Regulating reserve with large penetration of renewable energy using midterm dynamic simulation

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Abstract A novel renewable energy intermittency model and a new midterm dynamic simulation tool in power systems are developed for examining dynamic behavior along the load curve for different combinations of the system operation reserves and renewable portfolio standard (RPS) rates. The system's import limits are considered. It is concluded that ignoring intermittency and governor effects is an inadequate method to assess intermittency impact. The intermittency midterm dynamic impact must be studied. For the studied system, the instability is expected to be about 25 % RPS with current reserves. Besides, the most vulnerable peak hour to instability is the afternoon peak hour when solar begins to drop off. This article stimulates further dynamic intermittency studies on the issues caused by renewable intermittency. The studies on the issues caused by renewable intermittency have not been revealed because of inadequate/incomprehensive study methodologies so that effective, mitigative solutions can be developed to guarantee the reliability of power grid when incorporating higher RPS if high operation reserves are impractical.

Keywords Renewable energy intermittency, Midterm dynamic simulation, Power systems, Dynamic stability, Renewable portfolio standard (RPS)

1 Introduction

Growing environmental concerns and attempts to reduce dependency on fossil fuel energy resources are bringing

renewable energy resources to the generation portfolio of electric power utilities. Among the various renewable resources, wind power and solar power are assumed to have the most favorable technical and economical prospects. The effective integration of wind in power system operations requires a comprehensive approach to data management and decision making. The variability and uncertainty of wind power will require the increased flexibility from other power system resources, and the adaptation of business processes and control systems to manage these resources. Efficient use of grid resources to maintain reliability and minimize costs argues in favor of both tighter integration of systems and, at the same time, an open infrastructure can take advantage of evolving tools and grid devices.

California is aggressively bringing renewable generation online to meet its renewables portfolio standard (RPS), one of the most ambitious renewable standards in USA.

California's RPS requires retail sellers (investor-owned utilities (IOUs), electric service providers (ESPs), and community choice aggregators (CCAs)) regulated by the California Public Utilities Commission (CPUC) to procure 33 % of its retail sales per year from eligible renewable sources by 2020. The RPS also requires retail sellers to achieve intermediate RPS targets of 20 % from 2011 to 2013 and of 25 % from 2014 to 2016. The CPUC and the California Energy Commission (CEC) are jointly responsible for implementing California's 33 % RPS program [1].

In order to meet its mandated renewable generation goals, the company studied is bringing large amounts of wind generation from remote desert areas into the bulk system. In addition, it is planned to connect significant amounts of solar PV energy resources in its eastern service territory. The increase in the penetration of renewable resources, with effectively low inertia facilities, will cause a change in the system dynamics. In order to better understand these changes on the system dynamic behavior,

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adequate studies need to be conducted to assess the possible negative intermittency impact and solutions. Unlike the load, a renewable energy cannot accurately forecast far in advance, and renewable power can vary over its full range of the capacity. Though the impact on system reliability is similar to that of unscheduled outages, it occurs far more frequently, and the operating costs associated with reserve dispatch are much more significant. Power system operators secure different amounts and types of operating reserves to compensate for these characteristics to reliably serve load and maintain the system frequency.

The output of renewable generation varies with the energy source. For example, solar panels do not produce electricity when the sun does not shine, and wind turbines do not spin when the wind does not blow. However, it is not just an on-or-off proposition. The output from solar and wind can vary over relatively short periods depending on cloud cover and shifting wind speeds. This intermittency produces challenges to managing demand on specific parts of the grid and ensuring adequate capacity.

The impact of renewable energy intermittency on the system operation needs to be urgently studied when the load varies from minute to minute. Most of the renewable energy studies published so far focus on power flow balancing generation, load and losses, without taking the dynamic behavior of power system into consideration [1–4]. Some approaches for dealing with intermittency use probabilistic method to smooth out the variability [1, 3–11], which cannot guarantee a reliable grid operation all the time. It is challenging to study the renewable intermittency impact without commercial tools that can be used to model and study the intermittency. Some severe issues with integration of renewable energy can only be revealed by studying the dynamic intermittency behavior of the renewable energy, especially when the load varies from minute to minute.

This article develops a new renewable energy intermittency model and a novel power system simulation tool, and examines the dynamic behavior along the load curve for different combinations of the system operation reserves and RPS rates. The system stability is classified based on the midterm dynamic simulation. It is found that ignoring intermittency and governor effects is an inadequate method to assess intermittency impact. Therefore, the intermittency midterm dynamic impact must be studied. For the studied system, the instability is expected to be around 25 % RPS with the current reserves. It is also identified that most vulnerable peak hour to instability is the afternoon peak hour when solar power begins to drop off. This article tries to stimulate further dynamic intermittency studies on the issues caused by renewable intermittency, which have not been revealed because of inadequate/incomprehensive study methodologies. Based on the study, effective

mitigative solutions can be developed to guarantee the reliability of power grid when incorporating higher RPS if high regulating reserves are impractical.

2 Renewable energy model and new midterm dynamic simulation tool

The variability of wind and solar is measured over different time-scales. Beginning on the time-scale of minutes, Fig. 1 shows the variability in wind and solar PV generation on a minute-by-minute basis over the full day. The implication for system operations are that, unless the variability is smoothed by the variable energy resource itself, other resources have to increase or decrease their generation on similar time frames (seconds, minutes, and hours) to compensate for the supply variability.

In any power system, a frequency is controlled by balancing the power generation against the load demand on a second-by-second basis. There is a need for continuous adjustment of generator output as the load demand varies. In the meantime, the system can respond to larger mismatches in generation, renewable intermittency, and load changes [12–17].

The variable, nondispatchable nature of wind and solar has a significant impact on the utility reserve requirement. The effect analysis of the renewable resource intermittency provides a meaningful and concrete method for characterizing the variability of renewable energy resources.

Whenever there is load/generation imbalance, synchronous generators in a system respond in three stages to bring the system back to normal operation. The initial stage is characterized by the release or absorption of kinetic energy of the rotating mass—this is a physical and inherent characteristic of synchronous generators. For example, if there is a sudden increase in load or in renewable generation due to intermittency, the electrical torque increases to

Fig. 1 Wind and solar generation for 1 day

supply load increase, while the mechanical torque of the turbine initially remains constant. Hence, the acceleration becomes negative. The turbine-generator decelerates, and the rotor speed drops as kinetic energy is released to supply the load change. This response is called “inertial response.” As the frequency deviation exceeds certain limit, the turbine-governor control will be activated to change the power input to the prime mover. The rotor acceleration eventually becomes zero, and the frequency reaches a new steady state. This is called “primary frequency control.” After primary frequency support, there still exists steady-state frequency error. To remove the error, the governor set points are changed, and the frequency is brought back to nominal value, which is called “secondary frequency control.” These three phenomena take place in succession in any system to restore the normal operating equilibrium.

The characteristic of the wind generation is that it could ramp up from zero all the way to its maximum in half an hour, and it could also ramp down from its maximum to zero in half an hour. The questions to answer the renewable intermittency impact are as follows:

- (1) Is the operation reserve large enough when the load increases and, at the same time, wind generations ramp down to zero in half an hour?
- (2) Is the system’s response fast enough when the load decreases and, at the same time, wind generations ramp up to its maximum from zero in half an hour?

Note that there is no need to study the scenario that wind generation increases when the load increases. Similarly, there is no need to study the scenario that wind generation decreases when the load decreases as the key thing is to examine if the system has enough reserves and if the governor response is fast enough to compensate the renewable intermittency and load variation.

Since RPS in California will be 33 % in 2020, the scenarios will be studied in 2020. The load curve for Sept 27, 2020, based on load forecast, is shown in Fig. 2. It is assumed that Sept 27, 2020 will be the peak load day for the year of 2020.

Fig. 2 Load curve for Sept 27, 2020

To answer the above question, the renewable energy is modeled as follows:

- (1) When the load increases before hour 15, wind generation decreases from its maximum (2,061 MW) to zero in 30 min.
- (2) When the load decreases after hour 15, wind generation increases from zero to its maximum (2,061 MW) in 30 min.

In this article, the solar generation intermittency is not considered to enable a simplified approach. One of the justifications is that, in Southern California, the location of the company, there are about 300 sunny days in a year. However, the solar generation varies along the load curve. It starts from 6 a.m., reaches its maximum at noon, and goes down to zero around 7 p.m. The solar generation model is similar to what is shown in Fig. 1.

Figure 3 illustrates the process of intermittency dynamics study, in which the load peaks around 15 p.m., solar power output peaks around noon, and the wind generation variability is modeled.

As Positive Sequence Load Flow (PSLF) and Power System Simulation Engineering (PSS/E) (which are transient tools that examine a 10–20 s time period) cannot simulate midterm intermittency, which would require that load and generation changes occur with simulation time, typically held constant, a novel time domain simulation program was developed.

$$\begin{aligned} \frac{dx}{dt} &= f(x, V) \\ I(x, V) &= YV, \end{aligned}$$

where x is the state vector; f is the nonlinear vector function; V is the vector of complex nodal voltages; Y is the nodal admittance matrix; and I is the vector of injected nodal currents.

Fig. 3 Illustration of intermittency dynamics study

The differential equations represent the dynamic behavior of the system elements (synchronous machines and their controllers, etc.) and the algebraic equations represent the network equations and the connection of the external elements to the network. The generators are modeled in detailed model with excitation, PSS control, and governor/Automatic Generation Control (AGC) controls. The load is modeled in nonlinear Impedance, Current, Power (ZIP) model.

A mathematical intermittency model is developed using differential equations that describe the midterm dynamic space and, which uses trapezoidal integration methods to determine the stability/instability resulting from the intermittency changes arising from renewable resources and the natural time varying attributes of system load.

The solution scheme can be classified according to the numerical method applied to the differential equations (implicit or explicit) and the strategy to solve the differential and algebraic sets of equations (alternating or simultaneous).

3 Simulation results using renewable energy model and new midterm dynamic simulation tool

The impact of the high penetration of the renewable resources on the studied system can be described as follows. Significant amount of wind resources are added north-east of the system. The solar resources are primarily added east of the system.

The load, wind generation, solar generation, and generations with governor controls for different time intervals are listed in Table 1.

3.1 Study results for 30 % rps with 25 % reserve along the load curve

Table 2 shows the ramp rate results for 30 % RPS with 25 % reserve along the load curve. Table 2 is obtained by running midterm dynamic simulation for 30 min for 18 scenarios defined in Table 1.

During each dynamic simulation

- (1) The load is modeled using Fig. 2 for each corresponding time interval.
- (2) The solar generation is modeled using Table 1 for each corresponding time interval and follows the change shown in Fig. 3.
- (3) The wind generator is modeled as follows.

When the load increases before hour 15, wind generation decreases from its maximum (2,061 MW) to zero in 30 min, as shown in Fig. 4.

When the load decreases after hour 15, wind generation increases from zero to its maximum (2,061 MW) in 30 min, as shown in Fig. 5.

Table 2 shows that hour 15 requires the largest ramp rate, which is 81 MW/min. Note that hour 15 is the hour at

Table 1 Wind, solar, and conventional generations and loads for different time intervals

Time	Load P in MW	Load Q in MVAR	Wind Gen P in MW	Win Gen Q in MVAR	Solar Gen P in MW	Solar Gen Q in MVAR	Conventional Gen P in MW	Conventional Gen Q in MVAR
9/27/2020 11:00	21,620.09	1,081.005	2,061	206.1	3,646	364.6	8,851.094	510.305
9/27/2020 12:00	23,213.84	1,160.692	2,061	206.1	4,376	437.6	9,714.842	516.992
9/27/2020 13:00	24,819.07	1,240.954	2,061	206.1	3,646	364.6	12,050.072	670.254
9/27/2020 14:00	26,035.05	1,301.753	2,061	206.1	2,916	291.6	13,996.053	804.053
9/27/2020 15:00	26,149.88	1,307.494	2,061	206.1	2,186	218.6	14,840.875	882.794
9/27/2020 16:00	25,759.48	1,287.974	2,061	206.1	1,456	145.6	17,241.477	1,142.374
9/27/2020 17:00	25,443.71	1,272.186	2,061	206.1	726	72.6	17,655.713	1,199.586
9/27/2020 18:00	24,568.76	1,228.438	2,061	206.1	0	0	17,506.758	1,228.438
9/27/2020 19:00	25,005.09	1,250.254	2,061	206.1	0	0	17,943.086	1,250.254
9/27/2020 20:00	24,494.12	1,224.706	2,061	206.1	0	0	17,432.123	1,224.706
9/27/2020 21:00	23,104.76	1,155.238	2,061	206.1	0	0	16,042.76	1,155.238
9/28/2020 22:00	20,876.04	1,043.802	2,061	206.1	0	0	13,814.039	1,043.802
9/28/2020 23:00	18,289.07	914.453	2,061	206.1	0	0	11,227.068	914.453
9/28/2020 0:00	16,265.88	813.294	2,061	206.1	0	0	9,203.38	813.294
9/28/2020 1:00	14,935.08	746.754	2,061	206.1	0	0	7,873.077	746.754
9/28/2020 2:00	14,052.09	702.604	2,061	206.1	0	0	6,990.085	702.604
9/28/2020 3:00	13,469.93	673.497	2,061	206.1	0	0	6,407.931	673.497
9/28/2020 4:00	13,312.62	665.631	2,061	206.1	0	0	6,250.622	665.631

Table 2 Governor ramp rate for 30 % RPS along the load curve

ID	Time	Ramp rate (MW/Min)	Max. frequency variation (Hz)	Remarks
1	11	54	-0.02	Load peak
2	12	80	-0.03	
3	13	80	-0.03	
4	14	79.7	-0.03	
5	15	81	-0.03	
6	16	-57	0.002	
7	17	-56	0.019	
3	18	-67	0.023	
9	19	-67	0.023	
10	20	-67	0.023	
11	21	-67	0.023	
12	22	-67	0.023	
13	23	-67	0.023	
14	0 Next day	-66	0.023	
15	1	-67	0.023	
16	2	-67	0.023	
17	3	-67	0.0023

Fig. 4 Wind generation intermittency model when load increases

which load reaches its peak during that day, and when the load decreases, the ramp rate is almost the same.

The result shown in Table 2 is benchmarked with what was obtained from the Market Simulator used by the company's market operation department.

Figure 6 shows the total real power output of generators with governor control for hour 14.

Figure 7 shows the frequency response for hour 14. As the load increases and the wind generation decreases, the frequency decreases.

Figure 8 shows the real power of wind generator for hour 14.

Figures 9 and 10 show the output for hour 1 a.m. of the next morning. As the load decreases, the frequency increases

Fig. 5 Wind generation intermittency model when load decreases **Fig. 6** Total real power of generators with governor control for hour 14 **Fig. 7** Frequency response for hour 14

and the real power of generator with the governor decreases. It is assumed that the wind generation increases from zero to its maximum in 30 min as it is the worst scenario for the study. It is found that the governor response is not fast enough to reduce the generation, which is why there is chattering in the generator output, as shown in Fig. 9.

3.2 Study results for different rps and different reserves for hour 15

It is identified that hour 15 is the most critical one in system operation, and this section summarizes the detailed

Fig. 8 Real power of wind generator for hour 14

Fig. 9 Real power of generation with governor control

Fig. 10 Frequency for 1 a.m. of next morning

study for different RPSs for hour 15. In the simulation, wind generation decreases from its maximum to zero in 30 min. The solar generation is modeled, as shown in Fig. 1, for the time period between hour 15 and hour 15:30. The load is modeled using the load curve shown in Fig. 2 for the time period between hour 15 and hour 15:30.

In Table 3, the stable system is classified if the frequency recovers back to 58.0 Hz, and the unstable system is classified if the frequency cannot recover back to 58.0 Hz.

It is concluded from Table 3 that the higher the RPS, the higher the required reserve, and thus, the system can operate within the stability region when the renewable energy intermittence occurs for the worst scenarios.

Note that the system will become unstable when RPS reaches 25 % with 15 % reserve, which is the current reserve level. Currently, RPS rate is 20 %, and the reserve is 15 % at the company. The key findings of the study are helping the company to come up with effective mitigative solutions to guarantee the reliability of the power grid when incorporating higher RPS.

3.3 Study results for 33 % RPS for hour 15

Table 3 shows that 33 % RPS with 25 % Reserve will make the system unstable. Figures 11, 12, 13 show the dynamic responses for 30 min starting from hour 15. It is concluded that the system is unstable as the frequency drops below 55 Hz and never be able to recover. Note that Fig. 13 is numerical simulation results when the system collapses as the remedial action system is not enabled in the simulation. The oscillation is because the system becomes unstable, and the numerical simulation continues.

3.4 Mitigation for 33 % RPS for hour 15

Subsection 3.3 shows that the system is unstable for 33 % RPS. One of mitigations is to import more generations from external resources to stabilize the power system when the renewable energy penetration is very high.

Figure 14 shows the real power of generator with governor, and Fig. 15 shows the frequency response when

Table 3 Study results for different RPSs for hour 15

	15 % Reserve	20 % Reserve	25 % Reserve	30 % Reserve	35 % Reserve
20 % RPS	Stable (2,078 MW)	Stable (2,770 MW)	Stable (3,463 MW)	Stable (4,156 MW)	Stable (4,849 MW)
25 % RPS	Unstable (1,882 MW)	Stable (2,509 MW)	Stable (3,137 MW)	Stable (3,764 MW)	Stable (4,391 MW)
30 % RPS	Unstable (1,686 MW)	Unstable (2,248 MW)	Stable (2,810 MW)	Stable (3,372 MW)	Stable (3,934 MW)
33 % RPS	Unstable (1,568 MW)	Unstable (2,091 MW)	Unstable (2,613 MW)	Unstable (3,136 MW)	Stable (3,659 MW)
35 % RPS	Stable (1,489 MW)	Unstable (1,986 MW)	Unstable (2,483 MW)	Unstable (2,979 MW)	Unstable (3,476 MW)

Fig. 11 Frequency for 33 % RPS for hour 15

Fig. 12 Real power of generator with governor for 33 % RPS for hour 15

Fig. 13 Real power of wind generator for hour 15

adding external generation resources, indicating that the import helps in stabilizing the power grid.

4 Conclusions

This article developed a novel renewable energy intermittency model, a new power system simulation tool, and examined the dynamic behavior along the load curve for different combinations of the system operation reserves and RPS rates. The key findings of this study can help the company better prepare for the renewable integration and adopt effective mitigation. Besides, the study reveals some severe issues that can only be identified by studying the intermittency dynamics.

The conclusions and the suggestions for future study are as follows:

Fig. 14 Real power of generator with governor when adding external generation resources

Fig. 15 Frequency after adding external generation resource

- (1) Ignoring intermittency and governor effects is an inadequate method to assess intermittency impact.
- (2) The intermittency midterm dynamic impact is studied to gain better understanding of the high renewable penetration.
- (3) The higher the RPS, the higher the required reserve.
- (4) The company expects instability of around 25 % RPS with current reserves.
- (5) Dynamic stability depends on (1) RPS rate; and (2) operation reserves, governor response speed, quick start resources, and resources under AGC control; (3) import limit.
- (6) Most vulnerable peak hour to instability is the afternoon peak hour when solar begins to drop off.
- (7) Investigate energy storage to mitigate problems.
- (8) External generation resources will help in stabilizing the system with 33 % renewable energy integration.

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