Assessing the Impact of Increased Parameter Modeling of Combustion Turbines in a Grid with Varying Renewable Energy Penetration Using PLEXOS

by

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ABSTRACT

As the share of variable renewable energy generation in the power system increases, there is a growing need for flexible resources to balance the resulting variability. Although many systems are transitioning away from fossil fuels, open-cycle gas turbines are likely to fill this balancing role for some time. Accordingly, accurate production cost modeling of the operational parameters of gas turbines will be increasingly crucial as these units are relied on more heavily for flexibility. This thesis explores the impact of three additional parameters—start-up profiles/costs, run-up rates, and forced outage rates—in the production cost modeling of a system as it adopts higher levels of wind and solar. Using PLEXOS simulations of the publicly available National Renewable Energy Laboratory's 118 bus test system, the study examines how higher the increase in parameter modeling affects outcomes such as the number of start-ups and shut-downs, ramping, total generation costs for open-cycle gas turbines, and system-wide costs in three variable renewable energy penetration scenarios. The outcome of replacing certain conventional generation units with newer and more flexible combustion turbines is also examined. The results suggest the importance of detailed parameter modeling and continued research on the formulation of production cost models for flexible generation resources such as combustion turbines.

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LIST OF ABBREVIATIONS

ACOPF	Alternate Current Optimal Power Flow
BTU	British Thermal Unit
CAISO	California Independent System Operator
CCGT	Combined Cycle Power Plant
CTNG	Combustion Turbine Natural Gas
DA	Day Ahead
DA-UC	Day Ahead Unit Commitment
DCOPF	Direct Current Optimal Power Flow
EIA	Energy Information Administration
EFOR	Expected Forced Outage Rate
FOR	Forced Outage Rate
GHG	Greenhouse Gas
MILP	Mixed Integer Linear Programming
MIP	Mixed Integer Programming
MMBTU	Metric Million British Thermal Unit
NREL	National Renewable Energy Laboratory
OCGT	Open Cycle Gas Turbine
PCS	Production Cost Simulation
PV	Photovoltaic
ST	Short Term
SUSD	Startup Shutdown

SRMC	Short Run Marginal Cost
UC-ED	Unit Commitment Economic Dispatch
VO&M	Variable Operations and Maintenance
VRE	Variable Renewable Energy
WECC	Western Electric Coordination Council

CHAPTER 1 INTRODUCTION

1.1 Scope of the Thesis

This thesis examines the impact of increased operational parameter modeling of OCGTs on the PCS results. The impact is assessed on a practical section of the WECC system, represented by the NREL 118 bus test system, undergoing VRE penetration. PLEXOS software is utilized to run a whole year's worth of UC-ED based on DCOPF. The thesis assesses the comparison of operational as well as economic impact on the OCGT technology as well as the system under different VRE scenarios and test cases. The operational impact includes analysis of the overall dispatch profile, number of startups and shutdowns, and ramping requirements of the OCGTs part of the system. The economic impact specifically addresses the comparison of different generation costs for OCGTs and overall system costs. This thesis also examines the impact on the system of the replacement of conventional technology with state-of-the-art gas turbine technology at certain critical system nodes.

1.2 Motivation and Description

The following recent statistics show the fast adoption of an increasing share of VRE resources in the overall dispatch. In the year 2022, solar PV accounted for about 18% of California's total net electricity generation [1]. In addition, California targets to meet 50% of its electricity demand from renewable energy by 2030, as well as reduce GHG emissions to 1990 levels [2]. For the US, the combined wind and solar share of total generation increased from 12% to 14% from 2021 to 2022 [2]. As per the U.S. EIA, the combined share of renewable energy generation will be 44% by 2050 [3], primarily comprising solar and wind power. While this transition towards the increase in the dispatchable share of VREs in modern electric grids has great advantages, the variability, and uncertainty associated with these intermittent forms of energy resources, particularly solar PV, pose several operational challenges. These include the ability to meet steep ramping requirements and quick starting and shutting down profiles of certain units, in response to changing electricity demand during different intervals of the day. One of these operational concerns is shown and explained more through the net load curve in Fig 1.1.

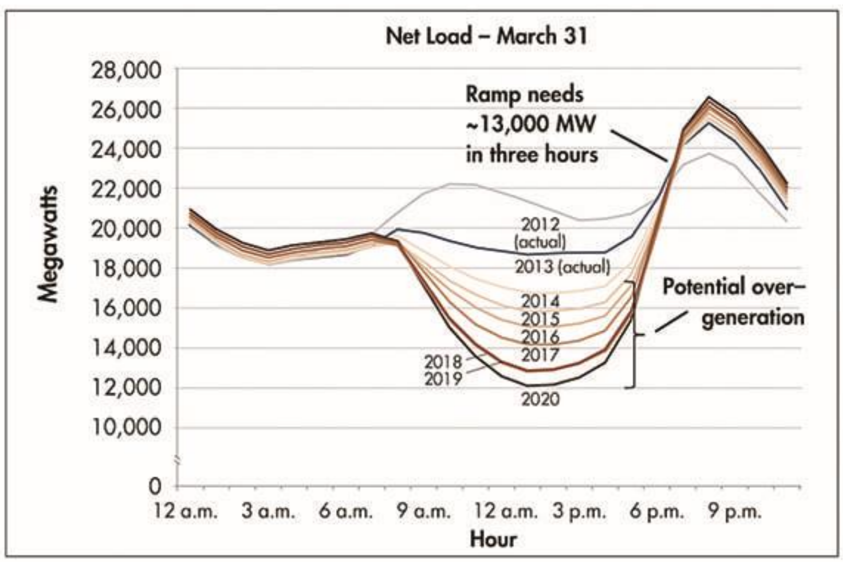


Fig 1.1 CAISO's Duck Curve [4].

This net-load curve is famously known as CAISO’s ‘duck curve’, a term coined by CAISO in 2013 to recognize the evolving shape of the net load profile. As shown in the figure above, the net load curves (years 2012-2020) are for a typical spring day. The y-axis or the net load (MW) is the difference between the forecasted load and electricity production from VREs, i.e., wind and solar for different periods of the day (x-axis). It is thus evident that the steep nature of the duck curve is increasing over the years, in response to the increase in VRE penetration. As an example, for the year 2020, it is noticed that around 7 a.m. the fall in the net load starts as the sun rises and conventional generation is replaced by solar PV. This steep fall continues till 12:00 am, after which the net-load trend is relatively stable till 4:00 pm. As the sun starts to subside after 4:00 pm, the load starts overcoming the VRE production, and a steep rise in the duck curve continues till about 9:00 pm. Hence, in the morning hours, there is a risk of potential over-generation of available electrical energy resources, and in the early evening hours, there is a requirement of ramping up of available generation technologies (e.g., 13,000 MW in 3 hours in Fig 1.1) to maintain the load-generation balance of the electrical grid. Fig 1.2 below shows the changing shape of CAISO's net load curve, having a much deeper "belly" in April 2023 compared to May 2018, with the net load dropping to below zero during the day when solar PV generation is dominant. It is now being termed a "canyon curve" [5], which is regarded as a fiercer form of the duck curve.

Fig 1.2 Evolving Shape of CAISO's Duck Curve, 2018 vs. 2023 [5].

Another example of operational concern is the recent scenario encountered by the Public Service Company of Colorado on March 7th, 2023. Wind generation declined from accounting for 58% of the generation dispatch at a certain period to 0% in just 12 hours [6]. This severe decline was compensated for by gas-based generation, requiring ramping from 25% to 76% in 12 hours.

The ISOs which monitor the electric grid of a particular region/s are tasked with ensuring its reliable operation while running the electricity market, aiming at minimizing the total system cost or maximizing social welfare. An ISO, therefore, needs to have flexible energy resources in place to deal with different critical scenarios such as the ones explained above. Especially, due to the trends observed in the evolving net-load curves in the early morning and evening hours (Fig 1.2), the generation mix in a region should have units with flexible characteristics. Such characteristics include continuous and fast upward or downward ramping capability, appreciable run-up, ramp rates, and the ability to quickly start up or shut down (possibly multiple times a day) to promptly change their generation output levels.

One of the key generation technologies that meet the above characteristics well is the combustion turbine or OCGT. This technology is and will be increasingly relied upon in the upcoming years of the energy transition process. As per the latest available data from the US EIA, the average capacity factor of OCGTs in the US was as high as 23% in the months of June and July 2022 [10]. This is a significant jump from the same months in 2017, wherein the capacity factor for OCGTs was about 11%. To scale and dispatch this technology more effectively in the future, it is essential to accurately quantify its associated operational and economic impact from the PCS results. One of the ways to do this is through the incorporation of detailed operational parameters in production cost models consisting of OCGTs. In some realistic publicly available PCS databases, such as the NREL-118 bus system [7], which reflects the southwest Californian region part of the WECC, some of the essential input operational parameters for modeling OCGTs such as their startup profiles (hot and cold starts), run-up rates and FORs are not included. Also, upon a careful literature review, studies addressing the importance of detailed modeling of flexible generation units in fast-evolving renewable energy penetration scenarios are scarce in the literature.

This thesis describes the incorporation of three additional operational parameters and presents the obtained PCS results in different VRE penetration scenarios and test cases. The PCS results are then analyzed to evaluate the impact of these parameters on the system costs, generation costs of OCGTs, and operational requirements, such as the number of startups/shutdowns for OCGTs and ramping profiles. The comparison is based on PCS done for a full year for all the test cases and scenarios, at an hourly time resolution. The PCS is performed on the renowned production cost modeling tool from Energy Exemplar, PLEXOS (version 9.0).

1.3 Thesis Organization

Chapter 1 provides a description of the research problem and motivation for considering detailed operational parameter modeling of OCGTs and performing PCS in increasing VRE penetration scenarios. Chapter 2 provides a background of some of the key topics, which are the focus of this thesis. The subtopics include the role of gas turbines in electric power dispatch and production cost modeling background. It also includes a brief description of the PLEXOS software and an explanation of some of its key features and modeling approach relevant to the scope of this thesis. Chapter 3 starts by providing a detailed description of the input operational parameters of OCGTs required to perform DA-UC on the test system. The relation of these input parameters to the ST operational constraints in production cost modeling studies such as UC has been explained. In addition, this chapter gives a description of the three additional operational parameters of OCGTs considered in PCS studies for this thesis. Chapter 4 describes the key features of the NREL-118 bus test system used for the PCS study. It then presents the different cases and VRE penetration scenarios for which the DA-UC studies have been performed. Chapter 5 starts by briefly explaining the simulation methodology and assumptions used to perform PCS studies in PLEXOS software in different VRE scenarios. It then proceeds to specifically analyze and discuss the results obtained, particularly addressing the comparison across different scenarios and test cases. Chapter 6 is the conclusion section, which summarizes the study results and the author's point of view and recommendations for future works in this area.

CHAPTER 2 BACKGROUND

2.1 Gas Turbines in Electrical Power Dispatch

Gas turbines for electric power generation are broadly classified into two types – combustion turbines or OCGTs and CCGTs. A combustion turbine or OCGT consists of a compressor, combustor, and turbine.

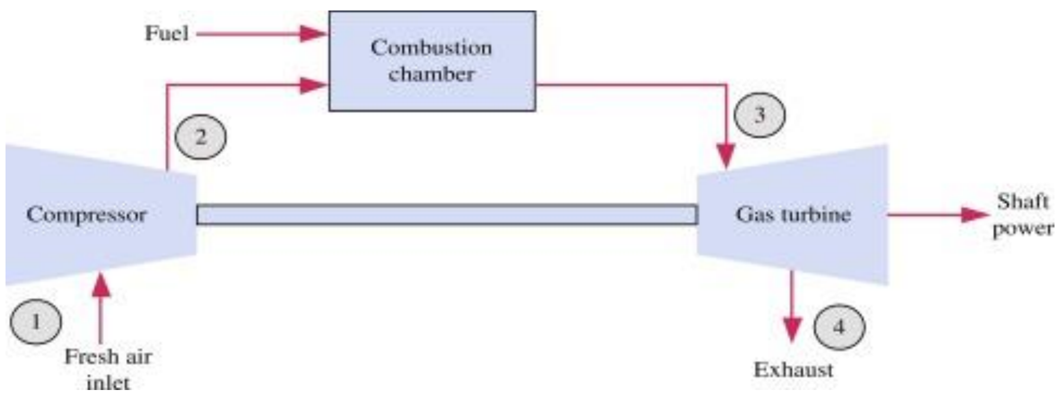


Fig 2.1 Working Principle of a Combustion Turbine [25].

The compressor compresses the drawn-in air molecules, heats them up, and increases the pressure. Next, fuel such as natural gas is injected through the combustor, mixed with the hot compressed air, and burnt. The hot gas created through the ignited mixture moves through the turbine blades, forcing them to spin at around 3000 rpm, converting chemical energy to mechanical energy. In a CCGT, the combustion turbine is used in combination with the steam turbine to generate about 50% more power. The high-heat exhaust generated from an OCGT is used to create steam, which is utilized by the CCGT to spin the prime mover. This technology, in addition to being environmentally friendly, also gives CCGTs a higher cycling efficiency compared to OCGTs as it utilizes steam turbine technology to produce additional electric power. OCGTs are not as efficient to operate as base load units as CCGTs are, considering a modern-day OCGT operates at only about 37% net efficiency, compared to a CCGT of similar capacity, operating at close to 60% [8]. The net heat rate for newer OCGTs is also higher by about 36% compared to CCGTs of similar capacity, leading to a higher fuel cost component of total generation costs. Thus, OCGTs are made to operate at a much lower capacity factor compared to CCGTs and are mostly utilized as peaking units for power generation. Also, with the retirement of coal-based generation plants, CCGTs have been operating at higher capacity factors, with their average capacity factor increasing to 60% in 2021 from about 35% in 2005 [9].

OCGTs have the characteristics required to respond rapidly to changes in the net load balance: these include the ability to quickly start up or shut down, and continuous and quick upward or downward ramping capability. While modern-day CCGTs also have these capabilities, the lower overnight build cost of OCGTs as well as ease of installation and associated scalability, have historically given them an advantage over CCGTs as peaking units. Also, CCGTs are also not as flexible as OCGTs when it comes to picking up load in a short time. As VRE penetration continues to increase in the US, the average capacity factor of CCGTs could drastically fall, thus raising questions on the financial engineering decision to choose them over OCGTs to serve as peaking units. As mentioned in subsection 1.2, the average capacity factor of OCGTs has been steadily rising in the past 5 years, especially during summer months.

In the US, there are about 1500 gas-fired power plants, and they are the primary source of electricity generation [6]. Gas turbines accounted for about 39% of electric power generation in the US in 2022 [2]. In 2021, CCGTs accounted for 56% of the gas-based generation compared to OCGTs at 28% [11]. As the deployment of VRE resources continues to increase in different states of the US, natural gas generation will potentially play a significant role in this transition process. The newer technology OCGTs have significantly quick starting profile capabilities (less than an hour), can ramp up to their maximum power output from minimum stable levels in a few minutes, have low minimum up and down times, and can use hydrogen as fuel. While the operational features of OCGTs continue to improve, making them favorable to manage extreme net-load variations, the shift to hydrogen from natural gas as liquid fuel has its own benefits. It not only leads to net zero GHG emissions, thus lowering the carbon footprint associated with combustion turbines but also has associated higher thermal efficiency. In the years to come, understanding the technical and economic ability of OCGTs to provide peaking services will be important for understanding the viability of these resources in higher VRE power systems.

2.2 Production Cost Modeling Background

Production costs in power systems are associated with operational costs to produce electrical energy. Production cost modeling comes under the broad area of power system operations and planning. The idea was originally developed in the mid-1970s to manage generator fuel inventories and budgets [12]. Production cost models or programs are used for a variety of purposes, but the main ones are to perform long-term power system expansion planning and simulate DA and real-time energy markets. They are created and simulated for energy markets based on an optimization approach. This approach is utilized by different ISOs to effectively allocate a fleet of available generation technologies in the grid to meet the system load while aiming to minimize the system-wide operational cost. In relation to the modeling of energy markets, PCS is presently done by utilizing the UC-ED optimization technique based on DCOPF. These simulations are essential to ensure the economic and reliable operation of the power system. Given below is a brief description of a few important concepts – economic dispatch, optimal power flow, and unit commitment - all related to performing PCS in a power system.

Economic dispatch is a simple optimization problem that considers the i) maximum and minimum capacity constraint of all the generators part of the network and ii) the system-wide node balance constraint. It optimally determines the generation dispatch while adhering to these two constraints with the objective of minimizing the total dispatch cost. It considers that all generators are committed while solving for the optimal dispatch and does not incorporate other crucial constraints such as transmission line limit constraints and electric bus angle limits.

The optimal power flow is another optimization problem, which is an extension of the economic dispatch, and it incorporates the above crucial constraints. As mentioned above, most industries run the DCOPF, which is a 'crude approximation' of the ACOPF [13], thus making it a linear optimization problem to solve. The relaxed assumptions include: i) all the node voltages part of the system are 1 p.u., ii) there is negligible difference in voltage angles between two buses part of a line, iii) reactance of line >> resistance of the line. These assumptions make the optimal power flow problem much simpler to solve without a significant compromise on accuracy. The objective of DCOPF is to minimize the total dispatch cost or maximize social welfare while meeting the different operational constraints.

An extension of DCOPF and a crucial problem to solve for simulating energy markets is the unit commitment (UC) problem. UC refers to a sequence of decisions for a generation unit being on or off at a particular period over a selected time horizon. It finds the optimal combination of these on or off decisions for all generating units across a specified time horizon. In addition to including the DCOPF operational constraints, this problem considers a binary variable constraint (0/1) representing (off/on) to perform optimal scheduling of the generator part of the system. The equations below show a very simple UC-ED formulation, wherein the generation units are dispatched based on their short-run marginal cost (SRMC), which is the unit's variable cost to produce one more MW of generation [14]. The SRMC is a function of the fuel cost in a particular period in addition to the variable operations & maintenance (VO&M) charge.

$$\text{Minimize } \sum_t \sum_g MC_g \,.\, P_{g,t} + C_{g,su} \,.\, u_{g,t} \quad (1)$$

$$\text{Subject to: } 0 <= u_{g,t} <= 1 \quad (2)$$

$$\sum_g u_{g,t} \,.\, P_{g,t} = D_t \quad (3)$$

$$u_{g,t} \,.\, P_{g,min} <= P_{g,t} <= u_{g,t} . P_{g,max} \quad (4)$$

$$u_{g,t} \cdot (P_{g,t+1} - P_{g,t}) <= R_{g+} \quad (5)$$

$$u_{g,t} \cdot (P_{g,t-1} - P_{g,t}) <= R_{g-} \quad (6)$$

The SRMC of a generator g, is given by MC_g. The objective is to minimize total system cost for all time periods, t. The total system cost in eq. (1) is the SRMC of the unit times its generation in that period $P_{g,t}$, in addition to the startup cost of the unit $C_{g,su}$, considering it is committed or $u_{g,t} = 1$. The first constraint, eq. (2) just enforces the UC variable to be binary. Eq. (3) ensures that the system-wide demand, D_t, is balanced in all periods. The third constraint (4) ensures that the unit's output in any period is between its min stable level, $P_{g,min}$ and max capacity, $P_{g,max}$, once it is on. Eqns. (5) and (6) depict the generic ramp rate constraints, with limitations due to the max ramp up parameter, R_{g+} and max ramp down parameter, R_{g-}. In brief they impose that difference in generation levels between two periods should not exceed the ramp rate limits specified by R_{g+} and R_{g-}. In addition to the above constraints, there are also a few intertemporal constraints related to UC variable such as minimum up time, down time and run up rate constraints for generators. Some of them are as follows:

$$u_{g,t} - u_{g,t-1} - u_{g,start,t} - u_{g,stop,t} = 0 \qquad (7)$$

$$u_{g,t} - \sum_{k=t-|MinUpTime|+1}^{t} (u_{g,start,k}) \geq 0 \qquad (8)$$

$$u_{g,t} - \sum_{k=t-|MinDownTime|+1}^{t} (u_{g,stop,k}) \leq 1 \qquad (9)$$

Eq. 7 imposes two additional binary variables, $u_{g,start}$ and $u_{g,stop}$, which aim to accurately capture the starting profiles of the generators. Eq. 8 and 9 are generic constraints to adhere to the unit's minimum up and down time requirements.

The inclusion of multiple binary variable constraints makes the UC problem difficult to solve, as it becomes a MILP problem. The problem becomes even more complex with the incorporation of intertemporal constraints such as the ones described above and time series data for the different generation technologies, load, and VRE resources. Moreover, the co-optimization with ancillary services requirements helps in more realistic capturing of scenarios and forecasting of DA energy markets but also makes the system more complex to solve. Thus, accuracy has a trade off with time, effort, and costs. This requires a balance to be maintained by ISOs to carry out UC-ED co-optimization studies efficiently after assessing the crucial scenarios in the monitored grid.

UC-ED is required to be solved by ISOs on a DA basis mostly on an hourly time resolution, to forecast the scheduling of the generators, i.e., periods of the day on which they should be on (1) or off (0). In this thesis, the DCOPF based UC-ED model for the test system was run for a whole year, at an hourly resolution, to assess the impact more accurately on the crucial operational and economic variables. Since it is very difficult to run the model for such a long horizon, PLEXOS solves it by dividing it into steps (explained in subsection 5.1).

2.3 PLEXOS Overview

PLEXOS is a power system optimization tool used in modeling electricity markets. It has been widely adopted by industries and researchers throughout the globe to aid in decision support for energy markets [15], particularly having a major use to carry out ambitious renewable grid integration studies. The commonly used applications of PLEXOS are production costing; expansion planning, which includes determining the optimal size and timing of new energy investments, and projection of short, medium, and long-term resource adequacy [16]. One of its main capabilities is solving UC-ED by co-optimizing over time series data and distinct constraints of varying generation technologies such as gas turbines, solar, wind, hydropower, coal, geothermal, etc., as well as gas and electric networks. There are four different simulation options within PLEXOS, i.e., long-term (LT) plan, projected assessment of system adequacy (PASA), medium-term (MT) schedule, and short-term (ST) schedule. A good summary of these schedules has been provided in [16], but the next part will briefly discuss the ST schedule, which is relevant to this thesis.

ST schedule is utilized to carry out production cost modeling to simulate day-ahead (1 hr. resolution) or real-time (5, 15, 25 minutes, etc. resolution) energy markets, solving for the dispatch and nodal pricing for the preferred time period. It performs chronological optimization through the MIP approach to solve key problems such as UC. The chronological consistency across the horizon is essential to analyze key period-dependent variables such as generator startup, shutdowns, and unit status. In the ST schedule, one can model over 300 UC parameters [17], part of the inter-temporal constraints, some of which are described in subsection 2.2. This schedule models over the selected days or months of a horizon at a selected resolution, also known as the period, which is one hour by default but can be adjusted to sub-hourly depending on user requirements and associated time series data availability. In the modern day increasingly flexible grid, the increase in resolution to sub-hourly in ST schedule can capture real-time operational conditions such as the number of startups/shutdowns, MW ramp up/down, costs, and pricing more effectively than at an hourly resolution [18]. It is shown in [18] that increase in temporal resolution from 1 hour to 5 minutes increases annual system costs on Ireland's power system by about $17.5 million.

PLEXOS is based on object-oriented programming design. The PLEXOS model file is saved as a database file in XML format. This file defines a set of rules, which hold information about the system in the form of objects, membership, and properties. A few important concepts of objected oriented programming utilized by PLEXOS are mentioned below [16]:

Class: The behavior and characteristics of all the objects part of the system are governed by a set of rules and definitions defined by a class. PLEXOS has 56 classes, divided into 9 groups. As a few examples, in the Production group, the classes include Generator, Fuel, and Emission; in the Transmission group – Region, Node, Line, and Transformer; Data group – Variable, Scenario; and in the Setting group – Transmission, Production, Performance.

Object: Each member or pattern of a class with some characteristics is an object. As an example, a generator 'G' is defined as an object in the class 'Generator'.

Membership: It provides the relationship between different objects, which could be a part of the same class or different classes. As an example, generator 'G' in class 'Generator' has a relationship with a fuel object in the same class as well as with a node object in class 'Transmission'. Each membership is defined during PLEXOS modeling of the system by defining a parent name and child name, to point out to a particular object within a class.

Collection: This feature is the key to establishing relationships or memberships between different objects of classes. For example, the collection 'Generator.Fuels' is used to establish a relation between the generators class and fuels class, after which memberships are assigned at an object level.

Properties: The properties or attributes are provided for each object. The modeler selects certain short term operational constraints specific to the objects within different classes in PLEXOS, for which corresponding values or datafiles (property) can be provided. The figures below show the application of the above discussed terms in PLEXOS software.

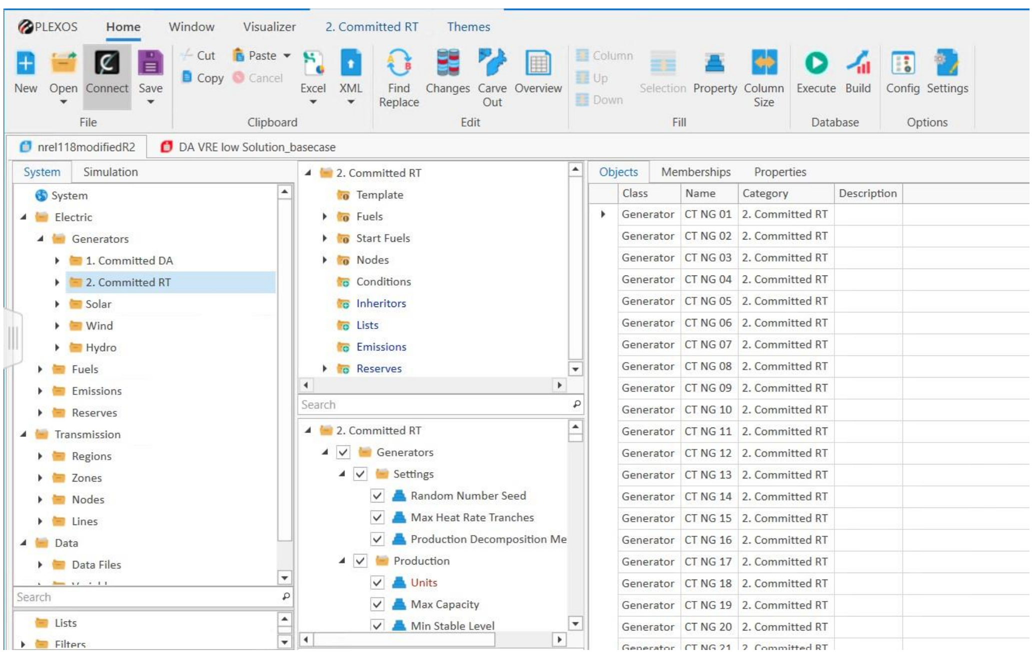
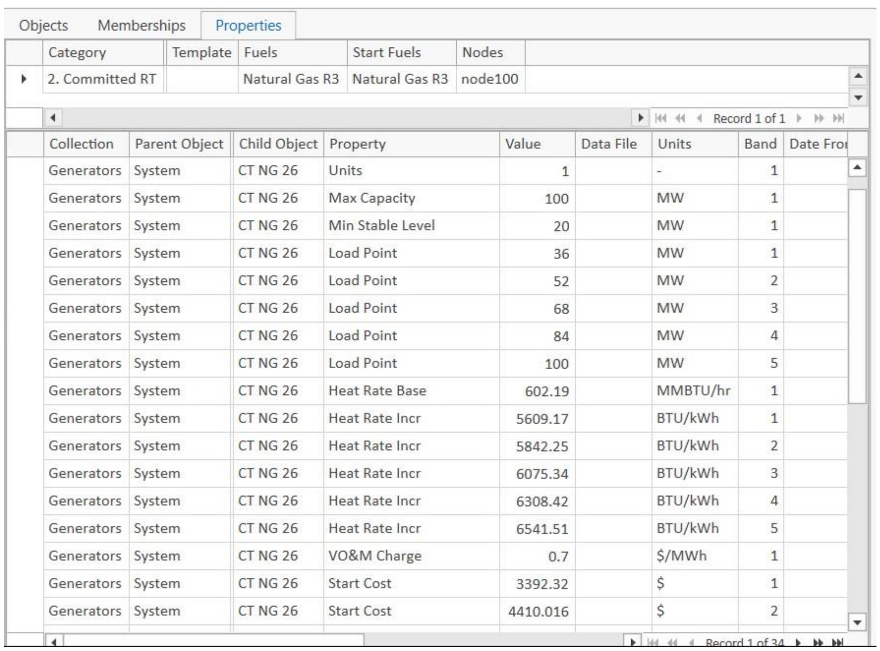


Fig 2.2 Snapshot of PLEXOS GUI Systems Tab

In Fig 2.2, 'nrel118modifiedR2' is an electric file in .xml format. A file in PLEXOS primarily has two tabs, a System tab, and a Simulation tab. The System tab has three groups, 'Electric', 'Transmission', and 'Data', and different classes within each group. In the 'Generator' class in the 'Electric' group, one can assign different categories or folders to segregate the types of generators. For this file, the OCGTs part of the system are included in the folder ‘Committed RT category’. For all the objects or generators in that category, there are associated memberships and properties.

Collection	Parent Name	Child Name	Parent Category	Child Category
Generator.Fuels	CT NG 26	Natural Gas R3	2. Committed RT	-
Generator.Start Fuels	CT NG 26	Natural Gas R3	2. Committed RT	-
Generator.Nodes	CT NG 26	node100	2. Committed RT	-
Reserve.Generators	Regulation Down R3	CT NG 26	Regulation Down	2. Committed RT
Reserve.Generators	Regulation Up R3	CT NG 26	Regulation Up	2. Committed RT
Reserve.Generators	Contingency Spinning R3	CT NG 26	Spinning	2. Committed RT

Fig 2.3 Example of Membership Feature of PLEXOS



Category	Template	Fuels	Start Fuels	Nodes
2. Committed RT		Natural Gas R3	Natural Gas R3	node100

Collection	Parent Object	Child Object	Property	Value	Data File	Units	Band	Date Fro
Generators	System	CT NG 26	Units	1		-	1	
Generators	System	CT NG 26	Max Capacity	100		MW	1	
Generators	System	CT NG 26	Min Stable Level	20		MW	1	
Generators	System	CT NG 26	Load Point	36		MW	1	
Generators	System	CT NG 26	Load Point	52		MW	2	
Generators	System	CT NG 26	Load Point	68		MW	3	
Generators	System	CT NG 26	Load Point	84		MW	4	
Generators	System	CT NG 26	Load Point	100		MW	5	
Generators	System	CT NG 26	Heat Rate Base	602.19		MMBTU/hr	1	
Generators	System	CT NG 26	Heat Rate Incr	5609.17		BTU/kWh	1	
Generators	System	CT NG 26	Heat Rate Incr	5842.25		BTU/kWh	2	
Generators	System	CT NG 26	Heat Rate Incr	6075.34		BTU/kWh	3	
Generators	System	CT NG 26	Heat Rate Incr	6308.42		BTU/kWh	4	
Generators	System	CT NG 26	Heat Rate Incr	6541.51		BTU/kWh	5	
Generators	System	CT NG 26	VO&M Charge	0.7		$/MWh	1	
Generators	System	CT NG 26	Start Cost	3392.32		$	1	
Generators	System	CT NG 26	Start Cost	4410.016		$	2	

Fig 2.4 Example of Properties Feature of PLEXOS

In Figs 2.3 and 2.4 above, the membership and some properties are shown for a generator object in the OCGT categories. The object is combustion turbine natural gas no. 26 or ‘CTNG 26’. For the membership feature, the class ‘Generator’ has a relationship with the following classes – ‘Fuels’, ‘Start Fuels’, ‘Nodes’, ‘Reserves’, as defined in the

‘Collection’ column. Corresponding to each entry in the ‘Collection column’, a parent name and child name must be provided to assign memberships to the object. The entry in the collection column is defined as parent.child, so for e.g. if ‘Generator.Nodes’ is the column entry, the corresponding parent name should be the generator object name (or ‘CTNG 26’), and the child name is the particular node object (‘node100’ in this case). This assigns a relationship between object ‘CTNG 26’ and node 100. Similarly, a relationship has been provided between the generator object and fuel object, with ‘CTNG 26 as the parent object’ and Natural Gas R3’ as the child object, for the memberships, ‘Generator.Fuels’ and ‘Generation.Start Fuels’. These relationships show that the price assigned for natural gas in region, R3 will be utilized as start fuel and operating fuel for ‘CTNG 26’. For the three collections of ‘Reserve.Generator’, regulation up, down, and spinning reserve object in region 3 has been assigned as a parent object to link the types of reserves modeled for the system to the child object ‘CTNG 26’. The ‘parent category’ column links to the folder on the System tab, where the parent object is located.

The properties feature shown above (Fig 2.4) includes some of the selected properties for object ‘CTNG 26’. Here, the collection/class of generators have the same parent object, i.e., ‘System’ for assigning all the properties. The child object is also the same throughout, as properties are being modeled for the generator ‘CTNG 26’. The ‘property’ column provides the choice of operational constraints which can be modeled. The user can input a value or data file (if applicable) to model that constraint and assign its units. Some properties also have a multi band option for detailed constraint modeling and that has been discussed more in Chapter 3. As mentioned before, one can model more than

300 properties for UC, and this is done as shown in Fig 2.5 below by going to ‘Config’ tab located at top right of the PLEXOS GUI in Fig 2.2.

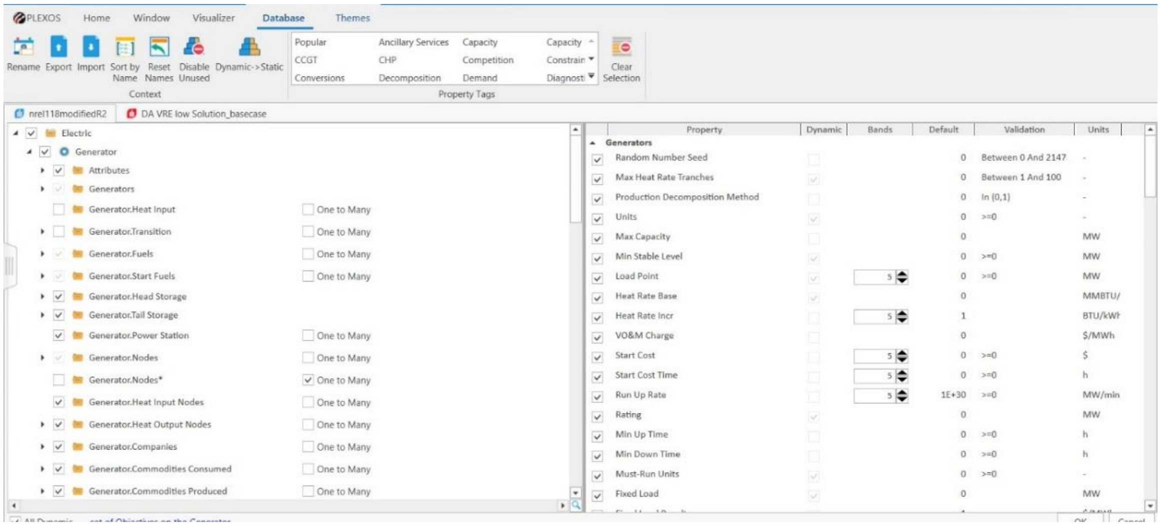


Fig 2.5 Configuration Tab in PLEXOS to Select Customized UC Properties.

As seen in the figure above, one can choose from different properties, which reflect operational constraints, by choosing from the drop-down menu of a particular group. The properties already chosen to be modeled for the different generators part of the system are shown as selected on the right-hand pane. It shows whether the property has a multiband feature, its default value provided by PLEXOS, validation criteria, and its units. As mentioned in subsection 2.3, assigning additional operational constraints has a trade-off with the time and complexity of the problem, so a balance needs to be ascertained in that regard by the modeler.

Fig 2.6 below shows the Simulation tab of PLEXOS with groups categorized as ‘Execute’, ‘Simulation’, ‘Settings’, and ‘Data’. Some of the main features of this tab include adding new models, assigning scenarios to the model, specifying simulation settings for different schedules such as ST schedule, MT schedule as well as setting options in output reports to select the different results to be output and analyzed.

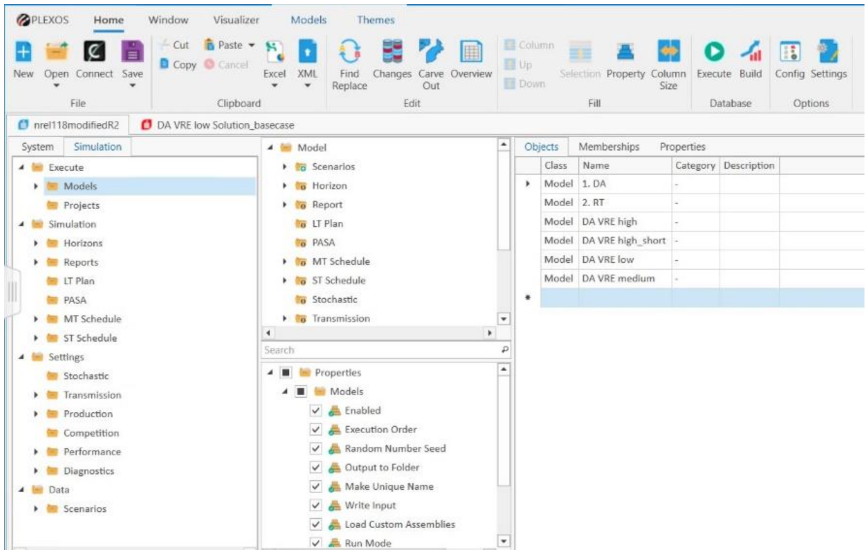


Fig 2.6 Snapshot of PLEXOS GUI Simulation Tab

The snapshot above shows the ‘Models’ class on the rightmost pane. There are six model objects, which represent the different models set up. Chapter 5.1 shows the setting up of these models. The membership tab in Fig 2.6 shows the relationship between each of these models to the different scenarios set up by the modeler. As an example, if one includes a scenario reflecting increased VRE penetration and names the object ‘High VRE’, the particular model object (‘DA VRE high’) in the figure above needs to be mapped to the scenario object ‘High VRE’ as a ‘parent.child’ membership.

For this thesis, PLEXOS’s production costing feature or ST schedule was utilized to solve for a year of DA-UC and economic dispatch at an hourly resolution, by co-optimizing over distinct operational constraints of varying generation technologies and time series VRE and load data. The generation units were dispatched based on their short-run marginal cost (SRMC), a simple formulation of which is shown in subsection 2.2. However, that formulation was just shown to demonstrate an example of UC formulation. In practicality, production cost formulation for each generator and their types can be customized according to the data and selected operational parameters or options [7] (Fig 2.5). This allows the user to easily include the intertemporal constraints as well as any additional customized operational parameters.

CHAPTER 3 OPERATIONAL PARAMETERS OF OCGTS FOR PRODUCTION COST MODELING

This chapter is divided into two parts. The first section describes all the operational parameters of OCGTs, which are included in the base case of the NREL-118 PLEXOS model. The relevance of these operational parameters to the setting up of the production cost model for UC studies is discussed. The second section defines the three additional OCGT operational parameters considered in the UC model. The significance of those parameters to provide a more accurate forecast of day-ahead dispatch is also discussed in this chapter.

3.1 Input Operational Parameters for OCGTs in NREL – 118 Bus Base Case

The NREL 118 bus system has 66 OCGTs of varying capacities (1.5 to 200 MW). The following operational parameters or properties are included in the base case of the PLEXOS model:

- Maximum capacity: As the term suggests, this is the maximum available capacity of an OCGT, corresponding to the parameter, $P_{g,max}$, in the sample UC formulation given in subsection 2.2. It enforces the following UC constraint: $u_{g,t} * P_{g,t} \leq P_{g,max}$.
- Minimum stable level: This corresponds to $P_{g,min}$ in the sample UC formulation of subsection 2.2. It is the minimum level that is enforced, and the unit should at least stay at that level when it is turned on.
- Commit: This parameter in PLEXOS specifies the UC parameter. It takes default value of -1, which allows the system to optimize the UC decision for the unit (on or off for

different periods) and consider the unit commitment decision as a variable while running PCS.

- SRMC: For this model, the generation units have been dispatched in PLEXOS according to their SRMC. SRMC, as the name depicts, is the unit's short-term marginal or incremental cost, i.e., the variable cost associated with producing one more MW of generation. It is a component of fuel price and the variable operations and maintenance (VO&M) charge and given as SRMC = (fuel price X marginal heat rate) + VO&M charge. The next two bullets provide more insight into these components of SRMC, i.e., fuel cost and VO&M charge.
- Heat rate modeling: This modeling is essential to determine the fuel cost optimally and accurately for a generating unit in a particular period in PCS studies. In PLEXOS, the heat input function is given by $y = f(x)$, where y is the heat input or the amount of fuel consumed to produce at megawatt level, x for one hour. The average heat rate is given by function $a(x) = f(x)/x$ and the marginal heat rate is given by the derivative of the heat input function, $m(x) = \delta y/\delta x$. For the OCGTs part of the NREL-118 bus system, the heat rate modeling is done by specifying a base heat rate along with multiple pairs of heat rate increment and load points. The heat rate base is the y-intercept of the heat input function and corresponds to the no-load cost. Heat rate increment is the marginal heat rate at the mid-point of the segment between the bands. As an example, let heat input function, $f(x) = a + bx$. Here, as per the definition above, the heat rate base is $f(x) = a$, and 'bx' represents the linear increment, wherein b is the marginal heat rate at the mid-point of the segment and x is the load operation point.

Child Object	Property	Value	Data File	Units	Band
CT NG 26	Max Capacity	100		MW	1
CT NG 26	Min Stable Level	20		MW	1
CT NG 26	Load Point	36		MW	1
CT NG 26	Load Point	52		MW	2
CT NG 26	Load Point	68		MW	3
CT NG 26	Load Point	84		MW	4
CT NG 26	Load Point	100		MW	5
CT NG 26	Heat Rate Base	602.19		MMBTU/hr	1
CT NG 26	Heat Rate Incr	5609.17		BTU/kWh	1
CT NG 26	Heat Rate Incr	5842.25		BTU/kWh	2
CT NG 26	Heat Rate Incr	6075.34		BTU/kWh	3
CT NG 26	Heat Rate Incr	6308.42		BTU/kWh	4
CT NG 26	Heat Rate Incr	6541.51		BTU/kWh	5

Fig 3.1 Heat Rate Modeling Example

Fig 3.1 provides an example of heat rate modeling for an OCGT in PLEXOS. There are five bands of load points, which correspond to give heat rate increments, with the maximum heat rate increment corresponding to the maximum capacity of the OCGT. If the actual load point lies anywhere between these bands (segment), the fuel cost is computed by multiplying the corresponding segment heat rate increment (BTU/kWh) with the fuel price (in $/MMBTU).

- VO&M charge: This charge is given in $/MWh and is a component of the unit's SRMC or the incremental generation cost. It thus has a direct influence on the generator's offer price in each period. This charge is used to recover maintenance costs such as wear and tear and other regular equipment replacement and servicing costs. The VO&M cost is obtained by multiplying the input VO&M charge for the unit and the generation output (MWh). The VO&M charge for all the OCGTs part of this test system is fixed at $0.7/MWh [7].

- Start cost: In addition to the fuel and VO&M cost, there is also a start cost parameter associated with each OCGT unit in the base case. It is another component of the unit's total generation cost. It reflects the O&M cost associated with each start-up of an OCGT and is given in $ per start. In simple terms, for this given base case, the start cost in PLEXOS is defined as the cost of turning the unit on and reaching its min stable level. In the next section, this cost component has been explained more, and how it is incorporated into the multiband start profile while considering detailed parameter modeling of OCGTs.
- Minimum up and down time: Minimum up and down time are static parameters (given in hrs.) associated with the modeling of OCGTs. These constitute the intertemporal constraints described in subsection 2.2 (eqns. (8) and (9)). Minimum up time reflects the minimum number of hours the unit must be on once it has been committed. The minimum down time reflects the minimum number of hours the unit must be off once it has been turned off. One of the key advantages for OCGTs is that these times are much lower compared to other conventional generation technologies, thus making them a flexible option for dispatch in critical scenarios.
- Maximum ramp-up capability: This property sets a limit on the amount of generation that can increase in a specified time interval (eqns. (5) and (6) in subsection 2.2). It is expressed in MW/min in PLEXOS. This constraint has a multiband feature and thus varying ramping up limits are specified for different generation levels. However, if a single band is defined, the limit applies for the unit between its minimum stable level and maximum capacity.

In addition to the above, some more parameters (defined below) were considered to reflect other short-term operational constraints related to OCGTs.

3.2 Additional Operational Parameters for OCGTs in NREL – 118 Bus Base Case

3.2.1 Startup Profiles

Two starting modes are modeled for each OCGT unit: hot start and cold start. The categorization is based on the time required since the last shutdown for the unit to start up again and each start mode incurs a specified fixed start cost. The startup profile in PLEXOS has a multiband feature with start cost times linked to their respective fixed start costs. The hot start time was considered 1 hour for each OCGT, while the cold start time was considered 2 hours since the last shutdown. These start times are more reflective of older grid-connected OCGTs since newer OCGTs have much quicker hot and cold start times [8]. Also, these offer the best assumption of start times for OCGTs since PCS is performed on an hourly resolution. Due to this reason, warm starts, which fall in the middle of the startup profile between hot starts and cold starts, are not modeled. Their inclusion would further delay the cold start time by at least an hour, making it unrealistic for flexible units such as OCGTs. The fixed start cost for a hot start is considered the same value as provided in the base case for OCGTs part of the NREL-118 bus [7]. Since the cost is higher for restarting a unit at or after a cold start time, its linked fixed start cost is assumed to be 1.3 times the fixed hot start cost. This assumption was based on the projected 2030 lower bound start cost data for different generation technologies in the Intertek-WECC study [19].

3.2.2 Run Up Rates

In the NREL-118 PLEXOS base case, the maximum ramp-up and down rates (MW/min) for OCGTs are modeled. This operational constraint is only enforced whenever the unit is committed; the ramp-up and down limitations are shown in constraints eqns. (5) and (6) in subsection 2.2. The modeling of this constraint by itself represents what is shown by the 'block loading of unit' feature in Fig 3.2 below [18]. This feature assumes that the unit instantaneously reaches its $P_{g,min}$, following which it can ramp up at a maximum of 3 MW/min (shown by the black line) or 180 MW/hr. This is however a relaxed assumption, as in reality, units such as OCGTs have run up rates associated with their start profiles (hot start, cold start). As shown by the grey line in Fig 3.2, this example has a run-up rate of 2 MW/min, which it adheres to till reaching its $P_{g,min}$, following which the max ramp up rate constraint becomes active, like shown by the black line.

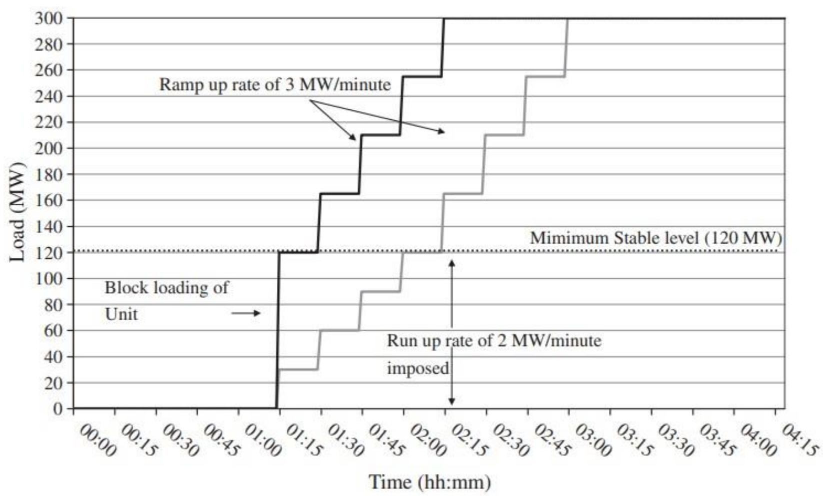


Fig 3.2 Example of Imposing Run Up Rate in Start Profile [18].

Run up rates are imposed in PLEXOS by utilizing its multiband feature. The run up rates are linked to the corresponding start profile times as shown in Fig 3.3.

Generator	Property	Band	Value	Units
Gen	Units	1	1	-
Gen	Max Capacity	1	300	MW
Gen	Min Stable Level	1	150	MW
Gen	Run Up Rate	1	1.0	MW/min.
Gen	Run Up Rate	2	0.8	MW/min.
Gen	Run Up Rate	3	0.5	MW/min.
Gen	Start Cost Time	1	2	hrs
Gen	Start Cost Time	2	4	hrs
Gen	Start Cost Time	3	4	hrs
Gen	Start Cost	1	1000	$
Gen	Start Cost	2	2500	$
Gen	Start Cost	3	3000	$

Fig 3.3 Multiband Feature of PLEXOS Linking Start Profile Times to Run Up Rates.

Fig 3.3 is an example of imposing run up rate using the multi-band feature in PLEXOS software. There are three bands corresponding to three different starting profiles, hot start, warm start, and cold start in this case. In this example, the unit stays 'hot' for up to two hours after being shut down and if it starts up prior to 2 hours, it has an associated run-up rate of 1 MW/min (linked by Band 1). The associated fixed start cost is $1000. Similarly, warm, and cold starts are modeled in the above example by using bands 2 and 3 respectively. One key point to note is that the start cost time after the first band is an increment to the previous start cost time. For example, the warm start time will not be 4 hours but 6 hours, as the input in PLEXOS represents the time in addition to the time corresponding to the previous band.

For this study, run up rates are modeled for OCGTs in their startup profiles, associated with hot and cold starts. The run up rate for a hot and cold start is estimated to be a fraction of the max ramp up rate for each OCGT. This assumption is made by analyzing input data of CCGTs part of the system [7], with their run up rates modeled. The run-up rate for a cold start is lower than that for a warm or hot start, as the unit is slower to start after being turned off for a longer time. The modeling of run up rates is expected to directly influence the start cost of the unit, as it will now include the fuel offtake cost while the unit is starting up, in addition to their fixed start cost.

3.2.3 Forced Outage Rates

The increased cycling of power plants associated with the rise in VRE penetration leads to reduced plant life [19], which results in higher EFOR. Since the increased cycling operation can accelerate forced outages, it is essential to model the FORs for each OCGT. FOR is provided in % and sets an expected level of unplanned outages, which could result in partial or complete loss of generating capacity for a certain period.

$$\%\ \mathrm{FOR} = \frac{\text{forced outage in hrs X 100}}{\text{duration without outage in hrs} + \text{forced outage in hrs}}$$

PLEXOS uses a triangular probability distribution function [20] to model this. This function is utilized when there is limited data availability to estimate a probabilistic impact. The associated parameters with the FOR (%) are min time to repair, max time to repair, and mean time to repair. In this setup, the unit will be modeled as out of service for a duration on average of FOR*periods of the year, with the duration of outage events varying from min time to repair to the max to repair, having a maximum frequency at mean time to repair. The FORs are obtained from [21], which provides upper bound data for expected FORs for varying capacities of OCGTs.

Table 3.1 below provides some of the sample parameters discussed above used to model a 220 MW OCGT in PLEXOS.

Table 3.1: Sample Input Parameters for 200 MW OCGT in PLEXOS

Param	Value	Param	Value
Max capacity	200 MW	Max ramp up/down	5.33 MW/min
Min stable level	90 MW	Forced outage rate	6.65 %
Hot start cost time	1 hr.	Min time to repair	3 hrs.
Cold start cost time	1 hr.	Max time to repair	100 hrs.
Hot start cost	$19654.25	Mean time to repair	36 hrs.
Cold start cost	$25550.53	Min up/down time	2 hrs.
Run up rate (hot start)	3.73 MW/min	VO&M charge	$ 0.6/MWh [7]
Run up rate (cold start)	2.67 MW/min	Fuel charge	$ 5.4/MMBTU [7]

As is seen in the table above, FOR has a value of 6.65%. This implies that the unit is expected to be out for approximately 0.0665*8760 hours = 583 hours in the fiscal year (considering hourly resolution), with repair times ranging from 3 to 100 hours, having a mode at 36 hours. It may also be noted that the max ramp up/down rates and run up rates are low for an OCGT compared to the modern-day General Electric OCGTs capable of ramp rates of tens of MW/min [8]. The same is the case with minimum up and down times or available fuel charges. However, the main goal of this thesis is to assess the impact of additional operational parameter modeling of OCGTs by benchmarking it against the PCS results of the open-source NREL-118 bus in different VRE scenarios. Hence, some of these crucial parameters were not modified for this thesis.

CHAPTER 4 TEST SYSTEM, SCENARIOS AND TEST CASES

4.1 NREL-118 Bus Test System

The test system used for this thesis is the NREL-118 bus system. The NREL-118 bus system is an extended version of the IEEE-118 bus system [22] and is available as an open-source economic dispatch and UC PLEXOS model [7]. It is a realistic and highly valuable detailed database comprising ten power generation technologies and is well suited to perform large-scale renewable grid integration studies. The system comprises three regions (R1, R2 and R3) in California - R1 represents the Pacific Gas & Electric Bay Area and has a total installed generation capacity of 10.5 GW, R2 is Sacramento district with an installed capacity of 5.4 GW and R3 represents the San Diego Gas & Electric with 8.6 GW of installed generation capacity. The system consists of 118 buses, 186 transmission lines, and 327 generators distributed across the three regions. The generation and regional data are obtained from the latest WECC 2024 Common Case Database [7][23]. Time synchronous actual and forecasted data for solar, wind, and regional electricity load (hourly resolution) for one year is also included, considering the seasonal variation. This data was generated using the base as the weather year of 2011. The system-wide peak load is 19,800 MW, which is scaled approximately to the expansion in generation compared to the IEEE-118 bus. The constraints of the generation technologies have been modeled in detail in the production cost model. They include max capacity (MW), min stable level (MW), heat rate (MMBTU/h), heat rate increment (BTU/KWh), load point (MW), start cost ($), VO&M charge ($/MWh), min. up time (hour), min. down time (hour), max. ramp up (MW/min) and max. ramp down (MW/min). There is also an allotment of reserves, regulation up/down and spinning reserves for each region, with a total of 234 generators participating except wind and solar. The regulation up and down reserves account for 1% of the total regional load in that period, whereas the contingency spinning reserve is 3% of the load per region.

The total installed capacity for all three regions is 24.5 GW. Fig 4.1(a) below shows the distribution of the system-wide installed capacity by generation type.

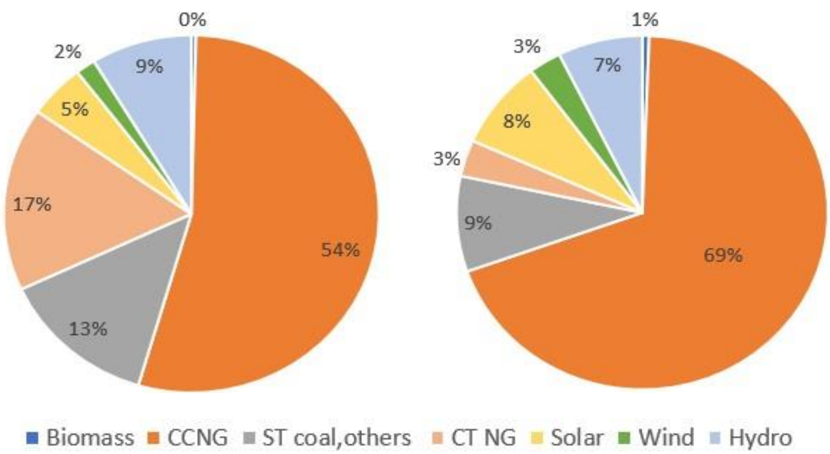


Fig 4.1 a) Distribution of the Total Installed Capacity (24.5 GW, left chart) and b) System-Wide Dispatch (right chart) for the Fiscal Year 2024 by Generation Type.

The system consists of 66 OCGTs of varying generation capacity across the three regions with the maximum capacity ranging from 1.3 – 200 MW. OCGTs comprise approximately 4.17 GW of the installed capacity out of the combined installed capacity of 24.5 GW in the test system. Out of this, R1 accounts for 1.58 GW, R2 for 0.54 GW, and R3 for about 2.05 GW. The higher share of installed capacity of OCGTs in R3 coincides with the fact that 27% of the installed capacity in R3 in the base case comes from intermittent forms of energy sources (18% solar and 9% wind), compared to 14% in R1 and just 8% in R2. Fig 4.1(b) shows the whole fiscal year’s (2024) system-wide dispatch according to the generation type. It is evident that the share of OCGTs in system-wide dispatch is quite low (3%) compared to their share in the installed capacity. The reason for that is the low net efficiency and high operational cost, primarily fuel costs associated with OCGTs.

4.2 Scenarios and Test Cases

For this thesis, PCS is performed for three VRE scenarios – low, medium, and high VRE. Low VRE reflects the NREL-118 bus base case, thus having an installed solar and wind capacity same as shown in Fig 4.1 a). In medium VRE, three times the installed capacity (3x) of wind and solar of the low VRE scenario or the base case is considered in each region. For the high VRE scenario, six times (6x) the installed wind and solar capacity of the base case is considered in each region. Table 4.1 below provides a summary of the installed VRE capacity (MW) for each scenario.

Table 4.1 Region-Wise Installed Wind and Solar Capacity in all VRE Scenarios

Scenario/Region	**Region 1**		**Region 2**		**Region 3**	
	Solar cap.	Wind cap.	Solar cap.	Wind cap.	Solar cap.	Wind cap.
Low VRE	1155 MW	315 MW	432 MW	-	1806 MW	774 MW
Medium VRE	3465 MW	945 MW	1296 MW	-	5418 MW	2322 MW
High VRE	6930 MW	1890 MW	2592 MW	-	10836 MW	4644 MW

Following this, three study cases were considered for this thesis. These three VRE scenarios are uniform for each study case. The study cases considered for PCS are as follows:

1) Case 1 - Base case of the NREL 118 bus system with given OCGT parameters for PCS analysis. The relevant results from this case would provide a comparison metric or a benchmark for Case 2.
2) Case 2 - Base case of the NREL 118 bus system with the additional OCGT parameters described in section II. that includes startup profiles, run-up rates, and FOR modeling for each of the 66 OCGTs.
3) Case 3 – Similar to Case 2, but the addition of state-of-the-art OCGT technology [8] with quicker ramp rates, run-up rates and lower minimum up/down times, at node 18, which has a large amount of solar PV capacity installed in the high VRE scenario. Table 4.2 shows the modifications made to Case 2 to address Case 3.

Table 4.2 Modifications Done to Case 2 for Case 3

Node no. (Region)	**Solar PV capacity installed - high VRE**	**Replacement status**	**OCGT numbering in PLEXOS**
18 (Region 1)	981 MW	ST Coal and CCGT technology of 250 MW by 100 MW X 3 OCGTs.	OCGT 77 (3 X 100 MW)

Table 4.3: Input Parameters for 3X100 MW OCGT for Case 3

Param	**Value**	**Param**	**Value**
Max capacity	100 MW	Max ramp up/down	25 MW/min
Min stable level	20 MW	Forced outage rate	7.53 %
Hot start cost time	1 hr.	Min time to repair	3 hrs.
Cold start cost time	1 hr.	Max time to repair	100 hrs.
Hot start cost	$3392	Mean time to repair	36 hrs.
Cold start cost	$4410	Min up/down time	1 hrs
Run up rate (hot start)	17.5 MW/min	VO&M charge	$ 0.6/MWh [7]
Run up rate (cold start)	12.5 MW/min	Fuel charge	$ 5.4/MMBTU [7]

All three VRE scenarios given are run for Case 1 and Case 2. Case 3 is introduced to examine the localized impact of grid integration of modern-day OCGTs with detailed parameter modeling in the high VRE scenario at a node with high installed solar PV capacity. It was observed that conventional technologies at node 18 operate with negligible capacity factors in the high VRE scenario, so they were replaced with the OCGTs. The impact of the replacement on system wide costs is compared by using the high VRE scenario of Case 2 as the benchmark since Case 3 is a minor adjustment to Case 2.

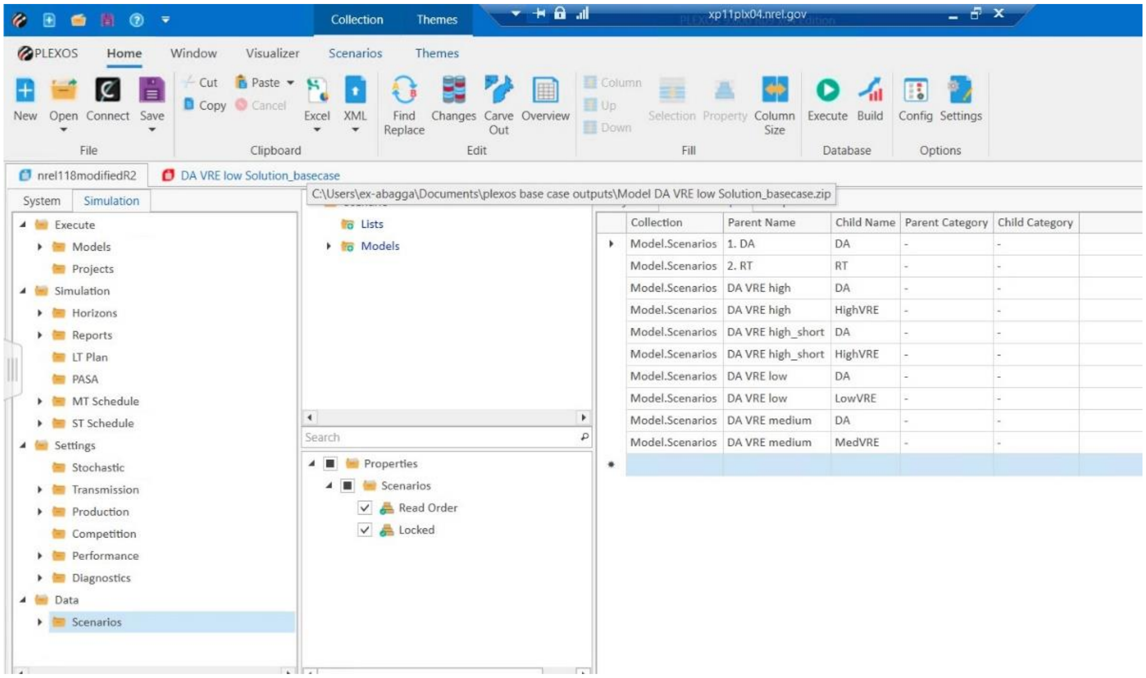
To focus on the impact of OGCT parameter assumptions at different VRE deployment levels, identical load levels is assumed across each of the seven scenarios. As the large deployment of VRE would likely require transmission expansion, which is beyond the modeling scope of this study, a copperplate transmission system is assumed with no transmission line limits imposed on any of the three regions.

CHAPTER 5 METHODOLOGY AND RESULTS

5.1 Methodology for PCS in PLEXOS

5.1.1 Modifications to NREL-118 Bus System

This section describes the main steps and changes performed on the PLEXOS NREL-118 bus case to carry out PCS studies for this thesis. Firstly, to incorporate the low, medium and high VRE scenarios, three new models were created in the base case, namely, ‘DA VRE low’, ‘DA VRE medium’ and ‘DA VRE high’. This is in addition to the models present in the base case of NREL-118 for DA and real time simulations, i.e. ‘1.DA’ and ‘1.RT’. Also, three new scenarios were created, namely, ‘LowVRE’, ‘MedVRE’ and ‘HighVRE’. These are again in addition to the existing scenarios corresponding to the models of the base case, i.e. ‘DA’ and ‘RT’. The PLEXOS memberships were then updated between these three newly created models and scenarios.



Collection	Parent Name	Child Name	Parent Category	Child Category
Model.Scenarios	1. DA	DA	-	-
Model.Scenarios	2. RT	RT	-	-
Model.Scenarios	DA VRE high	DA	-	-
Model.Scenarios	DA VRE high	HighVRE	-	-
Model.Scenarios	DA VRE high_short	DA	-	-
Model.Scenarios	DA VRE high_short	HighVRE	-	-
Model.Scenarios	DA VRE low	DA	-	-
Model.Scenarios	DA VRE low	LowVRE	-	-
Model.Scenarios	DA VRE medium	DA	-	-
Model.Scenarios	DA VRE medium	MedVRE	-	-

Fig 5.1 PLEXOS Snapshot for Membership Between VRE Penetration Scenarios and Models.

For each of the three new models, a membership was updated between the model and the existing base case 'DA' scenario, as well its corresponding VRE penetration scenario. As an example from Fig 5.1 above, for the 'DA VRE high' model, a model.scenario membership was created, linking the model to the base case scenarios of 'DA' and its associated VRE penetration scenario, 'HighVRE'. This was done to avoid the creation of duplicate PLEXOS .xml files to incorporate each scenario. The above mapping ensures that all the original base case data is incorporated into each VRE penetration model in addition to some new data, which are related to the respective VRE penetration scenarios. Next, a variable object, 'VREmultiplier' was created under the class 'Data' from the System tab, and specified three values – 1, 3 and 6 in the properties tab of the object. The created scenarios reflecting low, medium and high VRE were linked to these specified values, 1, 3 and 6 respectively. This was done to mimic the scaling of VRE integration. To complete the VRE penetration scenario setup, the capacity and rating of each solar and wind power plant was scaled by the VRE multiplier object, shown as an example in Fig 5.2 below.

	Parent Object	Child...	Property	Value	Data File	Units	Band	Date From	Date To	Timeslice	Action	Expression	Scenario
	System	Solar 01	Random Number Seed	1287		-	1				=		
	System	Solar 01	Units	1		-	1				=		
	System	Solar 01	Max Capacity	746.76		MW	1				×	VREMultiplier	
	System	Solar 01	Min Stable Level	0		MW	1				=		
	System	Solar 01	Rating		Solar 01	MW	1				×	VREMultiplier	DA
	System	Solar 01	Rating		Solar 01	MW	1				×	VREMultiplier	RT

Fig 5.2 Setting Up the Scaling of VRE Integration for a Solar Power Plant.

As seen in the figure above, the VRE multiplier object is included as an expression in the properties tab for each solar and wind object or plant. The corresponding property is the Max Capacity and the Rating for both DA and RT scenarios. The related action chosen is ‘X’ or multiplication to appropriately scale up VRE integration. As mentioned above, the variable object is linked to the three VRE penetration scenarios, which are in turn linked to the created models. This interlinking in PLEXOS enables to scale up the VRE capacity by the desired multiplier on selecting the execution or simulation of one of the three created models.

Since the focus of this thesis is on OCGT modeling, all the operational parameters related to the production cost modeling of the 66 OCGTs part of the base case were added or modified as explained in chapters 2 and 3, to model Case 2. For inclusion of startup profiles, the multi band feature of PLEXOS was utilized just as in the case of detailed heat rate modeling. For Case 3, a new OCGT object was created and modeled, again briefly explained in subsection 2.3, and the replaced generation objects were hidden.

5.1.2 Setting Up of PLEXOS Simulation

Prior to executing simulation of the models for Case 1 and 2, some PLEXOS simulation settings were set up as mentioned below.

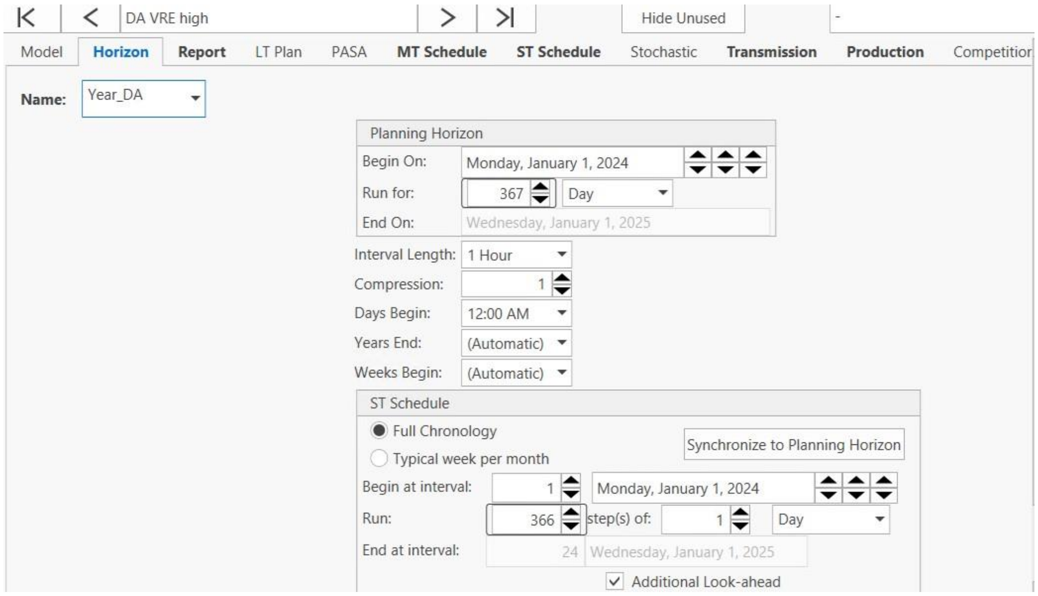


Fig 5.3 Planning Horizon Simulation Settings in PLEXOS Adjusted Prior to Simulation.

For each model, the horizon object shown in Fig 5.3 above was set up. As per the input data availability, the simulation was set to begin on January 1, 2024 and each model was simulated for a whole year at an hourly resolution, considering the availability of compatible time synchronous solar, wind and load data for the NREL-118 bus system. The ST schedule was set to full chronology to capture every hour of the year for DA-UC studies, in steps of one day. In summary, the model was run at an interval length of one hour at steps of one day for a horizon of one full year, thus amounting to 366 daily optimizations (for the year 2024).

A look ahead period of 8 hours was also provided in the short-term schedule simulation settings. PLEXOS solves this look ahead period window in addition to the optimization period (one day in this study) for more accurate decision making. Gurobi 9.5 was selected as a solver, with a relative optimality gap set at 0.5%. MIP relativity gap is a solver setting for MIP optimization. Since it is set to 0.5%, the solver stops solving once the gap between the integer solution and best bound linear relaxation reaches 0.5%. However, this is determined to be a strict limit as according to the PLEXOS manual, UC-ED problems with a relative gap between 3-7% provide a good balance of quality and performance, particularly associated with time required to solve. With sub-hourly resolutions and larger test systems, relativity gap of 0.5% would considerably increase the solving complexity. A 'performance max solver time' setting can also be provided that constraints the solver to find an integer solution within a specified time, otherwise reporting the linear relaxation.

In the properties section of the 'Reports' class of the Simulation tab (Fig 2.5 in subsection 2.3), one can also select the desired outputs or variables for which the time bounded results can be obtained after the PLEXOS simulation is completed.

Objects | Memberships | Properties

Collection	Property	Phase	Period	Summary	Statistics	Samples	Write Flat Files	Group	Description
Generators	Available Capacity	STSchedule	☑	☑	☐	☐	☑	Capacity	Available capacity
Generators	Average Cost	STSchedule	☑	☑	☐	☐	☐	Production	Average cost of generation
Generators	Average Heat Rate	STSchedule	☑	☑	☐	☐	☐	Production	Average heat rate
Generators	Average Total Cost	STSchedule	☑	☑	☐	☐	☐	Production	Average [Total Generation Cost]
Generators	Capacity Curtailed	STSchedule	☑	☑	☐	☐	☐	Production	Amount of non-positive-priced generation
Generators	Capacity Factor	STSchedule	☑	☑	☐	☐	☐	Production	Proportion of installed or rated capacity ge
Generators	Cleared Offer Price	STSchedule	☑	☑	☐	☐	☐	Production	Price of marginal offer band
Generators	Efficiency	STSchedule	☑	☑	☐	☐	☐	Production	Efficiency of generation
Generators	FO&M Cost	STSchedule	☑	☑	☐	☐	☐	Production	Fixed operation and maintenance cost
Generators	Fuel Cost	STSchedule	☑	☑	☐	☐	☑	Production	Total fuel bill
Generators	Fuel Offtake	STSchedule	☑	☑	☐	☐	☐	Production	Fuel offtake
Generators	Fuel Price	STSchedule	☑	☑	☐	☐	☐	Production	Fuel price (when not using Fuels collection)
Generators	Generation	STSchedule	☑	☑	☐	☐	☑	Production	Generation
Generators	Generation Cost	STSchedule	☑	☑	☐	☐	☐	Production	Cost of generation
Generators	Heat Rate	STSchedule	☑	☑	☐	☐	☐	Production	Average heat rate (total fuel divided by tot
Generators	Hours Curtailed	STSchedule	☐	☑	☐	☐	☐	Production	Number of hours that non-positive-priced
Generators	Hours Down	STSchedule	☑	☐	☐	☐	☐	Production	Number of hours since the last shutdown
Generators	Hours of Operation	STSchedule	☐	☑	☐	☐	☐	Production	Number of hours of operation.
Generators	Hours Up	STSchedule	☑	☐	☐	☐	☐	Production	Number of hours since the last start

Fig 5.4 Few Properties for ‘Reports’ Class of PLEXOS Adjusted Prior to Simulation.

The PCS was done on a Windows workstation with Intel Xeon Gold 2.5 GHz processors. The average simulation time for each scenario for a year’s worth of DA-UC was approximately 7 hours. The results shown below are categorized into operational impacts (on the OCGTs) and system costs, thus covering the analysis of key variables for this study. In total, seven scenarios were simulated, three each for cases 1 and 2 and the high VRE scenario for Case 3.

5.2 Results

Once the simulation is completed, the simulation file is automatically saved as a .zip folder in the same location/folder as the PLEXOS model’s xml file. In Fig 5.5, the simulation file is named ‘DA VRE low Solution_basecase’ and it represents the simulation outputs for Case 1 in the low VRE scenario.

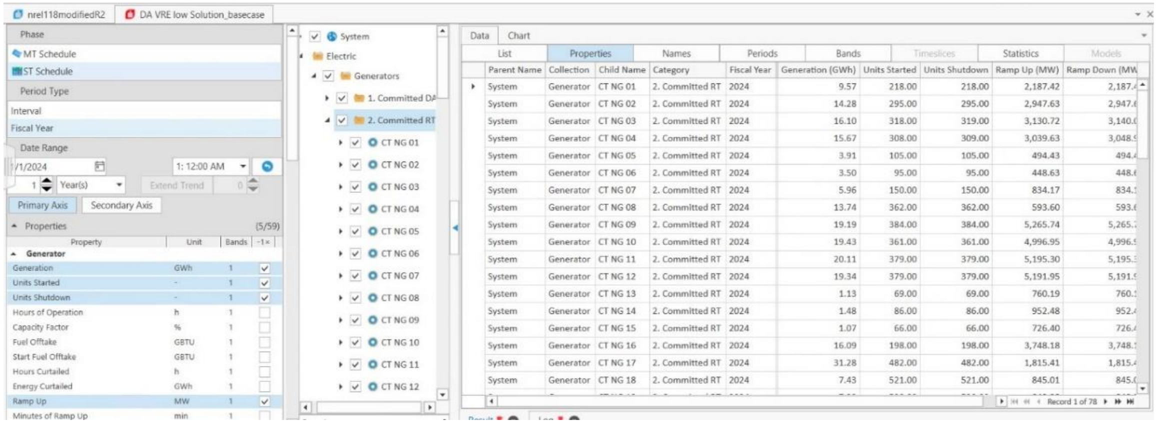


Fig 5.5 Selection of Output Options from Simulation File of PLEXOS.

The solution file once opened in PLEXOS gives the option to select the phase (‘ST schedule’ for these studies), the period type (‘Interval’ or ‘Fiscal Year’) as well as the Date Range, for which the results of the selected Report outputs/properties (Fig 5.4 above) can be retrieved, analyzed and plotted. If one chooses the period type to be ‘Interval’, they can adjust the ‘Date Range’ to analyze the results from a few hours, days, weeks, or months by using the date range options. This feature was utilized to retrieve data to plot the dispatch profiles or duck curves on the peak load day, as will be shown in the next sub section. However, in this thesis, the aim was to assess the yearlong operational and economic impact related to OCGTs part of the system. Hence most of the outputs were analyzed as a combined set for the whole fiscal year 2024. On selecting ‘Fiscal year’ and the relevant outputs, which are ‘Generation’, ‘Units Started’, ‘Units Shutdown’ and ‘Ramp Up’ for this example, PLEXOS will run it for the whole year/366 days of year 2024, by default. In the middle of Fig 5.5 is the ‘System’ tab from which the type of technology can be selected for which output is to be analyzed. Here, all the OCGTs have been selected from their folder, ‘Committed RT’ to focus on the combined annual impacts.

5.2.1 Dispatch Profiles and Duck Curves in the Base Case

The figures below show an example of the dispatch profiles according to generation type for the three VRE scenarios for two days (48 hours) of the year including the peak load day (07/05/2024) and 07/06/2024. The profiles are only shown for the base case to explain the operation of the NREL-118 bus system in different VRE penetration levels. They are not utilized for comparison between different cases as there is no major difference in the dispatch profiles.

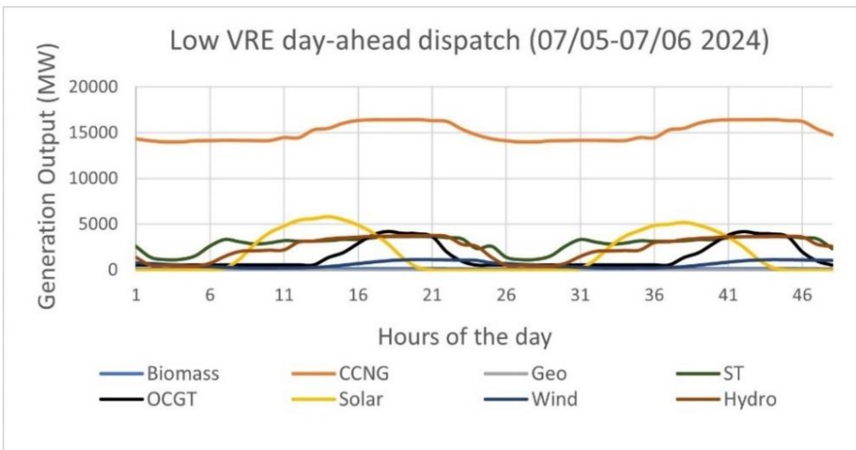


Fig 5.6 Sample Dispatch Profile for 48 Hours According to Generation Type (Low VRE).

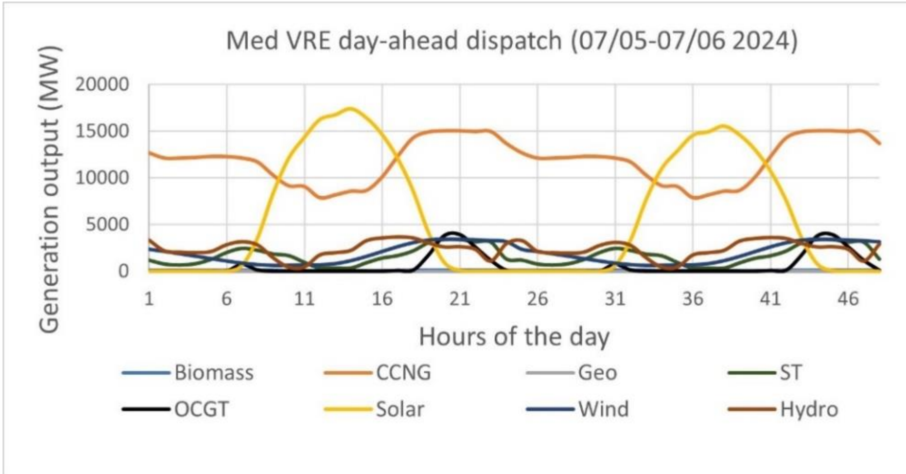


Fig 5.7 Sample Dispatch Profile for 48 Hours According to Generation Type (Medium VRE).

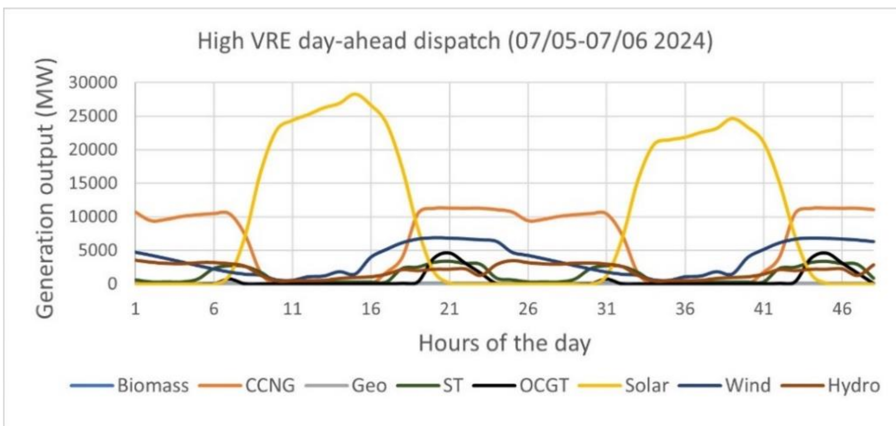


Fig 5.8 Sample Dispatch Profile for 48 Hours According to Generation Type (High VRE).

It is clearly observed from all the dispatch profiles above that OCGT technology (shown by black legend) contributes a minor percentage to the overall dispatch due to its high operational costs, primarily fuel costs. On the other hand, in the low VRE scenario, CCGTs are the dominant generation type and the base load units for the entire day with minimal ramping and maintain consistent generation output. For the low VRE dispatch profile, the main role of OCGT technology in the low VRE scenario is to ramp up and pick up a proportion of the system load, as the solar generation output starts declining around mid-day. The load is picked up by both CCGTs and OCGTs, however OCGT technology is faster to respond to the ramping down of solar generation, with a steeper ramping up compared to CCGTs during the evening hours. In medium and high VRE scenarios, the power dispatch is dominated by solar PVs in the day hours and CCGTs in the night hours. Figs. 5.7 and 5.8 show the importance of having flexible generation units in place to respond to these extreme scenarios due to the high deployment of intermittent resources. In medium VRE scenario, combined CCGT dispatch ramps up from 8500 MW to 14000 MW in four hours (2 pm to 6 pm) to replace the falling solar PV generation during the peak load day, whereas OCGT dispatch ramps up from 109 MW to 3500 MW in two hours (6 pm – 8 pm). More flexible characteristics of OCGTs allow it to ramp up so quickly, despite most of those units being off or generating at their minimums during the daytime. In the high VRE scenario, the ramping requirements are even more extensive during the peak load day, with the combined dispatch of CCGT technology ramping up from 1000 MW to 10,500 MW in three hours (4pm – 7pm), and OCGT technology ramping up from 300 MW to 3,800 MW in one hour (7pm – 8pm). While the CCGT technology extensively ramps up when solar PV generation falls and ramps down with moderate steepness when the load demand declines after 11 pm, its generation profile is consistent from late night to early morning hours, as a dominant baseload generation technology. The task of OCGT technology is however to just temporarily cater to the load requirement from 7 pm to 9 pm when it steeply ramps up, following which it again steeply ramps down from 9 pm to 11 pm, to minimize generation costs.

Next, the figure below shows the duck curves generated by utilizing output data for the base case for the peak load day in low, medium and high VRE scenarios. On the y-axis, is the difference between the load during the period of the peak load day and VRE dispatch (wind and solar).

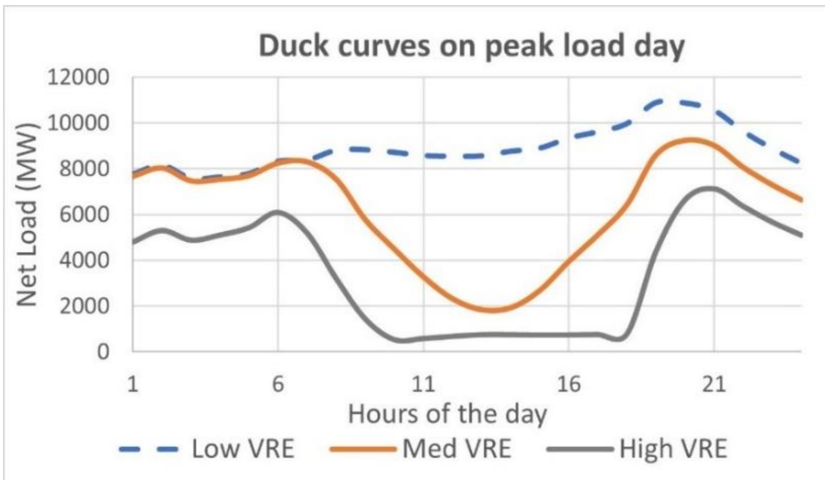


Fig 5.9 Duck Curves on Peak Load Day for Low, Medium and High VRE Scenario.

Fig 5.9 above closely aligns with Fig 1.1 and Fig 1.2 in Chapter 1, which presents the problem statement of the evolving duck curves as renewable penetration increases. The high VRE duck curve for the base case on peak load day presents issue encountered in the grid lately, wherein the net-load during daytime fell below 0. In the figure above, it does not touch 0 but validates that the assumptions used to account for different VRE scenarios in this study are realistic.

5.2.2 Operational Impacts on OCGTs

In this sub-section, the operational impact on OCGTs is analyzed. This includes the total no. of startups, shutdowns, and ramping requirements of OCGTs part of the NREL-118 bus, for Case 1 and 2. It was chosen to present combined annual startups, shutdowns as well as ramping requirements to best assess the impact of increased parameter modeling, as the changes performed just on the OCGT technology are not significant enough on a system wide level to fully capture the impact for a short planning horizon. Table 5.1 below shows the combined annual startups and shutdowns for the entire year, 2024, for each case in each VRE scenario.

Table 5.1 Total No. of Annual Startups/Shutdowns for OCGTs (FY-2024)

Case/scenario	**Low VRE**	**Medium VRE**	**High VRE**
Case 1			
Total no. of startups	14506	18252	21860
Total no. of shutdowns	14507	18256	21841
Case 2			
Total no. of startups	12342	15624	18692
Total no. of shutdowns	12345	15632	18680

Two findings are clearly observed in Table 5.1 – the number of startups/shutdowns increases as the VRE penetration increases for each case. This is expected due to an increase in variability caused by increased VRE penetration, the flexible OCGTs, particularly the ones with higher capacity factors are required to startup and shutdown to effectively manage the load-generation balance. It is also observed that for each scenario, the total annual number of startups/shutdowns decreases in Case 2 compared to Case 1. The intuitive reasoning behind this is that the increased parameter modeling of OCGTs for PCS studies results in accounting of more realistic assumptions such as inclusion of the startup profiles and FORs in the DA-UC model. To meet the prime objective of minimizing total system cost, the model compensates by reducing the number of starts and shutdowns while adhering to the additional short term operational constraints. The highest number of annual startups/shutdowns for an OCGT is 663 in the high VRE scenario in the base case/Case 1. Also, in the high VRE scenario, the average number of startups for an OCGT are 331 for Case 1 and 283 for Case 2.

Next, a comparison is shown between the annual number of startups in the high VRE scenario for both the cases, for the OCGTs rated at 100 MW and operating at a high annual average capacity factor. Table 5.2 provides a brief description of the OCGTs, which are highly participative in overall system dispatch compared to other OCGTs in the system and Fig 5.10 shows the comparison in results.

Table 5.2 OCGTs with Above Average Annual Capacity Factors

OCGT no.	Node no.	Region	Average annual capacity factor (%)
OCGT 21	085	R3	19.7
OCGT 22	091	R3	17.1
OCGT 23	091	R3	17.3
OCGT 24	100	R3	17.5
OCGT 25	100	R3	17.3
OCGT 26	100	R3	16.9

As is seen in the table above, the OCGTs with the highest average annual capacity factors are in region, R3, wherein the generation dispatch from intermittent sources of energy (solar and wind) is most compared to regions, R1 and R2. Fig 5.10 below shows the comparison of the combined annual number of startups (y-axis) in the high VRE scenario for the above OCGTs.

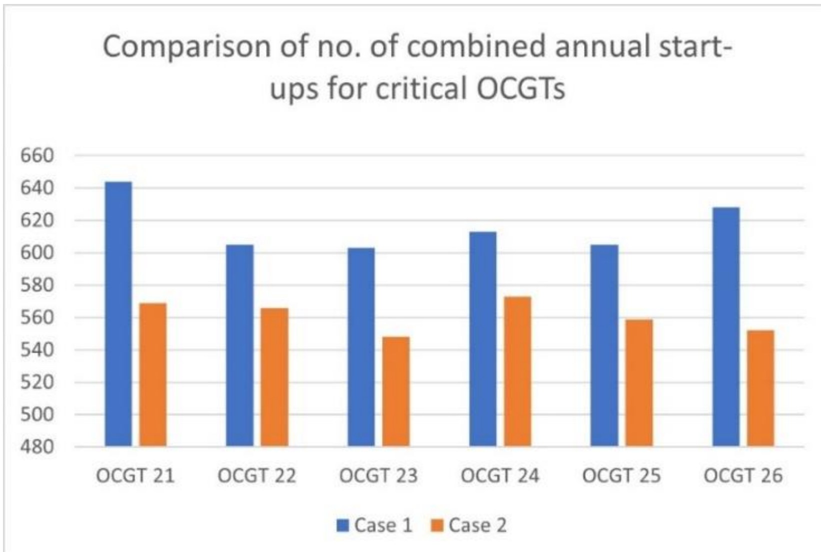


Fig 5.10 Comparison of No. of Combined Annual Startups for Critical OCGTs.

The largest difference is for OCGT 21 and 26 (569 vs. 644 and 552 vs. 628, respectively), with a decrease in the number of annual startups in Case 2 by about 11.7% compared to Case 1.

Next, the combined results for the annual ramping requirements (ramp up/down) of OCGTs part of the grid are shown, in the low, medium and high VRE scenario.

Table 5.3 Combined Annual Ramping Requirements for OCGTs

Case/scenario	**Ramp up (GW)**			**Ramp down (GW)**		
	Low	Medium	High	Low	Medium	High
Case 1	407.7	481.7	579.9	407.7	481.4	579.8
Case 2	354.0	454.7	500.5	353.9	454.7	500.3

As the VRE level increases, both up and down ramping requirements increase across both the cases to respond to the variability in generation. Also, the ramping requirements reduce with increased parameter modeling in Case 2 for both scenarios, with up to a 13.7% combined decrease in high VRE penetration scenario in Case 2 vs. Case 1, for both ramp up and down. The trend in the ramping changes is consistent with what was observed in the no. of SUSDs.

5.2.3 Generation and System Wide Costs

In this section, the differences in the test system's annual costs are examined to assess the impact of additional parameter modeling for the two cases and scenarios. The total generation costs for all the OCGTs comprise of the fuel cost, VO&M cost and startup/shutdown (SUSD) costs. Fig 5.11 shows the combined annual generation costs breakdown ($million) for the 66 OCGTs part of the system.

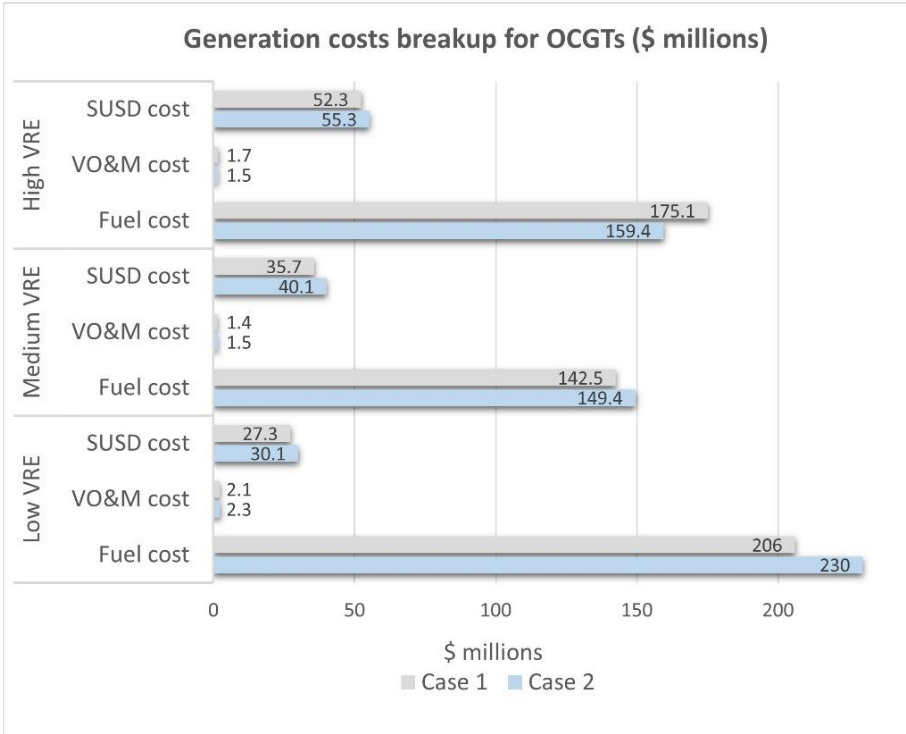


Fig 5.11 Comparison of Total Generation Costs Breakup for OCGTs

The combined annual OCGT generation costs for all scenarios comprise primarily of the fuel cost. The VO&M costs are a minor component of the overall costs. It is seen from Fig 5.11 that the total fuel costs decrease in medium and high VRE vs. the low VRE scenario. Also as expected, SUSD costs increase as the VRE penetration increases, due to higher number of startups and shutdowns. As an example, in the medium VRE, the combined fuel cost decreases by up to 35%, while the SUSD cost increases by about 33% vs. the low VRE scenario. In the high VRE scenario, the SUSD cost increases by about 84% in Case 2 vs. in the low VRE scenario for the same case. It is also observed that for both the low and medium VRE scenarios, all the generation cost components are higher for Case 2 vs. Case 1. The modeling of startup profiles in Case 2 results in addition to SUSD costs due to the fuel offtake as a result of the inclusion of different run-up rates, as well as higher fixed start costs for cold starts. There are also a few interesting observations. First, in Case 1, the total fuel cost in high VRE setting is greater by 23% vs. medium VRE, whereas the corresponding increase is only about 6% in Case 2. This first shows that the role of OCGTs in dispatch becomes prominent as the share of VRE is drastically higher (6x low VRE). However, in medium vs. high VRE scenario, the increase in fuel cost in Case 2 is not as significant as Case 1. The reason understood for that is that the stricter start up profiling in Case 2 limits the operation of OCGTs. The increased flexible requirements in high VRE cannot be met at the level as the base case, with the additional restrictions imposed on OCGT operations. This also results in lesser total generation cost in Case 2 vs. Case 1 for high VRE.

Next, the comparison of annual system wide costs for the two cases in the three VRE scenarios is analyzed. In the assumed model, the system wide costs include the annual cost of operation of all the generation technologies across the three regions.

Table 5.4 Annual System Wide Costs comparison

Scenario	**Case 1 ($billion)**	**Case 2 ($billion)**	**Approx. difference ($million)**
Low VRE	4.40	4.42	20
Med VRE	3.39	3.41	20
High VRE	2.48	2.50	17

While the percentage change in annual system wide costs in each scenario for Case 1 vs. Case 2 is very minor, the absolute change shows an increase of up to $20 million in low and medium VRE scenarios.

5.2.4 Grid Integration of Modern-Day OCGT

This case is simulated as an extension of Case 2 to examine the localized effect of grid integration of modern-day OCGTs [8] with quick ramping, run-up rates as well as lower minimum up and down times. The integration of 3X100 MW OCGTs is done at a node in region, R1, having a high solar PV penetration (about 1 GW in the high VRE scenario). As mentioned in subsection 4.2, this case is only simulated for the high VRE scenario, in which OCGT technology becomes critical as peaking units. Table 5.5 below shows the annual savings in total system cost vs. Case 2. The comparison has only been made with Case 2, as Case 3 also includes the additional operational parameters in the production cost model of OCGTs, thus comparing it with Case 1 will not provide an accurate picture of system wide impact of grid integration. In addition to the comparison of the total system cost, the yearlong profitability for this new OCGT is also analyzed. While the ISO's objective to justify grid integration of a technology is the minimization in total system cost, the profitability estimate of the technology is important to justify its participation in the electricity market. Besides the fuel cost, VO&M cost and SUSD cost, another cost component is considered to estimate an annualized payment for the owner of the new OCGT plant. To calculate the annualized payment, certain parameters were considered such as overnight build cost of OCGT ($/kW), lifespan, discount rate. This payment is added to the total cost component of the technology. The sum of pool and reserve revenues subtracted with the total costs is used to estimate the annual profit. A good amount of annualized profit obtained for 3X100 MW OCGTs further justifies its grid integration in addition to lowering the total system cost.

Table 5.5 Annual System Wide Costs (Case 2 vs. Case 3)

Scenario	**Case 2 ($billion)**	**Case 3 ($billion)**	**Annual savings ($million)**
High VRE	2.50	2.49	10

5.2.5 Ambitious Case Study

One more case study was carried out, similar to the above case study, Case 3. At a few other nodes in the system, having high solar PV installed capacity in the high VRE scenario, state of the art OCGTs with detailed parameter modeling were replaced against the installed conventional technologies at those nodes. This was done to analyze the system wide impact, particularly total system cost. This bulk replacement study took approximately 15 hours of simulation time but was not succesful in its impact on the total system cost, raising it significantly. This shows the importance of performing production cost modeling studies for a diverse set of scenarios as VRE penetration increases, with an aim to minimize total system cost or maximize social welfare.

CHAPTER 6 CONCLUSION AND RECOMMENDATIONS

This thesis examines the yearlong impact on PCS results, following the inclusion of three additional operational parameters in the production cost model of the OCGTs part of the NREL-118 bus system. The test system reflects a realistic section of the WECC grid in southwest California and includes one year (2024) of time varying data for different generation technologies including wind and solar PV as well as the load data. The simulations were performed using PLEXOS software, and the operational and economic impacts were evaluated across three VRE penetration scenarios – low, medium, and high VRE for primarily two different test cases, Case 1 or the base case and Case 2. In terms of operational impact, firstly the dispatch profiles in different VRE scenarios were analyzed. In the dispatch profile of the peak load day in high VRE scenario, combined generation from OCGT technology ramped up from 300 MW to 3,800 MW in just one hour in late evening (7pm – 8pm). This showcases the importance of detailed production cost modeling of flexible energy resources such as OCGTs as their role will continue to become increasingly crucial in the energy transition process. The other operational variables examined were the annual no. of startup/shutdowns and ramping requirement of OCGTs. The combined annual no. of OCGT startups and shutdowns increased significantly from low to high VRE scenario for both cases. However, the no. of SUSDs reduced in Case 2 compared to Case 1, for each VRE scenario. The reason is determined to be the inclusion of additional constraints, which are related to stricter startup profiles, reduce both the no. of SUSDs as well as ramping requirements in Case 2, with an objective to minimize total system costs. In terms of impact on the economic variables of PCS, the combined segregated annual generation costs for OCGTs for the whole year was analyzed across the VRE scenarios and cases. The annual total system cost, which is just the combined generation cost for all technologies, was also compared. In the low and medium VRE scenarios, the total system cost increased by $20 million in Case 2 compared to Case 1. This large increase is just from the minor modifications made to the generation technology, which presently has a low percentage wise contribution to the overall dispatch. In Case 3, the benefit of localized and small-scale grid integration by replacement of conventional technologies with modern OCGT technology was examined. The integration of 3 X 100 MW OCGTs at a node with high amount of installed solar capacity in the high VRE scenario (close to 1 GW) was analyzed. This resulted in annual savings of $10 million in total system cost, compared to Case 2.

The inclusion of just three additional operational parameters in the production cost models of 66 OCGTs part of the test system resulted in a noticeable difference in results for the three VRE scenarios. As addressed in Chapter 1, it, therefore, becomes crucial to focus on accurate production cost modeling of such resources, which will have a major role in managing extreme net load variability in the years to come. While doing the same, it will also become important to address other system wide requirements other than OCGT modeling for more accurate representation of different scenarios. As an example, for this thesis, transmission line limits were not imposed while performing PCS in increasing VRE penetration scenarios. This was done assuming that such a large increase in VRE deployment would not be possible without transmission expansion. However, for more accurate results, it will be beneficial to procure real time data for transmission expansion projects in place under an entity like WECC corresponding to expected increase in VRE penetration. Additionally, techniques like stochastic optimization, which allows variation in the yearly time varying data of generation and load, can help evaluating the impact with higher accuracy, unlike a deterministic approach.

For future work, it will be interesting to perform sub-hourly modeling on the modified test system considering the fast operation of modern OCGT technology. This would allow the inclusion of additional details in the startup profiles. The modern-day heavy duty OCGTs have starting profiles with hot starts as quick as 10 minutes. They can also ramp up to their full capacity from minimum stable level to maximum capacity in a few minutes. It would hence be unrealistic to assess the impact of PCS results on this technology without sub hourly modeling such as at 10-15 min resolution. However, that can only be done if there is access to compatible time resolution data for that test system. Also, it will not be easy to do so for larger systems due to solving complexity, as discussed in Chapter 2. The increase in simulation time would amount to several hours and studies such as impact evaluation done in this thesis, might not be deemed suitable for the time and effort. Another key factor to better understand the technical and economic viability of gas turbines going into the future is by carrying out studies with hydrogen as component of fuel for newer OCGTs, as compared to natural gas. The input parameters which are critical for the analysis are the fuel cost of hydrogen at the location as well as the operational parameters of newer OCGTs operating under different levels of hydrogen as fuel. The comparison of yearlong GHG emissions is also a key metric in such analysis. The availability of PCS software such as PLEXOS makes it possible to incorporate these above wide range of operational parameters in PCS studies and evaluate key system wide impacts using selectable variables. Its inbuilt and modifiable constraints save the user time and effort to formulate them from scratch.

As gas turbine technology continues to gain importance, it is also necessary to consider other studies related to its grid integration in addition to performing steady state expansion or PCS studies. To justify the grid integration and replacement with OCGT technology at nodes with high renewable penetration (as done in Case 3 in this thesis), it is required to carry out dynamic security assessment or stability studies for such scenarios. There could be a tradeoff there such as a decrease in system costs resulting in lowering of critical clearing time at certain nodes, thus requiring ample studies prior to recommending the integration of a technology.

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