

**A POWER-HARDWARE-IN-THE-LOOP TESTBED FOR DYNAMIC ANALYSIS AND
CONTROL OF PV-CSP PLANTS**

by

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CONVENTIONS

ABBREVIATIONS

AC alternatic current

BESS battery energy storage system

CAISO California Independent System Operator

CSP concentrating solar power

DC direct current

DNI direct normal irradiance

EES Engineering Equation Solver

HIL hardware-in-the-loop

IEEE Institute of Electrical and Electronics Engineers

ISO independent system operator

LCOE levelized cost of electricity

L-L line-to-line

L CSP plant's steam drum liquid level

MPPT maximum power point tracking

NERC North America Electric Reliability Corporation

PC personal computer

PHIL power-hardware-in-the-loop

PI proportional integral

PPPE photovoltaic power profile emulator, also referred to as 'solar emulator'

pu per unit

PV photovoltaic

PVI photovoltaic inverter

RGS regenerative grid simulator

RMS root mean square

RTO regional transmission operator

RTS real-time simulator

SCADA supervisory control and data acquisition

SGS steam generation system

TES thermal energy storage

UW University of Wisconsin-Madison

WEI Wisconsin Energy Institute

WEMPEC Wisconsin Electric Machines and Power Electronics Consortium

SUBSCRIPTS

B base – referring to total simulated grid generation capacity

chroma alternate term for RGS

e electrical

elec electrical power either being requested, drawn, or produced

evap evaporator

load the electrical power requested by a simulated grid or by the lab's resistive loadbank

max maximum value

mech the mechanical power driving a synchronous generator

min minimum value

MPP maximum power point

OC open circuit

req required

SHTR superheater

th thermal

turbine mechanical power from a turbine

ABSTRACT

As countries pursue decarbonization of their power generation sectors, solar generation offers an abundant resource of renewable energy. Unfortunately, solar energy's inherent intermittency poses a reliability issue. Hybrid solar parks consisting of photovoltaic (PV) fields and concentrating solar power (CSP) address this issue. CSP systems combined with long duration thermal energy storage can produce power during dark or cloudy hours. The addition of PV lowers the total cost of the system, as supplementary photovoltaic production during daylight hours decreases required CSP plant size. Literature indicates that properly managed hybrid PV-CSP plants outperform single technology PV or CSP plants and can have capacity factors higher than 80%. Optimal management of these hybrid plants is complex, however, requiring advanced control strategies. Operation during cloudy events is particularly challenging. A power-hardware-in-the-loop (PHiL) testbed is built for observing system dynamics and developing coordinated control strategies. A dynamic CSP plant rated for 40 MW_e is modeled and configured to interact with supplementary physical PV hardware via real power exchange. Using real-time testing techniques, various turbine inlet valve and steam generation system heating controls are tested and improved. Load following performance and key CSP plant variables are presented from live tests that experienced cloud cover effects. Results from a loss of generation test demonstrate the potential primary and secondary frequency responses of a hybrid plant. PHiL test results show that the control improvements successfully mitigate cloud-induced load following error during hybrid operation.

1 INTRODUCTION

The concerns of climate change are beginning to strongly affect national energy policies. Many governments have established aggressive decarbonization policies that include increased reliance on renewable power generation. For example, the United States seeks to decarbonize the electricity sector by 2035 [16]. As countries increase their dependence on renewable energy, renewable plants capable of steady, uninterrupted power generation become crucial for maintaining a healthy grid. Electricity generation in the United States was around 3.8 PWh in 2021 [17], yet the available solar resource far surpasses yearly U.S. electricity needs. As reference, M. El-Wakil estimates that the United States receives 22 EWh/year of terrestrial radiation [18]. The massive potential of solar energy has prompted significant research and commercialization efforts for the collection and storage of solar energy.

1.1 Solar Technologies and Hybridization Benefits

Utility-scale solar energy generation in the U.S. is made up of two primary technologies: thermal and photovoltaic [19]. Each method has its own advantages and drawbacks. Thermally-driven power generation is accomplished by concentrated solar power (CSP) technology which uses large fields of mirrors to concentrate direct irradiance onto a small area and thereby create a high local heat flux. A power block with access to this heat source can then generate AC power for the grid. There are several different solar field configurations, including parabolic trough, central receiver, linear fresnel, and parabolic dish [20]. Parabolic trough and central receiver are currently the most common solar field technologies used in industry [20]. Of these two, central receiver solar fields can accomplish higher solar concentration ratios and therefore can generate a higher temperature heat source at comparable thermal collection efficiencies. Since higher temperature heat sources lead to better power block cycle efficiency, central receiver plants

are the primary type of CSP considered in this paper. In contrast, photovoltaic plants are completely devoid of any thermodynamic power cycles. PV panels are arranged in series and in parallel to generate DC power that is then converted to AC power via an inverter.

PV and CSP generation can be compared via two metrics: *levelized cost of electricity* (LCOE) and *capacity factor*. LCOE is the total cost of the project divided by its lifetime energy production ($\$/\text{kWh}_e$). PV and CSP (without storage) generation costs were similar until approximately 2011, when recorded PV prices dropped below CSP prices for the first time [21]. Since then, the decrease in LCOE for PV technology has outpaced that of CSP. In fact, utility photovoltaic (PV) sites cost less than 20% of their 2010 price [22] and are now one of the cheapest power sources. The capacity factor metric is a ratio of net generation with available capacity. For example, in a 24 hour period, a 100 MW plant has an available production capacity of 2400 MWh. If its net generation is only 600 MWh of energy over that same time period, the plant's capacity factor would be 25%. Since both PV and CSP plants without storage are completely dependent on sunlight, both types of generation in the United States have historically operated at similar annual capacity factors of approximately 21-25% [23]. This low capacity factor implies that the United States' potential solar fraction — the total amount of generation that could be fueled by the sun — is severely limited if no storage is used. Storageless solar generation's inability to maintain output during dark periods means that solar generation can presently only supplement energy demand during daylight hours. Additionally, the intermittency of storageless renewables can pose challenges to grid operators. Figure 1.1 shows MISO's recorded demand curve for February 14, 2021 and predicts that same demand curve for several future solar production levels[4].

The 2021 net load curve in Fig. 1.1 represents electrical demand after hourly renewable energy production has been considered. All dispatchable resources must meet two demand peaks, one small morning demand peak and a larger afternoon spike. As demand changes, online plants must, at minimum, ramp their production at a rate equal to the

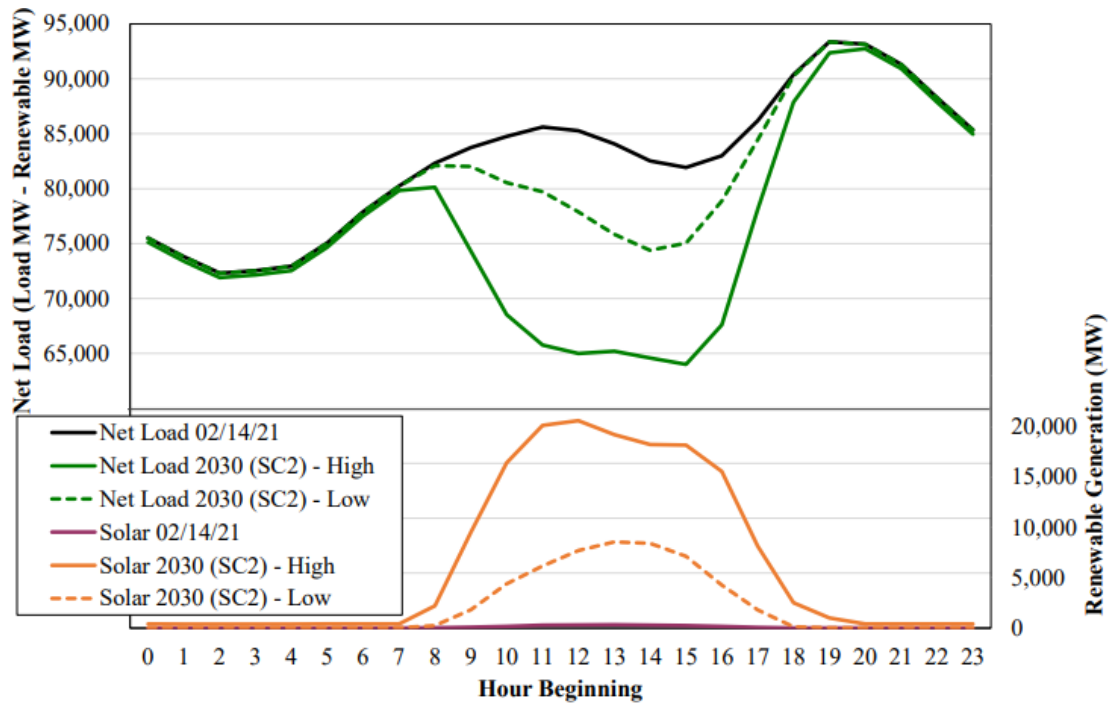


Figure 1.1: Present and projected electrical demand curve for a typical Midcontinent Independent System Operator (MISO) day [4].

slope of the demand curve. The solar curves in Fig. 1.1 represent two different projected levels of future solar production. It can be observed that as solar production increases, the demand curve adopts the famous shape of a duck curve. Although midday solar production does reduce the burning of fossil fuels during that period, the fossil plants must ramp up even faster than historically required because solar production decreases at the same time as typical evening grid demand begins to rise. This increased ramp rate can prove to be challenging on generation equipment, causing thermal stress or shock in cycle components and mechanical stress on the turbine. One solution for mitigating solar-energy-induced grid stress is to integrate energy storage units into the grid. Dispatchable energy storage can be used to compensate for solar production variability during intensely cloudy periods, or it can be used to more gradually ramp down production during evening hours.

Two common options exist for storage integrated into solar energy projects. PV plants typically store electrical energy in utility-scale lithium-ion battery banks while CSP is

naturally compatible with thermal energy storage. Most modern central receiver plants use molten salt nitrates ($\text{KNO}_3\text{-NaNO}_3$) because the mixture stays in its liquid phase within the temperature range $270\text{-}565\text{ }^\circ\text{C}$. Although, without storage, PV power has a lower LCOE, CSP's capability to be integrated with inexpensive thermal storage means that CSP becomes economically competitive with PV if storage costs are considered. This is primarily because battery storage is considerably more expensive compared to thermal energy storage. In the next 30 years total battery costs are projected to be, at best, $100\text{ } \$/\text{kWh}_e$ and $250\text{ } \$/\text{kWh}_e$ in the worst case [24]. NREL estimates that lithium-ion batteries alone cost $209\text{ } \$/\text{kWh}_e$ in 2018 [25] even neglecting the other system costs. Molten salt thermal energy storage capital costs on a $\$/\text{kWh}_e$ basis are significantly lower than that their electrical battery counterparts. Glatzmaier (2011) estimated molten salt storage cost for central receivers to be around $27\text{ } \$/\text{kWh}_{th}$ [26]. A storage cost of $30\text{ } \$/\text{kWh}_{th}$ was more recently used in Zurita's economic CSP-related analysis [27]. Thus, thermal storage has the potential to be cheaper than battery storage alternatives when coupled with cycles of sufficient thermodynamic efficiency, such as the Rankine-cycle. Molten salt storage cost would be approximately $75\text{ } \$/\text{kWh}_e$ if a thermodynamic cycle efficiency of 40% is assumed for conversion of thermal to electrical energy.

Although CSP technology could be solely used to provide dispatchable power with high capacity factor, the cheapest option may actually be a hybrid PV-CSP concept. PV-CSP plants can combine aspects of low-cost PV power production with the thermal storage opportunities of CSP. During daytime hours, CSP's solar fields can store thermal energy in molten salt tanks while PV production meets electrical demand. As evening progresses, CSP can ramp up while PV production decreases. Techno-economic PV-CSP analyses predict plant capacity factors that exceed 80% [5, 28, 29]. Figure 1.2 shows a typical PV-CSP schematic [5].

Several PV-CSP plant projects are already in operation. The Atacama I/Cerro Dominador project combines 110 MW_e CSP with an existing 100 MW_e PV plant and is pictured

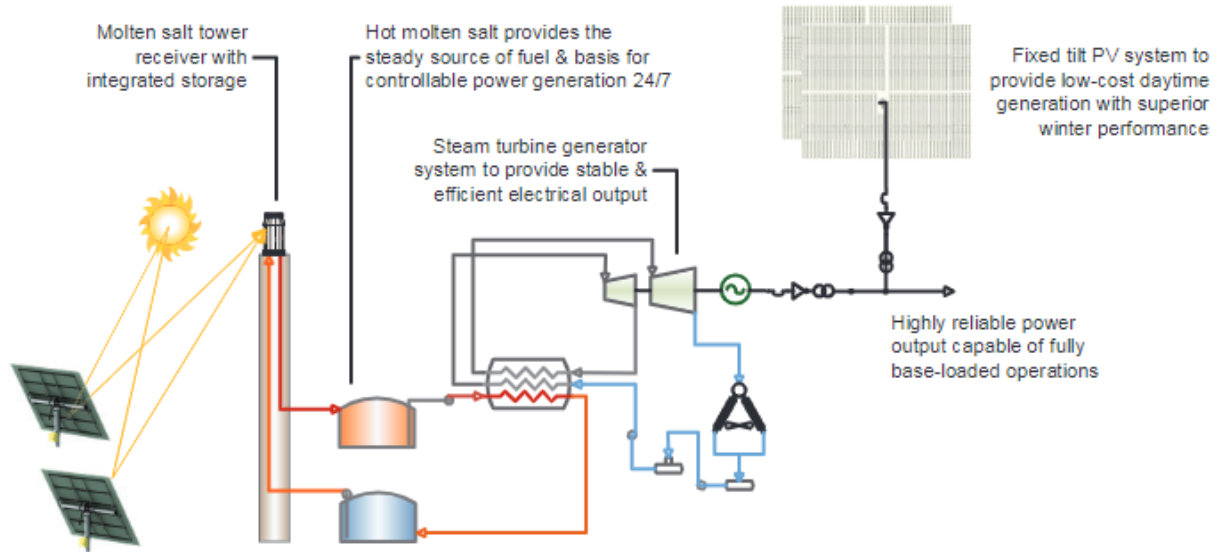


Figure 1.2: The hybrid PV-CSP concept layout according to Green et al [5].

in Fig. 1.3 [30]. The foreground of Fig. 1.3 shows the extensive heliostat field and central power tower solar receiver. The large molten salt tanks are at the base of the solar tower, and the existing PV is in the background.



Figure 1.3: Dominador, a hybrid PV-CSP solar park in Chile (photo credit: [6])

Additional projects under construction include the DunHuang 100 MW_e Fresnel and 600 MW_e PV plant in China and the Noor 700MW_e CSP/250MW_e PV project in Dubai

[30]. The NOOR hybrid solar project plans to sell energy at a tariff rate of 0.073\$/kWh_e, which is competitive with other existing fossil fuel generation alternatives [31].

1.2 Challenges of PV-CSP Plant Operation

These auspicious potential improvements in power quality, efficiency, and cost over single-technology renewable solutions are dependent on successful operation of the hybrid's PV and CSP systems. Most PV-CSP techno-economic research discussed in Chapter 2 assumes that the storage-equipped CSP plant can perfectly compensate for any PV production variability during cloud cover events. Unfortunately, this may be difficult to achieve in reality because, like any large conventional thermal plant, maximum CSP ramp rates are limited by control/actuator lag and available steam pressure. PV-CSP management must also consider component degradation effects resulting from ramping the CSP plant at its maximum rate, such as thermal shock or pressure fluctuations. CSP plant operators in a PV-CSP plant are likely to be faced with the tradeoff decision between maintaining high power quality via fast ramp rates or reducing component wear by ramping more slowly. This intricate issue prompts a plethora of questions:

- How do automatic controls for a CSP plant change when designed to coordinate with PV production?
- What are equipment degradation ramifications of CSP committing to high frequency load following schemes?
- Could there be an optimal PV curtailment level where CSP load fluctuation is minimized but PV production is still maximized to a reasonable degree?
- If CSP dynamic behavior is considered, would the steam generation system component sizing change?

- Would the operational benefits of a battery energy storage system (BESS) outweigh the additional incurred capital expenses?

This partially complete list of questions demonstrates the diverse range of engineering problems encountered when designing and operating a PV-CSP system. The overarching goal of this research is to develop holistic simulations and experiments that consider the electrical and thermal complexities of PV-CSP operation and use those results to provide control strategies at the component and system levels.

1.3 Dynamic Modeling and Potential Application of PHiL

Answering PV-CSP operation questions begins with recognizing the need for dynamic modeling. The term ‘dynamic modeling’ in this paper pertains to the formulation of all governing equations used. Any component modeled dynamically is not assumed to be at steady state — mass and energy can be stored. The term dynamic also means that every variable is considered to be time-dependent. Although dynamic effects are often trivial when considering overall thermodynamic design, the details of real-time operation and component degradation are more accurately studied with dynamic models. The efficacy of controls is evaluated by speed and accuracy of response. Long-term degradation effects of pressure fluctuations and thermal shock are partly rate dependent. Even on an overall system level, the speed of PV-CSP response to electrical frequency changes or loss of generation events will affect profits and reliability. For these reasons, system-representative work done in this research attempts to capture key transient effects with dynamic modeling.

The term “computer-only simulation” in this paper refers to simulation that occurs strictly inside one computer involving no interactions with exterior power hardware or other computers, and it is usually performed faster than real-time. It is oftentimes used as a first step in the development of an idea or product. Unfortunately, computer-only

simulation methods for PV-CSP dynamic studies have several limitations. As weather conditions depart from sunny conditions, the level of necessary electrical modeling becomes increasingly complex. Unless a highly detailed inverter model is utilized, computer-only simulation will likely idealize inverter control. In reality, since optimal operating setpoints change with varying irradiance, rapid irradiance variations pose significant challenges for inverter control. Although an ideal inverter would instantly output the maximum PV power, in practice the inverter may need time to find the correct balance of current and voltage. Additionally, any weather data needed as simulation input must have the required temporal resolution to sufficiently capture changes in photovoltaic panel characteristics and inverter control response. The time constant of photovoltaic power variation depends on the field size, panel configurations, and intensity of cloud cover. When considering the case that the PV field is not equipped with battery storage, if cloud cover changes slowly, irradiance data taken at large timesteps is sufficient for accurate simulation. However, quickly changing cloud cover directly translates to rapid PV power fluctuations. Irradiance data used in PV-CSP studies should ideally have high temporal resolution to capture rapid PV power fluctuations during variable cloud cover.

Physical experimentation offers higher fidelity dynamic research opportunities, but it is not cost-effective for PV-CSP studies due to the high capital cost of large scale electrical generation plants. Fortunately, an alternative exists between the two extremes of computer-only simulation and fully physical experimentation. Hardware in the loop simulation (HIL) is a method of interfacing simulation models, controllers and other physical hardware into one single testbed. The HiL definition can include controller-HiL (CHiL) and power-HiL (PHiL). Both types of testing are based on the concept of real-time simulation, where simulation time steps and elapsed real time are synchronized [32]. This means that the simulation computer delivers model outputs at the same elapsed time that an observer would register those outputs from a system in real life. This enables a simulation computer, sometimes called the real-time simulator (RTS), to

exchange physical inputs and outputs with real connected devices in the same way an actual piece of hardware would. As the name implies, CHiL tests place controller hardware in a communication loop with a real-time simulator that dynamically emulates the controller's targeted system. The controller receives digital or analog current and voltage measurements and produces the resultant output signal. The RTS receives the signal as a simulation input. After solving a model timestep, the RTS converts that model output into updated voltage and current waveforms for the controller. This idea is illustrated in Fig. 1.4.

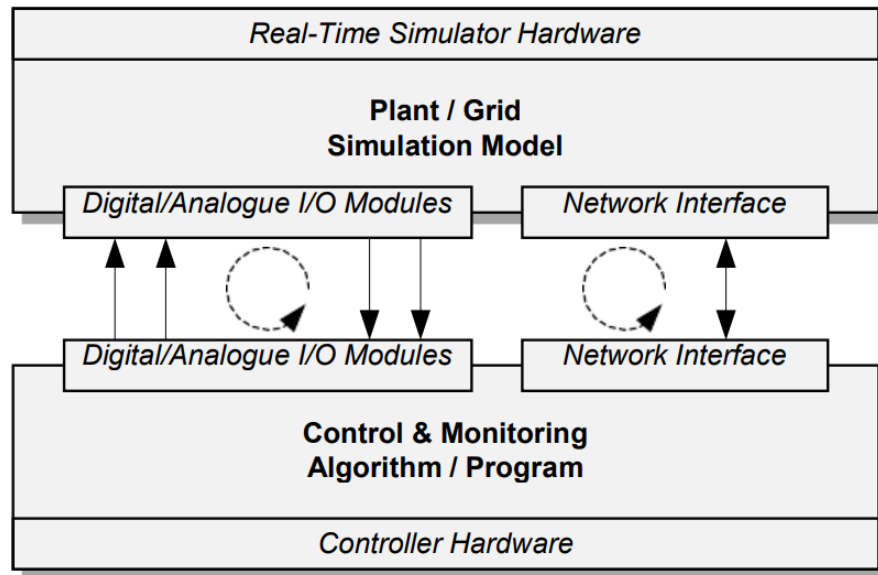


Figure 1.4: Schematic illustration of typical CHiL application from [7]

PHiL extends the same principle of CHiL to testing and validation of full-scale power hardware. One additional complication is that the RTS must now communicate to hardware through a power amplifier. PHiL is desirable, however, because power and current approach their full-scale application values, thereby improving the fidelity of the experiment [32]. In the general sense, PHiL simulations enable interaction between modeled environments and power hardware. This capability is ideal for power generation studies, allowing models to be tested alongside physical hardware in a real-time setting. Microgrids provide an excellent physical testbed for configuration of power sources, loads, and

RTS resources. The term *microgrid* refers to interconnected sources of energy resources and loads that can operate either independently from the grid or connected to a surrounding utility grid [33]. An existing microgrid at the Wisconsin Energy Institute (WEI) presents the opportunity of integrated PHiL testing. The WEI microgrid includes PV panels, an inverter specifically dedicated to PV applications, and electrical load banks. A dynamic CSP model can be developed and configured for use in an RTS and communication with a power amplifier. All physical components communicate via exchange of electrical power. The model is brought into the loop by communication with its respective power amplifier. RTS inputs consist of digital measurements of real power and electrical frequency. If grid inertia is included in the RTS model, the RTS outputs electrical frequency setpoints for its power amplifier.

1.4 Energy Market Considerations for Power Plants

It is important to discuss and define the various energy market opportunities that exist in order to understand what operation schemes might be the most profitable. This determines what scenarios the PHiL testbed should be built to evaluate. We primarily consider the U.S. opportunities. To provide power to its consumers, utilities must either own generation plants or purchase power. Utilities can enter bilateral transaction agreements, where the generation plant agrees to provide power to the utility. These are secure agreements that expect a high degree of reliability and in return the power plant has a guaranteed purchaser.

Utilities also have the opportunity to purchase power from an energy marketplace. Today's U.S. grid has several prominent energy marketplaces, called independent system operators (ISO) or regional transmission operators (RTO). Although many other traditional markets still exist, ISO/RTOs are prominent in the US grid and are a good representation of a typical U.S. energy market. It is useful to understand how a ISO/RTO

works because the function and needs observed within ISO/RTOs can be generalized to a typical regional grid. Figure 1.5 shows the primary ISO/RTO jurisdictions [1]. Like a successful commodity market that matches supply and demand, ISO/RTOs organizations can be thought of as a centralized grid operator that balances power generation with the power requested by any participating utility.

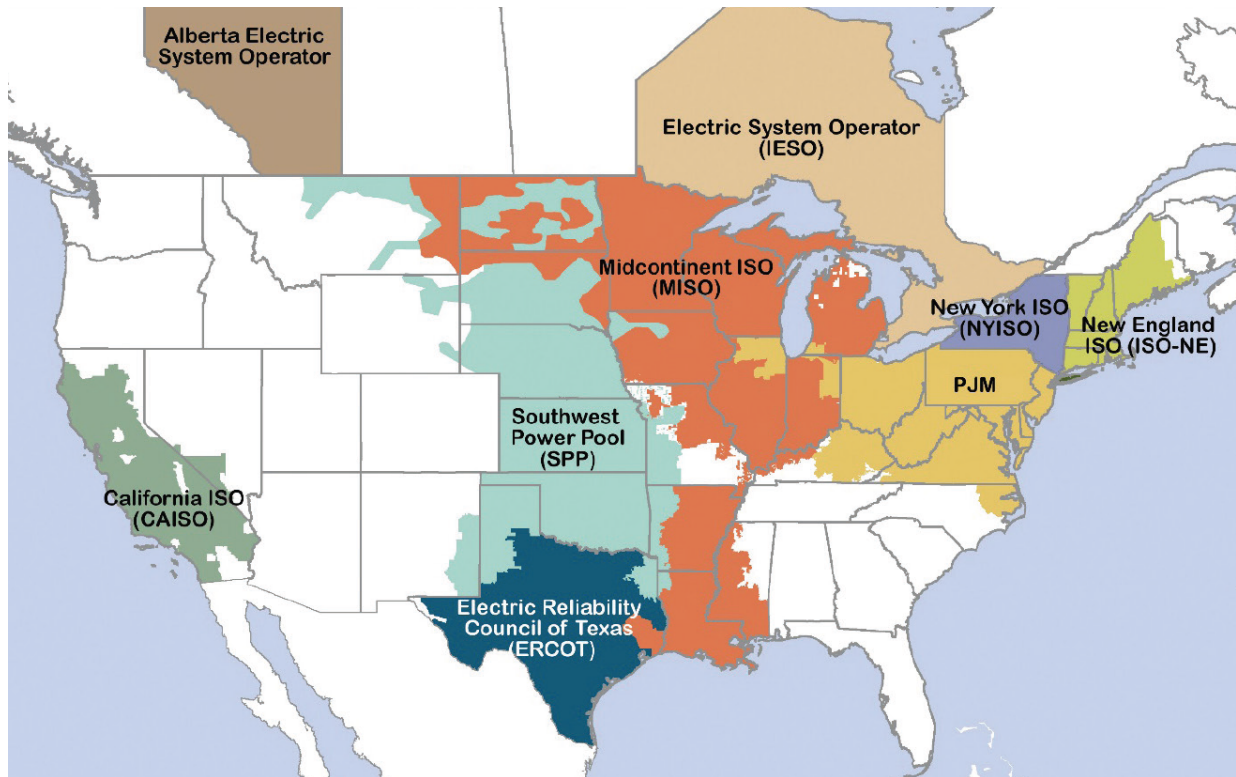


Figure 1.5: ISO/RTOs in the United States. Most other U.S. regions have energy marketplaces and oversight similar to ISO/RTOs [4].

In general, a perfect balance of power generation and load results in a stable electrical frequency. This is the goal of any grid operator: to meet load via scheduled generation and sufficient real-time purchases. CAISO is a California nonprofit public benefit corporation that manages energy and ancillary markets in day-ahead and real-time markets and maintains regional reliability [1]. They are responsible for coordinating regional grid operation and their market participants include various load-serving entities and generators. This ISO is unique; its capacity includes roughly half of the total U.S. installed solar capacity [1]. Grid operators utilize two market timescales: day-ahead and real-time.

Generation and demand entities in the day-ahead market will secure prices for the next energy day. The real-time market schedules those day-ahead commitments and will make 15 minute interval adjustments. Every five minutes the market balances generation and loads. Figure 1.6 shows CAISO-reported average prices for each market timescale in 2020.

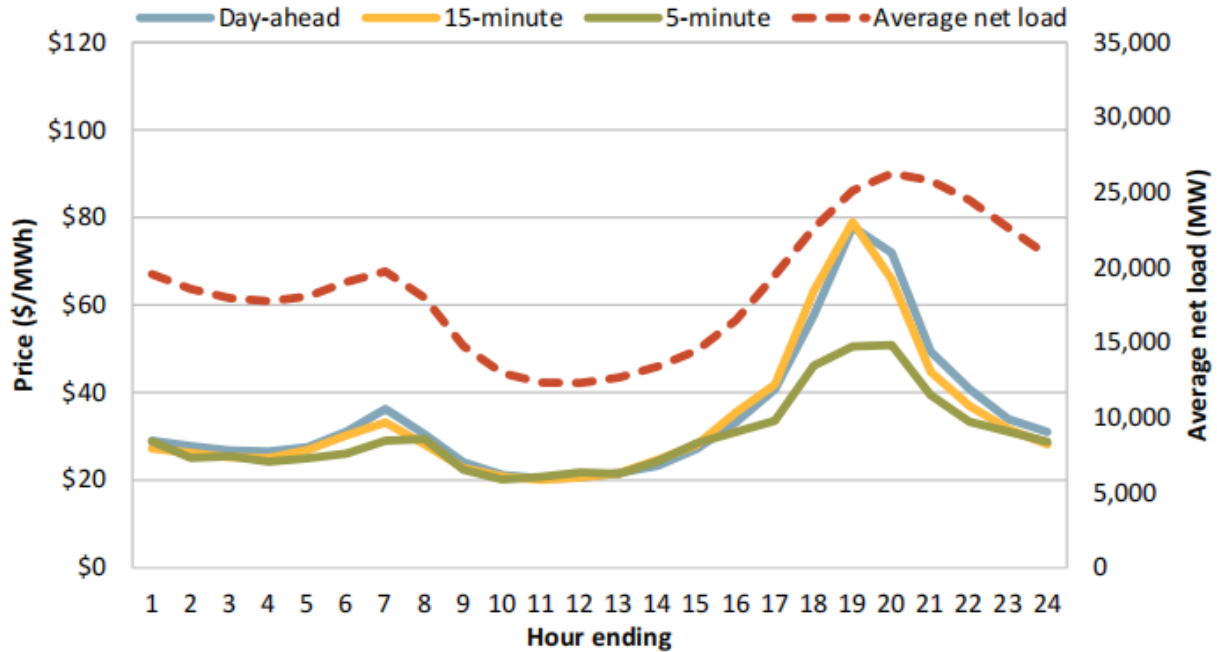


Figure 1.6: Day-ahead and real-time energy pricing for 2020 in the CAISO market [3]

Figure 1.6 infers that a plant capable of dispatchable generation has the potential to make significantly more money if it can shift production to favor the higher-price time periods. Ancillary marginal energy prices offer an additional form of income. Ancillary services are those functions performed to support reliability of the transmission system. Ancillary services can be procured in the day-ahead and real-time markets. A summary of the CAISO energy markets is shown in Table 1.1. Ancillary services can be scheduled in the day-ahead, 15-minute, and 5-minute markets just like other forms of generation.

Table 1.1: Ancillary market opportunities in CAISO and 2020 average prices [1] [2] [3]

service	description	timescale	price \$/MWh _e
regulation services	quickly increase or decrease generation. Used to maintain system frequency.	every 4s and sustained output for 30-60 min.	10-20
spinning reserves	available from resources synchronized with the grid. Used when unplanned outages occur.	response < 10 min.	9.5
non-spinning reserves	available if resource can synchronize with grid. Does not have to be synchronized at start of 10 min.	response < 10 min.	3.5
black start	must be capable of starting and paralleling with grid without any outside aid. asynchronous, and synchronous mode capability	start < 10 min. and sustained output for 12+ hrs.	
voltage support	generating units are equipped with an automatic voltage regulator that can correct bus voltages	< 1 min.	

Additionally, regulation generation must not exceed the maximum ramp rate (MW_e/min) of that resource times 10 minutes and must be capable of full range of movement without manual resource operator intervention of any kind. There is also a setpoint accuracy requirement: the capacity must meet or exceed minimum performance threshold of 25% accuracy [2].

Although ancillary services are not currently more valuable than basic generation bids, they are required to maintain stability of the grid system frequency. Aside from voltage support, the primary focus of ancillary service is to maintain grid frequency according to guidelines defined by the North America Electric Reliability Corporation (NERC). NERC defines several different levels of frequency response as seen in Fig. 1.7. The electrical frequency could decline due to loss of generation or a new load coming online. Regardless of the cause, the frequency response typically exhibits the same basic behavior.

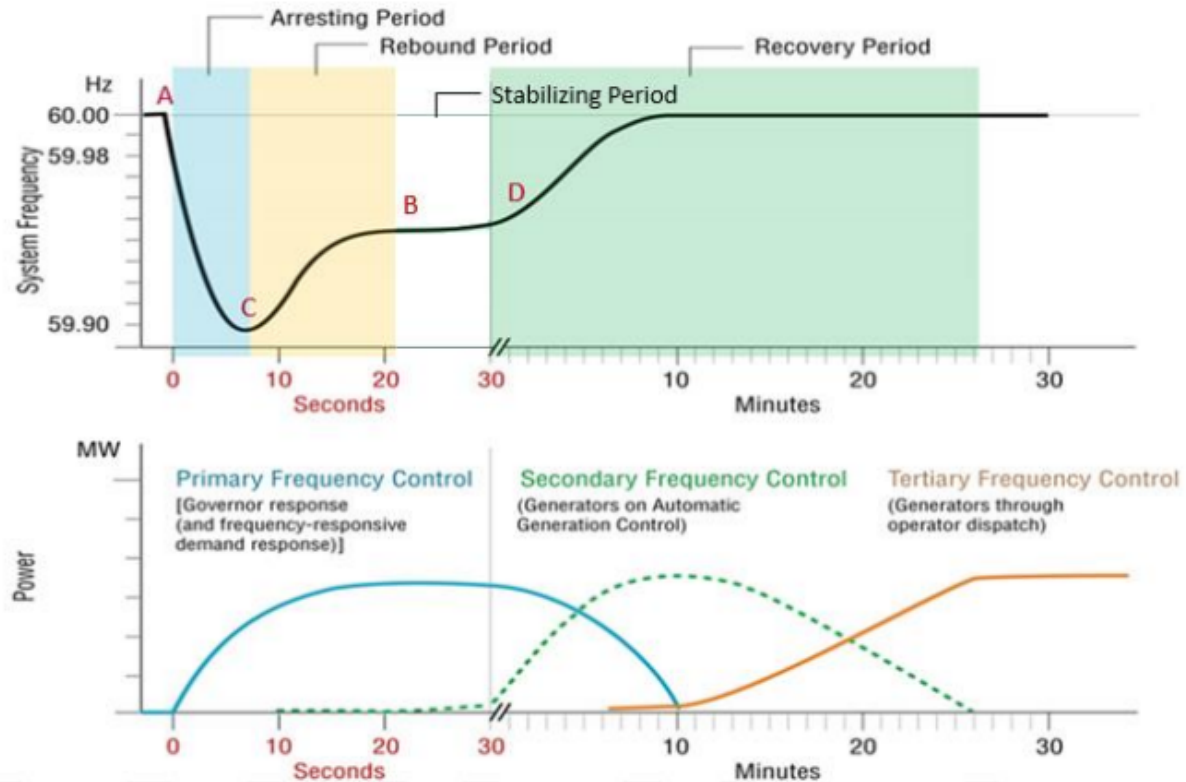


Figure 1.7: Levels of frequency response as defined by NERC [8]

The nadir observed at point 'C' in 1.7 is the lowest frequency that the grid will experience during a major event. Synchronous machines in the U.S. are built to operate at 60 Hz, and any frequency deviation is undesirable. If the arresting period is not successful and frequency continues to decline, the grid operator will begin under-frequency load shedding. Although load shedding stops the frequency decline, it is a reliability failure and should be avoided unless absolutely necessary. CAISO grid operating procedures suggest a minimum nadir of 59.5 Hz before load shedding [34]. NERC reports that interconnection minimum frequencies in the U.S. typically range between 59.3 – 59.7 Hz [35].

To summarize this market review, the bulk of energy sales depend on the baseload generation capacity of the plant. For markets with significant renewable generation variability such as CAISO, generation during peak hours is up to 4x more profitable than hours of lower demand. If a generation plant intends to participate in a regional energy

marketplace, dispatch capability is paramount to profitable operation. Although generation during peak demand far outweighs earning potential from the ancillary market, the ancillary market is significant and could further supplement generation earnings. Industry metrics include (but are not limited to): ramping rate, power setpoint accuracy, rate of change of frequency (RoCoF), and level of plant automation. These insights highlight the need for high-fidelity dynamic plant characterization. A well-designed CSP dynamic plant model could be a vital tool for engineers, investors, and grid planners. Although it should be noted that market pricing strategies can rapidly evolve to address grid operation concerns, we recommended that PV-CSP hybrid plant optimization controllers prioritize maximizing capacity factor and production during peak demand. Additionally, setpoint following capability and accuracy should be prioritized to enable participation in regulation services that have very short timescales.

1.5 Project Objectives and Research Overview

With the application of PHiL testbeds and PV-CSP market opportunities in mind, this research undertakes three objectives. The first goal is to establish the testbed. The second and third goals consider two different scenarios to gain insights and develop control strategies regarding total system dynamics, operational control, and grid frequency stability. These goals are formally stated here:

1. Develop a fully-integrated PV-CSP PHiL testbed. The principal steps in this process are development of a dynamic Rankine-cycle CSP model and configuration of microgrid hardware for real-time simulation.
2. Evaluate PV-CSP's load following ability during load changes or cloudy weather assuming a large-grid scenario in which electrical frequency is constant. Improve plant controls accordingly.

3. Evaluate the impact of PV-CSP plants on electrical frequency stability in small-grid scenarios using both actual and emulated cloudy conditions.

Chapter 2 covers modeling and simulation literature that pertains to hybrid systems. It discusses existing dynamic CSP models and legacy conventional plant models used by industry. This chapter also provides overview on two existing U.S. microgrids and an HiL application in a bench-scale microgrid. Although significant cycle modeling and technoeconomic research exists for PV-CSP, only a few research projects have focused on optimal operation of the steam generation system for PV-CSP plants.

Chapter 3 walks through the steps required to build a PHiL testbed for studying PV-CSP systems. First, the dynamic CSP plant model is described. Modeling methodology, *Simscape* implementation, and performance checks are discussed. Brief descriptions of CSP controls utilized during this research are also provided. On the physical side of the PHiL testbed, electrical hardware equipment is identified and fundamentals of operation are explained. Finally, the dynamic model and hardware components are integrated and real-time demonstration tests are performed.

Chapter 4 uses the dynamic CSP model built in Chapter 3 to demonstrate several key dynamic plant behaviors that are commonly seen throughout this research. This chapter then evaluates the load following performance of a PV-CSP plant in large grid scenarios, where it is assumed that there is sufficient inertia and grid generation reserve to compensate for any PV-CSP load-following error. Sunny and cloudy day PHiL tests are successfully performed, and they serve to highlight control improvement opportunities.

Chapter 5 investigates the impact of PV-CSP load following operation on grid frequency as well as the strength of this hybrid plant's response to electrical frequency changes. Unlike Chapter 4, system frequency is no longer assumed to be constant throughout the experiment. Instead, frequency changes are directly caused by PV-CSP load-following error. Three different grid sizes are tested. The photovoltaic inverter is powered by a solar emulator, which generates artificial cloud cycles for uniform testing of all three cases. A

final grid case is tested where the PVI is powered by rooftop PV panels. Test results from real cloud events are presented.

This research successfully creates an integrated PHiL environment for studying PV-CSP dynamics at timesteps as small as 1s. An open-loop dynamic CSP model is also developed, which provides insight on drum level dynamics during hybrid operation. This research shows that effectively controlling steam generation rates is of paramount importance when CSP plants must compensate for PV fluctuations. Maintaining boiler pressure is especially useful during cloudy events. Fast cloud shading during experiments caused rapid decreases in PV production. If boiler pressure was too low, the CSP plant could not immediately follow the rapidly shifting turbine power setpoints.

2 LITERATURE REVIEW

This chapter discusses techno-economic and dynamic modeling literature relevant to PV-CSP. Two prominent microgrids are also described to gain insight on their applications. Lastly, a HiL research project is reviewed to demonstrate the applicability of PHiL simulation for testing of PV-CSP systems.

2.1 Relevant Modeling and Simulation

Our modeling focus and approach is motivated by the following three questions:

- Firstly, what research exists regarding PV-CSP generation schemes?
- Secondly, what dynamic modeling methodologies have been used to characterize CSP behavior?
- Finally, what can be learned from other types of dynamic thermal plant models that are not PV-CSP or CSP?

Existing PV-CSP Research

When describing systems in this section, it should be assumed that CSP has built-in TES. However, PV does not have a battery energy storage system unless explicitly stated. Much of PV-CSP literature analyzes the techno-economic benefits and optimized dispatch. Most dynamic models are quasi-steady-state with timesteps from 10-60 minutes. PV-CSP papers consider two types of hybrid plant: compact and non-compact. A compact hybrid plant directly combines PV cells and mirrors together to use more of the light spectrum by absorbing much of what it does not reflect. Non-compact hybrid plants have both PV and CSP onsite but in separate solar fields. Although less spatially efficient, they are easier to develop and more common in industry. Non-compact hybrid plants are also

projected to have very high capacity factors in regions with sufficient DNI. Zurita et al. analyzed the performance of a hybrid CSP and PV plant integrated with a large-scale battery energy storage system tasked with delivering a baseload of 100 MW_e [28]. The model used hourly solar data and solved for an entire year of operation. Their parametric study concluded that LCOE was minimized when zero BESS was used and capacity factor could still exceed 80%. When high battery prices are factored in, PV-CSP-BESS systems are predicted to have higher LCOE than their PV-CSP counterparts. Green et al. used SolarReserve's proprietary SmartDispatch program to simulate hourly performance of a 100 MW_e CSP and a 60 MW_e PV plant. Without reliance on a BESS, the hybrid plant had a capacity factor of 95+ % for a baseload of 50 MW_e and 69 – 91% capacity factor for a baseload of 100 MW_e [5]. Hamilton et al. developed a novel dispatch method for PV-CSP and PV-CSP-BESS generation and tested it for two weather locations — southern Nevada and northern Chile [36] with 10 minute resolution. When comparing PV-CSP and PV-CSP-BESS, both location simulations predicted only marginal capacity factor improvements from addition of BESS. These findings are helpful to determine what to include in this paper's testbed. Current techno-economic literature suggests that the PV-CSP concept is viable with or without BESS. TES must be considered, however, because it is the most significant contributor to PV-CSP's impressive capacity factor predictions.

Most hybrid PV-CSP models share the same operating assumptions. If PV power is available, it will be used instead of CSP. This allows CSP to utilize its thermal storage during periods of low PV production, thereby significantly improving the system's capacity factor. CSP power output is typically treated like a backup to PV production, i.e. $P_{CSP} = P_{load} - P_{PV}$ [29] [27]. There are limits to this, however. If PV production exceeds the electrical interconnection limit it must be curtailed. Additionally, since CSP power blocks have large Rankine-cycle components, it is desirable to shutoff the plant as few times as possible. Thus, some optimized dispatch schemes will run the CSP at minimum power simply to prevent a shutdown. These conditions begin to offer insight into the

detailed complexities of daily plant operation.

Dynamic models designed to provide daily operational insights must consider the validity of their selected timestep. The performance of both CSP and PV elements are highly dependent on the irradiance levels. Many models assume a low frequency of irradiance variation — with weather resolution of 10 min to 1 hour. Although this is generally true for a fully sunny day, cloudy days can produce irradiance profiles whose amplitude varies each second. Simulations that rely on average irradiance profiles are useful for evaluating economic performance and optimal use of total available energy, but they do not provide insight on power plant management during rapidly fluctuating periods of irradiance. Capturing these complexities are crucial for development of dispatch algorithms and can also impact plant component sizing.

Zurita et al. assessed the impact of time resolution on a PV-CSP Transys model by testing the same model with 1, 5, 10, 15, 30, and 60 minute timesteps. This study found that the same controller strategy performed differently depending on the size of timestep. The conclusion was that the CSP's receiver and power block performance were most affected by the time resolution variation [27]. This suggests that a supporting CSP plant is not likely to be operated the same way for a steady PV production profile versus PV production that fluctuates around an average value. The expected operating point of a CSP plant's thermal power block is important for determining efficiency and sizing of components. This literature indicates the overarching PV-CSP management strategy is to operate PV whenever possible and depend on CSP for backup power. Also, the large timestep of most existing models highlights the need for simulations with high temporal resolution (i.e., short timesteps). These two observations are applied to the testbed and dynamic model presented in this thesis.

There have been significant efforts to optimize overall plant energy production for maximum capacity factors. However, these models assume ideal load-following operation. For example, in their PV-CSP integrated model, Giaconia et al. assume that the CSP

can provide on-demand generation during sudden drops in PV output unless thermal storage is empty [37]. However, as its author points out, in practice, the CSP plant's demand response is limited by its ramp rate. Thus, if PV fluctuations and ramp rate factors are considered, there may be short periods of time when total hybrid plant output does not match the baseload demand. This not only reduces profits, but may cause electrical frequency to decline in grids with low levels of inertia. In contrast, a hybrid plant could better participate in ancillary services and real-time markets for extra profit if their dynamic responses were fully understood. Wang et al. considered control of a PV-CSP system to provide frequency response services by incorporating electrical elements into their model [38]. Since the PV inverter and CSP generator can independently respond to grid frequency changes, a hierarchical control strategy was developed that optimized frequency response while preventing depletion of TES or curtailment of PV resources.

Literature indicates that properly managed hybrid PV-CSP plants outperform single technology PV or CSP plants and can have capacity factors higher than 80%. Although the addition of BESS is shown to slightly increase plants' capacity factor, techno-economic studies indicate the combined plant LCOE is sometimes decreased. Simulation timestep resolution has been shown to have important impacts on CSP plant operation decisions. This review emphasizes the need for PV-CSP studies which implement a holistic scenario that captures the thermal and electrical complexities of real-time hybrid operation. Operational insights from real-time PHiL simulation of PV-CSP plants could be used to advise plant operators or better inform dispatch optimization algorithms on the operational benefits of adding BESS to a hybrid system.

Dynamic Modeling of CSP Generation

A non-compact PV-CSP plant is simply the combination of two conventional systems. Therefore, it is worthwhile to also consider progress made in the dynamic modeling of CSP thermal systems. The primary objectives are to identify what approaches exist for

estimating plant ramp rates, what software tools are typically used, what transient effects are of interest, and the control elements used.

Zhang et al. described a molten salt power tower steam generation system using self-derived governing equations of mass, momentum, and energy with lumped parameter method assumptions [39]. This allowed the Zhang et al. to monitor heat load distribution between components and acquire time constants for each heat exchanger. Large temperature and pressure fluctuations were observed in the superheater. In general, the lumped parameter model provided adequate details and good operational insight on dynamic behavior of the steam generation system.

Wagner et al. used commercial software simulation tool *EBSILON* to build a transient model of a parabolic trough solar field, thermal energy storage, and power block [40]. Dynamic modeling sought to capture thermal energy losses incurred during start-up and shutdown. To accomplish this, the corresponding thermal masses were incorporated into most component's energy balances. Transient processes had high resolution — timesteps of 10 seconds. The main transient focus was the solar field and storage system. Mass flow through the power block was limited by a maximum ramp rate value to reduce thermal strain.

Al-Maliki et al. built a fully dynamic parabolic trough model based on the Andasol II plant using *Advanced Process Simulation Software* [41] [42]. The parabolic trough heat transfer fluid was at a much lower temperature compared to typical power tower molten salt, however. The difference in heat transfer fluid temperature might result in different thermal strain scenarios. Power block controls included: attemperator, steam bypass valve aperture, preheater levels, drum levels, and economiser water bypass. Drum level was maintained by adjusting a feedwater control valve. Turbine inlet pressure is not only regulated by boiler pressure, but also by a high pressure bypass valve that ensures turbine inlet pressure will not exceed a maximum.

In recent work, Yao et al. built a fully dynamic linear fresnel CSP with integrated

thermal energy storage using *Simulink*'s add-on toolbox *Simscape* [43]. Their focus is on modeling turbine and steam generation system with greater detail than past dynamic research. The model cycle is closed-loop and contains a realistic number of turbine stages and feedwater heating stages. This model is intended to be the thermodynamic digital twin of a Fresnel plant located in northwest China. The electrical generator's inertia is also included using the swing equation. Some user-defined blocks are built in the *Simscape* model, including equations for the steam drum and evaporator loop. Similar to Wagner et al. the maximum requested power is limited by a ramp rate determined from thermal stress evaluations. The plant also includes a detailed control scheme including steam drum control, turbine valve and bypass control. Although the model built by Yao et al. and this paper's model were both built in *Simscape*, they are not built for the same purpose. The open-loop dynamic model discussed in Section 3.2 has fewer controls and was built for robust performance during PHiL simulation. The controls that are used for Section 3.2's model have been designed with PV fluctuation-induced load variation in mind. This is in contrast to the Yao et al. model, whose maximum load demand signal change during simulation is 5%/min.

Few models have been created for dynamic simulation of CSP power blocks. Those that exist have typically been digital twins of existing plants that offered crucial insight on what controls might exist in practice. Almost all models use lumped parameter modeling for each component. Common simulation software platforms include TRNSYS, Modelica/Dymola, Simulink/Simscape or various other commercial tools. Control of turbine inlet state and drum liquid level control are two commonly-studied subjects. Each model differs, however, on its power setpoint operation control. Some use a constant boiler pressure approach, many use sliding pressure control, and a few rely on pure sliding control. Nearly every model assumes turbines are at quasi steady state and use Stodola's ellipse to model turbine efficiency and mass flow for off-design conditions. The simulated electrical demand reported is typically constant because most CSP management

research has concentrated on improving the plant capacity factor, which implies running at full power for as long as possible. Only a few dynamic models have explored dynamic operation in a hybrid PV-CSP setting, where a CSP plant will likely need to be quickly adjusting to new part-load operation setpoints. A review of existing CSP dynamic models suggests that thermal inertia modeling or existing plant data is necessary to estimate start-up or heating ramp rates. Consequently, our CSP model dedicates some attention to maintaining steam drum liquid levels and properly controlling the turbine inlet control valve for optimal power output.

IEEE Dynamic Modeling Recommendations

The IEEE technical report on turbine-governors in power system studies contained valuable industry insights on plant response [44] and provides an overview of commercial plant models used by interconnection operators to predict a unit's response. Key dynamic plant behaviors are considered from the electrical standpoint that any variation in individual plant power to the grid may impact grid power stability and quality. Models discussed in [44] are not first-principle based, instead they have time constants to account for steam travel time, speed control settings, and valve travel time. The older legacy models (TGOV1 or IEEEG1) assume constant steam pressure and temperature with essentially an unlimited source of steam from the boiler. More modern commercial plant models (like TGOV5) attempt to include the effects and control of boiler pressure drops with approximate time constants. Turbine inlet valve behavior is a primary focus, as these have a large impact on plant output. Valve control block diagrams from [44] were directly implemented in Section 3.2's model as a basis for feedforward control strategy and physical valve response characterization. The IEEE report was an invaluable tool for gaining industry insight on commercial models used for operators. However, the models listed in [44] are not first-principle based. Instead, they are largely dependent on the existence of plant data. In contrast, first-principle based modeling is necessary for CSP

plants because significantly less dynamic characterization research exists compared to conventional fossil fuel plants.

2.2 Microgrids and PHIL Testbeds for Solar Energy Research

The purpose of this section is to provide examples of existing microgrids and some of their applications. In practice, the scope of microgrid (HiL) configuration options is extremely diverse. One of the most well known microgrids came out of the Consortium for Electric Reliability Technology Solutions (CERTS) microgrid project [33, 45, 46]. This testbed sought to develop low-maintenance, semi-autonomous operating technology for microgrids. Its operating voltage was designed to be 480 Vac l-l with a network of inverters, CERTS-compatible conventional synchronous generators, four load banks and battery storage. The first set of installed load banks drew up to 360 kW and 180 kVar [45]. Researchers at the CERTS microgrid developed a control method to successfully manage system frequency and voltage without requiring high-speed communications. Electrical sources included directly coupled synchronous machine sources, and inverter-coupled sources. Many CERTS microgrid concepts were first investigated at bench-scale power levels in the WEI microgrid. For example, UW-Madison developed and demonstrated CERTS microgrid principles for photovoltaic inverter control which was directly used during operation of the microgrid for this thesis' research [47]. Although the CERTS microgrid was not solely developed for testing of new renewable energy systems, it was instrumental for understanding microgrid power system stability and control. The CERTS project also accelerated the development of the WEI microgrid, which can be used for HiL tests of renewable energy systems.

Wang et al. provides a helpful application example of microgrids used as HiL testbeds [48]. Wang et Al. developed a multilevel HiL platform and testing methodology for

evaluation of controllers and integration of new power sources for a multi-MW_e energy system in Borrego Springs [49]. Power amplifiers used in this testbed included battery inverters, PV inverters, and grid simulators. Generators and the distribution grid — both virtual — were placed in the loop via a digital RTS. To accomplish this, the digital RTS would scale up testbed measurements so that the lower power levels used during testing would be full-scale inputs to the RTS' virtual environment. The HiL testbed had three levels of communication: digital communication between the system controller and power sources, power transfer between the amplifiers, and analog current/voltage communication between RTS and all amplifiers.

Wang et al. demonstrates the functionality of hardware in the loop testbeds. System level controllers, device level controllers, and the electrical devices themselves can all be tested, developed, and validated via a well designed microgrid. Proper use of scaling can also enable low power levels to be used while still maintaining more system fidelity than computer-only simulation alternatives. The diverse and invaluable applications of hardware in the loop testing have led to the development of large-scale microgrids for testing electrical power systems. One of the U.S.'s most prominent microgrids for HiL testing is the Advanced Research on Integrated Energy Systems (ARIES) testbed. ARIES is an effort to combine existing power system labs with high performance computing resources for the purpose of emulating complex future energy systems [50]. It integrates real equipment and devices, emulated devices, hardware-in-the-loop experiments, and high-performance computing assets into a research platform for design and operation of future energy systems by connecting the existing Energy Systems Integration Facility (ESIF) and the Integrated Energy Systems at Scale (IESS) labs with digital RTS equipment for PHiL or CHiL experiments [50]. ESIF is an existing facility for distribution size experiments with maximum allowable power at 2 MW_e. IESS is built to sustain power levels exceeding 20 MW_e, thus it is more suited to represent interface between distribution and bulk power system levels. ARIES has available a diverse fleet of electrical power

sources and loads including inverters, battery storage, wind turbines, and conventional generators. ARIES defines its research according to two timescales: fast (>1 Hz) and slow (<1 Hz). Fast timescale research includes power system stability, fast resilience services, and device/system fault performance. Slow timescale research is focused on load generation balances and slow resilience services. Although ARIES has multiple research objectives, it has identified hybrid system integration as a subject of particular interest. Hybrid energy research at ARIES has three priorities: optimizing hybridization of multi-technology based on accurately captured dynamics and interdependencies, understanding the interaction complexities, and quantifying the benefits of multi-technology hybrid systems.

The emergence of large-scale microgrid HIL testing facilities such as ARIES emphasizes that many energy researchers have recognized that microgrids offer a useful intermediate technological development tool for implementation of renewable energy solutions. With this in mind, the following chapter explains how we accomplish the first research objective of establishing a HIL testbed at UW capable of integrating CSP real-time simulation models with actual photovoltaic hardware in a PHiL setting.

3 MAKING A PHIL TESTBED

The goal of this PHIL testbed is to enable interaction between physical components — solar panels, PVIs, Grid Simulators — and virtual thermal models. This objective has three primary challenges. Firstly, a thermal plant model must be created that realistically captures dominant thermodynamic and mechanical transient behavior. Secondly, the electrical hardware must be configured to safely transmit power in a coherent way that resembles power flow in an actual grid. Thirdly, the virtual model and physical hardware must communicate and interact in real time with high fidelity.

3.1 Dynamic Modeling of the Thermal Plant

The dynamic model is based on a Rankine cycle — a typical choice for commercial CSP plants. The thermal plant model is primarily comprised of the steam generation system (SGS) components and turbine. Plant sizing, component design, and thermodynamic states were based on the Crescent Dunes power plant in Nevada because it is one of the most modern US power tower Rankine cycle CSP plants in operation [30]. Basic valve and steam drum control elements have also been added. Figure 3.1 shows the overall cycle with the primary components included in the model. Note that the generator portion of the model, which accounts for rotational inertia, is only included for experiments discussed in Chapter 5. This modeled plant is based on the Crescent Dunes design. Crescent Dunes' steam generation system is separated into two trains, each producing half of the plant's required steam. Therefore, to reduce dynamic complexity, only one of the steam generation systems is modeled. The rated electrical power is 40 MW_e and the plant is assumed to be capable of partial-load operation in the range of $28\text{--}43.5 \text{ MW}_e$. The following section explains the cycle model and its accompanying assumptions, elaborates on software implementation, introduces the various controls, and shows the plant's thermodynamic states at several different part-load operating points.

3.2 Cycle Overview

A general schematic of the plant is shown in Fig. 3.1. To minimize model latency in real time simulation, model complexity must be carefully controlled. Complete Rankine model loop solutions have difficulty converging even with steady state assumptions due to complex steam extraction and regeneration schemes. By assuming fixed conditions at the model boundaries, convergence of the model is significantly simplified. Consequently, feedwater heating dynamics are not considered, which would affect the state of feedwater entering the boiler. On the model's inlet boundary, we assume feedwater enters the system at a fixed enthalpy of 1450 KJ/kg and pressure of 11 MPa. At the model outlet boundary, statepoints from conventional Rankine cycles indicate that condenser pressure stays fairly constant. Therefore, the condenser is assumed to always maintain turbine outlet pressure at $p_6 = 0.025$ MPa regardless of operating point. Key values discussed in this cycle overview are summarized in Table 3.1.

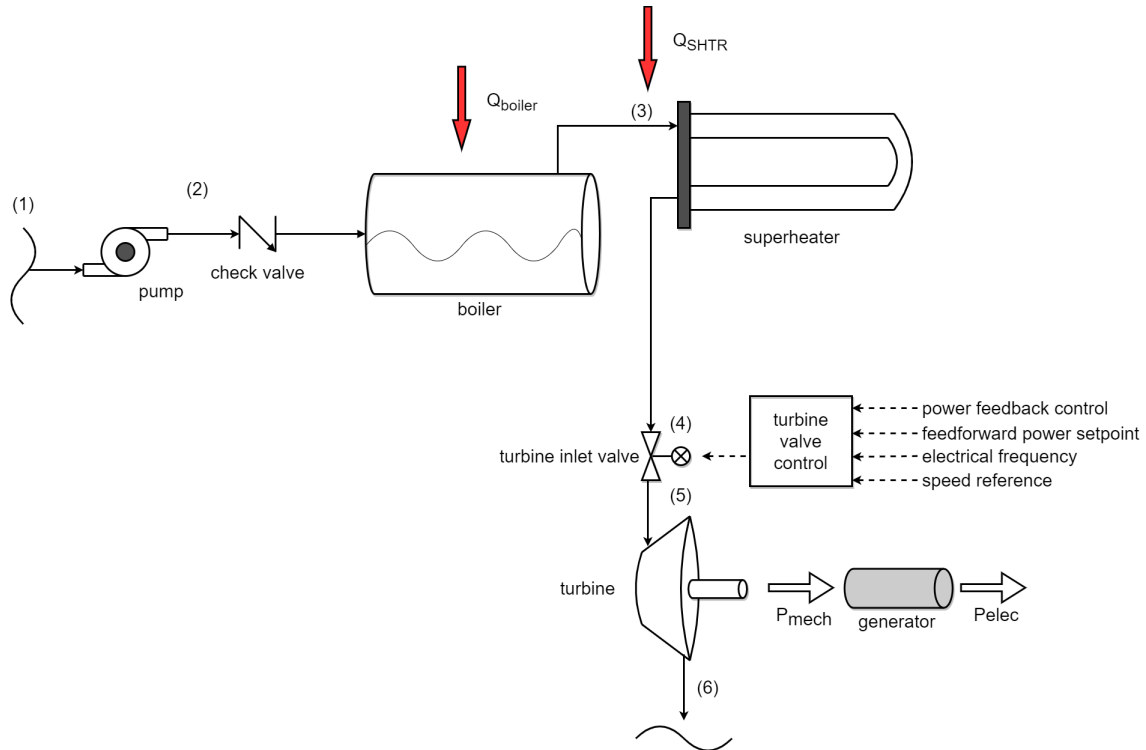


Figure 3.1: flow and control schematic for CSP plant model

The SGS model includes a feedwater pump, check valve, boiler, superheater, and turbine inlet valve. The thermal heat capacitance of each SGS component's metal is neglected in this model. Including heat capacitance effects would likely cause steam state changes to lag further behind the corresponding plant operational changes. Values for states 1-6 in Figure 3.1 correspond to steady state operating points of a conventionally designed Rankine cycle. Reheat and extraction design are not included in this model.

An isentropic pump regulates mass flow rate and pressurizes the feedwater up to boiler pressure, which is 12.15 MPa. Total Rankine-cycle pressure rise is accomplished through multiple stages of pumps. This model only includes the final stage pump, not the total requirement for pressurizing condenser liquid back up to boiler pressure. The pressure difference between final pump stage and the boiler determines flow rate from the feedwater line into the boiler. A check valve is included after the pump, and the corresponding pressure loss is assumed to be negligible. Minimum cracking pressure is 0.1 kPa and maximum opening pressure is 10 kPa. This means that the valve will be fully open if the pressure difference between pump and boiler is greater than 10 kPa. The check valve prevents reverse flow back to the feedwater source if the boiler pressure exceeds pump pressure. Check valves are used in actual powerplants for the same reason — to upstream components from sudden steam drum back flow if boiler pressure unexpectedly increases.

The boiler is an evaporative heat exchanger and steam drum with a total combined volume of 50 m³. Boiler volume has a large impact on the variability of the drum level (the amount of liquid in the steam drum). The drum level is of particular interest because boiler drums are designed to operate within a certain range of liquid levels. Liquid level is monitored and passed as feedback to the human operator during simulation. The model constrains all mass flow leaving the boiler at state 3 in Figure 3.1 to be steam with quality $x = 1$, which represents the steam separators present in actual steam drums. The boiler and superheater accommodate heat transfer at a user-specified rate. The inherent

complexity of the heat exchangers is not captured due to this assumption. Including these details would provide insight on thermal shock associated with different operating procedures as well as storage conversion efficiency. Since CSP plants generally have one continuous molten salt train to supply a steam generation unit, the heat transfer in every component is subject to the same molten salt mass flow changes. Therefore, it was assumed that $\dot{Q}_{\text{boiler}}$ and $\dot{Q}_{\text{SHTR}}$ would always proportionally change. The superheater has a steam-side volume of 1.7 m^3 . Similar to the boiler, heat transfer into the superheater is an input provided to the CSP plant model by the human operator during real-time simulation.

For a steam generation system operating in constant pressure mode or modified sliding pressure mode, turbine power is primarily controlled by the turbine inlet steam valve. Turbine power depends on the steam mass flow rate and the inlet steam thermodynamic state. A partially open valve introduces pressure loss that reduces system mass flow and turbine inlet pressure. The characteristics of this valve and its control are crucial to determining the plant's dynamic behavior, and, as such, are sometimes used to approximate the entire plant response [44]. The valve model is primarily composed of various control elements and a servo-motor subsystem. This servomotor is based on existing models found in [44]. Although the control signals are assumed to be transmitted instantly, the servomotor is a source of response lag. It is assumed to have a maximum opening rate of 0.2 pu/s , which means it would take 5 seconds for the valve to fully open or close. The valve can be at any position between 4 – 99 % open area. It was observed that most of the available pressure drop is achieved with very low areas because this is a nonlinear valve. Open valve areas close to 100% do not induce significant pressure loss. Based on information provided in [44], nonlinear valves are a commonly used in power plants. The servomotor subsystem model built in *Simscape* will be discussed in Section 3.3. The turbine component considers off-design operation. Output power is scaled from specified nominal operating conditions based on Stodola's ellipse relation [51]. The volume of the

turbine was assumed to be small compared to the steam drum and superheater. Although turbine inlet pressure is dependent on the control valve, outlet pressure was constant at $p_6 = 0.025 \text{ MPa}$.

Table 3.1: summary of SGS sizing and information, turbine information, and valve specifications

	description	typical value
A_{cv}	control valve area	$(4 - 100)\% \cdot A_{pre,t} \text{ m}^2$
$A_{pre,t}$	pipe area before entering turbine	0.12 m^2
$A_{post,t}$	pipe area after turbine	$15 \cdot A_{pre,t} \text{ m}^2$
$C_{d,chv}$	check valve discharge coefficient	0.64
$C_{d,cv}$	control valve discharge coefficient	0.25
$\dot{c}v_{rate}$	maximum valve travel rate	$0.2 \cdot A_{pre,t} \frac{\text{m}^2}{\text{s}}$
$\eta_i \text{ \& } \eta_m$	turbine isentropic and mechanical efficiencies	0.85, 0.9
$P_{chv,crack}$	minimum forward flow pressure in check valve	0.0001 MPa
$P_{chv,max}$	pressure required for maximum flow through check valve	0.01 MPa
$P_{t,nom,in}$	nominal turbine inlet pressure	11 MPa
$P_{t,nom,out}$	nominal turbine outlet pressure	0.025 MPa
p_6	turbine outlet pressure, set by condenser sink condition	0.025 MPa
$\dot{Q}_{boiler}$	boiler heat transfer rate	$42 - 64 \text{ MW}_{th}$
$\dot{Q}_{SHTR}$	superheater heat transfer rate	$20 - 30 \text{ MW}_{th}$
S_1	state of feedwater entering the system	11 MPa, $1450 \frac{\text{kJ}}{\text{kg}}$
V_{boiler}	combined total volume of steam drum and evaporator	50 m^3
V_{SHTR}	total volume of the superheater	1.7 m^3

The dynamic Rankine-cycle plant shown in Figure 3.1 was primarily built to provide

initial experience with the PHIL integration process. Although simpler than most steady-state Rankine-model counterparts, this model does consider several important dynamic effects including steam drum volume, superheater's steam tube volume, and controller dynamics. This model is also first-principle based, which is an improvement over most known industry dynamic modeling solutions that approximate responses with time constants and generalized transfer functions [44] [52]. By building a representation of this cycle in *Simscape*, system dynamics can be analyzed in computer-only simulation or PHiL real-time applications.

3.3 Implementation in Simscape

Simscape was selected for dynamic modeling because of its well-documented compatibility with *LabVIEW* via the model interface toolkit add-on. This process will be described in later in this chapter, but it should be noted that both the software's simulation quality and testbed integration attributes had to be considered. *Simscape* is a *Simulink* add-on that incorporates physical system modeling into the base functionality and premise of *Simulink*. *Simulink*'s base environment is commonly used for controller development. The CSP plant can be built by representing each component with a physical system block and connecting them into a network. Each component is typically modeled using a lumped parameter technique in which individual component behavior is described by mass, momentum, and energy balances. Since all components are connected, *Simscape* can relate all component equations and combine them into a physical network described by a large state-space vector containing each component's rate of change. *Simscape* has a variety of built-in numerical methods for stepping this state space vector through time. For example, the *ode45* solver is a Runge-Kutta based method that works well for most applications. The model is considered dynamic because energy storage terms are included, not because the model is at steady state. Mass flow is not assumed to be constant but is instead dependent

on pressure differences between each node. The CSP Rankine cycle described in this paper has been built in *Simscape* and can be seen in Fig. 3.2.

The *Simscape* model contains components joined together by blue lines. Red tags represent model inputs that can be set by human operator or automatic controls. The yellow P_{mech} tag is the most important model output: turbine power. The purple frequency tag is the model predicted electrical frequency. The purple subsystem labeled “swing equation” compares turbine output power to electrical power and calculates the resultant frequency. Since only the small-grid scenario accounts for frequency deviations, the swing equation subsystem and corresponding purple output do not exist in the large-grid scenario’s version of this model. Any desired model variables could be mapped as outputs. The green tags are model outputs of interest because they are either important control signals or useful state indicators.

Basic functionality of each *Simscape* block is now be discussed so the reader can understand how the cycle is represented in this software. It should be noted that the steam drum, turbine, and check valve were custom created by another Matlab user for a smaller Rankine cycle example available in [53]. Although [53] is a useful starting point, it considers a much smaller Rankine cycle that did not match the CSP component sizes considered for this research. Simple adaptation of [53] led to model convergence issues, so Fig. 3.2 was built as a foundation model for future CSP projects. Each block’s governing equations can be found online in the corresponding block’s *Simscape* documentation. These documentation pages are cited for the reader’s convenience.

Water and steam flow from left to right as pictured in Fig. 3.2. Reservoir blocks can act as source or sink for flow, depending on the system pressures [54]. This makes them ideal for building boundary conditions (B.C. in Fig. 3.3). An adjacent block’s port that is connected to the reservoir will have the same pressure. If the reservoir acts as a source, the flow leaves the reservoir at a user-specified enthalpy and pressure. The solver configuration block sets numerical solution techniques for the physical network. A

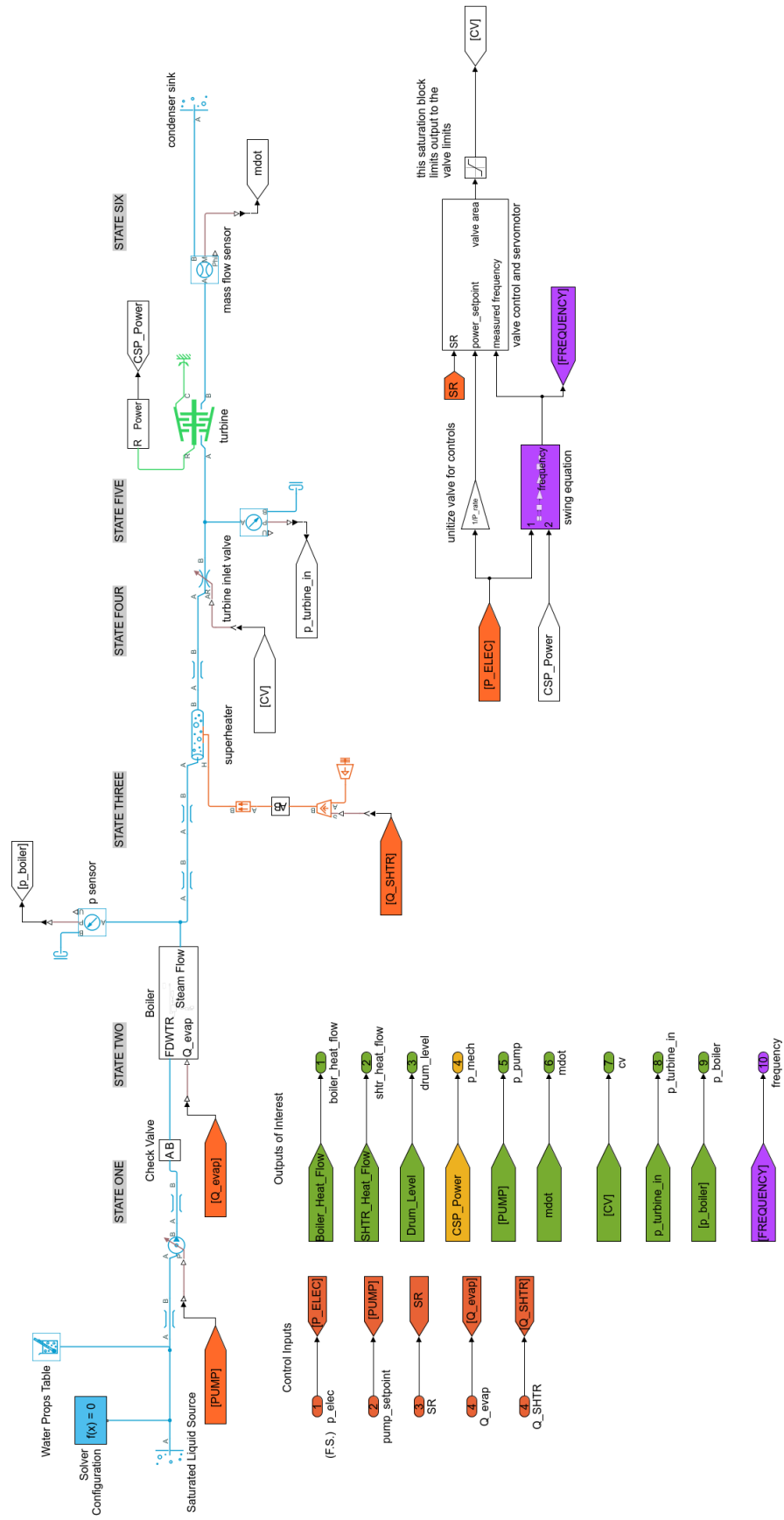


Figure 3.2: Dynamic model as built in Simscape

The superheater is represented by a thermal pipe block [60]. In this case, the pipe's thermal port is also coupled to a controllable heat source that can provide any heat transfer rate specified by the user. This model's superheater always provides $\dot{Q}_{SHTR}$ to the steam flow. The turbine inlet control valve is a variable-restriction block whose signal depends on the "valve controls and servomotor" subsystem [58]. The speed of the control valve's servomotor is a large source of system lag in power plants. This lag is taken into account within the subsystem shown in Fig. 3.4.

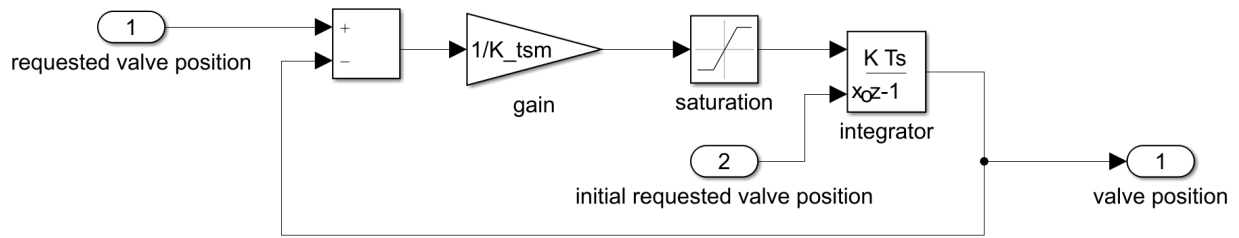


Figure 3.4: servomotor model used to describe control valve delay

The requested valve position depends on which feedback, feed-forward, droop, and speed reference signals it receives. Regardless of the instantaneous control signals, there will be a delay because the valve's motor takes time to respond to commands. This delay is modeled in Fig. 3.4 with a gain, saturation, and integration loop. The valve position output is initialized with a starting valve position at time $t = 0$. Subsequently, the valve position depends on the magnitude of the loop signal. The gain constant is found in [44]. Saturation limits of ± 0.2 pu/s are also based on information about electric valve motors in [44, 52]. The valve position is scaled from pu to m^2 via a gain block.

After the control valve has induced a pressure loss, the steam flows into the turbine [53]. The turbine block code calculates power output based on the change in enthalpy. $\Delta h_{turbine}$ is based on Stodola's ellipse law, which calculates turbine outlet conditions based on nominal operation points [51]. Turbine inlet and outlet areas are specified to calculate steam velocities. A turbine analysis in Engineering Equation Solver (EES) was used to find a reasonable turbine outlet area. It was determined that an outlet area of

approximately $15 \cdot A_{pre,t}$ was required for reasonable subsonic steam velocities. The EES model was also used as a benchmark. The turbine block was found to be consistent with EES-predicted values. Finally, another reservoir is used to set the turbine outlet pressure to the condenser pressure.

In summary, this section explains how the CSP cycle could be dynamically represented using *Simscape*. The model can be stepped through time to predict turbine output power for any given operating conditions. Inputs include heat transfer rate, speed reference, final pump state pressure, and requested turbine power. All of these inputs can be manually or automatically controlled during computer-only *Simscape* simulation or PHiL simulation, which will be discussed in later sections. For scenarios considering inertia of the system, the model can be configured to calculate resultant electrical frequency. The next section discusses the various plant control strategies that were explored during this research.

3.4 Power Output Controls

In the dynamic model described, there exist three mechanisms to control the turbine power output: pump pressure, steam generator heat addition, and valve position. These core mechanisms can be controlled manually or automated for PHiL testing. Although benefits and drawbacks of each control approach were observed during testing of scenarios 1 and 2 and will be discussed in Section 4, it is fitting to provide a brief control overview while describing the CSP plant model.

Manual Valve Control

The most basic form of valve control is manual adjustment of the valve openness via human operator. As mentioned in Chapter 2, however, many grid operators expect power plants to be equipped with automatic output control. The turbine inlet valve is typically the dominant mechanism for controlling turbine power. As a result, we assume that

primary valve position control is automated.

Automatic Valve Control

If the plant is operating in constant pressure mode, then the valve determines turbine power by changing pressure drop through the system. A fully open valve allows for unhindered steam flow at maximum pressure. In contrast, a mostly closed valve induces large pressure losses, decreasing turbine inlet pressure and mass flow. For any given boiler pressure, each position of the valve corresponds to a unique turbine power output. This concept can be implemented in a feed-forward control strategy for improved load following. This strategy's efficacy depends on the accuracy of its lookup table.

Using our SGS *Simscape* model, a valve-position-versus-power curve can be developed specifically for the plant of interest. The valve area in the *Simscape* model was decreased from fully open all the way down to the minimum restriction. This generates the curve seen in Fig. 3.5. A per-unit definition has been applied to the x-axis, therefore it is not in absolute units of MW_e . It should be noted that the curve in Fig. 3.5 extends past unity, meaning that it is possible for the plant to output more than 100% turbine power. This is physically possible because the per-unit definition can be selected to be any value. The maximum turbine output for this plant model is $43.5 - 45MW_e$, but as is typically the case for power plants, the per-unit definition was selected to be $40MW_e$ to give the plant some reserve margin.

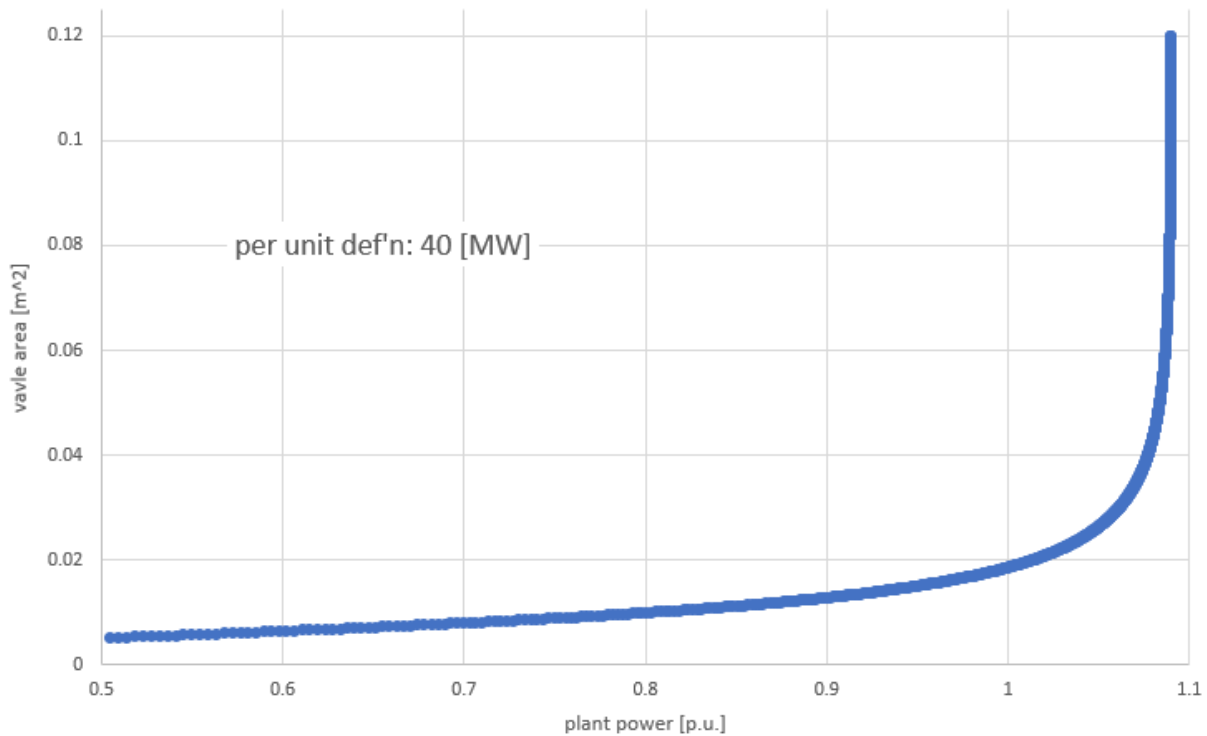


Figure 3.5: Valve area lookup table for various turbine power setpoints

The turbine inlet valve seen in Fig. 3.2 does not behave linearly, and for small valve areas, small changes in area result in large differences in plant power. This is a well known problem in power plants [44]. If a controller assumes a linear relationship between valve area and plant power, instability can become an issue. The lookup table shown is implemented in *Simscape* as shown in Fig. 3.6.

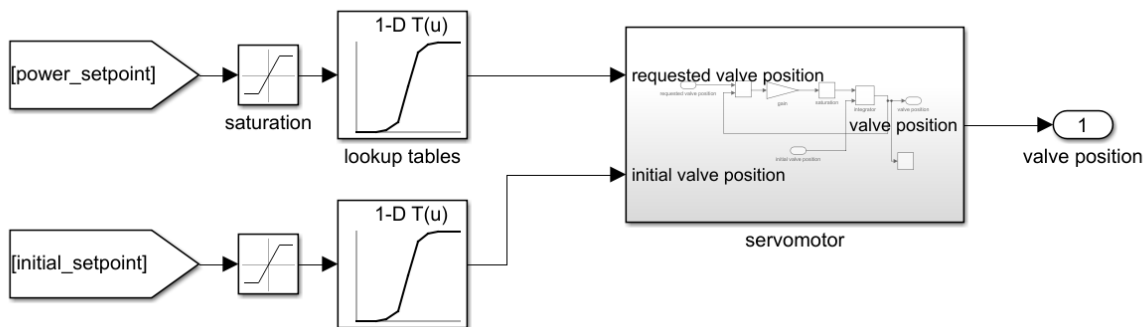


Figure 3.6: the valve area lookup table translates power setpoints into valve position commands for the turbine valve's servomotor

The two inputs for the section of the control/servomotor model seen in Fig. 3.6 are the power setpoint and initial setpoint. The initial setpoint provides a starting valve position to the turbine valve. This value initializes an integral block inside the servomotor (Fig. 3.4) and is only used once during operation. The power setpoint value is constantly changing based on the currently requested turbine power. Before the requested power signals reach the lookup table block, they are screened in a saturation block whose limits are from $0-P_{\max, \text{turbine}}$. Lookup tables in *Simscape* will extrapolate any value not within range of the table. To prevent unrealistic extrapolated control signals for the servomotor, the saturation blocks shown in Fig. 3.6 enforce a reasonable control value is sent to the lookup tables regardless of any signal the speed control, PID, or speed reference blocks push through the control system. The lookup tables interpret power signals as valve positions for the servomotor.

Speed Control

Similar to the governors found on combustion engines, speed control refers to a power change in response to a change in rotational speed. Each synchronous generator connected to the grid must spin at a speed directly proportional the desired 60 Hz electrical frequency. Governor controllers maintain a constant turbine-generator speed by regulating turbine power. Equation 5.2 shows that electrical grid frequency is dependent on the balance of total turbine power and electrical power draw. This idea forms the basis of speed control. In over-frequency cases, turbine power is decreased so that the turbine-generator decelerates. In the more common case of under-frequency, turbine power increases so that the turbine-generator accelerates back up to the nominal generator speed. Speed control is also referred to as droop control, especially when pertaining to nonsynchronous generation, and Fig. 3.7 shows a typical response [9].

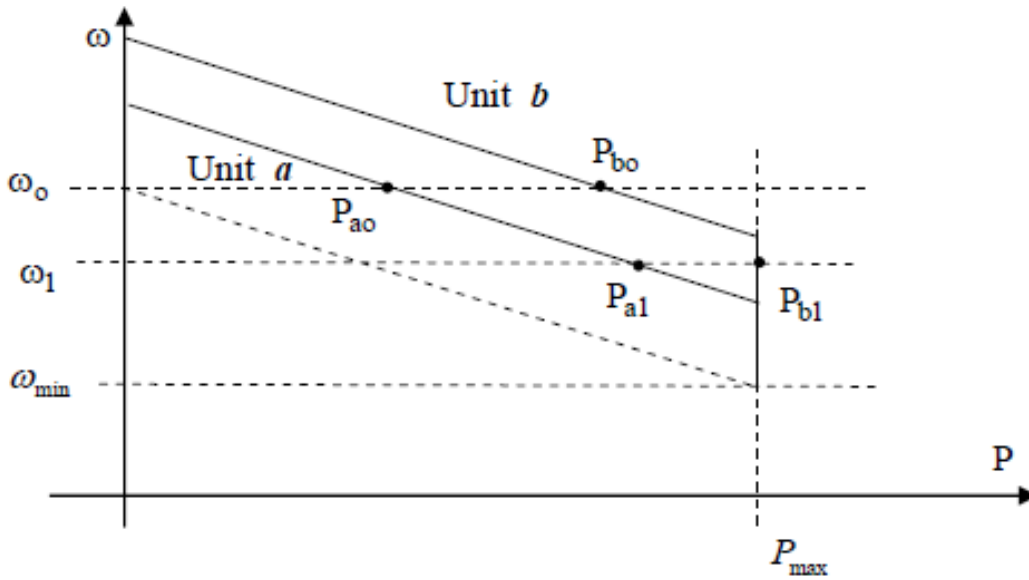


Figure 3.7: Droop concept for grid sources. Each frequency corresponds to a different power output based on initial setpoint [9]

Frequency control is implemented in the CSP *Simscape* plant as shown in Fig. 3.8. The error between measured and reference frequency is added to the turbine power setpoint to open the valve if electrical frequency is too low and *vice versa*. Nonsynchronous power sources can also respond to grid frequency deviations if programmed with speed control. The PV inverter code is programmed to provide droop response up to its maximum available power. Thus, the power inverter is programmed to mimic the droop response seen in steam turbines. A synchronous or nonsynchronous power source's droop response can be expressed by its droop constant, as seen in Eq. 3.1, where P is source's power output and f is the measured electrical frequency.

$$K_g = \frac{\Delta P[\text{pu}]}{\Delta f[\text{pu}]} \quad (3.1)$$

Another input to the turbine inlet valve can be seen in Fig. 3.8—target frequency. Grid operators can change this value to temporarily offset the turbine inlet valve position, even if the electrical frequency is at 60 Hz. By this definition, target frequency is an

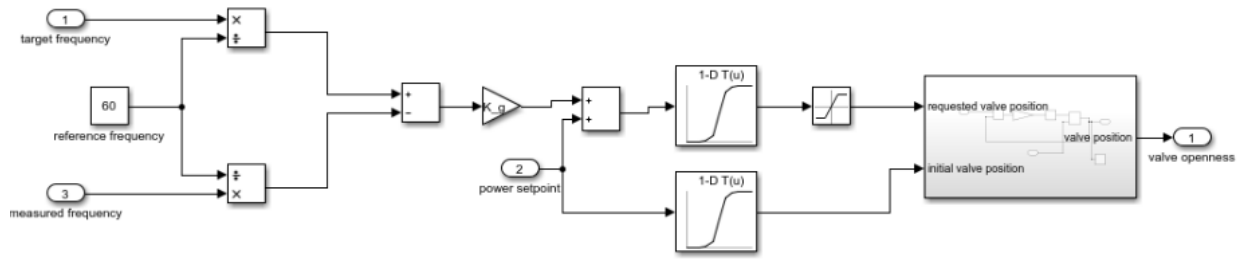


Figure 3.8: speed control module in Simscape CSP plant model

automatic generation control method that grid operators independent of the plant can use to change turbine power output. When target frequency control is used on In our experiments target frequency is typically synonymous with 60 Hz, although it is a model input in case the human operator wants to introduce speed bias as a way to change power output. Target frequency and the other input, “measured frequency” in Fig. 3.8, are both converted to a per-unit value in reference to nominal U.S. grid frequency. The difference block then calculates error between target and measured frequency. The speed control gain, K_g , has been set to 20, a typical speed control value used for plant models [44]. K_g controls the droop response. This means that some sources can be set to respond more or less aggressively than other sources on the same grid. Consequently, a source with high reserve power margins could be programmed with high sensitivity to frequency changes, and a source intended more for base generation could be operated with less sensitive droop. Giving sources different droop constants ultimately determines the level of frequency support provided by each. For example, consider two sources with different droop constants: source 1 has a sensitive droop constant, resulting in large power changes in response to frequency changes; source 2 is less sensitive, adopting more of a base load operational characteristic regardless of frequency deviations.

This concept has significant potential for application to hybrid plants. Inverters have faster droop response capabilities than synchronous generators. Thus, the generator can maintain inertial response while the solar inverters can provide immediate frequency support. If a less sensitive droop constant is used for the CSP plant, frequency changes will

not result in large operational deviations from design points. By utilizing solar inverters, however, the plant can still be seen by grid operators as a generation unit with excellent frequency response capability.

Manual Heating Control

By increasing or decreasing the amount of heat transfer occurring in the boiler and superheater, the operator can change steam production, boiler pressure, and ultimately power output. Heating rates have a strong impact on the plant response. The correct heating rate must be found for liquid drum levels to remain stable. Superheater heating is also important. Turbines are often designed to accept steam at a specific state. If the turbine inlet state is too far off of the design point, mass flowrate and power output may suffer. Manual control of heating could be done with a reference table with suggested heating fractions ($F \cdot \dot{Q}_{\max\%}$) for different power setpoints. As stated in Section 3.2, heating of both components is constrained to proportionately change together. It is assumed that a human operator could not tune the boiler and superheater inputs to have different heat transfer fractions. Although manual control has useful potential in underfrequency events, fully manual heating control puts a high workload on the plant operator. Manual heating can be further classified as reactive or proactive. Reactive heating control refers to actions taken to address a load change after the valve has already moved to the new operating point. Proactive heating control involves a human operator anticipating a load change and presetting the heating accordingly.

Automatic Heating Control

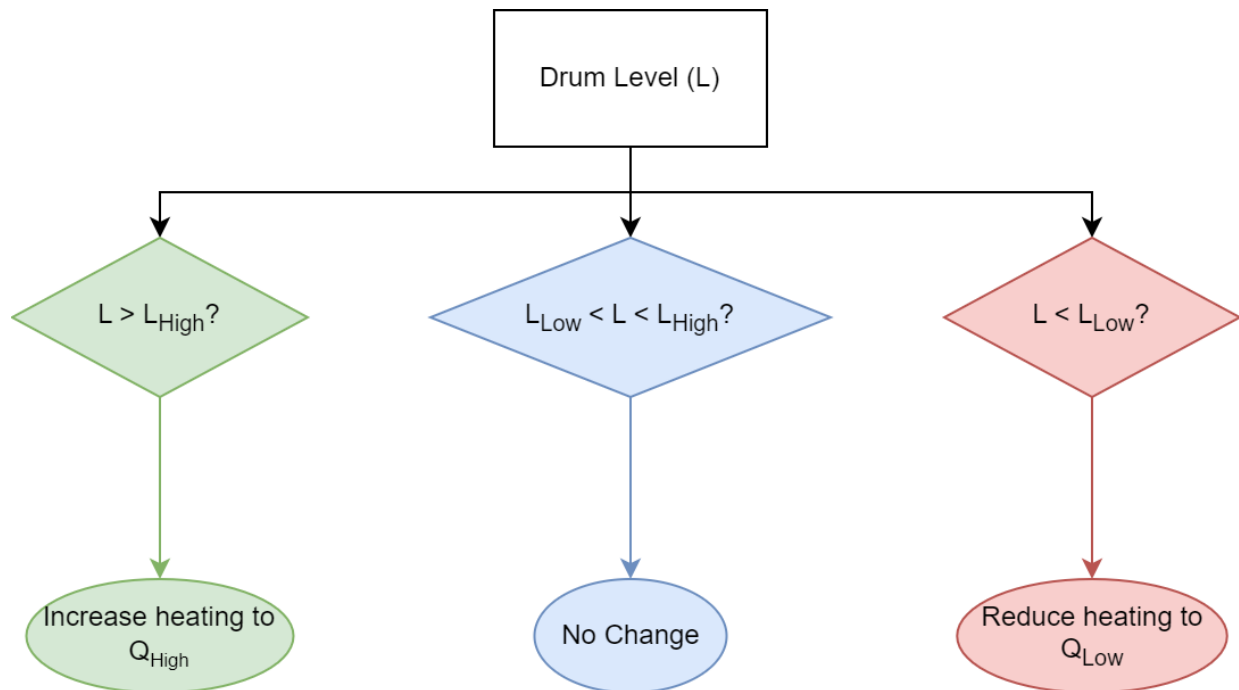
Automatic heating control can be implemented by assuming a heating fraction proportional to the fraction of maximum turbine power requested in real time as shown in Equation 3.2.

$$F = \frac{P_{t,req}}{P_{t,max}} = \frac{\dot{Q}_{SHTR}}{\dot{Q}_{SHTR,max}} = \frac{\dot{Q}_{boiler}}{\dot{Q}_{boiler,max}} \quad (3.2)$$

This control strategy is viable on the assumption that the maximum heating values have been correctly determined for a steady state maximum operating point. If any conditions change, however, the predetermined heating values are no longer correct. For example, if pump pressure is changed, the latent heat of vaporization will be different, resulting in a different rate of steam production for the same $\dot{Q}_{boiler}$.

Heating Control with a Deadband Region

The final method of heating control considered is called deadband heating control. The heating has two levels: low and high. If the liquid level is high, the heating increases to boil off as much liquid as possible. If the liquid level is too low, heating decreases to a predetermined low value that produces steam at a slower rate than feedwater inflow. The basic deadband decision tree is shown in Fig. 3.9.



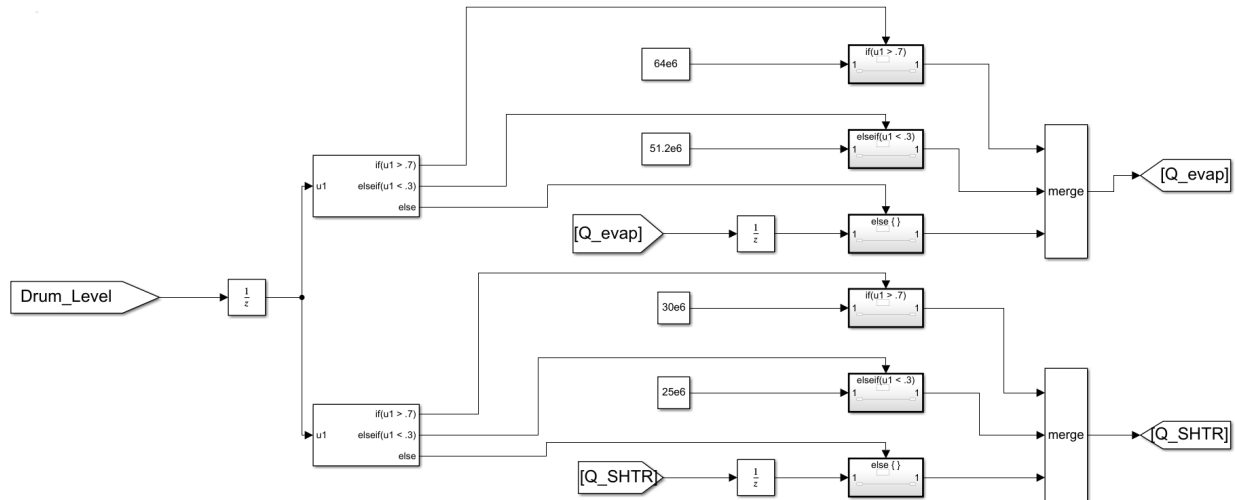


Figure 3.9: basic deadband heating control decision tree (top) and *Simscape* implementation (bottom)

This control strategy only has two programmed heating rates: the high setpoint matches 100% power production and low matches 40-60% production. In practice, the plant is oftentimes operating somewhere between these two limits. Since the two heating setpoints typically do not match the required boiling rate to keep drum level from changing, drum level will continuously oscillate between the high and low level limits. Oscillation could be dampened by adding automatic heating within in the deadband region so that the heating rate better matches the requested steam production, as seen in Fig. 3.10.

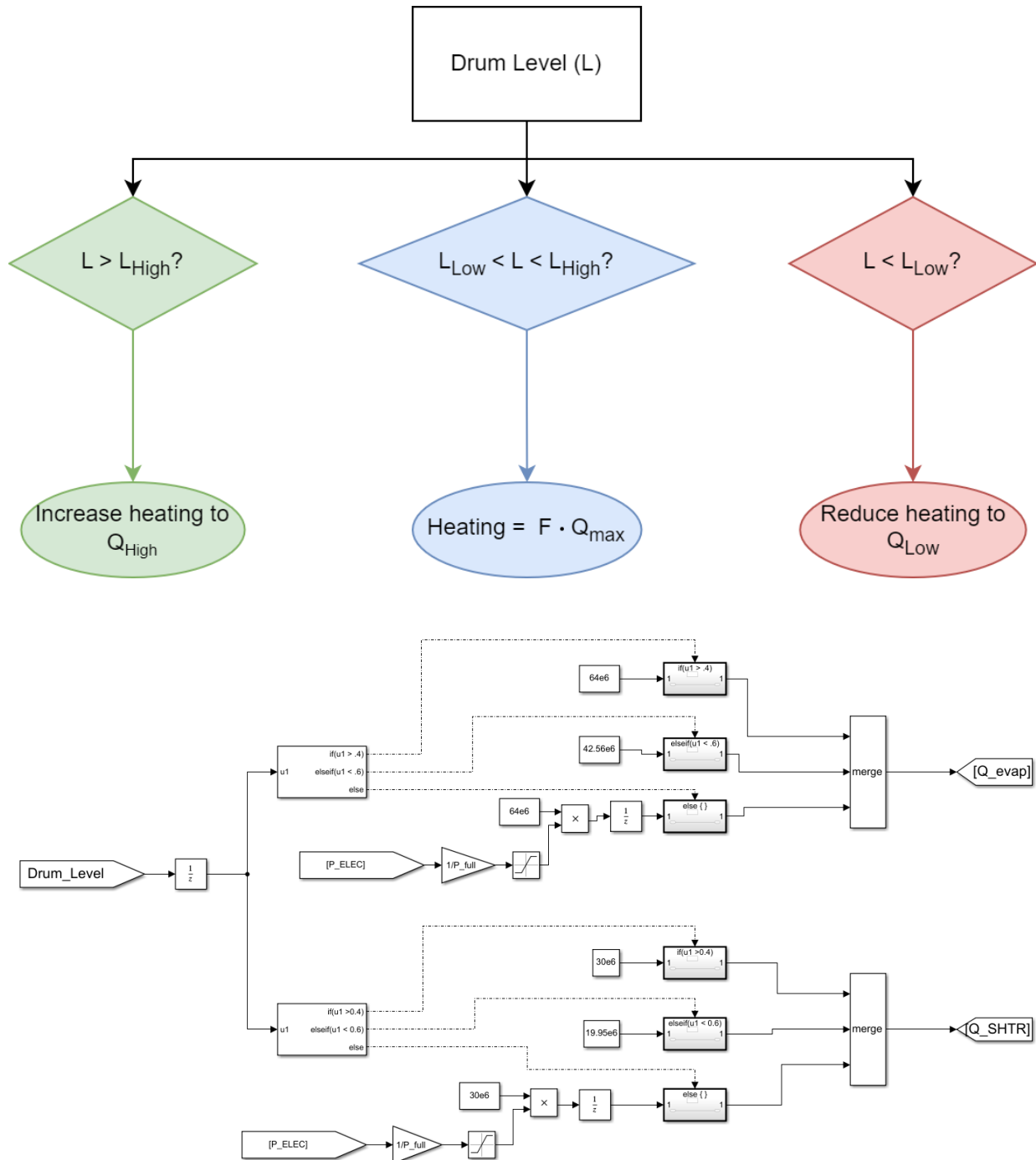


Figure 3.10: improved deadband decision tree (top) and *Simscape* implementation (bottom)

The efficacy of drum level oscillation dampening is largely dependent on the accuracy of the heating fraction F in correctly estimating the required steam generation rate. This improved deadband control was determined to be one of the most effective methods attempted, as will be discussed in a later section.

Pump Pressure Control

The pump pressure can be used to control power by indirectly raising the turbine inlet pressure and system mass flow. Drum levels can also be affected by pump pressure, since higher pressures can compress vapor into liquid. This research initially investigated drum level control by way of pump pressure, but real-time simulation indicates that changing pump pressure only temporarily relieves the symptoms of unstable liquid levels. Heating control is found to be more effective in stabilizing the drum level.

3.5 Plant Model Performance

This section aims to evaluate the validity of the dynamic plant model by checking its thermodynamic statepoints at four quasi steady-state operating points. Since the steam drum represents the dominant dynamic storage element in this model, the model is considered to be operating at steady state if the liquid drum level changes less than approximately 10% over 1000s. Heating and pump pressure setpoints are found that maintain the drum level within 10% for four different turbine power outputs. The model is simulated over 1000s and the final statepoint variables are checked at turbine power outputs of 70, 80, 90, and 109% of $P_{rate,e}$.

Table 3.2: Turbine inlet pressure, inlet valve pressure loss, and steam mass flow at four different power setpoints within the typical thermal operating range

P_{set} (MW _e)	$\dot{Q}_{boiler}$ (MW _{th})	$\dot{Q}_{SHTR}$ (MW _{th})	p_5 (MPa)	Δp_v (MPa)	$\dot{m}_t$ (kg/s)
28	42.6	20	7.34	4.38	32.6
32	48	22.4	8.26	3.32	38.76
36	53.1	24.9	9.18	2.23	43.11
43.75	63.4	29.7	10.9	0.13	51.35

Quasi steady state results seen in Table A.4 are in good agreement with steady state

predictions. It can also be seen that 40 MW_e is a conservative estimate for $P_{\text{rate},e}$, as the plant is capable of 43.75 MW_e when heating setpoints are high enough. Additional thermodynamic statepoints and T-s diagrams for each operating point can be found in Appendix A. The T-s diagram for 90% electric power is shown in Fig. 3.11.

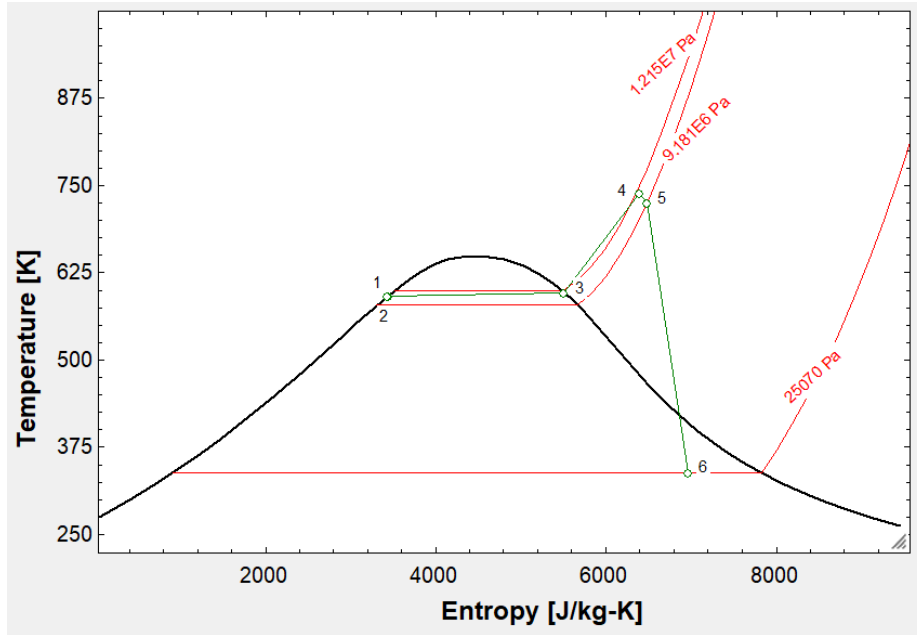


Figure 3.11: operating statepoints for plant output of approximately 36 MW_e

States 1 and 2 only differ by the pump pressure minus some minor head loss for a total increase of approximately 1 MPa. The feedwater entropy, as expected, does not increase through the isentropic pump. For all operating points, State 3 exits the boiler as high quality steam. The superheater introduces some pressure loss and a significant temperature increase. Boiler pressure stays approximately constant for all steady state operating points, so successful control of power output requires a pressure loss through the valve. The turbine exit quality ranges between 87 – 89% for all operating points. Condensing steam turbines designs typically target qualities greater than 90% to prevent blade damage from water droplets [61]. Thus, the dynamic model's turbine exit quality is slightly low but within reason. Exit quality could be improved by splitting the turbine into two stages and adding a reheater inbetween stages.

These steady-state checks show that the model generally behaves as expected. The virtual dynamic model is configured to predict plant power output changes in response to real-time changes in heating, requested power, pump pressure, and AGC setpoints. Discussion below focuses on how those model inputs are physically generated from the PHiL testbed's physical equipment.

3.6 Electrical Testbed Overview

To generate real-time signals for communication with the model, several steps are taken to configure an existing microgrid at the Wisconsin Energy Institute for PHiL testing. Although an experimental photovoltaic inverter (PVI) had already been built and tested in the microgrid by previous WEMPEC students, extensive testing, control review, and DC wiring were required to operate the PVI. This research integrates a new piece of hardware — a Chroma Regenerative Grid Simulator (RGS) — into the microgrid. Lastly, operational tests of the entire microgrid are performed to demonstrate its capability.

Existing WEI Microgrid

The microgrid located in Wisconsin Energy Institute's High Bay lab was built to study a wide array of electrical engineering problems including utility scale power flow and distributed energy resource utilization. Figure 3.12 presents the microgrid as documented in 2014.

The microgrid bus that connects each source is a series of 3-phase 1-AWG conducting cable with a maximum voltage of 480 V_{ac} L-L RMS. This research uses a maximum operating voltage of 208 L-L RMS because the PVI's controls are calibrated for that voltage. The load bank rack on the right of Fig. 3.13 connects or disconnects the microgrid bus to several resistive loads. One of those is the *Avtron* manufactured resistive load bank. This load bank's dissipation of power depends on the commanded resistance and the

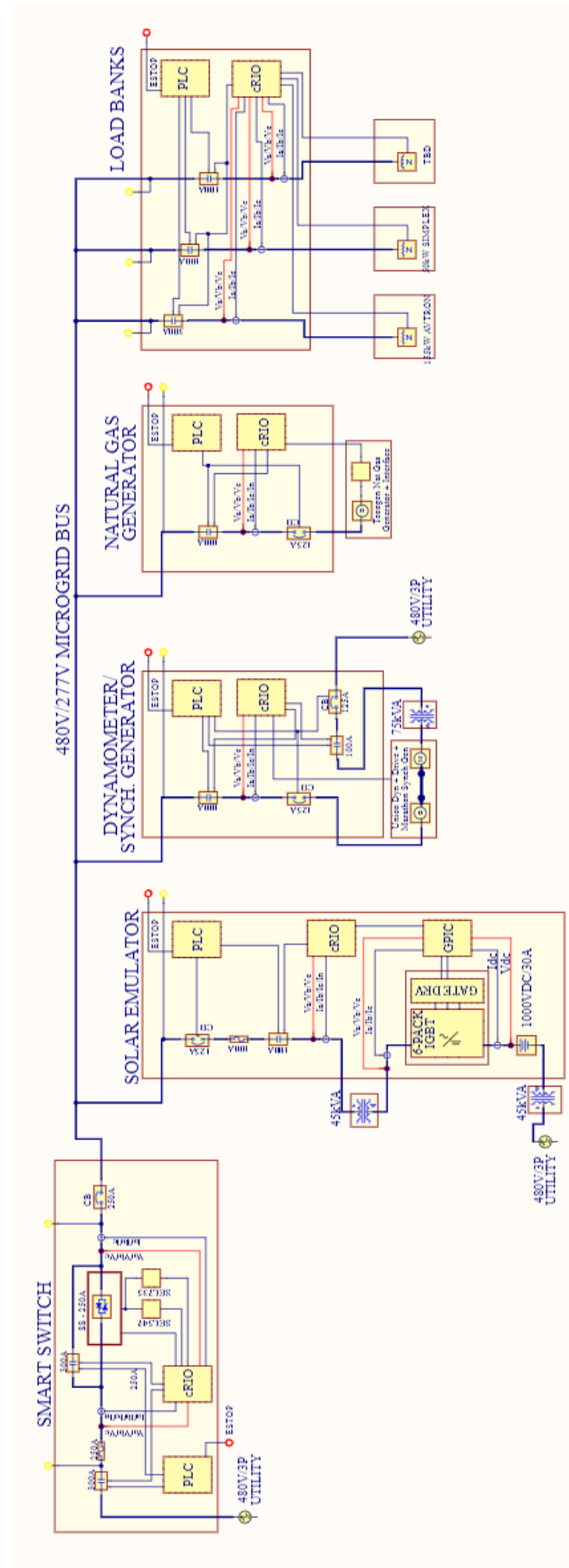


Figure 3.12: schematic of existing microgrid as documented by graduate student Austin Nelson in 2014

microgrid bus' operating voltage. For high voltages, the *Avtron*'s resistive load ranges between 0 – 150 kW in 5 kW increments. For a 120 Vac operating voltage, the *Avtron*'s load approximately range between 0 – 30 kW in 1 kW steps. The microgrid's design placed an emphasis on “plug and play” strategy, enabling sources and loads to be rapidly connected or disconnected to the bus depending on the desired test scenario. Our desired test scenario needs two new sources and the existing *Avtron* load bank. An experimental PVI (not shown in Fig. 3.13) and the RGS are now accessible to the microgrid bus. These two new additions are shown with the other legacy hardware in Fig. 3.13.



Figure 3.13: photo of the High Bay Lab microgrid in Wisconsin Energy Institute

Shown in order left to right: RGS, PVI, *semikron* rack (solar emulator), loadbank measurement rack, smart switch, *Avtron* load bank. The microgrid bus — sometimes called the racetrack — is a series of overhead conductors to which sources and loads can be connected. Three computers can also be seen in Fig. 3.13. The leftmost is called “pc#1”. This computer is responsible for executing real-time models and communicating with the RGS. The center laptop is named “pc#2” and contains a data acquisition system for

collecting power measurements from all sources and loads other than the RGS. PC#2 also controls all hardware other than the RGS. PC#2's LabVIEW program was designed and built by previous WEMPEC students, and the front panel is shown in Fig. 3.14.

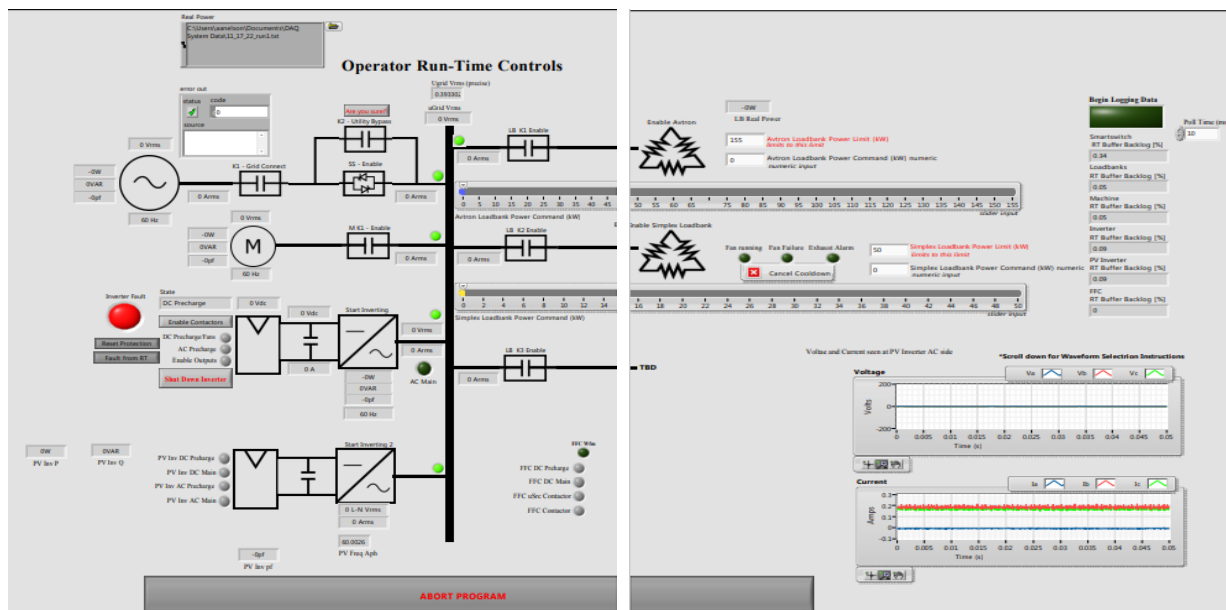


Figure 3.14: stitched front panel view of PC#2's existing microgrid SCADA LabVIEW program

This front panel can be used to control the connection, load setpoint, and heat exhaust fan for the *Avtron*. It can also engage AC and DC side switches for the PVI. Voltage and current waveforms can be measured at a variety of locations including: PVI AC output and textitAvtron input. The PVI's DC-link voltage can also be measured for tracking PV panel voltage. Various cRIOs measure waveforms at a continuous acquisition rate of 12.5 kHz. Reactive power, real power, apparent power, and power factor are measured at a slower rate of 2 Hz.

Photovoltaic Panels and Inverter

Although the CSP plant must be virtually represented in the system, the PV aspect is fully represented using physical hardware. WEI's existing rooftop PV panels were made safely accessible to High Bay Lab with up to 4 kW available during peak insolation. Figure 3.15 shows the rooftop wiring plan for the available PV panels.

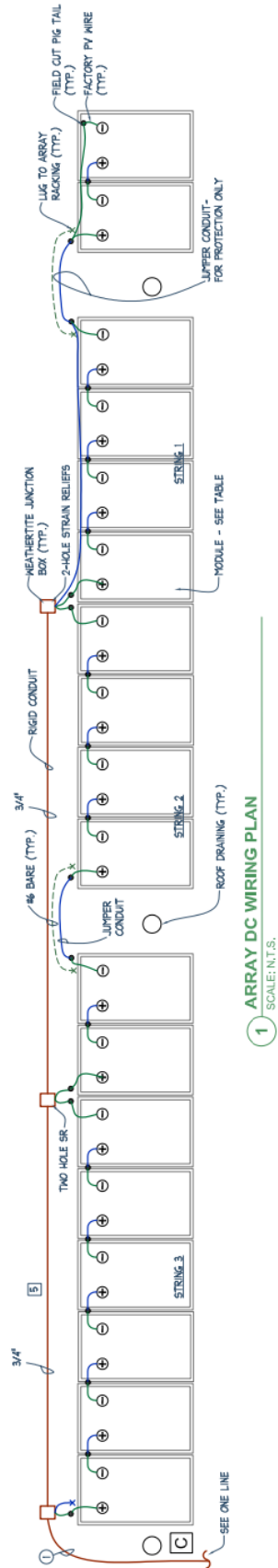


Figure 3.15: Rooftop PV wiring plan. 2 of the 3 strings shown here are currently accessible to the High Bay Lab.

Each string consists of 6 panels in series, and all three strings are arranged in parallel. The DC cable extends from rooftop to the High Bay Lab. Two of the total three strings are available for microgrid tests. The third string is only used to offset the building's electricity costs. At standard conditions, each panel has a maximum power point voltage of 57.3Vdc and current 6.02A. The nominal open circuit voltage per panel is 68.2Vdc. For 2 parallel strings with 6 panels in series, in standard solar conditions we can expect $V_{MPP,PV}$, $I_{MPP,PV}$, and $V_{OC,MPP}$ as shown in Table 3.3.

If PV power is installed without batteries, generation is entirely dependent on instantaneous solar flux incident on the PV panels. Power production is dictated by panel specific current-voltage (I-V) characteristic curves. Figure 3.16 shows I-V curves for several different insolation levels. The curves seen here were generated using equations from [10] and are specific to the SPR-X21-345 Sunpower panels installed on the roof of WEI.

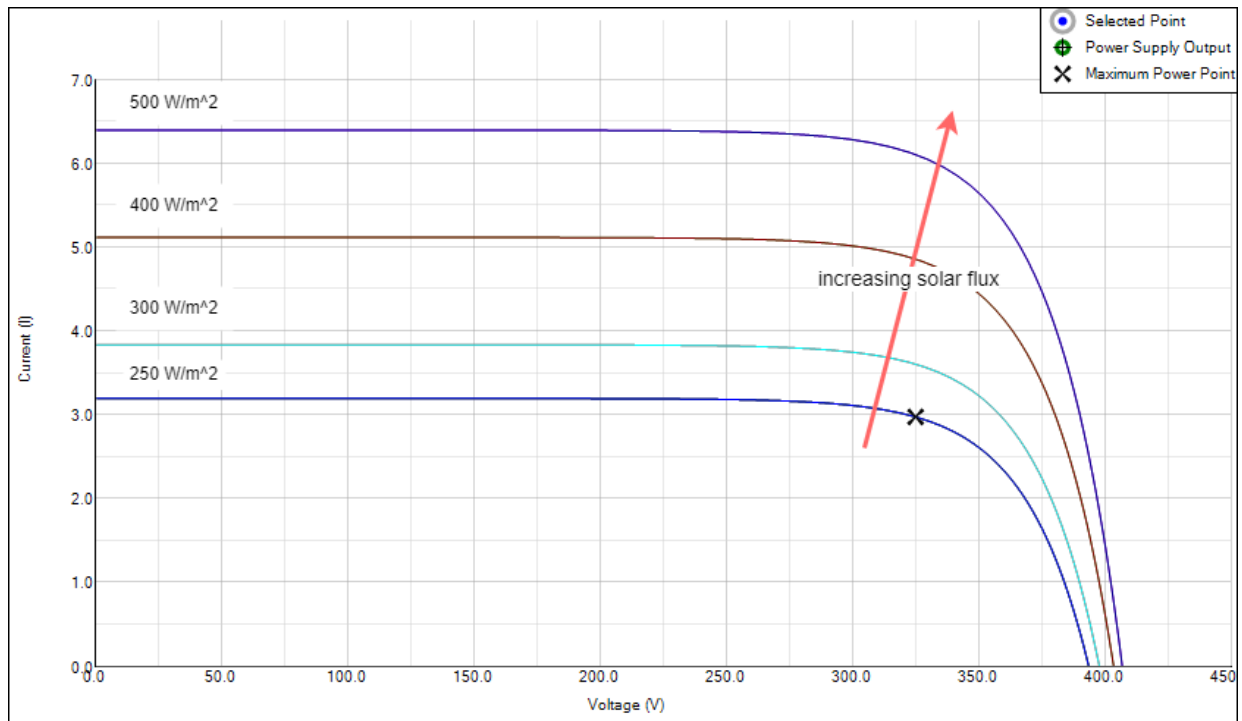


Figure 3.16: Sunpower PV panel I-V curves for various irradiation levels.

Fig. 3.16 shows that the panel characteristics change with irradiation. On the DC side of the PVI, the basic equation $P = I \cdot V$ accurately describes the relationship between power,

current, and voltage. The maximum $I \cdot V$ product occurs at a different current-voltage combination on each curve. Thus, there is a unique maximum power operating point at each irradiance. As illustrated in Fig. 3.17, the maximum power point voltage increases proportionally with irradiance. The concept of maximum power point is important to note because the PV inverter is equipped with an algorithm for finding its maximum power point voltage.

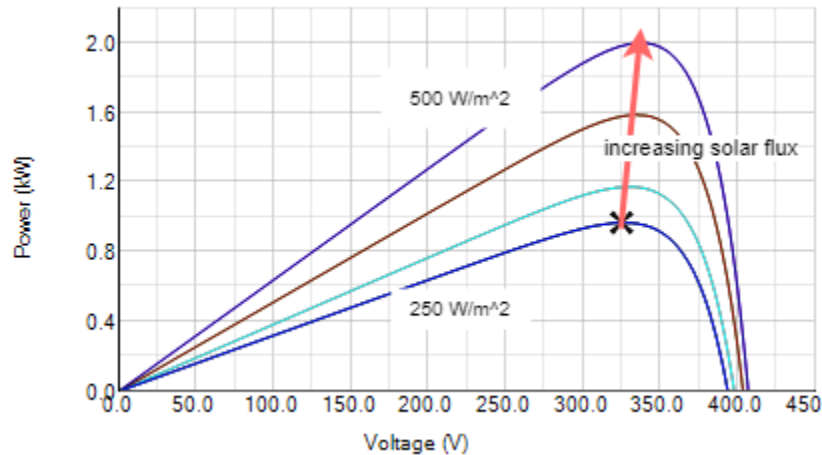


Figure 3.17: Sunpower PV panel P-V curves for various irradiation levels [10]

In a laboratory-controlled environment on a sunny day, a human operator could manually enter the maximum power point voltage and operate the PVI at full power. In any type of cloudy cover, however, the I-V curve changes with the real-time variations in irradiation. Panel temperature also directly affects panel characteristics [62]. Maximum power point tracking algorithms are used by conventional inverters to ensure that power production is as high as possible. The PVI uses a “perturb and observe” (hill climbing) MPPT algorithm as can be seen in Fig. 3.18.

DC voltage is constantly monitored and changed by the inverter. The method is similar to finding the maximum of a mathematical equation. The algorithm continues to decrease or increase DC voltage as long as power output increases. As soon as it begins to decrease, the theoretical maximum power point is reached [62]. How much the DC voltage changes is programmed via the V_{step} variable. Typical values used during this research are shown

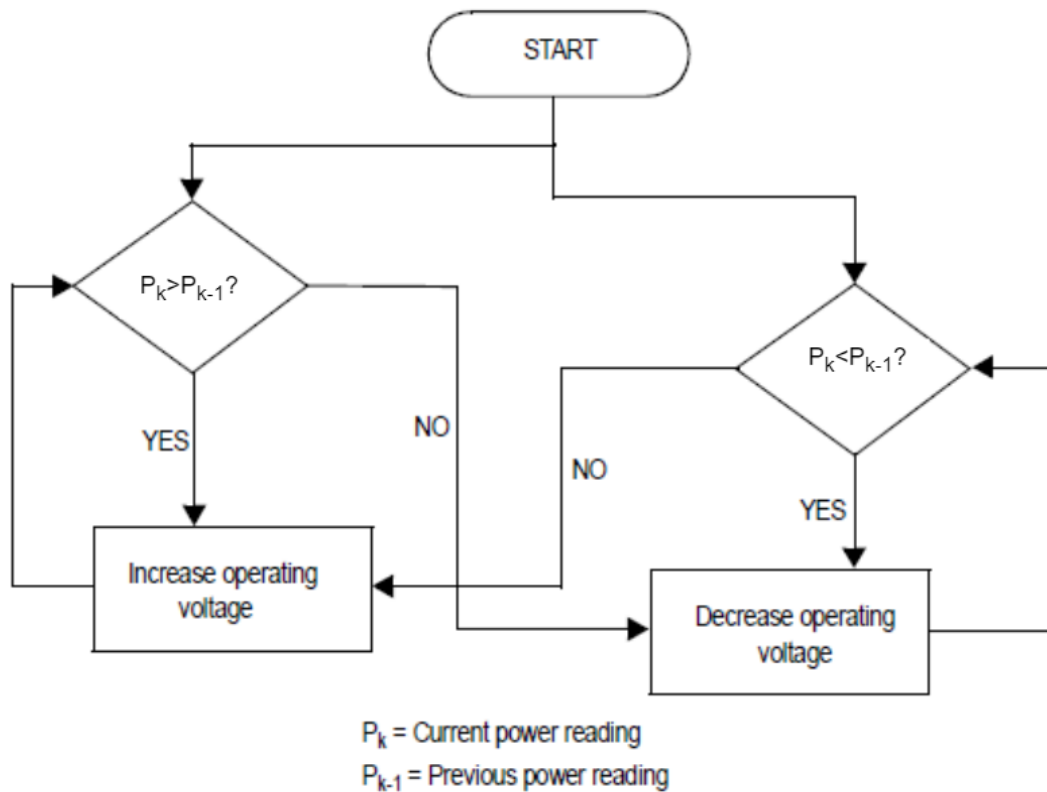


Figure 3.18: Decision tree for the perturb and observe maximum power point tracking algorithm [11].

in Table 3.3. How often the DC voltage is stepped depends on f_{mpp} .

With PV panels as a DC source, a PVI is used to convert panel DC power into AC power for grid use. Previous WEMPEC students built a highly programmable experimental PVI to generate power for the UW microgrid [12] [63]. Key PVI specifications are included in Table 3.3. The PVI can be powered by PV panels, or it can also use the *Magna* Power Profile Photovoltaic Emulator (PPPE) as an alternate DC power source. Although the PVI is grid-forming and does not require a frequency source upon startup (AKA grid-following), phase-locked-loop (PLL) code is executed during every PVI powerup to synchronize to any existing frequency signals on the microgrid. If no reference frequency is detected upon startup, the PVI will form its own frequency signal. The PVI code is based on Consortium for Electric Reliability Solutions (CERTS) controls, operating with a real power versus frequency droop and a reactive power versus voltage magnitude droop

[33]. The f-droop is adapted from synchronous generation control strategy, similar to Fig. 3.7 and enables response to any frequency deviation. The Q-droop (reactive droop) changes output voltage in response to measured reactive power. Both droop controls are presented in 3.19.

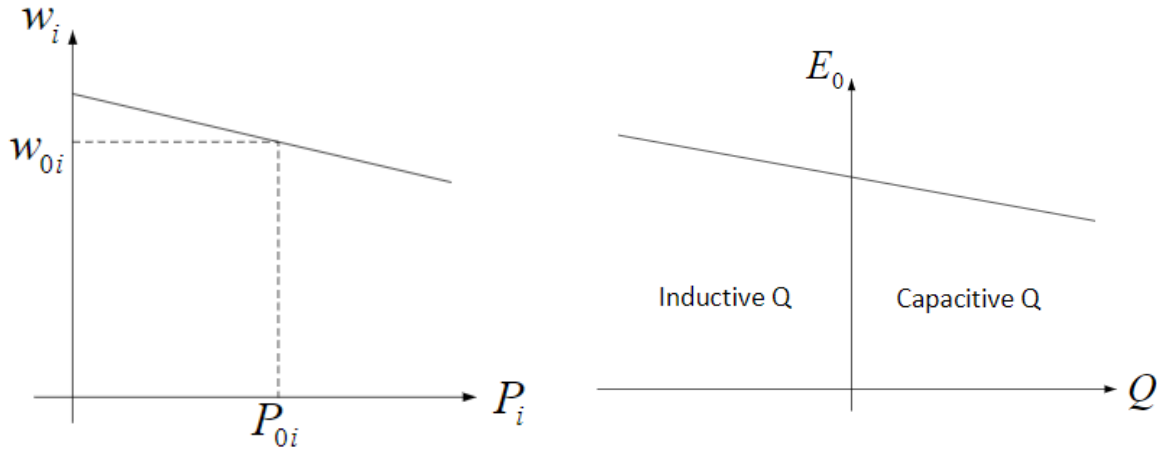


Figure 3.19: CERTS droop controls for PVI. These enable plug-and-play characteristics

Reactive droop enables compatibility of multiple grid-forming microgrid sources to operate in tandem [33]. In this case, the PVI measures reactive power in real time and changes E_0 , its AC output voltage, to adjust future reactive power output. The slope of the $E_0 - Q$ line is determined by m_q , and the $\omega - P_i$ slope is determined by m_p . Parameters m_q and m_p can be modified by human operator to adjust reactive or real power responses. This combination of droop control results in a robust, highly versatile microgrid source that can easily be run with other microgrid sources.

The entire PVI operational code has been created in *Simulink*, which gives the PVI a high degree of programmability. Upon each startup, the *Simulink* code is regenerated, compiled, and uploaded onto the PVI. Before each run, users can set the desired power output via the P_{set} parameter. There also exist two additional power controls: P_{min} and P_{max} . As their names suggest, these two parameters provide strict limits on the PVI power output. The PVI will operate either in setpoint mode or MPPT mode, depending on available insolation. If available solar power exceeds P_{set} , the inverter will hold output

steady at its setpoint. If, however, P_{set} exceeds available solar power, the PVI operates in MPPT mode, constantly trying to reach P_{set} . Due to physical circuit limits, the PVI presently cannot operate with any voltage source less than approximately 300 Vdc. This can be explained by studying the PVI block diagram (Fig. 3.21) and understanding the basic premise of inverters. Inverters function using pulse width modulation (PWM). Via high frequency switches, a DC square wave is switched on in varying duty cycles to approximate a sine wave as seen in Fig. 3.20. The peak AC output voltage is limited by the maximum DC link voltage.

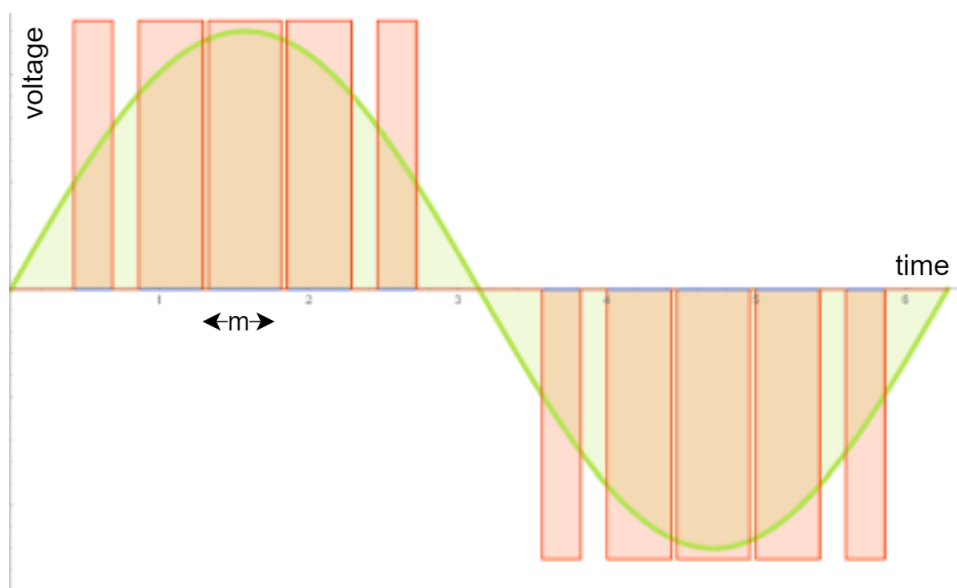


Figure 3.20: Pulse width modulation concept: how AC voltage is produced from DC panel voltage

Figure 3.21 shows a nominal 400 Vdc source connected to the switches. In reality, this represents either the Magna DC source or solar panel DC voltage. The minimum operating DC linkage voltage depends on the desired AC output voltage. If 208 Vac RMS $l-l$ is desired, the peak to peak voltage is $208 \cdot \sqrt{2}$ Vac $l-l$. Therefore, the minimum DC linkage must be approximately $V_{dc} > 295$. A V_{min} setting in the PVI program prevents the inverter from operating at too low of a DC link voltage and generating output harmonics. If V_{min} is set higher than the panel's maximum power point voltage at any time during operation, the PVI cannot track the maximum power point. In these cases, controller

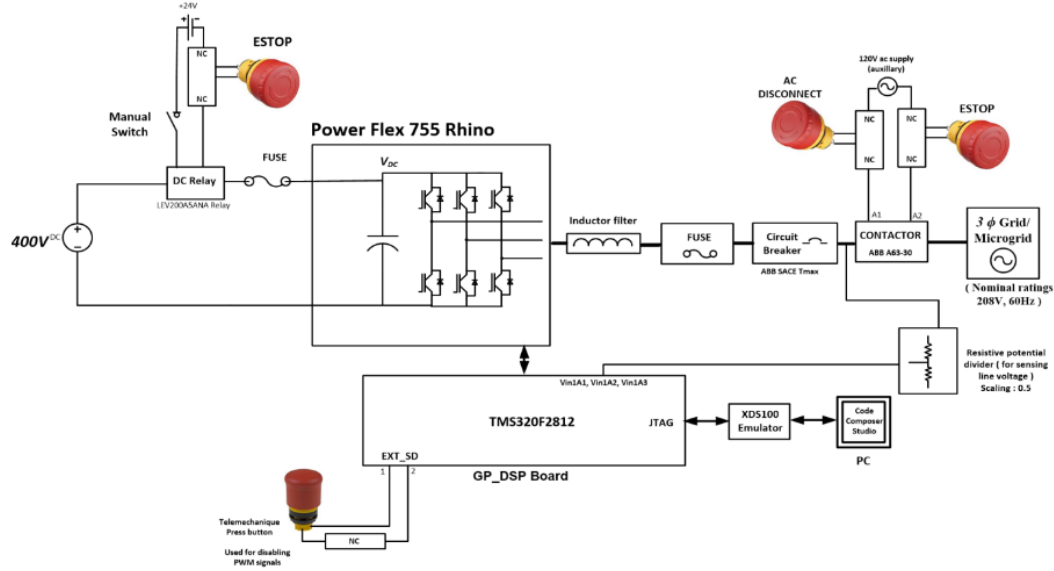


Figure 3.21: block diagram of experimental WEI photovoltaic inverter [12]

oscillation may occur because the power setpoint signals and $V_{\min}$ signals come into conflict. The resultant PVI power oscillations are not representative of commercial inverter behavior. An example of this inverter behavior is seen in Fig. B.1 just before 800s. The first theoretical voltage where PVI power control instabilities can possibly occur is when the minimum allowable DC voltage is less than the maximum power point voltage: $V_{\min} < V_{\text{mpp}}$. There are two $V_{\min}$ setpoints used in this research. 340 Vdc is used in Chapter 4 and Section 5.2 in Chapter 5. 310 Vdc is used in Chapter 5's last experiment. For the arrays installed on the WEI rooftop, existing photovoltaic power profile emulation software based on [10] predicts that the theoretical limit where $V_{\text{mpp}} < 340\text{Vdc}$ is at irradiance values of 250 W/m^2 . If $V_{\text{mpp}} < V_{\min}$ there is a chance of control instabilities impacting the PVI's function. Note that the PVI is capable of producing power at irradiances lower than 250 W/m^2 without experiencing instabilities. As long there are no significant instabilities from controller conflicts, the PVI simply obeys the $V_{\min}$ control signal and operates off of its maximum power point voltage within the DC voltage range $V_{\min} - V_{\text{oc}}$. The experiment in Section 5.3 uses $V_{\min} = 310$. The theoretical irradiance limit for this $V_{\min}$ is very low — 75 W/m^2 . Regardless of the $V_{\min}$ setpoint, if the PVI experiences controller

conflict, it is observed to be noticeably different from cloud events. PVI power fluctuations that are due to cloud events follow the general shape of the cloud, whereas controller conflict causes highly oscillatory power measurements. Therefore, it is difficult to confuse a period of controller conflict with PVI power fluctuations during cloudy periods.

Table 3.3: PV characteristics and PVI operational parameters with their typical experimental values

parameter	description	value
$V_{MPP,PV}$	maximum power point total panel array voltage at standard solar conditions	343.8 Vdc
$I_{MPP,PV}$	maximum power point total array current at standard solar conditions	12.02 A
$V_{OC,MPP}$	open circuit voltage for total panel array	409.2 Vdc
$P_{PVI,max}$	maximum inverter power	45 kW
$V_{PVI,AC}$	PVI operating AC output voltage range	208 – 480 Vac l – l rms
M_p	f – power droop slope; a large M_p would result in weaker power responses for the same change in frequency	10 Hz/12 Δ kW
M_q	voltage – Q droop slope; a large M_q would result in more gradual output voltage changes for the same change in measured reactive power	0.05 V/12 Δ kVA
f_{mpp}	frequency of DC voltage perturbations during maximum power point tracking	6 – 10 Hz
V_{step}	size of DC voltage steps during maximum power point tracking	2 – 8 Vdc
V_{dc}	DC voltage of the PVI input bus	300 – 400 Vdc
P_{set}	PVI AC power output	0.5 – 2 kW _e

The PVI is tied into the microgrid via a delta-wye transformer. Assuming a microgrid frequency is established and all sources are correctly synchronized, the PVI injects more or less power by adjusting its electrical power angle. This mode of operation works well

in tandem with the regenerative grid simulator.

Chroma Regenerative Grid Simulator

Since one goal of this testbed is to evaluate ancillary service responses, there must be a means to directly control the electrical frequency. In most cases, a stiff frequency reference will also be necessary. The RGS is purchased for these reasons. This device was designed as a grid emulation tool for PV inverter testing and validation. It is capable of maintaining any programmed AC voltage and frequency that the test requires. Its ability to operate as a source or load means it can emulate a generator, grid sink, or a combination of the two. Power flow can be 4-quadrant, and the RGS is fully regenerative up to 100% of the output current rating. This means the RGS can absorb reactive or real power in the microgrid and can safely return that excess system power to the supply grid [13]. Specifications are listed in Table 3.4.

Table 3.4: Chroma Regenerative Grid Simulator specifications

max. power	45 kVA 3ph
frequency	30 – 100 Hz $\pm 0.01\%$ & 0.01 Hz resolution
AC voltage range	0 – 300 Vac _{LN} & 0.1% + 0.2% F.S. accuracy
power factor	0.99 (typical)
measurement: power	0.4% + 0.4% F.S.
measurement: voltage	0.1% + 0.2% F.S. V _{LN}
measurement: current	0.4% + 0.3% F.S. RMS & 0.4% + 0.6% F.S. peak
weight	1850 lbs

The RGS is fully programmable via hard panel or remote communication to a PC. Chroma also developed a control and measurements LabVIEW library for remote RGS

interaction. LabVIEW programs were configured to control output frequency and voltage; the programs also periodically measure reactive and real power output. Measurement and control loops typically execute with a frequency of $f_{\text{chroma}} = 4 - 10$ Hz. It is important to note that unlike the PVI, a user cannot require that the RGS to produce a certain amount of power. Instead, it is more useful to think of the RGS as an ideal voltage source with fixed frequency. This is similar to how the main grid could be idealized. Figure 3.22 is a vendor-generated graphic illustrating how RGS devices are typically used by customers.

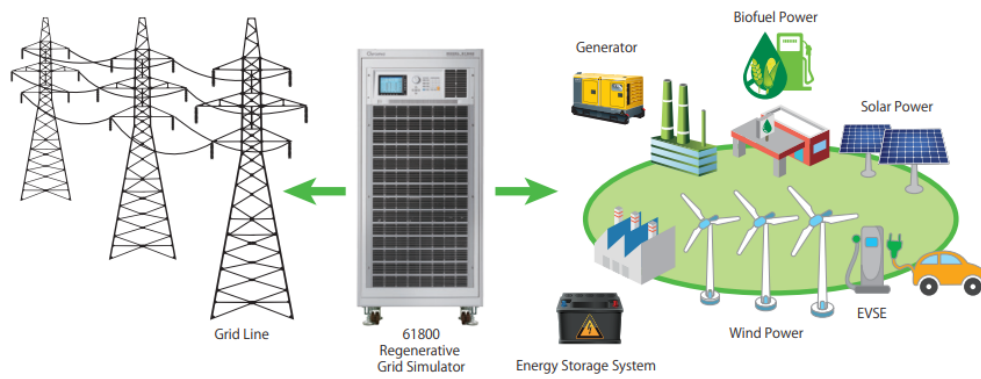


Figure 3.22: illustration of the typical RGS configuration in microgrids [13]

Although this research's testbed configuration is slightly different than Fig. 3.22, the electrical principles remain the same. When the microgrid fails to produce enough power, the RGS imports from the utility grid and sources power to the microgrid. If the microgrid's production exceeds its aggregate load, the RGS sinks and exports that power. Similar to a direct utility connection, the RGS provides a stable frequency source. Unlike a utility connection, the RGS can be set to frequencies other than 60 Hz. This allows for more experimental flexibility than a testbed basing its frequency on the utility connection. Using real-time or pre-programmed operational control, the RGS can simulate frequency deviations or voltage drops.

Simple Moving Average Filter

According to Table 3.4, the reported power measurement accuracy of the Chroma is 180 W. Although observed measurement accuracy is typically better, this accuracy limitation reduces the precision of low power tests due to a decrease in the signal-to-noise ratio. To mitigate this, a simple moving average filter is incorporated into the LabVIEW data acquisition program. As its name suggests, the filter reports at every time step an average of the last N samples of real-time data. The root mean squared error of RGS power measurements for different sample lengths can be seen in Fig. 3.23

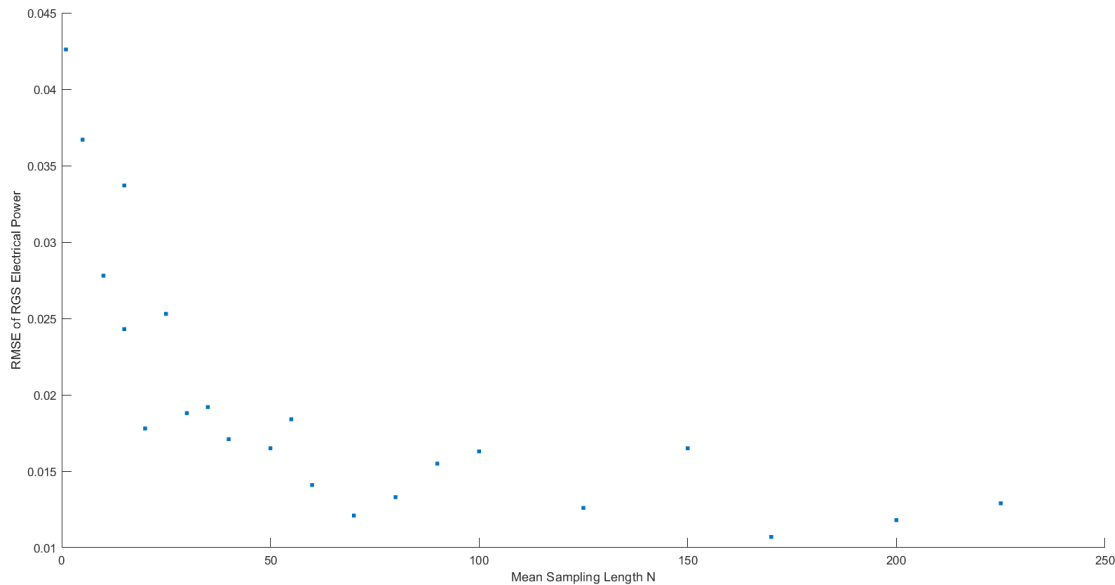


Figure 3.23: RMSE of measured power for different sampling length values

In real-time scenarios, there is a tradeoff between large sampling lengths and measurement variance. A large sampling length will result in lower RMSE, but a large average inherently dampens time varying phenomena. Figure 3.23 indicates that the largest improvement in RMSE will occur between a sample length of 25-50. Sample lengths longer than 50 samples show diminishing returns.

Electrical Hardware Operation Tests

The various electrical elements that have been described were configured as shown in Fig. 3.24. The primary electrical goal was to integrate the PVI and RGS in a way that enabled exchange of electrical power. During experiments, both sources are connected to the common microgrid AC bus.

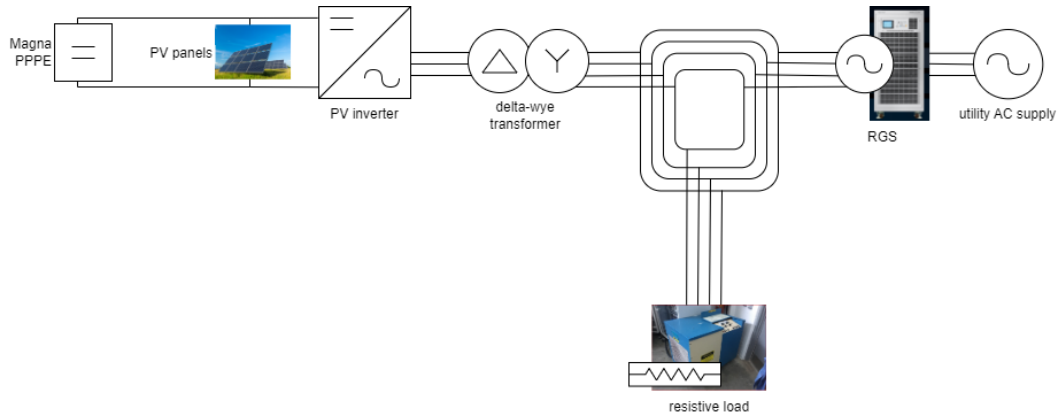


Figure 3.24: Electrical layout used for experiments

The RGS is always powered by a utility supply and behaves as a constant voltage source — it ensures that the voltage drop across the bus is maintained regardless of load (within load limits). In practice, this allows the RGS to provide a complementary power source to other sources on the same bus. During the experiments discussed in this thesis, the RGS is generally used as a source, although it could absorb any excess reactive power present during experiments. The PVI is powered one of two ways: the *Magna* PPPE DC source (powered by a utility connection) or the rooftop panels. When high repeatability is desired for controls development, the PPPE can be utilized. The PV panels are then used to validate or research any management strategies. Electrical frequency is established by first turning on the RGS. Then the PVI synchronizes to that waveform using phase-locked loop control and also matches RGS voltage. Once this is complete, the PVI injects power into the microgrid by changing its power angle relative to the RGS frequency.

A series of operational demonstrations are performed to demonstrate that all devices

work as expected. The first demonstration's goal is to show successful power source frequency synchronization, setpoint control, and proper PVI control. An additional objective is to confirm that varied insolation levels would effect PVI power output as expected. To accomplish this, the PPPE is used to power the PVI. Two irradiance profiles are pre-programmed: a low power P-V curve and a high power P-V curve. The first demonstration procedure is as follows:

1. turn on grid simulator
2. set resistive load to 2 load steps
3. PVI begins producing power with high power P-V curve
4. increase load to 3 steps
5. increase load to 4 steps
6. decrease load to 3 steps
7. decrease load to 2 steps
8. decrease PPPE to low power P-V curve

Figure 3.25 shows the real power measured via LabVIEW during the experiment. It should be noted that if the averaging filter is not implemented in RGS measurements, there would be no delay in RGS power changes during responses to load changes or PVI activation.

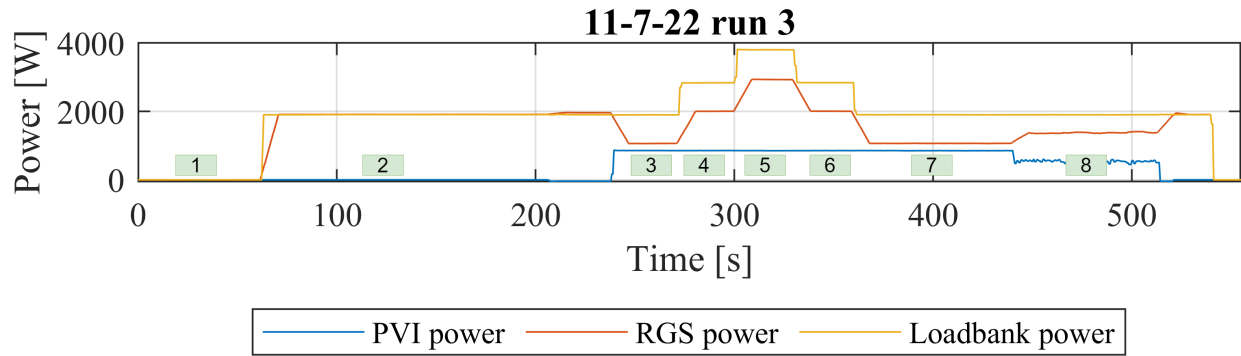


Figure 3.25: Real power during demo 1. Note that numbers correspond to procedure steps described above but do not exactly align with the time at which the step was taken.

Initially neither sources output real power because no load exists. At step 2, the load steps on and the RGS immediately produces real power. Once power production has started, PVI power never changes. This is expected, because PVI power is programmed to be 850 W. Even when electrical load increases, the PVI maintains its desired power output. Since the load must be met, the RGS voltage source provides the remaining real power demand. At step 8, the PPPE changes to a lower power P-V curve, and the PVI is unable to maintain its previous output. When the peak available solar power is insufficient for meeting a power setpoint, the PVI attempts to operate at the maximum power point. Figure 3.26 shows transition of P-V profiles between steps 7 and 8. Figure 3.26 shows that the DC-link voltage changes for the PVI depending on the solar profile, i.e., the I-V curve.

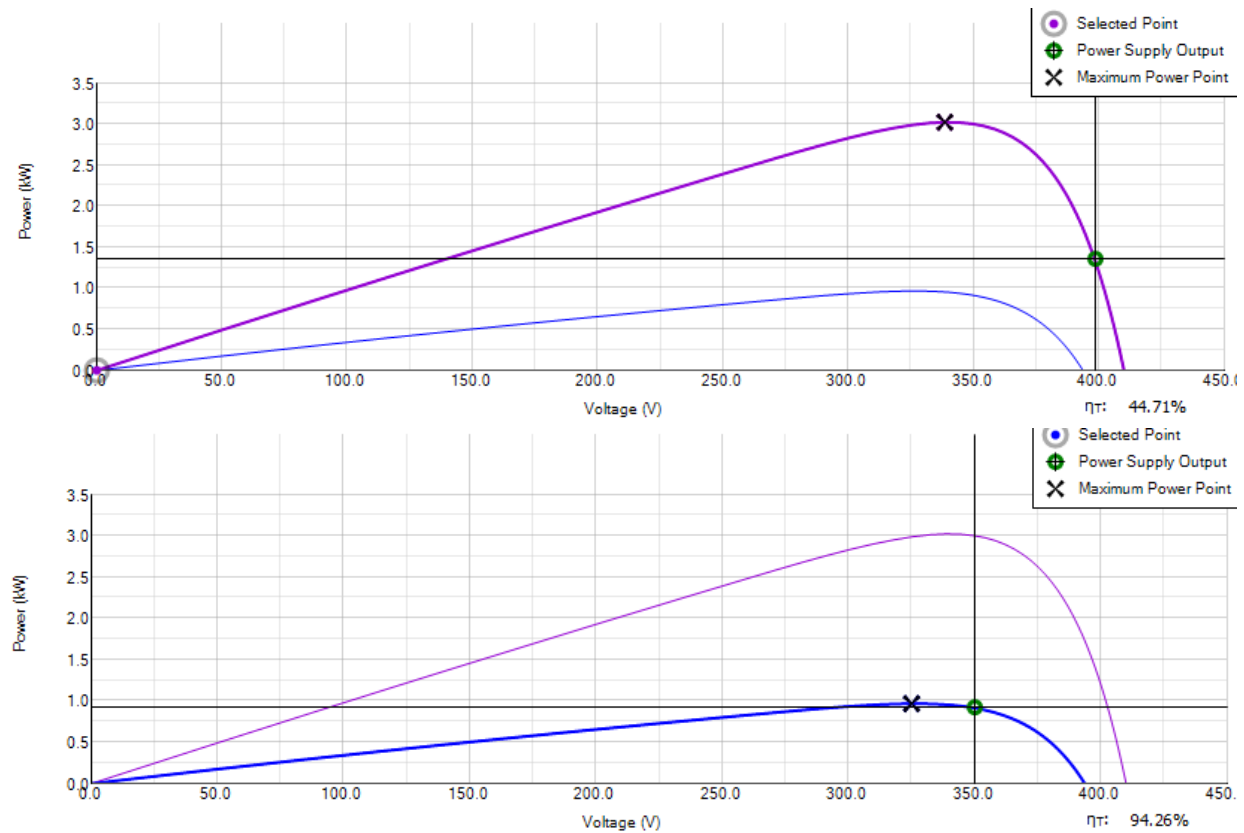


Figure 3.26: PPPE-recorded power point positions during operation. Procedure steps 1-7 (top), then step 8 (bottom)

The operating output AC voltage is currently set at 120 Vac RMS. Figure 3.27 shows 3 phase voltage data measured at the PVI and loadbank. Both locations record peak voltage of approximately 170Vac.

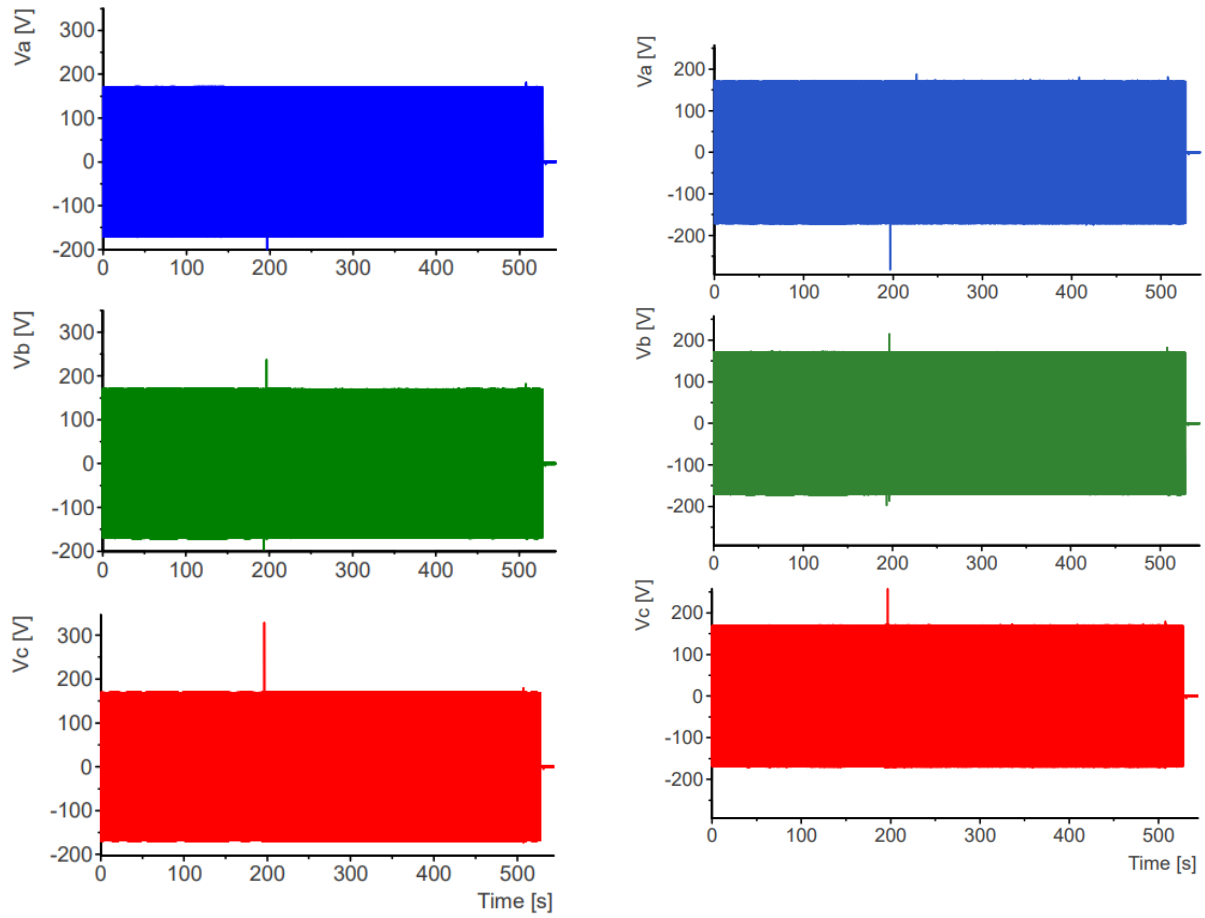


Figure 3.27: Each phase voltage measured at two locations: loadbank (left) and PVI output (right)

Besides a transient startup voltage spike at PVI activation, the correct V_{ac} voltage magnitude is maintained for the duration of the experiment. The current waveforms magnitudes, however, do vary as shown shown in Fig. 3.28.

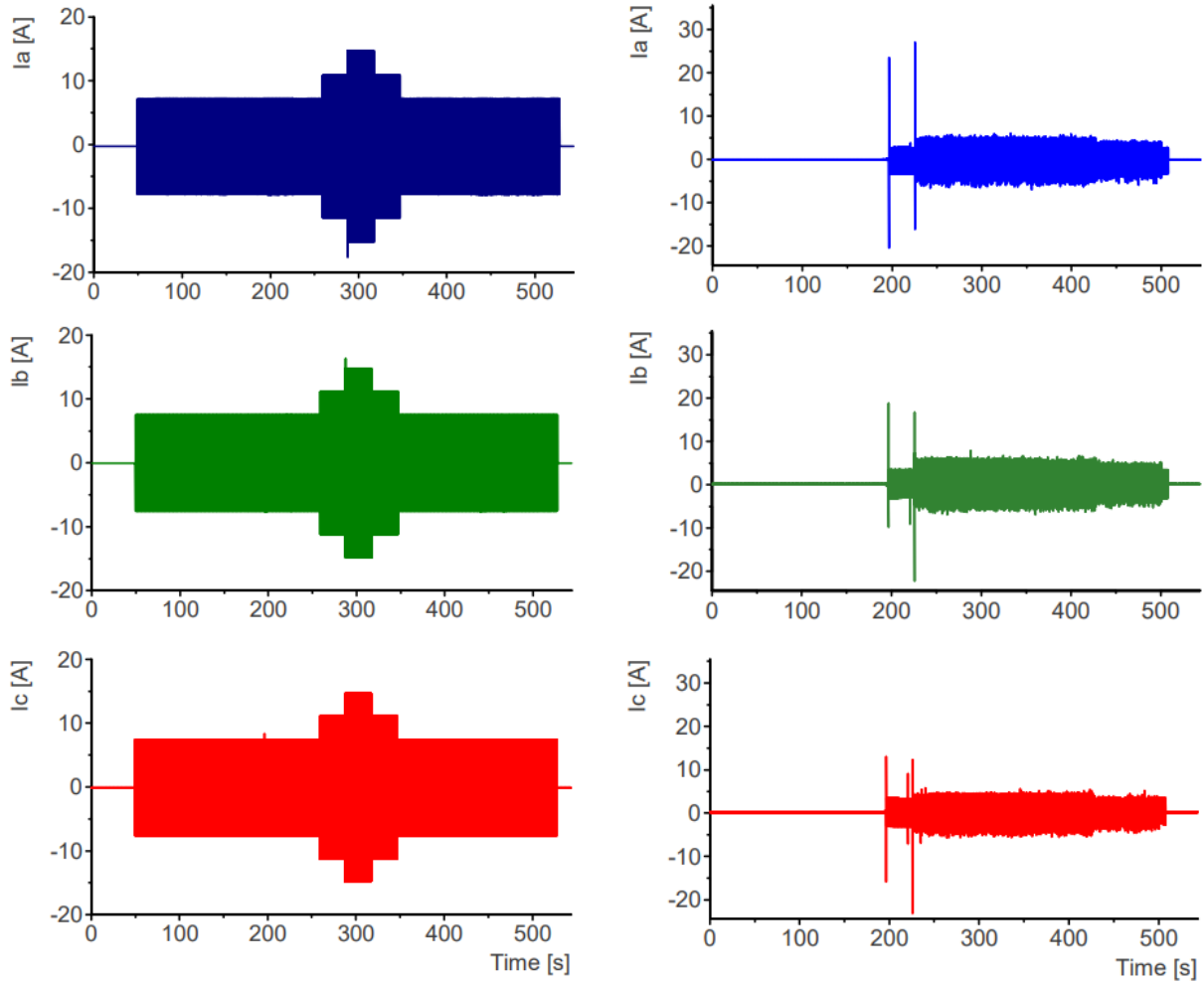


Figure 3.28: current waveforms at loadbank (left) and PVI output (right)

The current flow in the loadbank is proportional to the electrical load. Since PVI power is constant, current amplitude does not change until the PPPE I-V curve changes in step 8. Note that the measured current amplitude at the PVI prior to PVI producing power is not zero. This is because precharge resistors at PVI output cause a parasitic electrical loss upon closing the PVI AC connection to the microgrid.

Demonstration 1 shows that the basic operating principles for the RGS, loadbank, and PVI are correctly understood. The two power sources successfully synchronize and work in tandem to provide power to an electrical load which can be varied during experiments. Demonstration 2 seeks to answer the remaining electrical questions: if RGS frequency

changes during an experiment in similar fashion to a real over- or under-frequency event, would the PVI be able to resynchronize? Is the PVI's power-frequency droop response predictable during electrical frequency changes? To answer these questions, the following procedure was followed:

1. RGS turned on
2. 3 load steps activated
3. PVI begins producing power with high power P-V curve
4. decrease RGS frequency to 59.75 Hz
5. decrease RGS frequency to 59.5 Hz
6. increase RGS frequency to 60 Hz
7. increase RGS frequency to 60.25 Hz
8. increase RGS frequency to 60.5 Hz
9. decrease RGS frequency to 60 Hz

The RGS frequency is changed in real time using *LabVIEW* communication and the PPPE is used to power the PVI. The PVI power output at 60 Hz was set to 850 W. Figure 3.29 shows real power changes during the experiment for each component. As the frequency decreases, the programmed PVI droop response produces its expected effect; PVI power increases with decreasing frequency and *vice versa*. Since this is a constant-load operation, the RGS output always compensates for any PVI power changes.

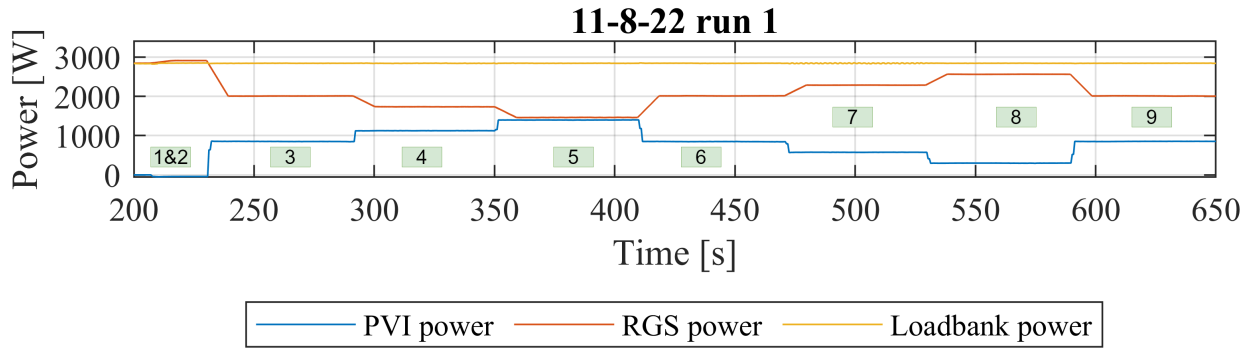


Figure 3.29: Real power during demo 2. The PVI behaves according to droop response.

As frequency deviates from 60 Hz, PVI output power follows a classic droop characteristic and departs from its nominal 850 W setting according to its M_p value specified in Table 3.3. Inspection of PVI reactive power output, shown in Fig. 3.30, suggests that the PVI successfully re-synchronizes after each frequency change.

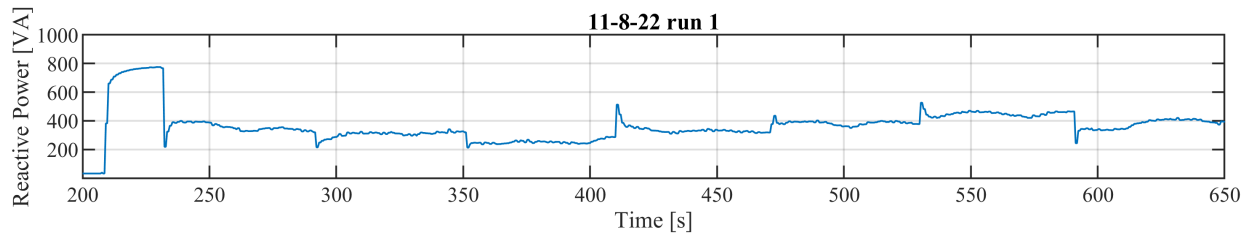


Figure 3.30: PVI reactive power during demo 2.

If the PVI was not successfully re-synchronizing after each frequency change, we would expect its reactive power output to strongly vary with each frequency change. Although the reactive power does change slightly, there are not large spikes as the RGS frequency shifts away from 60 Hz. The PVI reactive power is inversely proportional to real power output. There is a large reactive power output at the beginning of operation, but that is when the RGS energizes only one side of the transformer, before the PVI producing real power. Figure 3.31 shows electrical frequency measured at the PVI during operation.

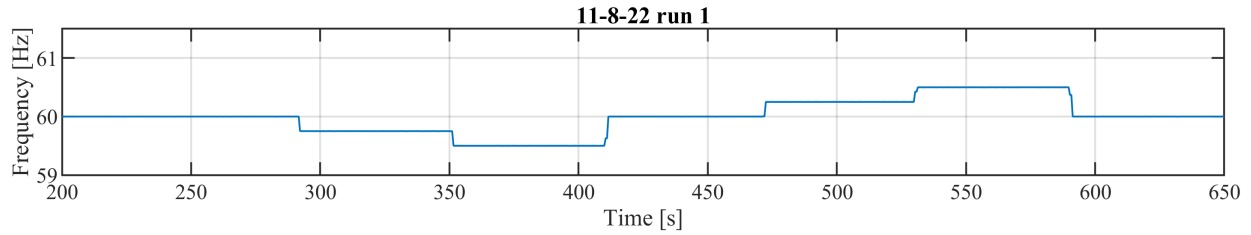


Figure 3.31: measured PVI frequency throughout demo 2. It correctly tracks the RGS setpoints.

In summary, this section describes and demonstrates the electrical functionality of the microgrid testbed. Inverter fundamentals are utilized for establishing reliable operation of an experimental photovoltaic inverter in tandem with the RGS. Human operators can set droop response, power output and operating voltage. An existing WEI microgrid layout is configured for real time PHIL simulations. The *Chroma* RGS' applications and electrical behavior are established. Using *LabVIEW*, computers can remotely program RGS frequency for simulation of frequency response. Real power measurements from the RGS are integrated into a PC lab program for future data feed into a virtual model. Finally, operational demonstrations show that the testbed is ready for the final step: integration of a virtual dynamic plant model. This step is described in the following section.

3.7 Integrating Virtual Model and Physical Testbed

The goal of this testbed design is to create an environment where models and hardware can interact. With the establishment of the CSP model, RGS, PVI, solar panels, and existing microgrid functionality, all elements are integrated for real-time simulation. *LabVIEW* is a commercial standard for data acquisition and is used to monitor and communicate within the PHIL testbed. *LabVIEW*'s *Veristand* add-on facilitates real-time testing of simulation models. The model interface toolkit (MIT) is a *LabVIEW* family of subprograms based on *Veristand* framework that enable a *LabVIEW* master code to open a model, take timesteps, set inputs, and receive model output information in real time. If desired, *LabVIEW* can pass these model outputs as setpoints to electrical hardware. The model only communicates

with the RGS. Measured RGS real power output is used as model input for all simulations discussed during this paper. The only setpoint that can be passed from the model to the testbed is RGS electrical frequency.

Every *Simscape* model must be packaged for export to *LabVIEW* prior to use in a PHiL simulation. The *Simulink* Coder toolbox compiles a *Simscape* model as a dynamically linked library (.dll) file. Models are configured to solve in discrete, fixed timestep intervals, which differs from the adaptive solver steps typically used by *Simscape*. By including an initialization states file during compilation, the CSP model can start at any operating point desired. Real-time simulation presents two challenges: timestep size sensitivities and overrun. When fixed step numerical methods are used to predict the dynamic behavior of a system, the step size must be small enough that the system of equations remains stable. Smaller timesteps ensure stability during simulation but come with a tradeoff. The most computationally efficient method is to take as large of timesteps as possible. If a model is solved over a given computational time horizon — $t_{\text{comp}} = 1 - 100\text{s}$, for example — and assuming the solution is stable, larger timesteps require the shortest clock time, t_{clock} . When the model faces instability, the computation timestep Δt_{clock} is forced to become small, resulting in a larger t_{clock} to evaluate over the same t_{comp} . Fig. 3.32 illustrates this problem. In (a), the computation time steps are solved by the computer faster than the equivalent clock time. This is ideal for offline simulations.

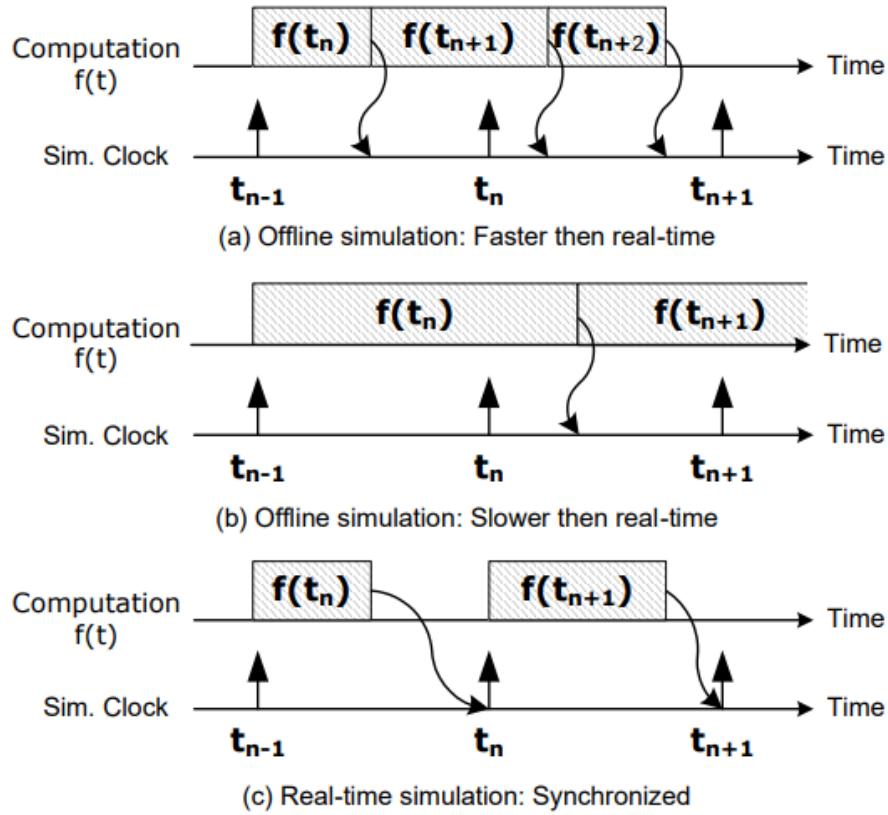


Figure 3.32: comparison of simulation clock and computation timesteps for 3 different types of simulation [14]

In Fig. 3.32 (b), the computation timesteps are taking longer than their equivalent clock times. In offline situations, there may not be serious consequence aside from a longer wait time for results. Real-time simulation requires a more rigorous computation schedule as illustrated in Fig. 3.32 (c). If scenario (b) is realized, the latency results in a mismatch between model input and corresponding outputs, therefore threatening the fidelity of the simulation results. As a result, selecting the proper model timestep requires knowledge of the computer's required Δt_{clock} to take a given Δt_{comp} . Operating experience for the current testbed indicates that a timestep $\Delta t_{\text{comp}} = 50$ ms can, on average, be taken in less than $\Delta t_{\text{clock}} = 30$ ms on a x64-based HP lab computer with a 9th generation Intel core i7 processor. By monitoring average model times, 20 ms of headroom is determined to be adequate for the experiments discussed in this paper.

After creating measurement and model loops for real-time simulation, the *LabVIEW* front panel is populated with waveform graphs that monitor the dynamic response of each output of interest. Figure 3.33 shows a front panel view from a testbed demonstration.

The first graph, "loop duration", helps an operator watch for overrun. The first timestep typically overruns if the model is not properly initialized, but all other timesteps compute within the required clock time of 50 ms. The list of model inports on the left are three of the five inputs seen in Fig. 3.2. The other two, superheater and boiler heating rates are configured for automatic deadband control in this experiment, and are therefore not accessible controls to the human operator. A human operator could, however, change the pump pressure and speed reference using the control cells to the left of the "heat flow" graph. Besides heat flow, and pump pressure, all other graphs in the top panel section are model outputs that can also be found in Fig. 3.2. The real-time Chroma electrical power output measurements are passed as model input and are graphed as a blue line in the power output graph. This specific *LabVIEW* panel is configured for scenario 2 because it also includes a "model calculated frequency" output, whose values are passed as setpoints as seen in "RGS Electrical Frequency". When the plant output fails to match this red line, electrical frequency changes. The frequency graphs of the RGS and model do not line up directly in this figure because the RGS and model operate in separate loops with different execution frequencies. One final change in frequency can be seen on both graphs, however. The RGS electrical frequency's programming precision is limited to increments of 0.01 Hz.

This chapter explains the methodology used to characterize, size, and develop a basic CSP cycle. That cycle is represented in *Simscape* with a set of governing equations that consider dynamic pressure and mass flow effects. Various heating and valve control methods are discussed, including manual and automatic strategies. Plant performance is checked at four different pseudo-steady states, yielding reasonable T-s cycle diagrams. Fundamental operation information is compiled and applied to control several electrical



Figure 3.33: PC 1 front panel in *LabVIEW*. All inputs and outputs can also be found in the *Simscape* model Fig. 3.2

hardware pieces. The WEI microgrid space is introduced and modified for a PHiL configuration that allows the dynamic model and a photovoltaic inverter to communicate using real power measurements. Two demonstrations are performed, showing general electrical system behavior. After compiling the model with a specific set of solving method instructions, a *LabVIEW* program is built to communicate between the RGS and model in real-time. Finally, the testbed's functionality is demonstrated by running a PHiL experiment in real time. The next section assesses and improves the hybrid setup's ability to provide constant or varying plant power to a stiff grid source.

4 LOAD FOLLOWING IN A LARGE-GRID SCENARIO

This chapter considers operation of PV-CSP plants in large-grid scenarios. Of the seven RTO/ISOs that operate in the United States, all reported peak generation of 28 – 165 GW last year [1]. When evaluating a power plant connected to a market grid of this size, the load following accuracy of the plant is the most important aspect to consider. The large grid scenario presented in this chapter is primarily configured to develop and test the PV-CSP plant’s ability to follow a requested power setpoint. The accompanying assumptions are listed in a later section of this chapter. Computer-only simulation is first used to observe dynamic CSP plant reactions during operational setpoint changes. Then, the PHiL large grid scenario is introduced and described. Finally, PHiL testing is used to assess and improve CSP control performance during tandem operation with physical PV hardware.

4.1 Dynamics Observed in Computer-Only Simulation

Computer-only simulation reveals that our dynamic model exhibits two key dynamic behaviors: steam drum liquid level instabilities and turbine power pulses. Although other dynamic behaviors also occur during simulation, this section focuses on these two behaviors because they commonly occur during testing and therefore drive other operational decisions. Only automatic valve control and manual heating are used to control the plant, but it becomes clear that control improvements are necessary.

Drum Liquid Level Changes

As mentioned in Chapter 3, steam drums are pressure vessels, typically with complicated internal structure as seen in Fig. 4.1. Their primary purpose is to separate incoming mixed-quality steam flow from the evaporator into high quality steam and low quality

recirculation water [64]. Proper function of the steam drum requires liquid water levels to stay within a specified range. Instabilities in steam drum liquid levels are normally caused by a failure to match steam flow rates with steam generation rates. Low liquid levels — referred to by this paper as “dryout” — occur when the fluid inside the drum’s is primarily steam. High liquid levels — referred to as “flooding” — result from excessive feedwater inflow for sustained periods of time.

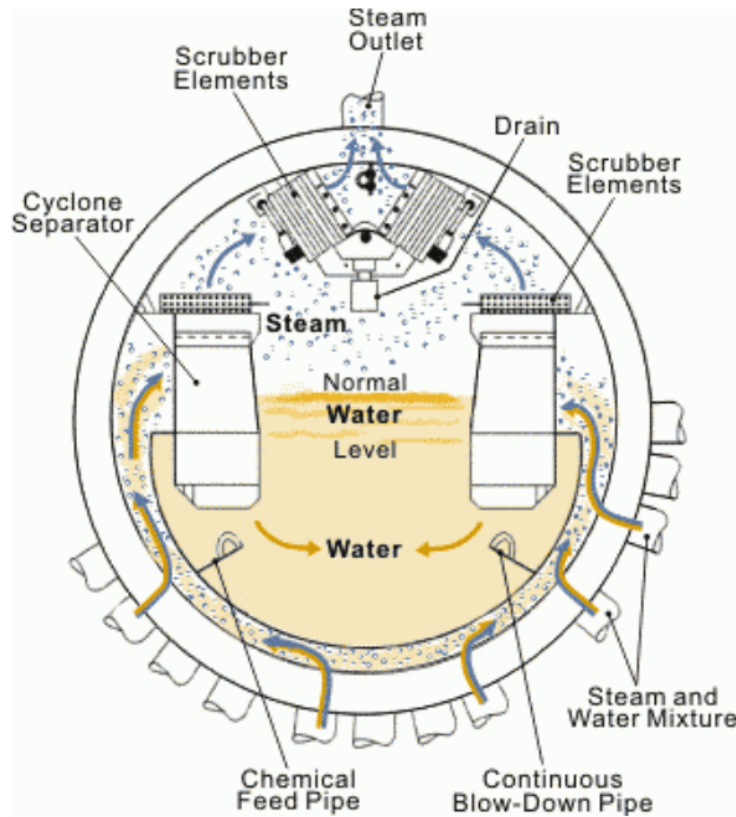


Figure 4.1: Steam drum cross section showing the complex internal structure [15]

Steam Drum Dryout

A simulation is performed to demonstrate drum dryout behavior. The CSP plant is initially at 100% power with 100% of rated heat flow to the superheater and boiler. At 60s, the requested turbine power is reduced to 75% and causes a decrease in the turbine inlet valve area. Heating stays at initial 100% levels, resulting in an overproduction of steam.

Pump pressure is increased at 90s in an attempt to re-establish feedwater flow. Figure 4.2 shows the timeseries data for several key variables.

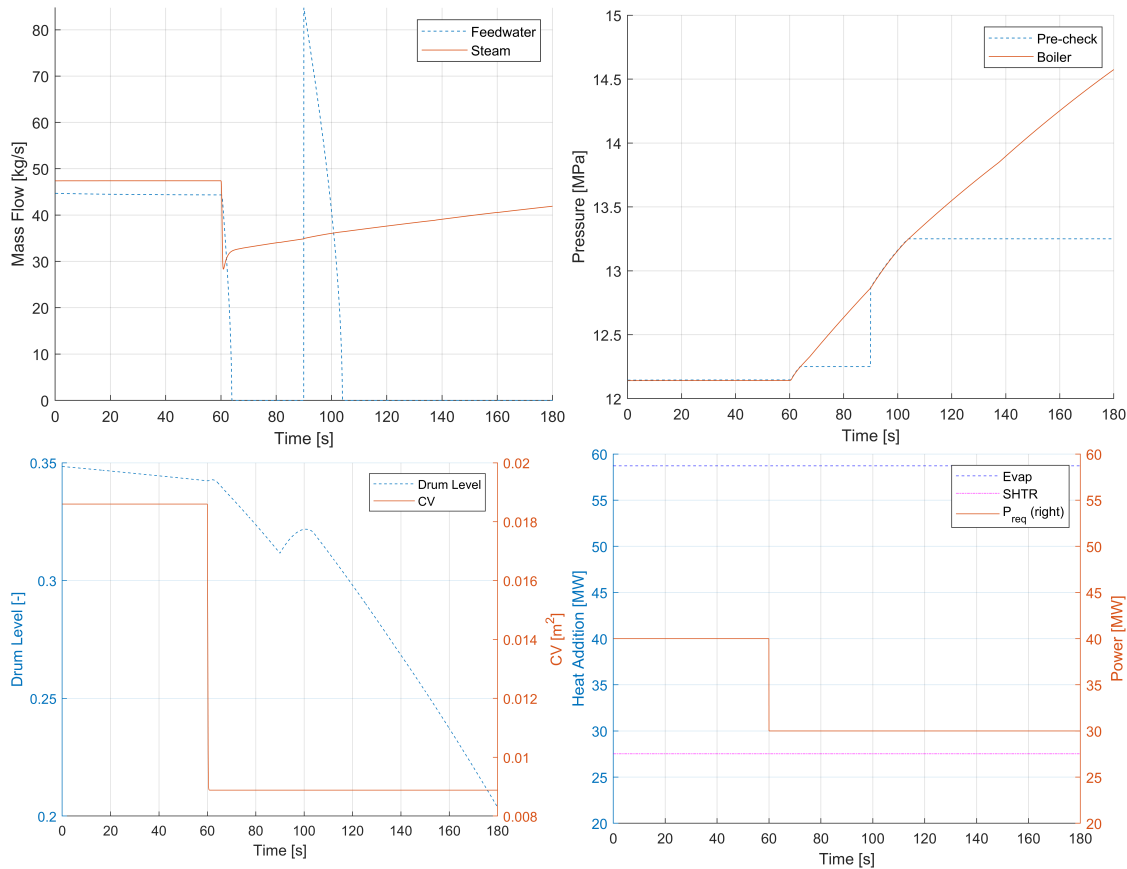


Figure 4.2: Dryout of the steam drum due to closing of downstream control valves.

Pressure differences drive every mass flow in the Simscape model. As the cycle schematic in Fig. 3.1 illustrates, flow into the boiler is based on the pressure rise provided in the final stage pump. Feedwater can only flow into the boiler — the check valve prevents any reverse flow. The turbine inlet valve controls downstream system pressure losses and therefore regulates steam flow out of the boiler. These principles explain the behavior seen in Fig. 4.2. When the requested turbine power reduces at 60s, the control valve simultaneously decreases its open area. Even though steam mass flow decreases, keeping the heat addition constant means the steam production rate does not decrease. Consequently, boiler pressure rises as steam accumulates. Feedwater can no longer flow through the check valve once the boiler pressure exceeds the pressure at check valve

inlet (pre-check in figure). The high boiler pressure completely stalls the pump because a bypass loop is not included in our model. When the pump pressure is increased at 90s, the decline in drum level is temporarily arrested. Feedwater flow eventually stops, however, as drum pressure continues to rise. Fig. 4.2 also shows that steam mass flow rises even as turbine inlet valve area stays constant. This is due to the increased boiler pressure driving a higher mass flow through the turbine. This simulation effectively demonstrates what happens when there is a large mismatch between feedwater flow and steam generation. However, this simulation may not be fully realistic. Our model does not include a drum pressure regulator valve, which power plants could use to ensure that the drum pressure always stays low enough to allow feedwater inflow. It is possible that omission of this valve forces us to operate the boiler more efficiently. Proficient management of steam drum dynamics without a pressure regulator ensures that the pressure regulator valve is not overly depended on. A constant venting of excess steam would generate entropy and therefore decrease cycle efficiency. Regardless of the presence of a drum pressure regulator valve, in practice, feedwater flow cannot fully stop — it must continue circulating via a bypass loop to prevent a loss of suction in the feedwater heaters.

Steam Drum Flooding

Next, a simulation is performed to demonstrate drum flooding behavior. The CSP plant begins simulation operating at 75% power with 75% heating. At 60s, requested power changes to 100% and causes the turbine inlet valve to further open. Pump pressure is reduced at 90s. Heating remains at its original part-load setpoint. Timeseries data for variables of interest is shown in Fig. 4.3.

Insufficient steam generation rates are caused by heating setpoints remaining low even as steam flow increased. Figure 4.3 shows that this steam imbalance results in rapidly decreasing boiler pressure. Since the drum's steam has significantly higher specific

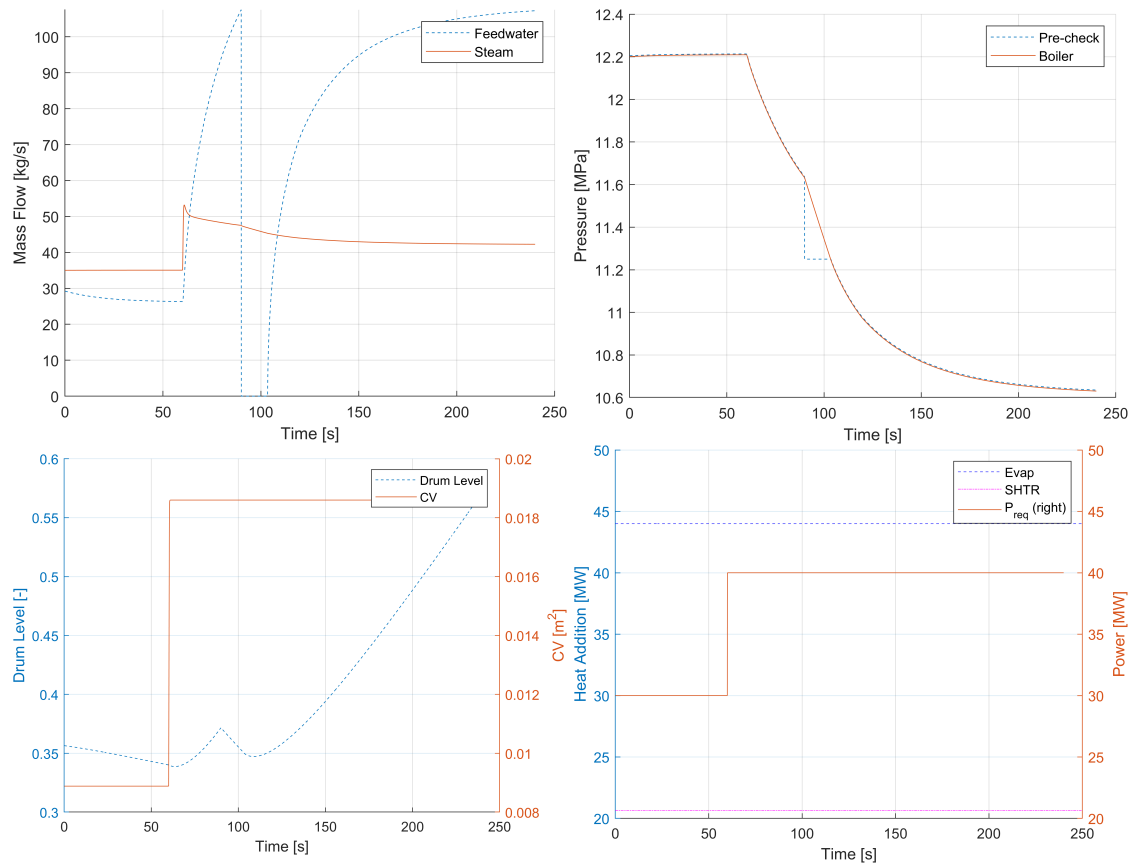


Figure 4.3: Flooding of the steam drum due to closing of downstream control valve.

volume compared to the liquid, boiler pressure continues to drop despite a net storage of liquid mass in the drum. The pump pressure decrease at 90s momentarily halts feedwater flow, but boiler pressure continues to drop. Downstream of the pump, pressure before the check valve stays constant around 70 – 105s when it is less than the boiler pressure because the check valve closes.

In regards to pump pressure control of drum level, these simulations indicate that it may only offer a short-term solution to fluctuating drum levels and that steam generation rate is a more effective control. In general, if heating addition is not adjusted accordingly, increased requested power results in drum flooding and *vice versa*. A mismatch in steam generation can be utilized for returning drum levels within an established range, however. Heating control with a deadband region, as described in Chapter 2, capitalizes on this strategy. Implementation of this is shown in Fig. 4.14, where heating decreases if drum

levels fall below L_{low} and increases if drum levels surpass L_{high} .

Turbine Power Pulses

The CSP plant can provide temporary spikes of turbine power output if sufficient boiler pressure exists. Four simulations are run to demonstrate this and the results are plotted in Fig. 4.4. Turbine inlet area is throttled to 0.14, 0.16, 0.20, and 0.28% open, and the heating setpoint remains at 100% to build boiler pressure. Maximum plant power is requested slightly after 60s.

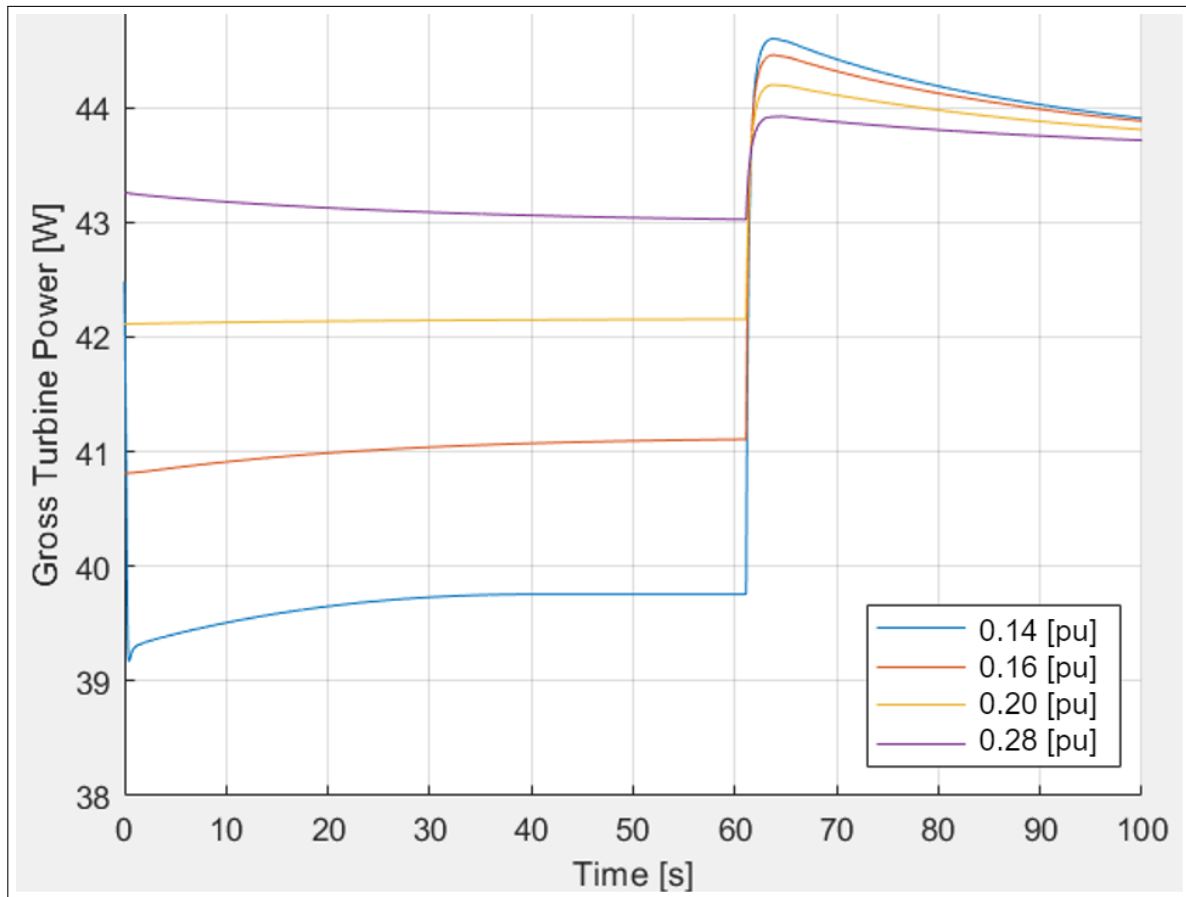


Figure 4.4: The steam drum has different pressures which causes varying capabilities to sustain increased power output.

Figure 4.4 shows that throttling of steam flow yields the largest peak power and longest sustained pulse. The model is behaving as expected, exhibiting behavior commonly seen

when plant boilers operate with throttled steam flow.

4.2 PHiL Testing

Computer-only simulation identifies key dynamic behaviors and brings attention to several controller complexities. PHiL testing in this chapter extends the scope of dynamic study to include inverter details and consider effects of varying PV production during cloudy weather. This section presents the large-grid scenario and its assumptions, shows hybrid performance on fully sunny days, and evaluates constant load operation on cloudy days.

Large-Grid Assumptions and Test Topology

The PHiL testbed is used to consider two power generation scenarios: large and small grid scenarios. In a large-grid scenario, there is sufficient reserve generation elsewhere on the grid and inertia to compensate for any PV-CSP load following error. The large-grid scenario does not consider grid effects. The small-grid's scenario does imply that PV-CSP load following error causes a subsequent decrease in electrical frequency of the grid, and this is investigated in Chapter 5. The large-grid scenario is developed for evaluating PV-CSP plant capability to follow load setpoints or maintain constant load during cloudy weather. Testbed and large-grid scenario assumptions are formalized as:

1. **PV-CSP power** is defined as the sum of PVI real electrical power and model-calculated CSP turbine power output. It is the power output this PV-CSP plant produces at any moment in time depending on operating state.
2. **Testbed power** is the real electrical power produced by the lab's electrical hardware: the PVI and RGS.

3. **Requested power** is the consumed real electrical power at the resistive loadbank. Due to the lab's electrical configuration, Testbed power always equals requested power.
4. Testbed/requested power measurements are scaled for RTS use according to $4.8\text{kW}_{e,\text{lab}} : 40\text{MW}_{e,\text{model}}$ for comparison to simulated power.
5. **Load following error** is the difference between RTS calculated PV-CSP power and testbed power. Since the CSP plant is expected to supplement the PV output, load following responsibility ultimately falls on the CSP plant.
6. Any load following error of the PV-CSP plant does not affect grid stability - the grid is large enough that one hybrid plant's effect is insignificant.

Fig. 4.5 illustrates the flow of electrical power, model information, and measurements in the large-grid scenario. The RGS and PVI's combined testbed power always meets requested power in the electrical load. The model interfaces with the testbed through its power amplifier — the RGS, which operates as an ideal voltage source that always compensates for PVI power fluctuations. This means that $P_{\text{elec,RGS}} = P_{\text{load}} - P_{\text{elec,PV}}$ is always true. Measured $P_{\text{elec,RGS}}$ is passed as a power setpoint for the CSP model. Frequency is controlled by the RGS and remains constant during Chapter 4's tests. PC#1 manages model-RGS interface and serves as the RTS. PC#2 measures testbed power flow at the electrical load and PVI.

Note that this PHiL testbed loop is not fully closed — meaning there are no model outputs feeding back to system hardware during tests. Thus, the PHiL testbed only provides high-quality real-time inputs to the CSP model.

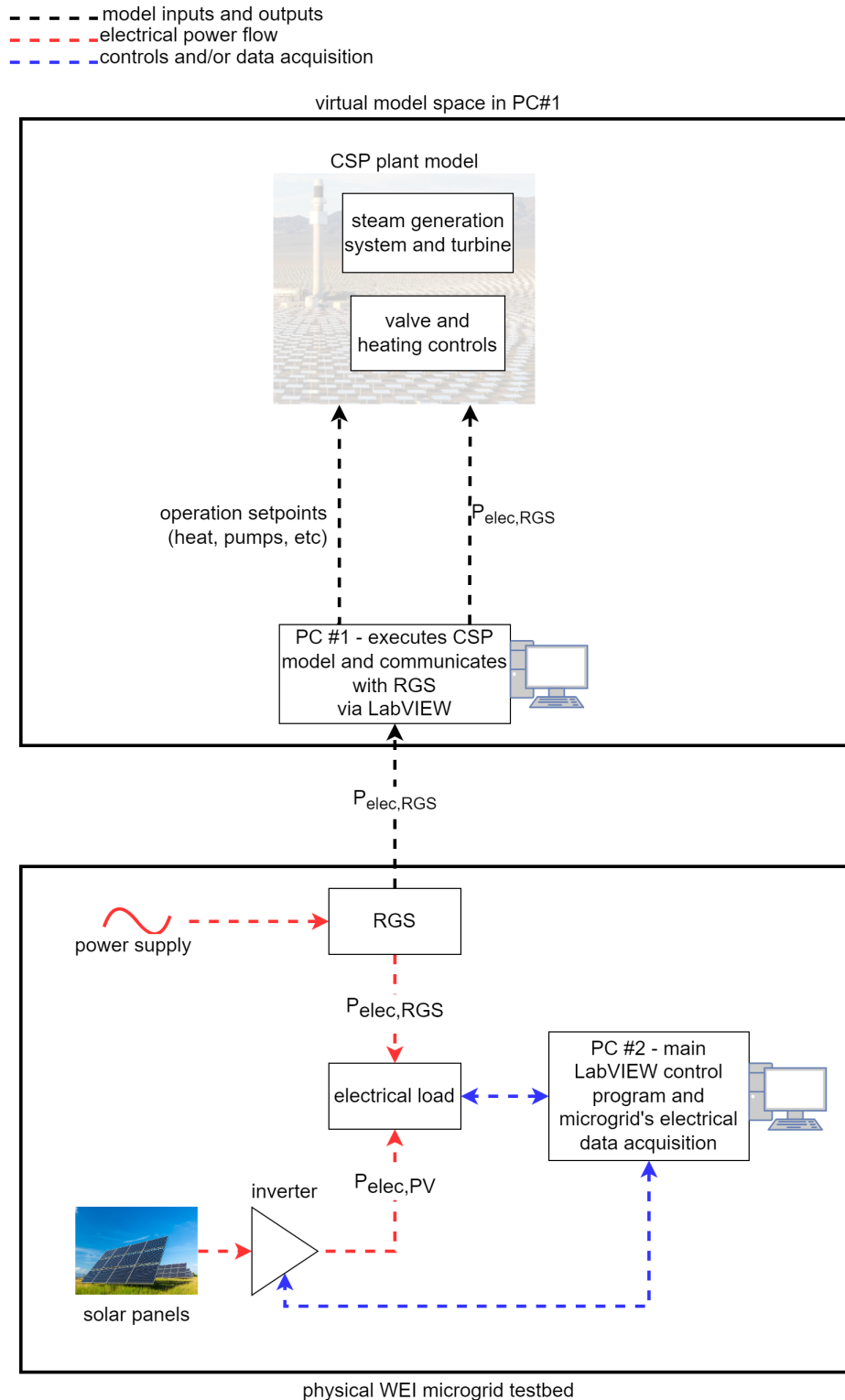


Figure 4.5: Testbed configuration for large-grid scenario.

Sunny Day Test

The overarching PHiL testing goal is to gain insight into dynamic behavior regarding how hybrid plants might export power to a very large-grid. The large-grid scenario can evaluate situations where keeping hybrid net electrical power output constant might be a challenge. The first PHiL test shown is from a fully sunny day and data is shown in Figures 4.6–4.8. This test starts with the loadbank set to draw 4.8 kW_e of requested power. The RGS output is enabled before the PVI and completely meets the requested power. Around 50s, the PVI begins to output approximately 0.85 kW_e , thereby reducing testbed power that the RGS must produce. PC#1 scales up the the measured electrical powers observed in Fig. 4.6 into MW-scale inputs for the CSP model.

The drop in RGS electrical power immediately affects the CSP model as shown in Figure 4.7. When RGS power decreases, the turbine inlet control closes according to the automatic valve control described in Chapter 3. Figure 4.7 shows model calculated turbine power and the RGS contribution to lab power output — $P_{elec,RGS}$. The difference between these two lines is the load-following error. Maximum valve speed determines the lag observed between RGS power and turbine power at approximately 50s. Immediately after throttling, turbine power begins moving toward exceeding the requested electrical power. However, a decrease of the heating setpoint results in turbine power settling below its target. This can be explained by again considering the automatic valve control. The automatic valve control was calibrated at 100% heating rates and constant boiler pressure and has some error when operating off of its calibration point. The second heating setpoint change just after 200s further exacerbates steady state error.

Figure 4.8 shows timeseries plots for model variables of interest. The turbine control valve partially closes upon PVI startup and remains constant throughout the test. The flow plotted Figure 4.8 refers to steam flow out of the turbine. The drum liquid level exhibits a nadir at approximately 200s, just before heating is further decreased. Overall, the CSP plant tracked requested electrical power through a constant PVI output test with

less than 3% error. Turbine inlet pressure changes more than the boiler, with a maximum change of 2 MPa. Maximum boiler pressure change, though significant, is less than 0.25 MPa.

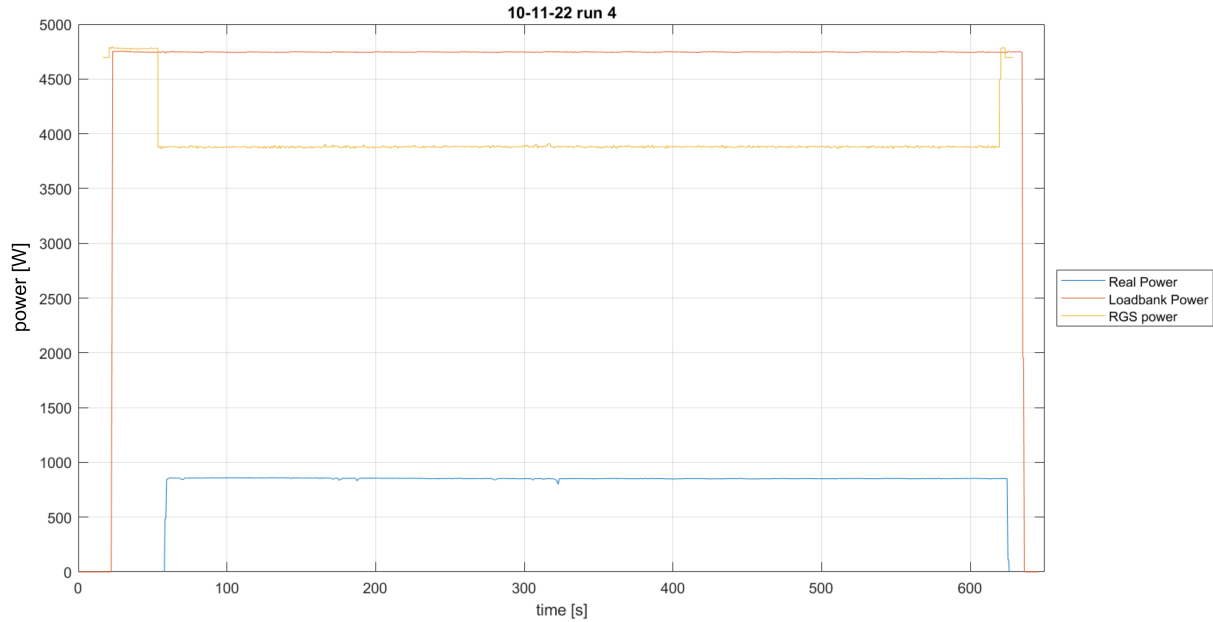


Figure 4.6: Electrical power exchange between PVI, RGS, and loadbank on a sunny day. Note that absolute value of consumed loadbank power is plotted here.

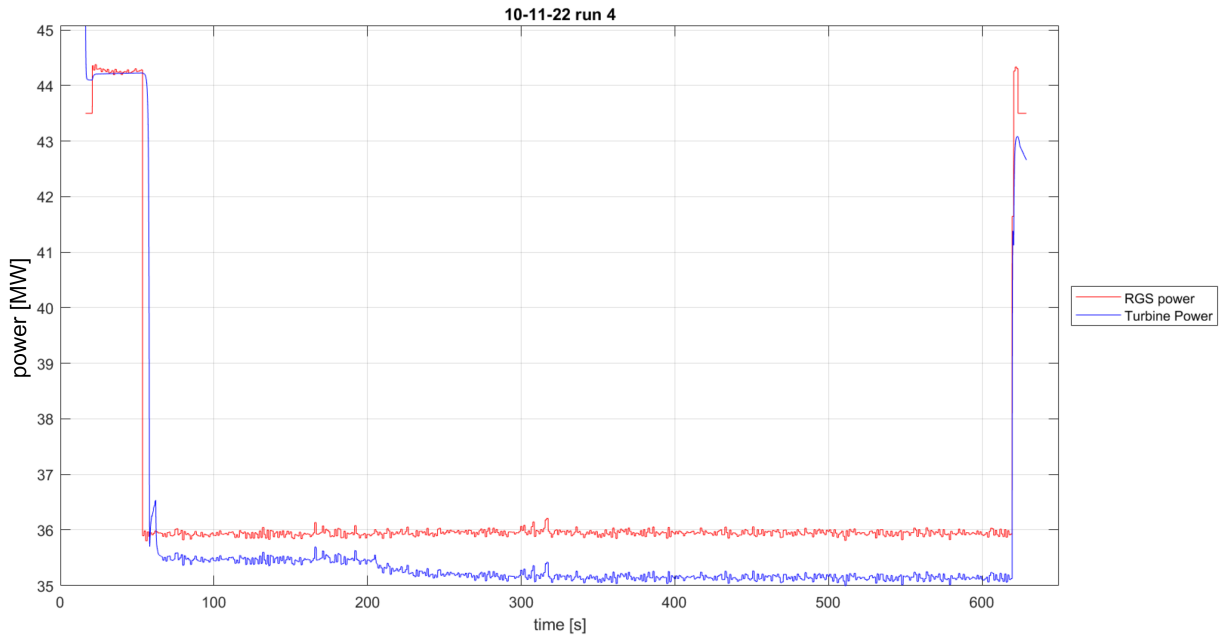


Figure 4.7: CSP plant setpoint tracking during sunny day test.

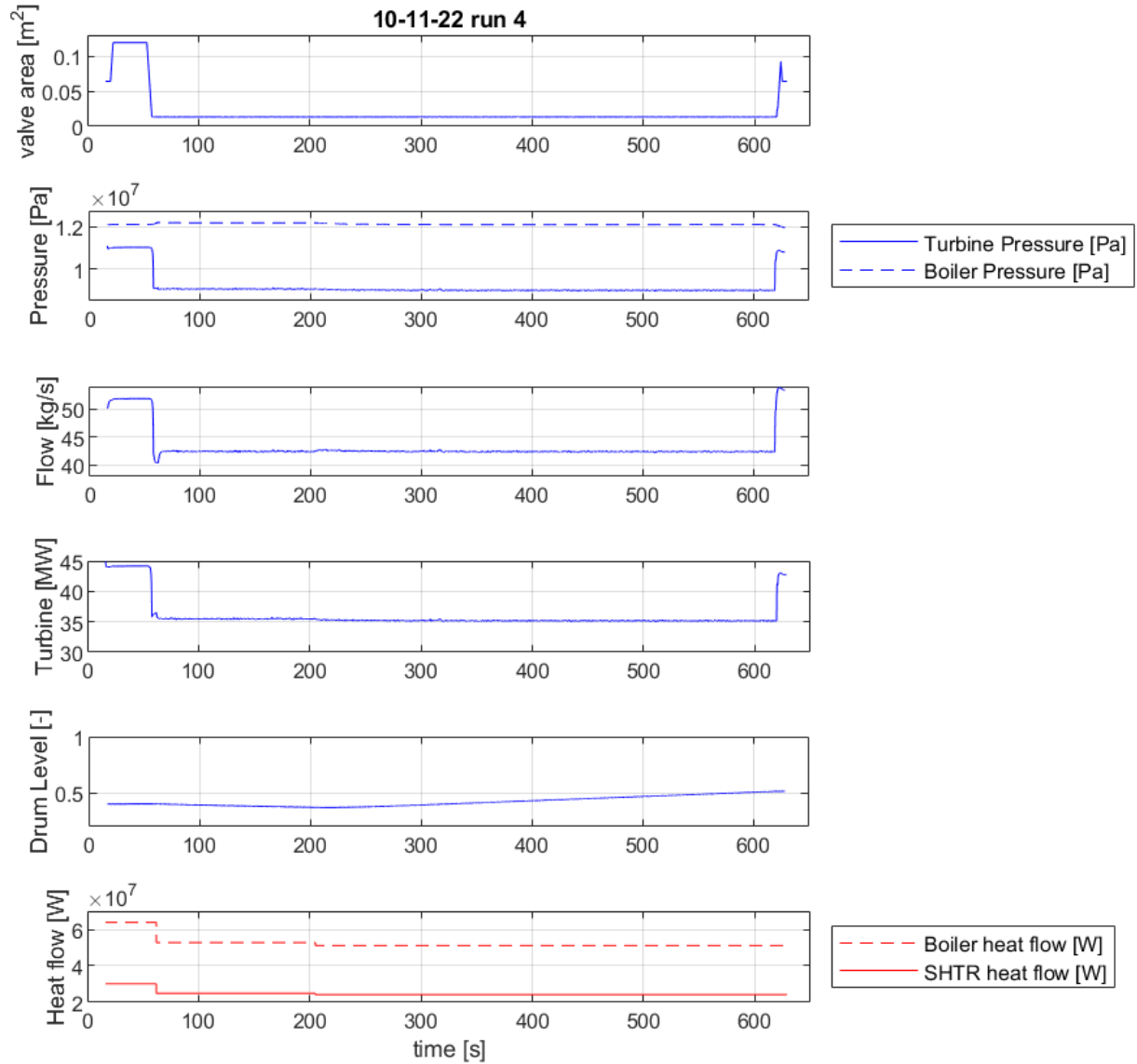


Figure 4.8: CSP state variables of interest during sunny day test.

Cloudy Day Tests

Cloudy day PHiL tests build on the control case provided by sunny day operation. Physical testbed operation is the same as that of the sunny day test and lab power flow is shown in Fig. 4.9. PVI and RGS cumulative lab power output must always match requested loadbank power. The PVI is programmed to provide a maximum 12.5% of requested electric power and seek the MPPT if cloud cover limits output to less than 12.5%. In

other words, the inverter is set to clip power output that exceeds the 12.5% limit for this simulation. The first 200s operate similarly to the sunny test. Cloud cover around 400s causes a boiler pressure drop as steam flow rate exceeds the generation rate. An increased load following error exists after this large cloud event because of boiler pressure drop. Boiler pressure continues to drop, resulting in steam drum flooding, until heating is adjusted to 90% at 550s. Although the next period of cloud cover between 800 – 1000s causes a boiler pressure drop, load following error is reduced because boiler pressure is better maintained throughout the event. After 1000s, clouds continue to affect PVI power production, but the short duration events do not significantly impact CSP plant operation.

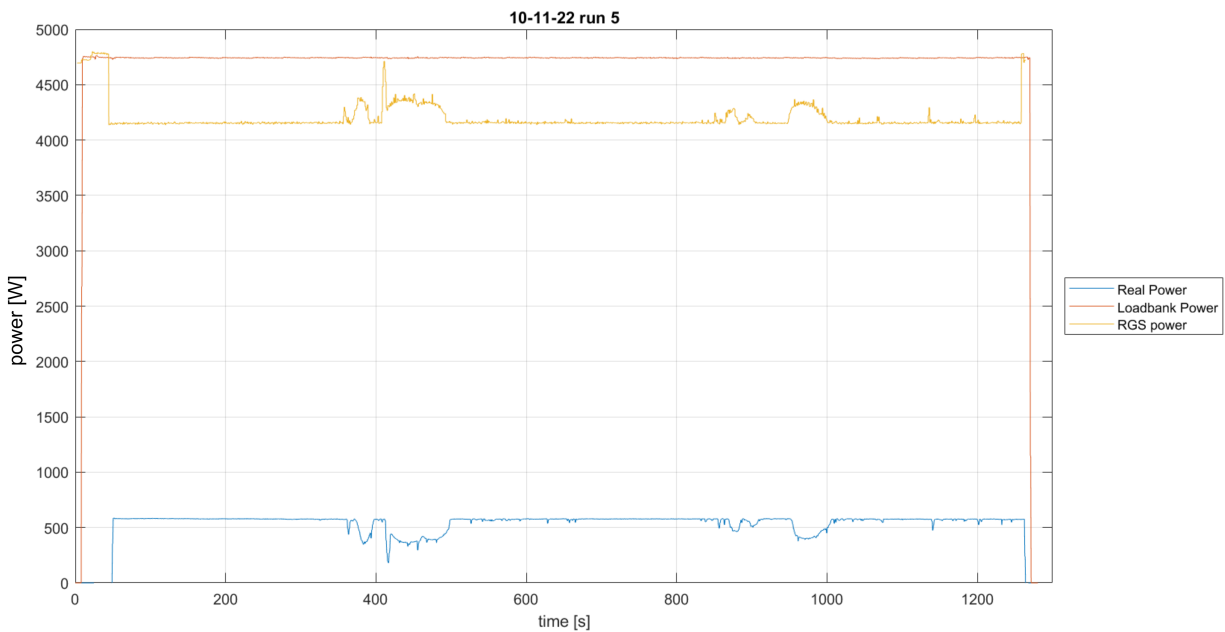


Figure 4.9: Scaled power exchange as seen by the testbed for cloudy day test.

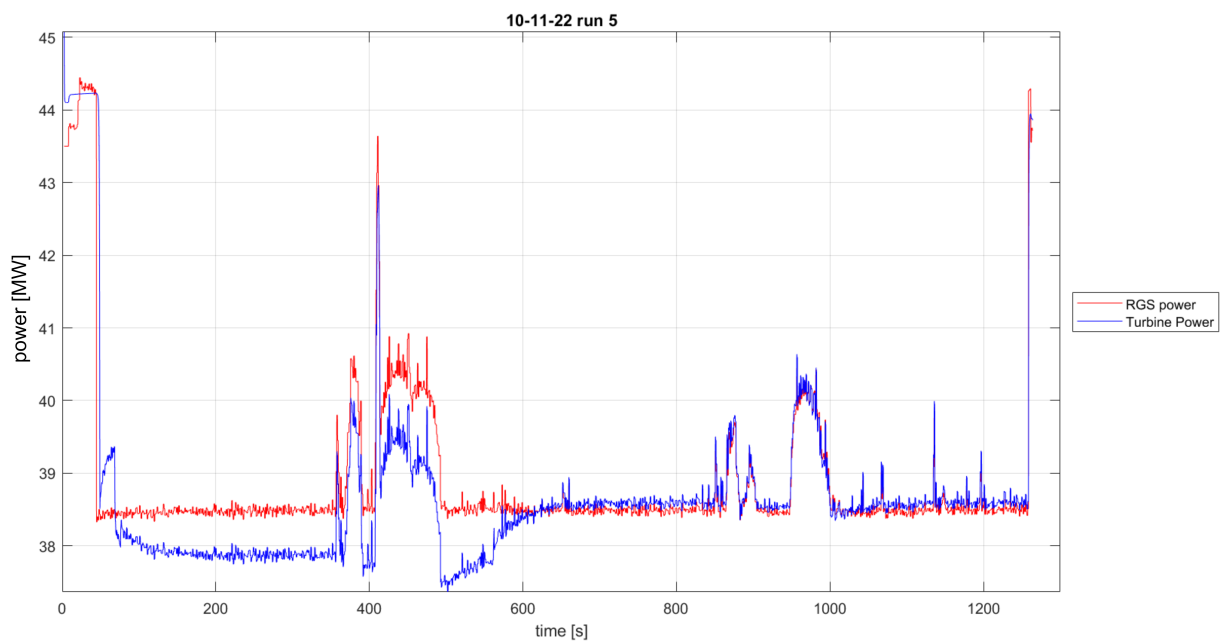


Figure 4.10: CSP plant setpoint tracking during cloudy day test.

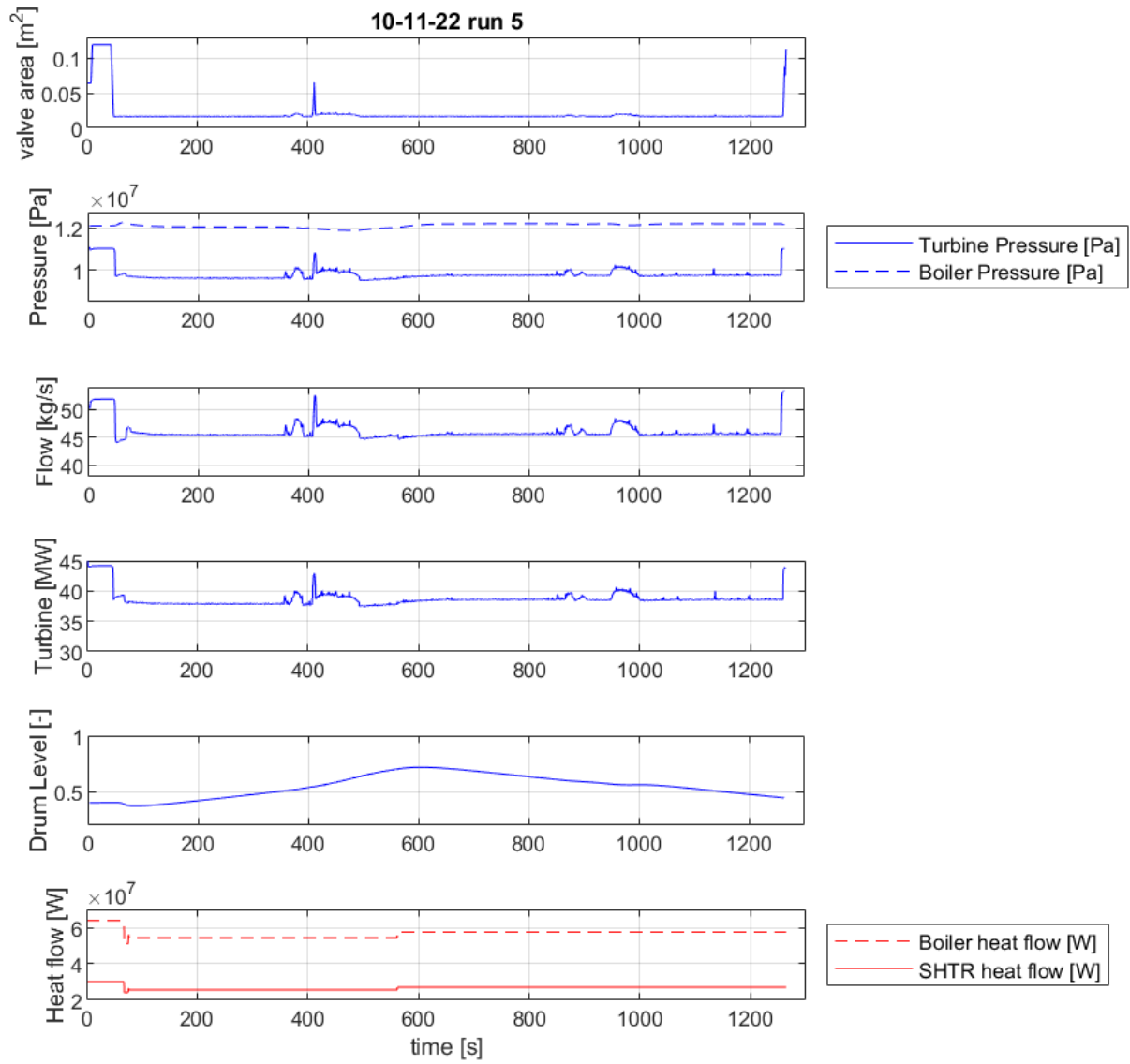


Figure 4.11: CSP state variables of interest during cloudy day test.

Implementation of a PI Controller

PHiL tests show that the CSP plant's boiler pressure sometimes depart from the automatic control's design pressure during cloudy periods. The automatic valve control must alter its signal accordingly to reduce load-following error. To accomplish this, a PI controller is added to the valve control system in the CSP *Simscape* model as shown in Fig. 4.12. Similar to Fig. 3.2, the inputs are colored red and output is colored green. Plant turbine power (CSP_{power} in Fig.) provides feedback for calculated setpoint error. Calculated error feeds into the PID controller whose gains are $K_p = 1.6$ and $K_i = 0.3$. The PID signal combines with speed control and setpoint signals before being translated into a valve position signal. Anti-windup tracking is also included in this system due to severe windup-induced plant delay observed in initial testing. PI controllers experience windup during long periods of significant steady state error. This is a concern in power plant operation when load following error is unavoidable. If the setpoint suddenly changes, it is important to clear the integrated load following error from the PI controller so that it correctly transitions to following the new setpoint and doesn't attempt to negate accumulated error by producing a control signal that simply reverses the sign of the error. PI controllers in *Simscape* prevent integrator windup by enabling tracking mode feedback [65]. Tracking feedback helps the PI controller determine what the new setpoint is at any given timestep.

A load-following test is conducted to evaluate the effect of adding a PI controller. As seen in Fig. 4.13, the load bank is switched from 4.8 kW_e to 5.7 kW_e every minute, and PVI power remains constant. Figure 4.15 shows that load following error stays minimal throughout the test. Heating control maintains drum levels and the PI controller adjusts the turbine inlet valve to maintain constant turbine power. PI signal tracking eliminates all windup error observed in initial PI testing except for two undershoots at the beginning of the third and fourth load cycles. The CSP plant model is shown in Fig. 4.14 to enter these cycles with a more open valve position compared to the other cycles. Since the turbine valve does not change positions instantly, the load following error incurred during

valve closure causes some minor undershoot. No other load cycles cause turbine power undershoot because the valve does not have to travel as far.

In summary, this chapter investigates CSP plant dynamics during computer-only simulation and PHiL testing. Steam drum dryout and flooding events are simulated and demonstrate that drum level is best controlled by timely adjustments of SGS heating. In situations where heating is out of the operator's control, an alternative would be to control power demand. Turbine pulses, though seen in computer-only simulation during step changes in requested power, are not observed during cloudy day PHiL tests. Actual PVI power fluctuations are expected to be more gradual than step behavior. The simulated step input is unlikely to occur during actual operation unless a PV outage occurs. It is observed that the RGS has some constant small variance in power measurement data during operation. This is considered measurement noise and must be accounted for when considering the actual effect clouds have on PVI power production. The fully sunny PHiL test can be used as a direct comparison to determine what power fluctuations are due to cloud cover versus measurement noise. The steady state RGS power varies less than 100 W during the sunny day test. Thus, RGS measurement changes that exceed 100 W are assumed to be caused by actual PVI power fluctuations. PHiL testing confirms that PI control addition is necessary and also visualizes dynamic CSP behavior during cloud events. Finally, a PI controller is implemented and successfully eliminates steady state load following error even when heating adjustments are made.

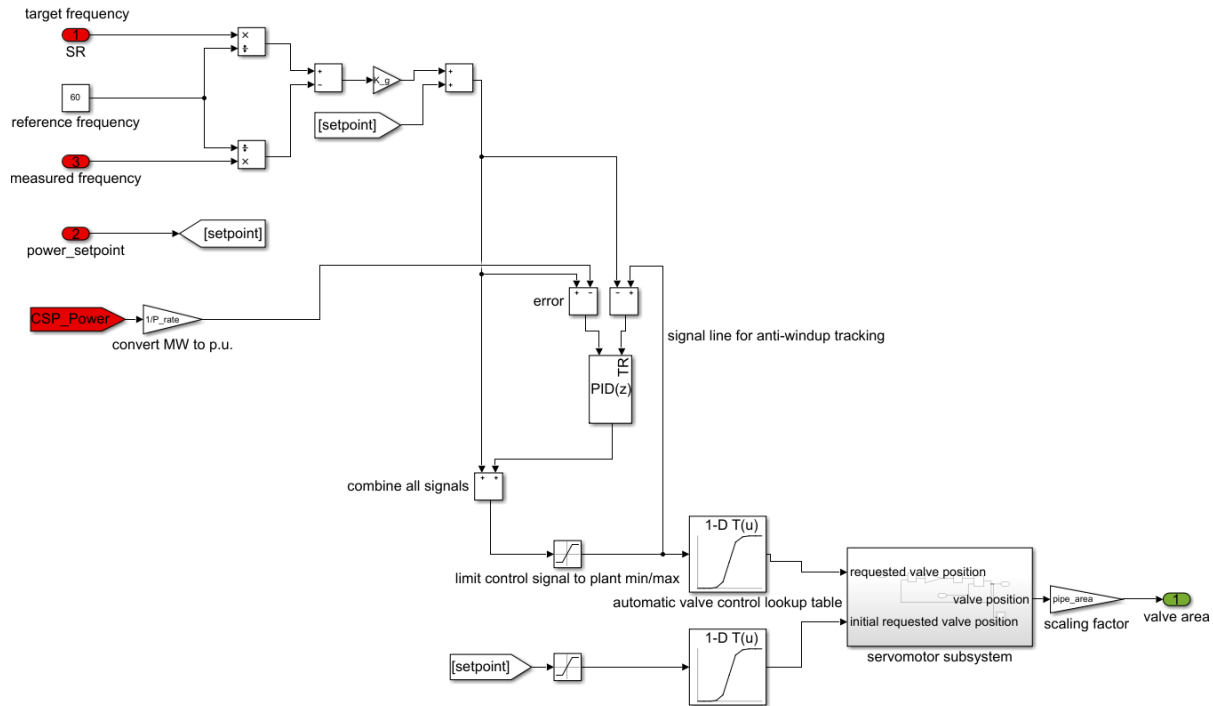


Figure 4.12: PI controller addition to valve control systems discussed in Chapter 3.

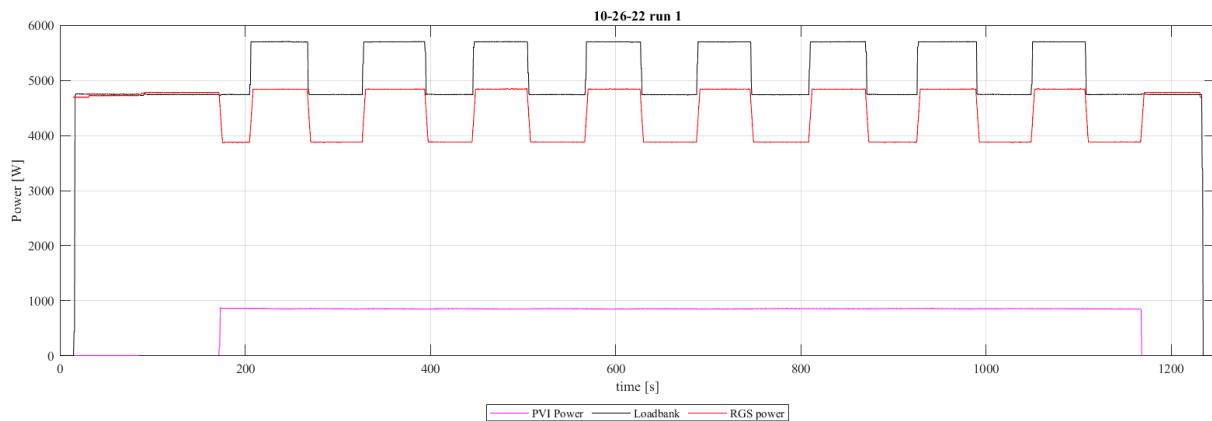


Figure 4.13: Scaled power exchange as seen by the testbed for load following test.

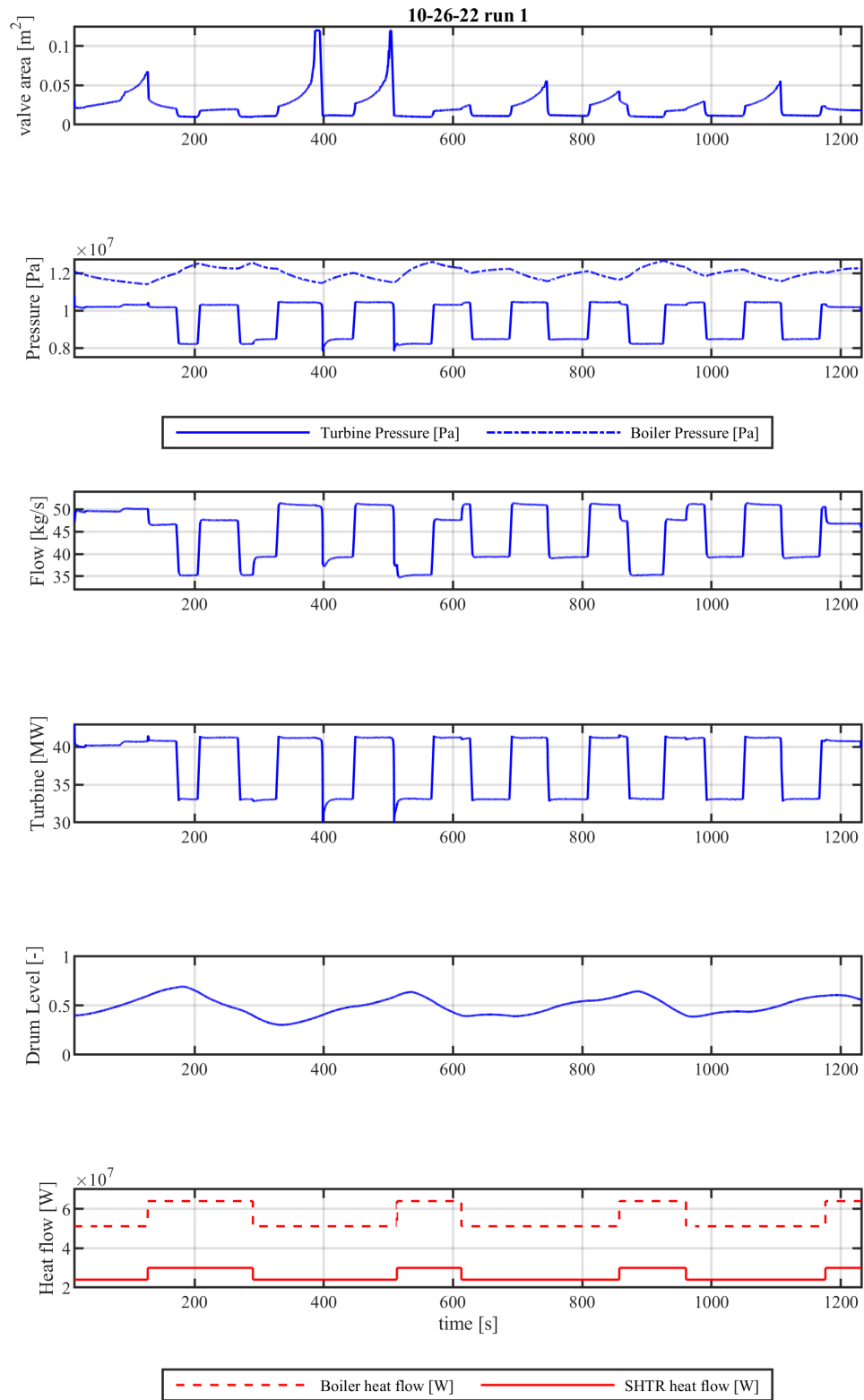


Figure 4.14: CSP plant setpoint tracking during load following test.

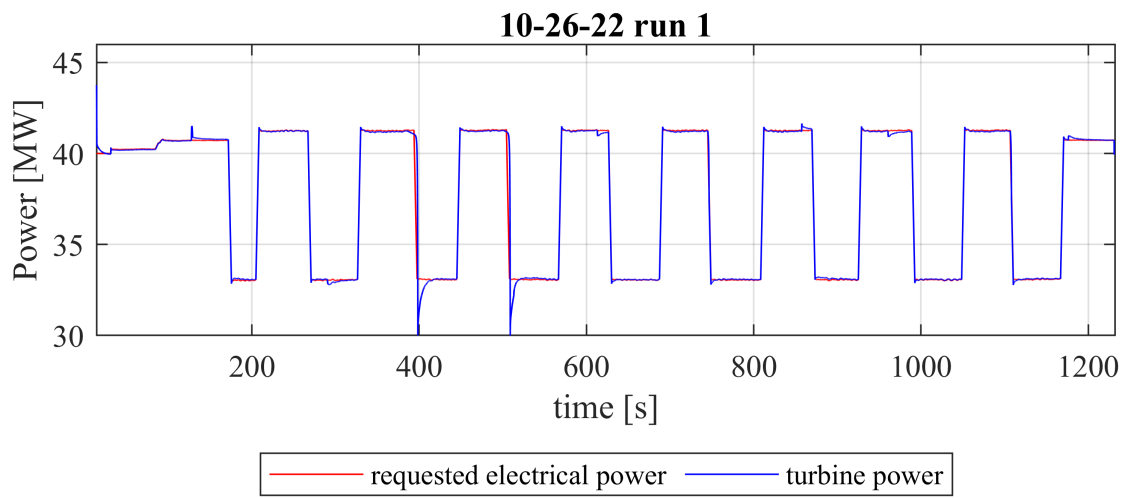


Figure 4.15: CSP state variables of interest during load following test.

5 INVESTIGATION OF VARIABLE FREQUENCY SITUATIONS

Although the large-grid assumption is useful for development of controls and basic plant dynamics, the large-grid scenario does not provide any insight on this hybrid plant's response to frequency changes. Power generation changes in large grids at one node are too small relative to the whole system. However, individual generators can have significant effects on power system stability in small grids because they comprise a larger fraction of total generation. Small-grid scenarios are defined in this research to be those with less than 1 GW of total generation. Examples of small grids include islands, military bases, mining operations, and isolated communities with limited transmission access. Use of solar resources in these situations may be more lucrative if fossil fuels are scarce. Reliable generation in these cases is not only profitable, it is essential; generation disruptions in small-grid scenarios can cause significant variations in electrical grid frequency. This chapter investigates frequency deviations during a loss of generation event as well as PV-CSP plant dynamics during cloudy conditions. First, a PV-CSP plant with $P_{\text{rate}} = 40 \text{ MW}_e$ is tested in simulated grid sizes of 900, 700, and 500 MW_e . The PVI is powered by the solar emulator, which executes a pre-programmed cloud cycle. Finally, the same PV-CSP plant is tested for a 300 MW_e grid scenario during which the PVI is powered by rooftop solar panels.

5.1 Small-Grid Assumptions and Testbed Topology

In large-grid scenario PHiL testing, grid frequency is assumed to be independent of the hybrid plant's load following accuracy. In contrast, this small-grid scenario considers the effect of load following accuracy on grid system frequency stability. The small grid has the following assumptions:

1. The PV-CSP plant's thermally-driven synchronous generator can use its spinning

inertia as reserve power (P_{inertia}), which involuntarily acts as a source or sink to address any mismatch between turbine power and the CSP's portion of the requested power. The model assumes Equation 5.1 will always be followed, where $P_{\text{req,total}}$ is power requested by the load bank scaled to the virtual model units.

$$P_{\text{turbine}} + P_{\text{PV}} + P_{\text{inertia}} = P_{\text{req,total}} \quad (5.1)$$

2. The PVI does not have any physical inertia, but its power output can reduce the need for power from rotational inertia.
3. There is no load shedding on the grid side during cloudy events. If PVI power output changes, the thermal generator immediately compensates for the electrical power difference so that PV-CSP power always meets requested power.
4. All other power generation on the grid $(1 - P_{\text{rate},e}/S_B) \%$ is ideal and perfectly load-following. The output power of other grid-connected units instantly matches the required electrical power for any given timestep.
5. The PV-CSP plant is responsible for providing $P_{\text{rate},e}/S_B \%$ of grid power at all times. When P_{inertia} must be used, the corresponding frequency change of the total system depends on the fraction of total generation that the PV-CSP plant comprises $P_{\text{rate},e}/S_B \%$.
6. The lab's requested power represents the grid load responsibility of the PV-CSP plant model according to the scale $4.8 \text{ kW}_e : P_{\text{rate},e} \text{ MW}_e$.

Figure 5.1 shows the flow of electrical power, data, and model outputs throughout the testbed. Most details are the same as the large-grid PHiL scenario (Fig. 4.5), but data flow between RGS and PC#1 is now bidirectional — this is a closed loop PHiL test. RGS power measurements ($P_{\text{elec,RGS}}$) are passed as input to the RTS, which in turn passes updated electrical frequency setpoints (f_{new}) back to the RGS. On the physical side, power flows

between all three machines and is dissipated in the electrical load. In accordance with the assumptions established, the RGS acts as an ideal voltage source providing whatever electrical power is required beyond what the PVI contributes. PVI frequency is able to resynchronize with the RGS as f_{new} changes. $P_{elec,RGS}$ is the primary input from the physical testbed, but operational inputs including heating, pump pressure, and speed regulation can also be set by the human operator at PC#1. On the virtual side, the RTS model is very similar to that used in Chapter 4. The modeling difference is that grid inertia is now considered. If the model output fails to meet $P_{elec,RGS}$, the frequency change is dependent on the size of the grid according to Eq. 5.2. The next section describes how grid inertia is considered and added to the RTS model.

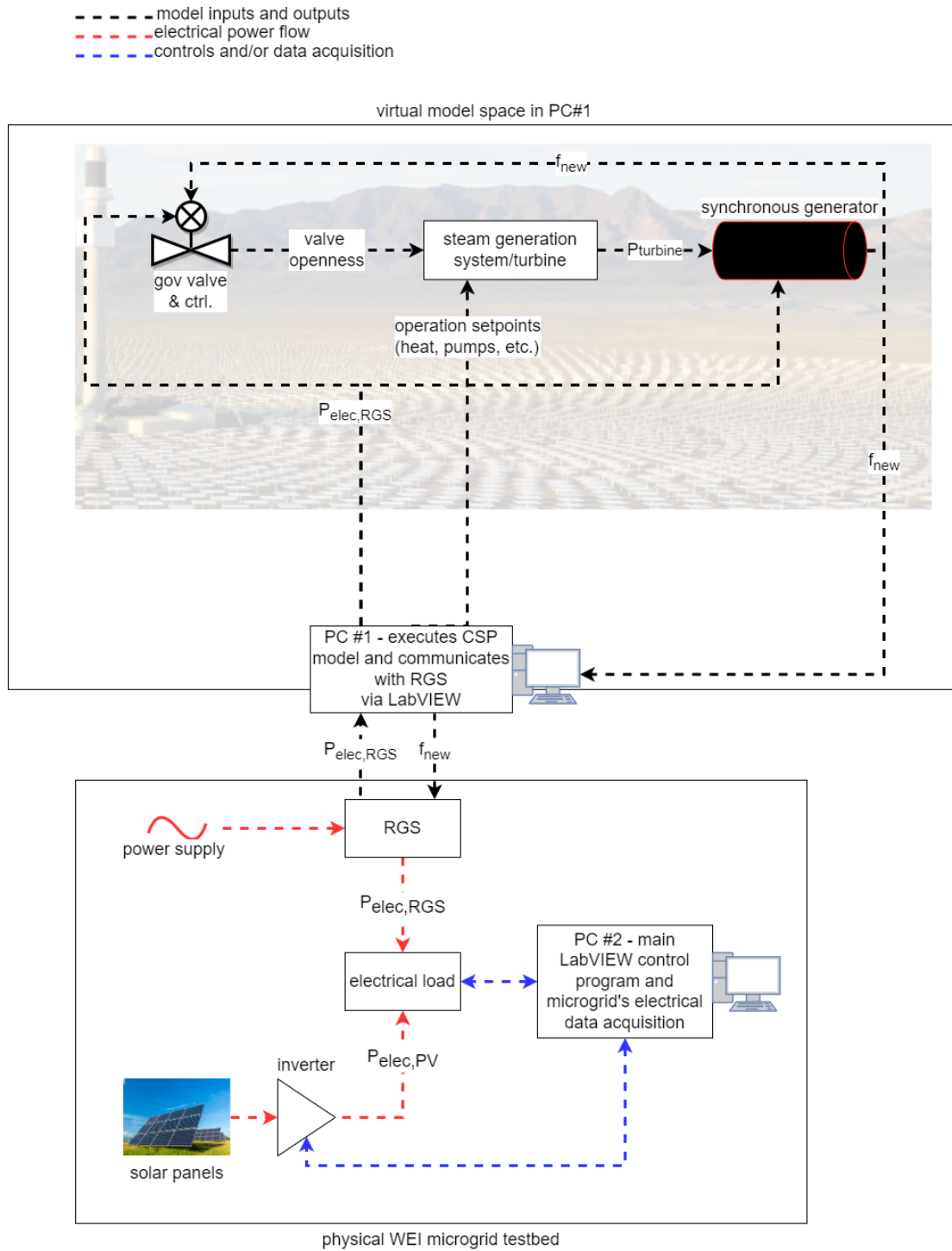


Figure 5.1: PHiL layout for small-grid scenario.

Grid Inertia Considerations

In a power plant, the turbines and synchronous generators are mechanically coupled together; mechanical torque from the steam turbine drives the generator, which exerts an opposing electrical torque. When the combined mass' rotational frequency does not vary largely from 60 Hz, torque is proportional to power. Rotational frequency remains constant when $P_{\text{turbine}} = P_{\text{elec}}$. However, if these two powers are unequal, the combined rotating mass will either accelerate or decelerate. This leads to the well-known swing equation, which defines an electrical system's change in electrical frequency in terms of the mechanical power input, electrical power drawn, and the physical inertia H present in the system [66]. If load damping frequency responses and parasitic power losses are neglected, the result is shown in Eq. 5.2 where $P_{\text{grid,total}}$ is the total electric grid demand, $P_{\text{mech,total}}$ is the total mechanical power produced by all turbines, H is the inertia constant, f_0 is the nominal frequency of 60 Hz, and S_B is the total rated generation power of the system. A grid inertia constant value of $H = 6$ s is used in this model.

$$\dot{f} = \frac{f_0}{2HS_B} (P_{\text{mech,total}} - P_{\text{grid,total}}) \quad (5.2)$$

If all other synchronous generators are assumed to ideally and instantly respond to load requests, any frequency deviations in this small grid will be caused by variations in PV-CSP output. Equation 5.2 is therefore dependent on the difference between the required CSP electrical power contribution ($P_{\text{elec,CSP}}$) and model-predicted plant power output (P_{turbine}). The required CSP electrical power contribution is the difference between total requested power and PVI output. Eq. 5.2 can be rewritten into terms representing PHiL real-time measurement variables as shown in Eq. 5.3.

$$\dot{f} = \frac{f_0}{2HS_B} (P_{\text{turbine}} - (P_{\text{elec}} - P_{\text{PVI}})) \quad (5.3)$$

Finally, since the RGS is always supplying the difference between P_{PVI} and P_{elec} ,

Eq. 5.3 can be further simplified to Eq. 5.4. $P_{elec,RGS}$ is the measured RGS electrical power output shown in Fig. 5.1.

$$\dot{f} = \frac{f_0}{2HS_B} (P_{turbine} - P_{elec,RGS}) \quad (5.4)$$

Equation 5.4 relates a physical variable ($P_{elec,RGS}$) to an RTS model variable ($P_{turbine}$), thus closing the PHiL's model-testbed communication loop. The RTS predicts frequency changes due to variations in PV-CSP power by integrating Eq. 5.4 at each time step and passing this f_{new} to the RGS.

5.2 Grid Impact Study

The effects of PV-CSP load following accuracy on small-grid frequency stability are evaluated in this section for three different grid sizes (S_B): 500, 700, and 900 MW_e . For repeatability, the photovoltaic power profile emulator (PPPE) powers the PVI's DC supply instead of using rooftop PV. Users program the custom I-V curve characteristics to emulate the rooftop panels' behavior. These characteristics are described in Chapter 3. Curves can be created for the same panel array at different irradiance levels. A cloud cover cycle is then built by constructing a 9-minute sequence consisting of 1-minute intervals at a set irradiance value. Figure 5.2 shows the 9-minute sequence as seen in the PPPE software. The first and last part of the sequence has large jumps in irradiance and the middle is more gradual. Each experiment is set to run for 2–3 full cloud cycles. In addition to the full cycles, each test has 0 – 60s of idle time before the start of cycle 1. This idle time gives the microgrid operator an opportunity to ensure all equipment is operating as expected. Two experiments are run at each grid size for a total of six experiments. Under nominal frequency, the PVI produces 0.85 kW_e , which is 17% of the lab power. For the first cloud cycle, the load bank requests 100% power or 4.8 kW_e . At the beginning of the second cycle, the load bank increases requested power to 5.6 kW_e or 120%. This change produces

additional data on performance during loss-of-generation events. If another plant shuts down, the PV-CSP plant may need to operate at maximum power for a short time. The requested load bank power returns to 100% at the beginning of the third cloud cycle, which some tests include.

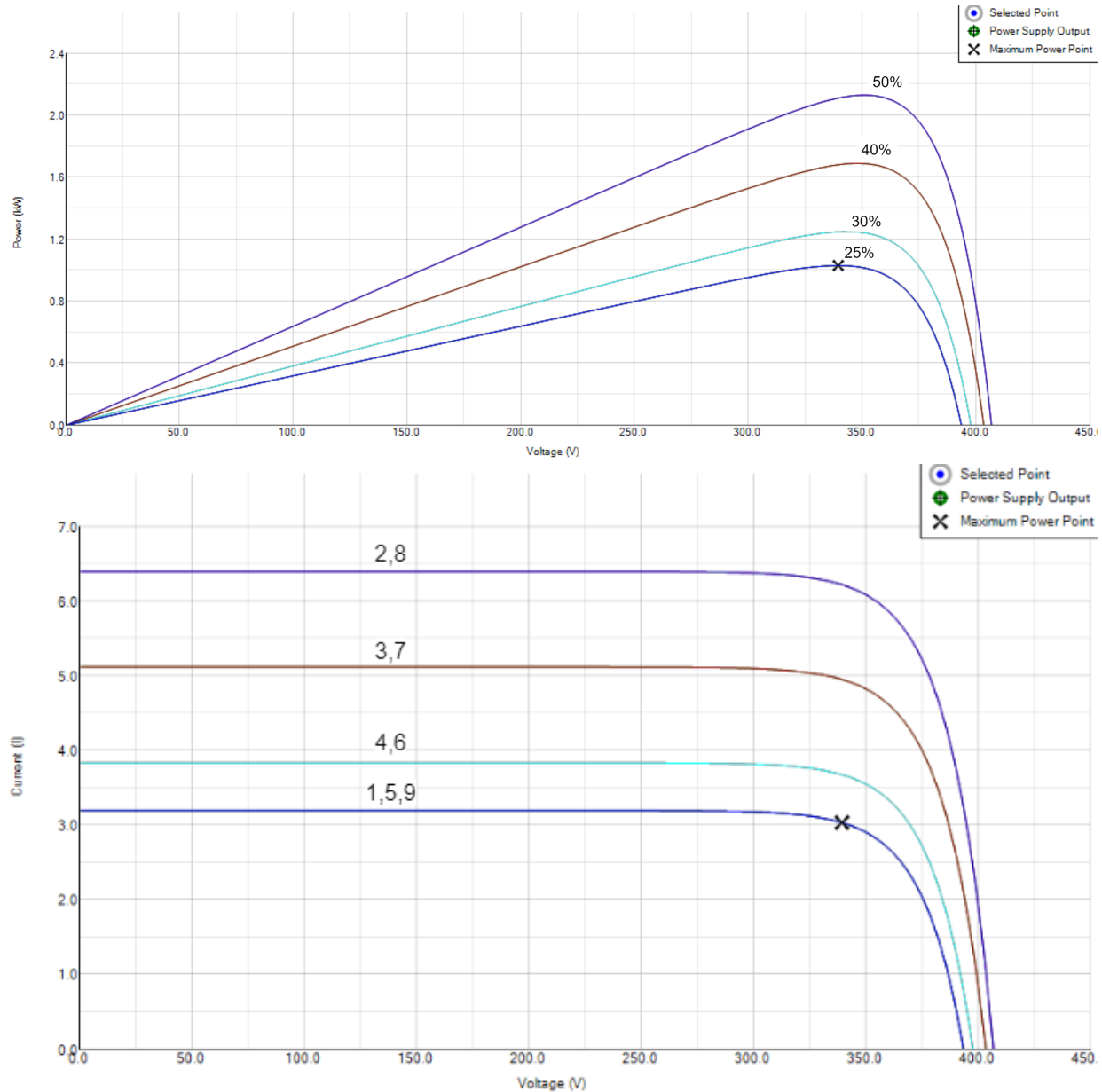


Figure 5.2: Power-voltage and current-voltage curves generated in Magna PPPE software. Percentages are based on 1000 W/m^2 and numbers refer to the order of use in 9-minute cycle.

Control of the CSP plant is fairly autonomous during these experiments. Basic heating control with a deadband region as described in Chapter 3 decreases heating when drum

level $L < L_{\text{low}}$ and increases if $L > L_{\text{high}}$. Turbine inlet valve is controlled by the PI controller discussed in Chapter 4 as well as the speed control and automatic valve control discussed in Chapter 3. Feedwater pump pressure stays constant throughout operation for each experiment. The RTS initializes the model with CSP providing 40 MW_e of power and grid frequency at 60 Hz. Results from the second 500 MW_e test are shown in Fig. 5.3 and Fig. 5.4. Note that requested electrical power refers only to the RGS' output, not the total requested power at the load bank. The other 500 MW_e test is found in Appendix B.

500 MW_e Grid

As seen in Fig. 5.3, the PVI exhibits three key behaviors: curtailment, maximum power point tracking, and frequency support. When the higher-irradiance curves are active, the inverter is curtailed — it stays at its power setpoint of 0.85 kW_e regardless of how high the maximum power could be. When lower irradiance curves are active, the inverter changes its DC voltage in search of the maximum possible power. When frequency dips far below the nominal 60 Hz, the inverter increases its output as soon as the irradiance is sufficient. The inverter's droop response successfully arrests frequency decline. PVI droop response is cut short, however, once irradiance is no longer sufficient.

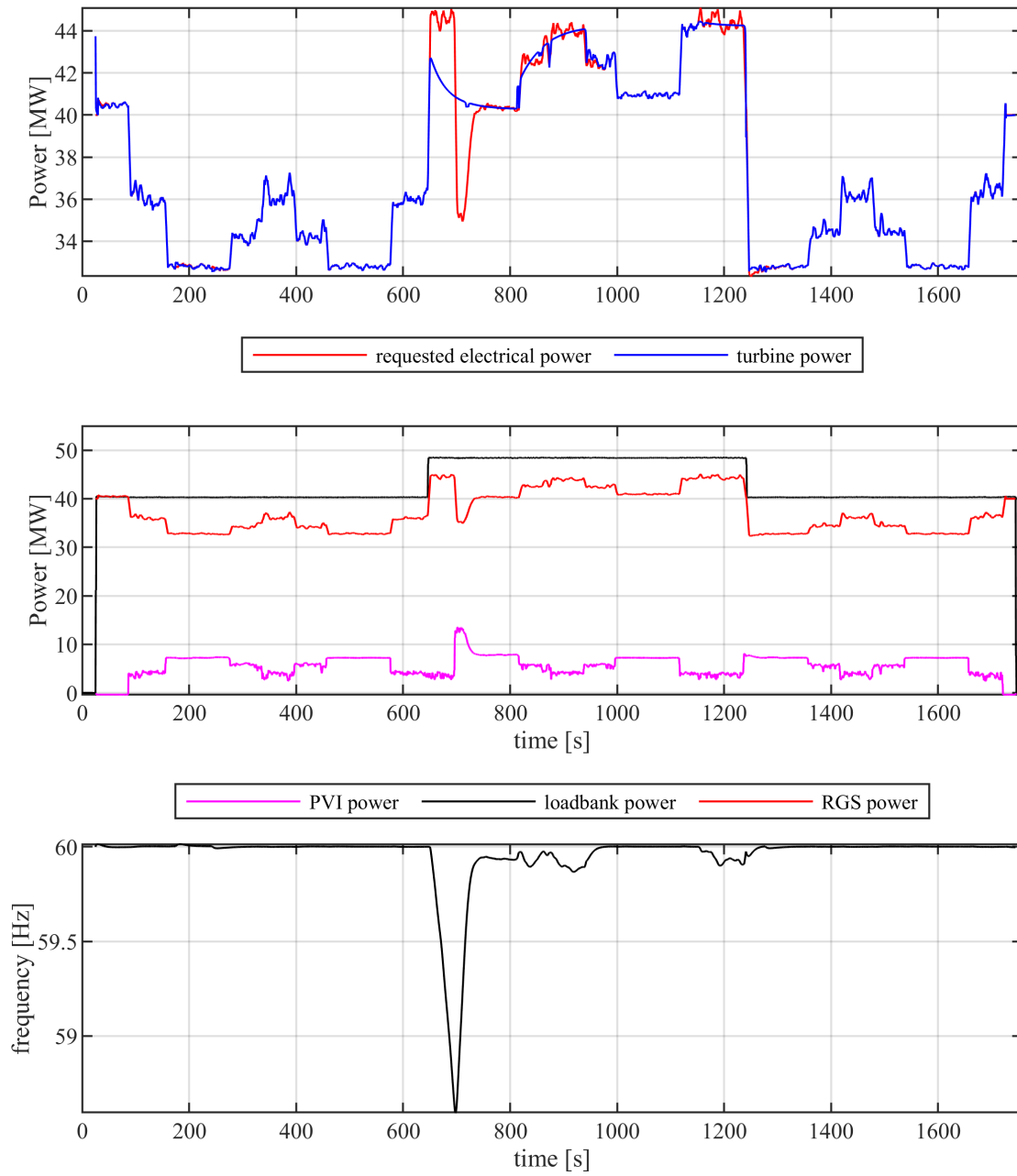


Figure 5.3: Frequency, model-scaled power, and load following accuracy for 500 MW_e case.

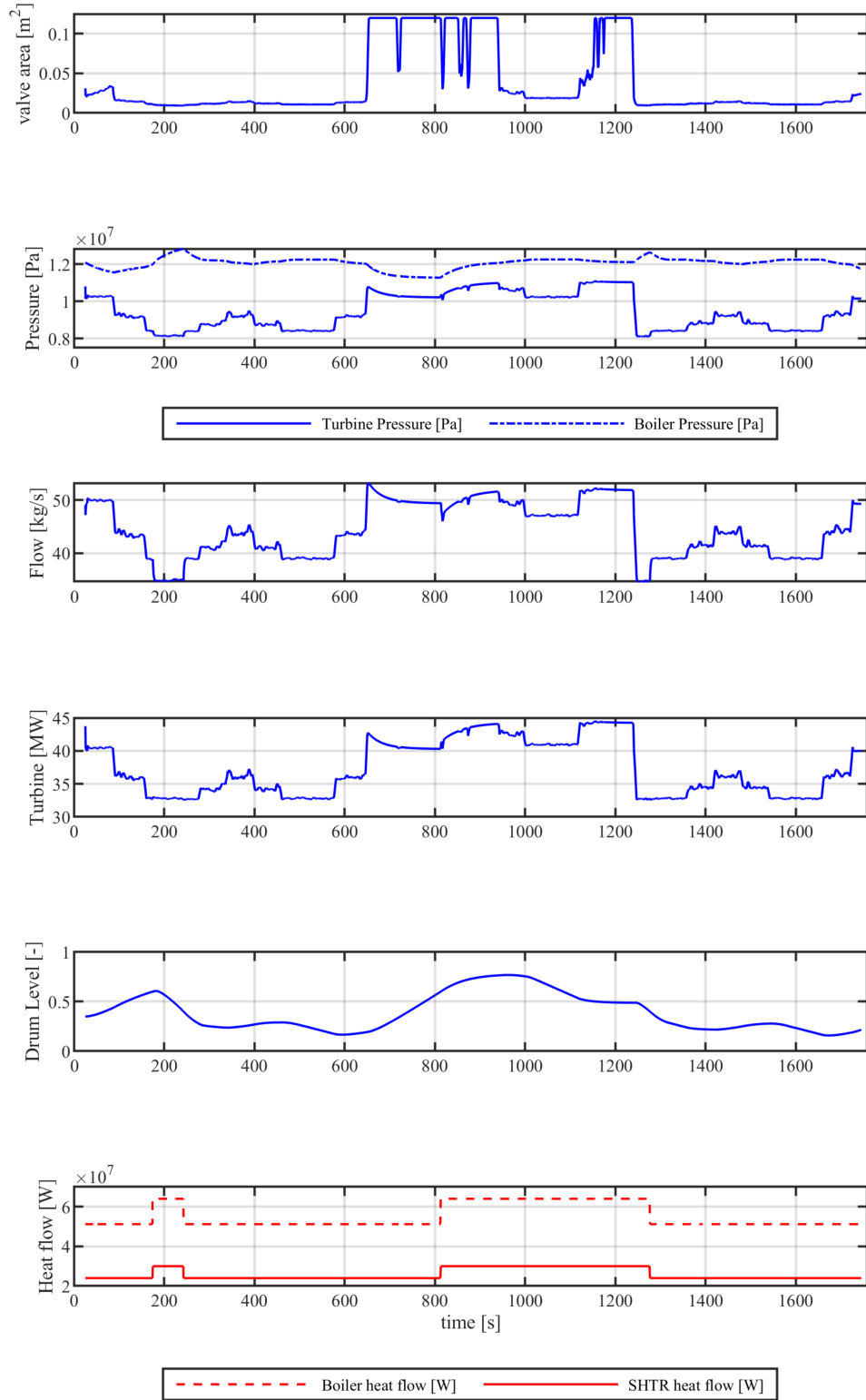


Figure 5.4: Key CSP state variables during testing of 500 MW_e grid case.

Figure 5.4 shows that the CSP plant complements PVI output well, as cycles 1 and 3

exhibit relatively constant grid frequency during these periods. Speed control signals continuously change the turbine inlet valve so that electrical frequency settles back to 60 Hz. When frequency is significantly different from 60 Hz, speed-control signals outweigh those from the PI controller, keeping the turbine inlet valve fully open instead of following the setpoint. This can be seen when the increased load in cloud cycle 2 necessitates maximum turbine output. The valve stays fully open even when requested power is less than turbine power for most of the time between 650 – 950s. Although the maximum operating point does cause drum flooding which eventually brings about a heating increase, low heating restricts maximum turbine power and adjusts too late to prevent a large under-frequency event. This is because the heating controller is not programmed to change its setpoint until the drum level exceeds l_{high} . The 500 MW_e cases have the lowest frequency nadirs and fastest rate of frequency change, which is expected because this case has the lowest grid inertia.

700 MW_e Grid

Results from the 700 MW_e grid, as seen in Fig. 5.5 and 5.6, are similar to the 500 MW_e case. Drum level continues fall throughout the first cycle. When cycle 2 begins at approximately 650s, the same issue occurs that is seen in the 500 MW_e case. This time there is a second frequency drop while heating recovers boiler pressure and steam power. This second frequency drop did not occur in the 500 MW_e case because heating changed to its high setting slightly sooner. Heating will only change after the drum level exceeds L_{high} . Since flooding rates stay constant in each case, the heating adjustment delay is dependent on the plant's drum level when it enters cycle 2. The inverter does not provide frequency response during the second event because there is insufficient solar power. Just before the third frequency event, turbine power follows the power fluctuations well. By approximately 1200s, however, the turbine power pulse is exhausted and the plant cannot meet the requested power. PVI power provides a smaller droop response as soon as it can.

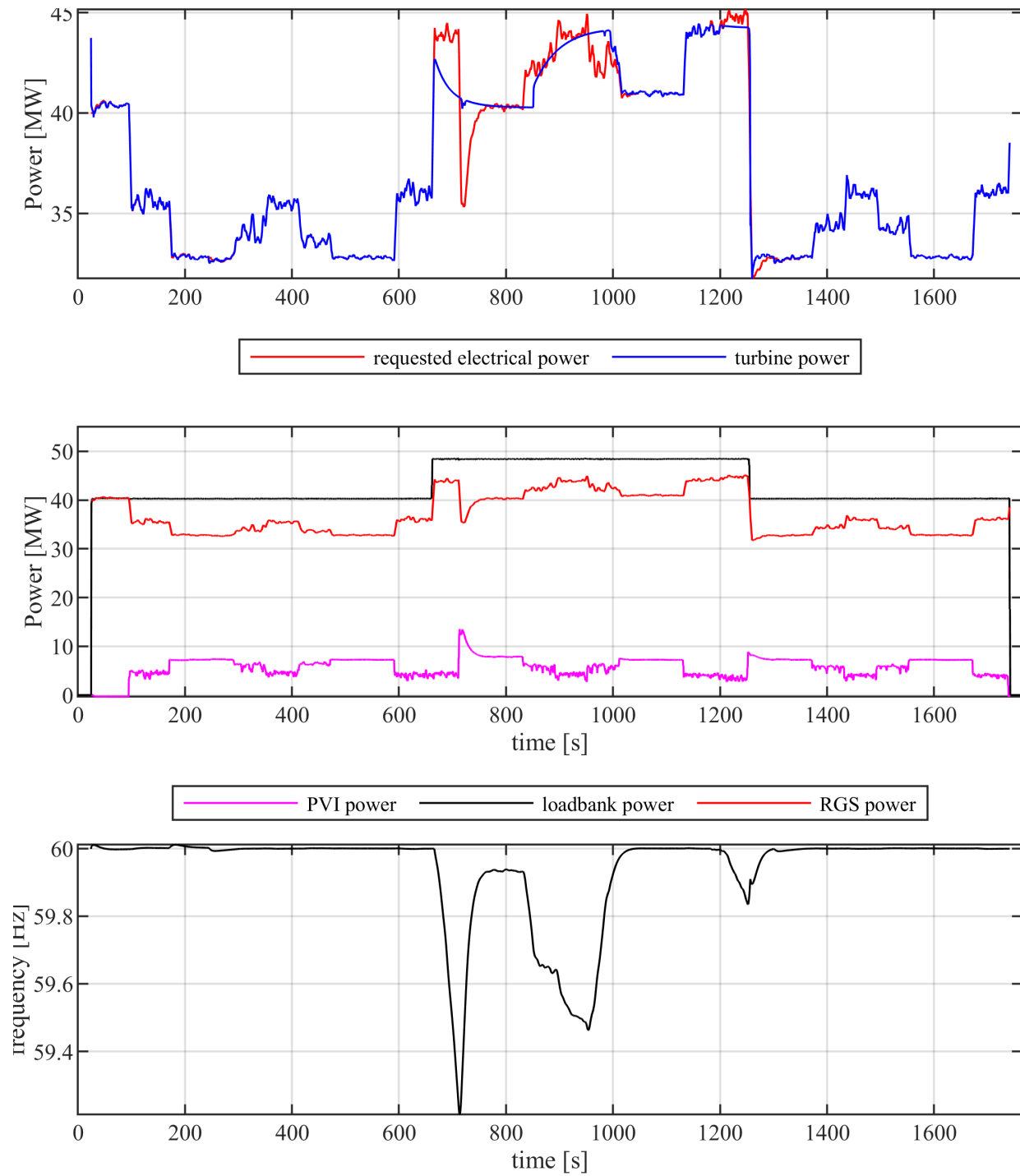


Figure 5.5: Frequency, model-scaled power, and load following accuracy for 700 MW_e case.

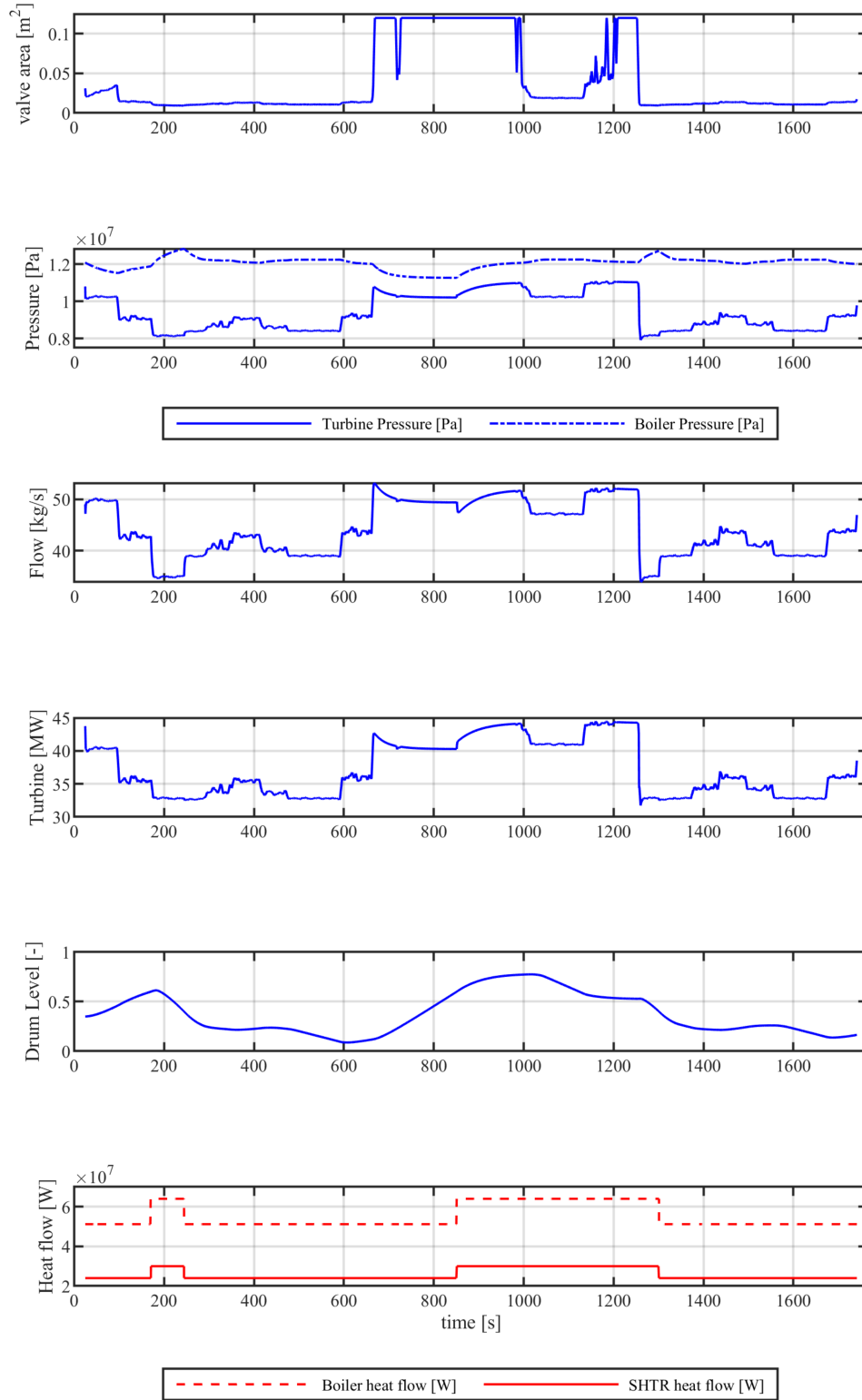


Figure 5.6: Key CSP state variables during testing of 700 MW_e grid case.

900 MW_e Grid

All key dynamic behaviors observed in the 500 and 700 MW_e cases are also seen in this 900 MW_e case (Fig. 5.7 & 5.8). It can also be observed that the PVI's droop response always returns the system to the same frequency after the first event. This could be the edge of the PVI's droop control deadband — frequency deviations within a deadband will not provoke a droop response.

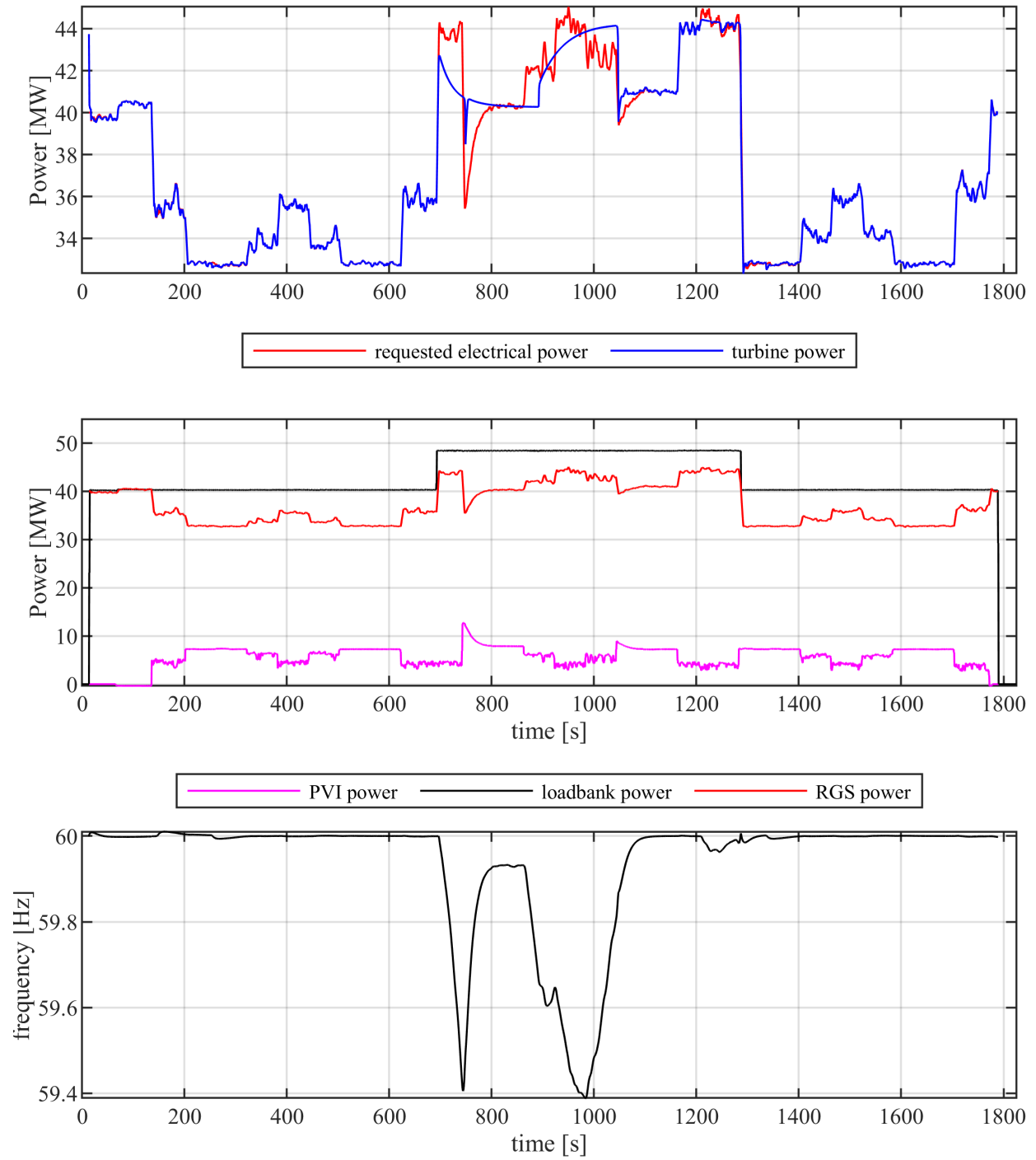


Figure 5.7: Frequency, model-scaled power, and load following accuracy for 900 MW_e case.

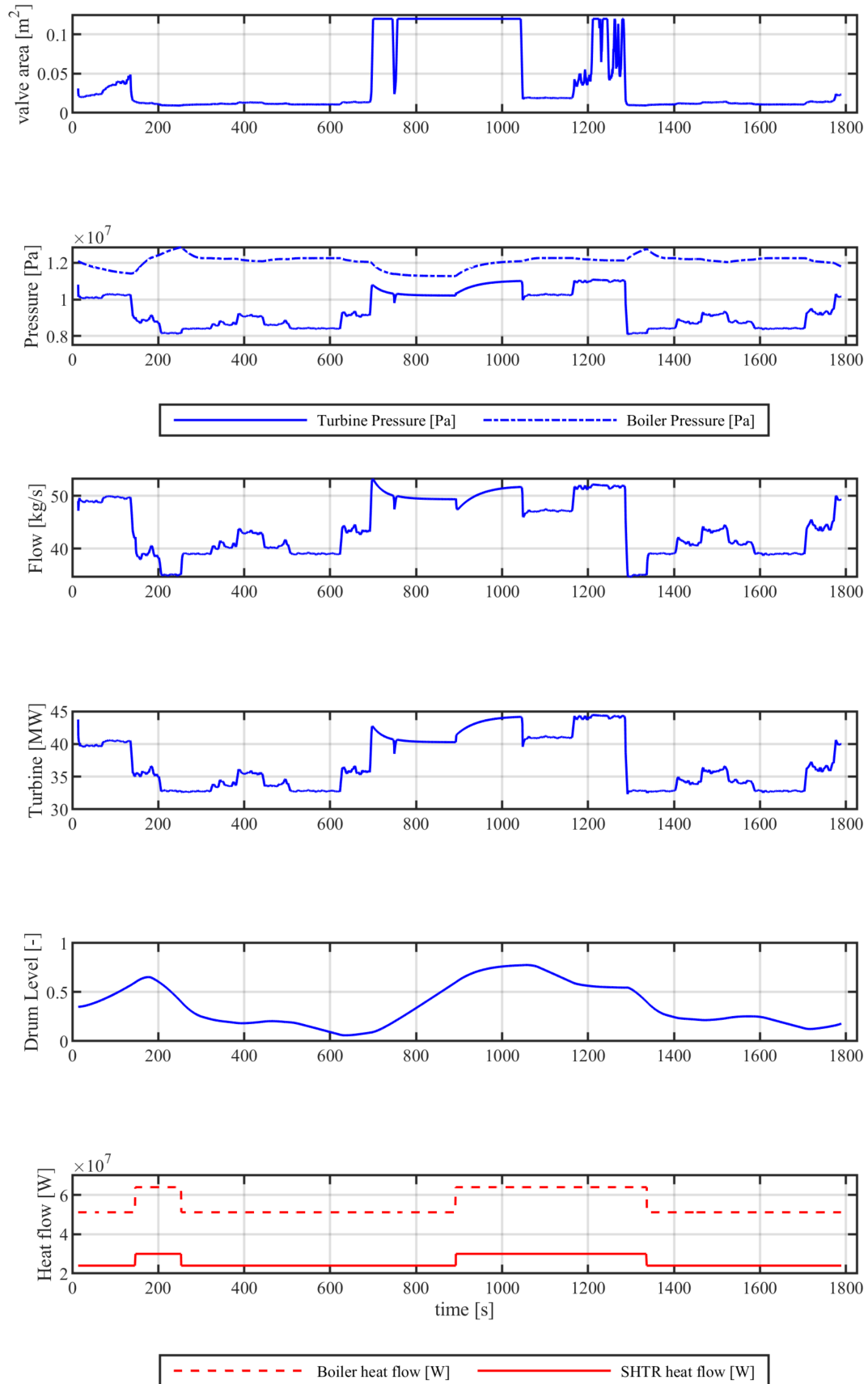


Figure 5.8: Key CSP state variables during testing of 900 MW_e grid case.

Table 5.1 summarizes key variable measurements from each run. All minimum frequencies were observed during cycle 2, when maximum output is requested. As expected, the largest grid is the most resistant to a loss of generation event. Minimum boiler pressure is the same for each run and occurs when the turbine control valve is fully open with low heating. L_{max} , the maximum liquid drum level, is the same for all runs. Heating is programmed to increase to the high setpoint when drum level exceeds 0.6. Thus, the drum level remained within 0.18 of the upper deadband limit. The low heating setpoint is not as effective at maintaining drum levels. As PVI production increases, steam flow reduces as requested turbine power decreases. The resultant dryout continues even as heating stays low. This indicates that the low heating setpoint needs to be further decreased if the dryout is to be effectively arrested. These tests point out a major drawback in the basic heating control scheme. To be successful, the low setpoint must be below the minimum expected part-load CSP operation point. However, anytime the plant operates fully open with low drum levels, the maximum turbine power is limited because of the low heating setpoint. The deadband range could be tightened, but heating setpoints would change more frequently, resulting in more thermal cycling of steam generation components. The minimum drum level difference is always at the start of cycle 2 and is proportional to the elapsed idle time before each test starts cycle 1. The longest idle time causes the longest total time at part-load, which correlates to the lowest observed steam drum levels. If the test cycles began immediately upon PVI startup, minimum drum levels would be the same for each test.

The plant follows varying setpoints with high accuracy. During a frequency event, both the CSP and PV systems demonstrated their droop control programming. The loss of generation event also demonstrates how hybrid systems can enhance frequency stability. The physical inertia provided by the rotating masses online during this event reduced the maximum rate of frequency decline. The PVI provides electric power in the short term while the CSP plant ramps up to provide a sustained response. These tests

Table 5.1: Frequencies, minimum pressure, and drum level values from grid impact study. Two identical runs are performed at each S_B . Once the first cloud cycle starts, each test has the same procedure.

S_B (MW _e)	$f_{\min}$ (Hz)	$P_{b,\min}$ (MPa)	$L_{\min}$	$L_{\max}$
500	58.7	11.27	0.088	0.777
	58.59	11.28	0.159	0.769
700	59.15	11.27	0.053	0.776
	59.21	11.27	0.088	0.775
900	59.3	11.28	0.138	0.769
	59.39	11.27	0.059	0.777

also provide plant control insight. Although the turbine inlet valve is now following power setpoints with minimal error, basic heating control with a deadband could be improved so that the heating can more closely support the power plant's setpoint goal. This is why improved automatic heating control was implemented, where heating is automatically adjusted proportionally to turbine power whenever $L_{\text{low}} < L < L_{\text{high}}$. Improved automatic heating control is explained in Chapter 3 and is implemented before the final test discussed in this chapter.

5.3 Frequency Stability During Real-time Cloud Cover

The emulator is an invaluable tool for reproducing designed cloud cycles. In practice, however, cloudy days are less predictable. A PHiL test similar to the grid impact study already discussed is performed to evaluate control performance, plant dynamics, and inverter behavior in the most realistic setting. Instead of using the emulator, the DC linkage is connected to the rooftop panel source. The PVI is programmed with output set to 1.2 kW_e during sunny periods or maximum power point track if clouds prevent the setpoint from being attainable. Unlike the previous grid impact study, the total electrical power requested by the load bank stays constant at 4.8 kW_e during the entire experiment.

The grid inertia and CSP plant in the RTS are only slightly modified from the previous grid impact study. The total generation capacity is lowered to 300 MW_e, meaning that the

PV-CSP plant is responsible for 13.3% of the total load. Therefore, load following accuracy is of paramount importance. With that in mind, the CSP heating control is equipped with improved automatic heating with a deadband region. Whereas basic heating control only changes heating setpoints in response to drum level exiting a specified range, improved automatic heating tunes the heating setpoint when drum level is within the specified range so that $\dot{Q}_{\text{setpoint}} = F \cdot \dot{Q}_{\text{max}}$ as described in Chapter 3. Key results from this PHiL test are shown in Fig. 5.9 and Fig. 5.10.

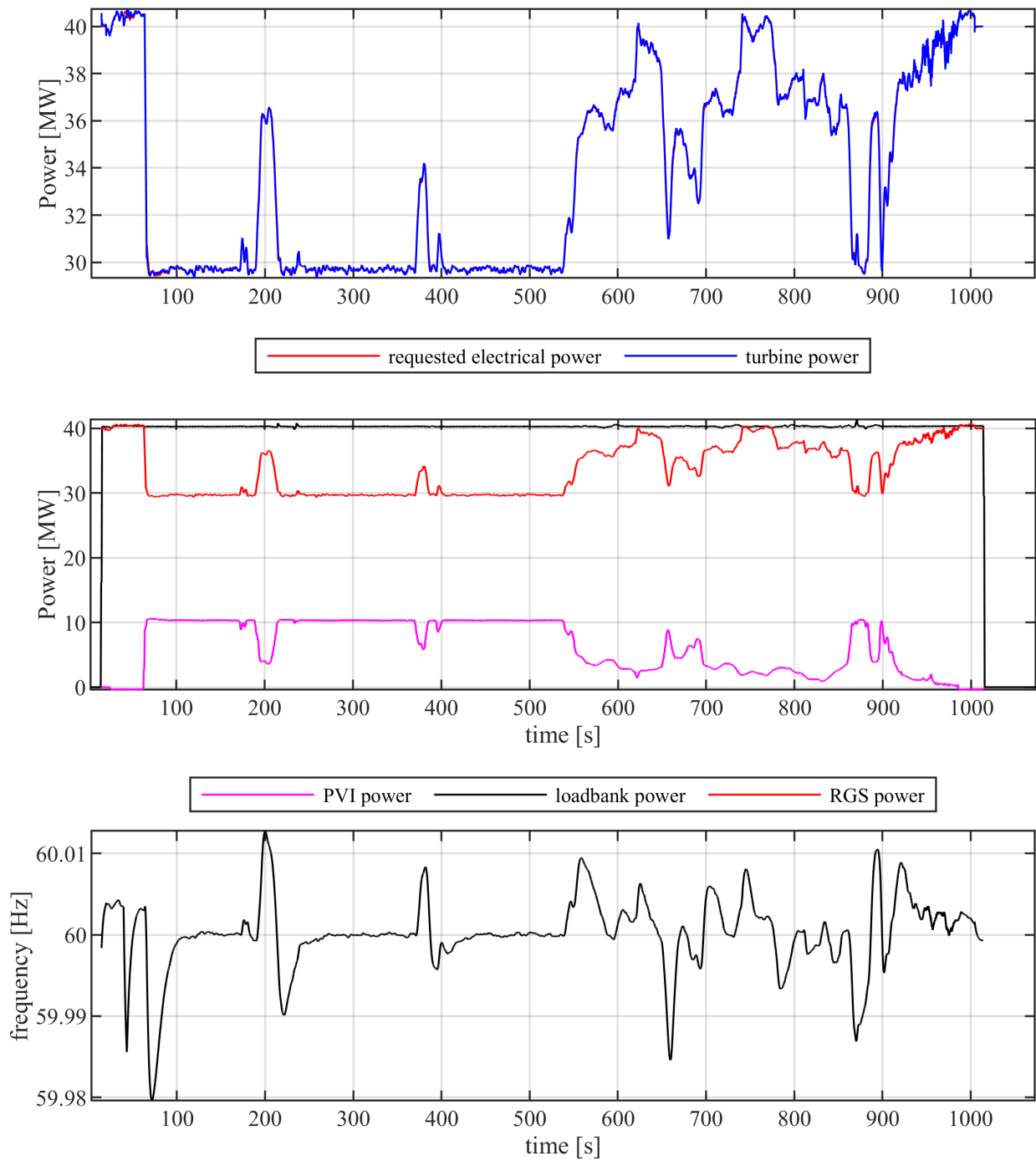


Figure 5.9: Frequency, model-scaled power, and load following during a cloudy day test of PV-CSP in a small-grid scenario.

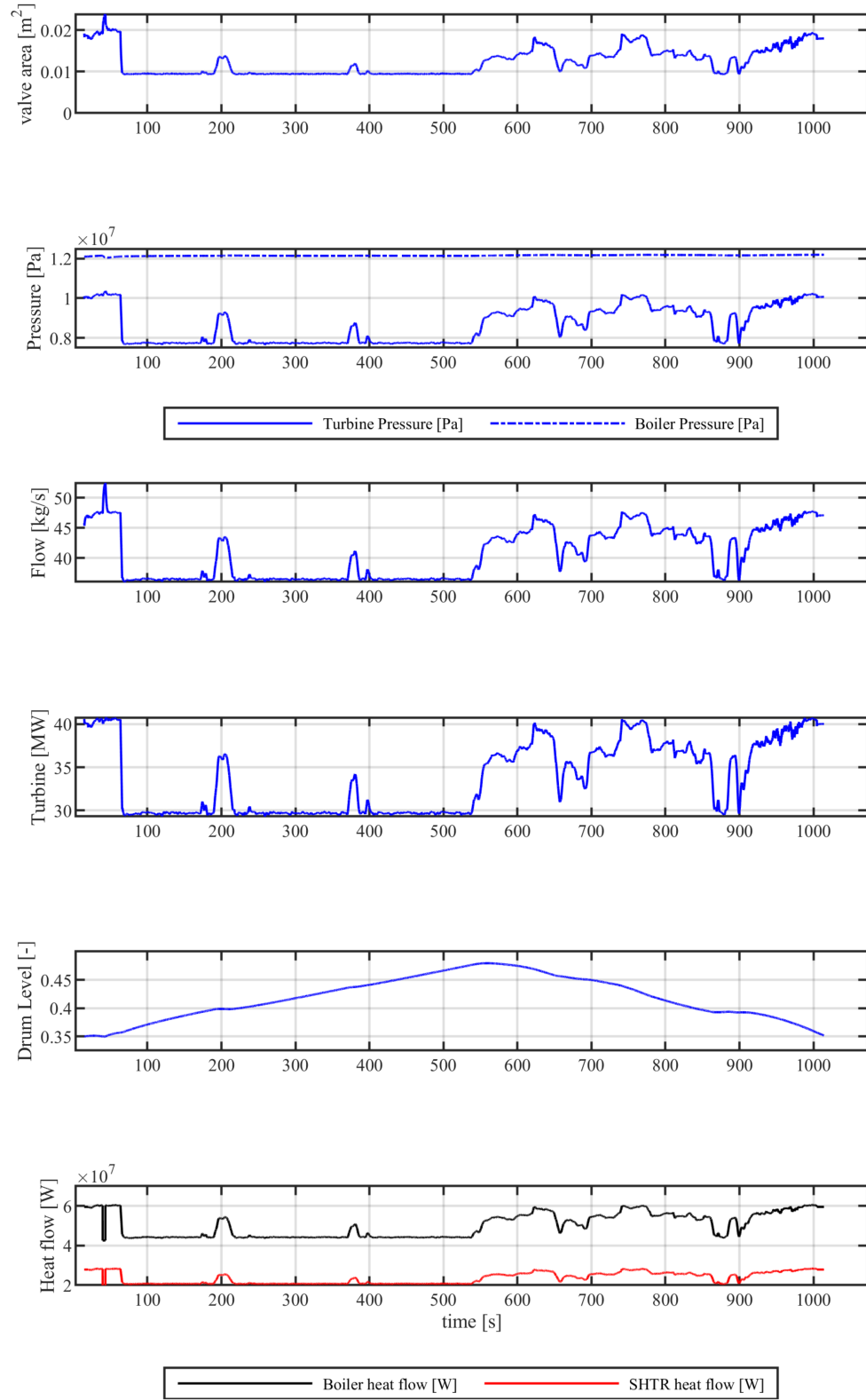


Figure 5.10: Key CSP state variables during a cloudy day test of PV-CSP in a small-grid scenario.

The first 500s of this test are relatively sunny, with only two cloud interruptions. In contrast, the last 500s are highly variable, PVI output greatly fluctuates. Cloud cover photos taken around the time of experiment are provided from the Atmospheric and Oceanic Sciences station on UW-Madison campus. They can be seen in Fig. 5.11. With ground wind speeds averaging over 15 mph, the clouds move relatively quickly, causing rapid changes to the rooftop panels.

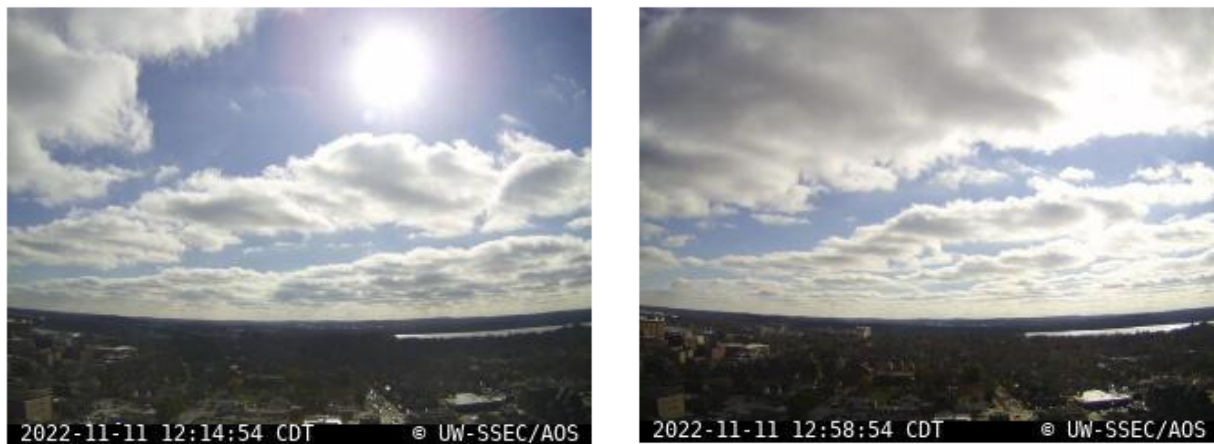


Figure 5.11: Cloud cover photos captured before and during experiment by UW AOS Rooftop Observation Station

Figure 5.9 shows that PVI successfully provides 25% of the requested power for over half of this experiment with only two significant interruptions. By the end of the experiment, however, PVI output is so affected by cloud cover it drops to zero. Maximum measured electrical frequency was 60.01 Hz. Minimum electrical frequency is 59.98 Hz and occurs almost exactly at startup of the PVI. This is because the large setpoint change causes some turbine power undershoot as the CSP plant adjusts to its new part-load operating point. Each cloud induced CSP power spike also has its own small frequency instability. The observed cloud effects on electrical frequency may seem counter intuitive. The first cloud begins to reduce PVI output power, the frequency actually increases. This is caused by the CSP plant overcompensating for the increase in its share of requested power. The opposite effect occurs as the cloud's shade moves off the panels — frequency

dips below the 60 Hz target as the turbine inlet valve undershoots the setpoint drop. This behavior persists as cloud cover worsens.

The valve inlet area and turbine inlet pressure seen in Figure 5.4 directly trace the transient cloud cover profile of this experiment. The improved automatic heating control works well, with drum level varying less than 0.13%. Boiler drum pressure also only varies less than 0.2 MPa. For this experiment with the current controls implemented, the primary component wear is expected to be on the turbine due to multiple large pressure fluctuations exceeding 2 MPa. The steam generation components also will experience more thermal cycling with this new heating control strategy.

As shown in Fig. 4.5 and Fig. 5.1, there are two computers performing data acquisition. PC#2's dataset can be used to verify the RGS power is always:

$$P_{\text{elec,RGS}} = \Delta P_{\text{req}} = P_{\text{loadbank}} - P_{\text{PVI}} \quad (5.5)$$

This ensures that the model is receiving realistic inputs. Figure 5.12 shows measured real RGS power from PC#1 and ΔP_{req} from PC#2, which is also expected to equal RGS power, from the real-time cloud cover test. The results indicate that the RGS produces and measures the correct ΔP_{req} for the majority of the time. There are three times between 600-900s when RGS power differs from ΔP_{req} . Maximum error is 7.03% at 842 seconds. Power factor measurements at the PVI output during these periods report power factors less than 0.2, indicating large spikes in reactive power. Disproportionate amounts of reactive power equates to large circulating currents, which could factor into the measurement discrepancy a number of different ways including: inductor effects, increased IGBT losses, and increased resistive losses.

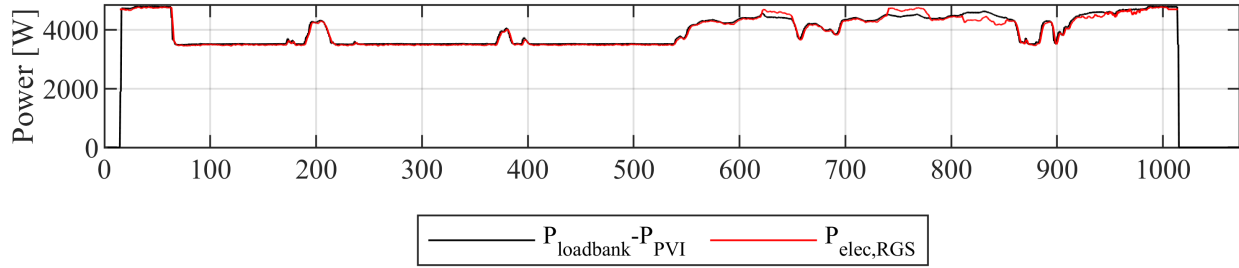


Figure 5.12: Measurement difference between PC#1 and PC#2's data acquisition programs from cloudy day test.

In summary, this chapter introduces and describes a scenario for PHiL testing of PV-CSP impacts in small grids. The swing equation is explained and implemented in the RTS for prediction of electrical frequency changes due to imbalances of generation and demand. Using a solar emulator to create regular cloud cycles, a loss of generation event is performed two times for each of three different grid sizes. The smallest grid, 500 MW_e , experiences a minimum frequency of 58.6 Hz when total requested PV-CSP power output increases from 40 MW_e to 48 MW_e . Although CSP attempts to immediately match the power increase, its response is limited by a low heating setpoint and insufficient boiler pressure. The PVI inverter provides frequency response as soon as sufficient irradiance exists. An improved automatic heating controller is added to the CSP plant and the hybrid system is tested again in actual cloudy conditions. Grid size was assumed to be extremely small — 300 MW_e . Even with PVI power output providing up to 25% power, the system's electrical frequency varies less than $\pm 0.02 \text{ Hz}$.

6 CONCLUSIONS

This research establishes and demonstrates a functional PHiL testbed for the study of future PV-CSP hybrid systems. On the virtual side, an open-loop Rankine cycle capable of over 40 MW_e is dynamically modeled in *Simscape* with component sizes and thermodynamic statepoints representative of a typical commercial CSP plant. A multi-level controller is developed for the turbine inlet valve that includes droop signals, PI feedback, and valve-curve feedforward signals. PHiL tests results provide examples of each of these control responses in action. The model succeeds in capturing dynamic drum level behavior during various plant operations. Heating control is implemented and improved to sustain drum levels during long periods of autonomous plant operation. On the physical side, existing PV inverter and panel hardware is described and configured for PHiL use. A new *Chroma* Regenerative Grid Simulator is integrated into the lab and can be remotely controlled during real-time operations via a newly developed *LabVIEW* program. Compatibility between compiled *Simscape* models and *LabVIEW* data acquisition software enables the host computer to behave as a real-time simulator, reading real power measurements from the RGS and feeding model outputs back to the RGS.

PHiL testing proves an effective way to study PV-CSP system dynamics. Although sunny day performance could be reproduced in computer-only simulation, there are few modeling replacements for real-time cloud behavior. This research considers hybrid plants where PV is not equipped with battery storage and the CSP plant must immediately compensate for any power fluctuations. In these situations, CSP turbine control valve behavior is shown to be directly proportional to the PV panel shading caused by cloud cover. As a result, dark, fast moving clouds were observed to impart the highest strain on the CSP plant because the PV panel shading quickly changes. Control valve changes cause turbine inlet pressure variations that are much larger than the corresponding boiler pressure reactions. Large cloud events are shown to exhaust steam reserves if steam

generation rates are not ramped up beforehand. Hybrid system tests demonstrate that PV production shifts the CSP plant into a state of partial load operation, where turbine power output is only a fraction of the rated plant power. This must be done carefully, however. When PV production is fully subject to irradiance fluctuations, the CSP plant must be prepared to provide full power within a few seconds of a cloud event to mitigate the hybrid plant's load following error.

Two grid scenarios are explained and used in this paper. The large grid scenario provides an environment solely focused on perfection of plant controls for load following accuracy. The small grid scenario is more complex, providing further dynamic system insights. Loss of generation tests are performed in three different grid sizes: 500, 700, and 900 MW_e. The CSP plant is ultimately unable to sustain the 20% increase in total requested power, and the grid experiences an underfrequency event. This frequency decline demonstrates some interesting frequency responses from both sides of the hybrid plant. The PVI provides a fast frequency response as soon as irradiance levels are sufficient to support the power increase. CSP responds immediately, but cannot meet its share of the required power because of low heating. Eventually the CSP provides a secondary frequency response as it builds boiler pressure back up by increasing heating. Finally, the hybrid system's performance in a small grid scenario is tested in actual cloud conditions. When the hybrid plant comprises 13.3% of total grid generation and PV produces up to 25% of the hybrid's plant power, the grid's electrical frequency varies less than ± 0.02 Hz during extreme cloud events.

7 FUTURE WORK

Now that a method for integrating CSP models with PHiL equipment is established, more resources can be dedicated to adding model complexity. More advanced versions of this dynamic model should include details of actual molten salt flow through the system. In contrast to the controlled heat source blocks used in the current *Simscape* model, the molten salt flow rate changes will not be instantaneous. The molten salt pumps will introduce heating lag into the system. Including heat capacitance of steam generation components would also be useful, as the large metal masses likely cause heat transfer to lag behind the change of setpoint. The molten salt train should also include a model of the thermal storage tanks. Since thermal storage is finite in hybrid systems, the real-time effects of cloud event operation on stored energy usage should be investigated. The turbine could be split into multiple pressure stages and an accompanying reheater and intermediate control valve added so that the model more closely matches cycle models of commercial CSP plants. A simple lookup table of typical incoming feedwater conditions at different plant power outputs could also be added for better consideration of changing feedwater temperatures at part-load operation.

Electrical hardware and computational resources used for PHiL could also be enhanced. The RGS has some measurement uncertainty during experiments. Increasing power levels of electrical operation would improve the signal to noise ratio. Additionally, once the model complexity increases, the RTS computational resources may need upgraded. A faster RTS could take smaller timesteps, ensuring that the dynamic model converges even as model complexity increases. Installment of a rooftop pyranometer for live irradiance measurements would enhance the quality of research. If real-time irradiance is known, PV panel performance and solar resource utilization could be assessed. Addition of a battery storage system would also increase research opportunities.

The current PHiL testbed should be used to further compare operation of PV in cur-

tailed versus maximum power point tracking modes during cloudy periods. Additionally, a controller should be developed that fully coordinates PV and CSP response. During this research, PVI power setpoints could only be programmed before each experiment. Manipulation of PVI power setpoints during cloud events might prove to be an effective way to support CSP operation. Finally, boiler drum pressure is identified as one of the key CSP dynamic factors in this research and has long been a topic of interest in dynamic modeling of thermal plants. Studies that investigate the effects of drum size on CSP dynamic response capabilities during cloud events would add further insight to existing knowledge about boiler pressure control.

A CSP THERMODYNAMIC INFORMATION

Table A.1: Statepoints for CSP plant operating at 70% turbine power output, where state numbers correspond to that in Fig. 3.1

p_1	10.97 MPa	T_1	591 K
p_2	12.19	T_2	591.6
p_3	11.83	x_3	1 [—]
p_4	11.83	T_4	739.6
p_5	7.34	T_5	713.9
p_6	0.025	h_6	2351 kJ/kg
		x_6	0.89 [—]
$\dot{m}_{\text{turbine}}$	32.61 kg/s		
$\dot{W}_{\text{turbine}}$	28 MW		
$\dot{Q}_{\text{evap}}$	42.6 MW		
$\dot{Q}_{\text{SHTR}}$	20.0 MW		

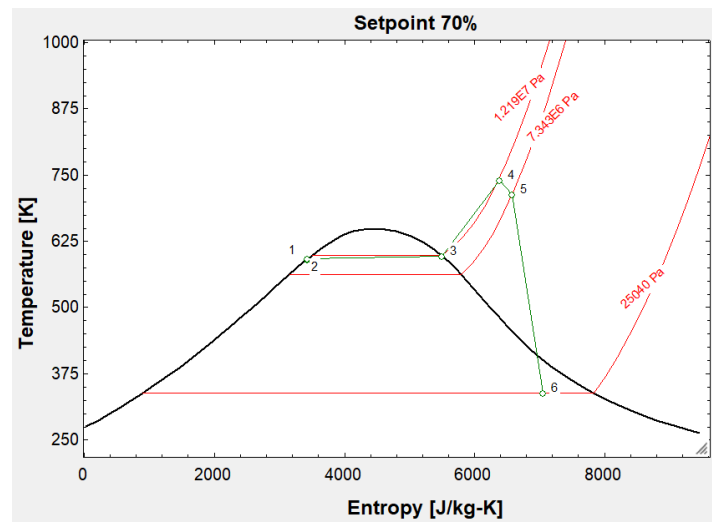


Figure A.1: CSP plant partial T-s diagram at 70% operating point

Table A.2: Statepoints for CSP plant operating at 80% turbine power output, where state numbers correspond to that in Fig. 3.1

p_1	10.97 MPa	T_1	591 K
p_2	12.18	T_2	591.5
p_3	11.72	x_3	1 [—]
p_4	11.72	T_4	739.5
p_5	8.27	T_5	720
p_6	0.025	h_6	2338 kJ/kg
		x_6	0.88 [—]
$\dot{m}_{\text{turbine}}$	38.76 kg/s		
$\dot{W}_{\text{turbine}}$	32 MW		
$\dot{Q}_{\text{evap}}$	48 MW		
$\dot{Q}_{\text{SHTR}}$	22.4 MW		

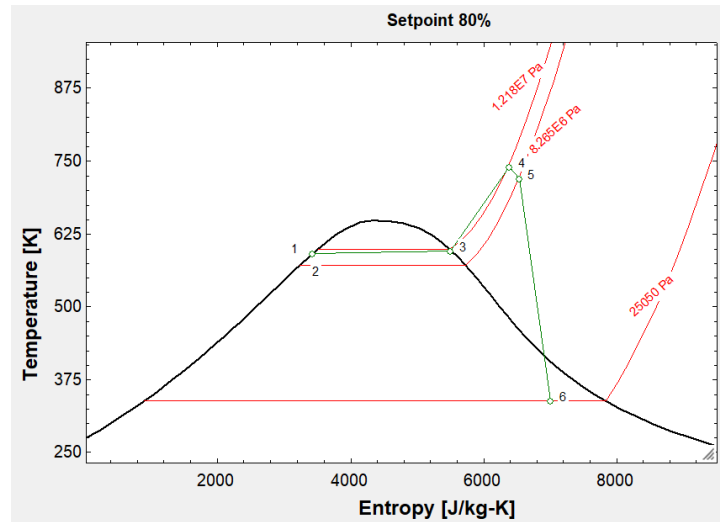


Figure A.2: CSP plant partial T-s diagram at 80% operating point

Table A.3: Statepoints for CSP plant operating at 90% turbine power output, where state numbers correspond to that in Fig. 3.1

p_1	10.95 MPa	T_1	590.9 K
p_2	12.15	T_2	591.5
p_3	11.58	x_3	1 [—]
p_4	11.58	T_4	738
p_5	9.18	T_5	724.6
p_6	0.025	h_6	2323 kJ/kg
		x_6	0.87 [—]
$\dot{m}_{\text{turbine}}$	43.11 kg/s		
$\dot{W}_{\text{turbine}}$	36 MW		
$\dot{Q}_{\text{evap}}$	53.1 MW		
$\dot{Q}_{\text{SHTR}}$	24.9 MW		

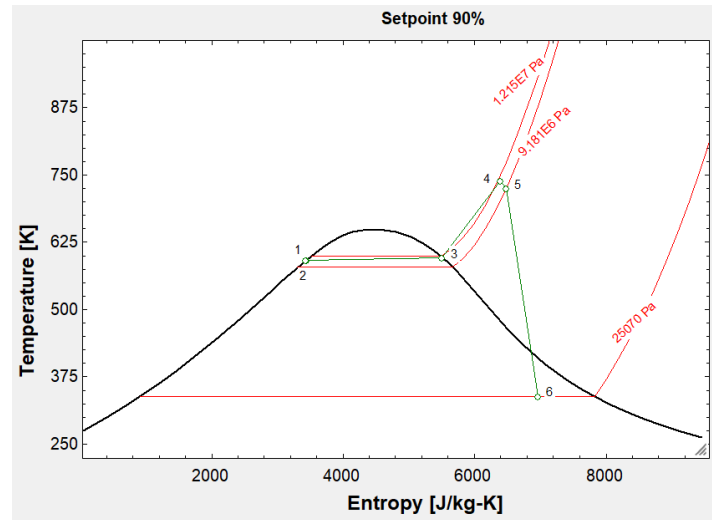


Figure A.3: CSP plant partial T-s diagram at 90% operating point

Table A.4: Statepoints for CSP plant operating at 109% turbine power output, where state numbers correspond to that in Fig. 3.1

p_1	10.93 MPa	T_1	590.7 K
p_2	12.11	T_2	591.5
p_3	11.30	x_3	1 [—]
p_4	11.30	T_4	737.1
p_5	10.92	T_5	735.2
p_6	0.025	h_6	2303 kJ/kg
		x_6	0.87 [—]
$\dot{m}_{\text{turbine}}$	51.35 kg/s		
$\dot{W}_{\text{turbine}}$	43.75 MW		
$\dot{Q}_{\text{evap}}$	63.4 MW		
$\dot{Q}_{\text{SHTR}}$	29.7 MW		

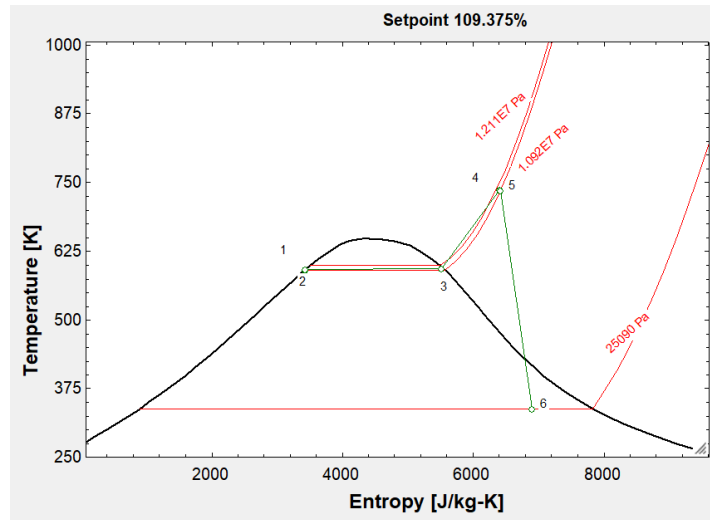


Figure A.4: CSP plant partial T-s diagram at 109% operating point

B ADDITIONAL PHIL TESTS

B.1 Large Grid Scenario

Loadbank was set to 4.7 kW and PVI output not to exceed 0.85 kW. 10-11-22 run 6 shown in Fig. B.1–B.3. Inverter experiences control error 770s and the system no longer behaves predictably after that.

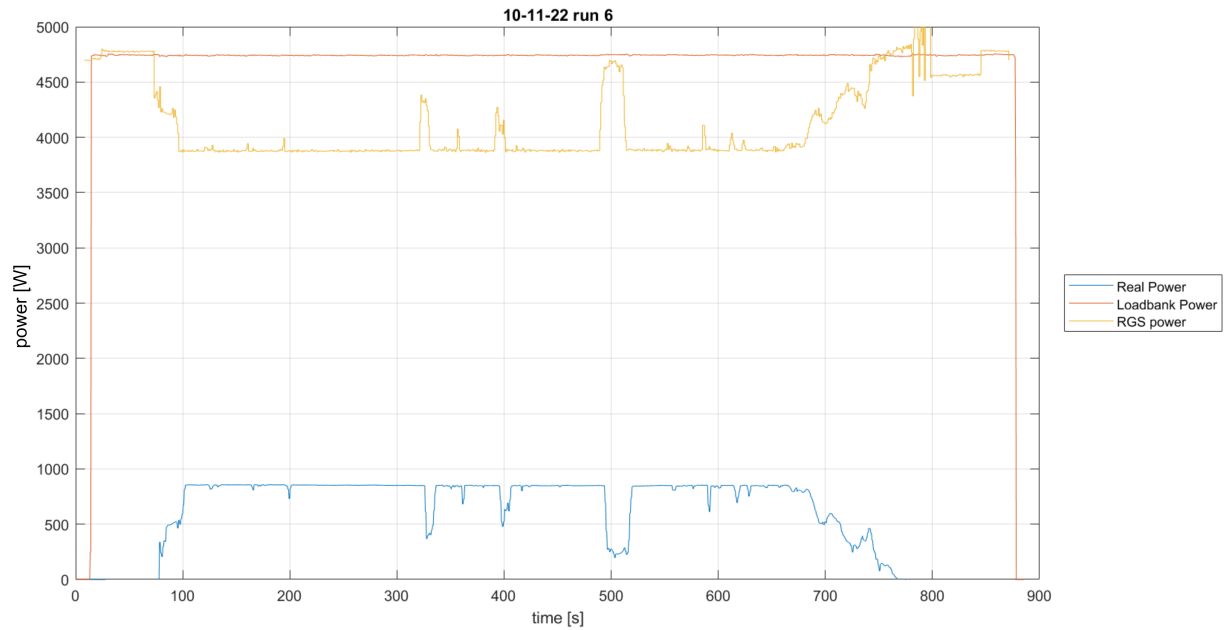


Figure B.1: model scale power exchange during cloudy test

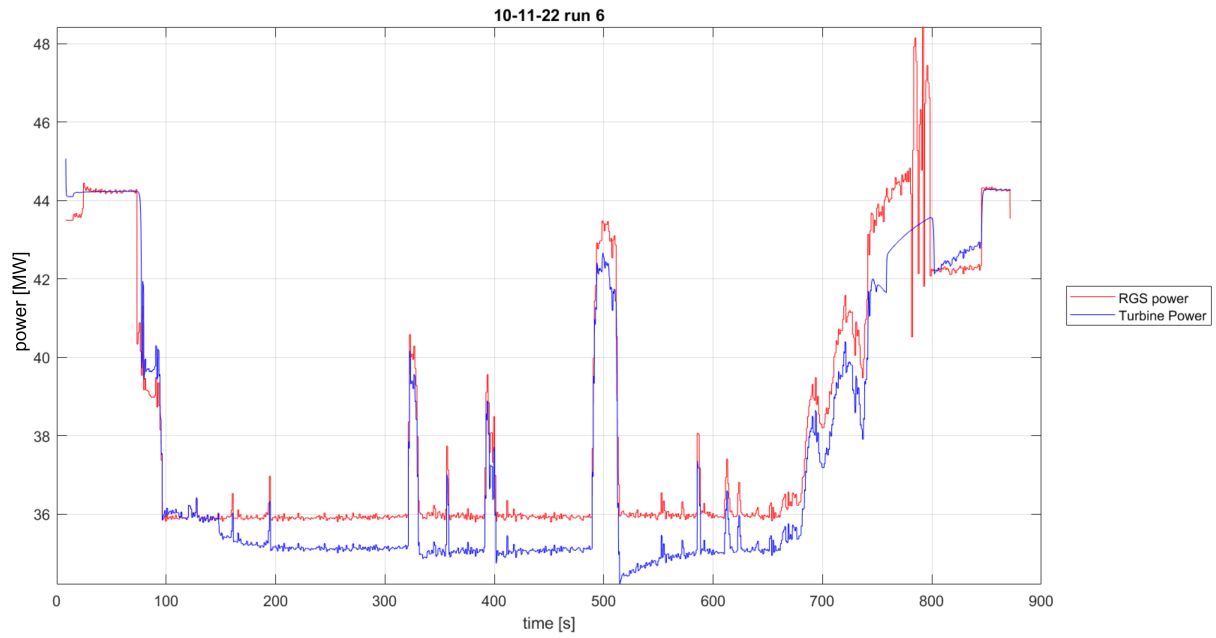


Figure B.2: Setpoint tracking accuracy during cloud test

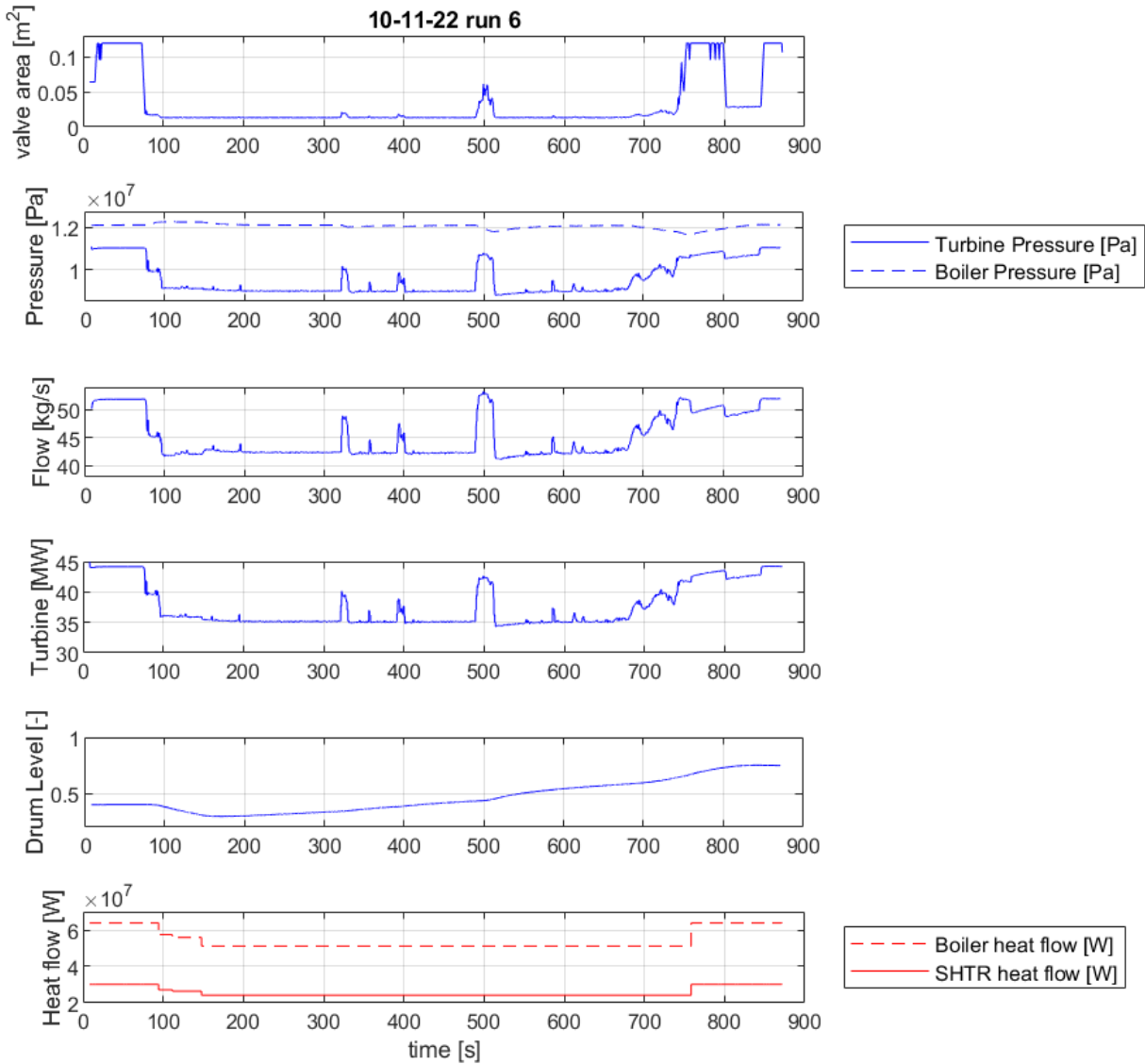


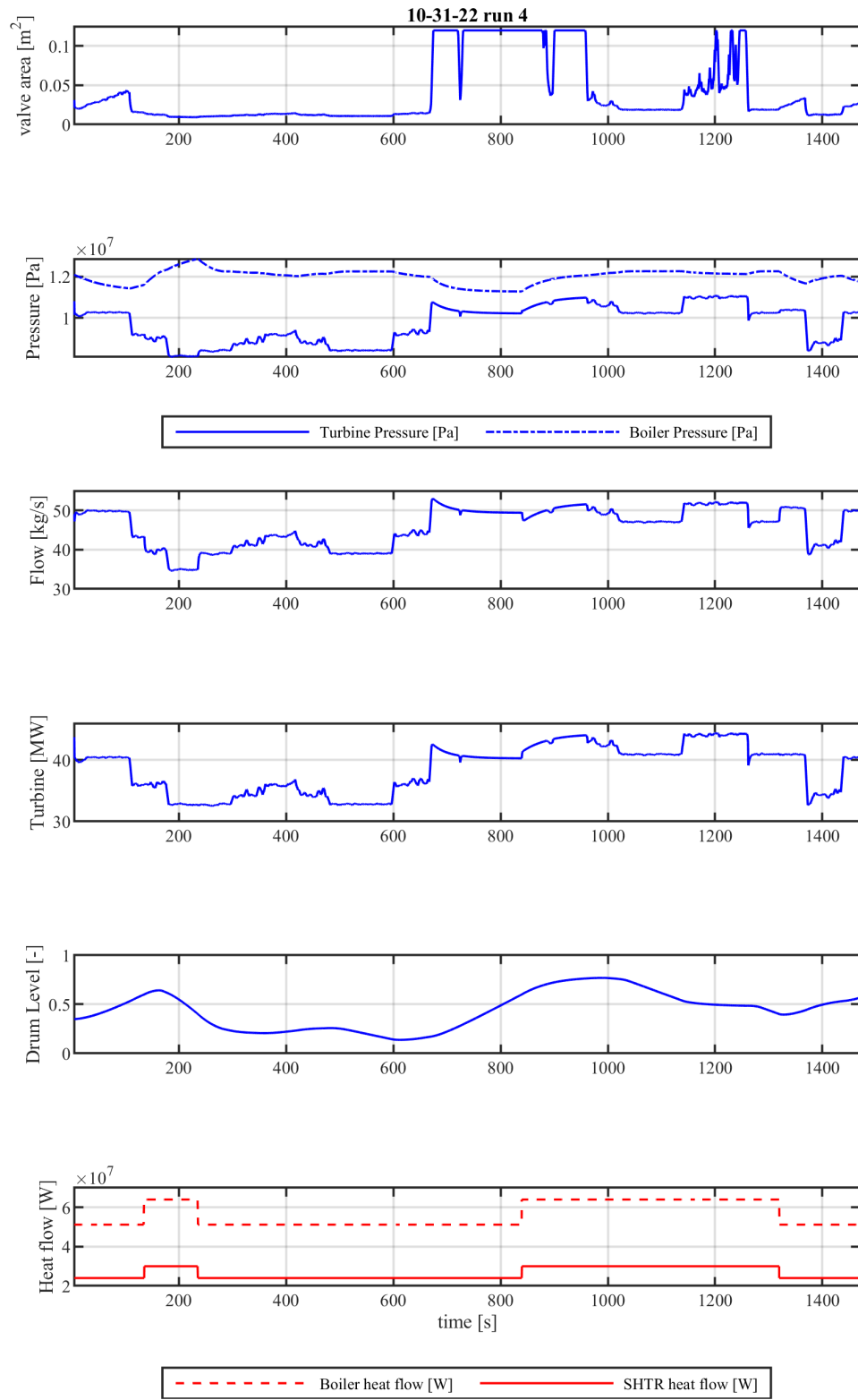
Figure B.3: CSP state variables during PHiL test

B.2 Small Grid Scenario

Data from Emulated Cloud Cycles

Since each grid size is tested twice, the other test data is included here. Note that some runs were only run for the first two cycles and then shut off.

900 MW

Figure B.4: CSP state variables from emulated cloud cycle test with $S_B = 900$.

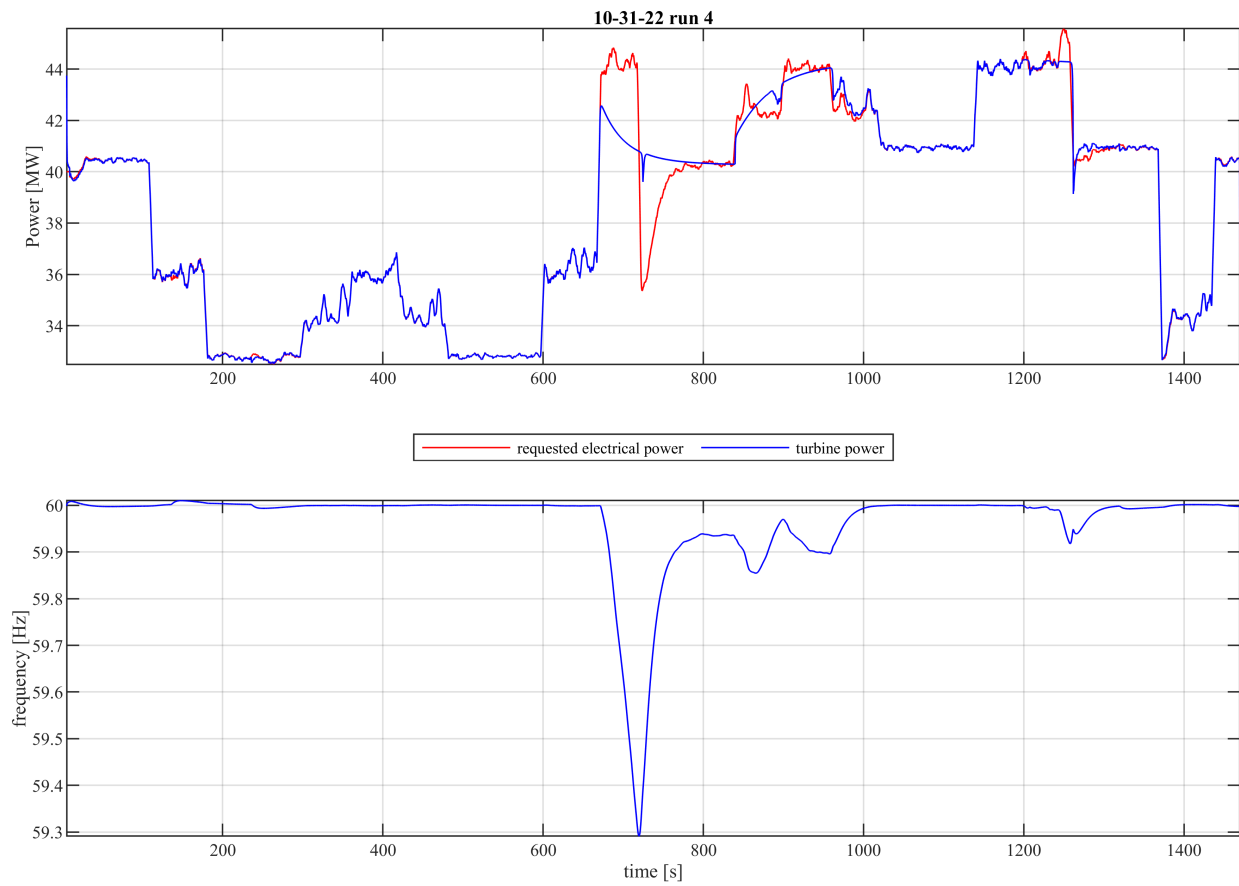
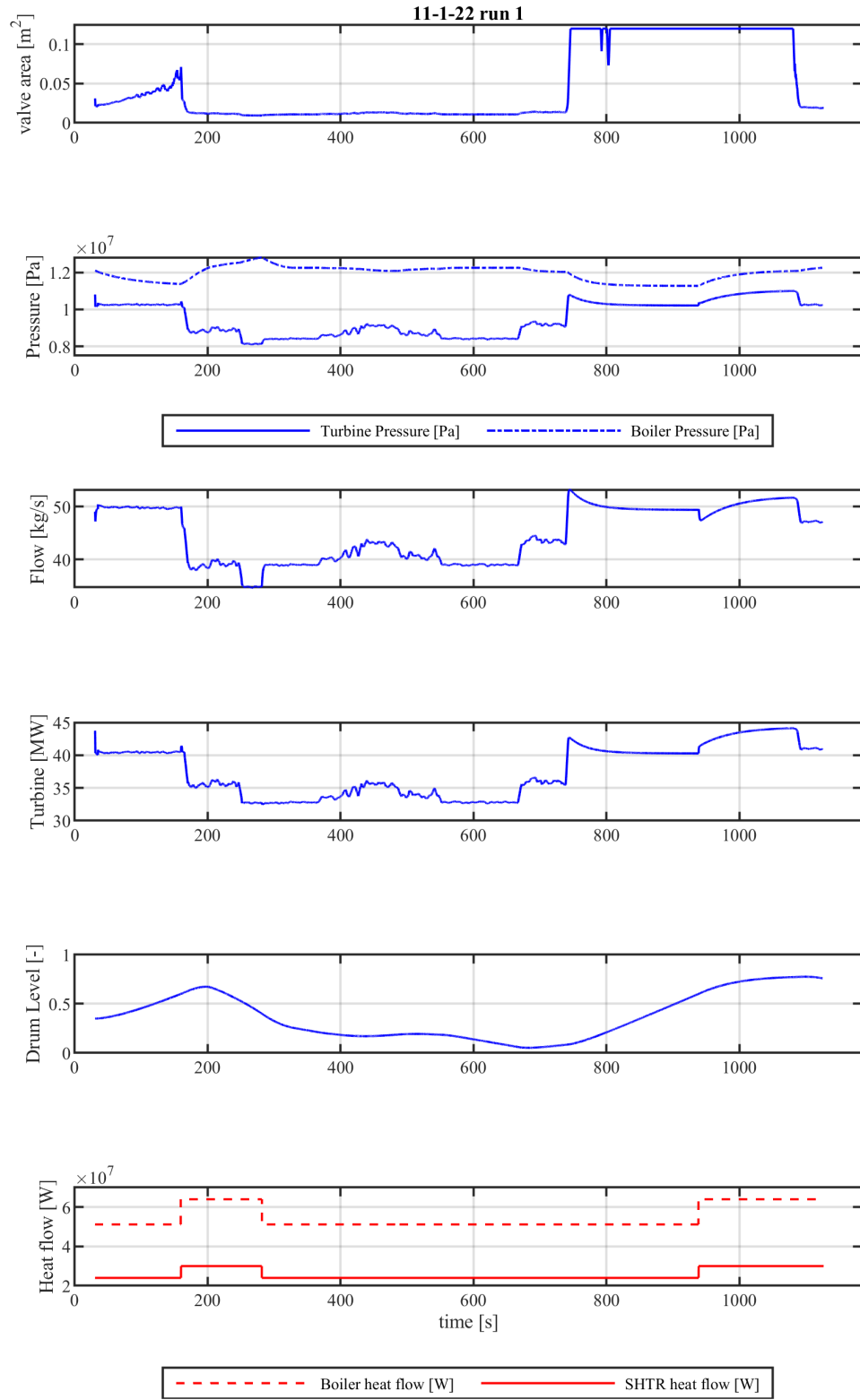


Figure B.5: Load following and electrical frequency from emulated cloud cycle test with $S_B = 900$.

700 MW

Figure B.6: CSP state variables from emulated cloud cycle test with $S_B = 700$.

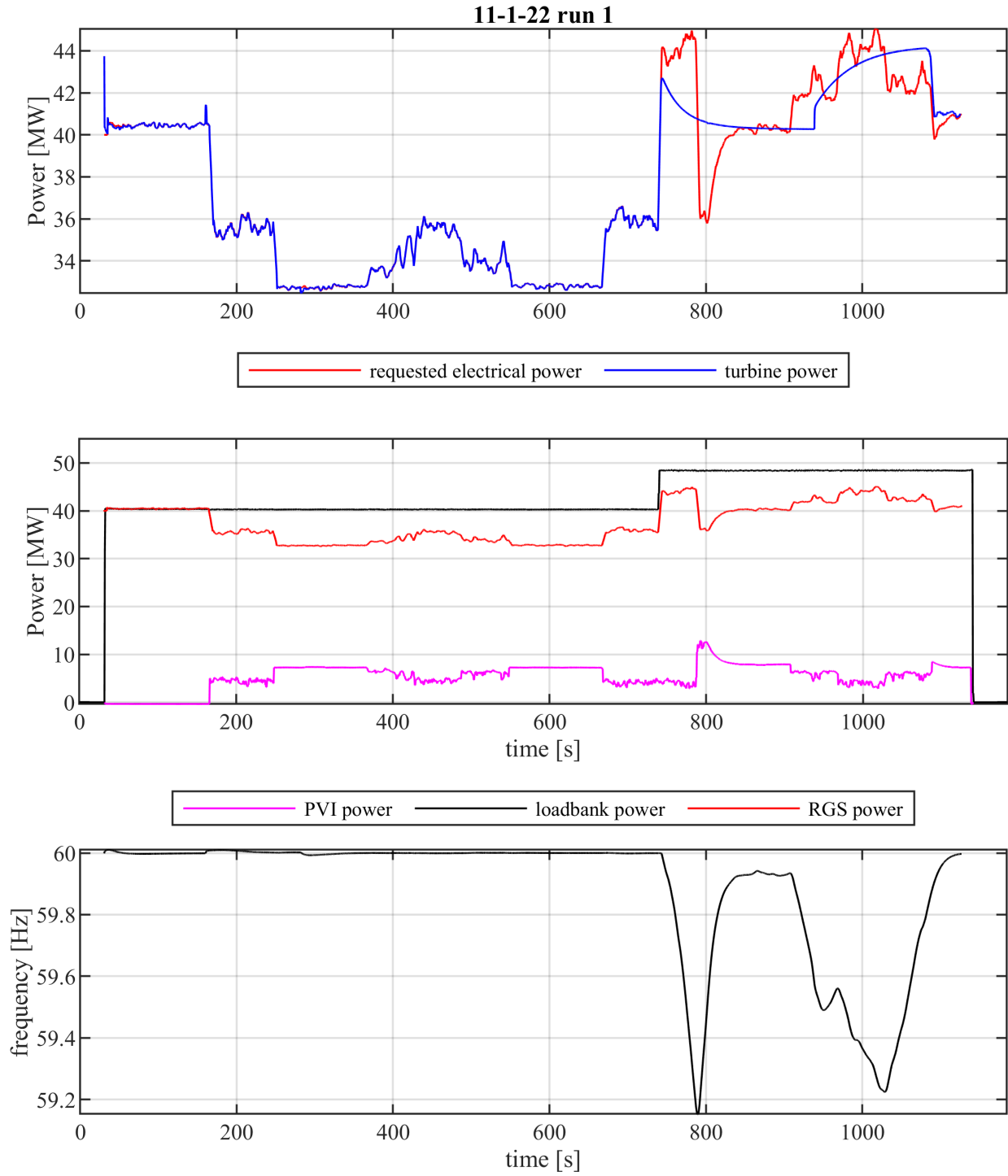
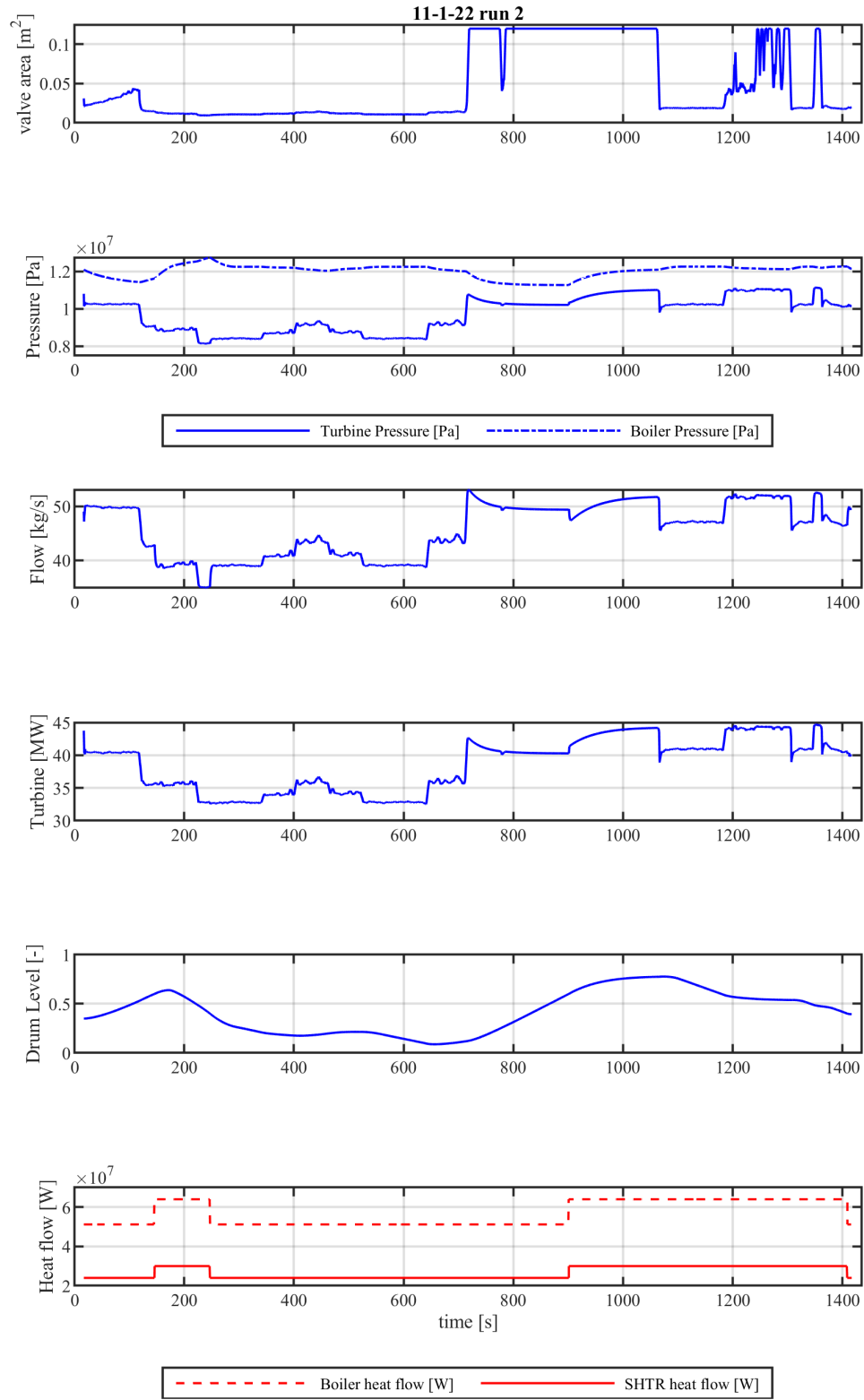


Figure B.7: Load following and electrical frequency from emulated cloud cycle test with $S_B = 700$.

500 MW

Figure B.8: CSP state variables from emulated cloud cycle test with $S_B = 500$.

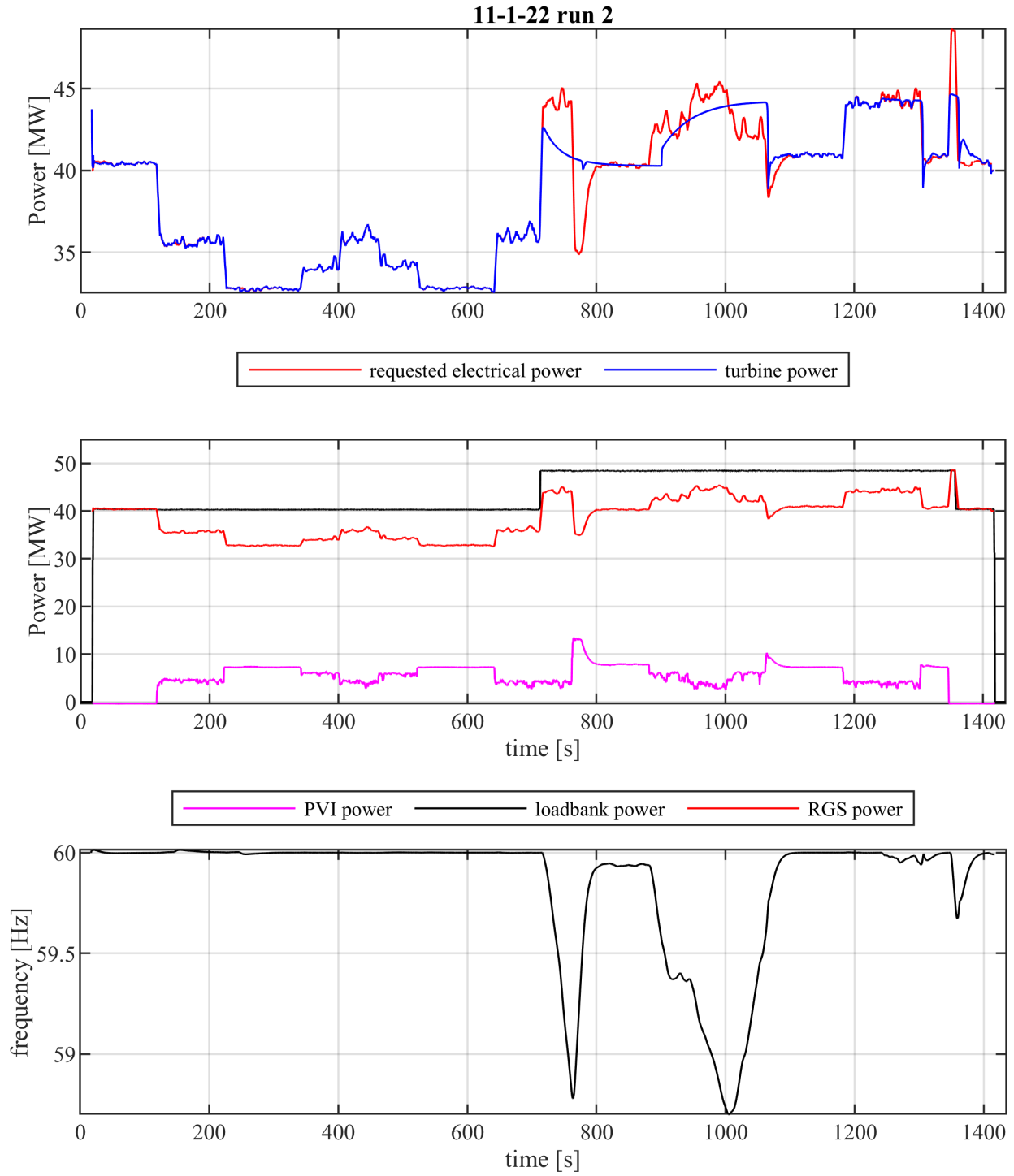


Figure B.9: Load following and electrical frequency from emulated cloud cycle test with $S_B = 500$.

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