Long-term Unit Commitment Problem with Optimal Zone Configuration: a Case Study in Martinique

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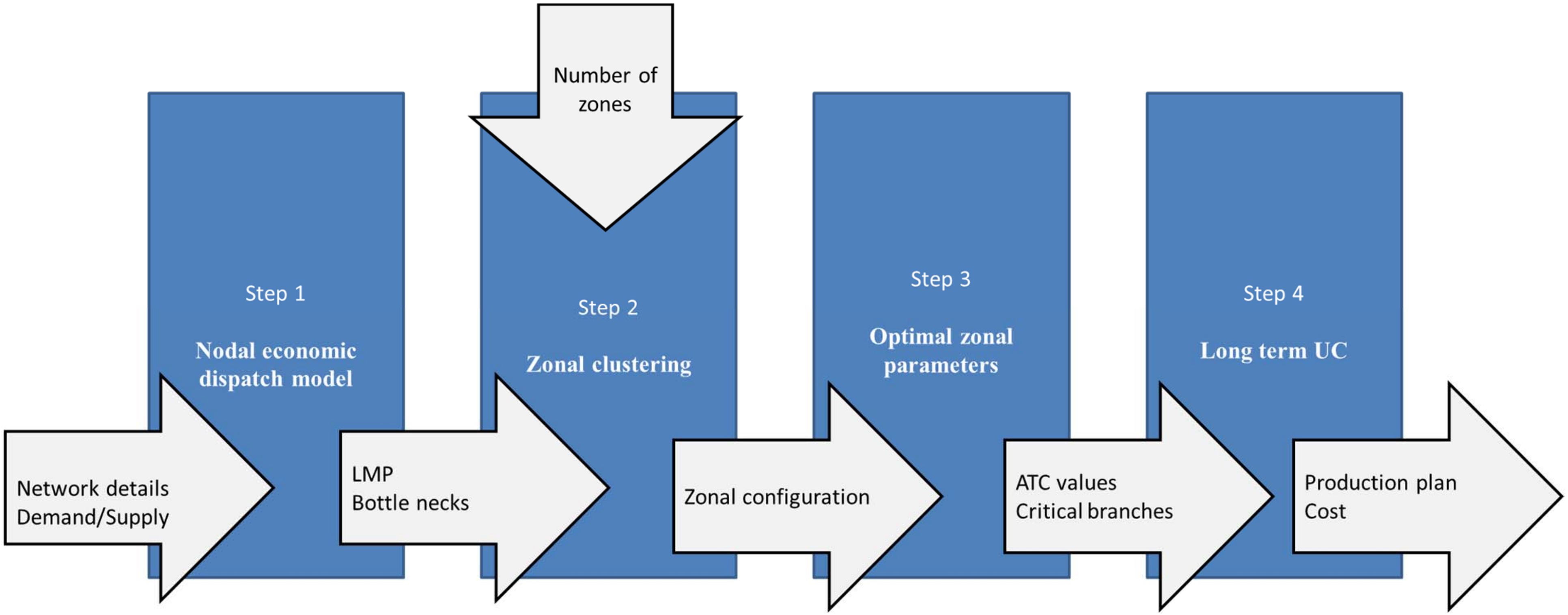
Introduction

- The isolation (which prevents connections to the continental electric grid), the geographic specificities (which limit the size of production tools), and the limited storage capacity (because of high cost) lead to:
  - Much higher production costs than in the mainland France (×2)
  - More fragile to the rapid variance caused by the electricity consumption or production: the electricity supply-demand balance has to be satisfied
- The electricity supply-demand imbalance is accentuated by the development of intermittent energies such as wind or solar.
  - On average, 25% of the energy produced in Corsica and the French overseas departments is from intermittent sources

Methodology Overview



Methodology - Step 1

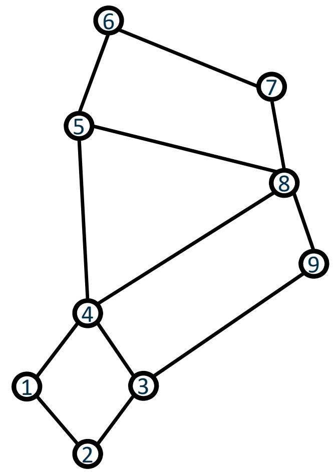


Figure 1: DC Power flow

- The nodal market outcome is simulated with an economic dispatch model based on a nodal network model
  - DC power flow approach.
  - A linearization of the AC power flow equations, based on the assumption of lossless transmission lines, small voltage angle differences between neighboring nodes and a flat voltage profile.

Methodology - Step 1

- Series susceptance of line
- Thermal transmission limit of transmission line
- The electricity generation cost for power plant
- Demand information

$$\max_{q^d, q^s, f, \theta} \sum_{i \in N} \left[\int_0^{q_i^d} p_i^d(q)dq - \int_0^{q_i^s} p_i^s(q)dq \right] \quad (1)$$

$$q_i^s - q_i^d = \sum_{j:(i,j)\in L} f_{ij} - \sum_{j:(j,i)\in L} f_{ji}, \forall i \in N \quad (2)$$

$$f_{ij} = H_{ij}(\theta_i - \theta_j), (i,j) \in l \setminus L^{DC}, \forall i,j \in N^{Nodal} \quad (3)$$

$$-CAP_{ji} \le f_{ij} \le CAP_{ij}, \forall i,j \in N^{Nodal} \quad (4)$$

Methodology - Step 2

- The optimal zonal clustering is determined by a clustering algorithm, given a number of zones and based on the critical lines identified and LMPs in the nodal simulation
- Principle: The clustering algorithm groups nodes into a predefined number of zones, in a way that intra-zonal congestion is infrequent and that nodes within a zone have a similar impact on inter-zonal lines.

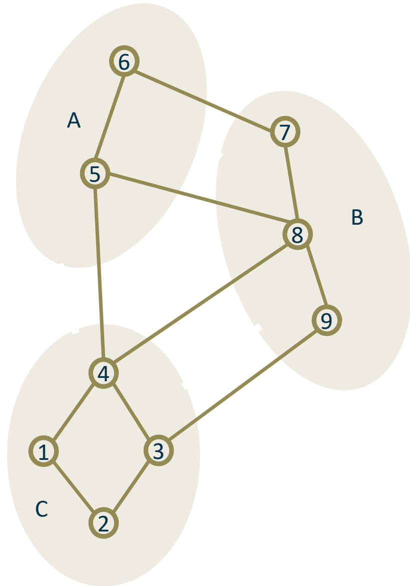


Figure 2: Zonal clustering

Methodology - Step 2

- Differences in LMPs indicate grid congestion. Group nodes with similar LMPs, clusters (i.e., bidding zones) to obtain a lower intra-zonal congestion configuration.
- Objection function is to minimizes the absolute differences of the LMF at the transmission substation and the average price in each zone.
  - ➢ Each node only belongs to one zone
  - ➢ All nodes within one zone are directly linked to each other
  - ➢ assign each zone a certain minimal size (e.g. load, number of substations, capacity from conventional generation units)

$$min \sum_{N} \sum_{Z} m_{iz}(p_i - p_z)^2$$

$$m_{iz} = \begin{cases} 1 \; if \; i \in z \\ 0 \; otherwise \end{cases}$$

$$\sum_{i}^{N} m_{iz} = 1$$

Methodology - Step 3

- The zonal network parameters are calculated based on the results from the previous two steps.
  - ATC model
  - FBMC

Methodology - Step 3

ATC model

Power exchange between two zones is limited by a pre-planned Net Transfer Capacity (NTC) value. Noted that the scheduled power exchange is not necessarily equal to the real (physical) power exchange.

$$NEX_z = \sum_{i \in N_z} Q_i^s - Q_i^d, \forall z \in Z$$

$$\mathrm{NEX}_z = \sum_{zz} (BEX_{z,zz} - BEX_{zz,z}), \forall z \in Z$$

$$0 \leq BEX_{z,zz} \leq atc_{z,zz}, \forall z, zz$$

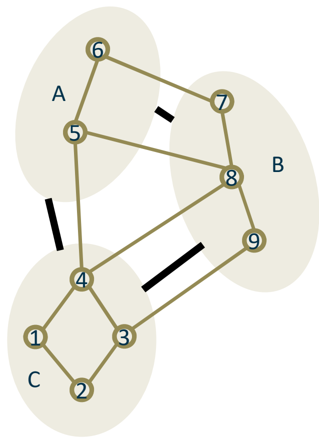


Figure 3: ATC

Methodology - Step 4

- Long term unit commitment outcome is simulated based on a zonal network model
  - ➢ The long term unit commitment problem for a period of 8750 (24*365) hours
  - ➢ Three main cost components namely fuel costs (stepwise), start-up, and shut-down costs
  - ➢ Simplified network constraints. i.e. ATC or FBMC constraint
  - ➢ Nodal network depending on the solving time

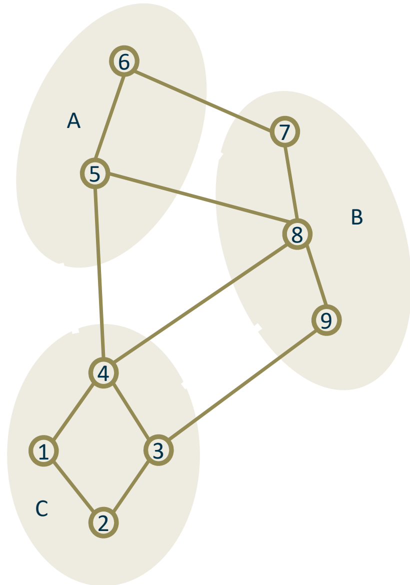


Figure 6: Zonal configuration

Methodology - Step 4

- C1. The maximum and minimum generation limit
- C2. Minimum ON time and minimum OFF time
- C3. Startup action and shutdown action on each unit at a time period t
- C4. The shortest ON duration has and the shortest OFF duration
- C5. Ramping rate
- C6. The hourly total generation is equal to the hourly demand
- C7. Spinning reserve (SR) : to cover the sudden increase in demand or supply, rapid reduction of renewable . The SR is supplied by online generating units.

Methodology - Step 4

- C1. A generator output in a time period is subject to the maximum and minimum generation limit. When a generator is scheduled online, the generation capacity is active giving bounds on dispatch level. Otherwise, a generator output is forced to zero.
- C2&3. The UC constraints state generator status restricted by specific operation requirements, such as minimum ON time and minimum OFF time, and also specify startup action and shutdown action on each unit at a time period t, respectively.
- C4. Because a generator can't be started up or shut down arbitrarily in consecutive hours, the shortest ON duration has to be met before a generator being shut down and the shortest OFF duration is also required before a generator being restarted.
- C5. In addition, a generator output can be adjusted, increasing or decreasing between two successive time periods. The generation difference between two adjacent time periods is called ramping.
- C6. The hourly total generation should be equal to the hourly demand
- C7. Spinning reserve (SR) It is used to cover the sudden increase in demand, rapid reduction of renewable energy production, or unplanned generating unit outage. The SR is supplied by online generating units which are synchronized to the system and are able to ramp-up in order to meet the demand.

Case study: Martinique

Figure 4: Network

Network data: Line, capacity, resistance, reactance
14 nodes, 25 AC liens(67kV)

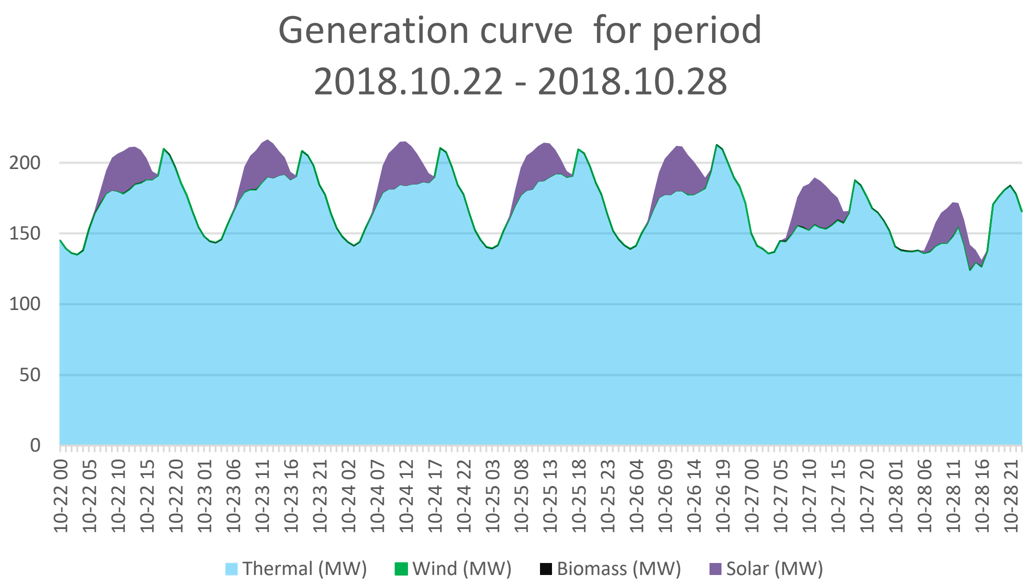
Generation data: capacity
20 thermal plants, Biomass, Wind, PV

Generation cost

Generation Location

Consumption data

Case study: Martinique



[source: opendata-martinique.edf.fr]

Figure 5 :Load curve for period 22rd -28th, Oct, 2018 (Monday to Sunday)

	Peak hours		Off-Peak hours	
	With solar	Without solar	With solar	Without solar
Reference load	210 MW		180 MW	
Wind generation	0.5 MW	0.5 MW	0.5 MW	0.5 MW
Solar generation	30 MW	0 MW	30 MW	0 MW
Biomass generation	0.4 MW	0.4 MW	0.4 MW	0.4 MW

Table 1: Reference load and generation for the case study

Results - Step 1

	Peak hours		Off-Peak hours	
AC lines	With solar	Without Solar	With solar	Without Solar
FL_LAMENTIN1	42 %	45 %	39 %	42 %
FL_LAMENTIN2	42 %	45 %	39 %	42 %
BF_SCHOELCHER1	49 %	60 %	47 %	54 %
BF_SCHOELCHER2	49 %	60 %	47 %	54 %
BF_ST_PIERRE	11 %	15 %	9 %	12 %
BF_FOND_LAILLET1	-28 %	-34 %	-26 %	-30 %
BF_FOND_LAILLET2	-28 %	-34 %	-26 %	-30 %
DESBROSSES_DILLON	61%	60%	64%	58%
DESBROSSES_SCHOELCHER	-85%	-84%	-84%	-78%
DILLON_HYDROBASE1	-22%	-23%	-10%	-21%
DILLON_HYDROBASE2	-22%	-23%	-10%	-21%
DILLON_HYDROBASE3	-25%	-27%	-12%	-24%
DILLON_LAMENTIN1	10%	11%	6%	10%
DILLON_LAMENTIN3	21%	23%	12%	22%
DILLON_LAMENTIN4	21%	23%	12%	22%
GALION_LAMENTIN	-47%	-45%	-29%	-53%
GALION_FRANCOIS	-9%	-7%	0%	-17%
GALION_TRINITE1	31%	43%	25%	37%
GALION_TRINITE2	32%	45%	26%	38%
LAMENTIN_FRANCOIS	39%	39%	30%	39%
LAMENTIN_PETIT_BOURG1	40%	40%	34%	35%
LAMENTIN_PETIT_BOURG2	40%	40%	34%	35%
FRANCOIS_MARIN	23%	24%	21%	19%
MARIGOT_TRINITE	-14%	-14%	-12%	-12%
MARIN_PETIT_BOURG	-25%	-26%	-21%	-23%

Table 2: Average utilization rate of the transmission lines

Figure 6: Bottleneck

	Peak hours		Off-Peak hours	
Node	With solar	Without Solar	With solar	Without Solar
Saint Pierre	148.02	148.01	146.10	154.33
FL	148.06	148.06	146.10	154.33
Bellefontaine	148.02	148.01	146.10	154.33
Schoelcher	146.79	148.21	145.89	155.93
Desbrosses	160.26	162.27	147.39	157.05
Dillon	157.54	159.10	147.22	156.56
Hydrobase	157.54	159.10	147.22	156.56
Lamentin	156.76	158.21	147.18	156.44
Petit Bourg	156.76	158.25	147.18	156.44
Marin	156.76	158.39	147.18	156.44
François	156.76	158.56	147.18	156.44
Galion	156.76	158.67	147.18	156.44
Trinité	156.76	158.67	147.18	156.44
Marigot	156.76	158.67	147.18	156.44

Table 3: Average nodal prices (EUR/MWh)

Results - Step 2

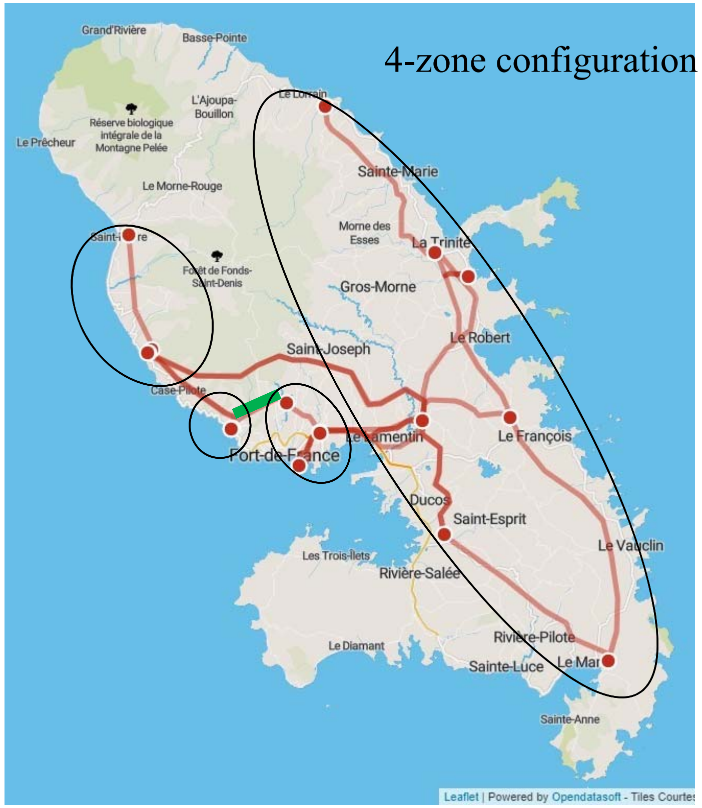


Figure 7: Zonal configurations

Results - Step 3

	maximum exchange capacity						peak-hour with solar solution						peak-hour without solar solution					
I		zone1	zone2	zone3				zone1	zone2	zone3				zone1	zone2	zone3		
	zone1		108	146			zone1		56	55			zone1		67	61		
	zone2	108		235			zone2	56		51			zone2	67		63		
	zone3	146	235				zone3	55	51				zone3	61	63			
II		zone1	zone2	zone3	zone4			zone1	zone2	zone3	zone4			zone1	zone2	zone3	zone4	
	zone1		108		146		zone1		56		55		zone1		67		61	
	zone2	108		54			zone2	56		49			zone2	67		49		
	zone3		54		235		zone3		49		51		zone3		49		63	
	zone4	146		235			zone4	55		51			zone4	61		63		

Table 4: Power exchanges based on nodal solution

Results - Step 3

	I				II			
	zone1	zone2	zone3		zone1	zone2	zone3	zone4
With solar	0.50	0.63	0.04		0.50	0.69	0.82	0.04
Without solar	0.50	2.87	0.04		0.50	0.69	0.13	0.04

Table 5: Zonal PTDF on bottleneck

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