Chapter 7
Look-Ahead Model-Predictive Generation Dispatch Methods

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7.1 Mathematical Formulation of Different Dispatch Methods

In this chapter, three different dispatch methods are tested and compared in Flores island. They are (1) physically implementable static dispatch, (2) centralized look-ahead dispatch, and (3) distributed look-ahead dispatch. The following notations are used throughout the chapter:

G : Set of all available generators
$G_{\mathrm{f}}, G_{\mathrm{s}}$: Set of fast and slow conventional generators
G_w : Set of wind energy generators
$\hat{L}(k)$: Expected demand at time step k
$C_i(P_{G_i})$: Cost function of generator i
$S_i(P_{G_i}(k))$: Supply bid function of unit i
$P_{G_i}^{\min}, P_{G_i}^{\max}$: Minimum and maximum generation output
$\hat{P}_{G_w}^{\min}, \hat{P}_{G_w}^{\max}$: Expected minimum and maximum wind generation output at time step k
R_i : Ramping rate of generator $i, i \in G$
K : Time steps in a look-ahead optimization period
$\lambda(k)$: Price of electricity at time step k

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Method 1: Physically Implementable Static Dispatch with Inelastic Demand:
In this formulation a simple static dispatch problem which is physically implementable is formulated as multistage optimization problem. Slow dispatchable power plants such as hydro units are dispatched hour ahead for the predicted load and predicted wind generation. This way, no explicit ramping rate exists, and only security-constrained economic dispatch (SCED) is carried out. Consequently, intra-hour, it becomes necessary to re-dispatch only fast-responding conventional units (e.g., diesel generation) in order to balance supply and demand in response to temporal deviations in wind and load. The mathematical formulation of Problem 1 is as follows:

At each hour H, solve the static economic dispatch problem

$$\min_{P_G} \sum_{i \in G \backslash G_w} (C_i(P_{G_i}(k))), \tag{7.1}$$

$$s.t. \quad \sum_{i \in G \backslash G_w} P_{G_i}(k) = \hat{L}(k) - \hat{P_{G_w}}(k); \tag{7.2}$$

$$P_{G_i}^{\min} \leq P_{G_i}(k) \leq P_{G_i}^{\max}, i \in G \backslash G_w; \tag{7.3}$$

The load and wind forecast are obtained from the data specified in Chap. 4. In principle, the wind forecast function would be based on finite impulse response filter-based models such as the methods specified in Chap. 6. The result of this optimization is $P_G^*(H) = \left[P_{G_s}^*(H)\ P_{G_f}^*(H)\right]^T$.

Then at each 10-min-interval k, the system operator updates the wind power forecast and rerun optimization (7.1)–(7.3) assuming the slow generator units' output stays the same within that hour.

Method 2: Centralized Look-Ahead Dispatch with Inelastic Demand

$$\min_{P_G} \sum_{k=1}^{K} \sum_{i \in G} (C_i(P_{G_i}(k))), i \in G \tag{7.4}$$

$$s.t. \sum_i P_{G_i}(k) = \hat{L}(k), i \in G; \tag{7.5}$$

$$\hat{P}_{G_w}^{\max}(k) = g_j(\hat{P}_{G_w}^{\max}(k-1)); \tag{7.6}$$

$$\hat{P}_{G_w}^{\min}(k) \leq P_{G_w}(k) \leq \hat{P}_{G_w}^{\max}(k); \tag{7.7}$$

$$P_{G_i}^{\min}(k) \leq P_{G_i}(k) \leq P_{G_i}^{\max}(k), i \in G \setminus G_w; \tag{7.8}$$

$$|P_{G_i}(k+1) - P_{G_i}(k)| \leq R_i, i \in G \tag{7.9}$$

Here instead of representing wind generation outputs as negative loads, the wind generation outputs $P_{G_r}(k)$ are considered as decision variables. A look-ahead moving horizon consisting of K samples is chosen over which all generation outputs are optimized. Intertemporal constraints such as ramping rates are explicitly modeled in this formulation, therefore eliminating the need for a two-step optimization stated above in Problem 1.

Method 3: Distributed Look-Ahead Dispatch with Inelastic Demand
For a given vector of prices $\underline{\hat{\lambda}(k)}$ defined as $\left[\hat{\lambda}(k) \cdots \hat{\lambda}(k+K-1)\right]$, each power producer will solve a local look-ahead optimization problem with the objective of maximizing its own profits in the next K time steps:

$$\max_{P_{G_i}(k)} \sum_{k+1}^{k+K} \hat{\lambda}(k)(P_{G_i}(k)) - (C_i(P_{G_i}(k))) \tag{7.10}$$

$$\text{s.t. } \hat{P}_{G_i}^{\max}(k) = g_i(\hat{P}_{G_i}^{\max}(k-1)); \tag{7.11}$$

$$\hat{P}_{G_i}^{\min}(k) = h_i(\hat{P}_{G_i}^{\min}(k-1)); \tag{7.12}$$

$$|P_{G_i}(k+1) - P_{G_i}(k)| \leq R_i; \text{ and,} \tag{7.13}$$

$$\hat{P}_{G_i}^{\min} \leq P_{G_i}(k) \leq \hat{P}_{G_i}^{\max} \tag{7.14}$$

The outcome of the above optimization procedure is vector of quantities scheduled $\underline{P_{G_i}}^*(k)$ defined as $\left[P_{G_i}^*(k+1)\ P_{G_i}^*(k+2) \cdots P_{G_i}^*(k+K)\right]$. Then, by varying the price uniformly up and down by $x\%$ generator obtains a set of optimal points corresponding to these perturbed prices by resolving the above formulation. These solutions are used to create a price sensitivity-based supply vector function $\underline{S}_i(\underline{P}_{G_i}(k))$ around the assumed electricity price. All generators are required to submit their supply functions to the system operator, and the market clears bids which are the least generation cost bids needed to balance supply and demand at time k. The system operator will then solve a static economic dispatch.

7.2 Simulation

7.2.1 Characterizing Different Generators

Generation equipment can be classified by characteristics of cost, physical dynamics, and controllability. Cost of electrical generation can be broken into O&M costs and capital costs. For unit commitment and economic dispatch, O&M costs are of primary concern, while capital costs are more important during planning stages. Diesel and fuel oil generators have nearly constant heat rates, giving a constant marginal cost related to the price of fuel as estimated in Chap. 4 and shown below in Tables 7.1 and 7.2. Relative cost is more important for generators that have very low fuel costs such as wind power, hydropower, and geothermal. Due to the inertia of rotating masses, throttle characteristics, existence of reservoirs, or communication

Table 7.1 Aggregated generation parameters for Flores

	Pgmax (MW)	Pgmin (MW)	Ramp rate (%/min)	Marginal cost ($/MWh)
Diesel	2.2	0.18	100	261
Hydro	1.8	0	5.10	88
Wind	0.66	0	67	87

Table 7.2 Aggregated generation parameters for St. Miguel

	Pgmax (MW)	Pgmin (MW)	Ramp rate (%/min)	Marginal cost ($/MWh)
Oil	102.66	8.41	100	185
Hydro	5.03	0	5.10	87
Wind	30	0	67	88
Geothermal	27.8	0	50	28.1

systems utilized, generators can have different dynamic capabilities. This is of importance when solving economic dispatch problems which require generators to change output from one time step to the next. Hydropower and wind power generators are believed to be able to generate power up to the amount allowed by the wind or water resource. How fast generation output can change is discussed thoroughly in Chap. 4 and shown below as the limiting ramp rates in Tables 7.1 and 7.2.

Controllability is also a key characteristic of generation resources. In Flores Island, hydropower is controllable and may even have some storage capability. In Sao Miguel island, geothermal and run-of-the-river hydropower generators are not generally controllable, other than shutting down for maintenance. Wind power and fossil fuel generators however can be dispatched such that the electric grid can be balanced.

7.2.2 The Computation of Supply Bids

For the distributed look-ahead dispatch formulation as described in Problem Formulation 3, all the generators solve 1-hour look-ahead optimization by perturbing around the vector of expected price $\lambda(k)$. The expected price $\lambda(k)$ can be obtained in day-ahead dispatch process (which, in this chapter, is obtained from the physically implementable static dispatch). By varying the expected price uniformly up and down by $x\%$, all the generators calculate optimal points corresponding to these perturbed prices by resolving the formulation in Problem 3. The typical supply bid function for diesel, wind, and hydro units is represented in Figs. 7.1–7.6. These supply curves provided at market participants' level already internalize the inter-temporal constraints such as ramping rates. Therefore, at the system operator level, static economic dispatch results will be physically implementable results.

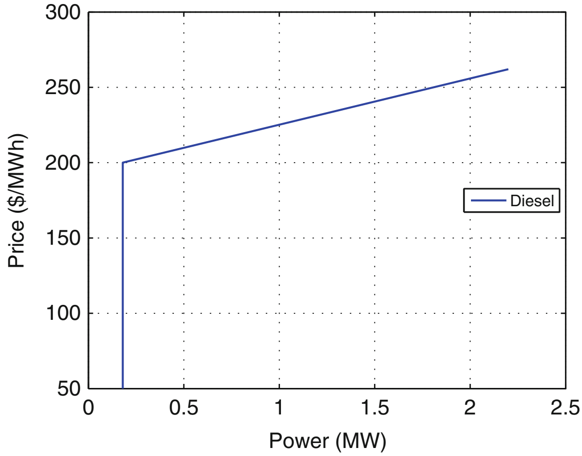


Fig. 7.1 Representative supply bids from diesel generation on Flores island

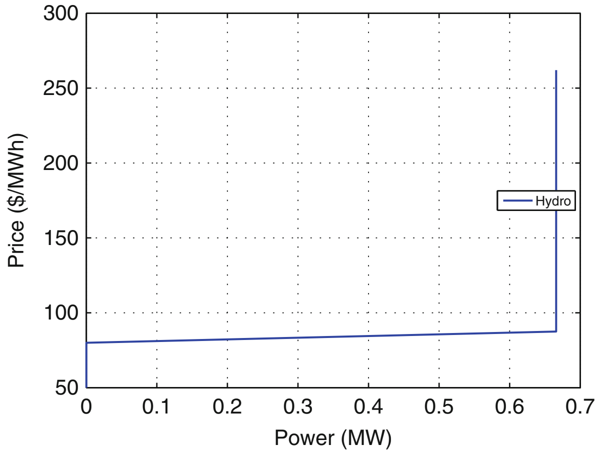


Fig. 7.2 Representative supply bids from hydro generation on Flores island

7.2.3 Flores Island Simulation

Figures 7.7–7.18 represent the unit dispatch results in Flores island under the aforementioned three dispatch methods. In particular, the physically implementable dispatch (Method 1) results are compared and benchmarked with the results presented in the previous chapter. Generation output from 4 representative days in each season are displayed.

In the physically implementable static dispatch, wind generation is treated as negative loads. Therefore, the wind generation is equal to whatever wind power that is available. In the MPC based look-ahead dispatch however, the wind generation becomes an active decision variable instead of an exogenous inputs in the dispatch.

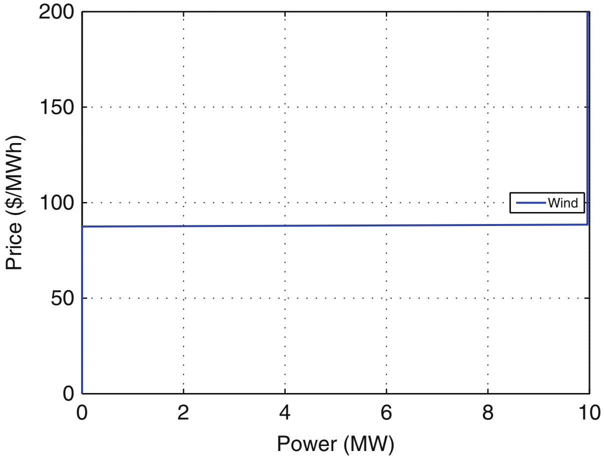


Fig. 7.3 Representative supply bids from wind generation on Flores island

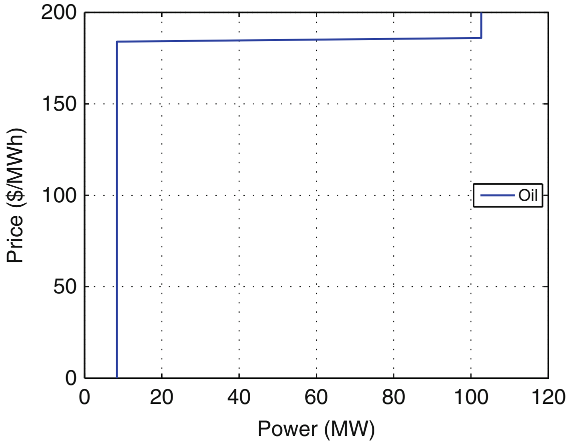


Fig. 7.4 Representative supply bids from oil generation on St. Miguel island

At times when the cost of using expensive diesel to follow the wind ramping offsets the relative cost saving from wind generation, it is more economic to the system to curtail the wind. In the static dispatch, the more expensive diesel unit generation is dispatched at higher level compared with MPC dispatch. The slower hydro unit, on the other hand, increases its output in the look-ahead dispatch because the look-ahead window allows even slower units to follow the fluctuations from wind and load. Compared with static dispatch which takes wind as negative load, the MPC -based dispatch may reduce the cheapest wind generation. However, the MPC dispatch will lead to an overall more economic total generation cost. Table 7.3 shows the daily economic dispatch results from these three dispatch methods. In Flores island, compared with static economic dispatch methods, the cost savings

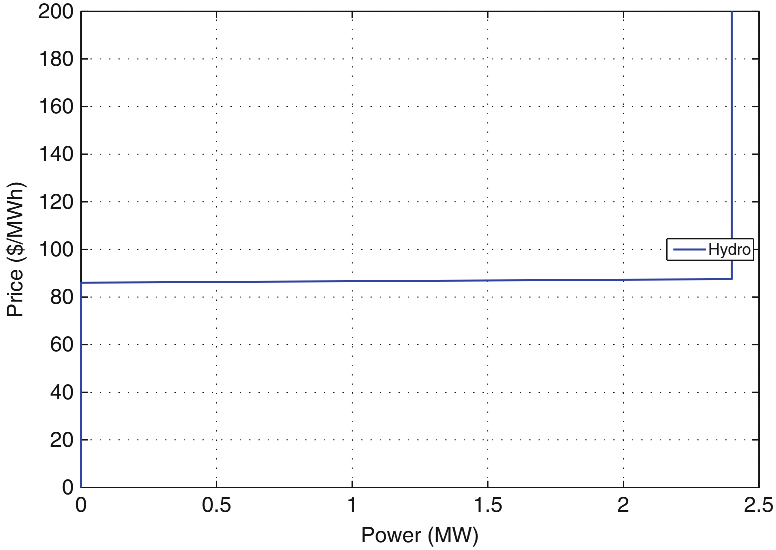
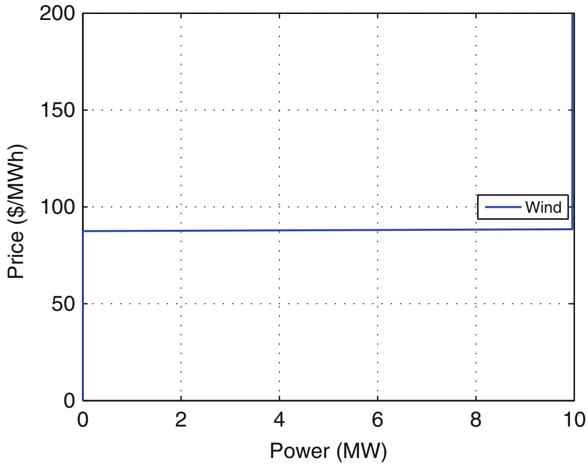


Fig. 7.5 Representative supply bids from hydro generation on St. Miguel island

Fig. 7.6 Representative supply bids from wind generation on St. Miguel island



of look-ahead dispatch is approximately 1%. The duality gap between centralized look-ahead dispatch and the distributed look-ahead dispatch is approximately 0.3% of the overall objective function. In other words, the look-ahead dispatch could be implemented in both centralized approach and distributed approach without too much performance degradation.

Sensitivity of Dispatch Cost Updating Rules of Distributed Look-Ahead Dispatch We study the impact of different updating rules of distributed look-ahead dispatch

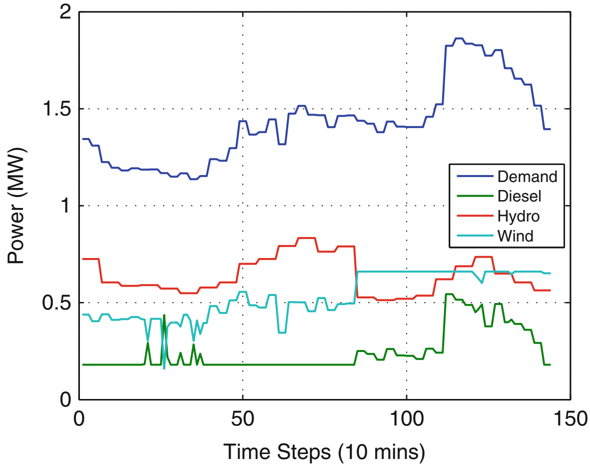


Fig. 7.7 Generation outputs with dispatch Method 1 in Flores on Jan 16

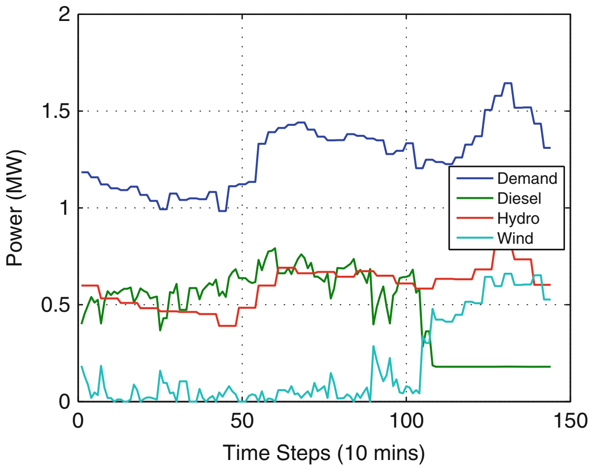


Fig. 7.8 Generation outputs with dispatch Method 1 in Flores on Apr 16

on the dispatch cost. Whereas in the formulation of Method 3, the initial price vector $\underline{\hat{\lambda}(k)} = \left[\hat{\lambda}(k) \cdots \hat{\lambda}(k+K-1)\right]$ is assumed to be obtained from day-ahead market clearing, and stay unchanged for the optimization within that day, there is possibility of updating the initial price vector $\underline{\hat{\lambda}(k+1)}$ for the next time step based on the updated real-time market clearing price at k. Therefore, the initial price vector for the next time step $k+1$ becomes:

$$\underline{\hat{\lambda}(k+1)} = \left[\lambda(k+1) \cdots \hat{\lambda}(k+K)\right] \tag{7.15}$$

where $\lambda(k+1)$ is the *actual* real-time market clearing price from the previous 10-min interval dispatch at the system operator level. The updated information brings about more accurate price forecast for the next time step. In this simulation,

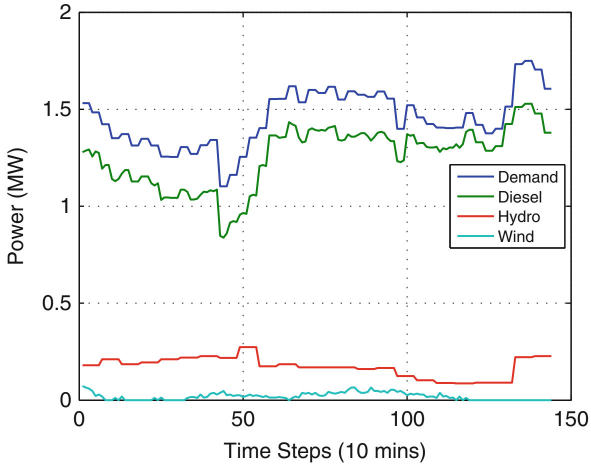


Fig. 7.9 Generation outputs with dispatch Method 1 in Flores on Jul 16

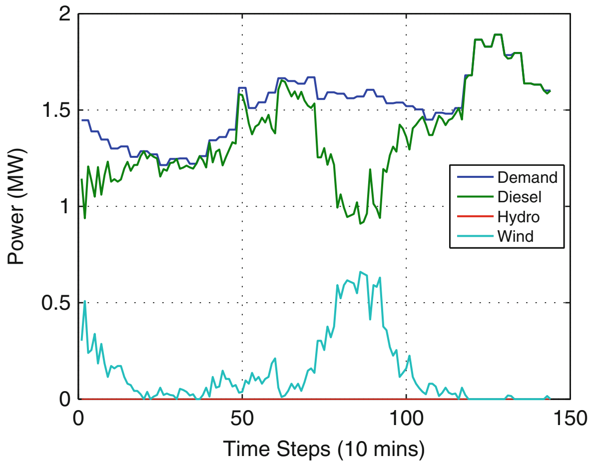


Fig. 7.10 Generation outputs with dispatch Method 1 in Flores on Oct 15

however, even if we update the price this way, the dispatch cost of Method 3 stays the same with the last column of Table 7.3. This is likely due to the fact that there are only three discretized price points possible in the island (the marginal costs of the three units). When the system becomes larger, the set of possible clearing prices will also increase. It would be likely that price updating rules may impact the economic performance of the distributed look-ahead dispatch .

Sensitivity of Dispatch Cost Savings with Respect to Cost Parameters

We also study the impact of different generation cost parameters on the performance of different dispatch methods. As specified in the Data Input chapter, we assume that the short-run marginal cost of wind, hydro, and diesel units in Flores are 87$/MWh, 88$/MWh, and 261$/MWh, respectively. Given this set of marginal cost data, the

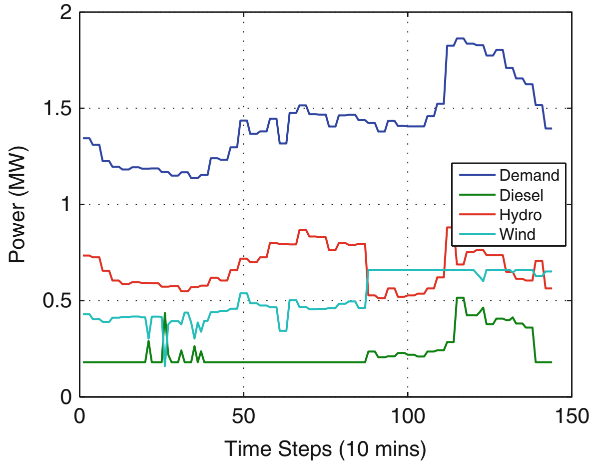


Fig. 7.11 Generation outputs with dispatch Method 2 in Flores on Jan 16

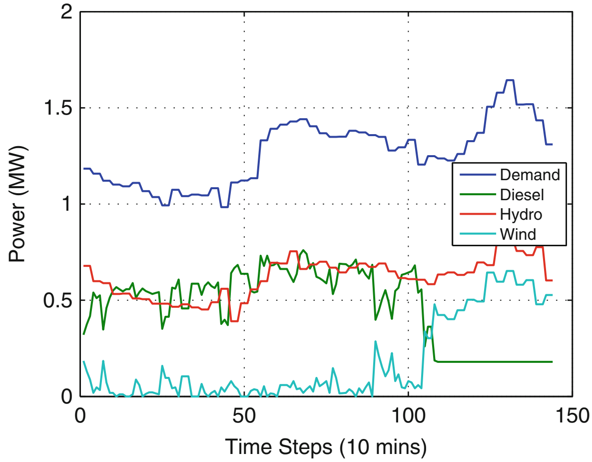


Fig. 7.12 Generation outputs with dispatch Method 2 in Flores on Apr 16

relative economic saving of look-ahead dispatch compared with static dispatch is approximately 1%. However, if the marginal cost of the wind, hydro, and diesel units are changed to 5$/MWh, 9$/MWh, and 50$/MWh, respectively, then the relative economic saving of look-ahead dispatch compared to static dispatch for the same period of time becomes 20%. Namely, the *relative cost difference* of various generating units will have significant impact on the economic performance difference between static and look-ahead dispatches. This could be explained as follows: given the same level of loads (loads assumed to be inelastic), the relative cost saving from look-ahead dispatch is the result of shifting some of the generation from more expensive units to the less expensive units. It is anticipated that with more diverse groups of generating units which have broader range of marginal costs, the potential economic saving from look-ahead dispatch is likely to be higher.

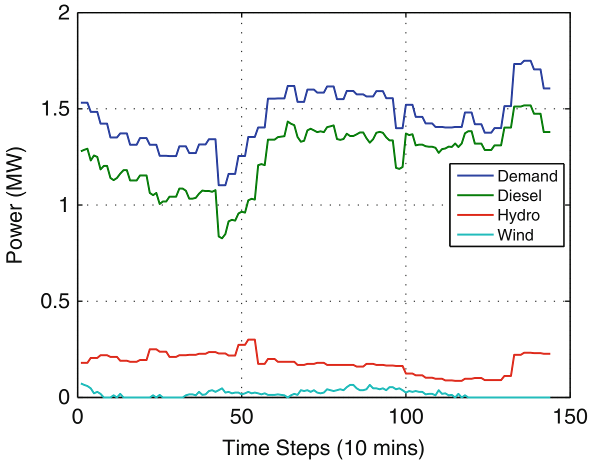


Fig. 7.13 Generation outputs with dispatch Method 2 in Flores on Jul 16

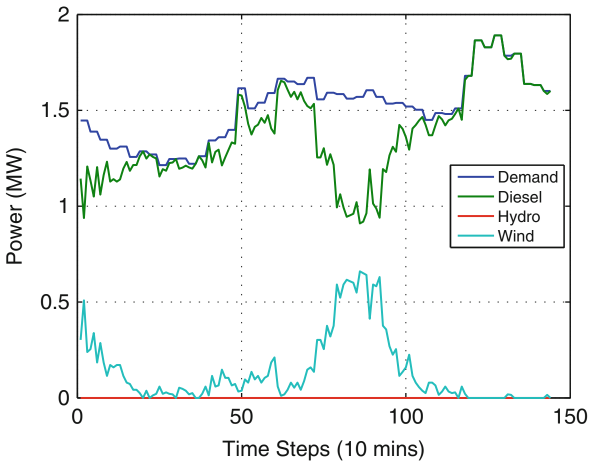


Fig. 7.14 Generation outputs with dispatch Method 2 in Flores on Oct 15

7.2.4 St. Miguel Simulation

Figures 7.19–7.22 represent the unit dispatch results in St. Miguel island under the aforementioned three dispatch methods. In contrast to the Flores island, the hydro units in St. Miguel are assumed to be run-of-the-river type. In other words, the hydro units also become non-dispatchable "negative loads." Table 7.4 shows the daily cost of economic dispatch under these three methods. For each of the 4 days, the dispatch cost stays the same across all the three dispatch methods. This is due to the fact that hydro units are run-of-the-river type, which are not dispatchable as in the case of Flores. The only dispatchable units in the St. Miguel island are the diesel units. Since both hydro and wind generation units are less expensive than the diesel units,

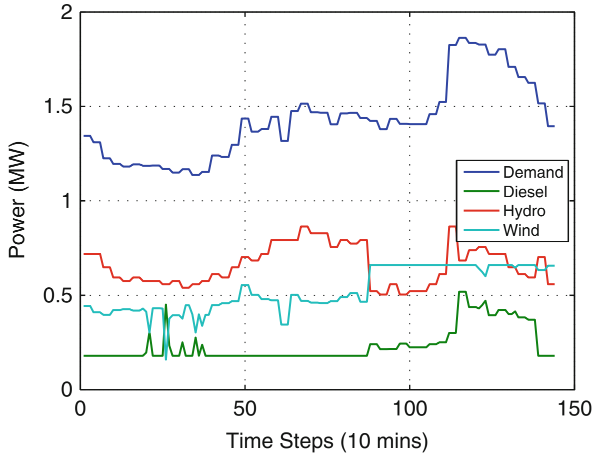


Fig. 7.15 Generation outputs with dispatch Method 3 in Flores on Jan 16

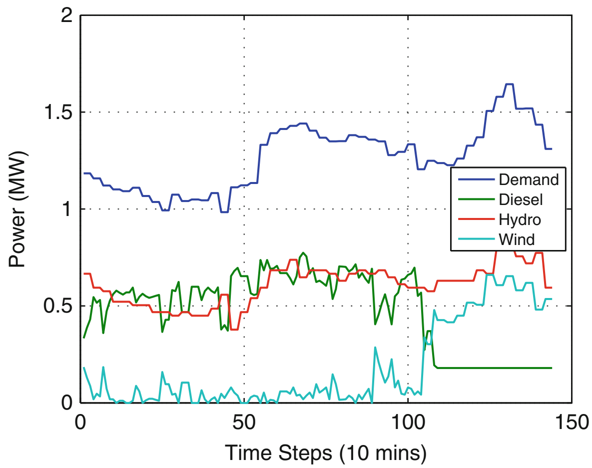


Fig. 7.16 Generation outputs with dispatch Method 3 in Flores on Apr 16

the diesel units always serve as the marginal units in that system. In other words, the dispatch results will stay unchanged due to the limited set of dispatchable units in St. Miguel island.

7.3 Discussions and Summary

In this chapter different dispatch methods are tested in Flores and St. Miguel islands assuming loads are inelastic. The value of incorporating near-term wind/load forecast information is manifested in more cost-effective dispatch results. The cost savings from advanced dispatch methods are heavily dependent on (1) the relative generation cost difference of the power plants in the system and (2) the ramp

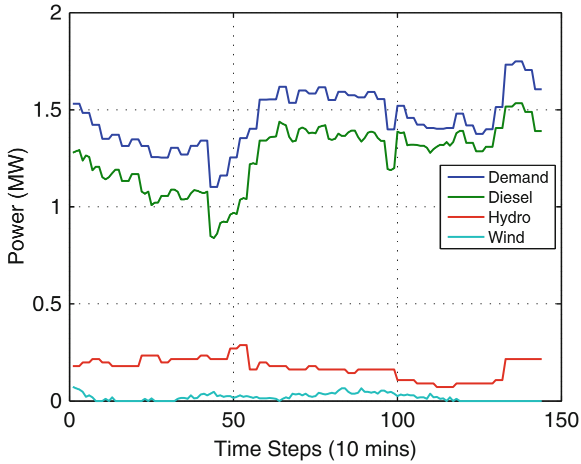


Fig. 7.17 Generation outputs with dispatch Method 3 in Flores on Jul 16

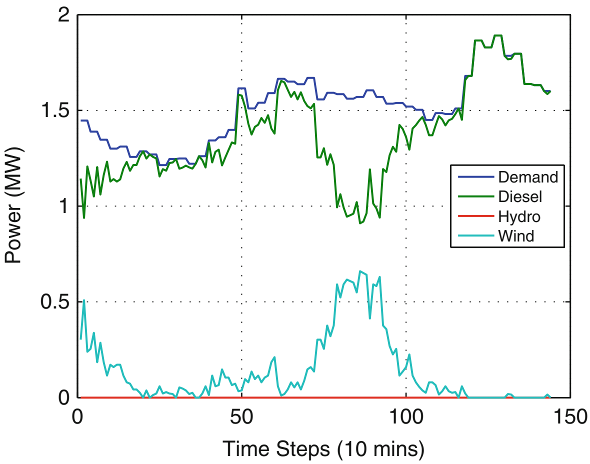


Fig. 7.18 Generation outputs with dispatch Method 3 in Flores on Oct 15

Table 7.3 Daily dispatch cost comparison ($) for Flores

Date	Method 1	Method 2	Method 3
Jan 16	4,017.11	3,953.94	3,970.28
Apr 16	4,676.08	4,604.45	4,633.94
Jul 16	8,287.53	8,257.15	8,290.98
Oct 15	8,890.01	8,890.01	8,890.01

rate capabilities of different units. In Flores island, compared with static economic dispatch methods , the cost savings of look-ahead dispatch is approximately 1%. The duality gap between centralized look-ahead dispatch and the distributed look-ahead dispatch is approximately 0.3% of the overall objective function. In other words, the look-ahead dispatch could be implemented in both centralized approach and distributed approach without too much performance degradation.

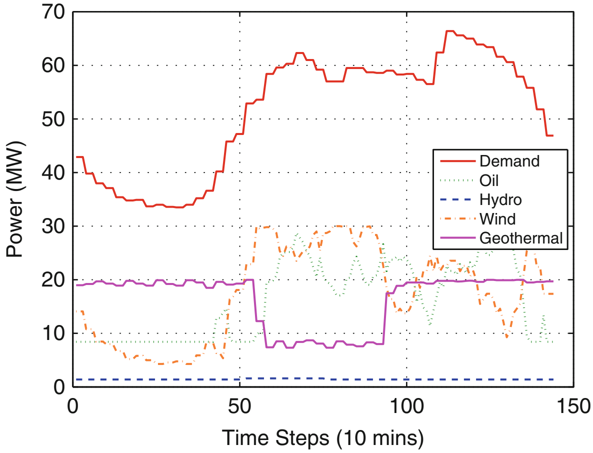


Fig. 7.19 Generation outputs in St. Miguel on Jan 16

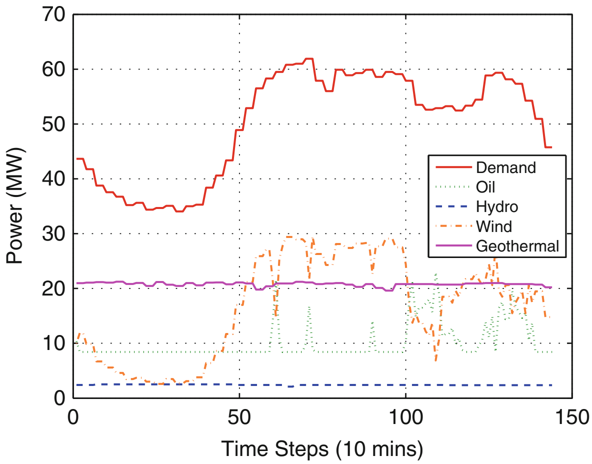


Fig. 7.20 Generation outputs in St. Miguel on Apr 16

In the case of St. Miguel island, on the other hand, there is limited cost savings from more advanced dispatch method. This is due to the fact that hydro units are run-of-the-river type, which are not dispatchable as in the case of Flores. The only dispatchable units in the St. Miguel island are the diesel units. Since both hydro and wind generation units are less expensive than the diesel units, the diesel units always serve as the marginal units in that system. In other words, the dispatch results will stay unchanged due to the limited set of dispatchable units in St. Miguel island.

One major assumption of simulation in this chapter is that the loads are assumed to be *inelastic*. When the loads are assumed to be flexible with respect to electricity price, the potential cost savings from more advanced dispatch methods are expected to be higher. In the next chapter we will discuss the economic cost savings when the advanced dispatch methods are coupled with adaptive load management (ALM).

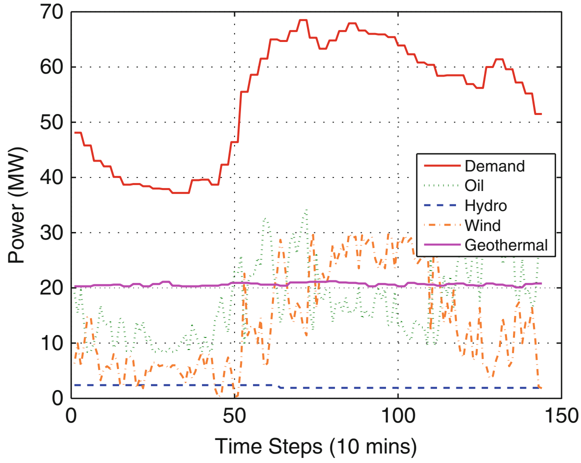


Fig. 7.21 Generation outputs in St. Miguel on Jul 16

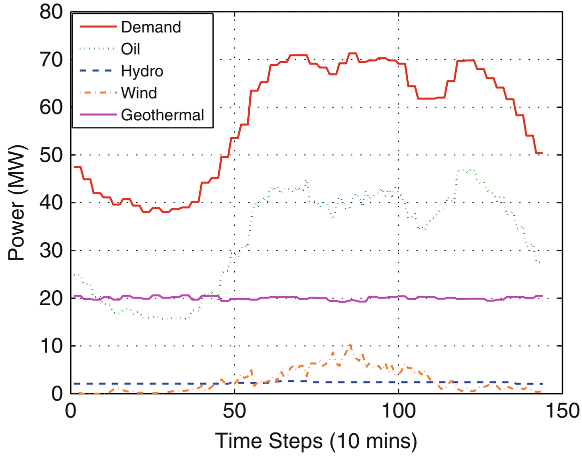


Fig. 7.22 Generation outputs in St. Miguel on Oct 15

Table 7.4 Daily dispatch cost comparison ($) for St. Miguel

Date	Method 1	Method 2	Method 3
Jan 16	122,149.27	122,149.27	122,149.27
Apr 16	99,451.98	99,451.98	99,451.98
Jul 16	114,124.32	114,124.32	114,124.32
Oct 15	168,017.17	168,017.17	168,017.17

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