Evaluating and Strengthening Iowa's Power Grid for High Wind/Solar Penetration Levels

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Evaluating and Strengthening Iowa’s Power Grid for High Wind/Solar Penetration Levels

Project Report #4
Incorporating an Inertial/Frequency Stability Constraint Into ACEP

Task G7

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Executive summary

More and more renewable generation is being planned and built. Utility-scale wind and solar generation is low cost and zero-carbon and therefore highly attractive when planning future energy resources. But most renewable generation is inverter-based, and so as renewables increase, the amount of synchronous generation remaining on the system decreases, especially with the retirement of older fossil units. With this change in generation mix, a new concern has arisen, that of maintaining frequency stability.

Synchronous generators have both inertia and primary frequency response (PFR), both of which are critical to maintaining frequency stability. Inertia provides short term energy during the first 0 to ~2 seconds following a system disturbance, thereby limiting the rate at which system frequency changes. On the other hand, PFR, also known as speed governing, is the sustained injection of power that arrests a drop in frequency and allows it to reach a stable state. PFR works on a longer timeframe and provides stabilizing energy for the first ~30 seconds. Both inertia and PFR are critical to stabilizing system frequency.

Early renewable generation did not provide significant levels of inertia and PFR, but now it is possible for inverter-based resources (IBRs) to provide these services if they are appropriately designed and controlled. When IBRs do provide these services, it is referred to as fast frequency response (FFR). In this report, we present various IBR technologies and their potential to contribute to stabilizing system frequency.

To maintain frequency stability in the coming years, it is essential that we consider system frequency response in long term expansion planning. To accomplish this, we added a constraint in ACEP to require enough inertia in the system to assure adequate frequency stability. The program allows contributions from both synchronous generators and IBRs. We tested the newly added ACEP constraint in two ways. The first test was very simple, where we assumed that renewable generators (IBRs) make no contribution to system inertia. In this case we saw that the modified ACEP invested in more synchronous generation as the minimum inertia requirement was increased. In the second test we gave appropriate levels inertial credit to renewable generators, assuming that the inverters and controls were able to provide effective inertia. As expected, this allowed investments in wind and solar to increase, while still maintaining minimum system inertia.

We also developed ACEP constraints for PFR and other required reserves. The constraints consider both the response rate and headroom of each generator. As a next step, we will test these newly added constraints and then apply the modified ACEP to larger systems. Overall, this will enable us to achieve our goal of addressing frequency stability as we perform long term system planning with high levels of renewable energy generation.

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1 Introduction

Renewable forms of generation are playing an increasingly larger role in the power system. This is due to their relatively low cost of energy and zero carbon emissions. In addition, batteries are decreasing in cost and playing a larger role in peak shaving, a function that would have otherwise been served by gas-fired synchronous generators. As illustrated in Figure 1.1, the overall effect is that system load is being served by an ever-increasing fraction of inverter-based resources (IBRs). While this is beneficial in terms of cost and decarbonization, synchronous generators have always been a source of stability to the system. For example, with the loss of a generator, the remaining generators give up inertia to stabilize system frequency until governor response elicits sustained increase in output power to arrest the frequency decline and restore it to a stable level. The current system must have at least some minimum amount of inertia and governor response in order to maintain satisfactory frequency stability. The aim of this work is to impose constraints in adaptive coordinated expansion planning (ACEP) to ensure that the long-term plans that it produces include adequate levels of frequency stability.

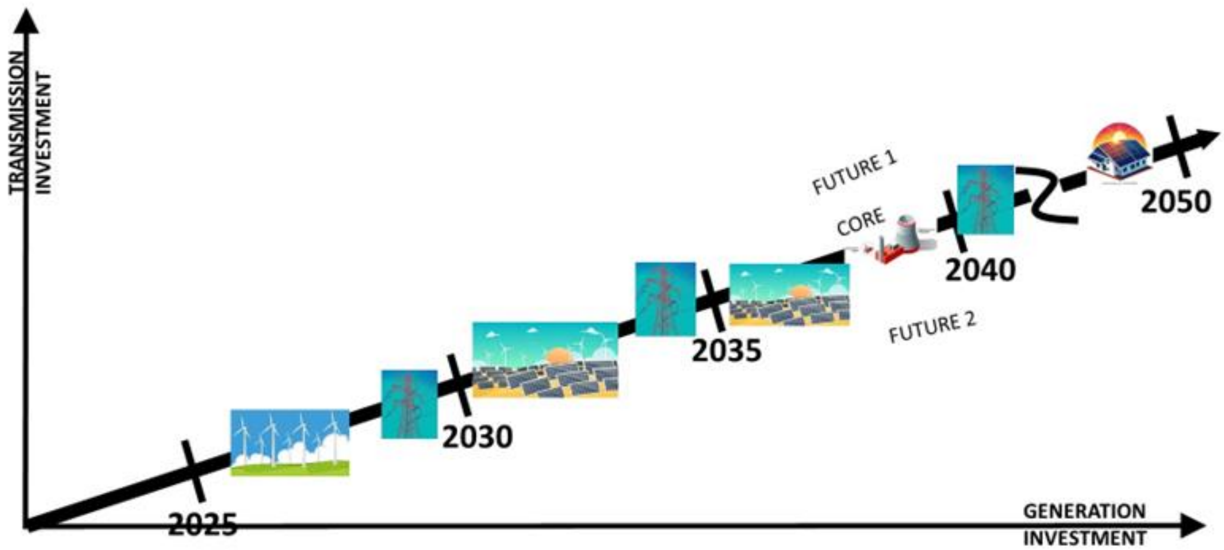

Figure 1.1: Expansion plans are using more IBRs and less synchronous generation

1.1 Low-cost renewable energy

During power system expansion planning, load growth and generator retirements must be served by newly installed generation. Of course, low-cost generation will be preferred because it keeps energy costs and capital costs low. Figure 1.2 below shows a comparison of the levelized cost of energy for various generation technologies[1]. On a levelized cost of energy basis, wind and solar generation have become quite competitive. The lowest cost technologies are onshore wind and utility-scale solar PV, with the lower costs coming from areas rich in wind or solar irradiance resources. As a result, any system planning application, such as ACEP will select large amounts of wind and solar generation.

[1] Levelized Cost of Energy+ | Lazard

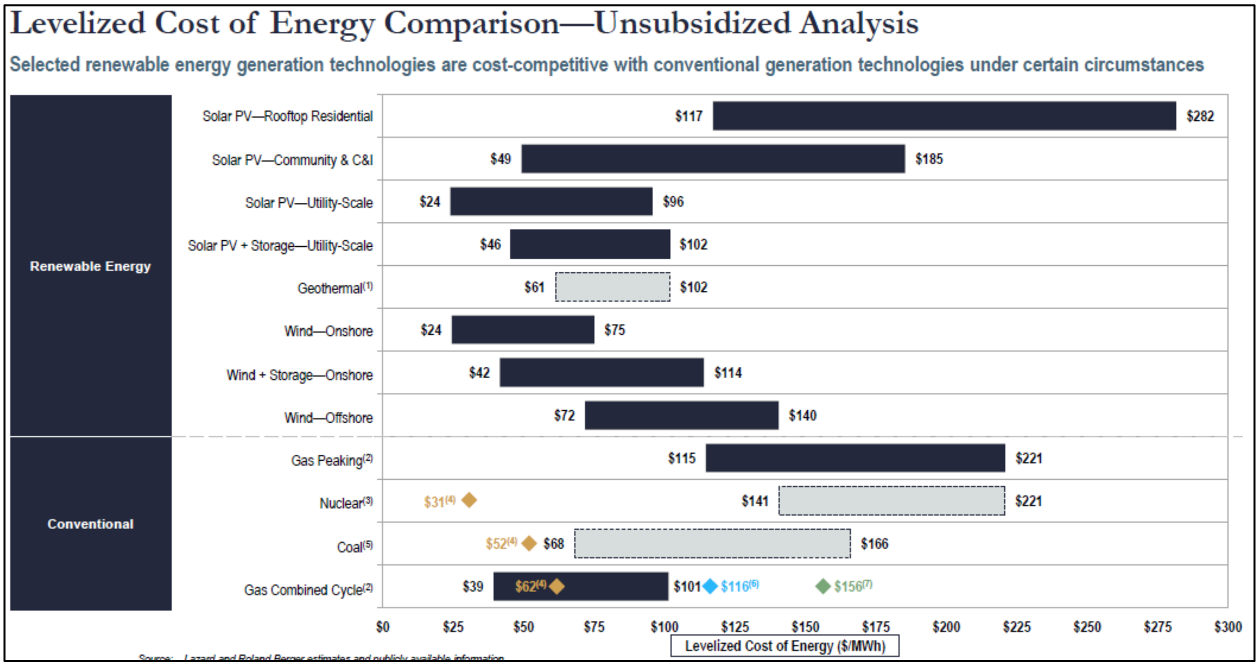

Figure 1.2: Levelized cost of energy for various technologies[1]

1.2 Decarbonization

The decarbonization goal also contributes to the growing fraction of renewable energy generation (and thus IBRs) through selection of non-carbon-emitting generation, a more aggressive retirement schedule, and electrification. Renewable generators have zero carbon emissions; but, except for nuclear and hydro, synchronous generators are carbon emitting. In addition, higher decarbonization goals are generally accompanied by a more aggressive fossil generation retirement schedule. The retired fossil units are then typically replaced with the lowest cost generation, which is wind and solar. Finally, decarbonization of other sectors, such as transportation, industrial, commercial, and residential, is accomplished through electrification. Electrification increases the demand for new generation, which will generally be wind and solar.

Thus, renewable generators, and therefore IBRs, will become a larger and larger part of the generation mix as decarbonization goals are increased. This is well illustrated by the recent MISO Series 1A Futures report[2], which includes expansion plans out to 2042. The three futures; designated 1A, 2A, and 3A, had increasing decarbonization goals of 71%, 76%, and 80% respectively, relative to 2007 levels. Figure 1.3 shows that the current MISO generation is 22% IBRs, but this percentage increases rapidly as the decarbonization goal in increased. The most aggressive decarbonization results in 79% IBRs, an almost fourfold increase over the 2022 level. This is a high percentage of IBRs; the Plan Iowa Energy (PIE) project, with 2053 as the final investment year, may see even higher levels because there is more time for synchronous generator retirements.

[2] Series1A_Futures_Report630735.pdf (misoenergy.org)

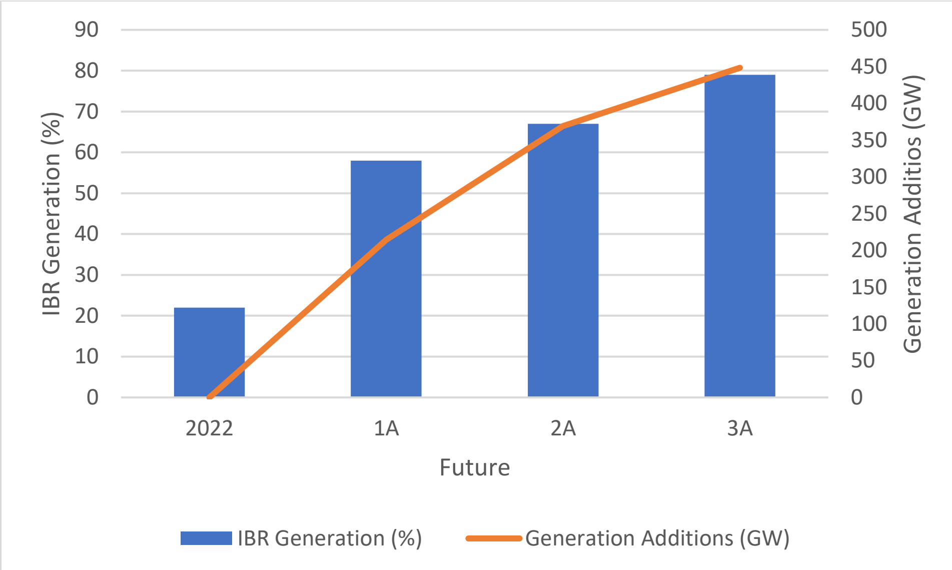

Figure 1.3: An example of increasing IBRs in long-term expansion plans

In summary, retirement of fossil-based synchronous generators and selection of low-cost renewable IBRs will result in fewer and fewer synchronous generators in the system. This is significant because synchronous generators are important for stabilizing system frequency through their inertial response and primary frequency response.

1.3 The general process of stabilizing system frequency after a system disturbance

The rotor of a synchronous generator spins at synchronous speed thereby storing kinetic energy in the rotating mass (Figure 1.4). If the load on the synchronous generator is suddenly increased by loss of another generator in the system, the electrical load increase results in an increased electromagnetic torque, which tends to decelerate the rotor. However, the inertia of the rotor resists deceleration according to Newton's first law of motion (a body in motion tends to stay in motion). In resisting the deceleration, the generator gives up kinetic energy and this energy is used to supply the load increase. At the same time, the rotor deceleration translates into a decreased electrical frequency (top of Figure 1.5), which is undesirable because system frequency must be maintained at 60Hz. However, in a stable response, the rotor deceleration will only be temporary because the governor of the machine will act to correct the speed. Specifically, the rotor shaft speed sensor sends a signal to the governor control system, which in turn opens a valve to send more steam to the turbine. The increase in mechanical torque from the turbine serves to accelerate the machine, increasing frequency and restoring it to a steady-state value close to (but, by design, not equal to 60 Hz). As illustrated in the bottom of Figure 1.5, this rapid but sustained injection of power is initiated by primary frequency control and is referred to as primary frequency response (PFR). It starts during the arresting period and continues through the recovery period. PFR stabilizes the frequency until the slower acting secondary frequency control restores frequency to be within a normal operating range. Secondary frequency control is implemented via automatic generation control (AGC) but is beyond the scope of this study.

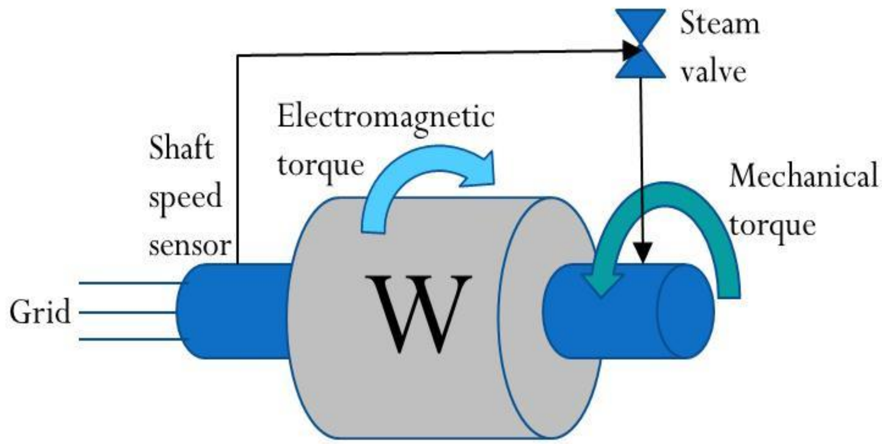

Figure 1.4: Conceptual drawing of the spinning rotor of a synchronous generator

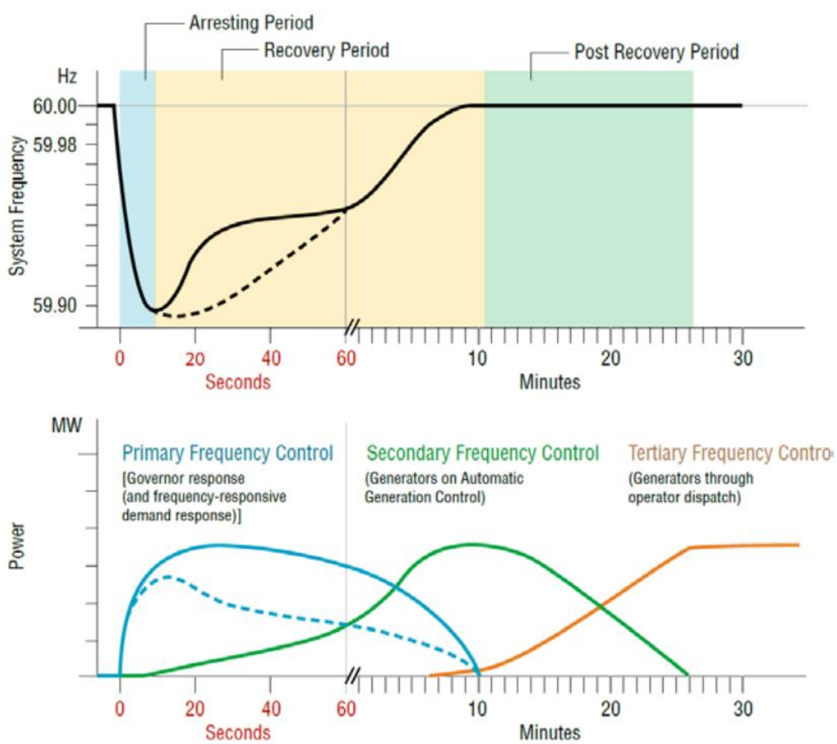

Figure 1.5: Frequency control time frames after the sudden loss of generation[3]

In summary, there are two separate responses from a synchronous generator that work to maintain stable frequency after a system disturbance: inertial response and PFR. Both are important and we will describe each of them in detail, starting with the inertial response.

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[3] NERC, Fast Frequency Response Concepts and Bulk Power System Reliability Needs, March 2020, https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf

When a generator is lost in a system, all the remaining generators participate in providing the lost generation. In the first second or so the response is due to the collective inertia of the remaining generators. If the total inertia of the remaining generators is high, the initial rate of change of frequency (ROCOF) will be low. But if the total inertia of the remaining generators is low, the frequency will drop rapidly and the ROCOF will be high. This is illustrated in Figure 1.6 which shows simulated system responses to the loss of a generator for various inertias. When the inertia of all the generators is artificially reduced (for the sake of simulation and illustration), the ROCOF increases. In other words, the initial drop in frequency is more rapid. Furthermore, the higher ROCOF is accompanied by a lower nadir (minimum frequency). This simple illustration shows the potential challenge of replacing synchronous generators with IBRs, which may have a much lower contribution to system inertia.

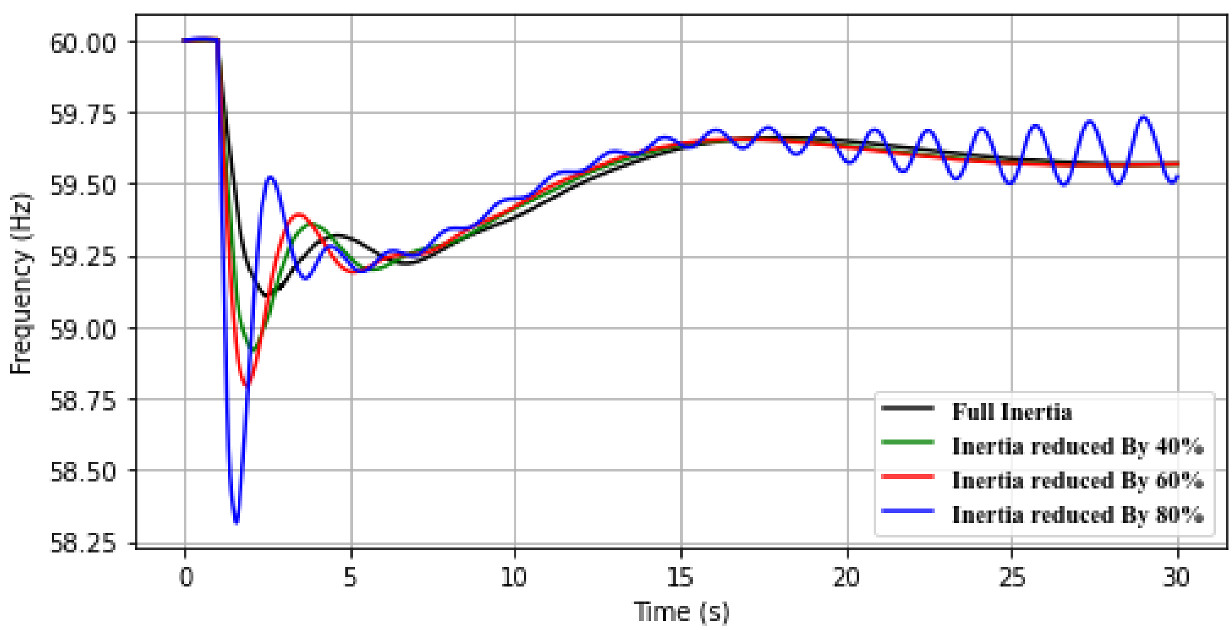

Figure 1.6: Simulations showing the effect of decreasing system inertia

On the other hand, PFR represents a more sustained injection of energy and for a synchronous generator, is provided via the governor. Since PFR arrests the drop in frequency, a reduction in governor capacity means that it will take more time to arrest the drop, resulting in a lower nadir. This is illustrated in Figure 1.7, where simulations of various levels of governor capacity (and therefore PFR) are shown. Notice that the ROCOF is unchanged, because the inertia of the synchronous generators has not been changed. But the nadirs move lower and lower as the PFR, expressed as MW of generation under governor control, is reduced.

In summary, inertia limits the ROCOF after a sudden power imbalance such as the loss of a generator. But PFR, which is a sustained injection of power, is necessary to arrest the decrease in frequency and enable it to recover to a stable level.

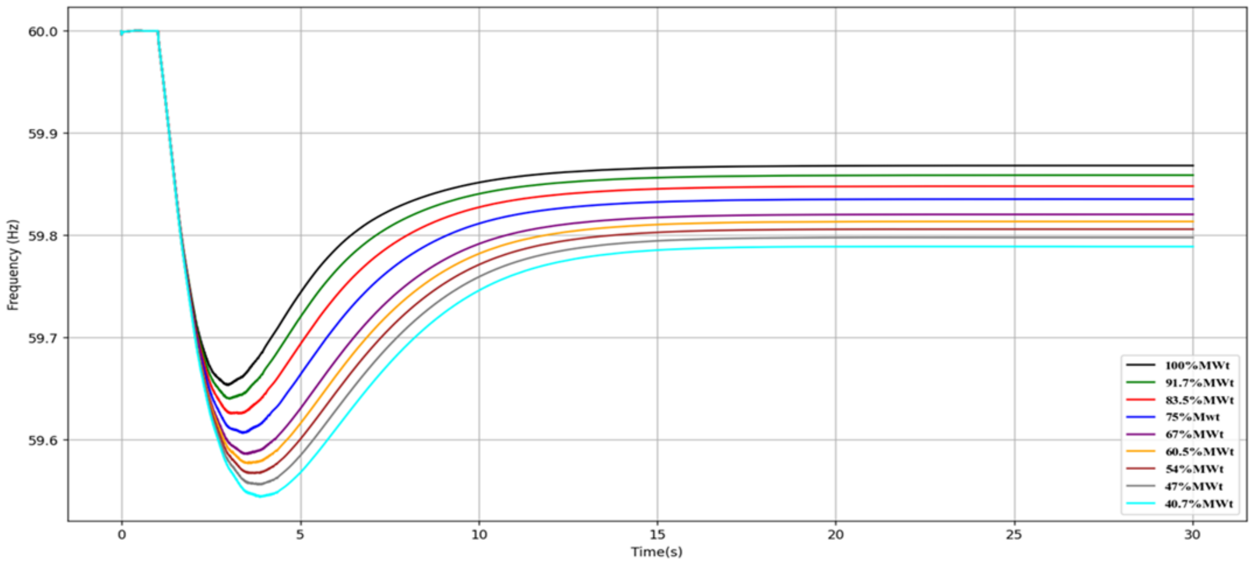

Figure 1.7: Simulations showing the effect of decreasing governor capacity

1.4 Why is frequency important?

As shown above, low inertia and low PFR systems are prone to larger frequency dips, which can also be described as lower nadir. It is very important that the nadir does not fall below the first set point for underfrequency load shedding (UFLS) relays (59.3 Hz in the Eastern Interconnection) because it would cause an unintended loss of load. Furthermore, a high ROCOF may cause other generators to trip offline. This is explained in a NERC white paper as follows[3]:
"a high ROCOF may have potential impacts on existing generator protection and operations. For example, some nuclear plants and natural gas turbines may trip on various turbine controls related to rapid changes or rates of change of speed (e.g., due to fuel flow or auxiliary cooling)."
Such loss of generation in response to the loss of a first generator would constitute cascading outages, which are very serious and must be avoided.

For this reason, NERC specifies frequency response guidelines for each interconnection[4]. The recommendations include the maximum delta frequency (MDF) for loss of a generator whose size is specified by the Resource Loss Protection Criteria (RLPC). For example, for the Eastern Interconnection (EI), the MDF should not exceed 0.42 Hertz for the sudden loss of 3,875 MW of generation[5,6].

1.5 Basic approach

The foregoing sections have shown that it is critical that we consider frequency response in long term system planning so that cascading outages and unintended underfrequency load shedding do not occur. In this research, we address this concern by imposing constraints in ACEP, forcing it to choose generators that provide enough inertia and PFR to maintain a robust frequency response.

[4] NERC BAL-003-2 – Frequency Response and Frequency Bias Setting. BAL-003-2.pdf (nerc.com)
[5] This is for the 2024 operating year and is subject to change each year.
[6] NERC, 2023 Frequency Response Annual Analysis, November 2023.

Up until now, the discussion has focused on how synchronous generators provide these important capabilities, but in the next chapter, we will show that certain IBR technologies are also able to provide inertia-like and PFR-like response. The inertia-like response from fast-responding IBRs can be modeled as an effective inertia where the inertia constant is found by empirical means such as field tests or numerical simulation. Similarly, the PFR-like response of IBRs can be expressed as the fraction of the rated capacity that can ramp up quickly and be sustained in response to a low frequency event. With this modelling, our ACEP constraints take full advantage of any inertia-like and PFR-like capabilities of renewable generators and batteries while still assuring that frequency response standards are met.

The rest of this document is organized as follows: Chapter 2 describes the frequency response capabilities of IBRs, Chapter 3 describes the development of ACEP constraints to assure that the system has adequate amounts of inertia and PFR, Chapter 4 provides test results, and Chapter 5 concludes.

2 PFR and inertia-like response from IBRs

In general, IBRs can respond quickly to a system disturbance, and some are capable of responding nearly as fast as synchronous machines, in other words, on an inertial time frame. However, most IBRs do not have any moving parts so they don't technically provide inertia. Furthermore, for those IBRs that have inertia, namely wind generators, the inertia is not synchronously coupled to the system, but rather is coupled through the inverter. Thus, a new term; namely fast frequency response (FFR), has emerged to describe the fast response from IBRs[7]. Depending on the technology, FFR may be fast but non-sustained like inertia, or it may be a more sustained injection of energy like PFR (see Figure 2.1). Finally, in many cases, FFR is both fast and sustained, thereby providing the same effects as inertia and PFR. We will show examples of each of these cases. For simplicity, we may refer to these effects as inertia and PFR even though they are produced by an IBR.

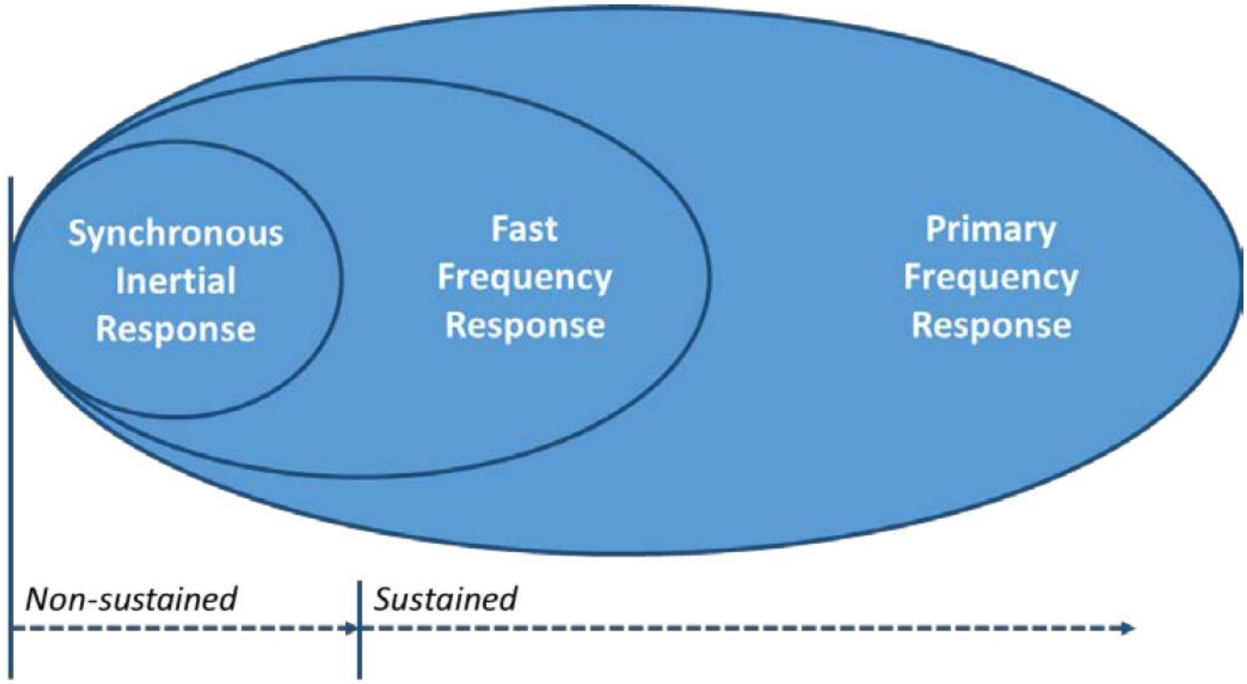

Figure 2.1: The fast frequency response concept (power injection versus time) [8]

To provide FFR, a generator must have a source of energy to inject onto the grid. For synchronous generators, the source of energy is mechanical inertia followed by governor action. The source of

[7] Denholm, Paul, Trieu Mai, Rick Wallace Kenyon, Ben Kroposki, and Mark O'Malley. 2020. Inertia and the Power Grid: A Guide Without the Spin. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6120-73856. https://www.nrel.gov/docs/fy20osti/73856.pdf.

[8] Fast Frequency Response Concepts and Bulk Power System Reliability Needs, NERC Inverter-Based Resource Performance Task Force (IRPTF) White Paper, March 2020. Report (nerc.com)

energy for IBRs could be the mechanical inertia of the rotating blades of a wind generator or the energy stored in a battery energy storage system (BESS). The energy could also be made available by operating a wind or solar PV plant below its potential output to provide "headroom" in case FFR is required. Currently, this is not common practice because it would result in overall lower energy production and lower revenue. But it could become more common practice in the future when alternative sources of inertial response and PFR are needed.

The speed of FFR from IBRs depends on the type of inverter used, either grid-following (GFL) or grid-forming (GFM). Both can inject current into the grid during a disturbance, and both can modulate real and reactive power output. But their control schemes are very different.[9,10] GFL inverters first measure the change in voltage and frequency and then take appropriate action. The measurement time causes them to have slower reaction time than a GFM inverter, which holds a constant voltage and frequency reference on short timescales of tens of milliseconds, allowing it to respond rapidly to variations in system frequency. GFM voltage magnitude and frequency references are then allowed to vary over several seconds to synchronize with other system devices. In summary, GFM inverters are faster than GFL inverters and can even provide FFR on an inertial timeframe, with more impact on the ROCOF after a system disturbance.

GFM inverters are currently available for many utility-scale batteries but are not yet widely available for grid-scale photovoltaics and wind.[10] Thus, the most common application of GFM inverters is in BESS installations and hybrid installations that combine BESS with renewable generation. Field demonstrations have shown that these facilities are able to provide FFR that is both fast and sustained, like that of a synchronous machine.[11]

2.1 Examples of inertial-like response and PFR from IBRs

Our first example is an inertia-like response from wind turbines, shown in Figure 2.2. Several wind turbine manufacturers provide control systems for wind turbines that use the mechanical inertia of the wind turbine to provide a short duration increase in electrical power injection to the grid. These wind turbines normally operate at their MPPT, but upon detecting a significant frequency drop, their controls increase electrical output by using the mechanical inertia of the turbine. However, this causes a slowing of the turbine and loss of mechanical energy that must be made up later. Consequently, the response of these systems (Figure 2.2) consists of a rapid increase in power output, followed by decrease in power output as the turbine is restored to its normal speed. The initial increase in power output has the same effect as an inertial response and has been shown to be effective in decreasing the ROCOF and increasing the nadir.[12]

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[9] Bahrani, B. et. al., Grid-Forming Inverter-Based Resource Research Landscape, IEEE Power & Energy Magazine, Vol. 22, No. 2, March/April 2024.

[10] Kroposki, B. and A. Hoke, Getting the Grid to Net Zero, IEEE Spectrum, 13 Apr, 2024. https://spectrum.ieee.org/electric-inverter

[11] NERC, Utilizing Excess Capability of BPSConnected Inverter-Based Resources for Frequency Support, April 19, 2022, https://www.nerc.com/comm/RSTC/IRPS/Webinar_Utilizing_Excess_IBR_Capability_FR.pdf

[12] J. Brisebois and N. Aubut, "Wind farm inertia emulation to fulfill Hydro-Québec's specific need," *2011 IEEE Power and Energy Society General Meeting*, Detroit, MI, USA, 2011, pp. 1-7, doi: 10.1109/PES.2011.6039121.

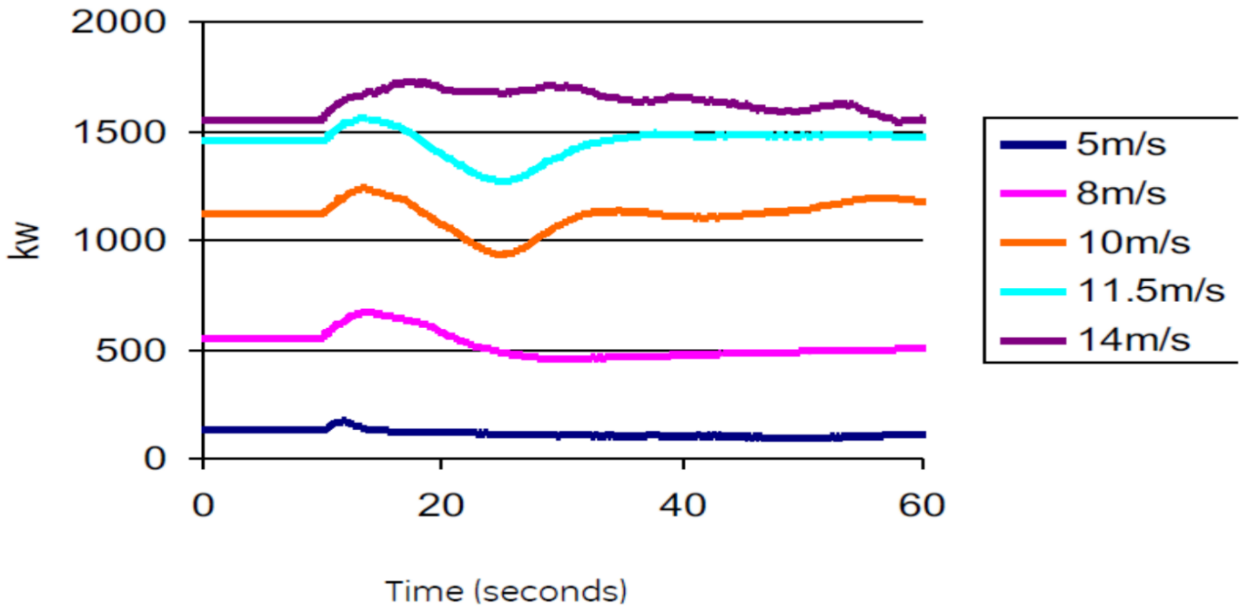

Figure 2.2: Inertia-like response from a wind turbine[13]

For economic reasons, wind turbines and solar arrays are normally operated at their maximum power point (MPPT) so that output power can't be increased to provide frequency response in case a dip in system frequency is detected. However, with proper controls, it is possible to operate wind or solar plants below their MPPT to provide headroom for frequency response. Figure 2.3 shows the response of a 250MW solar PV plant in WECC that was curtailed to 178MW output prior to the application of a synthetic frequency signal to the controller. The plant responds to the low frequency signal by rapidly increasing output and then maintaining a sustained output that gradually decreases as the frequency signal slowly returns to normal. Thus, plant provides both an inertia-like response and a sustained PFR-like response, just like a synchronous machine would.

[13] NERC Reliability Guideline Primary Frequency Control May 2019, PFR_Reliability_Guideline_rev20190501_clean (nerc.com)

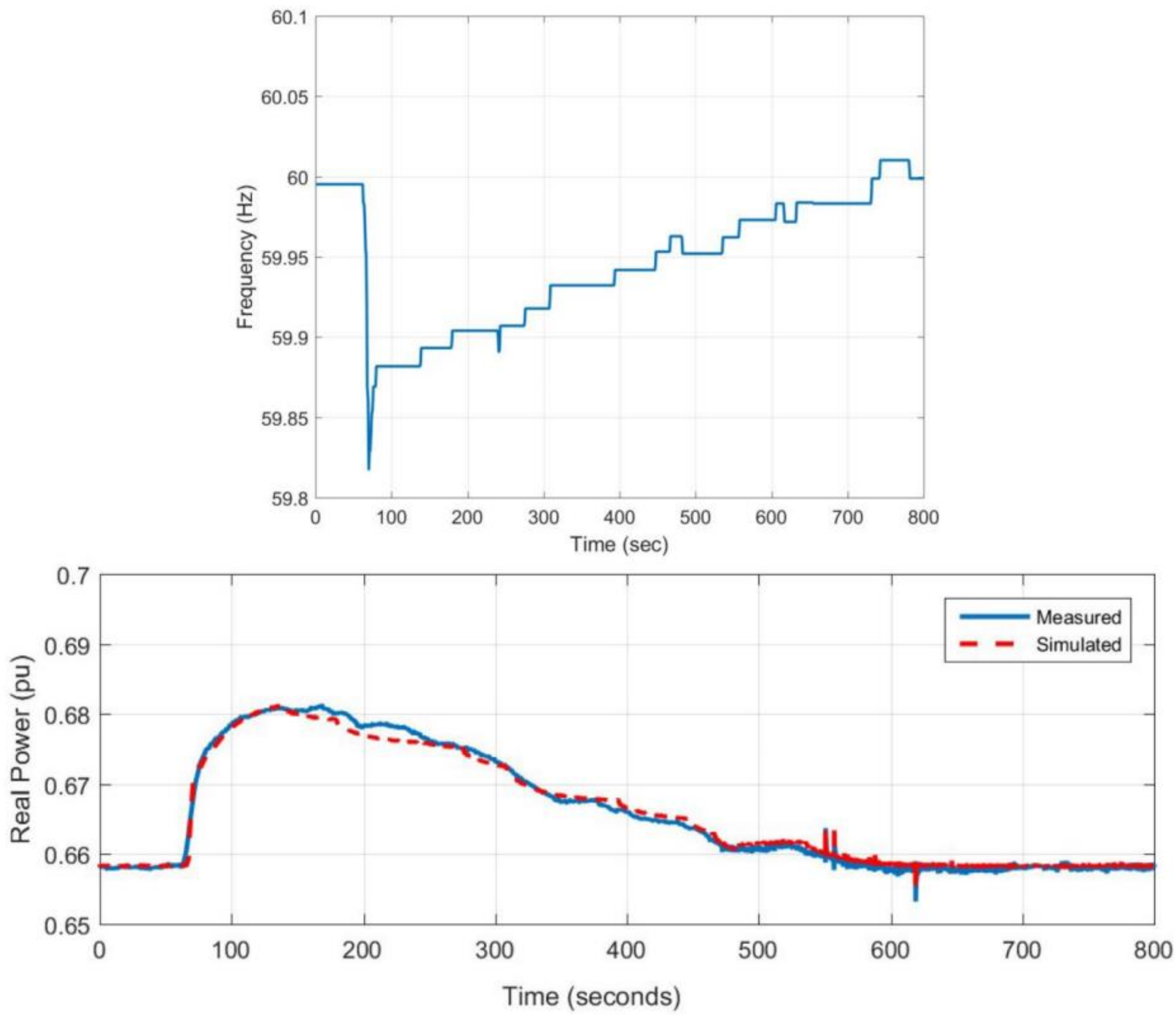

Figure 2.3: Response of a partially curtailed solar PV plant to a sudden decrease in frequency[14,15]

Another example is shown in Figure 2.4, where a partially curtailed type 4 wind power plant (WPP) is subjected to a sudden drop in frequency. Just as in the previous example, the plant responds to the low frequency signal by rapidly increasing output and then maintaining a sustained output that gradually decreases as the frequency signal slowly returns to normal. This inertia-like response combined with a sustained PFR-like response was made possible by partially curtailing the WPP so that it had headroom to respond. The disadvantage of such curtailment is that income from energy production and production tax credit (PTC) are lost. However, ancillary service markets may be established to financially reward partial curtailment for the sake of frequency response.[16]

[14] P. Pourbeik, S. Soni, A. Gaikwad and V. Chadliev, "Providing Primary Frequency Response from Photovoltaic Power Plants", CIGRE Symposium 2017, Dublin, Ireland, May 2017.

[15] NERC Power Plant Model Verification for Inverter-Based Resources Committee, Reliability Guideline Power Plant Model Verification for Inverter-Based Resources, NERC, September 2018.

[16] P. Du, N. V. Mago, W. Li, S. Sharma, Q. Hu and T. Ding, "New Ancillary Service Market for ERCOT," in *IEEE Access*, vol. 8, pp. 178391-178401, 2020, doi: 10.1109/ACCESS.2020.3027722.

Furthermore, partial curtailment as opposed to total curtailment (by simply dispatching synchronous generators when inertial or PFR system constraints are not met) may result in more wind production overall.[17]

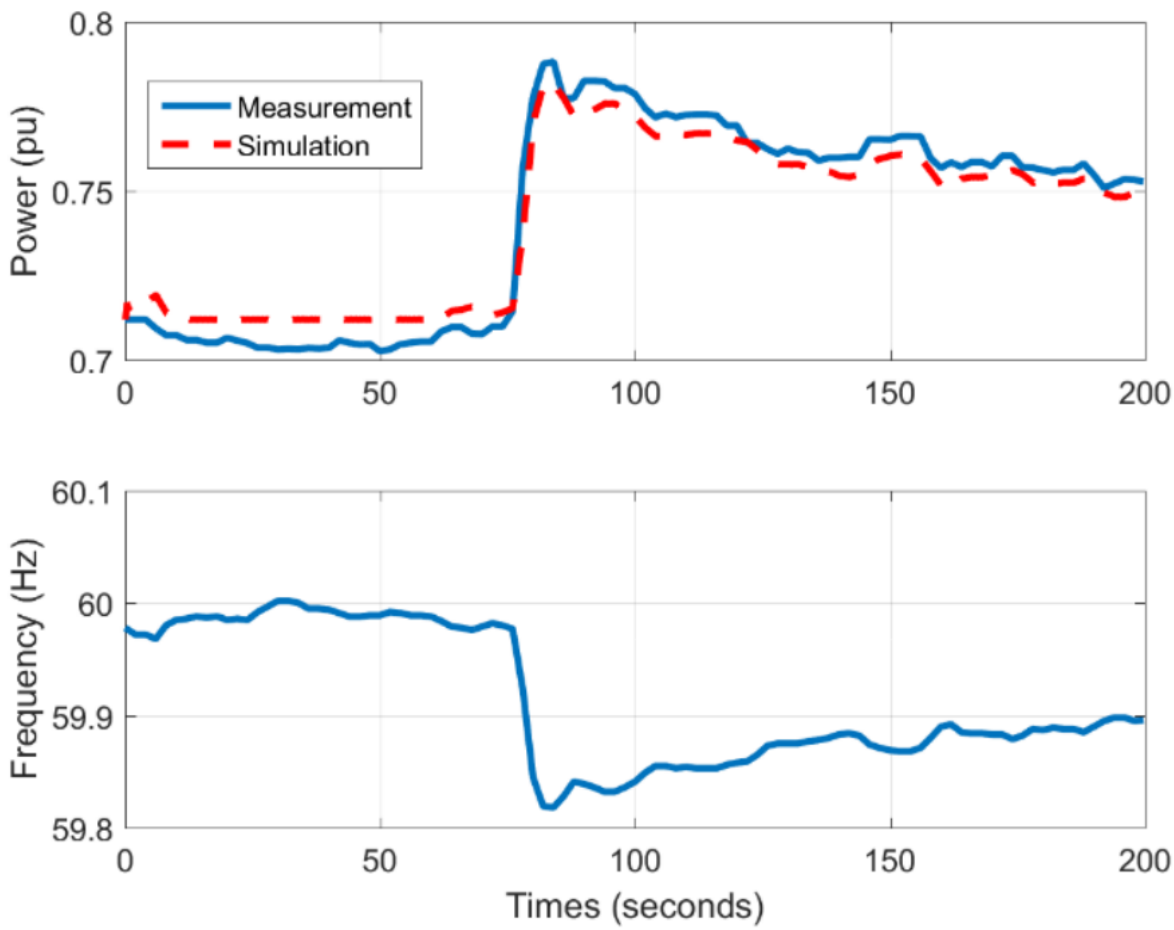

Figure 2.4: Underfrequency response of a partially curtailed type 4 WPP[18]

Battery energy storage systems (BESS) are also capable of fast and sustained response (Figure 2.5), which means that they can provide both inertia-like and PFR-like response. Batteries store a limited amount of energy, but most frequency events are short duration. For this reason, ERCOT, which incorporates FFR in its ancillary market, only requires a sustained power output of 15 minutes or less to qualify for the market.[16]

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[17] A. S. Ahmadyar, S. Riaz, G. Verbič, A. Chapman and D. J. Hill, "A Framework for Assessing Renewable Integration Limits With Respect to Frequency Performance," in *IEEE Transactions on Power Systems*, vol. 33, no. 4, pp. 4444-4453, July 2018, doi: 10.1109/TPWRS.2017.2773091.

[18] P. Pourbeik, J. Sanchez-Gasca, J. Senthil, J. Weber, P. Zadehkhost, Y. Kazachkov, S. Tacke and J. Wen, "Generic Dynamic Models for Modeling Wind Power Plants and other Renewable Technologies in Large Scale Power System Studies", IEEE Trans. on Energy Conversion, vol. 32, no. 3, September 2017. DOI: 10.1109/TEC.2016.2639050; http://ieeexplore.ieee.org/document/7782402/

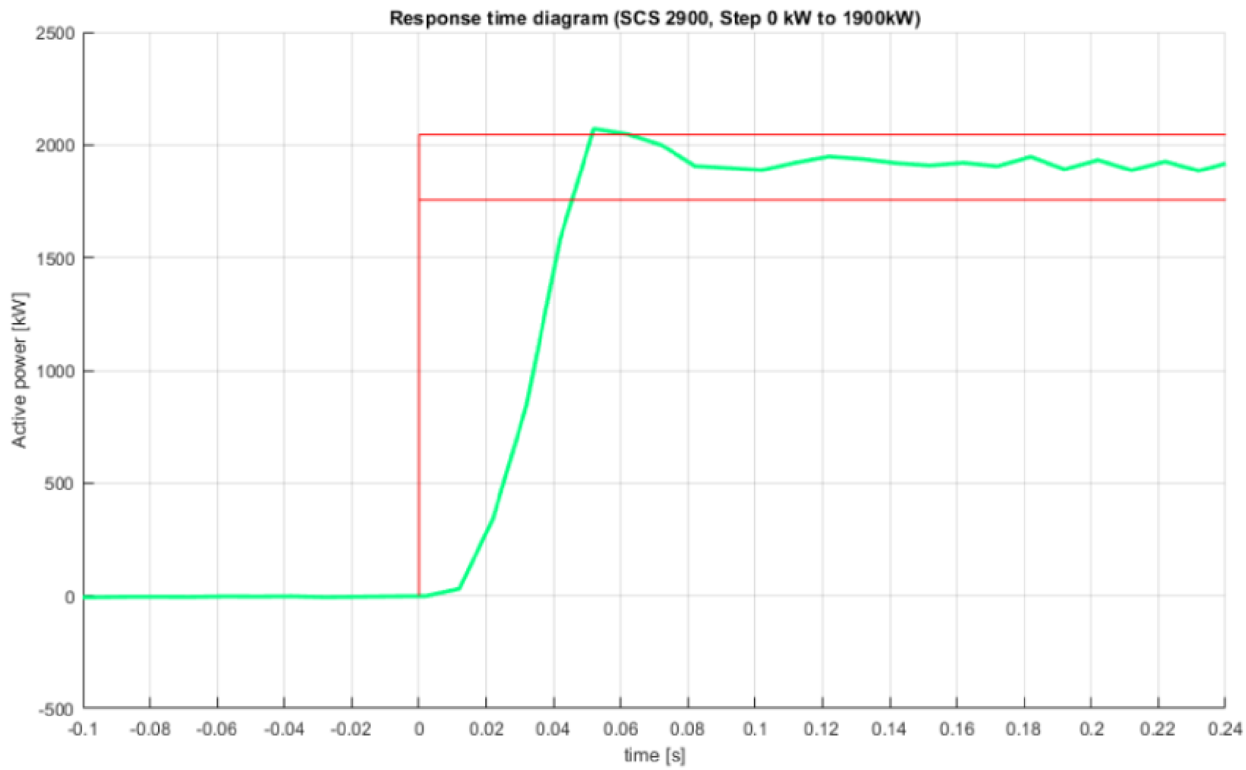

Figure 2.5: Step-response of a BESS[20]

In some facilities, a BESS is combined with wind or solar generation. The battery may be charged when the renewable output is high and discharged when the renewable output is low. Since the full output of both the BESS and the renewable generation are not typically used at the same time, the full output capacity of the plant may exceed the contracted steady-state interconnection limit (SSIL) of the point of interconnection (POI). NERC has proposed that short term interconnection limits (STIL) be established for such facilities so that the excess capability could be used to respond to low frequency events. [19,20] This would increase the effective inertia and effective PFC available from such facilities.

Finally, load resources (LR) can also be used to provide frequency response during a low frequency event by reducing the load instead of injecting extra power from a generator. In ERCOT, LR is deployed by opening the breaker on pre-contracted load when the system frequency drops below 59.7 Hz. This may be sufficient to arrest the frequency drop and prevent it from falling to the first-stage UFLS, which occurs at 59.3 Hz. LR typically takes 25 to 30 cycles (0.416 to 0.5 seconds) to respond, so the ROCOF must be kept adequately low for LR to be effective. Otherwise, UFLS would be initiated before LR influences the frequency.[16],[21]

[19] NERC Inverter-Based Resource Performance Working Group (IRPWG) White Paper, "Utilizing Excess Capability of BPS-Connected Inverter-Based Resources for Frequency Support", September 2021. Document Portrait (Two Pages) (nerc.com)

[20] NERC Inverter-Based Resource Performance Subcommittee (IRPS) Informational Webinar, "Utilizing Excess Capability of BPS-Connected Inverter-Based Resources for Frequency Support, April 19, 2022. https://www.nerc.com/comm/RSTC/IRPS/Webinar_Utilizing_Excess_IBR_Capability_FR.pdf

[21] Inertia: Basic Concepts and Impacts on the ERCOT Grid, ERCOT, 2018. DER_Reliability_Impacts (ercot.com)

2.2 Summary of Capabilities

Table 2-1 provides a summary of the frequency response capabilities of various technologies. Each of these technologies will be considered as alternatives to provide inertial response and PFR in this study.

Table 2-1: Summary of frequency response capabilities of various generator technologies

Resource	Capability			Cost[22]	
	Energy	Inertia[23]	PFR[24]	Cost[25] ($/kW)	FOM ($/kW-yr)
synchronous generator	Yes	Yes	Yes	Various	Various
synchronous condensor	No	Yes	No	445	[26]
Storage (BESS)	Yes	Yes	Yes	980	41
wind only	Yes	No	No	1217	29
wind + inertial emulation	Yes	Yes	No	1256	30
wind + BESS	Yes	Yes	Yes	2067	38
derated wind	Yes	Yes	Yes	1256	30
Solar only	Yes	No	No	1245	21
Solar + BESS (esp. AC-coupled)	Yes	Yes	Yes	2056	29
derated solar	Yes	Yes	Yes	1285	21
controllable load resources (LR)	Yes	No	Yes	[26]	[26]

[22] Unless otherwise noted, the source is: NREL, 2023 Electricity ATB Technologies and Data Overview (https://atb.nrel.gov/electricity/2023/index)
[23] For IBRs, this refers to a fast response on an inertial time frame and is dependent on the particular inverter and control design.
[24] For IBRs, this refers to the sustained injection of power to arrest and stabilize frequency, not on governor response.
[25] Overnight capital cost
[26] Cost not readily available

3 Formulating the ACEP constraints

ACEP is a linear program that minimizes a cost function subject to various constraints. The objective is to find the long-term plan with the lowest investment and operating cost, while satisfying specified constraints. The benefit of ACEP is that it can consider multiple futures in a single optimization calculation. Figure 3.1 illustrates the components of the cost function, which is composed of a core component and an adaptation component.

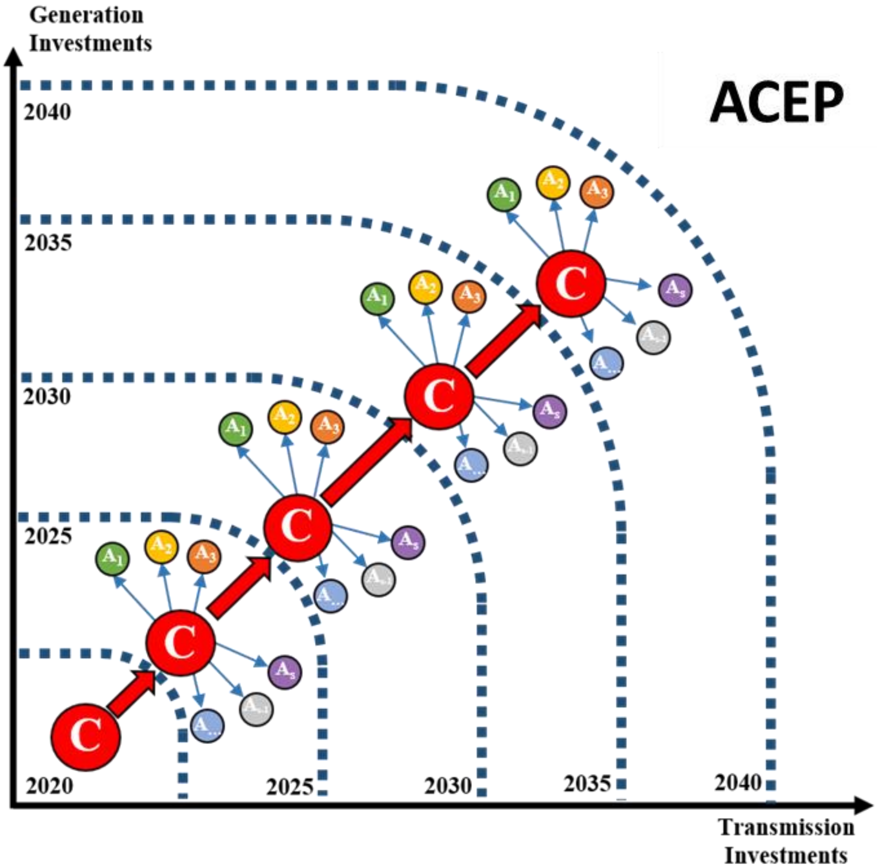

Figure 3.1: Illustration of the cost function of ACEP, which includes both a core cost and adaptation costs

The idea is to minimize adaptation costs in order to build a system that is optimally adaptable to whatever future actually transpires. The overall calculation can be expressed as:

Minimize:

$$\begin{aligned}&\mathrm{NetPresentWorth}\{\mathrm{CoreCosts}(\underline{x})\\&+ \beta\ \{\Sigma_k\ \mathrm{Probability}_k \times \mathrm{AdaptationCost}(\Delta\underline{x}_k)\}\\&+\quad \Sigma_k\ \mathrm{Probability}_k \times \{\mathrm{OperationalCost}(\Delta x_k)\}\end{aligned}$$

Subject to:

Operational constraints for each future k=1,…,n where Probability_k is the probability of the kth future occurring and β is a parameter expressing the emphasis on adaptation costs. If β is high, adaptation costs will be high, which will lead to a high degree of minimization of adaptation costs. This results in a robust core plan that would require little adaptation in the future.

Many constraints are included in ACEP, and these are critical to obtaining a valid system design. For example, one constraint ensures that the generation is sufficient to supply the load, and another constraint is that line flows cannot violate thermal limits. Each constraint is a mathematical expression specifying that specific system parameters must be above, below, or equal to a threshold. The expressions are manipulated into a form that is amenable for use in ACEP and then coded into the program and tested on a simple system (testing will be covered in the next chapter).

3.1 Mathematical relationship between inertia and ROCOF

The first step in forming an inertial constraint is to mathematically express the relationship between total system inertia and the ROCOF. The ROCOF can be defined as the change in frequency during the first 0.5 seconds immediately following a sudden loss of generation[27]. Figure 3.2 illustrates this part of the frequency response curve, showing the lower ROCOF for higher inertia and vice versa. The primary factors that affect ROCOF are[7]:

1) The size of the generator lost
2) The overall system inertia
3) The speed of response of the governor
4) Sensitivity of load to the change in frequency

However, the biggest factors are the first two, the size of the generator lost and the total system inertia, especially in the first second after the contingency.

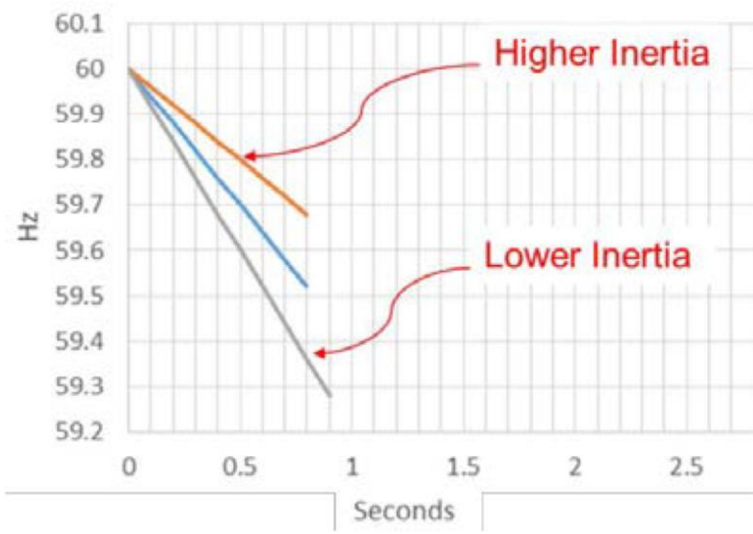

Figure 3.2: High inertia systems have a lower ROCOF and visa versa[27]

Furthermore, the relationship between ROCOF, the magnitude of lost generation, and inertia is well known and can be expressed as[27,28]:

[27] NERC, Fast Frequency Response Concepts and Bulk Power System Reliability Needs, March 2020.
[28] Vittal,V.,J.D. McCalley,P.M. Anderson, A.A. Fouad, *Power System Control and Stability*, 3rd edition, 2020, p79.

$$ROCOF = \frac{\Delta P_{lost}}{2(\sum_i H_i S_{B_i} - H_{lost} S_{B_{lost}})} \cdot 60 \qquad \text{(Equation 1)}$$

where:
ΔP_{lost} is the amount of generation lost (MW),
H_i is the inertia of the i^{th} generator (seconds),
H_{lost} is the inertia of the lost generator (seconds),
S_{B_i} is the apparent power base of the i^{th} generator (MVA), and
$S_{B_{lost}}$ is the apparent power base of the lost generator (MVA).

If the inertia of the lost generation ($H_{lost} S_{B_{lost}}$) is small compared to the total system inertia, this term can be neglected without significant loss of accuracy. This is generally the case. For example, in ERCOT the inertia of the lost generation is less than four percent of the total system inertia, and ERCOT would be a worst-case scenario, being smaller than the eastern interconnection or WECC. With this simplification, ROCOF can be expressed as:

$$ROCOF \approx \frac{30 \Delta P_{lost}}{\sum_i H_i S_{B_i}} \qquad \text{(Equation 2)}$$

The sum in the denominator of the right-hand side of this equation represents the system inertia. From the equation we observe that a decrease in system inertia will cause an increase in the ROCOF. The problem is that if ROCOF becomes too high, the frequency will quickly reach the UFLS threshold before PFR is able to arrest the drop. We address this problem by specifying a maximum allowable ROCOF ($ROCOF_{max}$). For example, we could specify $ROCOF_{max}$ based on avoiding underfrequency load shedding within the first two seconds after the contingency, which infers a 0.5 hertz frequency change in 2 seconds or an $ROCOF_{max}$ of 0.25 Hz/second.[29]

In summary, the system inertia must remain high enough to maintain an ROCOF at or above $ROCOF_{max}$. This can be expressed mathematically by manipulating equation 2 and applying an inequality:

$$\sum_i H_i S_{B_i} \geq \left(\frac{30 \Delta P_{lost}}{ROCOF_{max}}\right) \qquad \text{(Equation 3)}$$

As mentioned in section 1.4, NERC specifies the size of the lost generation contingency that the system should be able to withstand without UFLS, referring to it as the RLPC.[6] Thus, both variables on the right-hand side of equation 3 are specified and the right-hand side evaluates to a constant, which indicates the minimum allowable system inertia.

[29] This value of $ROCOF_{max}$ may be refined based on any available simulation results for the Iowa system.

3.2 Incorporating the inertial constraint into ACEP

Having developed a constraint for the minimum system inertia in the previous section, we now incorporate the constraint into ACEP. A summary of the overall ACEP calculation was provided at the beginning of this chapter. It consists of the minimization of the net present cost subject to constraints. As such, Equation 3 is a linear constraint that can be incorporated into ACEP. The apparent power rating of the machines are decision variables, and the inertia constants are parameters that are assumed for each particular generation technology. With the addition of the inertial constraint, the optimization problem can be expressed as:

Minimize:

NetPresentWorth{CoreCosts($\underline{x}$)
+ β {Σ_k Probability$_k$ × AdaptationCost($\Delta\underline{x}_k$)}
+ Σ_k Probability$_k$ × {OperationalCost(Δx_k)}

Subject to:

Operational constraints for each future k=1,…,n
…
$\sum_i H_i S_{B_i} \geq \left(\frac{30\Delta P_{lost}}{ROCOF_{max}}\right)$

where:

$\underline{x}$ is a given plan,
k is a future (among n total futures),
β is a robustness constant, and
i corresponds to the *i*th generator in plan $\underline{x}$.

In summary, the inertial constraint is added to the list of other operational constraints to assure that the optimal plan has adequate system inertia.

3.3 Constraint on PFR

The generation capacity required for PFR must be held in reserve in case a contingency occurs. As such, PFR is one of several system operating reserves, which further complicates the problem. Thus, in this section we will develop the PFR constraints without considering other reserves and in the next section we will expand the development to consider all system operating reserves. This will allow the introduction of some important concepts that will later be applied to all reserves.

In general, a PFR requirement can be imposed by adding three constraints to the inertial constraint shown section 2.2.[30] We will first show the equations and then explain the meaning of each one. The three constraints are:

$\sum_g pfr_{g,t} \geq PFR_{req}$ for all g,t (Equation 4)

[30] Jorgenson, Jennie and Paul Denholm. 2018. Modeling Primary Frequency Response for Grid Studies. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72355. https://www.nrel.gov/docs/fy19osti/72355.pdf.

$P_{Energy_{g,t}} + pfr_{g,t} \leq P_g^{max}$ for all g,t (Equation 5)

$pfr_{g,t} \leq \mu_{PFR} R_g^{max}$ for all g,t (Equation 6)

where:

$pfr_{g,t}$	is the PFR (MW) contribution of generator g at time *t*,
PFR_{req}	is the minimum PFR in MW that the system must maintain at all times,
$P_{Energy_{g,t}}$	is the output of generator *g* (MW) at time *t*,
P_g^{max}	is the maximum output of generator *g* (MW),
R_g^{max}	is the maximum response (ramp) rate of generator g in MW/minute
μ_{PFR}	is the response time in minutes

Equation 4 states that the PFR of the system is the sum of the PFR contributions from all generators, and that the sum must meet or exceed the required PFR.

Equation 5 states that for each generator, the sum of pre-contingency output , P_{Energy}, and PFR is limited to the maximum output of the generator. The difference between the maximum output and the pre-contingency output is often referred to as headroom. In other words, the generator must have headroom to respond.

Equation 6 states that the PFR contribution of each generator is limited by its response rate and response time. PFR is a "sub-minute" reserve product so the response time for PFR will be less than one minute.[31]

The above equations are easily adapted to ACEP by applying them to every load block instead of every time, *t* (load blocks are the most temporally granular units in ACEP). Furthermore, the overall PFR requirement is very slow to change and can probably be maintained as a constant throughout the planning study.

3.4 Including all operating reserves in the constraints

In this section we extend the discussion of PFR constraints by considering their relationship to other system operating reserves. We will first introduce these reserves and then rewrite the PFR constraints to include their effect. Lastly, we will add constraints for all the reserves.

Since most of the Iowa system is in MISO, we refer to MISO reserve products, which are listed in Table 3.1. As the table indicates, there are six reserve products in the MISO market, all of which have longer response times than PFR. The fastest of these is regulating reserve, which is classified as secondary frequency response (Figure 1.5). More time is allowed for the other reserve products, which make up tertiary frequency response. The overall combination of this mix of PFR and reserves is used to arrest a drop in frequency, stabilize frequency, and then return frequency to its normal range.

[31] NERC Reliability Guideline, Operating Reserve Management: Version 3, p20, https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_Template_Operating_Reserve_Management_Version_3.pdf .

Table 3.1: Summary of MISO reserve products

MISO Product Name	Symbol(s) in This Report	MISO Response Time (μ)	Comments[32]
Short-term reserve	P_{STR_g}, μ_{STR}	30 min	Used to meet local, sub-regional, and market-wide flexibility needs.
Ramp up	P_{RampUp_g}, μ_{RampUp}	10 min	Ability to increase power output for a generator or ability to decrease load. Accommodates load variation and uncertainty.
Ramp down	P_{RampDn_g}, μ_{RampDn}	10 min	Ability to decrease power output for a generator or ability to increase load. Accommodates load variation and uncertainty.
Spinning reserve	P_{Spin_g}, μ_{Spin}	10 min	Online portion of contingency reserves.
Supplemental reserve	P_{Suppl_g}, μ_{Suppl}	10 min	Part of contingency reserves. Not required to be online but may be online. (Online resources qualify for both spinning and supplemental reserves).
Regulating reserve	P_{Reg_g}, μ_{Reg}	5 min	Responds to AGC to correct area control error (ACE) in order to balance load and generation.

The combination of spinning and supplemental reserves makes up contingency reserves. Both reserve types require the same 10-minute response time. However, spinning reserves, as the name implies, are necessarily online, but supplemental reserves may or may not be online. It turns out that ACEP does not differentiate between online and offline resources, so we can simplify our analysis by accounting for contingency reserves instead of explicitly accounting for spinning and supplemental reserves. Of course, a spinning unit would have higher auxiliary load and therefore variable operating and maintenance (VOM) costs than an offline unit, so this results in some error in the cost calculation. However, we do not believe that the error is significant enough to warrant more detailed modelling.

Having introduced the various reserves, we now modify the PFR constraints to reflect reserves. For completeness, we include all the equations even though two of them have not changed:

$\sum_g pfr_{g,t} \geq PFR_{req}$ for all g,t (Equation 7)

$P_{Energy_{g,t}} + pfr_{g,t} + P_{Reg_{g,t}} + P_{Cont_{g,t}} + P_{RampUp_{g,t}} + P_{STR_{g,t}} \leq P_g^{max}$

for all g,t (Equation 8)

$P_{Energy_{g,t}} - P_{RampDn_{g,t}} \geq P_g^{min}$ for all g,t (Equation 9)

$pfr_{g,t} \leq \mu_{PFR} R_g^{max}$ for all g,t (Equation 10)

[32] MISO, Energy and Operating Reserve Markets, Business Practices Manual, BPM-002-r24, Effective Date: SEP-30-2023

where P_{Cont} corresponds to contingency reserves, which are the combination of spinning and supplemental reserves. When compared to the original set of PFR constraints presented in Section 3.3, the headroom equation has changed (Equation 8) to accommodate the effect of other reserve types. There is no overlap between PFR and any of the other reserve types, so separate headroom must be allocated for each. Of course, a given generating unit will probably not provide all reserve types and may not even provide any reserves. But the equation is generic and can accommodate any reserve situation. Similarly, a "foot room" equation (Equation 9) has been added in case the unit provides ramp down reserves.

The actual reserve products that a generator can provide depend on the generator technology. For example, a simple cycle gas turbine generator may be capable of providing any of the reserve products, but a wind generator (without BESS or inertial emulation) may only be capable of ramping down. A summary of reserve capabilities for various technologies is provided in Table 3.2. Ultimately, the actual level of reserve also depends on the reserve market and the price at which the technology provides the reserve.

Table 3.2: Reserve capabilities of various generating technologies

Product Technology	**Spinning**	**Supplemental**	**Regulating**	**Ramp-up**	**Ramp-dwn**	**STR**
GCC	Yes	Yes	Yes	Yes	Yes	Yes
coal	Yes	No	Yes	Yes	Yes	No
Nuclear	No	No	No	No	No	No
New nuclear	No	No	No	No	No	No
hydro	Yes	Yes	Yes	Yes	Yes	Yes
Others…						
synchronous condensor	No	No	No	No	No	No
Storage (BESS)	Yes	Yes	Yes	Yes	Yes	Yes
wind only	No	No	No	No	Yes	No
wind + inertial emulation	No	No	No	No	Yes	No
wind + BESS	Yes	Yes	Yes	Yes	Yes	Yes
derated wind	No	No	No	No	Yes	No
Solar only	No	No	No	No	Yes	No
Solar + BESS (esp. AC-coupled)	Yes	Yes	Yes	Yes	Yes	Yes
derated solar	No	No	No	No	Yes	No
controllable load resources (LR)	Yes	Yes	Yes	Yes	Yes	Yes

Having modified the PFR constraints, we will now present constraints related to the other reserve products. First, the MISO BPM specifies that contingency reserve must not fall below the largest single supply contingency (LSSC), either generation resource or transmission.[33] Thus the constraints for contingency reserves are:

$\sum_g P_{Cont_{g,t}} \geq LSCC$ for all g,t

$P_{Cont_{g,t}} \leq \mu_{Cont} R_g^{max}$ for all g,t.

And the constraints for the remaining reserves are:

$\sum_g P_{Reg_{g,t}} \geq Total\ Required\ Regulating\ Reserve$ for all g,t

$P_{Reg_{g,t}} \leq \mu_{Reg} R_g^{max}$ for all g,t

$\sum_g P_{RampUp_{g,t}} \geq Total\ Required\ Ramp\ Up\ Reserve$ for all g,t

$P_{RampUp_{g,t}} \leq \mu_{RampUp} R_g^{max}$ for all g,t

$\sum_g P_{RampDn_{g,t}} \geq Total\ Required\ Ramp\ Down\ Reserve$ for all g,t

$P_{RampDn_{g,t}} \leq \mu_{RampDn} R_g^{max}$ for all g,t

$\sum_g P_{STR_{g,t}} \geq Total\ Required\ Short\ Term\ Reserve$ for all g,t

$P_{STR_{g,t}} \leq \mu_{STR} R_g^{max}$ for all g,t

A summary of MISO reserve requirements is shown in Figure 3.3. While reserve requirements do not change rapidly, we expect them to change over time. Thus, as part of our future work, we will do more research to project these changes through the end of the planning period.

[33] MISO, Energy and Operating Reserve Markets, Business Practices Manual, BPM-002-r24, Effective Date: SEP-30-2023, section 3.2.2.

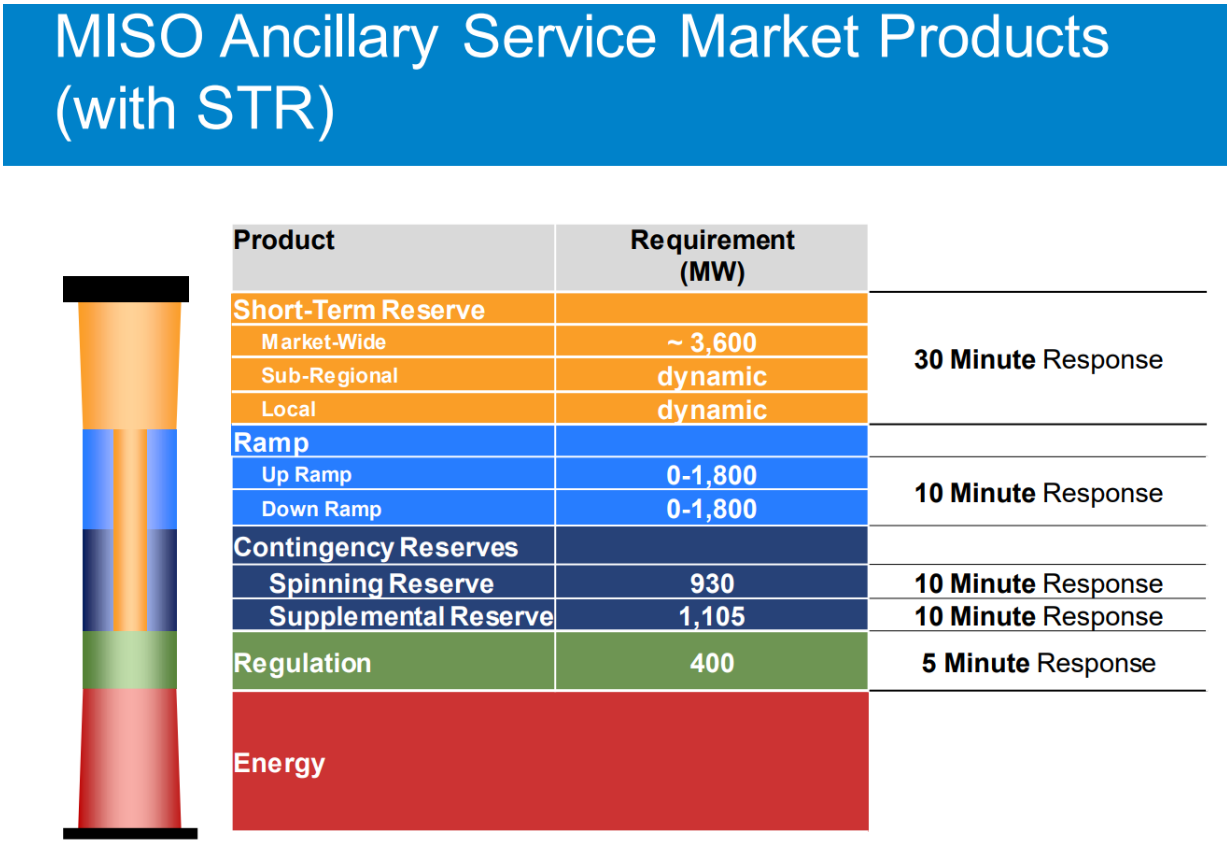

Figure 3.3: A summary of MISO reserve requirements[34]

[34] MISO, Getting Started with Short-Term Reserve Offers to Settlements Workshop, November 2, 2021, https://cdn.misoenergy.org/20211102%20STR%20Workshop%20Presentation%20(IR010)600624.pdf

4 Test Results

We added the inertial constraint into ACEP and now we test the program to see if it produces the expected results. We start with a small 9-bus test system and first assume that wind and solar contribute no inertia to the system and that combined cycle natural gas (CCNG) is the only synchronous generator alternative. Here, we expect the program to invest in more and more CCNG as we increase the minimum system inertia required. After this initial test, we go one step further and assume that wind and solar make some contribution to system inertia, which is probably the case with newer IBRs. This should cause reliance on CCNG for frequency stability to decrease.

4.1 Test system

We are using the IEEE 9-bus test system, patterned after the Western System Coordinated Council 9-bus test case[35]. It is a highly reduced model of the western interconnection in the United States. This small and simple system is well suited for demonstrating the effect of the new inertial constraint.

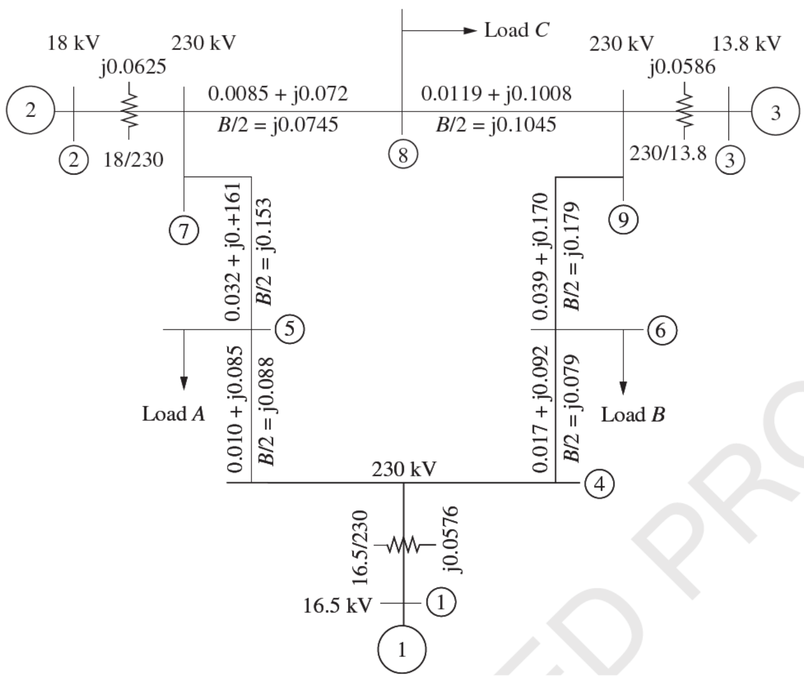

Figure 4.1: 9-bus test system[35]

4.2 Futures and potential generation investments

The original system has three generator buses in its original form; we modify this by allowing certain types of generation at all buses. In the initial configuration, the only generation is combined cycle natural gas (CCNG). Generation investment options include additional CCNG, wind, and solar. The planning horizon is 2031 to 2041, with 2031, 2036, and 2041 designated as investment

[35] S. Peyghami, P. Davari, M. Fotuhi-Firuzabad and F. Blaabjerg, "Standard Test Systems for Modern Power System Analysis: An Overview," in *IEEE Industrial Electronics Magazine*, vol. 13, no. 4, pp. 86-105, Dec. 2019.

years. This example considers a single uncertainty, which is the uncertainty of load growth. By allowing load growth to be low, medium, or high, we obtain a total of three futures[36]. ACEP will determine the core investment, which is the plan that minimizes the total core cost plus the probability-weighted adaptation and operating cost of each future.

The economic input data for this problem includes the investment and operational costs of the three technologies; they are shown in Table 4-1, where OCC is the overnight capital cost, FOM is the fixed operation and maintenance cost, and VOM is the variable operation and maintenance cost.

Table 4-1: Costs of generation technologies used in test

Technology	OCC ($/kW)	FOM ($/MWhr)	VOM ($/MWhr)	Fuel ($/MMBtu)
Wind	1,208	39.55	0	0
CCNG	866	28	2	2
Solar	1,004	18.07	0	0

4.3 Initial results

Figure 4.2 and Table 4.2 show the initial ACEP results, where renewables are not given any credit for inertia. The vertical axis of the figure shows the total investment activity for each technology. This is the total capacity installed over all futures and investment years. These initial results show that as the minimum system inertia is increased, CCNG investment increases to satisfy the inertial requirement. At the same time, solar investment decreases but wind investment is unchanged. This is because wind has a higher capacity factor than solar, making it overall more cost effective for providing the needed energy. This energy is not provided by CCNG because of its higher fuel and variable operating cost.

[36] Low, medium, and high load growth rates correspond to 2%,3%, and 4% CAGR respectively.

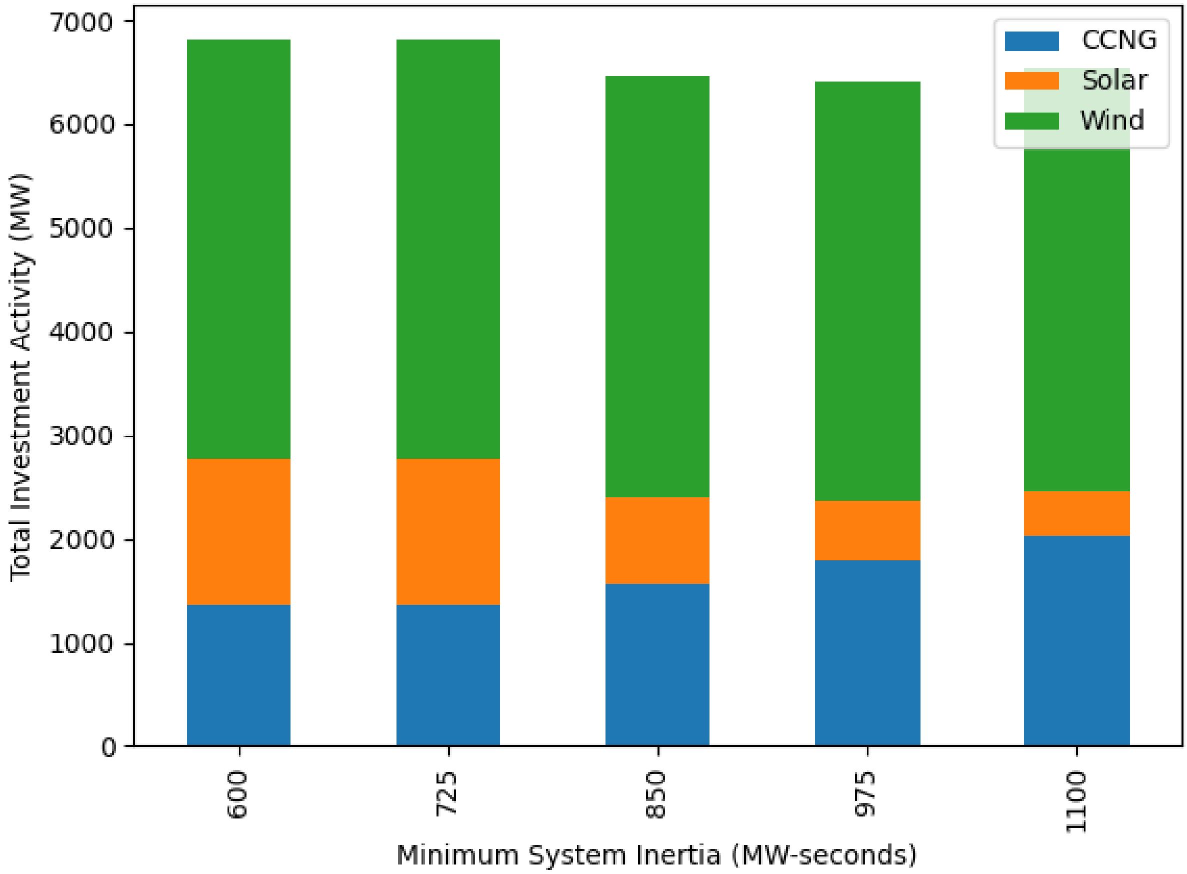

Figure 4.2: Initial results of ACEP with inertial constraint

Table 4-2: Total investment activity for various levels of inertial constraint

inertia (MWs)	CCNG (MW)	Solar (MW)	Wind (MW)
600	1362.6	1402.3	4044.4
725	1362.6	1402.3	4044.4
850	1564.4	832.2	4074.7
975	1794.5	570.1	4047.9
1100	2024.5	433.2	4077.8

4.4 Second test with inertial contribution from renewables.

In the second test, we repeat the same experiment, but assume that wind and solar generation can provide some inertial effect through fast response (FFR) of the inverters. Specifically, we assume that wind and solar generation have an inertial constant that is 1/20th the inertial constant of CCNG. The total investment activity for this test is shown in Figure 4.3 and Table 4-3.

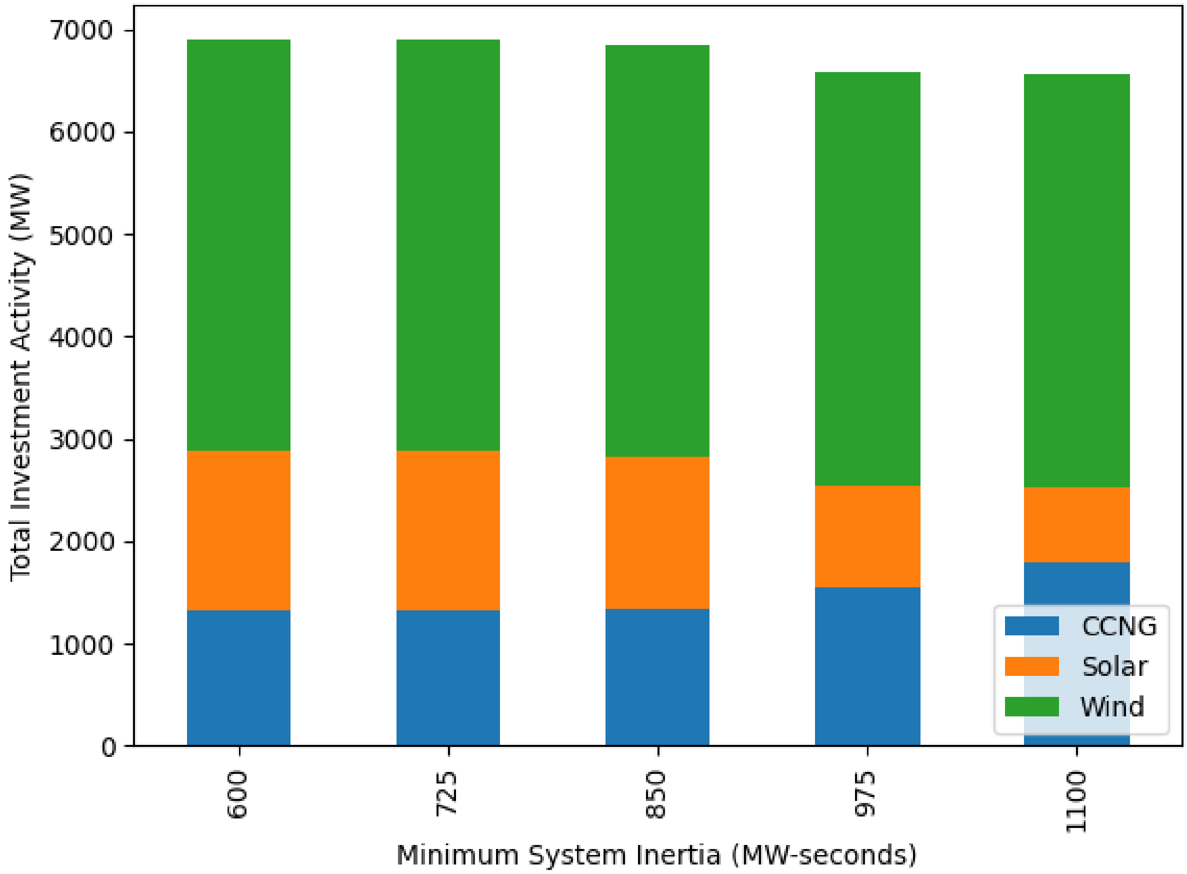

Figure 4.3: Results of ACEP with inertial constraint, and inertial contribution from renewable generation

Table 4-3: Total investment activity for various levels of inertial constraint with inertial contribution from renewable generation

inertia (MWs)	CCNG (MW)	Solar (MW)	Wind (MW)
600	1328.1	1563.0	4002.6
725	1328.1	1563.0	4002.6
850	1346.8	1480.1	4022.6
975	1549.2	985.8	4044.2
1100	1785.2	748.7	4037.4

Even with the relatively small inertial contribution from renewable generation, CCNG investments decrease and solar investment increases. The difference in investment is illustrated in Figure 4.4, where the investment activity before and after assuming inertial credit for renewable generation is shown on a single graph.

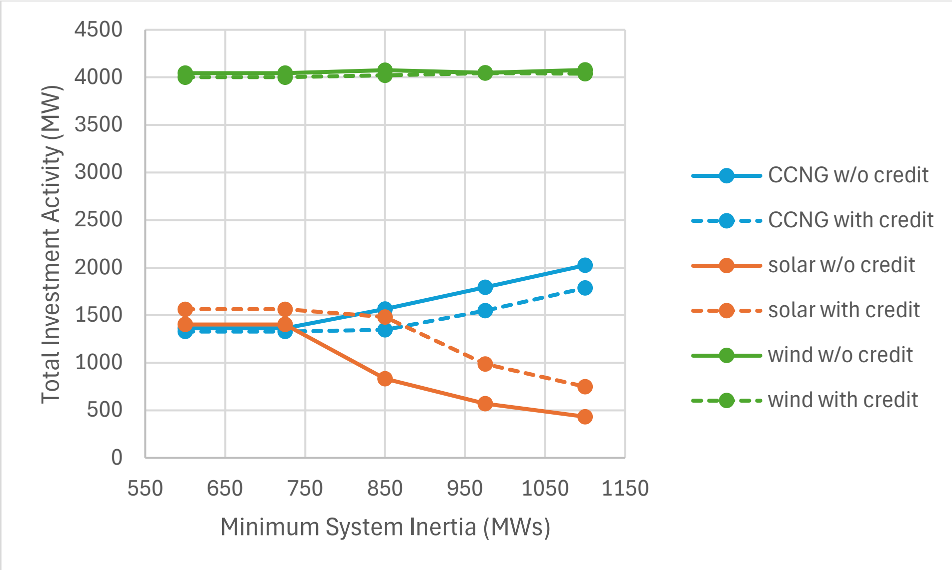

Figure 4.4: Comparison of total investment activity with and without inertial credit for renewable generation

Overall, these results show the effect we would expect from inserting a constraint in ACEP that requires a minimum system inertia. First, we see that when the minimum required inertia is increased, more CCNG generation is installed to provide the required inertia. This is due to the fact that CCNG generators are synchronous machines with significant inertia. Secondly, we see that when we assume that renewable generation is able to provide some inertial effect through fast response of the inverter and controls, the level of CCNG investment drops and the level of renewable generation investment increases.

4.5 Results in terms of energy production

The results of the previous two sections can also be viewed in terms of energy production from each generation technology. As the minimum system inertia is increased, we would expect more energy to be produced by CCNG and less to be produced by renewables. As shown in Figure 4.5 and Figure 4.6, this is exactly the result produced by ACEP with the inertial constraint. As the minimum system inertia is increased, energy generated by CCNG increases and energy generated by solar generation decreases significantly. On the other hand, the energy generated by wind is relatively unchanged and even increases slightly as more inertia is required, owing to its low cost and higher capacity factor (than solar).

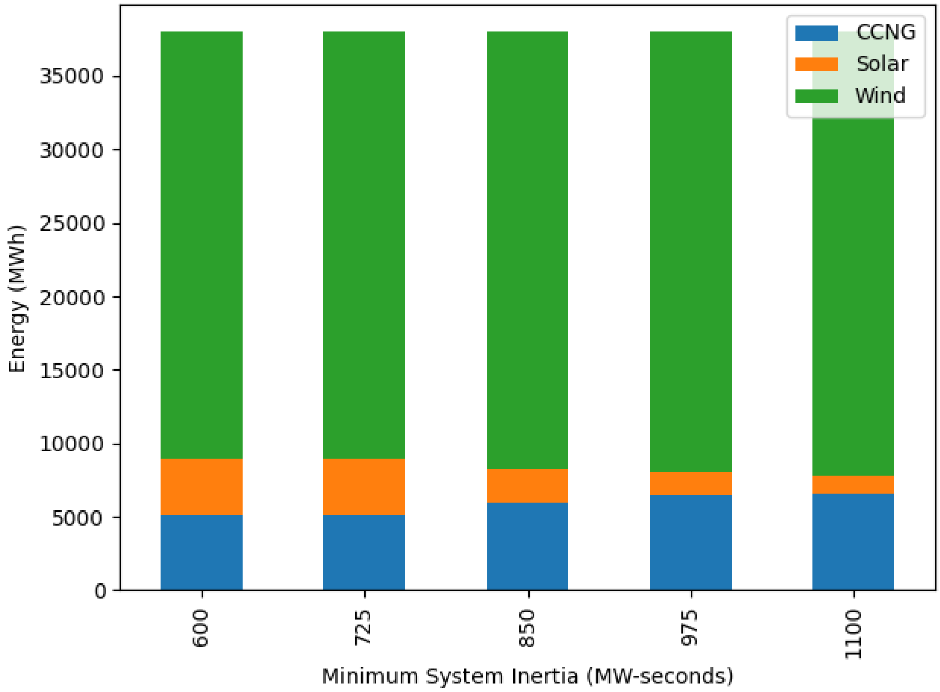

Figure 4.5: Energy produced by each generation technology as the minimum system inertia is increased (assuming that renewable generation has no effective inertia)

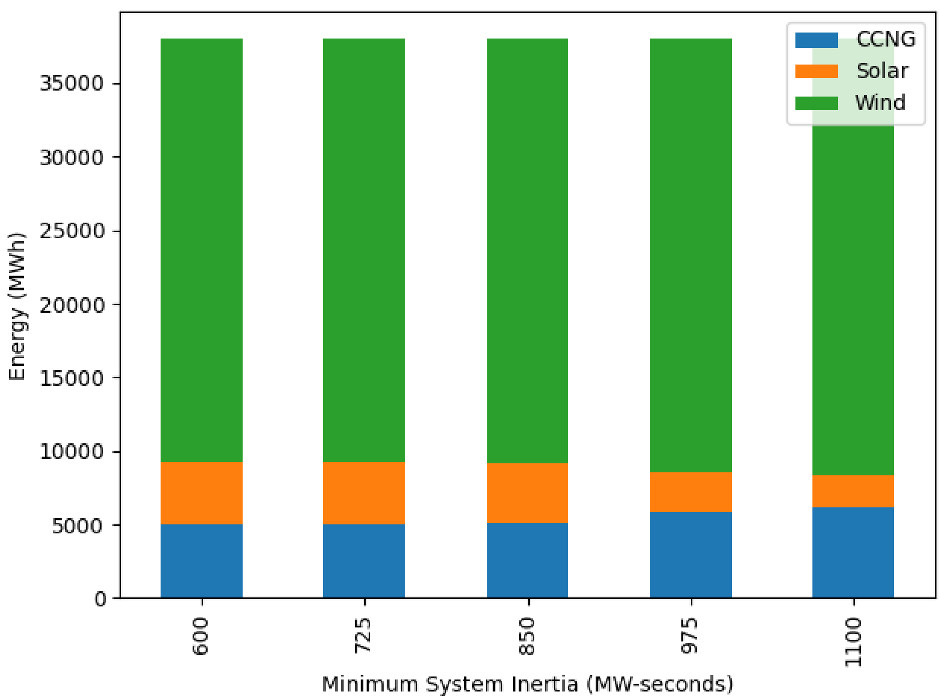

Figure 4.6: Energy produced by each generation technology as the minimum system inertia is increased and is assumed to have some effective inertia

Figure 4.7 shows the ACEP results in terms of energy before and after renewable generation is assumed to provide some effective inertial response. When renewable generation provides effective inertia, energy generation by CCNG decreases and energy production by renewables increases. In particular solar production increases significantly and wind production decreases slightly, but the overall effect is that more energy is produced by renewables.

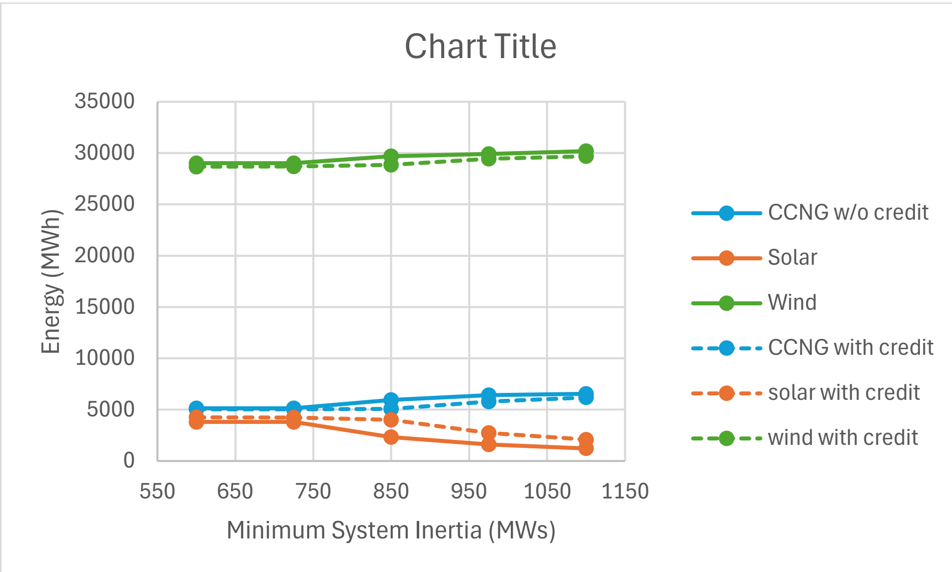

Figure 4.7: Energy production of each generator technology with and without giving renewable generation credit for inertial response

5 Conclusions and future work

More and more renewable generation is being planned and built. Utility-scale wind and solar generation is low cost and fits well with the current emphasis on decarbonization. But most renewable generation is inverter-based, which means that the amount of synchronous generation remaining on the system is decreasing, especially with the retirement of older fossil units. Synchronous generators have inertia and can provide PFR, both of which are critical to stabilizing system frequency. However, IBRs are also able to respond to system disturbances and help stabilize system frequency. We presented various technologies and their potential for inertial and PFR contributions.

Inertia provides short term energy following a system disturbance, thereby limiting the rate at which system frequency changes. Consequently, there is a strong relationship between system inertia and ROCOF after a system disturbance. Thus, some minimum system inertia (or effective inertia) is required to assure adequate frequency stability. In response to this need, we added a constraint in ACEP to require enough inertia in the system to assure adequate stability. We tested the newly added ACEP constraint in two ways. The first test was very simple, where we assumed that renewable generators make no contribution to system inertia. In this case we saw that the modified ACEP invested in more synchronous generation as the minimum inertia requirement was increased. In the second test we gave some inertial credit to renewable generators, assuming that the inverters and controls were able to simulate inertia. As expected, the simulated inertia allowed investments in wind and solar to increase, while still maintaining minimum system inertia.

We also developed constraints for PFR and other reserves, which consider the response rate and headroom of each generator. These equations can be applied to both synchronous machines and IBRs, including batteries. The required PFR can be calculated for any balancing area in an interconnection, which will allow us to address the resources in specific planning areas such as Iowa or MISO.

As a next step in this research, we will test the reserve and PFR constraints on the same test system shown in this report. Then, we will apply the modified ACEP to the Iowa system. In terms of input data, we will develop estimates of the effective inertia and PFR of the IBRs by referring to published papers and IBR test reports. If time permits, we will also perform time simulations to confirm these parameters.