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AN ENHANCED SCREENING CURVES METHOD FOR CONSIDERING THERMAL CYCLING OPERATION COSTS IN GENERATION EXPANSION PLANNING

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Abstract

Generation capacity expansion trends have clearly evolved in the last decades. In the present context, renewable generation technologies are expected to reach large penetration levels. Among other effects, these technologies are changing the scheduling regime (and thus the unit-commitment costs) of the rest of the generating facilities, increasing for instance the need of cycling conventional thermal generation. In this paper we further develop the traditional screening curves technique so as to incorporate a sound representation of the cycling operation of thermal units. The so-resulting approach provides a more comprehensive representation of thermal operation while keeping the screening curves well-known capability to provide valuable analytic insights on the capacity expansion problem.

1 INTRODUCTION

Non-dispatchable, not fully predictable and intermittent energy resources (hereafter Variable Energy Resources, or simply VER) are expected to play an increasing role in capacity expansion planning. Among other effects, see Pérez-Arriaga and Batlle (2012), one that is attracting a growing attention in the literature is how VER can change the short-term scheduling regime of the conventional thermal plants, increasing the need of cycling them[1], see for example Denny (2007). These operation-related issues also impact on the capacity expansion problem because, for instance, flexibility will be valued along with low capital investment units to minimize the cost of cycled scheduling.

A number of noteworthy papers have discussed how VER can change the optimal capacity mix in the long term. For example, Lamont (2008) and Nicolosi and Fürsch (2009) include the consideration of VER in the standard screening curves approach (hereafter SSCC) to illustrate how increasing VER leads in the long-run to a lower share of base-load technologies and a lower average utilization of the generating capacities. Bushnell (2010) and Green & Vasilakos (2011) assess the long-term impact of the introduction of large amounts of wind on electricity prices and capacity expansion (in the US and Great Britain respectively), extracting similar conclusions on the basis of stylized equilibrium models.

However, there is still a significant lack of tools dealing with the implications of detailed short-term operation costs on the long-term capacity expansion problem, which may no longer be negligible when the amount of VER becomes significant. One attempt in this respect is the one developed by Traber and Kemfert (2011), where a simplified representation of start-up costs is included in a long-term analysis focused on evaluating the need for regulatory technology-oriented incentives.

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[1] The term "cycling" refers to the cyclical operating modes of thermal plants that occur in response to dispatch requirements: on/off operation, low-load cycling operations and load following.

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With the objective of filling this gap, we propose an augmented SSCC methodology built on a heuristic short-term optimization model. The short-term model provides a detailed representation of the economic scheduling and the resulting production costs, including those mainly driven by cycling operation. In this respect, we develop a particularly detailed representation of O&M costs, which as we show, are called to play an increasing role under heavy cycling regimes.

The so-resulting model named as LEEMA model (Low-Emissions Electricity Market Analysis), adds further detail to the SSCC, see e.g. Baldick et al. (2011), while keeping the well-known capability to provide valuable analytic insights on the capacity expansion problem at a very low computational cost[2].

The paper is structured as follows: section 2 describes the conventional SSCC method, so as to introduce some relevant ideas and terminology. Then, section 3 describes the LEEMA model, which is used in section 4 to solve a real-size case example with VER. Finally, section 5 gathers the conclusions.

2 THE CONVENTIONAL SCREENING CURVES

The SSCC method, originally proposed in Phillips et al. (1969), serves to compute the optimal mix of generating technologies. It aims at minimizing the total supply costs, relying on a simplified representation of both the generation cost structure (just investment fixed costs and variable energy costs) and dispatch scheduling criteria. In order to pave the way for the later description of the approach proposed, we next review this classic methodology as a sequence of two modeling steps:

- The computation of the generating units production profiles.
- The identification of the technologies capable of producing each of the profiles previously computed at a minimum cost.

2.1 GENERATING UNITS SCHEDULING (MERIT-ORDER-BASED DISPATCH)

When just variable energy costs and no operating constraints are considered, the optimal unit commitment of an already installed generation mix simply entails loading the thermal units according to the merit order established by their variable energy costs. In the figure below, we have represented the so-resulting production profile for a 1MW capacity thermal plant both over the chronological net load curve[3] (CNLC), and over the net load duration curve (NLDC). The CNLC is computed by subtracting on a chronological and hourly basis the value of wind generation from the load (and NLDC by sorting these CNLC values).

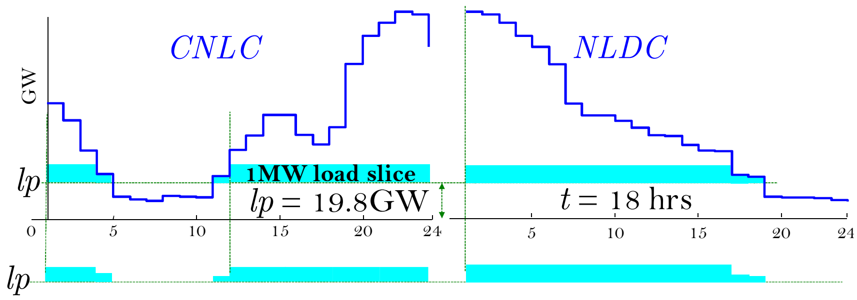

Fig. 1. 1MW production profiles.

[2] The algorithm developed copes with real-size problems (9 different technologies and 8760 hours) in a few seconds (6.3s with an Intel® Core™ i7-2600 Processor, 8M Cache), evaluating the optimal capacity expansion and the expected chronological hourly economic dispatch.

[3] Since costs' expressions are extremely simplified and no inter-temporal constraints are considered, no chronology of demand and production has to be taken into account, since it adds no relevant information. However, we will also explicitly represent the underlying dispatch over the CNLC, because we will later use this chronologic representation in the approach proposed.

In this scheme, there are two equivalent variables that can be used to identify each of the 1MW[4] production profiles. First, the loading point (lp), i.e. the demand level at which the plant is loaded. The plant that is loaded at lp will produce in the hourly periods in which the corresponding demand values go above the lp value. The other alternative is to identify each particular 1MW production profile by the associated number of hours of production (t). There is a one-to-one relationship between these two variables, since $lp = NLDC(t)$. As shown in Figure 1, by making reference to the production profile associated to the $lp = 19.8$ GW or implying 18 hours of production we are pointing exactly at the same production profile (the one represented in solid cyan).

2.2 COSTS LINKED TO PRODUCTION PROFILES: TRADITIONAL APPROACH

The total annual cost of supplying a certain 1MW profile, TC, with a 1MW generation unit of technology i is computed as the sum of the annualized capital costs, CC_i, the annual energy fuel production costs, EFC_i, and the annual operation and maintenance (O&M) costs, OMC_i.

$$TC_i = CC_i + EFC_i + OMC_i \tag{1}$$

The annual energy fuel production costs per installed MW are computed as the energy fuel cost, efc (in \$/MWh), times the number of hours it produces in a year, t. O&M is broken down in two components: annual fixed O&M costs, $FOMC_i$ (in \$/MW) and annual variable (energy-related) O&M cost, $eomc_i$ (in \$/MWh). If we rearrange these terms depending on whether they correspond to fixed costs, FC_i, or to variable energy-related costs, ec_i, we get:

$$TC_i(t) = FC_i + ec_i \cdot t; \quad \begin{cases} FC_i = CC_i + FOMC_i \\ ec_i = efc_i + eomc_i \end{cases} \tag{2}$$

2.3 COMPUTING THE OPTIMAL GENERATION MIX

Computing the optimal generation mix entails calculating which technology can provide at the lowest cost each of the 1MW slices making up the load curve. This is easily achieved by representing the cost functions of all the technologies as a function of t, see equation (2), and then selecting for each t (recall that each value makes reference to a 1MW load slice) the technology i supplying the corresponding profile at the lowest cost. We illustrate this in the case example next.

2.4 CASE EXAMPLE OF THE CONVENTIONAL SSCC APPROACH

The conventional SSCC is next applied for a real-size case example with VER. The objective is to further illustrate its use and also to create a reference benchmark later used to compare the results of the refined model developed in this paper.

The hourly demand and hourly wind production considered were the historical values in the Spanish system in 2010 (the installed capacity of wind amounted to 20 GW). The conventional thermal generation operation costs data can be found below in Table I in section 4.

[4] For the sake of clarity in the model description we use a 1MW production profile. However, both the conventional and the proposed methodology allows in a quite straight forward manner considering more real profiles (indeed the real-size case example is computed considering a unit's size of 400 MW).

2.4.1 Scheduling regimes calculation

Once the CNLC is obtained, we can get the scheduling regime for each load level (loading point) as described previously. Fig. 2 shows the basic simplified scheduling regime corresponding to one of these loading points (30 GW).

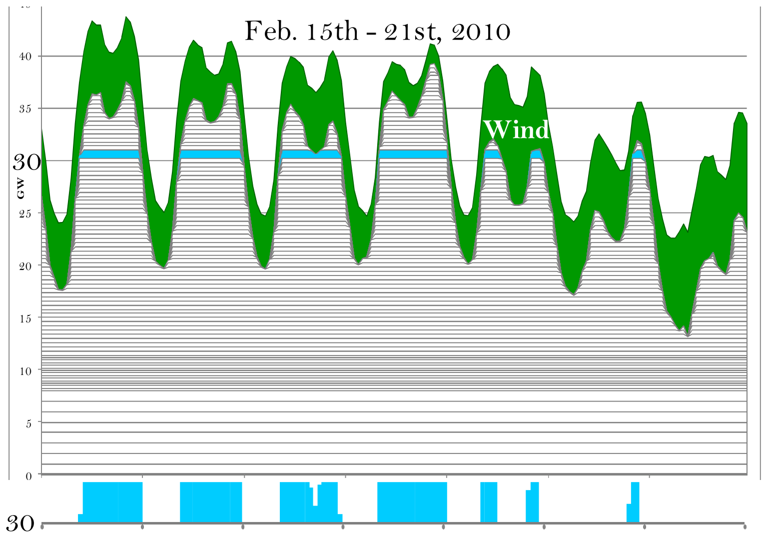

Fig. 2. Scheduling regime detail corresponding to the traditional SSCC

2.4.2 Optimal generation mix calculation

Fig. 3 shows the total production cost curve per installed MW for each technology as a function of the number of production hours (firing hours). The intersections of these curves determine the number of hours of production that separate the annual regimes where the different technologies are optimal. The least-cost technologies are thus determined by the lower envelope curve (the solid line). Installed capacities are determined by simple inspection in the NLDC.

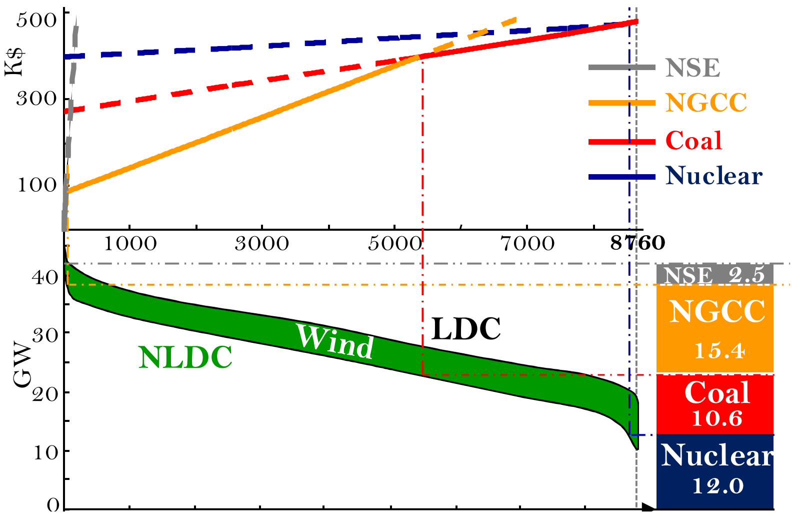

Fig. 3. Optimal generation mix resulting from the conventional SSCC

2.5 EQUIVALENT FORMULATION OF THE CONVENTIONAL SSCC

We next propose an alternative formulation that expresses the total production costs as a function of what has been previously defined as the loading point lp (MW), instead of t .

In the conventional model just reviewed, changing this variable translates into expressing the hours of production as a function of the loading point, $t(lp)$, i.e. the inverse of the load duration curve function. Thus, the cost function is:

$$TC_i(lp) = FC_i + ec_i \cdot t(lp) \tag{3}$$

The cost functions from the previous example using this new formulation lead to the curves represented in Fig. 4. We have chosen to invert the x-axis (now representing the loading points, expressed in GW) to maintain the resemblance with the conventional SSCC representation of the problem, where the x-values closer to the origin correspond to peak demand.

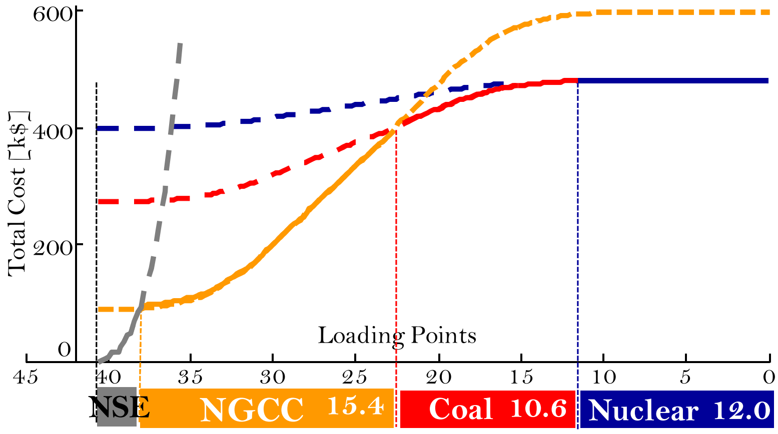

Fig. 4. Conventional SSCC method in the equivalent formulation.

As shown in the figure, for loading points close to the maximum load the curves are relatively flat, since at a sufficiently high value of loading point, the operating patterns and hence the total costs are very similar (plants run very few hours per year). At lower values of loading point, the slope increases in magnitude (reflecting how the operation conditions and the resulting costs are highly dependent on the loading position), but then falls again to zero as all loading points below a certain threshold load level (which is always lower or equal to the minimum load) imply the same pattern of continuous base-load operation.

Modeling total costs as a function of lp allows directly obtaining the amount of optimal capacity to be installed for each technology, since the intervals in the x-axis defining the lower envelope are directly expressed in terms of capacity. As shown next, this formulation proves to be better suited when complex dispatches are to be considered (and it is not possible to just characterize them by the number of firing hours).

3 THE LEEMA MODEL: A SOPHISTICATED SSCC APPROACH

The LEEMA model is structured in two modules:

- First, the scheduling module performs a heuristic optimization that calculates the detailed chronological hourly production profiles.
- Second, the economic operation and planning module derives the production cost functions that would result if each of the previous production profiles were to be supplied by each one of the conventional thermal technologies being considered[5]. Then, we derive the technology which is most cost-efficient at producing each profile, from both the capital and operating cost perspective.

[5] If the production profile turns out to be unfeasible for a certain technology, (for example, for involving exceeding the maximum number of annual starts) then the associated cost of supplying that production profile with that technology is set to infinite.

3.1 THERMAL SCHEDULING OPTIMIZATION MODULE

The first module carries out the heuristic optimization of the scheduling of the thermal plants. This scheduling is computed on the basis of a constant merit-order-based dispatch[6] where the scheduling of a thermal plant just depends on its position in the merit order (the loading point at which it is scheduled).

As it is well-known, one of the results provided by the unit commitment problem is that, given the cost involved in stopping and re-starting plants, one scheduling alternative is to keep the plant running at the minimum stable output so as to avoid incurring in the subsequent start-up costs. To take this fact into account, we define a heuristic optimization algorithm which considers three relevant parameters that determine the optimal scheduling in this respect:

- first, the ratio (μ) between the maximum capacity and the minimum stable load of the thermal units,
- second, the maximum number of consecutive hours a unit would be willing to be kept running at the minimum stable load (ml)to avoid a subsequent start (denoted as $\overline{t}_{ml}$),
- and third, the amount of inflexible generation capacity (mainly nuclear) producing (I_g).

Thus, we go beyond the traditional formulation of the SSCC and divide the generation technology types into flexible and inflexible. For the flexible ones, since the dispatch is technology independent, we have to assume some general values for the parameters that serve to approximately represent all potential generating technologies: μ is considered to be 40% (i.e. the minimum load limit for a 400 MW plant would be 160 MW). Regarding the other two parameters, in the case example we consider that $\overline{t}_{ml}$ equals 10 hours (the value usually ranges from 8 to 12 hours). Regarding the amount of inflexible capacity installed we have considered two scenarios: 8 and 12 GW respectively. The consideration of these two scenarios will allow us illustrating the relevant impact that increasing the amount of inflexible capacity may have in a context with large penetration of wind.

3.1.1 Heuristic optimization of start-up decisions

At each loading point lp, the heuristic optimization of the production profile is carried out in three consecutive steps:

<u>Step 1</u>: we compute a preliminary scheduling of the unit at lp. This dispatch (see the upper chart in Fig. 5) corresponds to the one implicitly considered by the conventional SSCC methodology. In the period shown, four starts and four off-line periods preceding each start can be identified. $t_{off}(lp,n)$ is the vector storing in each position the number of hours the unit is off-line prior to each of the starts, denoted with index n.

<u>Step 2</u>: we evaluate if the duration of each off-line period preceding a start exceeds the $\overline{t}_{ml}$ threshold. Those exceeding the threshold are discarded and not further analyzed.

<u>Step 3</u>: we check in each case if there is enough flexibility available so as to allow avoiding each start by producing at the minimum load regime during valley hours. This flexibility is the production output that plants scheduled at lower loading points could reduce if needed, to allow the plant analyzed avoiding the start. Let us recall that since the minimum output of a 1 MW capacity plant is μ, its

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[6] Thermal units produce following a fixed merit order which does not change with operating conditions (generators are assumed to never be out of order for maintenance). A unit can only produce if all units which are earlier in the merit order are also producing (at least at their minimum stable load)

capability to reduce load is $(1-\mu)$. The installed capacity of flexible generation below loading point lp amounts for $(lp-I_g)$. Then, the available flexibility at a certain loading point, denoted as $\phi(lp)$, can be directly estimated as:

$$\phi(lp)=(1-\mu)\cdot(lp-I_g) \tag{4}$$

$lp-\phi(lp)$ corresponds to the minimum level of production that units scheduled below loading point lp can provide. Therefore, only if this value is lower than the demand in the period analyzed, there will be enough system flexibility.

Let us check these two conditions in the example in Fig. 5:

<u>Step 2:</u> considering that $\bar{t}_{ml}=12$ hours, starts 1, 2 and 4 do fulfill the economic criterion, while on the contrary it would be not worth avoiding start 3 (since it would imply producing 34 hours at the minimum load regime).

<u>Step 3:</u> let us assume that the flexibility of the groups producing below lp is $\phi(lp)$. Then, the production of these groups cannot be reduced below $lp-\phi(lp)$ (see the red line in the upper chart of Fig. 5). This reduction is not enough to avoid starts 1 and 3, since the load values in this valley hours are below this threshold. On the contrary this flexibility allows avoiding starts 2 and 4.

Thus, only starts 2 and 4 are finally avoided, leading to the dispatch represented in the lower chart in Fig. 5.

3.1.2 Results provided by the thermal scheduling module

The thermal scheduling module provides the production profile of generation for each loading point. Fig. 6 illustrates these profiles for a certain week of the simulation scope considered. As highlighted in the red box, we can see how there are a large number of units producing during valley hours as a consequence of the heuristic optimization dispatch. Contrary to the conventional SSCC, the new 1 MW load slices associated to the loading points are no longer rectangular, but rather detailed profiles (lower chart in Fig. 6).

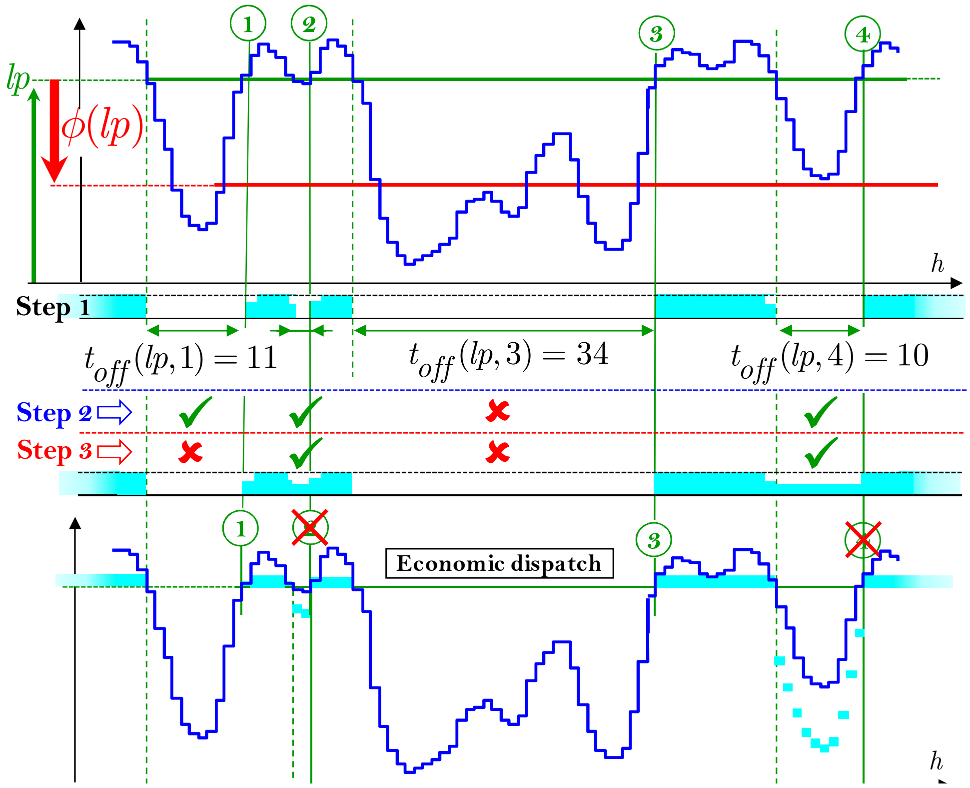

Fig. 5. Economic dispatch calculation considering system flexibility.

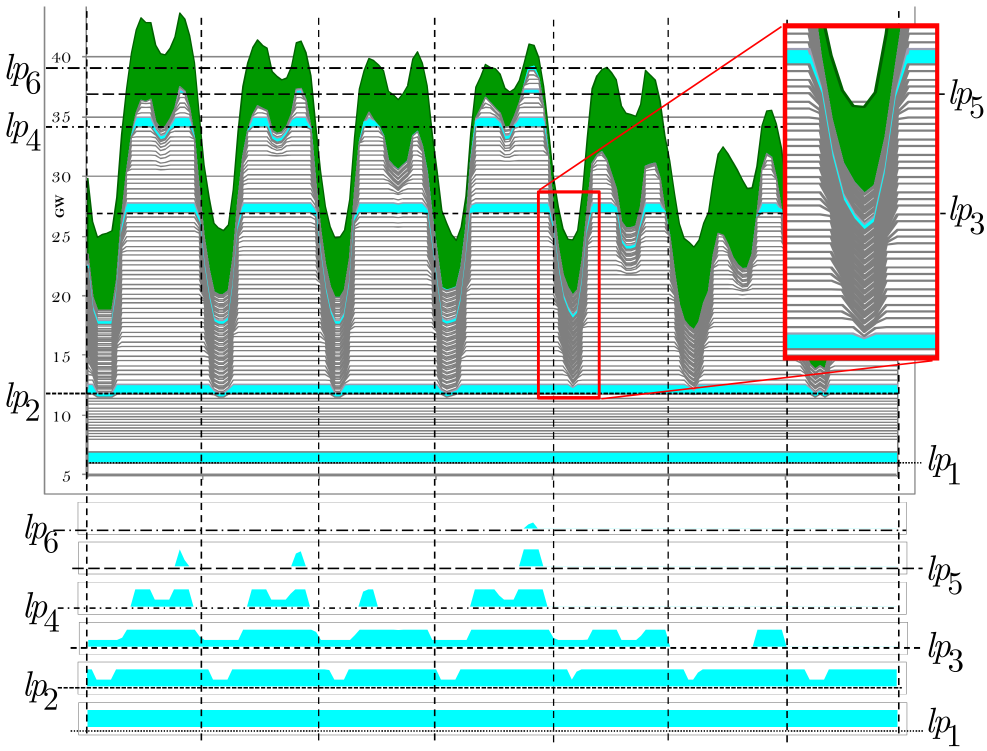

Fig. 6. Production profiles per loading point.

As shown in Fig. 7, these production profiles implicitly include relevant pieces of information regarding the dispatch that are later needed in the technology optimization module. Apart from the already introduced t_{off}, we define:

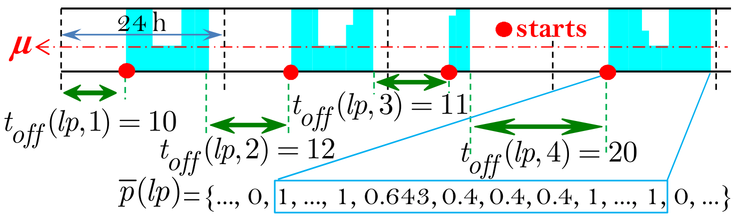

Fig. 7. Variables defining a production profile.

Apart from the already introduced t_{off}, we define:

- $\overline{p}(lp)$, is the annual production profile vector that corresponds to the unit scheduled at lp, i.e. a yearly vector storing the production in each hourly period, i.e. $\overline{p}(lp)=\{p(lp,h_1),\ldots,p(lp,H)\}$, where $p(lp,h)$ stands for the production that corresponds to the loading point lp in hour h (hours are considered in chronologic order).
- $S(lp)$, is the total number of annual starts.
- $F(lp)$, is the total number of annual firing hours

Once the thermal scheduling module has estimated the production profiles of the units as a sole function of the loading point, the next step is to determine the technologies that would supply such profiles at the lowest cost.

3.2 TECHNOLOGY OPTIMIZATION MODULE

The following sources of costs are considered: capital costs, energy fuel production costs, fuel start-up cost and operation and maintenance costs (both fixed and variable). For 1 MW installed of one particular technology i operating at loading point lp, $TC_i(lp)$ takes now the form:

$$TC_i(lp)=CC_i+EFC_i(lp)+SFC_i(lp)+OMC_i(lp) \quad (5)$$

Where we have now introduced with respect to (1) $SFC_i(lp)$, as the total annual fuel start-up cost.

3.2.1 Energy Fuel Cost

The total annual variable operating fuel cost is:

$$EFC_i(\overline{p}(lp))=\sum_{h=1}^{H} efc_i(p(lp,h))\cdot p(lp,h) \quad (6)$$

Where the average energy production fuel cost efc_i in each hour (in \$/MWh) is a function of the output level, see Fig. 8.

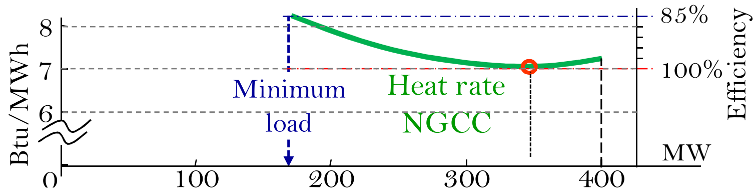

Fig. 8. Unit heat rate as a function of the output level (400MW NGCC), (Wood and Wollenberg, 1996).

3.2.2 Start-up fuel cost

The fuel cost of each start is a function of the number of hours the unit has been off before starting. Usually three different types of starts are considered: hot start, when the unit has been less than 10 hours out of operation, warm start, for more than ten but less than 50 hours and cold start, for more than 50 hours. Typical values for the start fuel costs for the technologies considered can be found in section 4.1.

3.2.3 O&M costs

O&M costs are usually divided into fixed and variable cost components. Fixed O&M costs include minor periodic wages, maintenances, property taxes, facility fees, insurances and overheads, while variable O&M usually include inspections that are triggered after certain accumulated operation conditions are met (e.g. number of operating hours with a baseline fuel type and firing temperature, number of starts or trips, etc.). We next focus on this variable O&M component.

Most of these previous inspection procedures are reflected in the so-called Long-Term Service Agreements (LTSA), see Sundheim (2001). For example, in the case of gas turbines, the most relevant milestone embedded in the LTSA is the hot-gas-path inspection (aka major overhaul) for it represents the major driver behind the LTSA cost.

The methodology to determine the maintenance intervals of this major overhaul is based on the definition of a Maintenance Interval Function (MIF) relating the maximum number of starts and firing hours before a maintenance is triggered. The shape of the function varies between manufacturers, see Power Planning Associates (2002) and Balevic et al. (2010). In Fig. 9, we represent three of the most well-known type MIFs for gas turbines.

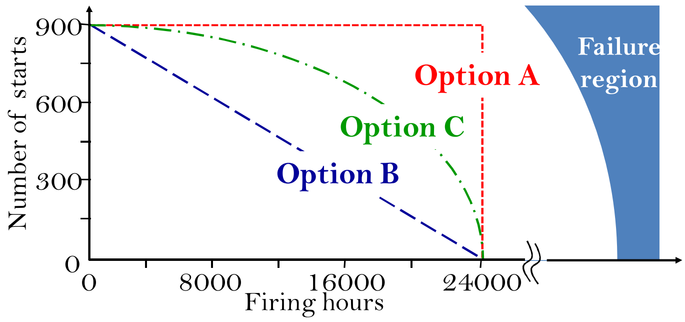

Fig. 9. Baseline functions for maintenance interval.

The annual variable O&M cost

The annual variable O&M cost of the unit producing at a certain lp, is directly computed from the MIF and also from the number of annual firing hours (F) and starts (S) the scheduling module has determined for such production profile.

Let the cycling ratio $\rho(lp)$ be the quotient between the number of firing hours and starts. This ratio directly affects the wear and tear of the plant; the lower this ratio, the larger the effect of O&M costs in average production costs.

We can compute the threshold conditions triggering the major maintenance, S^* and F^*, by simply finding the point of the MIF that exactly fulfills this same $\rho(lp)$ [7].

[7] This entails assuming that this ratio remains constant throughout the whole period preceding the major overhaul.

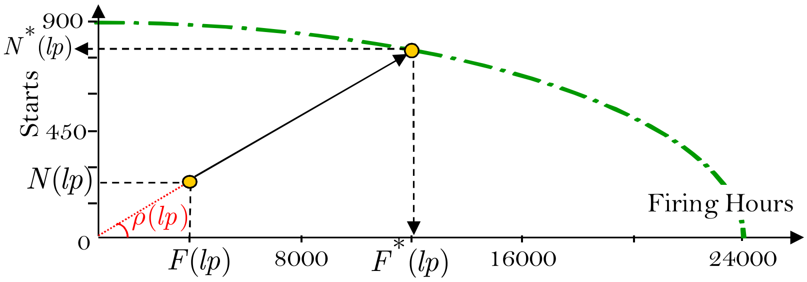

Fig. 10. Unit threshold conditions triggering the major maintenance.

The fraction of the major overhaul cost to be imputed in one year is the quotient between F and F^*. The annual variable O&M cost is thus the product of this quotient and the cost of a major overhaul inspection MOC:

$$VOMC(lp) = (F(lp) \,/\, F^*(lp)) \cdot MOC \tag{7}$$

4 REAL CASE EXAMPLE WITH LARGE VER PENETRATION

Next, we analyze with the LEEMA model the real-size case example introduced back in section II.D. The objective is to illustrate the impact that representing short-term cycling operation costs may have on long-term expansion analyses.

4.1 CASE EXAMPLE DATA ASSUMPTIONS

We considered four generating technologies: nuclear, coal (single advanced unit PC), natural gas combined cycle (CCGT) and onshore wind. A fifth "technology" is used so as to represent the non-served energy (NSE) value. This virtual technology has zero investment capital costs and a variable cost of 1000 $/MWh. Table I contains the data used.

TABLE I
THERMAL GENERATING TECHNOLOGIES COST STRUCTURES

	Nuclear	Coal	CCGT	Wind
Capital* [k$/MW-yr]	5335	3167	978	2438
FOM* [k$/MW-yr]	88.8	37.0	14.4	28.1
VOM* [$/MWh]	2.0	4.3	3.4	0
Variable [$/MWh]	6.6	23.6	55.1	-
Cold Start** [$/MW]	1000	150	75	-
Hot Start** [$/MW]	1000	75	30	-
HRE Loss [%]	-	12	12	-

* Data taken from the Energy Information Administration (2010). ** These data have been calculated as a reasonable average of the different estimations provided by a number of representatives of utilities and manufacturers consulted and they are in line with the ones that can be found in the literature, as for instance in Troy et al. (2010).

FOM stands for Fixed O&M, VOM for Variable O&M, HREL for the relative Heat Rate Efficiency Loss that takes place when the unit produces at the minimum stable load. The MOC [$/MW] is the VOM [$/MWh] times the maintenance interval period implicitly assumed in Energy Information Administration (2010) (24000 hours).

To calculate the annualized capital costs, different economic life values and required rates of return were considered: 40 years for the three thermal technologies and 20 years for wind. The rates of return were assumed to be 7% for coal and CCGT, and 5% for wind and nuclear[8].

CCGTs are subject to a maintenance contract having the characteristics of those we have denoted as Option A. According to the references consulted, the cost of a major maintenance ranges from 20 million to 60 million dollars, see for instance Power Planning Associates (2002) or Wembridge et al. (2009). The major maintenance cost for a 540 MWs CCGT is considered to be 40 million US$. The maximum amount of starts and firing hours defined in the baseline function depend on the type of turbine and manufacturer. They can range from 8,000 to 24,000 hours and 400 to 900 starts for hot-gas-path inspections (Balevic et al., 2010). We assumed 600 starts and 24000 firing hours.

Coal plants category involves an immense variety of different plant designs. This makes much more complicated to opt for a comprehensive representation of O&M contracts. After discussing this issue with different representatives of the industry, we opted for assuming an Option A contract (24000 hours and 75 starts). We also assumed that coal plants cannot start more than 75 times a year; neither exceeds the threshold of one daily start. Nuclear is assumed to produce at base-load, so it does not start. The consequence is that the production profiles exceeding these threshold conditions will be assumed to be not feasible regimes for these technologies.

We consider two scenarios of nuclear inflexible[9] installed capacity (8000 and 12000). We first analyze in further detail the first case (8000 MW), and then show the results obtained when increasing installed nuclear capacity up to 12000 MW.

4.2 RESULTING PRODUCTION PROFILES (8000 MW NUCLEAR)

The model computes the detailed production profile associated to the units being loaded at each of the loading points lp. In Fig. 11 we represent the two major variables summarizing and characterizing each of these production profiles: the number of starts and the number of firing hours (we have also represented hours at full-load and hours at minimum-load production regime)[10].

Usually, the higher the loading point, the lower the cycling ratio associated to the corresponding production profile. Since the lower this ratio the larger the effect of O&M costs (in average production costs), these units at the peak are consequently the ones subject to larger O&M costs. Let us emphasize that larger number of starts does not necessarily imply larger O&M costs (again, speaking in terms of average production costs). For instance, as shown in Fig. 11, for the unit loaded at loading point 37 GW (peak unit) the number of starts is 25, and the number of firing hours is 108, thus resulting in a cycling ratio of 4.32. The unit loaded at 30 GW (mid-range unit), which starts almost 160 times (indeed it is the unit starting the largest number of times), presents a much higher cycling ratio (18), so it has lower O&M costs.

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[8] We considered a lower value for the case of wind, since until now, it is an income-regulated generation technology, significantly less exposed to market price risk. In the case of nuclear, since considering a rate of return of 7% would turn it into a not competitive technology, we have opted for considering a lower rate of return. We assume that the regulator will decide to implement a way to financially subsidize investments in nuclear generation technology, as for instance offering a long-term hedge only for this technology, in a similar way RES-E technologies are supported, see e.g. Department of Energy & Climate Change (2011).

[9] According to EURELECTRIC (2010), properly designed or refurbished nuclear plants may perform in a rather flexible mode, but in most power systems (with e.g. the exceptions of France and Germany) nuclear plants are operated in a pure base-load mode, mainly based on security rather than economic reasons.

[10] Let us recall that the x-axis (loading points) has been reversed so as to keep resemblance with the traditional screening curves methodology when later representing production costs. Thus, it has to be born in mind that the x-values which are close to the origin correspond to peak (net) demand values.

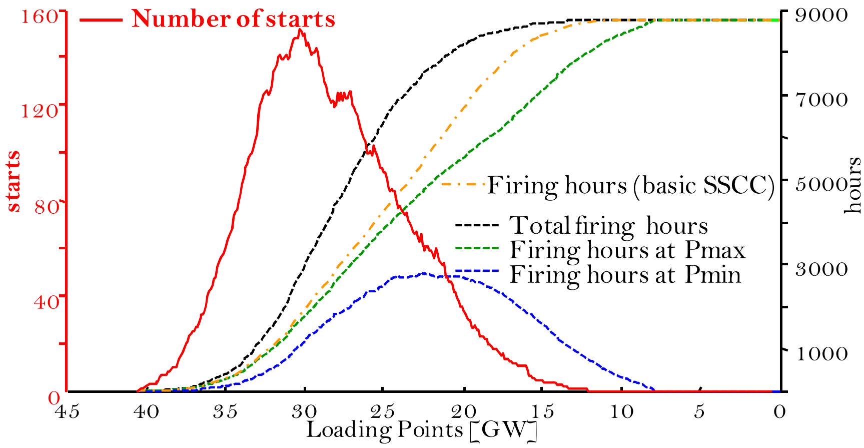

Fig. 11. Number of starts and firing hours per loading point.

The previous chart shows how the basic SSCC method underestimates the total number of firing hours thermal units produce, while also overestimates the production that units carry out at the plant's maximum output (because all firing hours are assumed to be at full load in the basic SSCC).

Additionally, the basic SSCC assumes a full base load regime for all units being loaded below the minimum net demand value (9750 MW in the case example). Conversely, the proposed approach considers that below that level some units, although keeping a continuous production regime, produce sometimes at minimum load so as to leave room for the minimum stable load production of units situated at higher loading points.

4.3 OPERATING COSTS COMPONENTS FOR A CCGT UNIT

To illustrate the differences between the costs computed with the conventional and the proposed approach, we break down and represent the cost components for one particular technology (CCGT). Later, we analyze and show the new resulting SSCC including all technologies.

<u>Fuel start costs:</u> Fig. 12 shows in solid red the fuel start cost versus loading point. This cost has traditionally been considered as negligible in most long-term studies[11].

<u>Variable O&M costs:</u> Fig. 12 also includes the resulting annualized cost for the variable O&M component. When compared with the start fuel costs, it is evident that these O&M costs have a considerably higher relevance.

The O&M costs estimated with LEEMA can also be compared with those implicitly stemming from the application of the conventional methodology (the per-MWh O&M cost multiplied by the load factor). The differences at certain loading points can be quite large (e.g. at loading point 25 GW, the traditional approach estimates 13 k$/MW, instead of 31 k$/MW). These differences are the consequence of taking into account how the number of starts impacts into the annual variable O&M costs. Under the light of this result, we can conclude that ignoring the effect of starts may not be an accurate approach in a context with large penetration of VER.

[11] This was justified by two arguments, first, the cost of a start is low when compared with other long-term costs, and second, the number of starts has traditionally been relatively small (and particularly in systems with a certain amount of hydro resources).

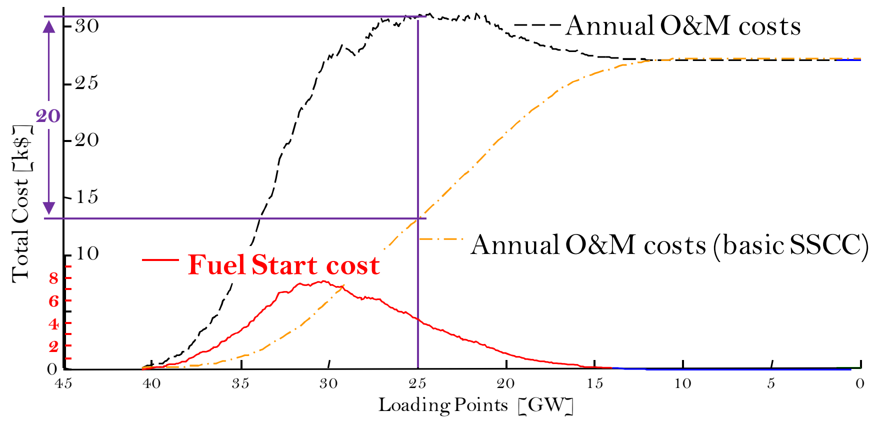

Fig. 12. Fuel start costs and Variable O&M costs per installed MW.

Variable energy production costs: The fact that some units produce at minimum load output to avoid some starts, when compared with the conventional methodology, leads to higher production and thus higher production cost at loading points close to peak demand. This difference may be significant: e.g. at loading point 25 GW, it is around 50 k$/MW (around a 20% increase). The opposite occurs at lower loading points, where the production is lower in the proposed methodology. We also represent the previous O&M costs in the figure above, as well as the differences with the conventional methodology, so as to show its relative weight in terms of total costs.

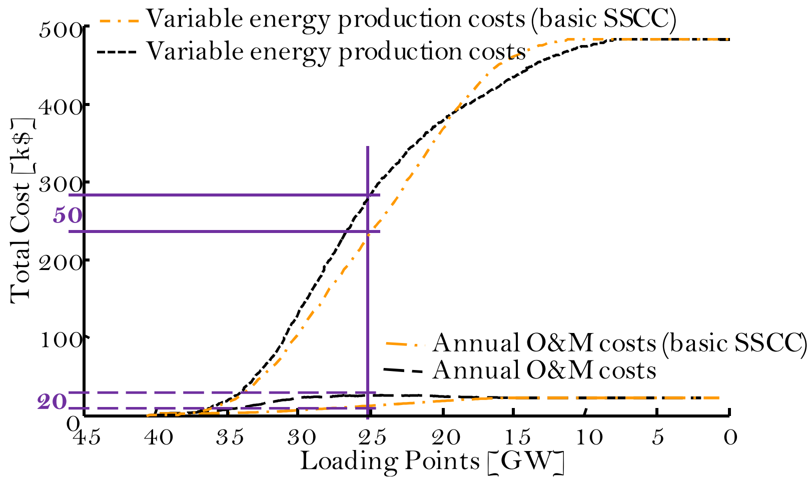

Fig. 13. Energy fuel cost curves per installed MW.

4.4 OPTIMAL GENERATION MIX

The new SSCC are obtained by just adding the different costs components. Fig. 14 reflects the addition of these curves for all the technologies considered. It also shows the results obtained with the conventional methodology. In the resulting mix obtained with the conventional methodology, nuclear has been fixed to 8000MW to allow for the comparison.

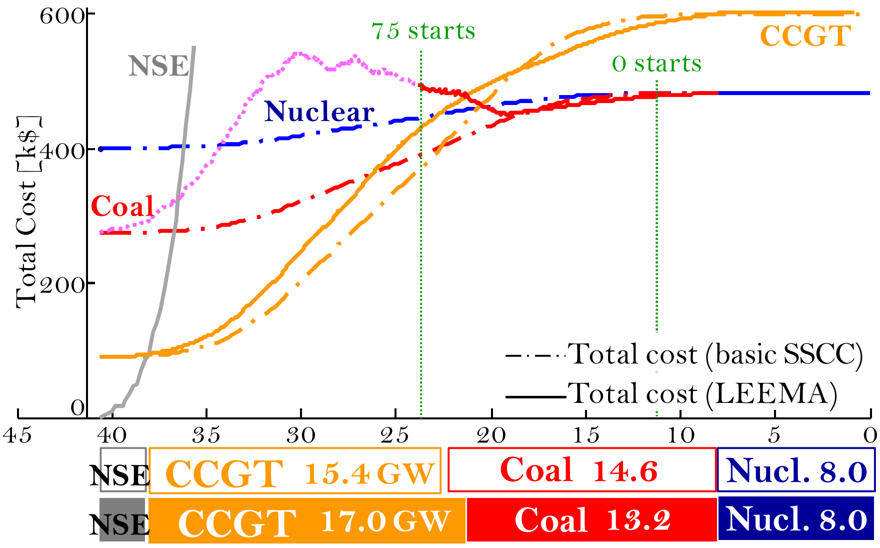

Fig. 14. Total cost by technology and loading point computed (8000 MW).

The coal cost curve has been depicted with a dotted line for certain loading points. The reason is that the operation regime exceeds the previously described limits.

Due to the different amount of firing hours considered and the impact of considering starts, LEEMA provides higher costs than the basic SSCC at the heavier cycling regimes associated to high loading points (while the opposite occurs at low loading points). These effects favor the installation of the more flexible technologies, in this case CCGT, to the detriment of those less flexible, in this case coal. The installed capacities resulting both from the traditional SSCC and LEEMA are shown in the figure.

4.5 THE IMPACT OF THE LACK OF FLEXIBILITY IN A CONTEXT WITH VER

With the objective of illustrating how less flexible units are less economical when nuclear (assumed to be fully inflexible) is increased in a context with larger VER penetration, we have run the model for the case of installing 12000 MW of nuclear (in the conventional methodology, nuclear has also been fixed to the same value, which is indeed the value we obtained back in section 2.4.2).

Both CCGT and coal costs increase, with a larger increment for the latter than the former. This leads to a further reduction of the coal installed capacity with respect to CCGT.

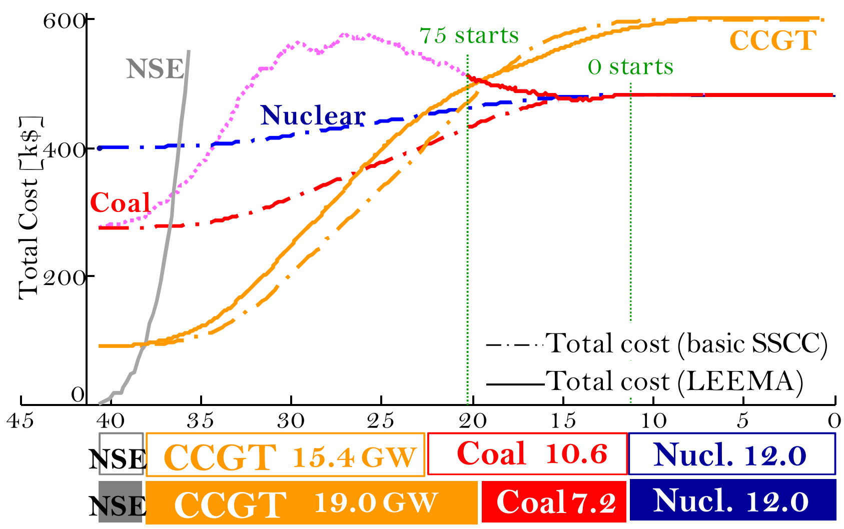

Fig. 15. Total cost by technology and loading point computed (12000 MW).

4.6 PRODUCTION PROFILES OF THE RESULTING MIXES

To illustrate the scheduling results of the model once the mix is determined, Fig. 16 shows the dispatches for both scenarios (8000 MW and 12000 MW of nuclear), for the same two particular days contained within the simulation. The blue box highlights the situation in the valley hours in both scenarios: as a consequence of the different system's available flexibility, a larger number of units are able to avoid the next day start when installed nuclear capacity is 8000 MW.

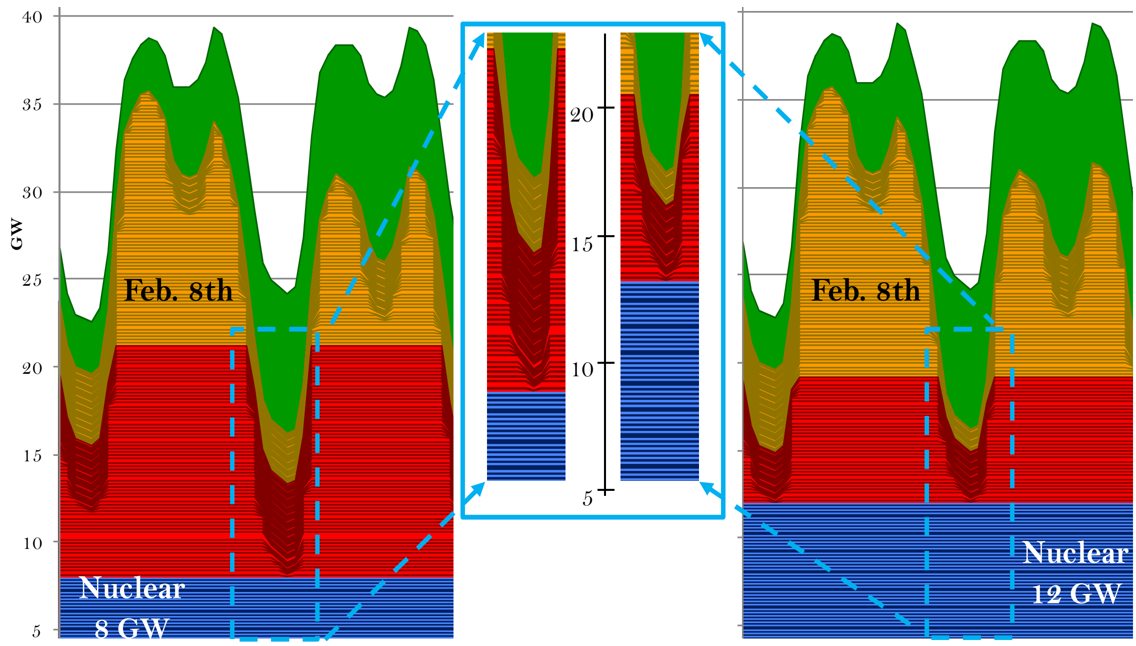

Fig. 16. Hourly scheduling of the units.

5 CONCLUSION

We augment the screening curves method to include further detail on both the economic scheduling regime and the associated production costs. We represent four major sources of costs: investment capital costs, energy fuel cost, start fuel cost and a detailed representation of O&M cost. We analyze the not-so-well-known impact of the number of starts on these O&M costs, arguing that these cycling costs should no longer be ignored when facing long-term expansion analysis involving a large penetration of VER.

The main differences when compared with the conventional screening curves analysis have been shown by means of a real-size case example. We show how the computed operation costs and the resulting mix can be significantly different.

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