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Power grids for high penetration of solar photovoltaic power plants- a review

Siddhartha Bhatt M*

This paper presents a review of power grids which have high component (~ 80 %) of solar photovoltaic (SPV) plants. It can be concluded that variability or infirmness of SPV is controllable to a large extent through detailed probabilistic modeling of the variation patterns. The immediate, short term and long term variation of SPV power plants has been discussed in depth. In a grid composed of a large number of 1-50 MW plants, the dispatchable power can be scheduled to as high as 80 % of the declared capacity in that time slot (since SPV varies in every time slot).

Keywords: *solar photovoltaic, synchronous inertia, synthetic inertia, rate of change of frequency, governor droop, automatic generation control, primary response, secondary response.*

1.0 INTRODUCTION

The present trend in electrical power systems are to go in for large sized grids with large capacity interconnections between regional grids. Electrical grids being dynamic entities, dynamic equilibrium is achieved through maintain the power frequency at their synchronous set point (50 Hz in most cases). The lock out limits for power frequency are ± 5 %, viz., 47.5 Hz and 52.5 Hz. Movement of the single largest generator into and out of a grid must be below the lock out limit or in other words the grid size must be over 20 times the size of the largest generation unit. Loss of generation from one or more of the generating units is handled by primary control via governor response of the balance of the units. In the event of the response not being achieved, load shedding has to be resorted to maintain the dynamic equilibrium. The grid stiffness is the load change per unit change in frequency ($\Delta P / \Delta f$ in MW/Hz) (typically 1-3 GW/Hz) and the grid number is the load change required for lock out of the grid, i.e., 5 % of the frequency, corresponding to approximately 5 % of the load on the grid (typically 0.5-1.0 GW/Hz). The permissible safe operating range of the grid is given in Table 1.

TABLE 1

PERMISSIBLE SAFE OPERATIONAL RANGE OF GRID

Sl No.	Power frequency range (% of nominal)	Power frequency range (Hz)	Permissible time for safe operation (min)
1	± 1.0 %	49.5-50.5	unlimited
2	± 1.0 % to ±2.0 %	49.5-49.0 & 50.5-51.0	Unlimited or 90 min. (depending on utility)
3	± 2.0 % to ±3.0 %	49.0-48.5 & 51.0-51.5	90 min.
4	± 3.0 % to ±4.0 %	48.5-48.0 & 51.5-52.0	30 min.
5	± 4.0 % to ±5.0 %	48.0-47.5 & 52.0- 52.5	30 s
6	Near lock out limit	47.8+ & 52.3+	6 s

*Energy Efficiency & Renewable Energy Division, Central Power Research Institute, PO Box 8066, Sir CV Raman Road, Bangalore-560080, India
Mobile : +919448459587, E-mail : msb@cpri.in

The earlier scenario was of conventional generation of 'firm' power. Gradually, with the advent of renewable sources, 'infirm' power has begun to become an important contributor to the grid. Infirm power is weather dependent and has a substantial stochastic element. The power output of any single infirm generator cannot be set at a prefixed value (scheduled) but power has to be drawn at whatever value it is able to deliver at that point of time. However over a period of time, the integrated energy generation can be guaranteed.

TABLE 2

RESPONSE DOMAINS FOR GRID CONTROL

Sl. No.	Particulars	Time
1	Primary control (synchronous inertia/ synthetic inertia) (for system stability)	4-8 s
2	Primary Control (Frequency Response through droop control) (for system stability)	30-60 s
3	Secondary Control (AGC) (for bridging power)	2 min. to 2 h
4	Regulation reserves (for bridging power)	5 min. to 15 min.
5	Spinning Reserves (for bridging power)	15 min. to 30 min.
6	Supplementary Reserves(for bridging power)	30 min. to 2 h
7	Stand-by Reserves (for energy management)	4-6 h
8	Tertiary Control (Reserve Deployment) (for energy management)	2-4 h
9	Time Control(for energy management)	8-10 h

For the purpose of grid management, the day is divided into 144 time slots of 10 min each. Primary response to loss of generation is handled by three elements:

- System synchronous inertia in the large coal fired thermal and hydro turbo-generators.
- Governor response of other generators (denoted by governor droop).
- reduction in their power drawn by rotating machine loads in response to fall in the power frequency

Primary response to a drop in generation implies utilization of the reserves available with the grid. Responsive reserve is the reserve capacity to immediately control change in the frequency. Secondary response is the regulation of the new set point frequency after the primary response to the nominal frequency. Regulatory reserve is the reserve capacity to restore back the nominal frequency. Figure 1 show a schematic of a typical event involving the loss a generating unit from the grid. The response domains for grid control are given in Table 2.

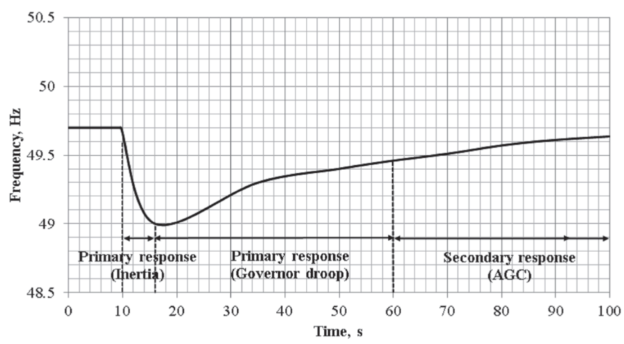

FIG. 1 SEQUENCE OF A TYPICAL EVENT INVOLVING TRIPPING OF A PLANT

Loss of generation from renewable sources (solar and wind) is handled as follows:

- When the penetration of renewable sources is within the peaking limit (10 % of the grid capacity), synthetic inertia and primary governor response of other generating units will handle primary fluctuations and secondary responses. The peaking generators (either gas turbines or pumped hydro) will handle the tertiary loss of generation.
- When the penetration exceeds 30 % of the grid capacity, the system inertia and primary governor response of other generating units will handle primary and secondary response. The hydro generators in the system in addition to the peaking units will have to provide the tertiary back-up reserve support against loss of generation.

- When the penetration of SPV exceeds 80 % of the grid capacity, then there are two options:
  - 10 % spinning reserve have to be maintained in all SPV plants for transient contingencies to provide primary and secondary response.
  - Load response in the form of load shedding will have to be resorted to maintain the dynamic equilibrium and also to provide tertiary and energy management support.

Structuring of large capacity renewable grids must take into consideration the number of individual units, their capacities and their distance apart.

2. PRIMARY RESPONSE OF CONVENTIONAL UNITS

Primary control does not provide complete power frequency regulation because the frequency does not return to its nominal set point. Primary response is through free governor mode of operation (FGMO), Regulated governor mode of operation (RGMO) or Locked or blocked governor mode of operation (BGMO).

The inherent governor dead band (0.005 Hz) is the equipment lag. The operating dead band (normally 0.036 Hz) is set by design and represent the frequency change limit over which the governors do not respond. When the frequency change exceeds the dead band, the governors are activated.

In the event of a loss of a unit and fall in generation and consequent frequency the response is as follows:

- FGMO: All governors will response by increasing their output and thereby restoring back the generation irrespective of whether the absolute value of frequency is super synchronous 50+ (say 50-52.4 Hz) or sub synchronous 50- (47.6-50 Hz).
- RGMO: All governors will response by increasing their output and thereby restoring back the generation only if the absolute value of frequency is 50- (47.6-50 Hz) or a set point in the 50- sub synchronous region (say 49.7 Hz).
- BGMO: governors do not respond to change in grid frequency within the lock out period (47.5-52.5 Hz). Blocked governors are prevalent in coal units with sliding pressure operation and combustion turbines with exhaust temperature control.

Figures 2 and 3 show the response of the FGMO and RGMO.

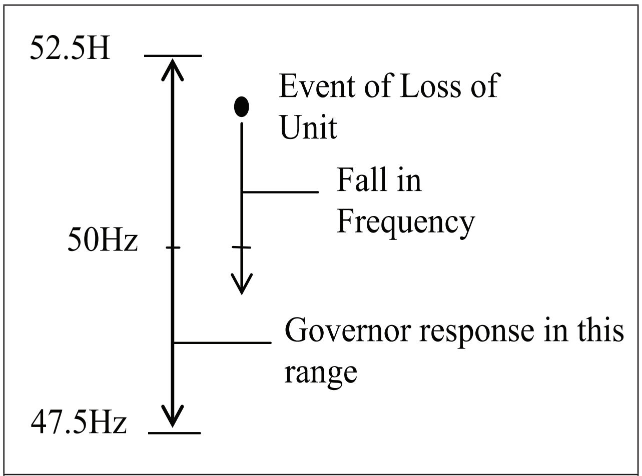

FIG. 2 RESPONSE OF FGMO

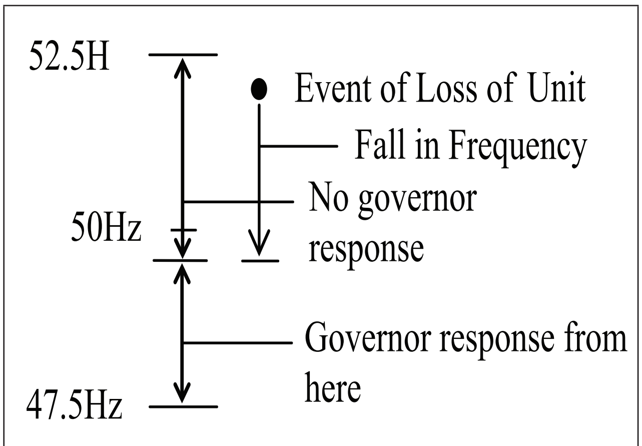

FIG. 3 RESPONSE OF RGMO

The operational experience in large grids is that though FGMO gives a faster response it gives an over response. RGMO gives better response because it gets activated only in the sub-synchronous frequency regime.

2.1 System inertia- synchronous and synthetic

Inertia is the rotational energy stored in the system. Inertia in the grid termed as 'synchronous' inertia resists change in the grid frequency through conversion of the stored kinetic energy in electrical power output. This surge in electrical power output is the first response to the fall in the frequency. If the machine is off grid (stand alone), increase or decrease of primary input causes a change in the machine speed or power frequency but in the case of grid synchronized machines, the torque will increase causing an increase in the delivered power.

Grid code review [1] has brought out the effect of inertia on the response of synchronous generators and the grid to change in the power frequency. In the case of loss of generation, in the absence of inertia, active power injection should be available within 200 ms (10 cycles). Recovery period for 3-5 % of the rated power should be within 60 s. The dead band can be adjustable from 0.02 to 0.5 Hz/s in steps of 0.01 Hz/s.

The stored kinetic energy in the system is given by,

$$\left(P_{supply} - P_{demand}\right) = J\omega\frac{d\omega}{dt}\ 10^3 \qquad \text{....(1)}$$

Where P is the electric power (MW), J is the moment of inertia (kg/m2), is the angular velocity (rad/s).

The inertial energy stored is given the inertial constant (H in MWs/MVA or in units of s) as,

$$H = \frac{\frac{1}{2}J\omega^2}{MVA} \qquad \text{....(2)}$$

Where J is the synchronous inertia and MVA is the apparent power.

The total inertia in the grid is given by,

$$P_n H_n = \sum P_i H_i = \sum \frac{P_{MCRi}}{PLF_i Cos\emptyset_i} H_i \qquad \text{....(3)}$$

Where PLF is the plant load factor (p.u.) and cosφ is the power factor (p.u.). Table 3 gives the inertial constants for different generating units.

TABLE 3

INERTIAL CONSTANTS OF GENERATING UNITS.

Sl. No.	Generation Type	Inertia Constant, H (MWs)
1	Rankine cycle steam from coal firing	4.5-6.0
2	Combined cycle gas turbine	5.5-6.0
3	Gas turbine	4.0-5.0
4	Combustion turbine	3.5-4.5
5	Nuclear Rankine cycle	5.5-6.0
6	IGCC	5.5-6.0
7	Pumped Hydro	3-4.5
8	Hydro	3-4.5
9	Mixed Fuel engine	3-4.0
10	Biomass	3.5-4.0
11	Lignite	3.5-6.0
12	Wind (synchronous motor)	2.0-3.0
13	Solar thermal (remote cycle)	2.0-3.0

The rate of change of frequency is given by,

$$\frac{df}{dt} \equiv ROCOF = \frac{\Delta P}{2H} \qquad \text{....(4)}$$

Where df/dt is the rate of change of frequency (ROCOF) (Hz/s).

The synthetic inertia (K) is defined as the ratio of the largest overproduction capacity to the largest ROCOF [4],

$$K = \frac{\Delta P}{ROCOF} \quad \text{....(5)}$$

The need for quantification of inertial capability and delivery of all generating units in the grid is essential for optimal primary control. In the case of wind machines, their rotating mode of generation provide partial inertial response which is not the case in SPV which have no rotating elements. In wind machines which do not operate on synchronous machines, there is no direct relationship between the wind rotor speed and the system frequency, active power can be increased (4-5 %) in the event of a fall in the system frequency. This increased power output gives rise to what is termed as 'synthetic' inertia. The wind machine is required to operate with a margin of upto 5 % to accommodate the increase in power. Synthetic inertia aids in mitigating power frequency nadirs but are limited to ROCOF mitigation only and not a replacement for synchronous inertia. A synthetic inertia of 5 % of the input power is adequate for a ROCOF of 0.1 Hz/s. Synthetic inertia reduces ROCOF by almost 50 % as given in the equation above.

Battery Energy storage (BES) has been recommended for handling fluctuations in the energy output of SPV plants. Deep discharge lead acid batteries with capacity of 5 % of the power generation capacities have been recommended for providing primary response.

Besides inertia in the generating units, the motor loads serviced by the grid also contribute to mitigation of drop in frequency. Every 1 % reduction in power frequency reduces the motor power output by 3 %. Considering 60 % motors, there would be a drop in load by 2 %.

2.2 ROCOF of the grid

The ROCOF is normally taken as 0.5 Hz/s giving a lock out period of 5 s. Low inertial grids such as those with SPV experience high power frequency excursions (ROCOF as high as 2 Hz/s) [10]. The normal unlimited tolerance zone in large interconnected networks is ± 1% or 0.5 Hz (49.5-51.5 Hz). Limited time tolerance zone is ± 2% or 1 Hz (49-51 Hz). Very high ROCOF without opportunity for recovery can lead to cascade tripping and ultimately blackout or 'grid collapse'. The minimum system synchronous inertia is that which ensures ROCOF does not exceed 0.5 Hz/s [15]. The present trend calls for a ROCOF of 1 Hz/s and even 2 Hz/s which would require very high inertial responses and droop response. Severe voltage dips can cause ROCOF as high as 50 Hz/s which can lead to load swings and ultimately grid collapse unless the origin is marginalized. Voltage recovery should be within 500 ms of the network fault (25 cycles). Anti-islanding technique using ROCOF relays could be substituted by phase angle drift or vector shift to detect islanding.

For higher levels of non-synchronous generation, ROCOF must be defined and ROCOF capability of all generators must be identified. Grid stiffness (MW/Hz) also influences ROCOF. Decreased grid stiffness increases ROCOF.

2.3 Governor droop

Overall or absolute droop (%) is defined as the change in % frequency required to obtain a response of the generator from no load to its rated capacity [maximum continuous rating (MCR)]:

$$\text{Absolute droop (\%)} = \frac{\Delta f}{f_0} x\ 100\ \% \quad \text{....(6)}$$

Where Δf is the change in frequency (Hz) corresponding to a generator output of 0 to 100 % MCR and f0 is the nominal frequency of the grid (normally 50 Hz).

Isochronous droop is zero droop wherein the governor will keep opening the valve till the frequency is restored to the original value.

Incremental droop (%) is defined as the change in % frequency required to obtain a response of the generator from its loading point to its unloading point:

$$Incremental\ droop\ (\%) = \frac{\frac{\Delta f}{f_0}}{\frac{\Delta P}{P}} \quad ....(7)$$

Where Δf is the change in frequency (Hz) corresponding to the change generator output from loading point to unloading point, f0 is the nominal frequency of the grid (normally 50 Hz) and P is the MCR of the unit.

The frequency response can be improved by lowering the dead bands to 0.0166 Hz (1 rpm) from the usual 0.036 Hz. The grid stiffness in excess of 1 GW/Hz improves the response [1]. Most thermal units operate on coordinated controls with boiler follow turbine or turbine follow boiler modes. The governor droop is usually 5 % for thermal units and 2 % for hydro units. In micro-grids with low system inertia and grid stiffness, droop control provides better stability than maintaining a set frequency limit. Governors with different droops can create an unbalance in load sharing of micro-grids. It is preferable to have all generators with the same droop gain will deliver stable and reliable power.

Droop settings of hydro power plants of 2 % can contribute to damping of oscillatory frequency and improve response of the grid. The oscillations due to frequency drop in one or more generators can be reduced by refinement of the droop model. Governor droop setting for achieving permissible time limits for frequency deviation, voltage deviation and active power range is in the range of 2-10%

3. SECONDARY RESPONSE OF CONVENTIONAL UNITS

3.1 Availability of margin in conventional units

Reserve availability as percent of grid total capacity is generally as follows:

- Fast disturbance reserve: 15 %
- Peaking reserve: 10 %
- Spinning reserve: 15 %

Generator rate limiting is said to occur when the unit cannot ramp up its power out due to either reaching the maximum value or operational limitation in the system.

Coal based thermal plants which are the work horses, are subject to capacity limitations which hinder the raising of the load beyond their maximum operating levels due to:

- Load peaking margin
- Equipment operating limitations especially motor currents, boiler limitations, turbine limitations, generator limitations, etc.
- Coal quality deterioration
- Coal or water shortages

Coal fired thermal sets are commercially limited by their technical minimum which is in the range of 70-75 % of their maximum continuous rating (MCR). Operation below these values would involve use of fuel oil support which adds to the cost of generation.

Hydro power plants in India are subject to capacity limitations due to:

- Overflow of water during the rainy season necessitating them to be operated at their maximum possible load to avoid wastage of water.
- Water shortages in fair and summer season.

3.2 Automatic generation control (AGC)

The operating frequency variations permitted for unlimited period are 49.5-50.5 Hz. AGC [load frequency control (LFC)] also called as aims at restoration or fine regulation of the operating frequency after an event back to its nominal value. It is based on power allocation capacity based on demand supply dynamics and economic factors. AGC limits dispatch based on contracted demand and the optimized dispatch takes into consideration the ranges required for raising and lowering load in the event of a transient event. Besides, LFC AGC also handles interchanging scheduling flow, economic dispatch, interconnection scheduling. The possible accuracies of equipment required for efficient AGC are [1]:

- Digital frequency transducer ≤ 0.001 Hz
- MW, MVAR, and voltage transducer ≤ 0.25 % of full scale
- Remote terminal unit ≤ 0.25 % of full scale
- Potential transformer ≤ 0.30 % of full scale
- Current transformer ≤ 0.50 % of full scale

The requirements for a good AGC are [2]:

- High stiffness in the grid (1-3 GW/Hz)
- Reactive power and voltage excursions (± 10 %) under limits.
- Largest unit frequency drop below 0.5 Hz
- Initial rate of frequency drop in the event of an excursion is below 0.5 Hz/s.
- Time constant for lock out frequency limit of 5 s.
- Automatic load shedding scheme in place

The primary response (system inertia and droop response) stabilizes and dampen the oscillations and restrict the drop to a new stable value. AGC restores the stabilized value to its nominal value while smoothening of large ripples.

In grids with large number and capacity of thermal units, automatic under frequency load shedding can be facilitated through protection schemes.

Knowledge based accelerated feedback control and Hybrid neuro fuzzy approach has been used successfully for AGC. In AGC issues of voltage and reactive power have been sorted out through integration of automatic voltage control (AVC) with AGC to restore the operating frequency to its nominal value. Power system stabilizers (using Hephron-Philips model) and optimization of integral controllers have been achieve smooth transition to their nominal frequency by the aid to interconnecting power flows and sharing of the total load economically by all the generating units.

3.3 Ramping rates of units

Ramping rate is the rate at which a generating unit can increase or decrease it load (MW/min. or % MCR/min.). Ramping rates are fixed by the original equipment manufacturer. Adoption of ramping gradients higher than these designated values would reduce the life of the equipment by 8-20 hours per excursion and also reduce the heat rate. Factors which reduce the ramping rates are large governor dead bands, sliding pressure operation, blocked governor operation and lack of synchronous inertia. Ramp rates for different types of generators- peaking and base, have been benchmarked. Table 4 gives the ramping rates (without affecting life) of different generating units. Higher ramping rates can be set but result in acceleration of life of the generation plant from considerations of thermal stress, fatigue and creep rupture. In the case of storage systems the power to energy storage ratio also plays a role in determining the ramp rate. In case the power to energy ratio is 1 the discharge rate is rapid. Storage systems also need to consider their charging time between discharges (total charge-discharge cycle)

4. TERTIARY RESPONSE OF CONVENTIONAL UNITS

Tertiary response generally invoking peaking units or bringing in thermal units over a 4-6 hour period. The technical minimum load is the minimum economical load at which a unit can be operated only with primary fuel (in the case of fossil units) and lowest economically possible load (in the case of renewable and storage units). The technical minimum load is not the unit capacity but the ex-bus capacity (after subtracting the auxiliary power drawn before the generating transformer) at injection point into the grid. Auxiliary power drawn via station transformer from the grid (usually 10 % of the total auxiliary power) is not considered as it cannot be monitored at any point of time. Only the ex-bus generating power at the injection point is the unit load. Table 5 gives the technical minimum for different generating and storage plants.

TABLE 4					
RAMPING RATES OF POWER PLANTS					
Sl No.	**Type**	**Spin ramp rate (%/ min)**	**Quick start ramp rate (%/min)**	**Load ramp up rate (%/min)**	**Load ramp down rate (%/min)**
	Generating plants (conventional)				
1	Pulverized coal-fired power plant	2.0	5.0	1.6	3.0
2	Lignite fired plant	2.0	3.0	2.0	3.0
3	Gas turbine -simple cycle	8.33	22.20	21.0	21.0
4	Gas turbine Combined-Cycle power plant	5.00	4-4.44	2.2	5.0
5	Integrated gasification combined cycle power plant	5.00	2.50	2.5	2.5
6	Conventional hydro	5 %/s	6 %/s	6 %/s	6 %/s
7	Nuclear power plants	5.00	5.00	1.5	3.0
8	Stand-alone Biomass power plant	2.0	3.0	2.0	3.0
	Generating plants (renewable)				
9	Solar PV	1.0	1.0-5.0	0.4	0.4
10	Wind	1.0	1.0-10	1.0	1.0
	Storage plants(*)				
11	Pumped Storage Hydro power plant	5 %/s	6 %/s	6 %/s	6 %/s
12	Compressed air storage plant	0.5	1.1-2.0	0.3	0.3
13	Battery energy storage plant	1.5	2.0	1.0	1.0
14	H_2 Storage	0.3	0.5	0.3	0.1

(*) In storage plants spin, quick start and load ramp up rates refer to discharge of power into the grid from the system and load ramp down rate refers to charging into the system from the grid.

TABLE 5							
TECHNICALLY MINIMUM LOAD OF POWER GENERATING PLANTS							
Sl No.	**Type**	**Minimum load (% MCR)**	**Max load (% MCR)**	**Auxiliary power (ST+UAT) %**	**Technical Minimum load (gross) (% MCR)**	**Technical Minimum load (net) (% MCR)**	**Technical Minimum load (ex-bus) (% MCR)**
	Generating plants (conventional)						
1	Pulverized coal-fired power plant	25-40	110	10	75	67.5	69
2	Lignite fired plant	40	110	8	75	69	70.2
3	Gas turbine -simple cycle	25-50	110	0.9	30	30	30
4	Gas turbine Combined-Cycle power plant	50	110	2.5	50	40	40

5	Integrated gasification combined cycle power plant	50	110	12	75	66	67.8
6	Conventional hydro	40	110	1.3	40	40	40
7	Nuclear power plants	50	100	10	70	63	64.4
8	Stand-alone Biomass power plant	40	110	10	75	67.5	69
9	Solar PV	0	105	0.3	10	10	10
10	Wind	0	110	0.5	10	10	10
	Storage plants						
11	Pumped Storage Hydro power plant	33	110	1.5	40	39.4	39.5
12	Compressed air storage plant	50	100	20	50	40	42
13	Battery energy storage plant	0	100	20	30	24	25.2
14	H_2 Storage	0	100	20	50	40	42

The start up time of a unit is also a consideration for ramping up the capacity. Table 6 gives the time required for cold, warm and hot starts of different types of generating units.

TABLE 6

START UP CHARACTERISTICS OF GENERATING UNITS

Power plants	Cold Start-up time (h)	Warm Start-up time (h)	Hot Start-up time (h)
Nuclear	40	40	4.0
Hard Coal-fired	6	4	0.3
Lignite-fired	10	4	0.3
CCG	2	1.5	0.3
Pumped storage	0.1	0.1	0.1

5. BEHAVIOR OF SPV SYSTEMS FOR GRID OPERATION- EXTENT OF STOCHASTICITY OR INFIRMNESS OF SPV

SPV reaches a peak during the period of solar window (10:00 to 14:00) and beyond this period their output is only partial just as wind also follows daily and seasonal patterns. SPV rises from 0 to 1 kW/m^2 in around 6 hours giving a ramp rate of 0.28 %/min. The normal process of variation of the SPV plant (deterministic component) is intruded by atmospheric radiative obstructions like clouds which reflect 10-30 % of the radiation causing an instantaneous drop in the solar incident energy available at the panel [3]. The instantaneous reduction could range from 10 % to 38 % due to 3-dimensional radiative transfer processes such as cloud, fog, rain, reflection and multiple scattering. The overall average drop over the year due to clouds could be 17-24 W/m^2[3].

Three factors to quantify the effect of this intermission of grid operated SPV generation by the atmospheric effects are:

- Percentage change in power output (% of the nominal value). Figure 4 represents the change in power output and its probability of occurrence.
- Ramp rate of change in power output (%/min.).
- Inter-site variability located at given distance say 25 km away. Figure 5 represents the inter-site variation [4,5].

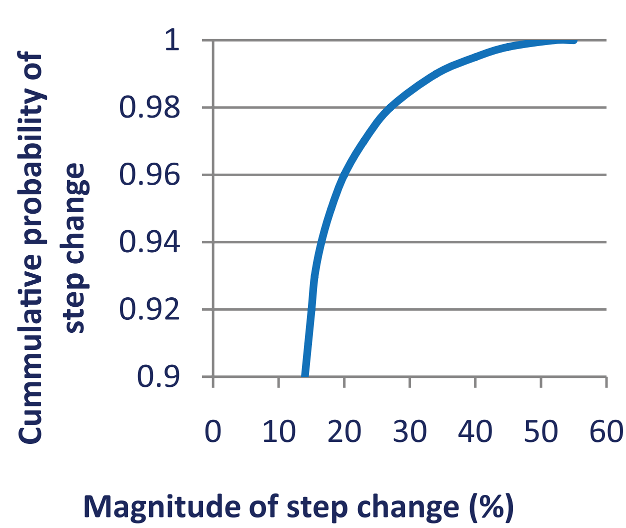

FIG. 4 CHANGE IN POWER OUTPUT AND ITS PROBABILITY OF OCCURRENCE

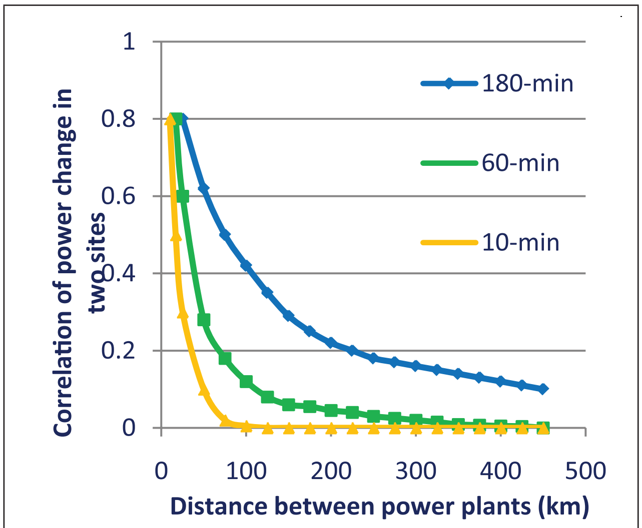

FIG. 5 VARIATION IN INTER SITE POWER OUTPUTS OF DIFFERENT PLANTS

Global solar radiation (the energy input to SPV plants) is a function of the cloud number in Okta (0 for clear and 8 for fully cloudy) [6] as,

$$\frac{P_I(N)}{P_I(0)} = 1 - a_1 \left(\frac{N}{8}\right)^{a_2} \quad ....(8)$$

Where a_1 is +0.75 and a_2 is 3.4[6].

Ramp rates of 1 %/min. has been measured for plants larger than 1 MW. The inter site variability reduces not only with distance but also with increased size of the unit. For example, the variability in a 20 MW plant is much lower than a 1 MW plant because of lower probability of cloud covering the whole plant. A 5 minute fluctuation is of the order of ± 5 % and the ramp rate is in the range of ± 0.85 %/min. Another study [7] indicates 33 % variation over a 10 minute interval with a confidence level of 95 %. The normal ramping rate is 0.27 %/min which can go upto 0.8 %/min.

A detailed study has been undertaken by the author to understand the variability of SPV. Since the power output of SPV system is a linear function of the solar radiation, any change in input will induce proportional change in the power output.

The most restrictive condition is given in Figures 6 and 7 for a one day data for one single plant. The variation measured for 1 s it is ±25 %, for 5 s it is ±60 % and for 15 m and above it is ±72 % for one plant. However, from statistical considerations, the probability is low. For multiple plants, as the inter plant distance increases, the correlation between the power output from the plants decreases.

SPV is generally considered as non-dispatch able, non-schedulable power- infirm power as compared to firm power. The grid inertia being low could give a fast grid response as compared to firm power. One study declares 20 % of the SPV capacity as reliable and dispatch able [8]. The system design for renewable power should be such that frequency nadirs should be lower than pre-designed lower limits through primary frequency control reserves. In a grid consisting of 'n' number SPV plants, all of these must not operate in a 'gang' or 'orchestrated' operation as this would lead to fluctuation in the entire grid. The variability of 'n' plants located at 'n' different locations should be (1/√n) of a single plant. As the distance from the plants increase the variability in terms of correlation of the individual variability decreases and tends to zero (Figure 5). Up to 30 min. the correlation between two sites 100 km away is almost zero [4]. Over a 3 hour interval, the correlation between 2 sites 450 km away is almost zero [4]. Ramp rates of 0.5 %/min. have been observed over a 95 % confidence level [4].

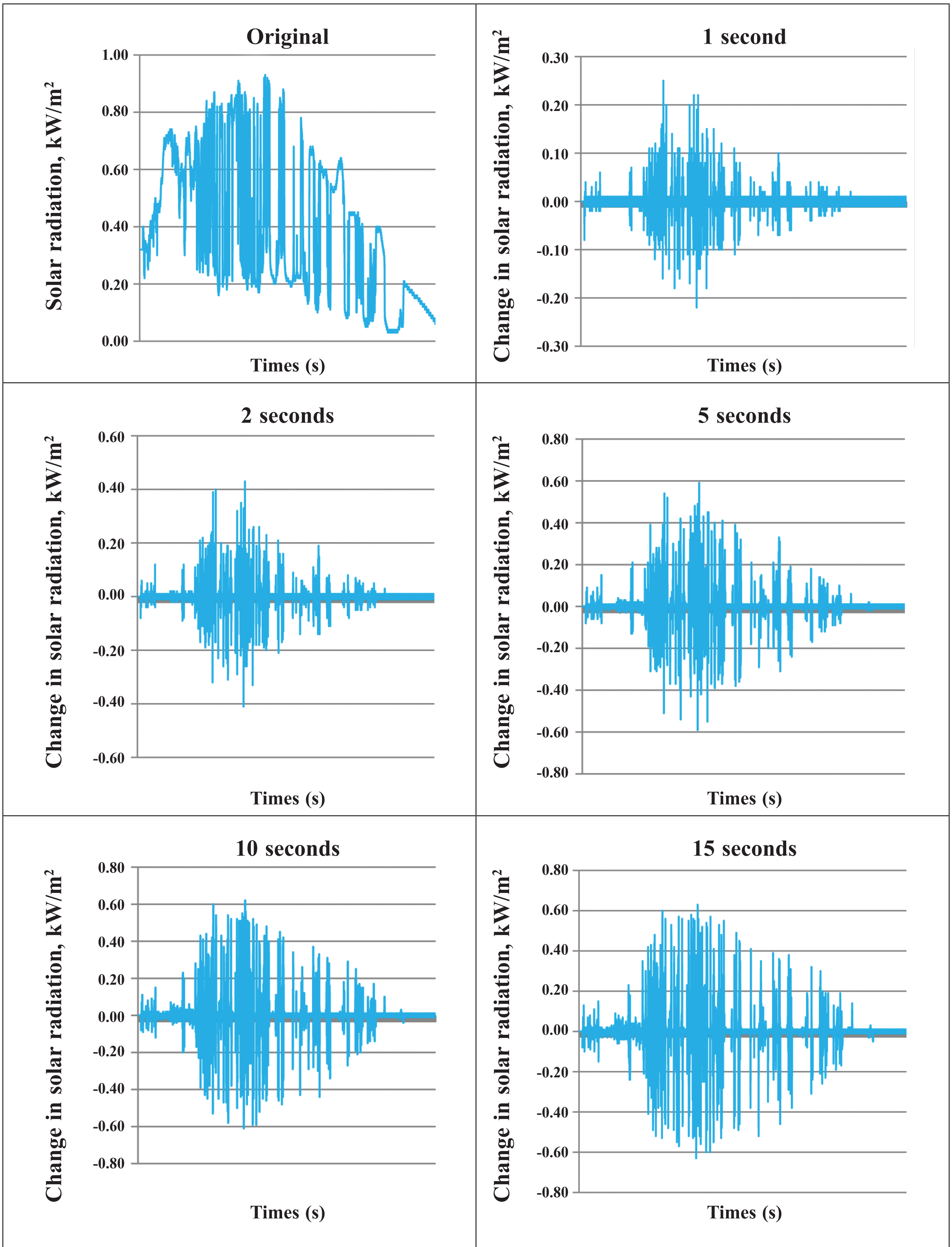

FIG. 6 VARIATIONS BASED ON ONE DAY DATA

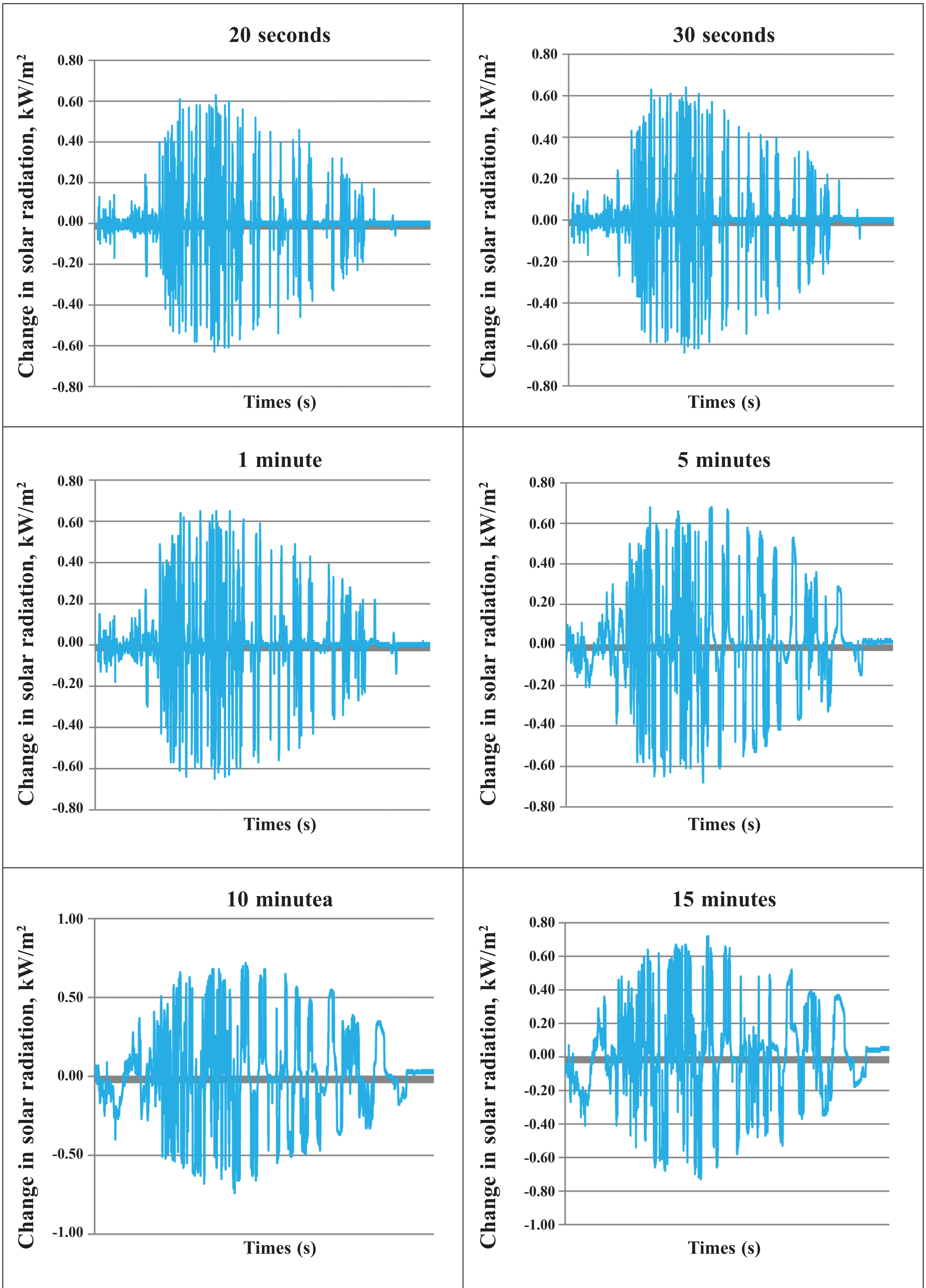

FIG. 7 VARIATIONS BASED ON ONE DAY DATA

The grid with predominant SPV components is envisaged to be composed of a large number of small plants of 1 MW to 50 MW. This would help in evening out the variations arising from cloud cover and weather oscillations. Variation to the extent of 72 % in a single plant in a 15 minute time interval can be easily evened out if the number of plants is increased and capacity kept small. Considering all the above, it can be concluded that the dispatch able or scheduled power from SPV grid composed of a number of small SPV plants can be as high as 80 % of the declared capacity in that time slot.

Thermal ramping has an effect on the SPV hardware life and long term performance. A20 %/min. power ramp could correspond to a thermal ramp of 7.5 ºC/min. SPV plants can tolerate a 7.5 C/min thermal ramp but a thermal ramp of 15 C/min. will seriously affect the life [5].

The tertiary response of SPV can be considered as variation of daily energy generation (kWh per kW of installed capacity). This varies in Bangalore between 3.0 kWh/kW to 4.6 kWh/kW. The variation is 41.4 % of the average value (3.7 kWh/kW).

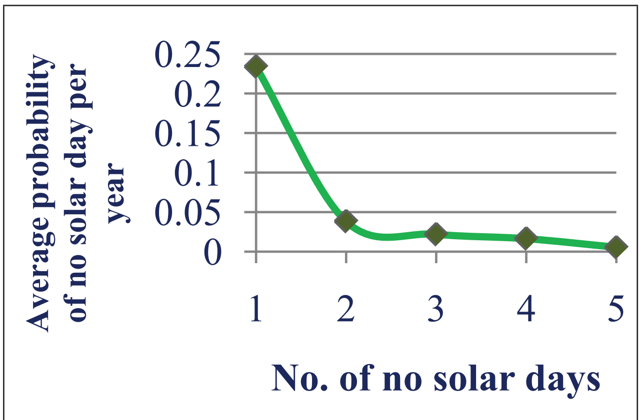

FIG. 8 AVERAGE PROBABILITY OF NO SOLAR DAYS IN AN YEAR

The time management power of SPV can be assessed by the number of no solar days (i.e., when the power output is below 20 % of the MCR). Figure 8 shows the variation of monthly probability of occurrence of no solar days. During the rainy season of 4 months the probability of occurrence of one no solar day is 0.77 and the probability is low in the other seasons. Figure 8 gives the variation of probability of occurrence of number of no solar days from one to five. The probability of continuous no solar days decreases from 0.23 for one no solar day to 0.005 for 5 no solar days.

From the above figures, it can be seen that SPV power can be modeled probabilistically to determine the rate of change of output and its frequency of occurrence. Since the inter plant distance is a factor affecting overall grid variability, having a large number of units of 1-50 MW widespread considerably reduces the probability of changes in output thereby providing stable power to the extent of 80 % of the SPV capacity in any time slot.

6. CONCLUSION

The main conclusions of the study are as follows:

i. If the penetration of SPV is around 10 % of the grid capacity , the primary response in the firm of synchronous inertia and governor droop of the other existing units can handle variations in solar power.

ii. When the penetration exceeds 30 % of the grid size, besides the primary response from existing units, the AGC response would be required for which detailed mapping of the ramping rates, technical minimum and time to cold, warm or hot start would be required for bringing in units to handle the variations.

iii. When the penetration of SPV exceeds 80 % of the size of the grid, the SPV units must be operated with a spinning reserve of 10 % to provide synthetic inertia and primary response to loss of other units. The grid with predominant SPV components is envisaged to be composed of a large number of small plants of 1 MW to 50 MW. This would help in evening out the variations arising from cloud cover and weather oscillations.

iv. The variability or infirmness of SPV is controllable to a large extent through detailed probabilistic modeling of the variation patterns.

v. The immediate, short term and long term variation of SPV power plants has been discussed in depth. In a 15 minute interval the change in SPV power in a single plant can go up to 72 % of the nominal value. However, this is restricted to the particular plant only and can be easily absorbed by the grid.

vi. In a grid composed of a large number of 1-50 MW plants, the dispatch able power can be scheduled to as high as 80 % of the declared capacity in that time slot (since SPV varies in every time slot).

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