5	203	0.3	203	0.2	257	0.1
1 (one) Minute	Average	130	1.2	612	0.8	494	0.5	730	0.3
	Standard Deviation	225	2.1	1,038	1.3	849	0.8	1,486	0.6
10 (ten) Minutes	Average	329	3.1	1,658	2.1	2,243	2.2	3,713	1.5
	Standard Deviation	548	5.2	2,750	3.5	3,810	3.7	6,418	2.7
1 (one) Hour	Average	736	7.0	3,732	4.7	6,582	6.4	12,755	5.3
	Standard Deviation	1,124	10.7	5,932	7.5	10,032	9.7	19,213	7.9

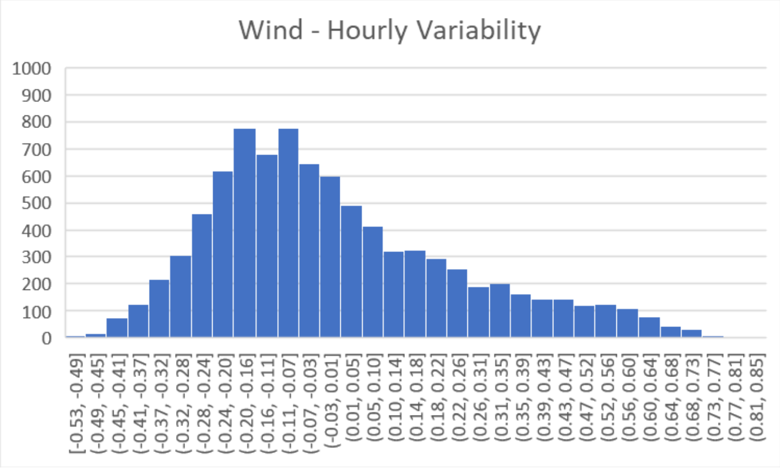
- Source: NREL

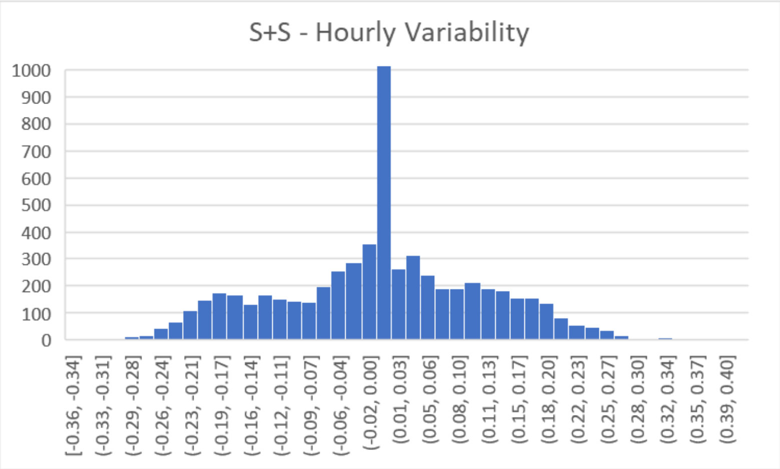
Variability Analysis

- Measure the variability of output from average levels for that hour and time of year. Statistics calculated during active production times.

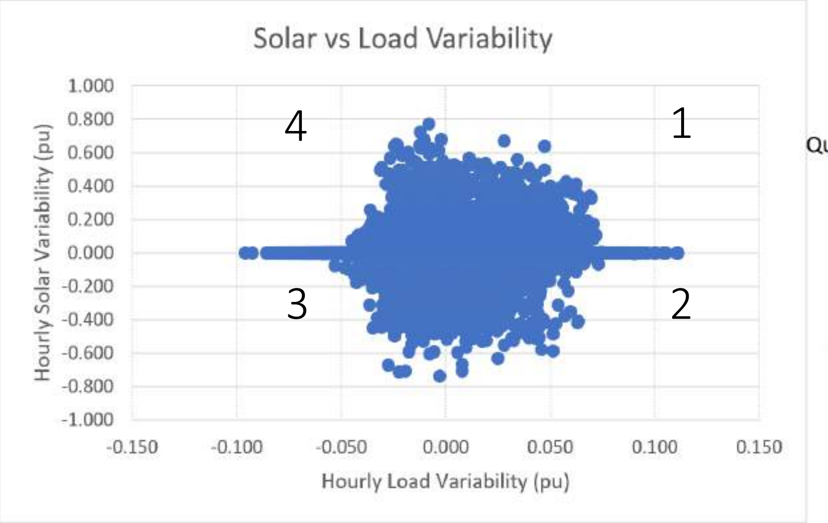
Hourly Variability	Solar	Wind	S+S
Std. Deviation (1 σ)	22.7%	24.3%	12.7%
Min	-56.3%	-53.5%	-36.2%
Max	60.5%	81.2%	41.9%
Median	0.0%	-5.3%	0.0%
68.3% Percentile (1 σ)	12.1%	7.8%	6.8%
95.4% Percentile (2 σ)	35.8%	55.9%	20.8%
99.7% Percentile (3 σ)	50.8%	72.5%	31.3%
90% Percentile	29.6%	37.1%	17.4%



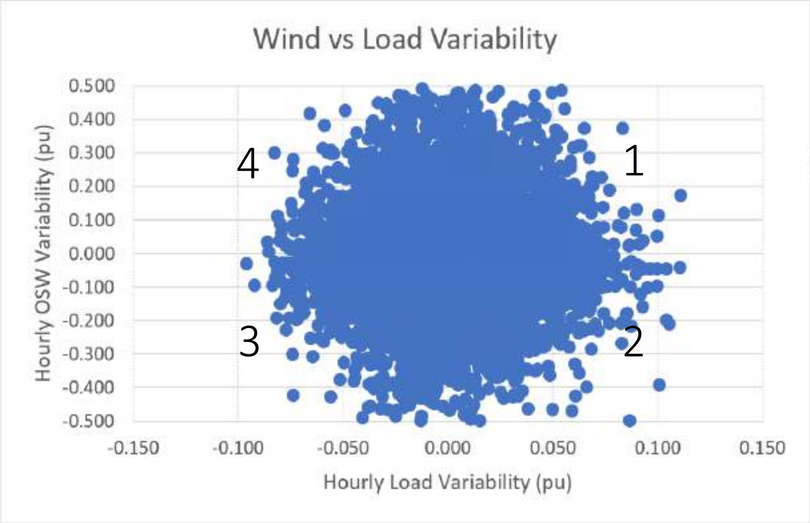




Alignment of Solar & Wind Hourly Variability with Load



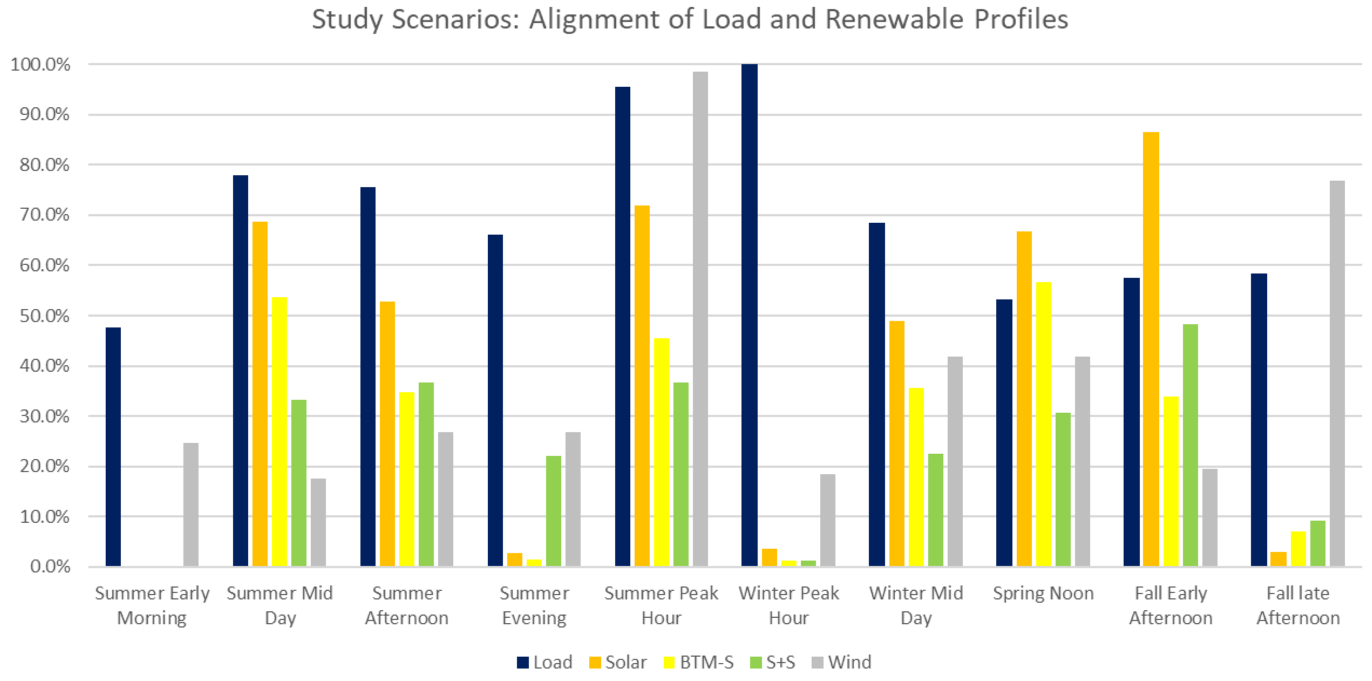
Quadrant	#hrs/Yr	%
0	3992	46%
1	1458	17%
2	1444	16%
3	968	11%
4	898	10%
Total	8760	100%

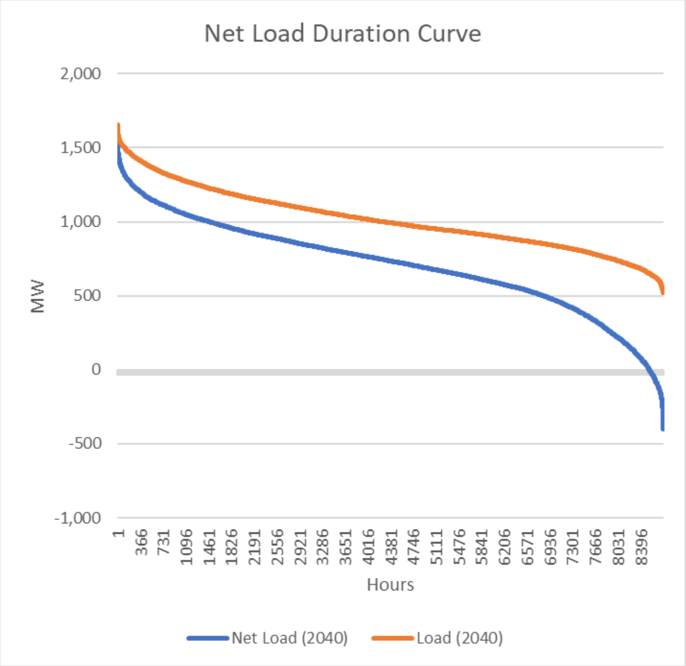


Quadrant	#hrs/Yr	%
0	344	4%
1	2007	23%
2	2124	24%
3	2042	23%
4	2243	26%
Total	8760	100%

- Solar and Wind are not correlated to the Load as shown in the two charts. Points are spread across the quadrants with no discernable pattern.

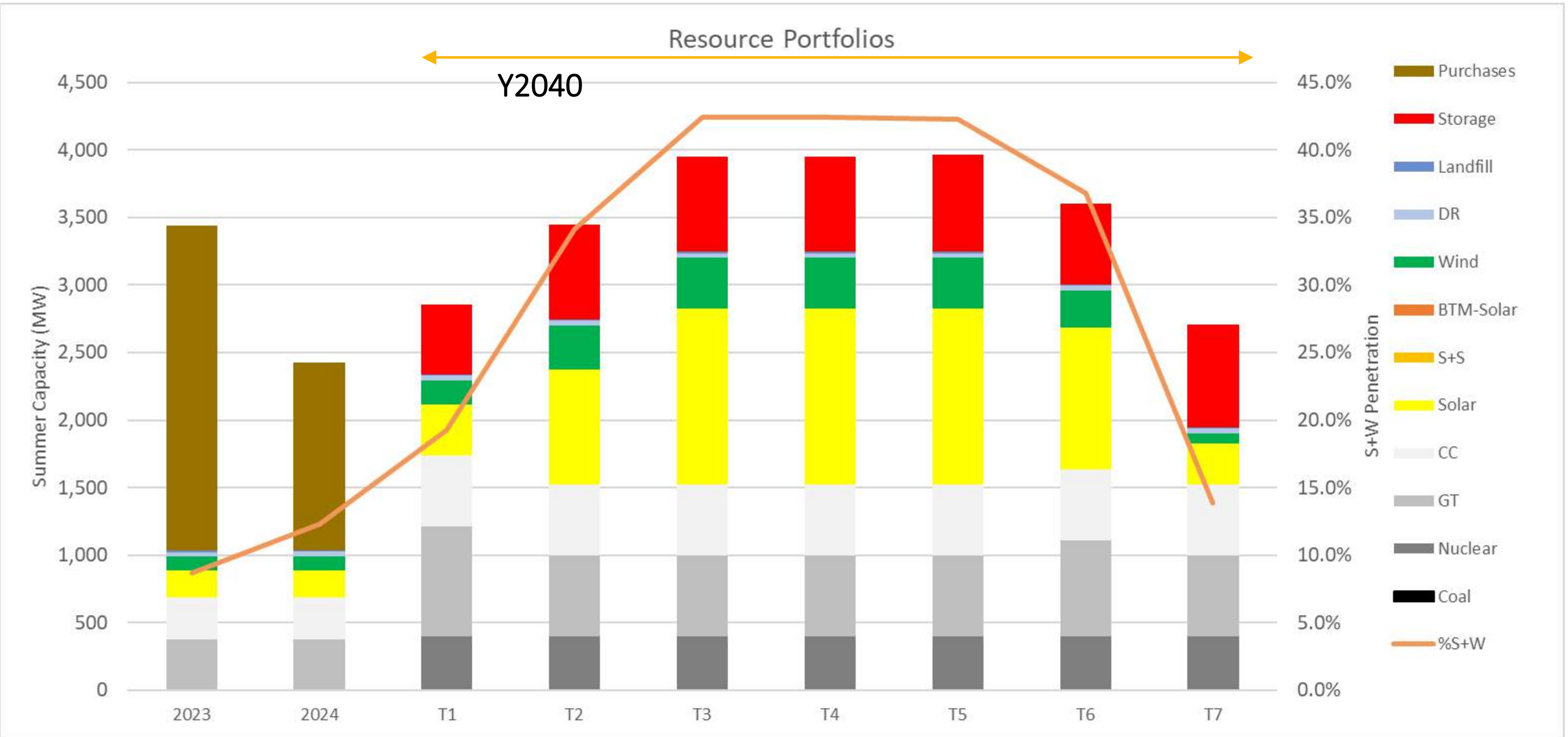
Study Periods - Alignment of Load and Renewable Profiles





ID	Name	From Month	To Month	From Day	To Day	From Hour	To Hour	Season	Load	Solar	S+S	Wind	BTM-S	2023 Load
1	Summer Early Morning	7	9	1	31	0	5	Summer	47.5%	0.0%	0.0%	24.7%	0.0%	720
2	Summer Mid Day	8	8	1	31	11	16	Summer	77.9%	68.6%	33.2%	17.6%	53.7%	1,180
3	Summer Afternoon	5	9	1	31	15	17	Summer	75.7%	52.8%	36.8%	26.7%	34.7%	1,146
4	Summer Evening	5	9	1	31	18	23	Summer	66.1%	2.8%	22.1%	26.8%	1.5%	1,001
5	Summer Peak Hour	7	7	21	21	16	16	Summer	95.6%	71.9%	36.6%	98.7%	45.6%	1,448
6	Winter Peak Hour	1	1	16	16	8	8	Winter	100.0%	3.6%	1.2%	18.4%	1.2%	1,515
7	Winter Mid Day	1	1	1	31	11	16	Winter	68.5%	49.0%	22.5%	41.9%	35.7%	1,038
8	Spring Noon	4	4	1	31	11	12	Spring	53.2%	66.8%	30.6%	41.9%	56.7%	806
9	Fall Early Afternoon	10	10	18	18	15	15	Fall	57.6%	86.5%	48.2%	19.4%	33.8%	873
10	Fall late Afternoon	10	10	19	19	17	17	Fall	58.4%	3.0%	9.2%	76.9%	7.1%	884

Portfolios (T1-T7)



Portfolios:

- T1: Reference Case
- T2: Phase 1 EPA Rule
- T3: CO2 Tax Scenario
- T4: EPA and CO2 Tax
- T5: Aggressive Enviro
- T6: High Price Scenario
- T7: Low Price Scenario

2040 Portfolio	T1 - Reference Case	T2 - Phase 1 EPA Rule	T3 -CO2 Tax Scenario	T4 - EPA and CO2 Tax	T5 - Agg Enviro	T6 - High Price Scenario	T7 - Low Price Scenario
Disp%	81%	66%	58%	58%	58%	63%	86%
S&W%	19.3%	34.1%	42.4%	42.4%	42.2%	36.8%	13.9%
RE Penetration %	8.5%	19.3%	29.5%	29.5%	29.5%	23.9%	6.8%

Portfolios (T1-T7)

			Portfolios						
			1. Reference Case	2. Phase 1 EPA Rule	3. CO2 Tax Scenario	4. EPA and CO2 Tax	5. Agg Enviro	6. High Price Scenario	7. Low Price Scenario
			2040						
	2023	2024	T1	T2	T3	T4	T5	T6	T7
Solar	200	200	375	850	1,300	1,300	1,300	1,050	300
BTM-Solar	0	0	0	0	0	0	0	0	0
Wind	100	100	175	325	375	375	375	275	75
S+S	0	0	0	0	0	0	0	0	0
Storage	0	0	520	700	700	700	720	600	760
Nuclear	0	0	400	400	400	400	400	400	400
GT	374	374	816	600	600	600	600	708	600
CC	316	316	525	525	525	525	525	525	525
Coal	0	0	0	0	0	0	0	0	0
Purchases	2,407	1,390	0	0	0	0	0	0	0
Landfill	11	11	11	11	11	11	11	11	11
Hydro	4	4	0	0	0	0	0	0	0
DR	33	35	35	35	35	35	35	35	35
Thermal	694	694	1,741	1,525	1,525	1,525	1,525	1,633	1,525
Total	3,445	2,430	2,857	3,446	3,946	3,946	3,966	3,604	2,706
%S+W	8.7%	12.3%	19.3%	34.1%	42.4%	42.4%	42.2%	36.8%	13.9%
Summer Peak	1,515	1,567	1,656	1,656	1,656	1,656	1,656	1,656	1,656
RE Penetration (without Curtailment)%	5.0%	4.8%	8.5%	19.3%	29.5%	29.5%	29.5%	23.9%	6.8%
Pmin of All Units	270	270	707	643	643	643	643	675	643

Portfolios (T1-T7)

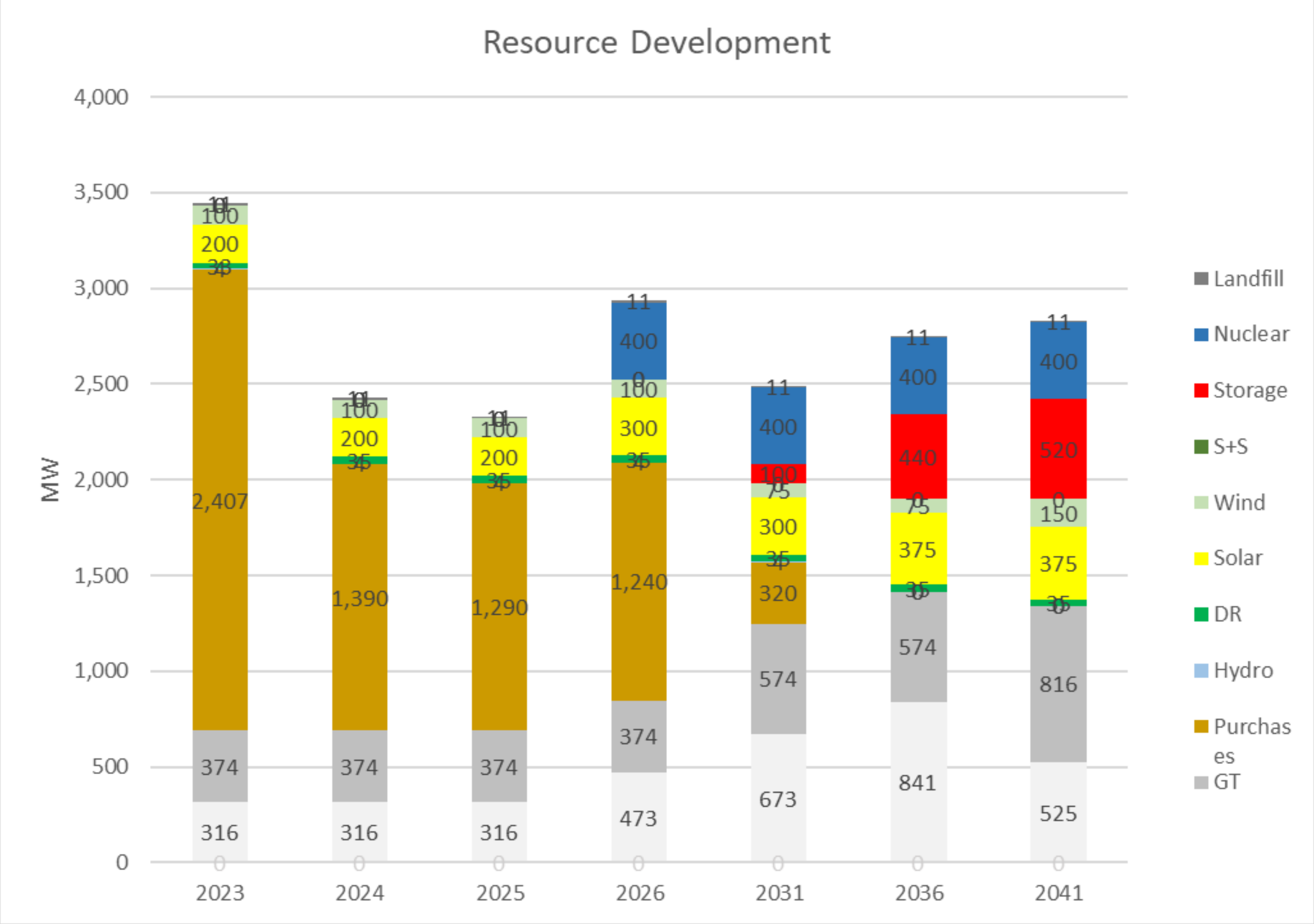
Conventional Resources (CC, GT, Purchases, Hydro, Nuclear)

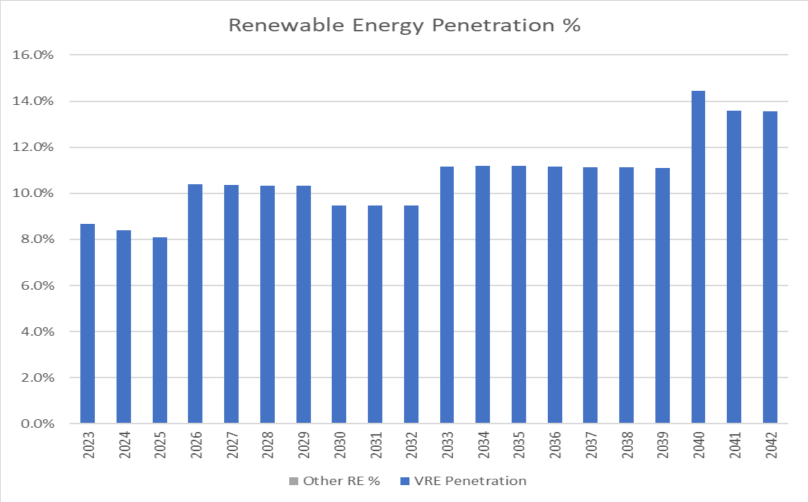
		Portfolios						
		1. Reference Case	2. Phase 1 EPA Rule	3. CO2 Tax Scenario	4. EPA and CO2 Tax	5. Agg Enviro	6. High Price Scenario	7. Low Price Scenario
Year 2040 Resource	**Technology**	**T1**	**T2**	**T3**	**T4**	**T5**	**T6**	**T7**
BP Energy 5x16	Purchases							
Dayton Hydro	Hydro							
Duke 250	Purchases							
Duke Contract Original	Purchases							
EmberClear_LincolnLand	CC	200	200	200	200	200	200	200
Exelon	Purchases							
Exelon 7x24	Purchases							
Holland CC	CC							
Invenergy_Nelson	CC							
Lawrence	GT							
Merom PPA:1	Purchases							
Merom PPA:2	Purchases							
Morgan Stanley 7x24	Purchases							
New Gas Combined Cycle:CC1	CC	325	325	325	325	325	325	325
New Gas CT:1	GT	600	600	600	600	600	600	600
New Gas RICE:IC1	GT	216					108	
NextEra	Purchases							
Palisades	Purchases							400
Rockland Gibson City	Purchases							
Rockland Shelby County	Purchases							
Worthington	GT							

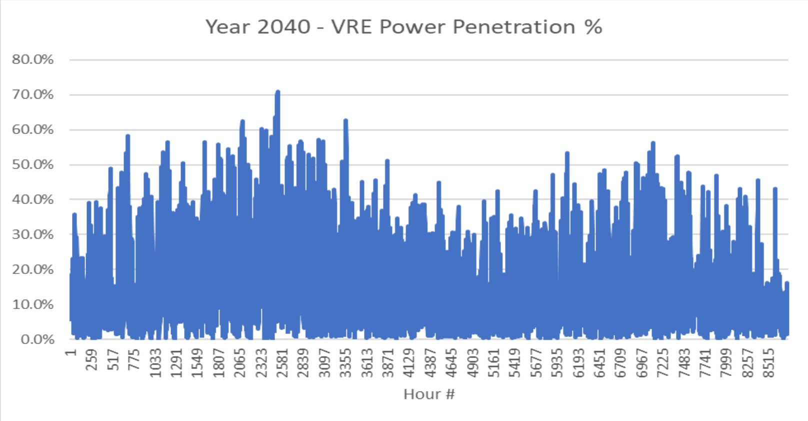
Solar, Wind, Storage, DR, Landfill

		Portfolios						
		1. Reference Case [CapExp]	2. Phase 1 EPA Rule [CapExp]	3. CO2 Tax Scenario [CapExp]	4. EPA and CO2 Tax [CapExp]	5. Agg Enviro [CapExp]	6. High Price Scenario [CapExp]	7. Low Price Scenario [CapExp]
Resource	**Technology**	**T1**	**T2**	**T3**	**T4**	**T5**	**T6**	**T7**
Hoosier LMRs	DR	35	35	35	35	35	35	35
Livingston	Landfill	11	11	11	11	11	11	11
Meadow Lake	Wind	75	75	75	75	75	75	75
New Battery Storage:BAT1	Storage	520	700	700	700	720	600	760
New Solar:PV1	Solar	75	550	1000	1000	1000	750	
New Wind:WT1	Wind	100	250	300	300	300	200	
Railsplitter Wind	Wind							
Riverstart Solar	Solar	200	200	200	200	200	200	200
Rustic Hills	Solar	100	100	100	100	100	100	100

T1 Portfolio (Reference Case)

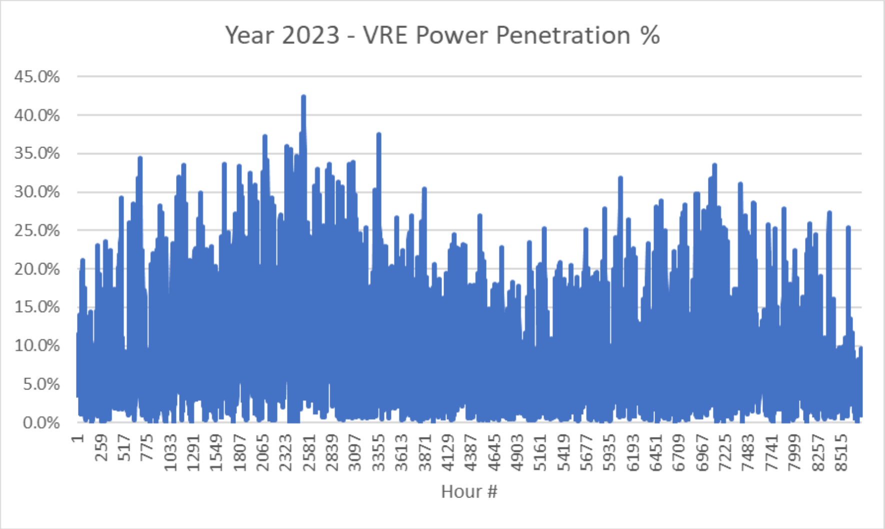


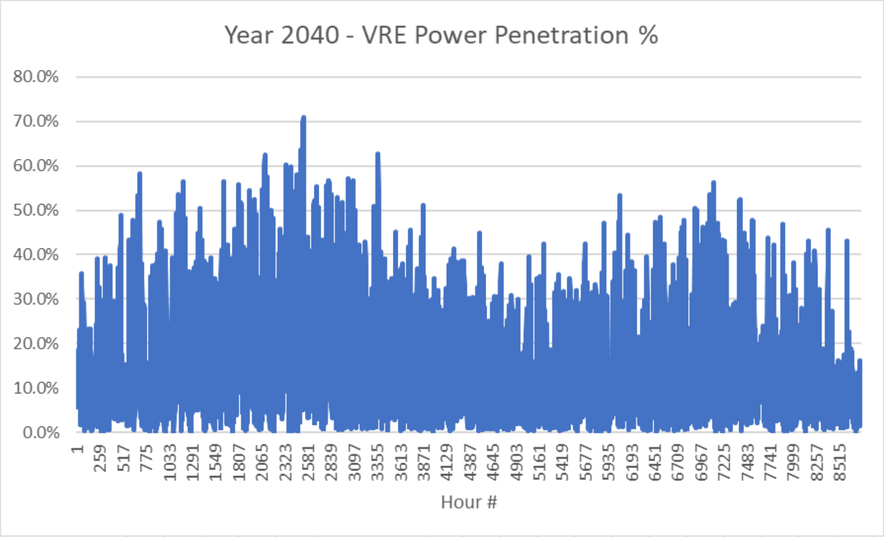




- Variable Resources (VRE) generation exceed the load level whenever the penetration exceeds 100%.

T1 Portfolio: Power Penetration Level by Intermittent Resources



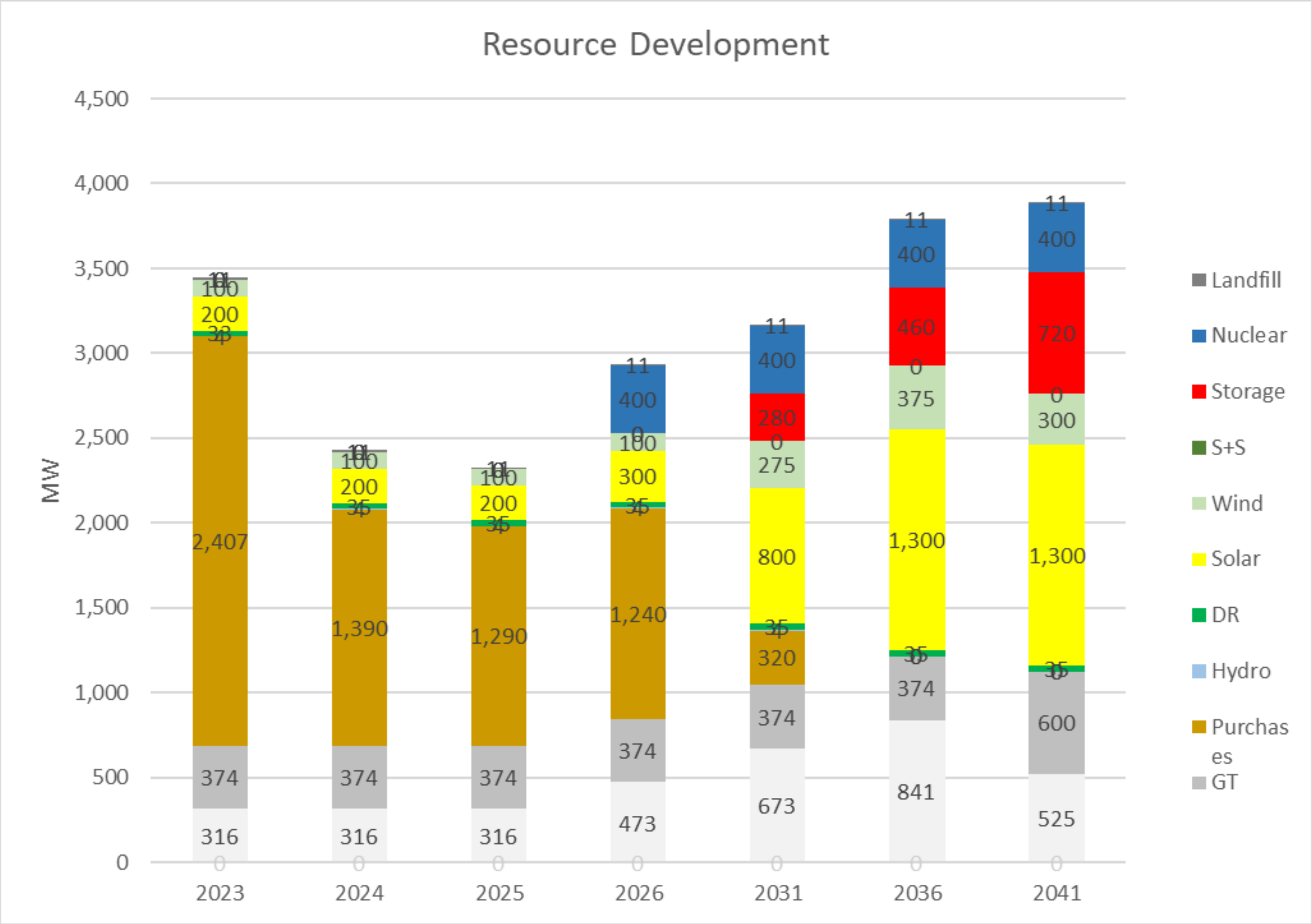


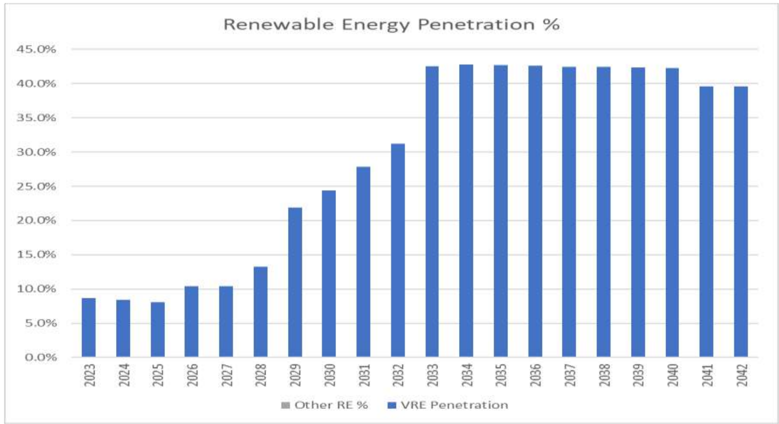
Average VRE Power Penetration %										Hour Ending														
Month/Hr	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	5%	6%	6%	7%	6%	5%	4%	3%	6%	9%	12%	14%	15%	15%	15%	13%	10%	6%	4%	5%	5%	5%	5%	5%
2	5%	6%	7%	7%	6%	5%	4%	4%	8%	12%	15%	17%	17%	17%	17%	16%	14%	8%	4%	4%	4%	4%	5%	5%
3	5%	6%	5%	6%	5%	4%	4%	5%	10%	14%	16%	17%	19%	18%	18%	17%	15%	11%	6%	4%	4%	5%	5%	5%
4	8%	8%	8%	9%	7%	6%	7%	11%	17%	20%	22%	22%	22%	22%	23%	23%	20%	15%	8%	5%	5%	6%	7%	7%
5	5%	6%	6%	6%	5%	6%	9%	11%	16%	18%	20%	20%	20%	20%	19%	17%	16%	13%	6%	4%	3%	3%	4%	4%
6	4%	4%	4%	4%	4%	5%	8%	10%	15%	17%	17%	17%	16%	15%	15%	13%	13%	10%	6%	4%	3%	3%	3%	4%
7	3%	3%	3%	3%	3%	3%	6%	8%	13%	14%	15%	14%	14%	14%	13%	12%	11%	9%	5%	3%	2%	2%	2%	2%
8	3%	3%	3%	3%	3%	3%	5%	7%	12%	14%	14%	14%	13%	14%	14%	13%	12%	9%	4%	2%	2%	2%	2%	3%
9	4%	5%	5%	5%	5%	4%	4%	8%	13%	15%	17%	16%	17%	16%	15%	13%	12%	8%	3%	3%	3%	3%	3%	4%
10	4%	4%	5%	5%	4%	4%	3%	7%	14%	17%	19%	20%	20%	19%	18%	15%	11%	5%	3%	3%	4%	3%	4%	4%
11	6%	6%	6%	6%	5%	5%	4%	4%	9%	12%	13%	15%	15%	15%	15%	13%	8%	4%	4%	4%	5%	6%	6%	6%
12	5%	5%	5%	5%	5%	4%	3%	3%	5%	8%	10%	11%	12%	11%	10%	8%	6%	3%	4%	4%	4%	4%	5%	5%
Average	*5%*	*5%*	*5%*	*5%*	*5%*	*4%*	*5%*	*7%*	*12%*	*14%*	*16%*	*16%*	*17%*	*16%*	*16%*	*14%*	*12%*	*8%*	*5%*	*4%*	*4%*	*4%*	*4%*	*5%*
Minimum	*0%*	*0%*	*0%*	*1%*	*0%*	*0%*	*0%*	*0%*	*1%*	*1%*	*3%*	*4%*	*3%*	*3%*	*3%*	*2%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*
Maximum	*17%*	*18%*	*19%*	*18%*	*17%*	*16%*	*23%*	*23%*	*31%*	*37%*	*37%*	*36%*	*42%*	*42%*	*39%*	*38%*	*35%*	*26%*	*16%*	*12%*	*12%*	*14%*	*14%*	*15%*

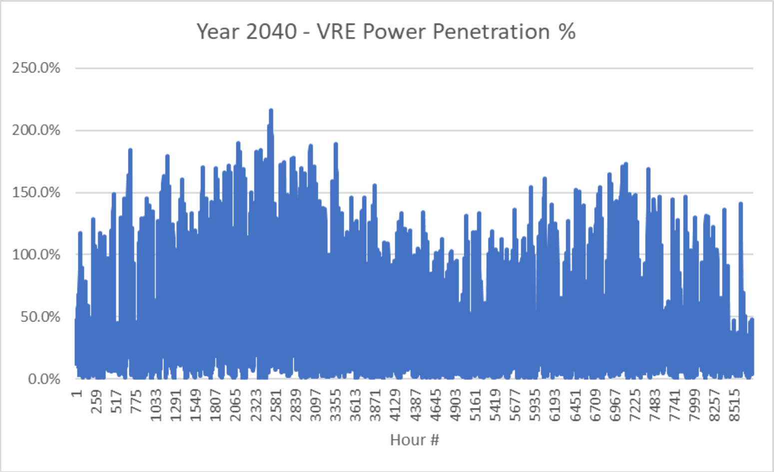
Average VRE Power Penetration %										Hour Ending																	
Month/Hr	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	*Avg*	*Min*	*Max*
1	9%	9%	10%	11%	9%	8%	6%	5%	9%	15%	20%	23%	25%	26%	25%	21%	17%	9%	7%	7%	8%	8%	8%	9%	*13%*	*0%*	*58%*
2	9%	9%	11%	10%	10%	8%	7%	6%	13%	20%	26%	29%	29%	29%	29%	27%	23%	14%	7%	7%	7%	7%	8%	8%	*15%*	*0%*	*57%*
3	8%	9%	9%	9%	8%	6%	6%	9%	16%	24%	27%	29%	32%	31%	31%	29%	26%	19%	9%	7%	7%	7%	8%	8%	*16%*	*0%*	*62%*
4	12%	13%	13%	14%	12%	9%	12%	19%	29%	35%	37%	37%	36%	37%	39%	38%	33%	25%	13%	8%	8%	10%	11%	12%	*21%*	*0%*	*71%*
5	8%	9%	10%	10%	9%	9%	14%	19%	28%	31%	33%	33%	35%	34%	33%	29%	27%	21%	9%	6%	4%	5%	6%	6%	*18%*	*0%*	*63%*
6	6%	6%	7%	7%	6%	7%	14%	17%	26%	29%	28%	29%	28%	26%	25%	22%	21%	17%	9%	7%	5%	4%	5%	6%	*15%*	*0%*	*51%*
7	4%	5%	5%	5%	5%	5%	11%	14%	22%	24%	25%	24%	24%	23%	22%	21%	19%	15%	8%	5%	3%	3%	4%	4%	*12%*	*0%*	*45%*
8	5%	5%	5%	5%	5%	4%	8%	12%	21%	24%	24%	24%	22%	25%	24%	22%	20%	16%	7%	4%	4%	3%	3%	4%	*12%*	*0%*	*43%*
9	7%	7%	7%	8%	7%	6%	6%	14%	23%	26%	29%	28%	28%	27%	25%	22%	19%	13%	5%	4%	5%	4%	5%	6%	*14%*	*0%*	*53%*
10	6%	7%	7%	7%	7%	6%	6%	11%	23%	29%	32%	33%	34%	33%	30%	25%	19%	9%	4%	5%	6%	5%	6%	6%	*15%*	*0%*	*56%*
11	9%	10%	10%	10%	8%	8%	7%	7%	15%	20%	22%	25%	26%	25%	25%	21%	13%	7%	7%	7%	8%	10%	9%	10%	*13%*	*0%*	*52%*
12	8%	8%	8%	8%	7%	6%	6%	5%	8%	13%	16%	19%	20%	19%	17%	13%	9%	6%	6%	6%	7%	7%	8%	8%	*10%*	*0%*	*46%*
Average	*8%*	*8%*	*9%*	*9%*	*8%*	*7%*	*9%*	*11%*	*20%*	*24%*	*27%*	*28%*	*28%*	*28%*	*27%*	*24%*	*21%*	*14%*	*8%*	*6%*	*6%*	*6%*	*7%*	*7%*			
Minimum	*1%*	*1%*	*1%*	*1%*	*1%*	*1%*	*1%*	*0%*	*1%*	*2%*	*5%*	*6%*	*5%*	*5%*	*4%*	*3%*	*1%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*1%*			
Maximum	*28%*	*29%*	*30%*	*29%*	*26%*	*25%*	*38%*	*38%*	*53%*	*63%*	*62%*	*60%*	*70%*	*71%*	*65%*	*64%*	*59%*	*43%*	*25%*	*19%*	*19%*	*22%*	*22%*	*23%*			

- The power penetration of intermittent resources will increase between 2023 and 2040 as more solar and wind are introduced in the system.
- Exceeding 60% penetration is potentially problematic for islanded systems, while exceeding 100% relies strongly on the tie-lines to neighboring utilities.

T5 Portfolio (Aggressive Enviro)

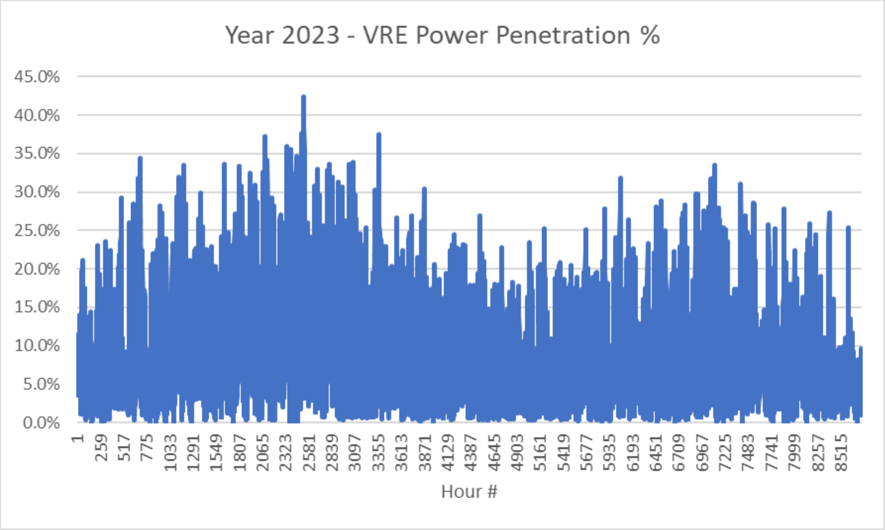


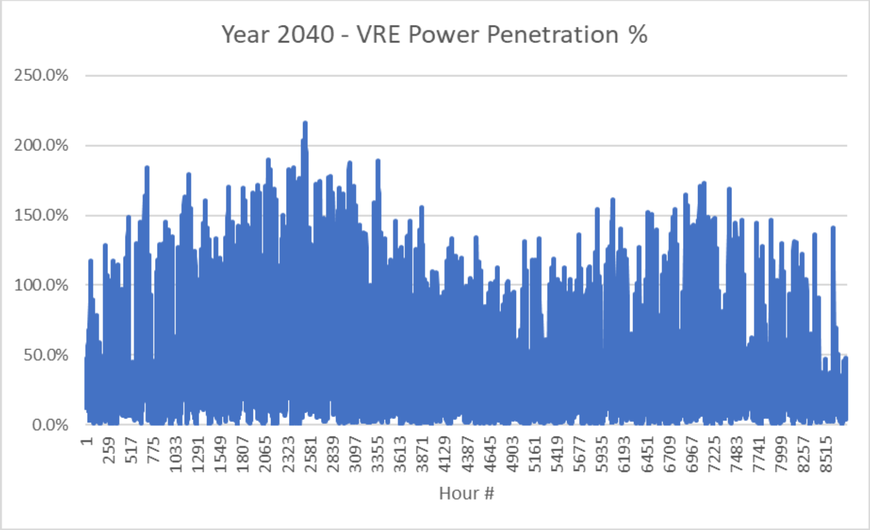




- Variable Resources (VRE) generation exceed the load level whenever the penetration exceeds 100%.
- Higher Solar and Wind resource values as compared to the reference case T1.

T5 Portfolio: Power Penetration Level by Intermittent Resources





Average VRE Power Penetration %										Hour Ending														
Month/Hr	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	5%	6%	6%	7%	6%	5%	4%	3%	6%	9%	12%	14%	15%	15%	15%	13%	10%	6%	4%	5%	5%	5%	5%	5%
2	5%	6%	7%	7%	6%	5%	4%	4%	8%	12%	15%	17%	17%	17%	17%	16%	14%	8%	4%	4%	4%	4%	5%	5%
3	5%	6%	5%	6%	5%	4%	4%	5%	10%	14%	16%	17%	19%	18%	18%	17%	15%	11%	6%	4%	4%	5%	5%	5%
4	8%	8%	8%	9%	7%	6%	7%	11%	17%	20%	22%	22%	22%	22%	23%	23%	20%	15%	8%	5%	5%	6%	7%	7%
5	5%	6%	6%	6%	5%	6%	9%	11%	16%	18%	20%	20%	20%	20%	19%	17%	16%	13%	6%	4%	3%	3%	4%	4%
6	4%	4%	4%	4%	4%	5%	8%	10%	15%	17%	17%	17%	16%	15%	15%	13%	13%	10%	6%	4%	3%	3%	3%	4%
7	3%	3%	3%	3%	3%	3%	6%	8%	13%	14%	15%	14%	14%	14%	13%	12%	11%	9%	5%	3%	2%	2%	2%	2%
8	3%	3%	3%	3%	3%	3%	5%	7%	12%	14%	14%	14%	13%	14%	14%	13%	12%	9%	4%	2%	2%	2%	2%	3%
9	4%	5%	5%	5%	5%	4%	4%	8%	13%	15%	17%	16%	17%	16%	15%	13%	12%	8%	3%	3%	3%	3%	3%	4%
10	4%	4%	5%	5%	4%	4%	3%	7%	14%	17%	19%	20%	20%	19%	18%	15%	11%	5%	3%	3%	4%	3%	4%	4%
11	6%	6%	6%	6%	5%	5%	4%	4%	9%	12%	13%	15%	15%	15%	15%	13%	8%	4%	4%	4%	5%	6%	6%	6%
12	5%	5%	5%	5%	5%	4%	3%	3%	5%	8%	10%	11%	12%	11%	10%	8%	6%	3%	4%	4%	4%	4%	5%	5%
Average	*5%*	*5%*	*5%*	*5%*	*5%*	*4%*	*5%*	*7%*	*12%*	*14%*	*16%*	*16%*	*17%*	*16%*	*16%*	*14%*	*12%*	*8%*	*5%*	*4%*	*4%*	*4%*	*4%*	*5%*
Minimum	*0%*	*0%*	*0%*	*1%*	*0%*	*0%*	*0%*	*0%*	*1%*	*1%*	*3%*	*4%*	*3%*	*3%*	*3%*	*2%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*
Maximum	*17%*	*18%*	*19%*	*18%*	*17%*	*16%*	*23%*	*23%*	*31%*	*37%*	*37%*	*36%*	*42%*	*42%*	*39%*	*38%*	*35%*	*26%*	*16%*	*12%*	*12%*	*14%*	*14%*	*15%*

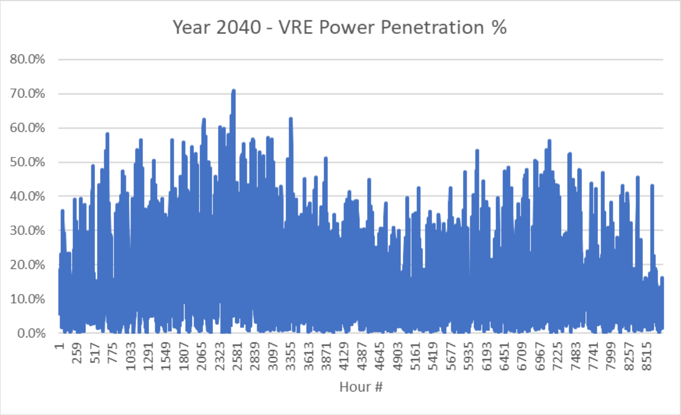
Average VRE Power Penetration %										Hour Ending														
Month/Hr	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	18%	19%	21%	23%	20%	17%	14%	12%	24%	44%	62%	73%	78%	82%	78%	64%	50%	23%	15%	16%	17%	17%	17%	18%
2	18%	20%	23%	22%	21%	17%	14%	14%	37%	63%	81%	92%	94%	92%	93%	85%	70%	40%	16%	14%	15%	15%	17%	18%
3	18%	19%	19%	20%	18%	14%	13%	23%	48%	75%	85%	93%	103%	99%	98%	92%	79%	55%	23%	14%	15%	16%	16%	17%
4	27%	28%	29%	31%	25%	20%	30%	52%	90%	109%	116%	117%	116%	118%	124%	121%	102%	73%	33%	18%	16%	21%	23%	25%
5	16%	20%	21%	21%	18%	20%	40%	55%	88%	99%	107%	108%	112%	110%	107%	93%	85%	64%	26%	16%	9%	10%	13%	12%
6	13%	13%	14%	14%	12%	17%	40%	50%	84%	95%	93%	95%	92%	84%	81%	72%	67%	54%	26%	18%	10%	9%	11%	12%
7	9%	11%	11%	11%	10%	11%	31%	43%	74%	81%	84%	80%	79%	77%	74%	67%	62%	46%	22%	15%	6%	6%	8%	8%
8	10%	11%	12%	11%	10%	9%	22%	36%	68%	80%	81%	80%	75%	81%	79%	73%	66%	50%	20%	10%	8%	6%	7%	9%
9	15%	16%	16%	16%	16%	12%	15%	41%	73%	82%	93%	91%	91%	88%	83%	71%	61%	41%	13%	9%	10%	9%	11%	14%
10	13%	15%	16%	16%	15%	14%	12%	32%	74%	94%	106%	109%	111%	107%	99%	81%	61%	26%	9%	11%	12%	11%	12%	13%
11	20%	22%	22%	21%	18%	17%	15%	17%	44%	60%	68%	77%	80%	79%	77%	65%	39%	16%	14%	15%	17%	21%	20%	21%
12	17%	18%	18%	17%	16%	14%	12%	10%	23%	39%	51%	59%	63%	59%	53%	39%	26%	12%	12%	13%	15%	15%	16%	17%
Average	*16%*	*18%*	*18%*	*18%*	*17%*	*15%*	*21%*	*32%*	*61%*	*77%*	*86%*	*89%*	*91%*	*90%*	*87%*	*77%*	*64%*	*42%*	*19%*	*14%*	*12%*	*13%*	*14%*	*15%*
Minimum	*1%*	*1%*	*1%*	*2%*	*1%*	*2%*	*1%*	*0%*	*3%*	*6%*	*16%*	*22%*	*17%*	*18%*	*14%*	*9%*	*3%*	*0%*	*0%*	*0%*	*1%*	*1%*	*1%*	*1%*
Maximum	*59%*	*62%*	*65%*	*63%*	*57%*	*54%*	*109%*	*109%*	*161%*	*189%*	*193%*	*190%*	*213%*	*216%*	*203%*	*194%*	*177%*	*126%*	*62%*	*41%*	*41%*	*48%*	*48%*	*50%*

- The power penetration of intermittent resources will increase substantially between 2022 and 2031 as more solar and wind are introduced in the system.
- Exceeding 60% penetration is potentially problematic for islanded systems, while exceeding 100% relies strongly on the tie-lines to neighboring utilities.

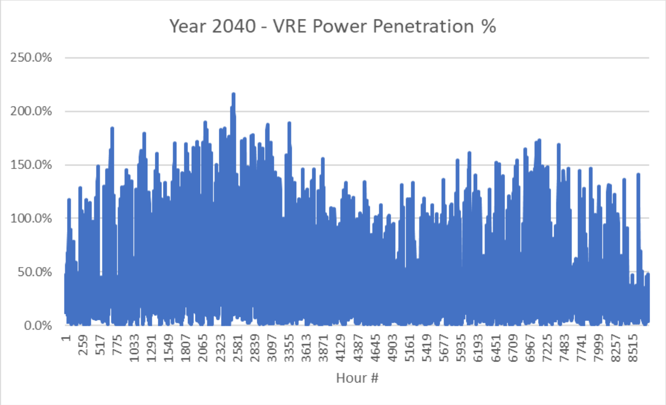
VRE penetration across Portfolios

Portfolios Penetration Level in 2040

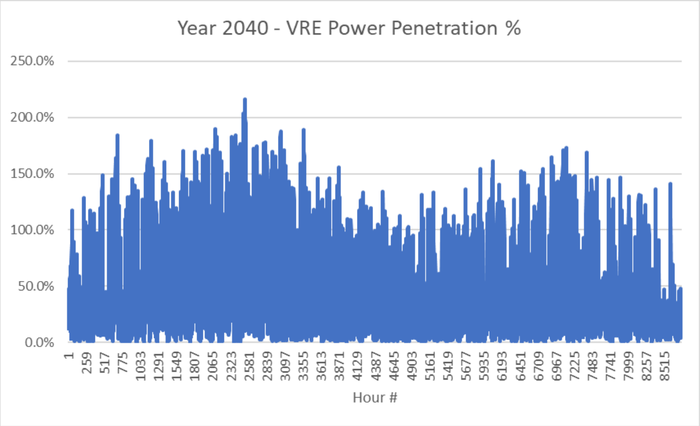
T1



T3



T5



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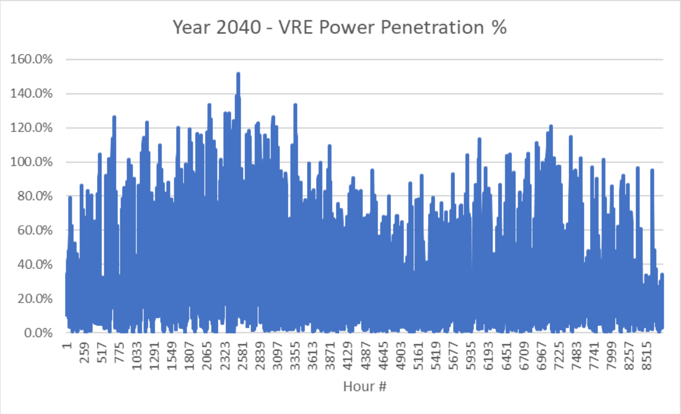

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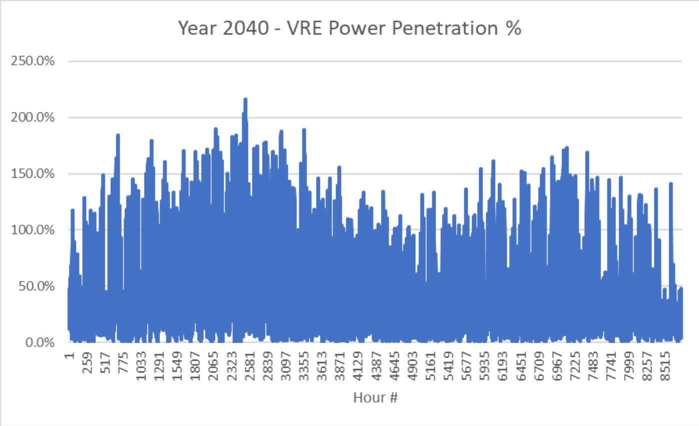

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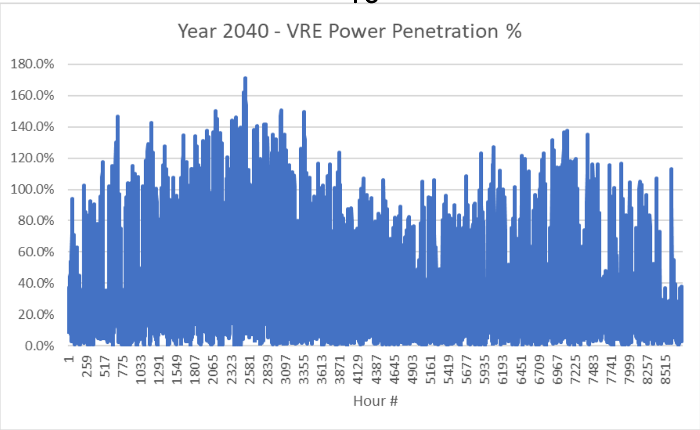


- Portfolios T1 and T7 are lowest in terms of VRE penetration levels, followed by T2 and T6, while T3-T5 has the highest power penetration levels.

Reliability Analysis Methodologies and Results - Focus on Area 207

- Energy Balance
  - Ramping
  - Flexibility
  - Load following / dispatchability

- Stability
  - Inertial response
  - Primary frequency response
  - System Stability

- Voltage Response and System Strength
  - Dynamic VAR support
  - System short circuit strength

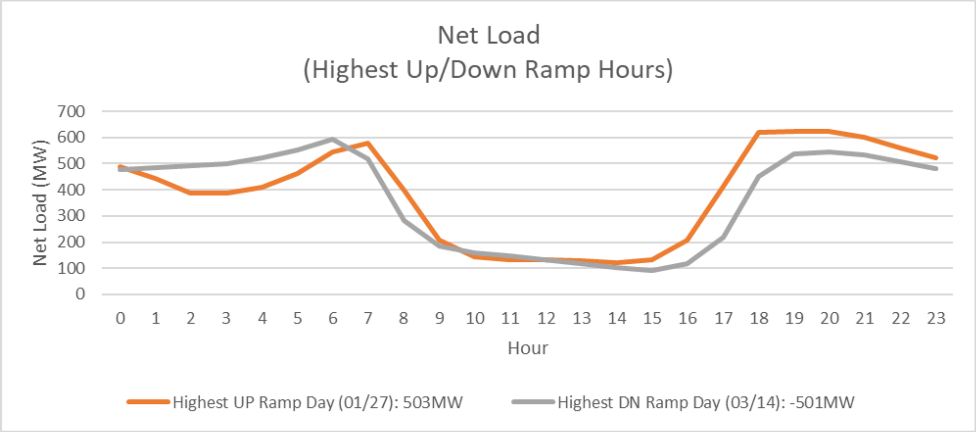
Power Ramps

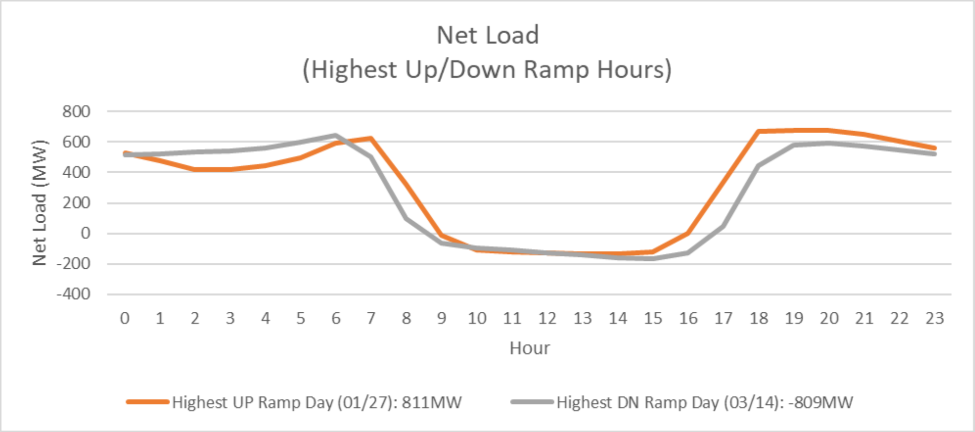
- The electric power industry has documented over the past decade an expected change in the hourly load profiles as intermittent renewable penetration of solar and wind resources increases. This has been dubbed the "Duck Curve".
- System operation is challenged during periods of high-power ramp rates. This has prompted CAISO and later MISO to adopt a new ancillary service product called Ramping Product, with the objective of acquiring fast ramping resources that can be committed and dispatched rapidly to balance the system supply and demand during these periods of high-power ramps.
- Power ramps can occur at different time scales:
    - Intra-hour ramping: intermittency of renewable resources due to cloud cover or wind bursts. These ramps can be quantified at a second, minute, 5-min, and 10-min basis. These ramps can be mitigated by procuring additional fast regulation reserves including energy storage.
    - Hour to hour: changes in power output between two consecutive hours.
    - Multi-Hour during a day: sustained increase or decrease in power output across several successive hours in a day.
- Hourly and daily power ramps can be partially mitigated by properly forecasting and scheduling these ramps in the day-ahead and real-time markets. However, any unscheduled hourly ramps will affect control area performance and have to be mitigated within the control area. Energy is scheduled with MISO in the day-ahead hourly market and in the real-time 5-minute market. Schedules are submitted up to 38 hours ahead of the actual hour time for the day-ahead market and 30 minutes for the real time market.

Energy Balance: Net Load Power Ramps (T1)

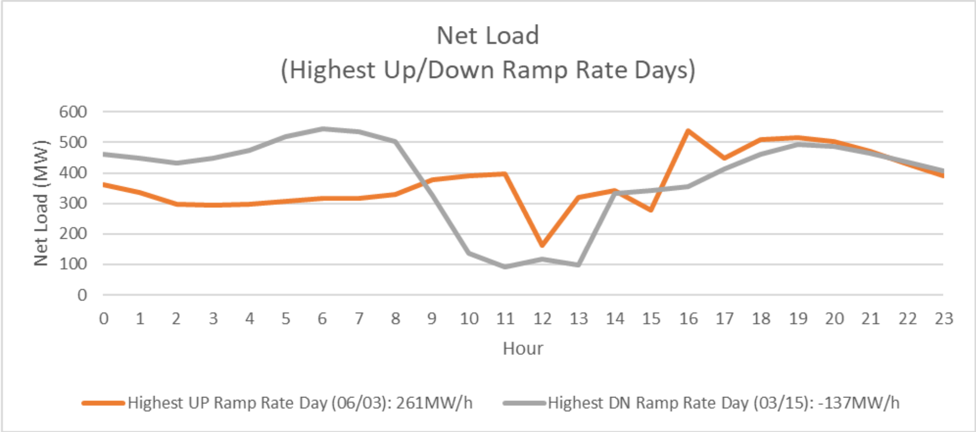
Y2023 | Y2030

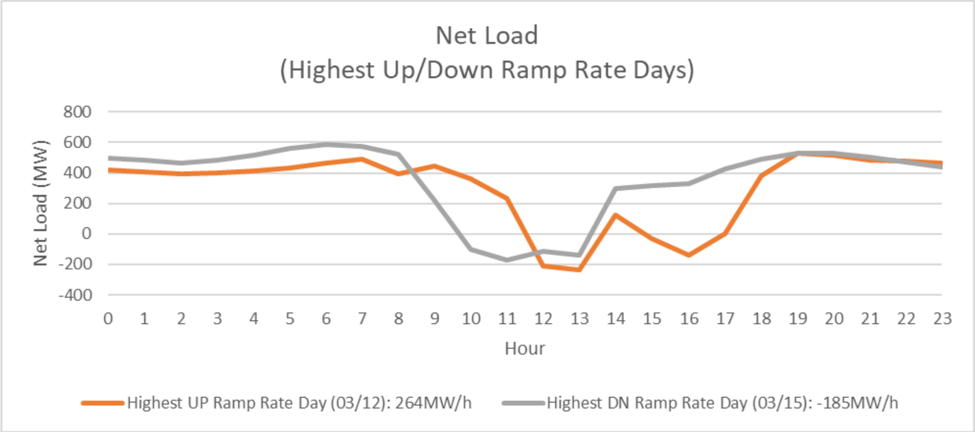
Highest Up/Down Ramp Days





Highest Up / Down Ramp Rate Hours





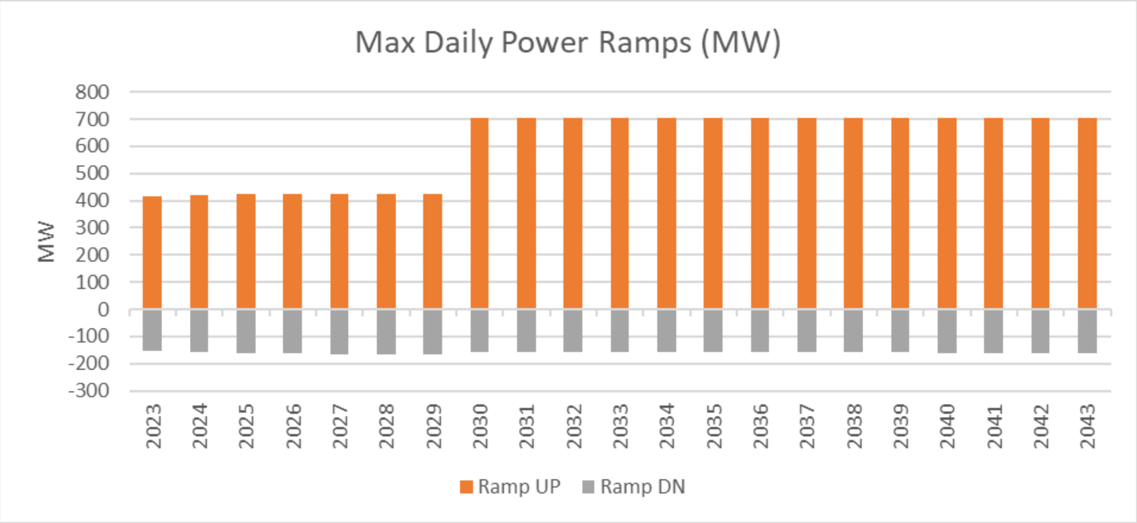
Net Load profile in 2023 and 2030 is shaped like a "Duck Curve". In 2030, the load becomes negative mid day

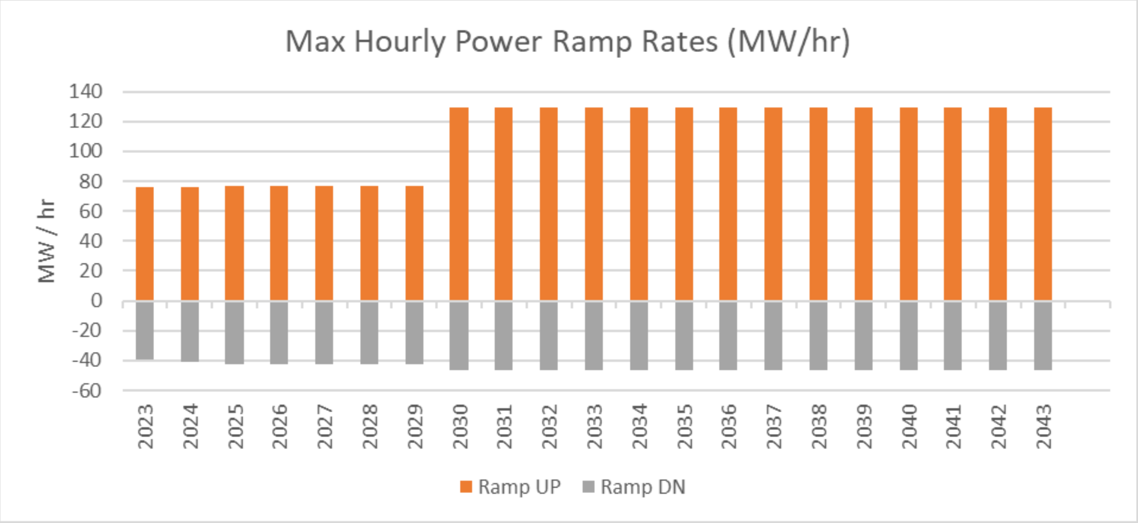
Energy Balance : Net Load Power Ramps (T1)

Portfolio T1 (without Storage/Peakers Dispatch)

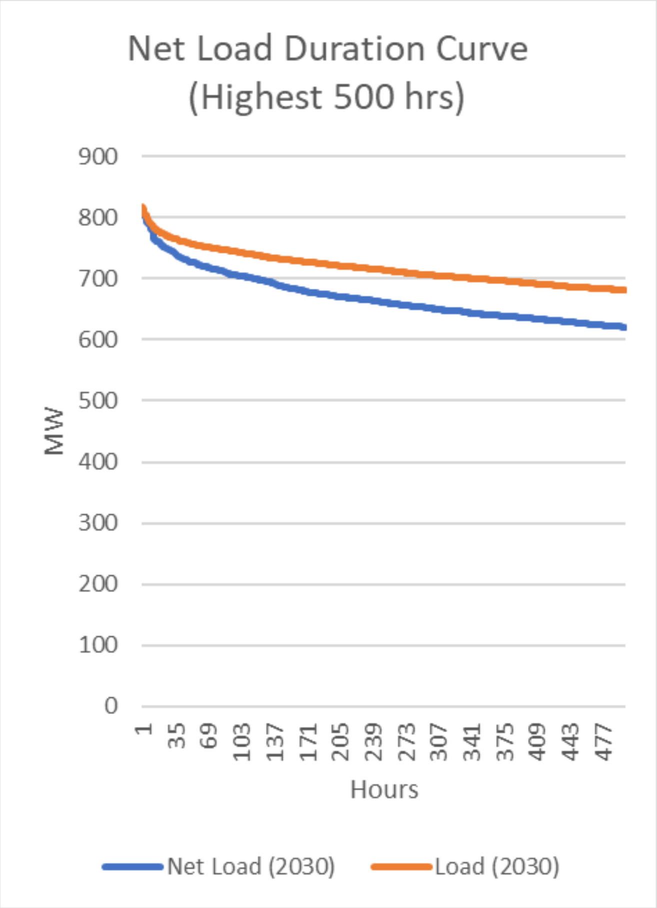
Year	Ramp UP	Ramp DN	Ramp Rate UP	Ramp Rate DN
2023	417	-151	76	-39
2024	419	-157	76	-41
2025	423	-164	77	-42
2026	423	-164	77	-42
2027	423	-164	77	-42
2028	423	-165	77	-43
2029	424	-165	77	-43
2030	705	-157	129	-46
2031	705	-157	129	-46
2032	705	-158	129	-46
2033	705	-159	129	-46
2034	705	-157	129	-46
2035	705	-158	129	-46
2036	705	-158	129	-46
2037	705	-159	129	-46
2038	705	-159	129	-46
2039	705	-159	129	-46
2040	705	-160	129	-47

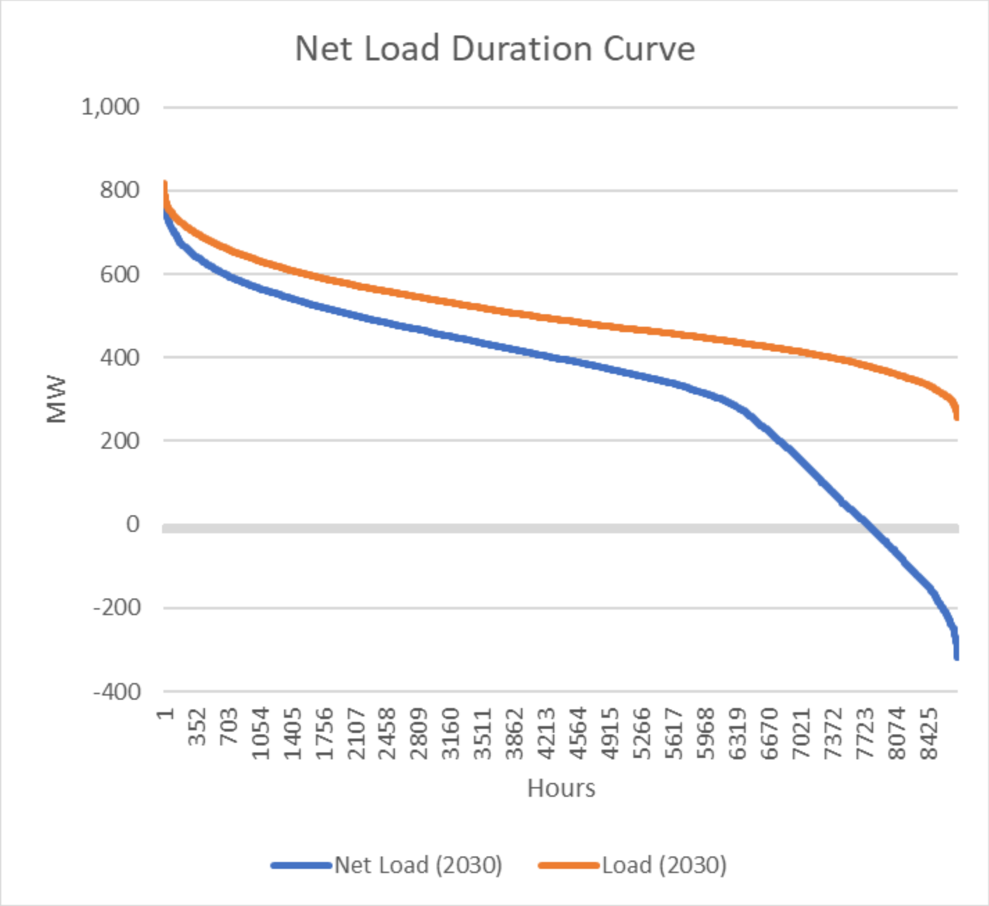
Ramping Category (P90)	2023 MW	%Peak	2030 MW	%Peak	Increased MW 2040 .vs. 2023
1-hr Up	76	5.0%	129	7.9%	53
1-hr Down	-39	2.6%	-46	2.8%	-7
Day Up	417	27.5%	705	43.1%	288
Day Down	-151	10.0%	-157	9.6%	-6





Energy Balance T1: Net Load (Y2030)





Energy Balance : Renewable Power Ramping and Mitigation Capability

Portfolio/ Y2030	Solar	BTM Solar	Wind	Solar + Storage	Day Ramping Up (MW)	Day Ramping Down (MW)	1hr Ramping Up (MW)	1hr Ramping Down (MW)	Peaker/Storage (MW) - 10min Ramping Capability	10-min Forecast Error 90th Percentile	Excess Ramping Capability (MW)
2023	383	0	0	0	417	-151	76	-39	262	19	167
T1	682	0	0	0	705	-157	129	-46	362	34	199
T2	682	0	0	0	705	-157	129	-46	262	34	99
T3	682	0	0	0	705	-157	129	-46	442	34	279
T4	682	0	0	0	705	-157	129	-46	342	34	179
T5	682	0	0	0	705	-157	129	-46	542	34	379
T6	682	0	0	0	705	-157	129	-46	342	34	179
T7	682	0	0	0	705	-157	129	-46	362	34	199

- Balancing areas are required per BAL-003 to comply with CPS1 and CPS2. CPS2 is a monthly standard intended to limit unscheduled flows. It requires compliance better than 90% that the average ACE will remain below a threshold over all 10-min intervals in the month. For a balancing area with a peak load of 1515 MW, the threshold is around 80 MW.
- A small percentage (≈20%) of the hourly ramps in Net Load can be forecasted an hour ahead using a persistent forecast method and thus can be scheduled in the real time market or accounted for in the dispatch algorithm,. Example, Portfolio T5 has total 1-hour ramp up of 868 MW while its forecast error has a 90th percentile of 421 MW, or 28%.
- The unforecasted changes in renewable resource outputs should be mitigated using fast ramping resources.
- Portfolios will be ranked according to their ability to mitigate unscheduled flow.

Energy Balance: Portfolio Ramping and VAR Capability

Y 2030

Portfolio	1-min Ramp Capability (MW)	10-min Ramp Capability (MW)	VAR Capability (MVAr)
T1	139	362	609
T2	39	262	556
T3	219	442	651
T4	119	342	598
T5	319	542	704
T6	119	342	598
T7	139	362	609

- The ramping capability of the system is measured at 1-min and 10-mins. The higher the ramping capability the better flexibility the system will have to respond to sudden disturbance.

Import/Export Analysis

Year	2030	
Peak Load MW	817	
Annual Load GWh	4,366	
# Import Hrs	4,128	47.1%of time
# Export-Capable Hrs	4,592	52.4%of time
Import GWhs	483	11.1%Of Consumption
Max Import MW	440	

	# Import Hrs																							
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	31	30	28	28	28	29	30	30	25	23	14	9	10	6	7	13	12	22	31	31	31	30	31	31
2	27	27	24	24	25	26	27	28	19	11	7	5	3	3	2	2	6	10	26	28	28	28	28	28
3	23	23	21	22	23	24	27	24	18	11	6	2	1	1	1	1	1	3	9	26	25	20	20	23
4	6	6	6	6	6	9	12	7	0	0	0	0	0	0	0	0	0	0	1	14	13	5	6	6
5	8	1	0	0	0	1	2	3	1	1	0	0	0	0	0	0	0	3	9	12	21	12	12	13
6	26	19	10	9	11	13	6	5	3	3	2	1	3	1	1	1	3	7	23	26	30	30	28	29
7	30	26	17	15	17	18	10	6	3	2	2	2	2	2	2	3	4	11	29	29	31	31	31	31
8	31	25	14	13	17	22	19	9	4	3	2	2	4	0	2	1	2	6	31	31	31	30	31	31
9	17	9	5	5	7	12	14	8	4	4	2	2	3	4	3	5	5	8	25	29	25	20	24	25
10	19	12	11	11	16	18	24	13	4	2	1	0	0	0	0	0	1	5	25	25	15	15	25	25
11	26	24	21	21	23	26	26	27	17	14	10	7	4	4	4	5	9	16	26	26	27	29	29	28
12	31	31	29	29	30	30	30	31	28	20	16	11	11	6	7	12	17	29	31	31	30	31	31	31

Import / Export Analysis

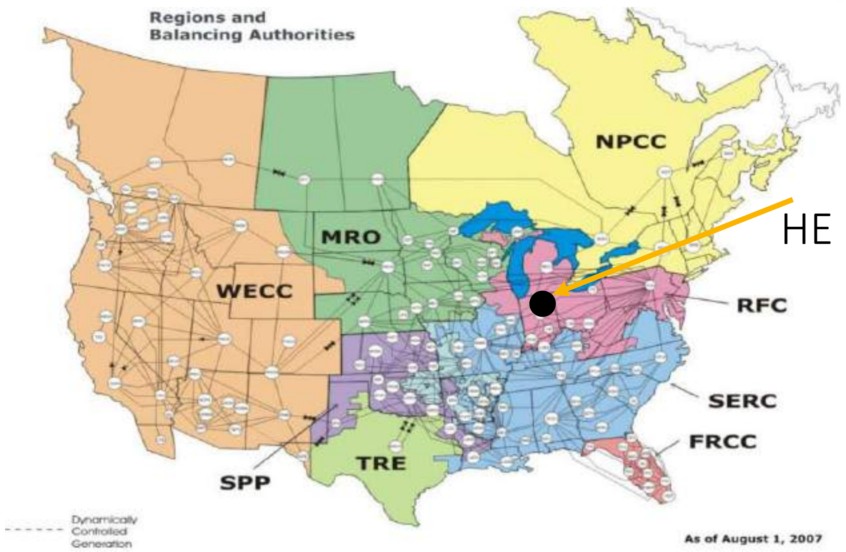
Y 2030

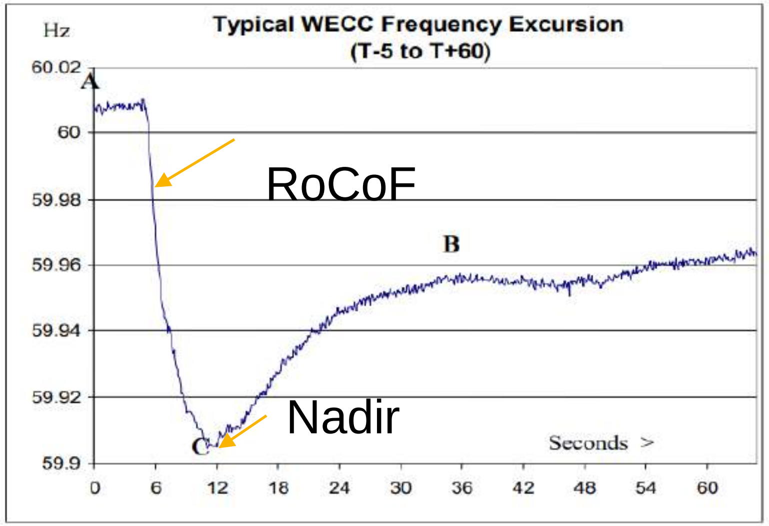
50/50 Forecast	T1	T2	T3	T4	T5	T6	T7
Peak Load MW	817	817	817	817	817	817	817
Annual Load GWh	4,366	4,366	4,366	4,366	4,366	4,366	4,366
# Deficit/Import Hrs	4,128	4,867	3,364	4,286	2,531	4,286	4,128
Deficit/Import Hrs %	47%	56%	38%	49%	29%	49%	47%
# Potential Excess/Export Hrs	4,592	3,854	5,369	4,436	6,208	4,436	4,592
Excess/Export Hrs %	52%	44%	61%	51%	71%	51%	52%
Deficit/Import GWh/Yr	483	607	414	504	352	504	483
Deficit/Import Energy (% load GWh/yr)	11.1%	13.9%	9.5%	11.5%	8.1%	11.5%	11.1%
Max Deficit/Import (Excess/Export) MW	440	440	440	440	440	440	440
Max Deficit/Import -(Excess/Export) %Peak Laod	54%	54%	54%	54%	54%	54%	54%

90/10 Forecast	T1	T2	T3	T4	T5	T6	T7
Peak Load MW	923	923	923	923	923	923	923
Annual Load GWh	5,200	5,200	5,200	5,200	5,200	5,200	5,200
# Deficit/Import Hrs	4,504	5,175	3,878	4,642	3,183	4,642	4,504
Deficit/Import Hrs %	51%	59%	44%	53%	36%	53%	51%
# Potential Excess/Export Hrs	4,228	3,553	4,867	4,088	5,566	4,088	4,228
Excess/Export Hrs %	48%	41%	56%	47%	64%	47%	48%
Deficit/Import GWh/Yr	662	780	594	682	531	682	662
Deficit/Import Energy (% load GWh/yr)	12.7%	15.0%	11.4%	13.1%	10.2%	13.1%	12.7%
Max Deficit/Import (Excess/Export) MW	545	545	545	545	545	545	545
Max Deficit/Import -(Excess/Export) %Peak Laod	59%	59%	59%	59%	59%	59%	59%

Frequency Control - Overview

- Hoosier operates a balancing control area, within the MISO balancing control area within the Eastern Interconnection.
- Dispatchers at each Balancing Authority fulfill their NERC obligations by monitoring ACE and keeping the value within limits that are generally proportional to Balancing Authority size.
- Generators contribute to the frequency response through Governors while loads contribute through their natural sensitivity to frequency. Frequency Response is measured as change in MW per 0.1Hz change in frequency. Governor's droop of 5% translates to a response of 3.3% while load response is typically 1-2%. Frequency Response is particularly important during disturbances and islanding situations. Per BAL-003, each balancing area should carry a frequency bias, whose monthly average is no less than 1% of peak load.
- Following the loss of a large generator, frequency drops initially at a rate (RoCoF) that depends on the level of inertia in the system. After few seconds, it will stabilize at a lower value (Nadir) due to the primary frequency response of generators and loads. Afterwards, AGC systems will inject regulation reserves that raise the frequency to within a settling range within a minute. Tertiary reserves are called upon if required to help.





Control	Ancillary Service/IOS	Timeframe	NERC Standard
Primary Control	Frequency Response	10-60 Seconds	FRS-CPS1
Secondary Control	Regulation	1-10 Minutes	CPS1– CPS2 – DCS - BAAL
Tertiary Control	Imbalance/Reserves	10 Minutes - Hours	BAAL - DCS
Time Control	Time Error Correction	Hours	TEC

Frequency Response and Simplified Model

- Inertial Response
  - $\frac{2H}{f_0}\frac{df}{dt} = \Delta P$
  - ΔP = Loss of power resources due to contingency event

    + Variability of intermittent resources solar+wind resources at 1s

    - Virtual inertial contribution from online solar+wind resources

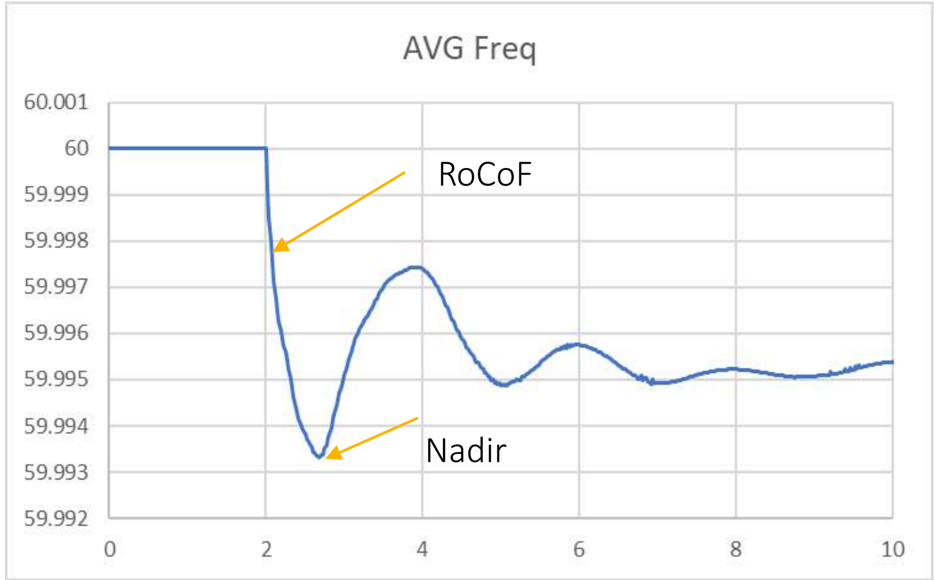
    - Virtual inertial contribution from battery energy storage

    - Inertial response contribution from outside areas over tie-lines

  - Inertia to limit RoCoF: H= ΔP/(2 x RoCoF Limit) f_0
  - Inertia to avoid triggering UFLS before the responsive reserves load: H=ΔP/(2 x UFLS speed) f_0 ;

    where UFLS speed = (pickup frequency – trip frequency)/delay

- Primary Freq Response
  - Δf(pu)= - (R .ΔP)/(D.R+1)
  - Where:
    - R is governor droop,
    - D is load damping,
    - ΔP is system disturbance, and all are in per unit using the same MW base value, such as system load level



Stability Analysis

- Transient analysis was performed on the following cases:
  - Summer Peak PF Case: MISO22_2027_SUM___TA
  - Summer Light Load PF Case: MISO22_2027_SLL70_TA
  - Summer High Wind PF Case: MISO22_2027_SHHW__TA

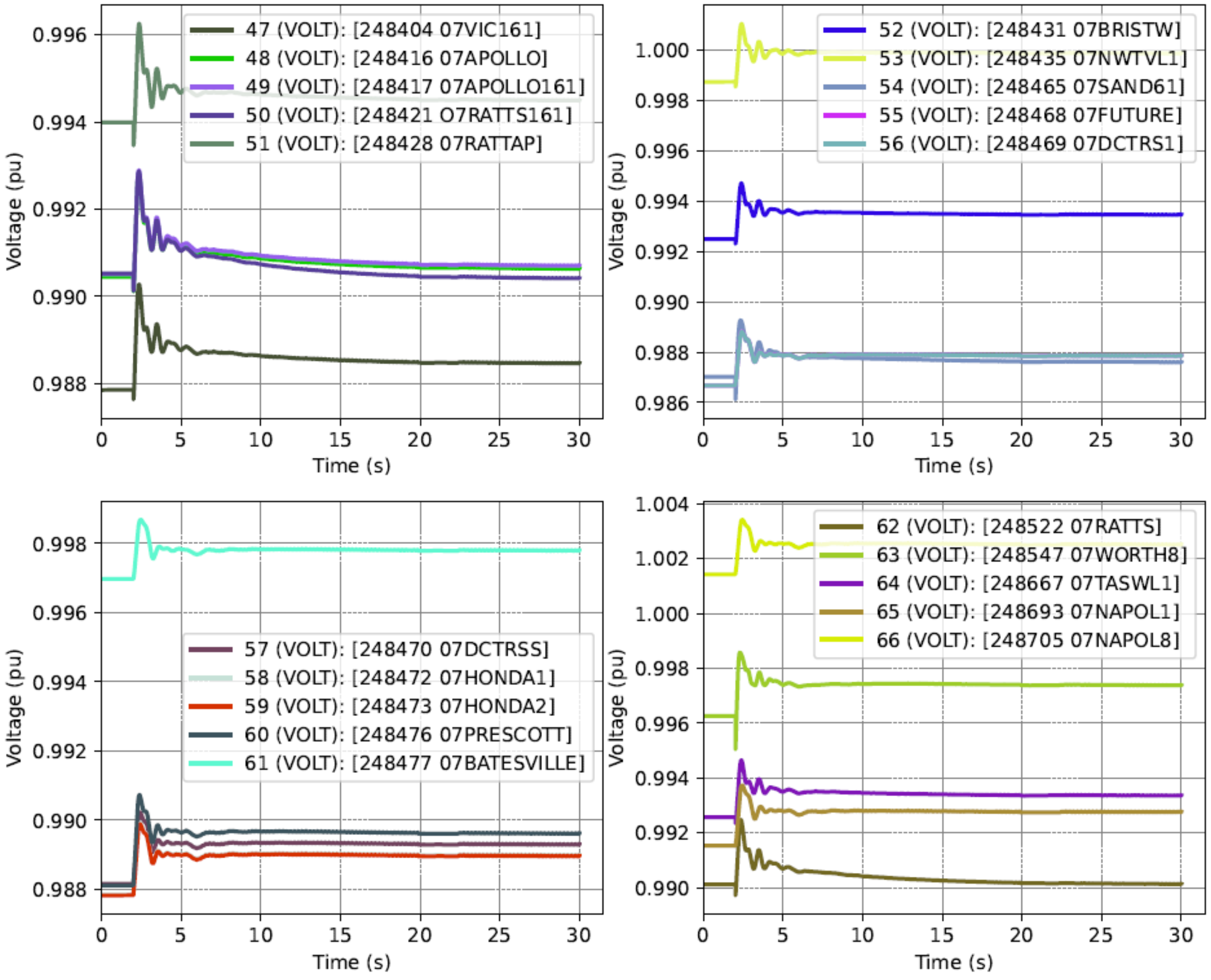
- The simulated contingency was the loss of the largest unit in the Hoosier Energy system: Merom Unit 1
  - Total generation lost: 522 MW

- Results observed were similar across the runs, hence plots from the Summer Peak case will be presented for simplicity

Voltage Response

- All buses in the Hoosier Energy system were monitored
- The voltage response is healthy for all the buses
  - A sample of buses is presented as a reference

- Summer Peak PF Case MISO22_2027_SUM___TA
- Contingency: Loss of Merom Unit 1
- Total generation lost: 522 MW

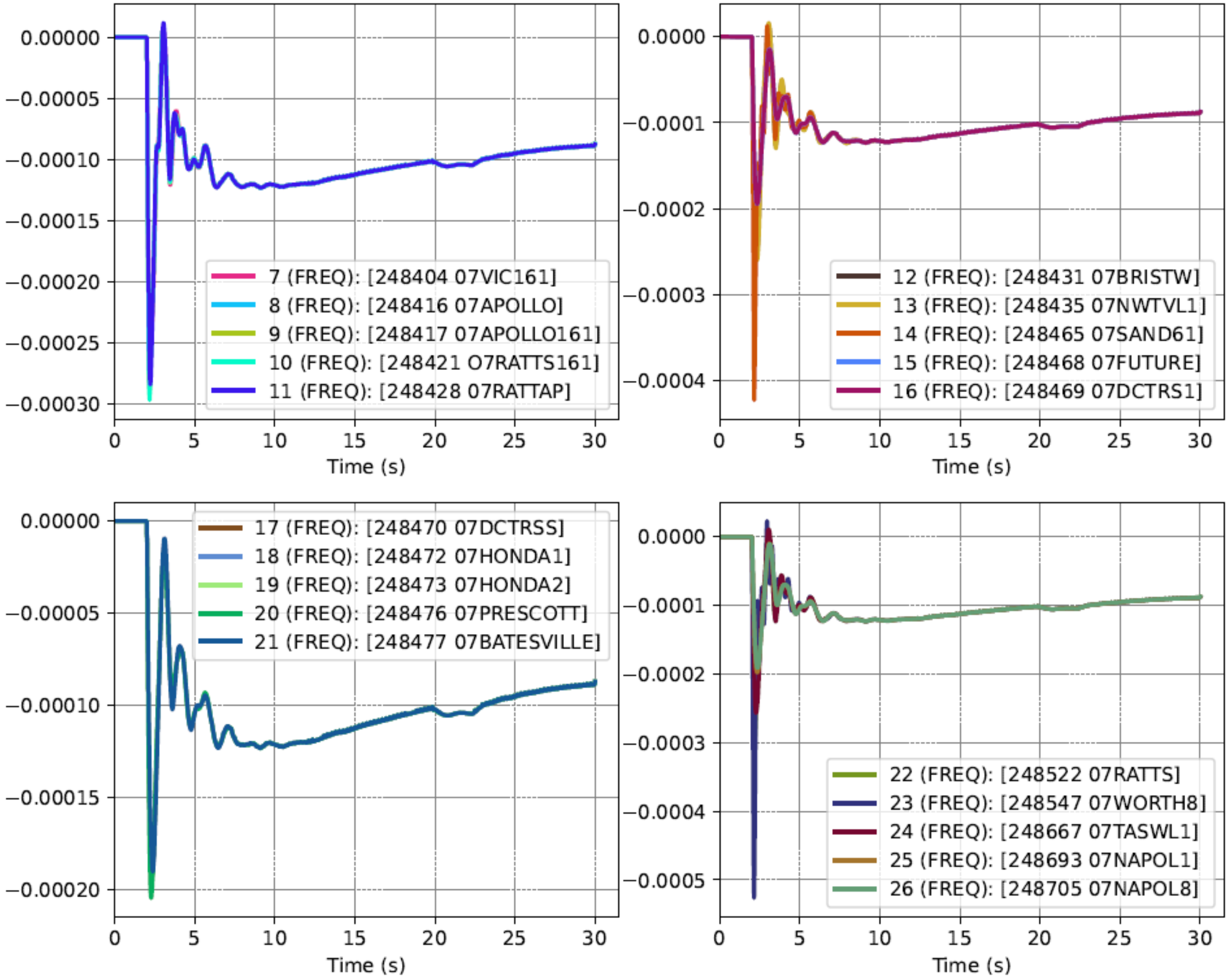


Frequency Response

- All buses in the Hoosier Energy system were monitored
- The frequency response is healthy for all the buses
    - A sample of buses is presented as a reference

- Summer Peak PF Case MISO22_2027_SUM___TA
- Contingency: Loss of Merom Unit 1
- Total generation lost: 522 MW

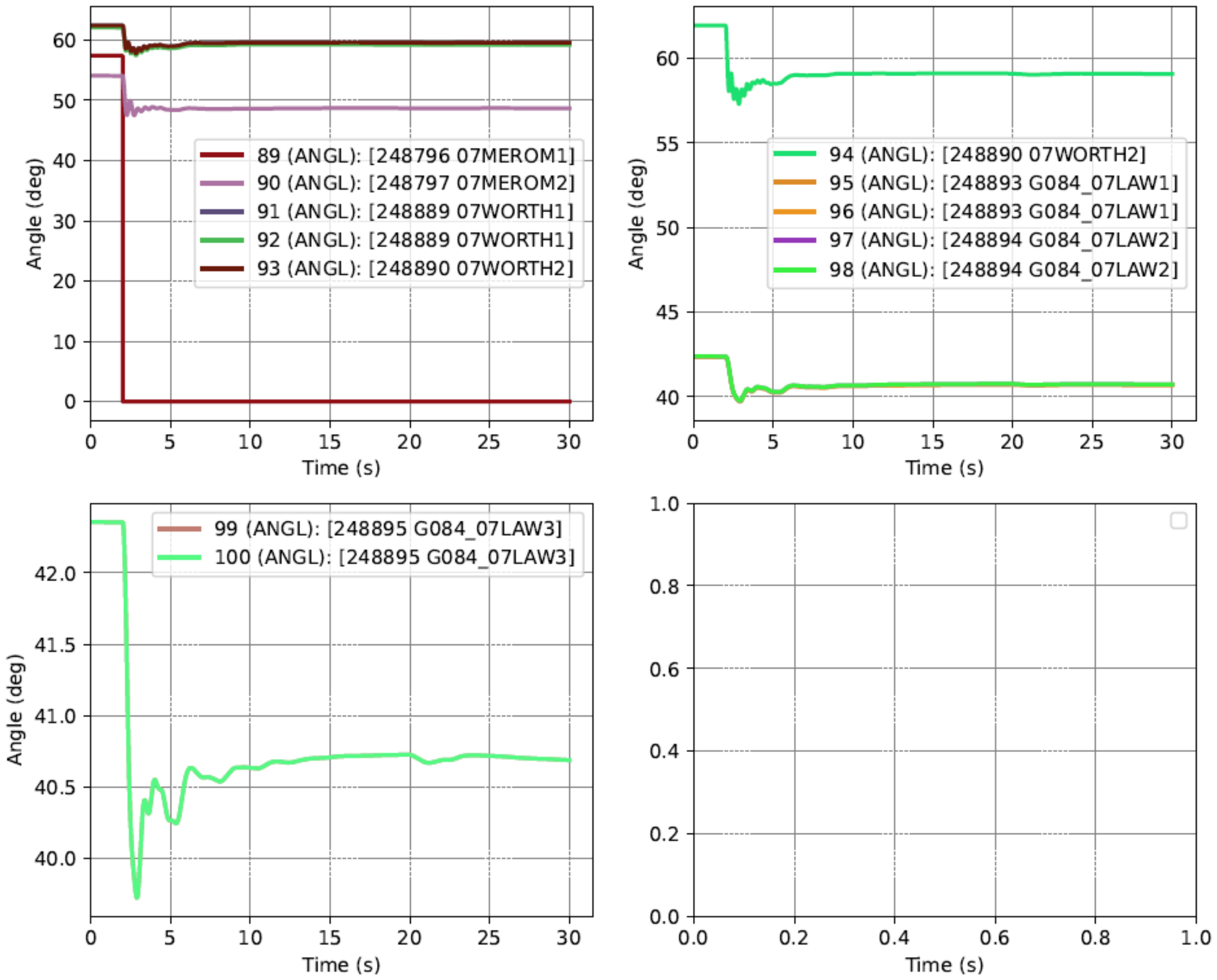
Frequency at 20 sec	Frequency nadir	RoCoF at cycle 2 (Hz/s)
59.994 Hz	59.985 Hz @ 2.20 sec	0.07359



Rotor Angle Response

- The rotor angles for all synchronous machines in the Hoosier Energy system were monitored
- The rotor angle response is stable for all machines

- Summer Peak PF Case MISO22_2027_SUM___TA
- Contingency: Loss of Merom Unit 1
- Total generation lost: 522 MW

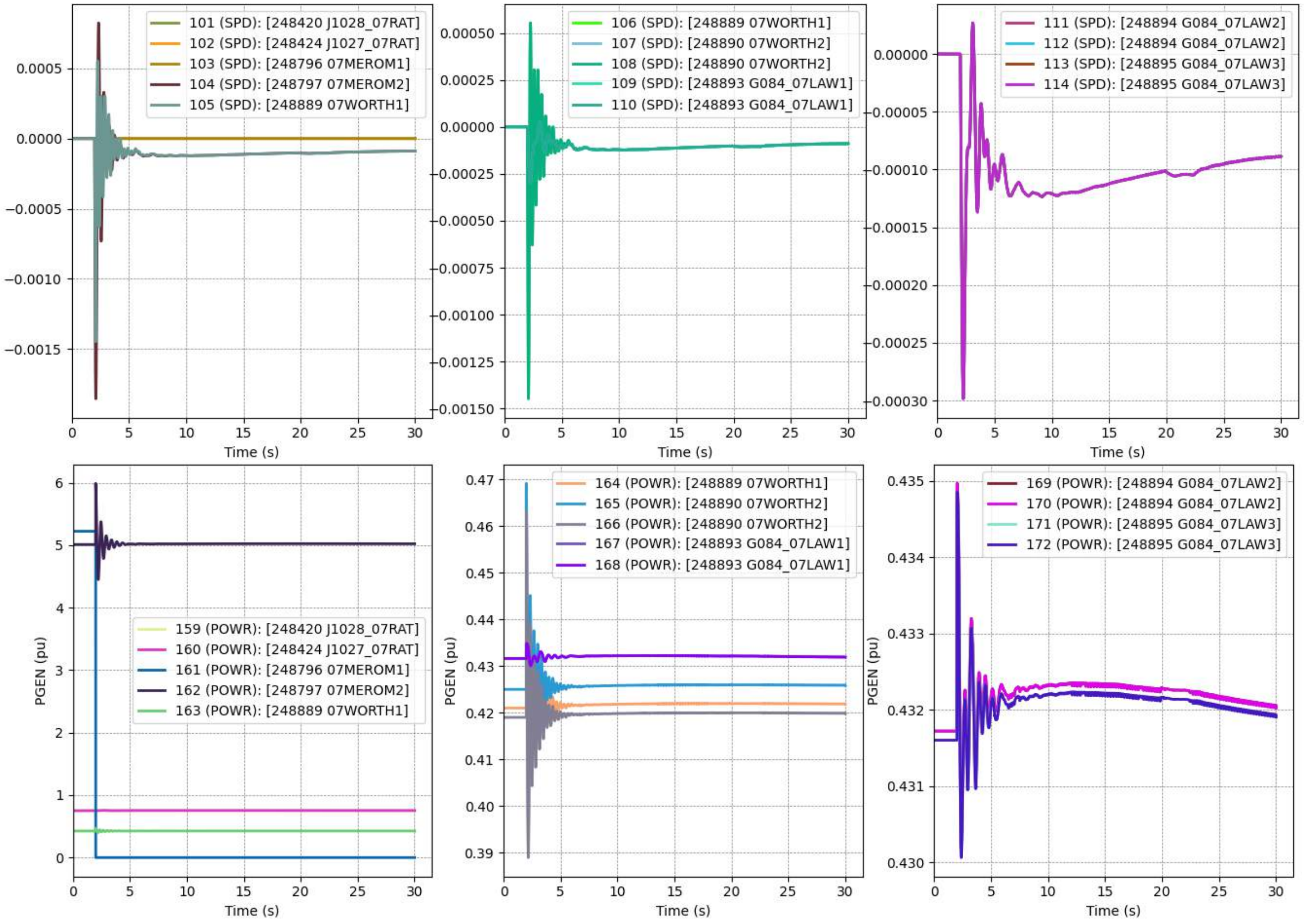


Machine Speed and Power Output Response

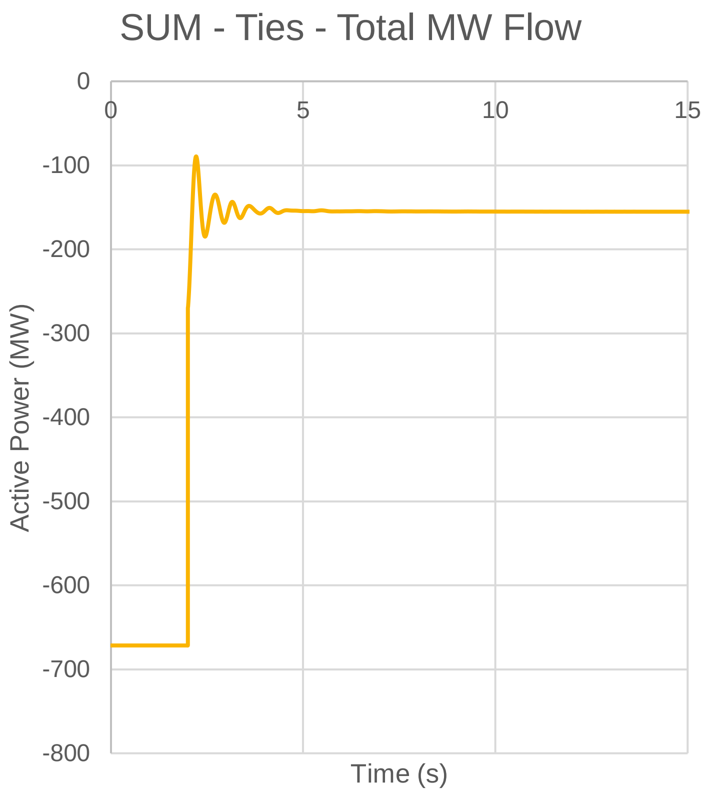
- Machine speed and power output for all synchronous machines in the Hoosier Energy system were monitored

- The responses are stable for all machines in the Hoosier Energy system

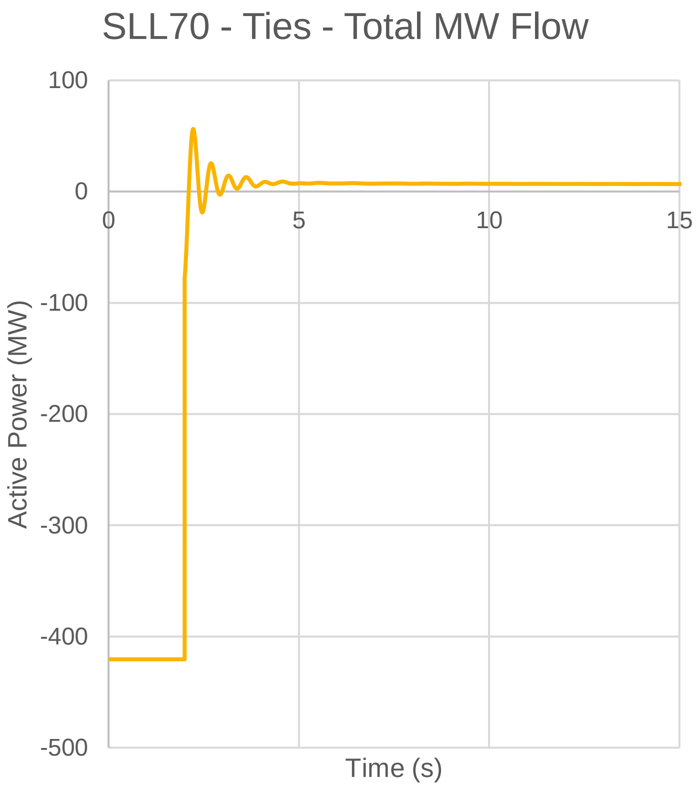
- Summer Peak PF Case MISO22_2027_SUM___TA
- Contingency: Loss of Merom Unit 1
- Total generation lost: 522 MW



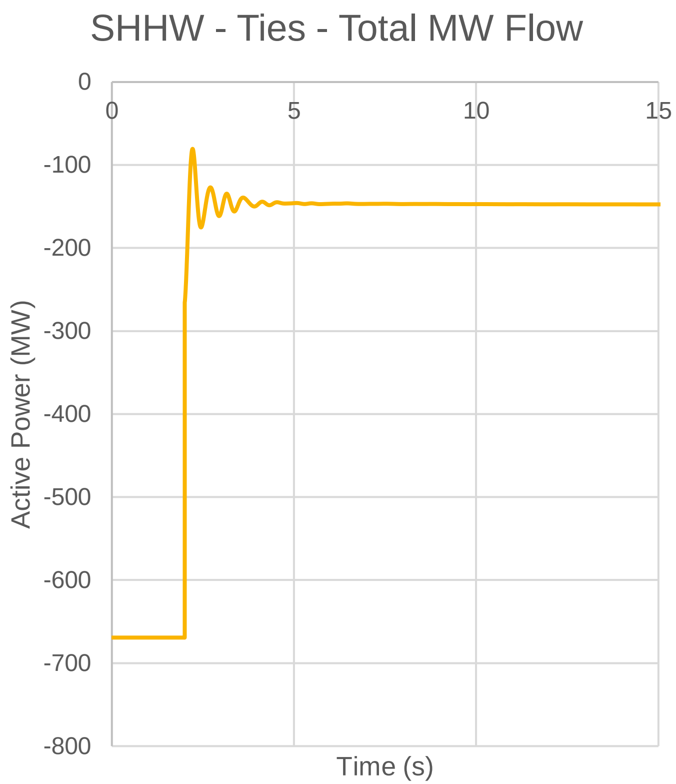
Flow Across Area Ties



- Summer Peak PF Case MISO22_2027_SUM___TA
- Contingency: Loss of Merom Unit 1
- Total generation lost: 522 MW

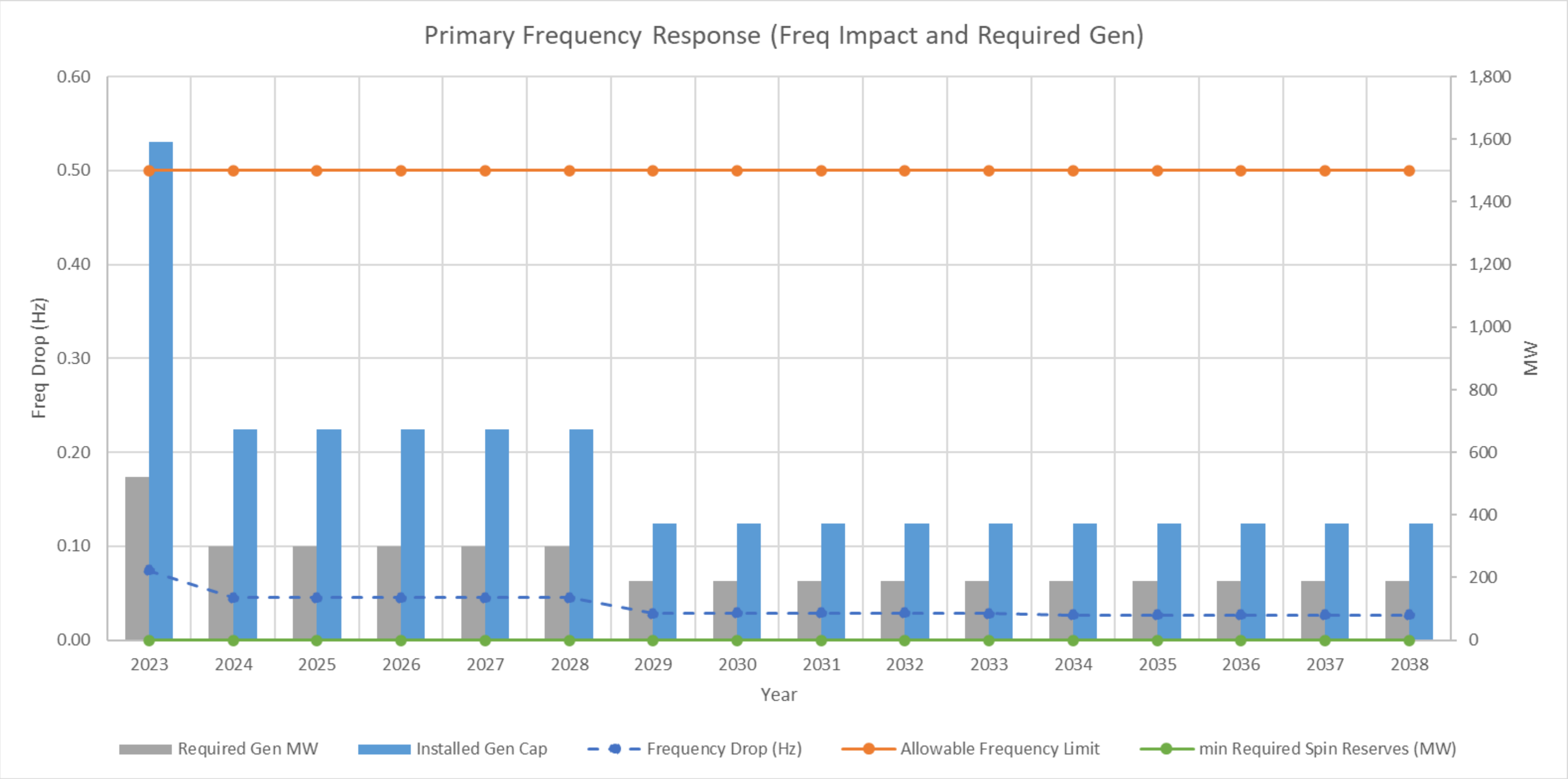


- Summer Light Load PF Case MISO22_2027_SLL70_TA
- Contingency: Loss of Merom Unit 1
- Total generation lost: 431 MW



- Summer High Wind PF Case MISO22_2027_SHHW__TA
- Contingency: Loss of Merom Unit 1
- Total generation lost: 527 MW

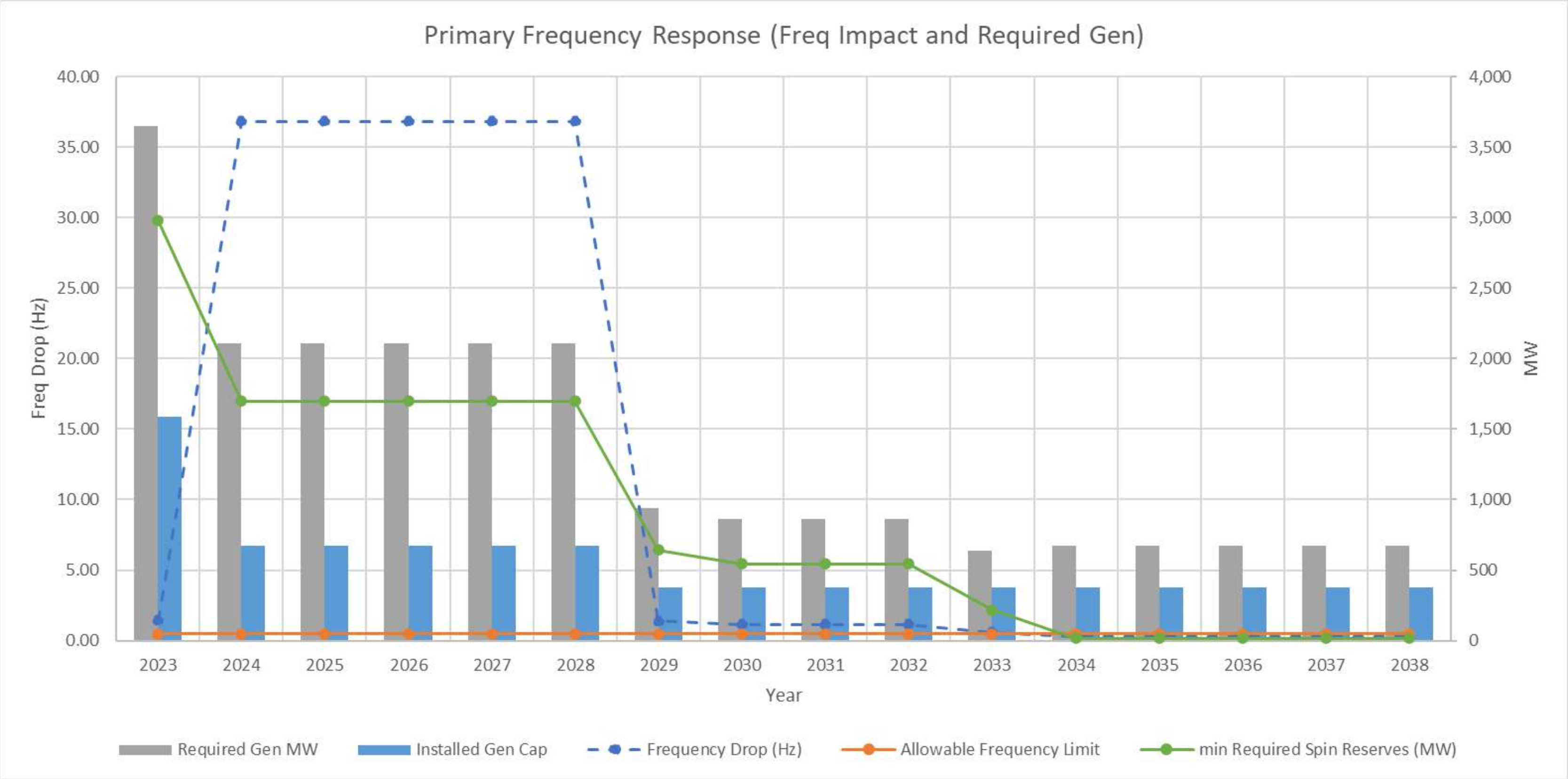
T1: Primary Frequency Response (Hoosier connected to MISO)



Contingency Size:

2023	522MW
2030	190MW
Droop	5% for Gen
	1% for ESS

T1: Primary Frequency Response without Load Shedding (Hoosier Islanded from MISO)



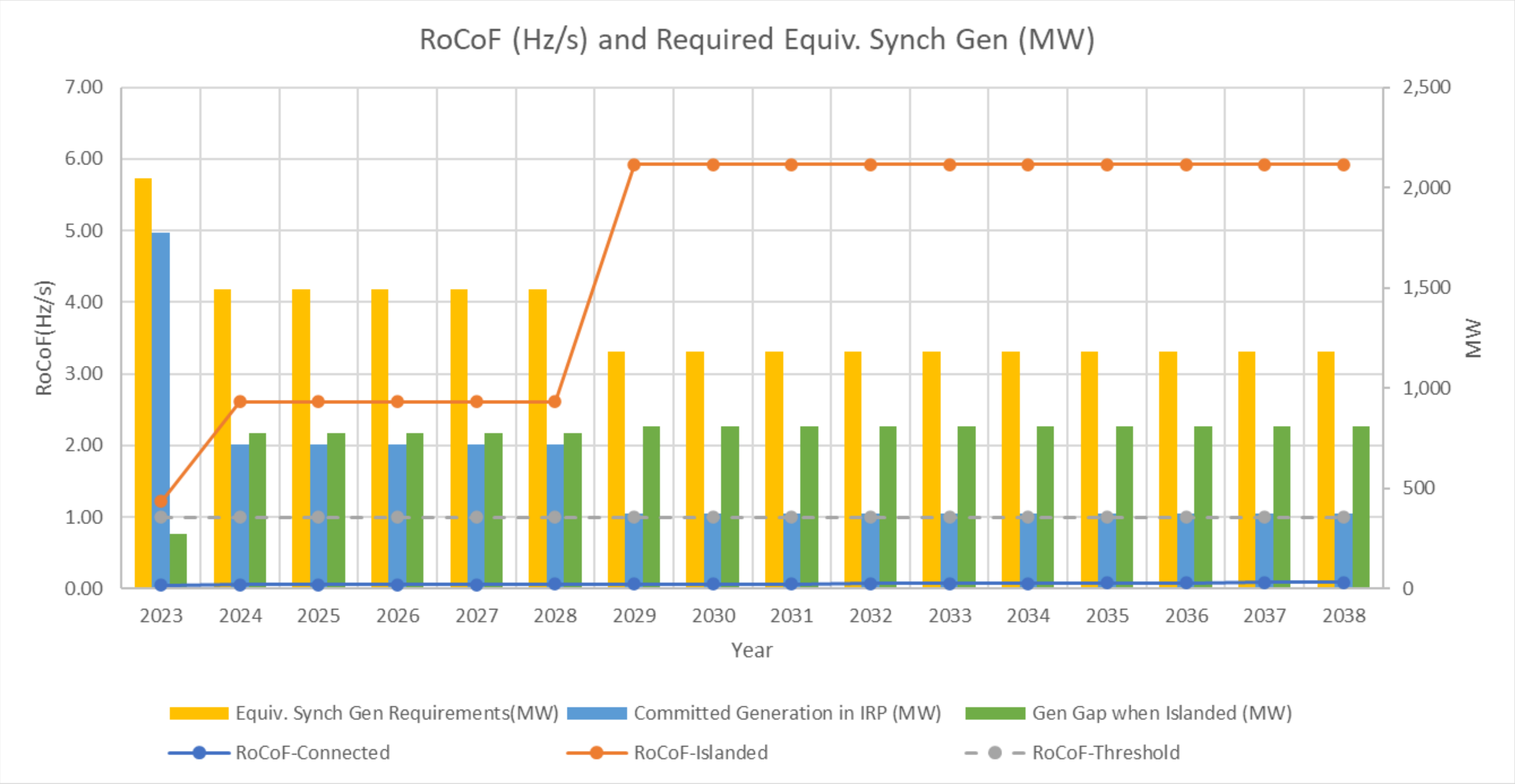
Contingency Size:

2023	522MW
2030	190MW
Droop	5% for Gen 1% for ESS

When the Hoosier system is entirely islanded, the primary frequency response drop is very high and a cause of major concern. It is in the best interest that the Hoosier System maintains connections to neighboring systems for support.

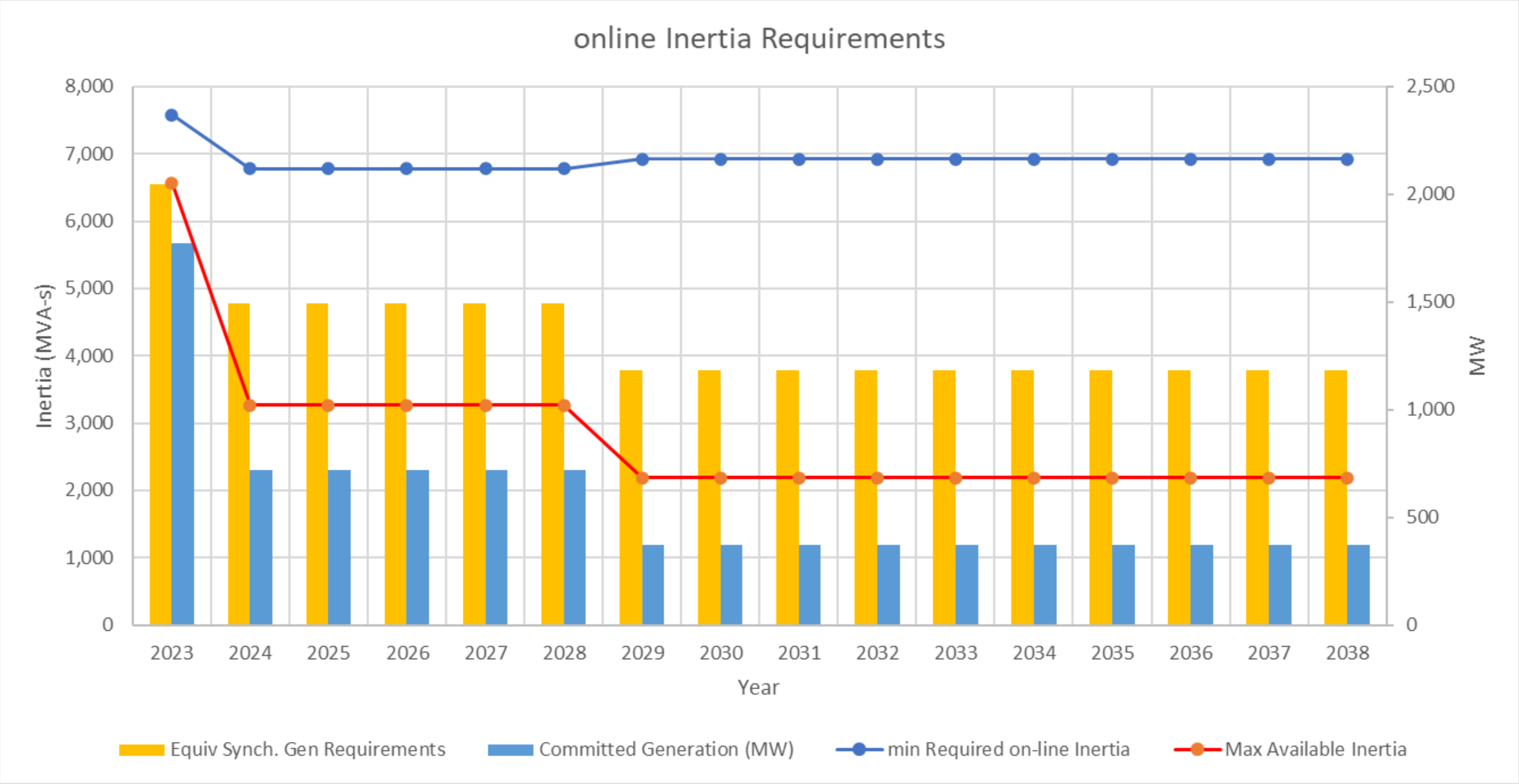
T1: Inertial Response (ESS with Grid Following Inverters)

Fall Early Afternoon



T1: Inertial Response (ESS with Grid Following Inverters)

Fall Early Afternoon



System Inertia

Portfolio	2023		2025		2030	
	Summer Rating MW	Inertia MVA-s	Summer Rating MW	Inertia MVA-s	Summer Rating MW	Inertia MVA-s
T1	1,591	6,566	674	3,265	374	2,185
T2	1,591	6,566	674	3,265	374	2,185
T3	1,591	6,566	674	3,265	374	2,185
T4	1,591	6,566	674	3,265	374	2,185
T5	1,591	6,566	674	3,265	374	2,185
T6	1,591	6,566	674	3,265	374	2,185
T7	1,591	6,566	674	3,265	374	2,185

Inertial Response

									Normal System (Connected)					Islanded System				
Portfolio	On-Line Gen MVA (Y2023)	On-Line Gen MVA (Y2030)	On-Line Inertia MVA-s (Y2023)	On-Line Inertia MVA-s (Y2030)	Energy Storage MW (Y2030)	Largest Gen MW (Y2030)	Fast Frequency Response (MW)	RoCoF Limit Hz/s	RoCoF Normal (Y2023)	RoCoF Normal (Y2030)	Gap Inertia (MVA-s) (Y2030)	Mitigation BESS GFI[1] (MW)	Additional Required BESS GFM (MW)	RoCoF Islanded (Y2023)	RoCoF Islanded (Y2030)	Gap Inertia (MVA-s) (Y2030)	Required Mitigation BESS GFM[1] (MW)	Additional Required BESS GFM (MW)
T1	978	408	3,436	2,185	100	190	173	1.00	0.04	0.05	0	0.00	0	42.20	5.92	4,737	158	58
T2	978	408	3,436	2,185	0	190	73	1.00	0.04	0.05	0	0.00	0	42.20	5.92	4,737	158	158
T3	978	408	3,436	2,185	180	190	253	1.00	0.04	0.05	0	0.00	0	42.20	5.92	4,737	158	0
T4	978	408	3,436	2,185	80	190	153	1.00	0.04	0.05	0	0.00	0	42.20	5.92	4,737	158	78
T5	978	408	3,436	2,185	280	190	353	1.00	0.04	0.05	0	0.00	0	42.20	5.92	4,737	158	0
T6	978	408	3,436	2,185	80	190	153	1.00	0.04	0.05	0	0.00	0	42.20	5.92	4,737	158	78
T7	978	408	3,436	2,185	100	190	173	1.00	0.04	0.05	0	0.00	0	42.20	5.92	4,737	158	58

- During normal operations when Hoosier is connected to MISO system, RoCoF starts in 2023 at a small value of 0.04 Hz/s and increases to 0.05 Hz/s by 2030. This increase is due to retirements of synchronous generation within the system and also within MISO. However, it remains acceptable below 1.0Hz/s.
- When Islanded, RoCoF greatly exceeds the acceptable threshold starting at 42.2 Hz/s in 2023. However, it decreases below to 5.92 Hz/s by 2030. Some level of mitigation is required when the system is islanded. This mitigation can take the form of equipping the storage systems with grid-forming inverters and inertial response capability.

Primary Frequency Response

Portfolio	Committed Generation MW (2023)	Committed Generation MW (2030)	Energy Storage MW (2030)	On-Line Reserves MW (2023)	On-Line Reserves MW (2030)	Primary Freq Response (MW)	Freq Nadir Threshold (Hz)	Islanded System: Freq Nadir Hz (2023)	Islanded System: Freq Nadir Hz (2030)	Islanded System: Required Gen Resources (MW)	Islanded System: or Requied Storage Resources (MW)	Islanded System: or Required Load Shedding (MW)
T1	1,591	374	100	921	155	83	0.5	10.6	1.09	490	135	103
T2	1,591	374	0	921	155	0	0.5	10.6	30.33	995	236	187
T3	1,591	374	180	921	155	150	0.5	10.6	0.61	260	54	35
T4	1,591	374	80	921	155	67	0.5	10.6	1.35	591	155	120
T5	1,591	374	280	921	155	233	0.5	10.6	0.40	276	0	0
T6	1,591	374	80	921	155	67	0.5	10.6	1.35	591	155	120
T7	1,591	374	100	921	155	83	0.5	10.6	1.09	490	135	103

- The portfolios were simulated to assess the level of frequency drop in response to the sudden loss of largest generation. The simulations were conducted when the system was in normal interconnected modes and did not find any reliability issues with any portfolio. However, when the system was simulated under emergency operation in islanded mode, several portfolios experienced frequency violation of the nadir dropping by more than 0.5Hz potentially triggering under frequency load shedding schemes.
- The analysis continued to quantify the level of additional fast response requirements from storage systems to mitigate the reliability violations.
- Note: The analysis assumed a droop of 5% for conventional assets, and 1% for storage assets, all limited by the resource ramp rates.
- When the Hoosier system is islanded, significant frequency nadir takes place. This demonstrates the importance of system support from Hoosier's tie lines and external generators.

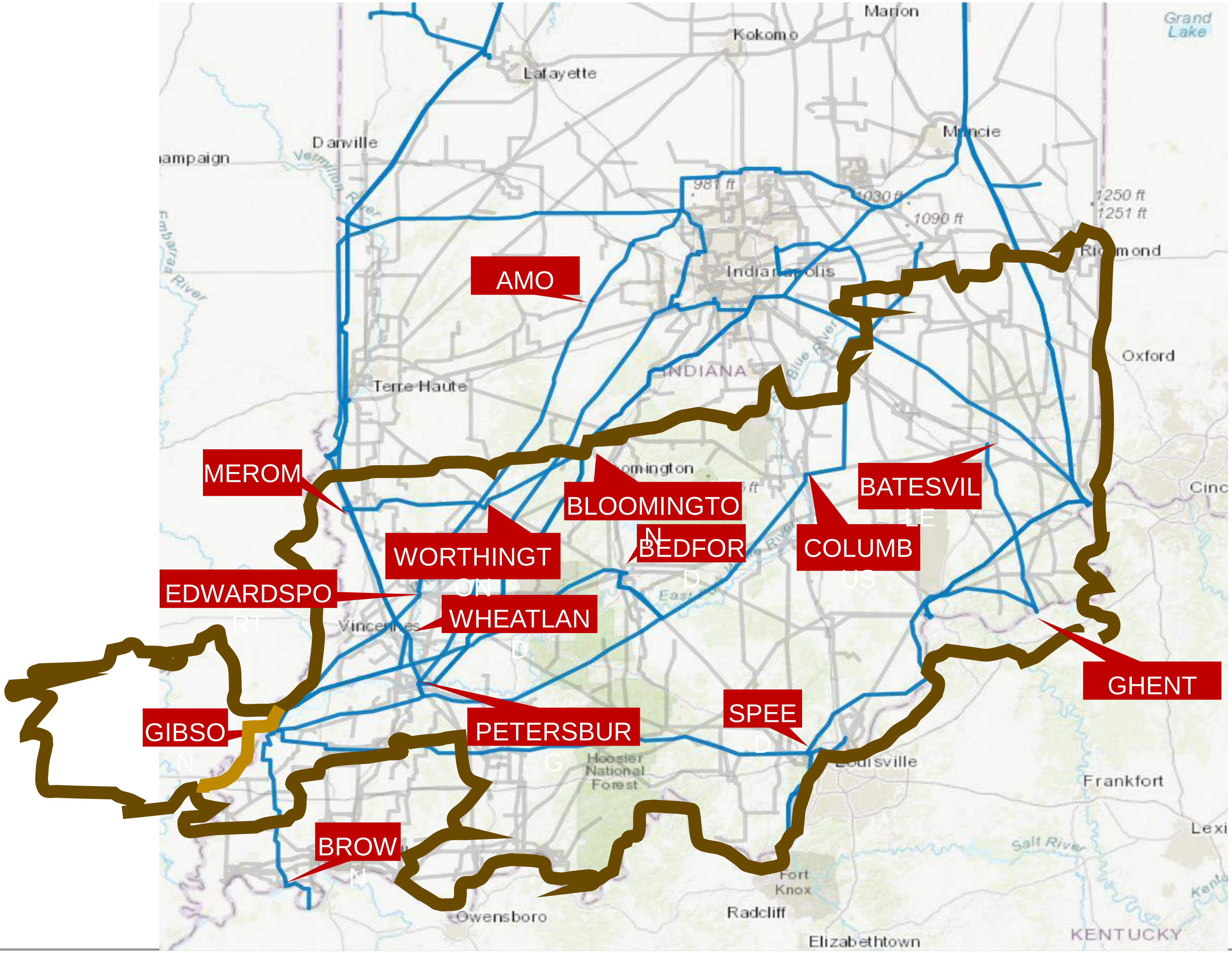
Increased Frequency Regulation Requirements

Y 2030

Portfolio	Increase in Freq Regulation Requirements (MW)
T1	14
T2	14
T3	14
T4	14
T5	14
T6	14
T7	14

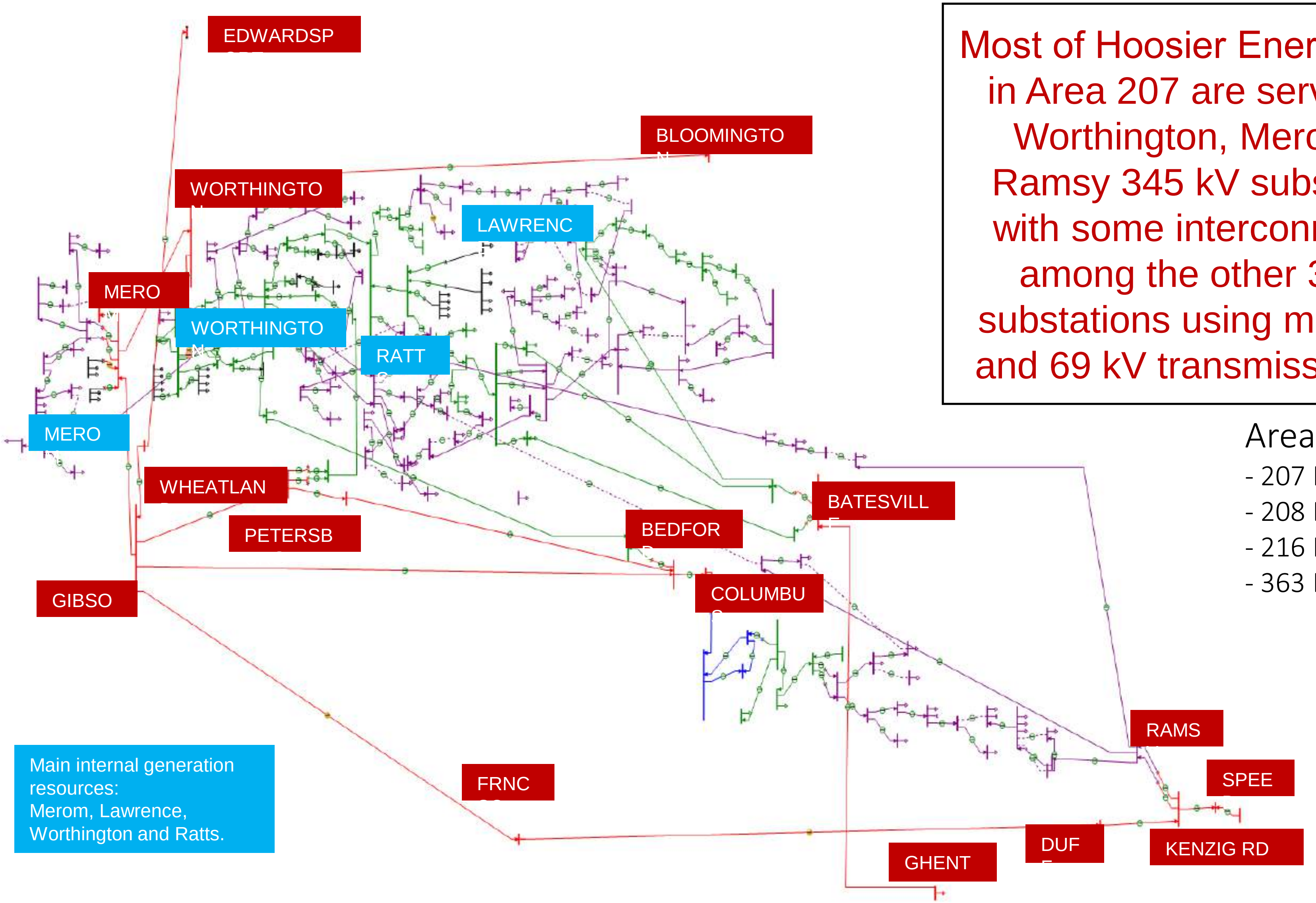
- The short-term intermittency of solar and wind resources increases the need for frequency regulation. This analysis quantifies the increased level of regulation services.

345 kV Transmission System Indiana



345 kV network as the main transmission corridors serving Hoosier Energy territories

Main Hoosier power system - Indiana (Area 207)



Most of Hoosier Energy's loads in Area 207 are served from Worthington, Merom and Ramsy 345 kV substations, with some interconnections among the other 345 kV substations using mainly 138 and 69 kV transmission lines.

Areas:

- 207 Hoosier
- 208 Duke
- 216 IPL
- 363 LGEE

Importance and Impacts of Short Circuit Strength

- Importance:

- Short Circuit MVA (SCMVA) is a measure of the strength of a bus in a system. The larger SCMVA, the stronger the bus. That indicates the bus is close to large voltage sources, and thus it will take large injections of real or reactive power to change its voltage. SCMVA changes depending on grid configuration and on-line resources. The lowest SCMVA is usually utilized for engineering calculations.

- When IBRs are interconnected to a system, it is desirable to maintain a stable bus voltage irrespective of the fluctuation of the IBR's output. Similarly, grid following (GFL) inverters rely on stable voltage and frequency to synchronize to the grid using their phase locked loops (PLL).

- The maximum allowable size of IBR desiring to interconnect to a bus is limited to a fraction of the bus's short circuit MVA, say less than 20-50%. This is expressed as Short Circuit Ratio (SCR) of the ratio of SCMVA to the rating of the IBR. This will translate to SCR of 2-5.

- When multiple IBRs are interconnected at a close electrical distance, their controls interact, and the impact of system voltages will increase. Thus, a modified measure was adopted to be ESCR (Effective SCR) to capture this interaction.

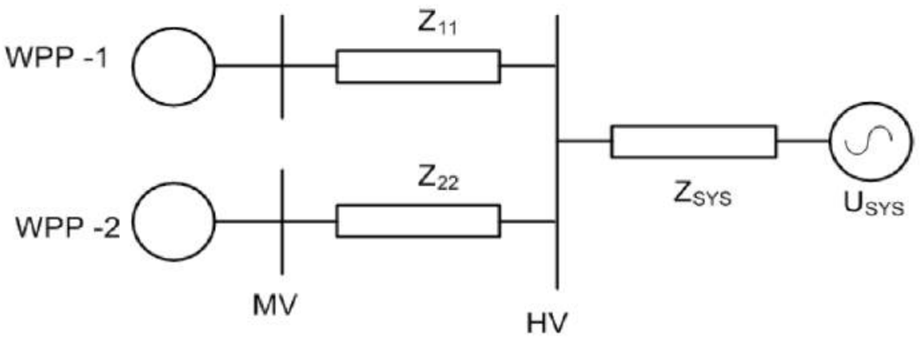
- Impact:

- When conventional power plants with synchronous generators are retired and/or the system tie-lines are severed, the short circuit currents will dramatically decline. IBRs are not a substitute because their short circuit contribution is limited, and also the phase of their current (real) is not aligned with typical short circuit currents (reactive).

- Declining SCMVA and increasing IBRs will eventually violate the ESCR limits, requiring either a prohibition on additional IBR interconnections, or provisioning additional mitigation measures.

- Mitigations can come in the form of optimal placement of IBRs to avoid clustering them in a manner that violates the ESCR limits, provisioning synchronous condensers, or requiring inverters to have grid-forming (GFM) capability.

Short Circuit Strength – Equivalent Short Circuit Ratio



Bus #	IBR (MW)	SCMVA	SCR	ESCR	ESCR with SC
237	30	343	11.5	2.1	3.2
59200	32	369	11.5	2.3	3.7
59100	32	600	18.7	2.5	4.0
238	23	206	8.9	2.2	4.2
1813	10	605	60.0	2.6	4.2
99000	20	481	24.0	2.6	4.2
119	29	311	10.8	3.0	4.2
56	29	343	12.0	2.2	4.3
94	28	1092	39.0	2.7	4.6
59400	23	736	32.0	3.1	4.8
2803	28	548	19.8	3.0	4.9

SCR is not a good indicator under high IBR penetration
Synchronous Condensers (SC) can increase short circuit strength

$$ESCR_i = \frac{S_i}{P_i + \sum_j IF_{ji} * P_j}$$

where $IF_{ji} = \frac{\Delta V_j}{\Delta V_i}$ is the interaction factor between buses i and j and can be calculated using Zbus.

Pi and Pj are the inverter ratings at buses i and j respectively, while Si is the minimum short circuit MVA at bus i.

Optimal Placement of IBRs from Short Circuit perspective to avoid ESCR limitation:

$$MAXIMIZE \ \sum_{j \in buses} P_j$$

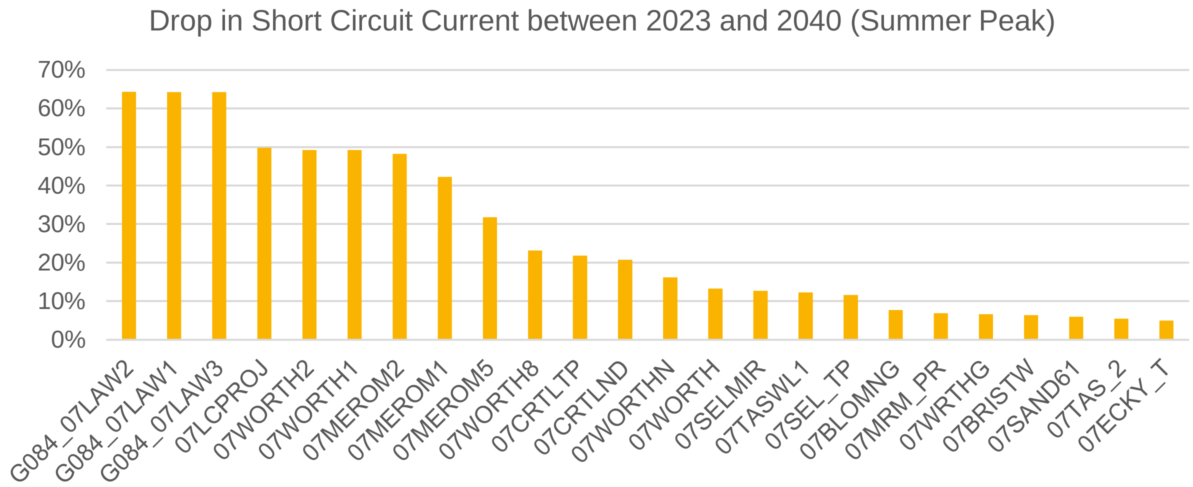
Subject to $\sum_j IF_{ji} * P_j \leq \frac{S_i}{ESCR\ Threshold}$

$$P_j \geq 0$$

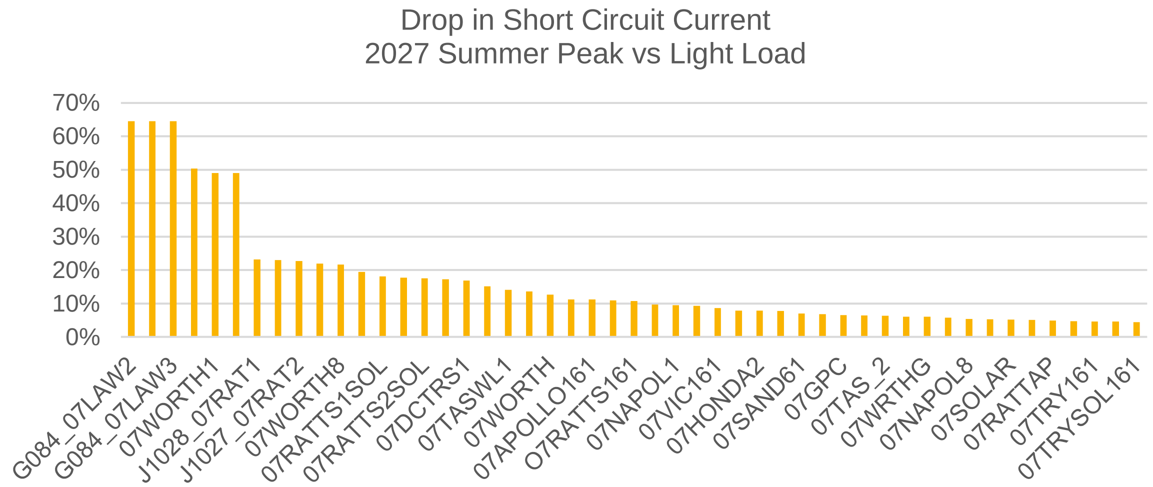
Short Circuit Study Procedure

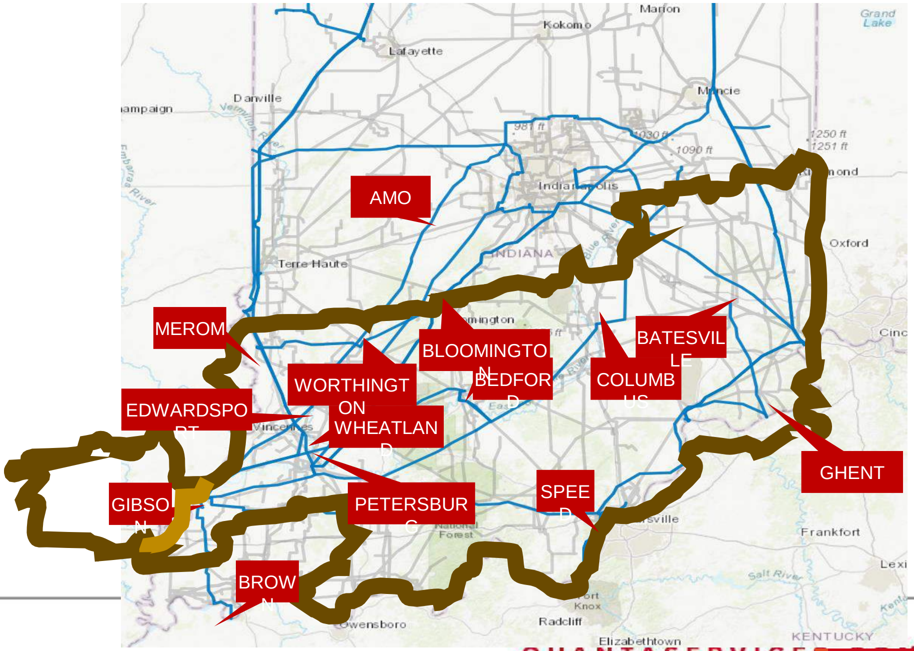
- The system is modeled in both intact and islanded modes.
- System Zbus matrix is calculated, and the Interaction Factor matrix is derived.
- The Effective Short Circuit Ratio (ESCR) is calculated at each bus to assess the strength of the system to integrate IBRs in each Portfolio.
- If the ESCR is above 3.5, the Portfolio is deemed satisfactory from a short circuit strength perspective.
- Otherwise, additional synchronous condensers are placed in the system and their sizes optimized to enable full integration of the Portfolio resources (not withstanding potential violations of other planned resources outside of the portfolio).
- The portfolios are compared based on the total MVA of the synchronous condensers that will be required to mitigate short circuit strength violations.
- NOTE: This is a screening level analysis and is not accurate but indicative. Detailed system studies should be conducted by system planners to assess the selected Portfolio in detail.

Short Circuit Currents

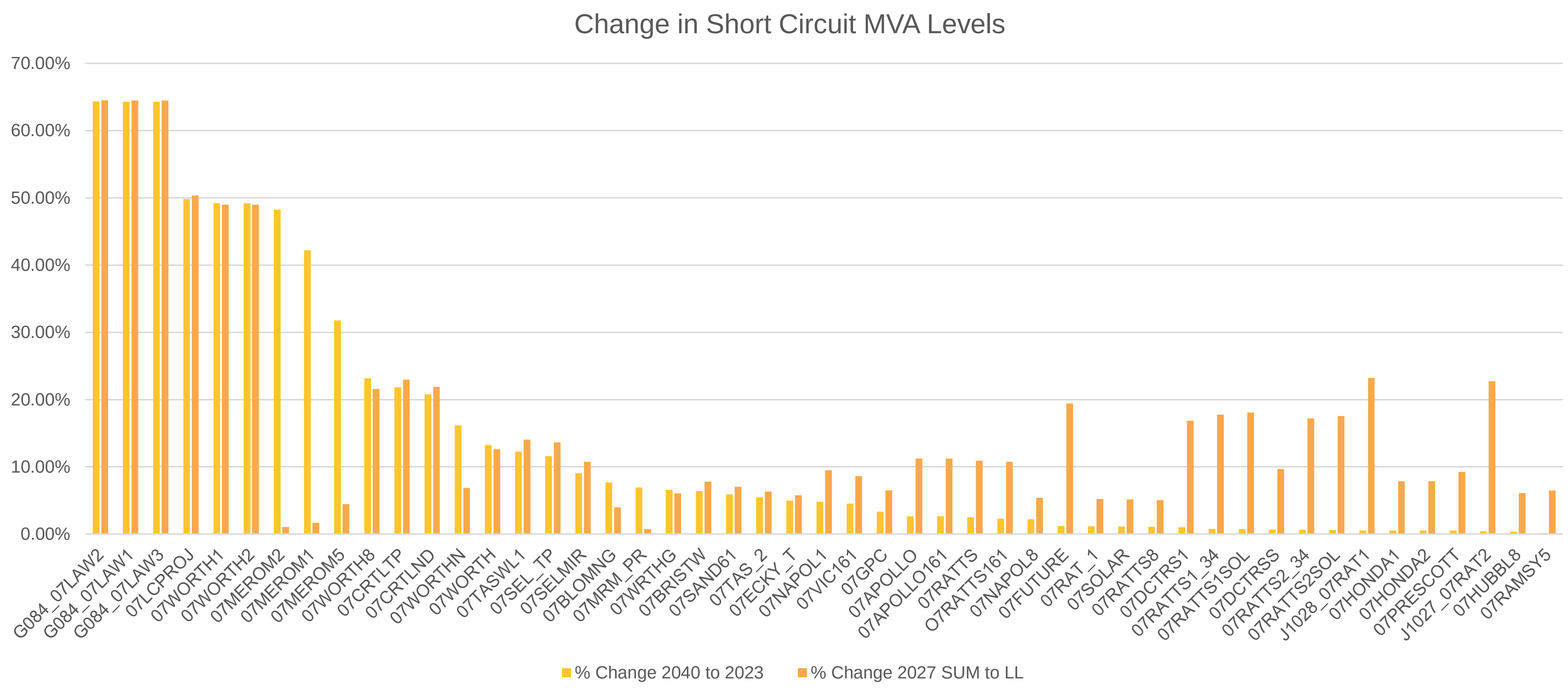


Gens in Area 207	MEROM1	MEROM2	LAWRENCE	WORTHINGTON
2023	X	X	X	X
2025	X	X	X	X
2030			X	X
2035			X	X
2040				
2027 SUM	X	X	X	X
2027 SHHW	X	X	X	X
2027 LL	X	X		





Short Circuit Currents



Effective Short Circuit Ratio (ESCR)

Summer Peak

IBRs with the least ESCR (Portfolio T1) — Y2023

Id	Bus #	Bus Name	Base kV	Zone #	Zone Name	IBR MW	SCMVA	ESCR	SCR
1	248417	07APOLLO161	161	1207	ZONE_1207	153.0	2,437	8.70	15.93
2	248421	O7RATTS161	161	1207	ZONE_1207	153.0	2,681	9.26	17.52
3	248868	07TRYSOL161	161	1207	ZONE_1207	75.6	2,638	20.35	34.90

IBRs with the least ESCR (Portfolio T1) — Y2030

Id	Bus #	Bus Name	Base kV	Zone #	Zone Name	IBR MW	SCMVA	ESCR	SCR
1	248417	07APOLLO161	161	1207	ZONE_1207	303.0	2,433	5.43	8.03
2	248421	O7RATTS161	161	1207	ZONE_1207	153.0	2,675	6.16	17.49
3	248868	07TRYSOL161	161	1207	ZONE_1207	75.6	2,637	16.04	34.89
4	248547	07WORTH8	138	1207	ZONE_1207	150.0	4,426	17.07	29.50

IBRs with the least ESCR (Portfolio T1) — Y2040

Id	Bus #	Bus Name	Base kV	Zone #	Zone Name	IBR MW	SCMVA	ESCR	SCR
1	248417	07APOLLO161	161	1207	ZONE_1207	303.0	2,372	5.21	7.83
2	248421	O7RATTS161	161	1207	ZONE_1207	153.0	2,619	5.91	17.12
3	248547	07WORTH8	138	1207	ZONE_1207	150.0	3,502	13.38	23.35
4	248868	07TRYSOL161	161	1207	ZONE_1207	75.6	2,556	14.63	33.81

IBRs with the least ESCR (Portfolio T1) – Islanded

Id	Bus #	Bus Name	Base kV	Zone #	Zone Name	IBR MW	SCMVA	ESCR	SCR
1	248417	07APOLLO161	161	1207	ZONE_1207	303.0	913	1.65	3.01
2	248421	O7RATTS161	161	1207	ZONE_1207	153.0	901	1.68	5.89
3	248868	07TRYSOL161	161	1207	ZONE_1207	75.6	578	2.09	7.65
4	248547	07WORTH8	138	1207	ZONE_1207	150.0	1,163	2.77	7.75

Although short circuit strength weakens between 2023 and 2040, it remains sufficient to ensure the stability of IBRs in Area 207 due to the location of future solar systems and their ratings.

If Area 207 is islanded, the short circuit strength drop significantly below 3.5 and will require mitigations.

Effective Short Circuit Ratio (ESCR) – Islanded Operation

Summer Peak

Without Synchronous Condensers

IBRs with the least ESCR (Portfolio T1) – Islanded

Id	Bus #	Bus Name	Base kV	Zone #	Zone Name	IBR MW	SCMVA	ESCR	SCR
1	248417	07APOLLO161	161	1207	ZONE_1207	303.0	913	1.65	3.01
2	248421	O7RATTS161	161	1207	ZONE_1207	153.0	901	1.68	5.89
3	248868	07TRYSOL161	161	1207	ZONE_1207	75.6	578	2.09	7.65
4	248547	07WORTH8	138	1207	ZONE_1207	150.0	1,163	2.77	7.75

With 325MVA Synchronous Condensers at 07APOLLO161

IBRs with the least ESCR (Portfolio T1)

Id	Bus #	Bus Name	Base kV	Zone #	Zone Name	IBR MW	SCMVA	ESCR	SCR
1	248421	O7RATTS161	161	1207	ZONE_1207	153.0	1,702	3.53	11.12
2	248417	07APOLLO161	161	1207	ZONE_1207	303.0	2,072	3.74	6.84
3	248868	07TRYSOL161	161	1207	ZONE_1207	75.6	671	3.77	8.87
4	248547	07WORTH8	138	1207	ZONE_1207	150.0	1,323	4.52	8.82

Although short circuit strength weakens between 2023 and 2040, it remains sufficient to ensure the stability of IBRs in Area 207 due to the location of future solar systems and their ratings.

If Area 207 is islanded, the short circuit strength drop significantly below 3.5 and will require mitigations. One potential mitigation is to install 325MVA synchronous condenser at Apollo 161kV substations

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Effective Short Circuit Ratio (ESCR) – Impact of Seasons

IBRs with the least ESCR (Portfolio T1) — **Y2027 SUM** — Summer Peak

Id	Bus #	Bus Name	Base kV	Zone #	Zone Name	IBR MW	SCMVA	ESCR	SCR
1	248417	07APOLLO161	161	1207	ZONE_1207	303.0	2,437	5.44	8.04
2	248421	O7RATTS161	161	1207	ZONE_1207	153.0	2,680	6.19	17.52
3	248868	07TRYSOL161	161	1207	ZONE_1207	75.6	2,637	16.10	34.89
4	248547	07WORTH8	138	1207	ZONE_1207	150.0	4,556	17.67	30.38

IBRs with the least ESCR (Portfolio T1) — **Y2027 SHHW** — Shoulder Heavy Wind

Id	Bus #	Bus Name	Base kV	Zone #	Zone Name	IBR MW	SCMVA	ESCR	SCR
1	248417	07APOLLO161	161	1207	ZONE_1207	150.0	2,236	12.28	14.90
2	248868	07TRYSOL161	161	1207	ZONE_1207	75.6	2,616	23.11	34.60
3	248547	07WORTH8	138	1207	ZONE_1207	150.0	4,527	23.70	30.18

IBRs with the least ESCR (Portfolio T1) — **Y2027 SLL** — Summer Light Load

Id	Bus #	Bus Name	Base kV	Zone #	Zone Name	IBR MW	SCMVA	ESCR	SCR
1	248417	07APOLLO161	161	1207	ZONE_1207	150.0	2,164	11.46	14.42
2	248547	07WORTH8	138	1207	ZONE_1207	150.0	3,583	18.52	23.89
3	248868	07TRYSOL161	161	1207	ZONE_1207	75.6	2,520	21.11	33.33

Dynamic Reactive Power Capability and Distance to Load

- Hoosier provides the dynamic reactive power requirements of customers in Area 207.
- The resources within HE footprint can generate dynamic reactive power. However, given the localized nature of reactive power, the closer "electrically" the generator VARs to the load centers, the more valuable they are to the system.
- The available dynamic VArs that can be produced are calculated assuming all resources have the capability to operate +/- 0.9 power factor.
- The electrical distance of each resource to each load point is calculated using the Zbus matrix in the form of electrical impedance. The impedance from each resource to the "Center of Load" is also calculated.
- Each portfolio will be evaluated based on its ability to deliver its dynamic VARs to the load centers as follows:
    - The dynamic VARs that can be delivered to the center of load after accounting for line impedance losses is utilized to rank portfolios.
    - Since reactive power does not travel well, resources outside of HE's service territory are excluded from this analysis.

How much Dynamic Reactive Power is Needed?

- Reactive power is typically provided locally within the distribution system.
- However, during post-fault recovery, induction motor loads require additional dynamic reactive power to avoid stalling. This dynamic reactive power is supplied from resources equipped with Automatic Voltage Control (AVR), such as generating plants, SVCs, and inverters of solar, wind, and storage systems.
- Immediately after the fault, as the voltage starts to recover, the motor slows down as it continues to provide mechanical torque to the load (drawn from its inertia) thus increasing its slip, and the reactive current flow into the motor. As the motor speed increases and the slip decreases the reactive current requirement declines until it reaches its steady-state value. If the power system fails to provide the required level of dynamic reactive current, the motor will slip further and stall.
- The minimum required level of dynamic reactive power to be supplied by the grid at the motor's point of interconnection (POI), in excess of the steady-state static reactive power, depends on the grid's stiffness (i.e., short circuit MVA), and is assessed to be around 2.5 times the steady-state reactive power.
- Though it depends on location, induction motors account for 50-80% of the load. Assuming that the motor's power factor is 90% (i.e., reactive power is 43% of active of power in steady state), then the dynamic reactive power requirement will range between **55% - 85%** of active power demand in each load pocket, or **24% - 37%** of the steady state reactive power consumption of the load.

VAR Deliverability

Base System – Connected to MISO: Y2030

with VARs from Solar

		T1	T2	T3	T4	T5	T6	T7
Qload (MVArs)	133	133	133	133	133	133	133	133
Qload (Load pu)	0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.191
Synch Condensers (MVAr)	0	0	0	0	0	0	0	0
Pgen (MW) - Total	1,344	1,344	1,344	1,344	1,344	1,344	1,344	1,344
Qgen (MVAr) - Total	651	651	651	651	651	651	651	651
Impedance: Gen to COL (system pu)	0.1439	0.1439	0.1439	0.1439	0.1439	0.1439	0.1439	0.1439
Deliverable Dynamic VAR (MVAr)	**535**	**535**	**535**	**535**	**535**	**535**	**535**	**535**
Ratio of Deliverable MVArs to Qgen	82%	82%	82%	82%	82%	82%	82%	82%
min Ratio of Deliverable MVArs to Load MW (if all Qloads are uniformly increased)	25%	25%	25%	25%	25%	25%	25%	25%
min Ratio of Deliverable MVArs to Load MW (if only 1 load is increased)	1315%	1315%	1315%	1315%	1315%	1315%	1315%	1315%

Without VARs from Solar

		T1	T2	T3	T4	T5	T6	T7
Qload (MVArs)	133	133	133	133	133	133	133	133
Qload (Load pu)	0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.191
Synch Condensers (MVAr)	0	0	0	0	0	0	0	0
Pgen (MW) - Total	731	731	731	731	731	731	731	731
Qgen (MVAr) - Total	354	354	354	354	354	354	354	354
Impedance: Gen to COL (system pu)	0.2298	0.2298	0.2298	0.2298	0.2298	0.2298	0.2298	0.2298
Deliverable Dynamic VAR (MVAr)	**221**	**221**	**221**	**221**	**221**	**221**	**221**	**221**
Ratio of Deliverable MVArs to Qgen	62%	62%	62%	62%	62%	62%	62%	62%
min Ratio of Deliverable MVArs to Load MW (if all Qloads are uniformly increased)	2%	2%	2%	2%	2%	2%	2%	2%
min Ratio of Deliverable MVArs to Load MW (if only 1 load is increased)	80%	80%	80%	80%	80%	80%	80%	80%

VAR Deliverability

Base System – Islanded : Y2030

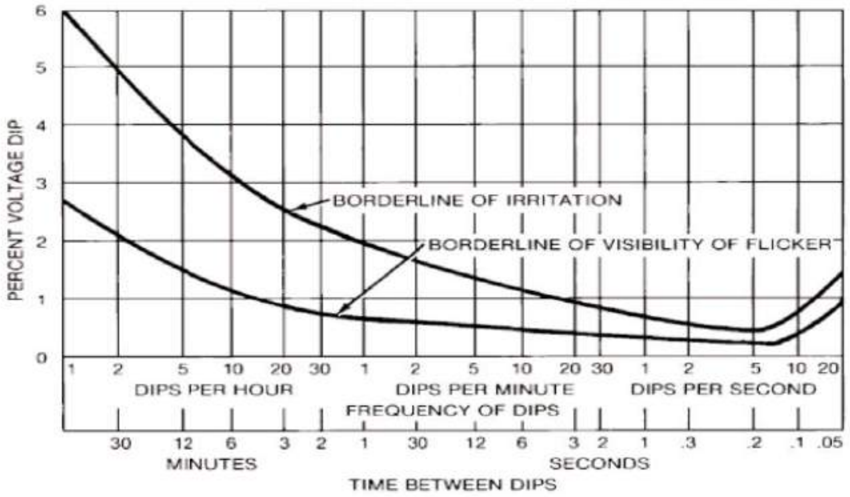
With VARs from Solar		T1	T2	T3	T4	T5	T6	T7
Qload (MVArs)	133	133	133	133	133	133	133	133
Qload (Load pu)	0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.191
Synch Condensers (MVAr)	0	0	0	0	0	0	0	0
Pgen (MW) - Total	1,344	1,344	1,344	1,344	1,344	1,344	1,344	1,344
Qgen (MVAr) - Total	651	651	651	651	651	651	651	651
Impedance: Gen to COL (system pu)	0.2508	0.2508	0.2508	0.2508	0.2508	0.2508	0.2508	0.2508
Deliverable Dynamic VAR (MVAr)	**395**	**395**	**395**	**395**	**395**	**395**	**395**	**395**
Ratio of Deliverable MVArs to Qgen	61%	61%	61%	61%	61%	61%	61%	61%
min Ratio of Deliverable MVArs to Load MW (if all Qloads are uniformly increased)	8%	8%	8%	8%	8%	8%	8%	8%
min Ratio of Deliverable MVArs to Load MW (if only 1 load is increased)	706%	706%	706%	706%	706%	706%	706%	706%

Without VARs from Solar		T1	T2	T3	T4	T5	T6	T7
Qload (MVArs)	133	133	133	133	133	133	133	133
Qload (Load pu)	0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.191
Synch Condensers (MVAr)	0	0	0	0	0	0	0	0
Pgen (MW) - Total	1,412	1,412	1,412	1,412	1,412	1,412	1,412	1,412
Qgen (MVAr) - Total	354	354	354	354	354	354	354	354
Impedance: Gen to COL (system pu)	0.4890	0.4890	0.4890	0.4890	0.4890	0.4890	0.4890	0.4890
Deliverable Dynamic VAR (MVAr)	**157**	**157**	**157**	**157**	**157**	**157**	**157**	**157**
Ratio of Deliverable MVArs to Qgen	44%	44%	44%	44%	44%	44%	44%	44%
min Ratio of Deliverable MVArs to Load MW (if all Qloads are uniformly increased)	7%	7%	7%	7%	7%	7%	7%	7%
min Ratio of Deliverable MVArs to Load MW (if only 1 load is increased)	35%	35%	35%	35%	35%	35%	35%	35%

Flicker

- Screening Level Assessment using GE Flicker Curve:
  - Max Allowable Power Variability at a bus due to a single IBR is:
    - $\frac{\Delta P(f)}{S_{sc}} = \frac{\text{Flicker Tolerance }(f)}{\cos(\arctan(\frac{X}{R}))}$, where X/R relates to grid's Thevenin equivalent at the POI.
    - The table below shows the limitation on solar variability becomes tighter when the frequency of solar intermittency is higher, or when the Grid's (X/R) ratio at the POI is lower.
    - This formula can be extended to include the impact of other inverters using system Zbus.
    - The solar reactive power variability also impacts flicker but is ignored in this scanning analysis for expedience.

Solar Intermittency Frequency	Flicker Tolerance Limit ΔV/V %	Grid Thev Equiv at POI X/R=20	Grid Thev Equiv at POI X/R=10	Grid Thev Equiv at POI X/R=5	Grid Thev Equiv at POI X/R=1
1/6 s	0.40%	8.0%	4.0%	2.0%	0.6%
1 s	0.70%	14.0%	7.0%	3.6%	1.0%
3 s	1.00%	20.0%	10.0%	5.1%	1.4%
10 s	1.30%	26.0%	13.1%	6.6%	1.8%
1 min	2.00%	40.0%	20.1%	10.2%	2.8%
10 min	3.50%	70.1%	35.2%	17.8%	4.9%



Flicker severity factor	MV system	HV system
Short term (P_{st})	0.9	0.8
Long term (P_{lt})	0.7	0.6

Pst planning level of 0.9 from the IEC® 61000-3-7 standard is essentially equal to the line of irritation on the IEEE® 519 chart.

Flicker Screening Study Approach

- Obtain a recording of the power variability of a solar PV system.
- Characterize the solar power variability at different time intervals to generate a power variability vs frequency plot for solar at the study location.
- Calculate system Zbus between all POI buses.
- Calculate the anticipated flicker levels at each POI using the approximate analytical formulae.
- Identify flicker concerns at each solar POI and provide statistics on the % of IBRs with flicker problems and associated POIs.
- Following formulae are utilized in the analysis:

$$\frac{\Delta V}{V} \approx \Delta V_R = \frac{\Delta P cos(\varphi_{sc}) + \Delta Q sin(\varphi_{sc})}{S_{sc}}$$

$$\Delta V_j = Z_{ij} \Delta I_i = Z_{ij} \frac{\Delta V_i}{Z_{ii}}$$

Where φ_{sc} is the angle of the grid's Thevenin impedance at the POI, and Z is the impedance matrix of the grid.

Flicker Analysis

Y2030	T1	T2	T3	T4	T5	T6	T7
IBR MW Pass (Connected)	100%	100%	100%	100%	100%	100%	100%
IBR MW Pass (Islanded)	100%	100%	100%	100%	100%	100%	100%
Required Synch Condensors (MVA)	0	0	0	0	0	0	0

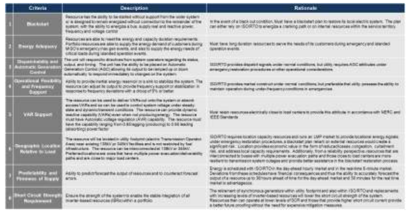
Essential Reliability Analysis Scoring Matrix

Reliability Assessment and Portfolio Ranking Methodology

Select a core set of System Reliability Needs

- Resource Adequacy
- Energy Adequacy
- Ramping Capability
- Dispatchability & Predictability
- Frequency Response
- Frequency Regulation
- Short Circuit Strength
- VAR Deliverability
- Power Quality- Flicker

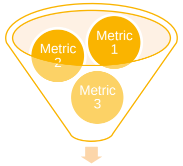
Review & Update Reliability Metrics



Apply a Series of Reliability Filters to IRP Portfolios

Scoring Criteria

Ranking Portfolios



Reliability Metrics (1/2)

	Metric	Description	Rationale
2	**Energy Adequacy**	Resources are able to meet the energy and capacity duration requirements. Portfolio resources are able to supply the energy demand of customers during normal and emergency max gen events, and also to supply the energy needs of critical loads during islanded operation events.	Utility must have long duration resources to serve the needs of its customers during emergency and islanded operation events.
3	**Operational Flexibility and Frequency Support**	Ability to provide inertial energy reservoir or a sink to stabilize the system. Additionally, resources can adjust their output to provide frequency support or stabilization in response to frequency deviations with a droop of 5% or better.	Regional markets and/or control centers balance supply and demand under different time frames according to prevailing market construct under normal conditions, but preferable that local control centers possess the ability to maintain operation during under-frequency conditions in emergencies.
4	**Short Circuit Strength Requirement**	Ensure the strength of the system to enable the stable integration of all inverter-based resources (IBRs) within a portfolio.	The retirement of synchronous generators within utility footprint and replacements with increasing levels of inverter-based resources will lower the short circuit strength of the system. Resources than can operate at lower levels of short circuit ratio (SCR) and those that provide higher short circuit current provide a better future proofing without the need for expensive mitigation measures.
5	**Power Quality (Flicker)**	The "stiffness of the grid" affect the sensitivity of grid voltages to the intermittency of renewable resources. Ensuring the grid can deliver power quality in accordance with IEEE standards is essential.	Retirement of large thermal generation plants lower the strength of the grid and increases its susceptibility to voltage flicker due to intermittency of renewable resources, unless properly assessed and mitigated.
6	**Dynamic VAR Support**	Customer equipment driven by induction motors (e.g., air conditioning or factories) requires dynamic reactive power after a grid fault to avoid stalling. The ability of portfolio resources to provide this service depends on their closeness to the load centers.	Utility must retain resources electrically close to load centers to provide this attribute in accordance with NERC and IEEE Standards

Reliability Metrics (2/2)

	Metric	Description	Rationale
7	**Dispatchability and Automatic Generation Control**	Resources should respond to directives from system operators regarding their status, output, and timing. Resources that can be ramped up and down automatically to respond immediately to changes in the system contribute more to reliability than resources which can be ramped only up or only down, and those in turn are better than ones that cannot be ramped.	Ability to control frequency is paramount to stability of the electric system and the quality of power delivered to customers. Control centers (regional or local) provide dispatch signals under normal conditions, and under emergency restoration procedures or other operational considerations.
8	**Predictability and Firmness of Supply**	Ability to predict/forecast the output of resources and to counteract forecast errors.	The ability to predict resource output from a day-ahead to real-time is advantageous to minimize the need for spinning reserves. In places with an active energy market, energy is scheduled with the market in the day-ahead hourly market and in the real-time 5-minute market. Deviations from these schedules have financial consequences and thus the ability to accurately forecast the output of a resource up to 38 hours ahead of time for the day-ahead market and 30 minutes for the real time market is advantageous.

Scoring Criteria Thresholds (1/2)

	Year 2031		1 (Pass)	2 (Caution)	3 (Problem)	Rationale
2	Energy Adequacy	Loss of Load Hours (LOLH) - normal system, 50/50 forecast	<2.4 hrs	2.4-4.8 hrs	>4.8 hrs	Expected number of hours in a year the portfolio is energy short and relies on imports (2.4hrs = 1day in 10 years)
		Expected Energy not Served (GWh) - normal system 50/50 fcst	<2.4*Peak	2.4-4.8*Peak	>4.8*Peak	The energy consumption which is not supplied due to insufficient capacity resources within portfolio to meet the demand
		max MW Short (MW) - normal system 50/50 forecast	<90%	90-110%	>110%	The maximum hourly power shortage in the portfolio that has to be supplied by imports (% of Tie-line Import Limits)
		max MW Short - loss of 50% of tieline capacity, 50/50 fcst	<45%	45-55%	>55%	The energy consumption which is not supplied due to insufficient resources and imports to meet the demand, when tieline import capacity is halved
		max MW Short (islanded, 50/50 forecast)	<70%	70-85%	>85%	Ability of Resources to serve critical loads, estimated at 15% of total load. Adding other important loads brings the total to 30%
		max MW Short (normal system, 90/10 forecast)	<5%	5-20%	>20%	Ability of portfolio resources to serve unanticipated growth in load consumption during MISO emergency max-gen events
3	Operational Flexibility and Frequency Support	Inertia MVA-s	>4.2 *Peak	2.6-4.2 *Peak	<2.6 *Peak	Synchronous machine has inertia of 2-5xMVA rating. Conventional systems have inertia that exceeds 2-5x (Peak load x 1.3)
		Inertial Gap FFR MW (% CAP)	0	0-10% of CAP	>10% of CAP	System should have enough inertial response, so gap should be 0. Inertial response of synch machine ≈ 10% of CAP
		Primary Gap PFR MW (% CAP)	0	0-2% of CAP	>2% of CAP	System should have enough primary response, so gap should be 0. Primary response of synch machine ≈ 3.3%of CAP/0.1Hz (Droop 5%)
4	Short Circuit Strength	Inverter MWs passing ESCR limits (%) - Connected System	95%	80-95%	80%	Grid following inverters require short circuit strength at the point of connection to operate properly (ESCR threshold of 3.5)
		Inverter MWs passing ESCR limits (%) - Islanded System	80%	50-80%	>50%	Grid following inverters require short circuit strength at the point of connection to operate properly (ESCR threshold of 3.5)
		Required Additional Synch Condensers MVA (% peak load) - Connected	0	0-500	>500	Portfolio should not require additional synchronous condensers. 500MVArs is a threshold
		Required Additional Synch Condensers MVA (% peak load) - Islanded	0	0-500	>500	Portfolio should not require additional synchronous condensers. 500MVArs is a threshold

Scoring Criteria Thresholds (2/2)

	Year 2031		1 (Pass)	2 (Caution)	3 (Problem)	Rationale
5	Flicker	Compliance with Flicker limits when Connected (GE Flicker Curve or IEC Flicker Meter)	>95%	80-95%	<80%	% of system load buses that is likely to experience flicker (>100% of Border line of irritation or Pst>1)
		Compliance with Flicker limits when Islanded	>80%	50-80%	<50%	% of system load buses that is likely to experience flicker (>100% of Border line of irritation or Pst>1)
		Required Synchronous Condensers MVA to mitigate Flicker	0%	0-500	>500	Size of Synchronous condensers required to mitigate flicker (500MVArs is a threshold)
6	Dynamic VAR Support	Dynamic VAR to load Center Capability (% of Peak Load)	≥85%	55-85%	<55%	Dynamic reactive power (DRP) should exceed 55-85% of the peak load served by the load centers. DRP requirement to prevent induction motor stalling is 2.5x the steady state reactive consumption. Assuming a PF=0.9, and Induction motors account for 50-80% of the load. Assume that only 20% of the load can experience a common voltage event.
7	Dispatchability	Dispatchable (%CAP)	>60%	50-60%	<50%	Dipatchable resource are essential for system operation
		Unavoidable VER Penetration %	<60%	60-70%	>70%	Intermittent Power Penetration above 60% is problematic when islanded
		Increased Freq Regulation Requirements (% Peak Load)	<2% of peak load	2-3% of Peak Load	>3% of peak load	Regulation of Conventional Systems ≈1%
		1-min Ramp Capability (MW)	>15% of CAP	10-15% of CAP	<10% of CAP	10% per minute was the norm for conventional systems. Renewable portfolios require more ramping capability
		10-min Ramp Capability (MW)	>65% of CAP	50-65% of CAP	<50% of CAP	10% per minute was the norm for conventional systems. But with 50% min loading, that will be 50% in 10 min. Renewable portfolios require more ramping capability
8	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) (%VER MW)	≥ 0	-10% - 0% of CAP	<-10% of CAP	Excess ramping capability to offset higher levels of intermittent resource output variability is desired

Portfolio Reliability Metrics and Measures

	Year 2030		T1	T2	T3	T4	T5	T6	T7
1	Resource Adequacy	Additional Reserve Margin Required - Summer (MW)	232	279	194	241	146	241	232
2	Energy Adequacy	Loss of Load Hours (LOLH) - normal system, 50/50 forecast	0	0	0	0	0	0	0
		Expected Energy not Served (GWh) - normal system 50/50 fcst	0	0	0	0	0	0	0
		max MW Short (MW) - normal system 50/50 forecast	0	0	0	0	0	0	0
		max MW Short - loss of 50% of tieline capacity, 50/50 fcst	0	0	0	0	0	0	0
		max MW Short (islanded, 50/50 forecast)	274	172	330	251	409	251	510
		max MW Short (normal system, 90/10 forecast)	0	0	0	0	0	0	0
3	Operational Flexibility and Frequency Support	Inertia MVA-s	2,185	2,185	2,185	2,185	2,185	2,185	2,185
		Inertial Gap FFR MW	158	158	158	158	158	158	158
		Primary Gap PFR MW	135	236	54	155	0	155	135
4	Short Circuit Strength	Inverter MWs passing ESCR limits (%) - Connected System	100%	100%	100%	100%	100%	100%	0%
		Inverter MWs passing ESCR limits (%) - Islanded System	0%	0%	0%	0%	0%	0%	0%
		Required Additional Synch Condensers MVA (when Connected)	0	0	0	0	0	0	0
		Required Additional Synch Condensers MVA (when Islanded)	325	325	325	325	325	325	0
5	Power Quality (Flicker)	Compliance with Flicker limits when Connected (GE Flicker Curve or IEC Flicker Meter)	100%	100%	100%	100%	100%	100%	100%
		Compliance with Flicker limits when Islanded	100%	100%	100%	100%	100%	100%	100%
		Required Synchronous Condensers MVA to mitigate Flicker	0	0	0	0	0	0	0
6	Dynamic VAR Support	Dynamic VARs that can be delivered to select load centers (% of Load) at peak	25%	25%	25%	25%	25%	25%	25%
7	Dispatchability and Automatic Generation Control	Dispatchable (%CAP)	68%	65%	70%	68%	72%	68%	68%
		Unavoidable VER Penetration %	38%	50%	28%	40%	16%	40%	38%
		Increased Freq Regulation Requirements (MW)	14	14	14	14	14	14	14
		1-min Ramp Capability (MW)	139	39	219	119	319	119	139
		10-min Ramp Capability (MW)	362	262	442	342	542	342	362
8	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) MW	199	99	279	179	379	179	199

Portfolios:

- T1: Reference Case
- T2: Phase 1 EPA Rule
- T3: CO2 Tax Scenario
- T4: EPA and CO2 Tax
- T5: Aggressive Enviro
- T6: High Price Scenario
- T7: Low Price Scenario

Summary of Reliability Study Findings

- Screening studies indicate the potential need for the following reliability mitigations:

	T1	T2	T3	T4	T5	T6	T7
Equip Stand-alone ESS with GFM inverters (MW)	**158**	**158**	**158**	**158**	**158**	**158**	**158**
Additional Synchronous Condensers (MVA)	**325**	**325**	**325**	**325**	**325**	**325**	**0**
Additional Power Mitigations (MW)	**135**[1]	**236**	**54**[1]	**155**[1]	**0**	**155**[1]	**135**[1]
Increased Freq Regulation	14	14	14	14	14	14	14
Address Inertial Response Gaps[2]	58	158	0	78	0	78	58
Address Primary Response Gaps	135	236	54	155	0	155	135
Firm up Intermittent Renewable Forecast	0	0	0	0	0	0	0

[1] Can utilize existing portfolio storage to provide frequency regulation. No need for additional storage.

[2] Requires fast frequency response within 100ms. Can be in the form of battery storage, super capacitors, or appropriately upsized combustion engines or gas turbines. Blackstart will require long duration for the energy component (4 hours or higher).

Portfolio Reliability Metrics and Measures (Normalized)

	Year 2030		T1	T2	T3	T4	T5	T6	T7
1	Resource Adequacy	Additional Reserve Margin Required	28.4%	34.2%	23.7%	29.5%	17.9%	29.5%	28.4%
2	Energy Adequacy	Loss of Load Hours (LOLH) - normal system, 50/50 forecast	0	0	0	0	0	0	0
		Expected Energy not Served (GWh) - normal system 50/50 fcst	0%	0%	0%	0%	0%	0%	0%
		max MW Short (MW) - normal system 50/50 forecast	0%	0%	0%	0%	0%	0%	0%
		max MW Short - loss of 50% of tieline capacity, 50/50 fcst	0%	0%	0%	0%	0%	0%	0%
		max MW Short (islanded, 50/50 forecast)	29%	17%	36%	26%	46%	26%	58%
		max MW Short (normal system, 90/10 forecast)	0%	0%	0%	0%	0%	0%	0%
3	Operational Flexibility and Frequency Support	Inertia MVA-s : Islanded System	3.20	3.47	3.02	3.25	2.81	3.25	3.20
		Inertial Gap FFR MW (% CAP) : Islanded System	25.4%	27.6%	24.0%	25.8%	22.4%	25.8%	25.4%
		Primary Gap PFR MW (% CAP): Islanded System	21.7%	41.1%	8.2%	25.4%	0.0%	25.4%	21.7%
4	Short Circuit Strength	Inverter MWs passing ESCR limits (%) - Connected System	100%	100%	100%	100%	100%	100%	0%
		Inverter MWs passing ESCR limits (%) - Islanded System	0%	0%	0%	0%	0%	0%	0%
		Required Additional Synch Condensers MVA (when Connected)	0%	0%	0%	0%	0%	0%	0%
		Required Additional Synch Condensers MVA (when Islanded)	40%	40%	40%	40%	40%	40%	0%
5	Power Quality	Compliance with Flicker limits when Connected (GE Flicker Curve or IEC Flicker Meter)	100%	100%	100%	100%	100%	100%	100%
		Compliance with Flicker limits when Islanded	100%	100%	100%	100%	100%	100%	100%
		Required Synchronous Condensers MVA to mitigate Flicker	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	Dynamic VAR Support	Dynamic VARs that can be delivered to select load centers (% of Peak Load)	25%	25%	25%	25%	25%	25%	25%
7	Dispatchability and Automatic Generation Control	Dispatchable (%CAP)	68%	65%	70%	68%	72%	68%	68%
		Unavoidable VER Penetration %	38%	50%	28%	40%	16%	40%	38%
		Increased Freq Regulation Requirements (% Peak Load)	0%	2%	0%	0%	0%	0%	0%
		1-min Ramp Capability (MW)	22%	7%	33%	19%	45%	19%	22%
		10-min Ramp Capability (MW)	58%	46%	67%	56%	77%	56%	58%
8	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) (%VER MW)	29%	14%	41%	26%	56%	26%	29%

Portfolios:

- T1: Reference Case
- T2: Phase 1 EPA Rule
- T3: CO2 Tax Scenario
- T4: EPA and CO2 Tax
- T5: Aggressive Enviro
- T6: High Price Scenario
- T7: Low Price Scenario

VER: Variable Energy Resources (e.g., solar, wind)
CAP: Capacity credit of all resources including existing, planned, and portfolio

Portfolio Reliability Ranking

1	Portfolio passes the screening test
½	Portfolio requires minor to moderate mitigation measures
0	Portfolio requires significant mitigation measures

	Year 2030		T1	T2	T3	T4	T5	T6	T7
1	Resource Adequacy	Additional Reserve Margin Required	0	0	0	0	0	0	0
2	Energy Adequacy	Loss of Load Hours (LOLH) - normal system, 50/50 forecast	1	1	1	1	1	1	1
		Expected Energy not Served (GWh) - normal system 50/50 fcst	1	1	1	1	1	1	1
		max MW Short (MW) - normal system 50/50 forecast	1	1	1	1	1	1	1
		max MW Short - loss of 50% of tieline capacity, 50/50 fcst	1	1	1	1	1	1	1
		max MW Short (islanded, 50/50 forecast)	1	1	1	1	1	1	1
		max MW Short (normal system, 90/10 forecast)	1	1	1	1	1	1	1
3	Operational Flexibility and Frequency Support	Inertia MVA-s	1/2	1/2	1/2	1/2	1/2	1/2	1/2
		Inertial Gap FFR MW (% CAP)	0	0	0	0	0	0	0
		Primary Gap PFR MW (% CAP)	0	0	0	0	1	0	0
4	Short Circuit Strength	Inverter MWs passing ESCR limits (%) - Connected System	1	1	1	1	1	1	0
		Inverter MWs passing ESCR limits (%) - Islanded System	0	0	0	0	0	0	0
		Required Additional Synch Condensers MVA (when Connected)	1	1	1	1	1	1	1
		Required Additional Synch Condensers MVA (when Islanded)	0	0	0	0	0	0	1
5	Power Quality	Compliance with Flicker limits when Connected (GE Flicker Curve or IEC Flicker Meter)	1	1	1	1	1	1	1
		Compliance with Flicker limits when Islanded	1	1	1	1	1	1	1
		Required Synchronous Condensers MVA to mitigate Flicker	1	1	1	1	1	1	1
6	Dynamic VAR Support	Dynamic VAR to load Center Capability (% of Peak Load)	1	1	1	1	1	1	1
7	Dispatchability and Automatic Generation Control	Dispatchable (%CAP)	1	1	1	1	1	1	1
		Unavoidable VER Penetration %	1	1	1	1	1	1	1
		Increased Freq Regulation Requirements (% Peak Load)	1	1	1	1	1	1	1
		1-min Ramp Capability (MW)	1	0	1	1	1	1	1
		10-min Ramp Capability (MW)	1/2	0	1	1/2	1	1/2	1/2
8	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) (%VER MW)	1	1	1	1	1	1	1

Portfolio Reliability Ranking

	Year 2030	T1	T2	T3	T4	T5	T6	T7
1	Resource Adequacy	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	Energy Adequacy	1.00	1.00	1.00	1.00	1.00	1.00	1.00
3	Operational Flexibility and Frequency Support	0.17	0.17	0.17	0.17	0.50	0.17	0.17
4	Short Circuit Strength	0.50	0.50	0.50	0.50	0.50	0.50	0.50
5	Power Quality	1.00	1.00	1.00	1.00	1.00	1.00	1.00
6	Dynamic VAR Support	1.00	1.00	1.00	1.00	1.00	1.00	1.00
7	Dispatchability and Automatic Generation Control	0.90	0.60	1.00	0.90	1.00	0.90	0.90
8	Predictability and Firmness	1.00	1.00	1.00	1.00	1.00	1.00	1.00

	T1	T2	T3	T4	T5	T6	T7
Cumulative core (out of possible 8)	5.57	5.27	5.67	5.57	6.00	5.57	5.57
Percent Score	70%	66%	71%	70%	75%	70%	70%
Ranking	**3**	**7**	**2**	**3**	**1**	**3**	**3**

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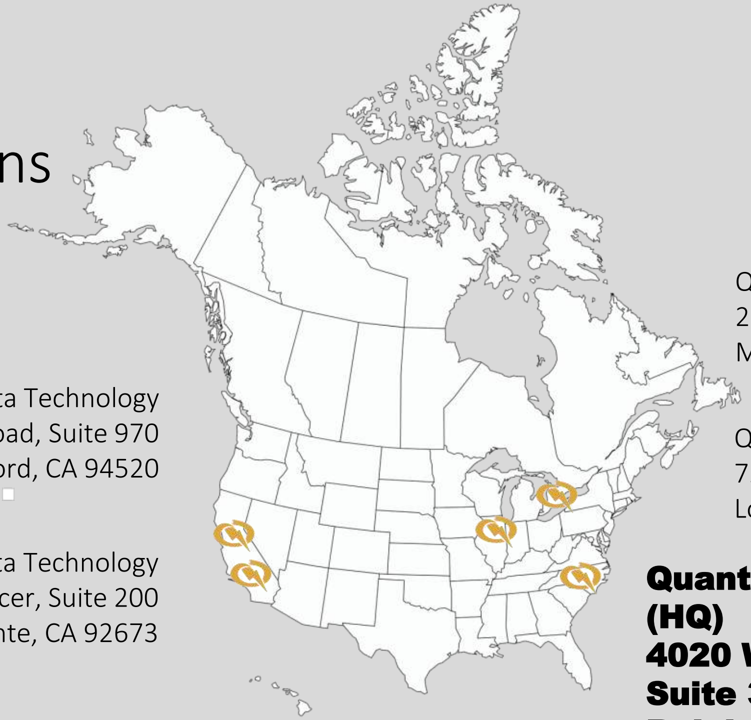
Thank you!

Office Locations



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