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EleMod: A model for capacity expansion planning, hourly operation and economic dispatch in electric power systems with intermittent renewable generation

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EleMod: A model for capacity expansion planning, hourly operation and economic dispatch in electric power systems with intermittent renewable generation

Karen D. Tapia-Ahumada[1]

Abstract: This paper presents EleMod, an annual recursive-dynamic regional electric power capacity expansion and hourly operation model, which has been formulated to assess the evolution over time of the energy mix of a power system, in terms of capacity and generation, with increasing penetration of intermittent generation such as wind or solar photovoltaic. The model includes interregional transmission. It also includes low carbon technologies such as utility-scale storage, carbon capture and sequestration for fossil-based plants, and nuclear technologies. By ether minimizing the total cost of producing electricity or maximizing the total system welfare, the model is designed to calculate marginal prices for the wholesale supply of energy in the short-term, and also the prices for the provision of guaranteeing of supply and operating reserves. The EleMod model considers the hourly variability of intermittent resources (wind and solar) and hydro resources, and also an hourly variability of regional electricity demand as well. This simulation tool can be used to understand the long-term adaptation of a power system to the penetration of intermittent generation and to the evolving climate and energy policies in the U.S. It also can be used to assess the short-term operational decisions of the system in response to the long-term planning. The model can also serve to estimate CO_2 prices and regional hourly marginal prices, and more general generation and emissions pathways under various costs and policy scenarios.

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1. Introduction

There are a wide range of electricity sector models with different levels of detail, covering timeframes that range from milliseconds to years or decades. Capacity planning considers investment in power plants with lifetimes of 20 to 30 years or more, and therefore focuses on years to decades. On the other end are concerns about stability of the grid, and network flows at minutes, seconds, and milliseconds (Schweppe and Mitter, 1972; Graves, 1995; Palmintier, 2013; Gómez-Expósito *et al,* 2018) (**Figure 1**).

The EleMod model has been designed specifically to determine the most cost-effective electric generation expansion and operation subject to technical and policy constraints. It does not address load flow and stability issues of the system that arise at time intervals of less than one hour. However, among the technical constraints, there are short- and long- term reserve requirements and minimum loading limits to recognize the need to manage the system at sub-hourly levels. These are exogenously specified and not optimized for specific stability and load flow issues that may arise from integrating renewables[1].

EleMod is a regional capacity expansion and economic dispatch simulation tool that either maximizes total welfare or minimizes the total energy costs of producing electricity[2]. It is solved as either a Linear Program (LP) problem in the case of cost minimization, or a Quadratic Program (QP) in the case of welfare maximization. The model is deterministic with a recursive-dynamic structure, and it was originally inspired by the MARGEN model, a large-scale generation expansion power system model that has been extensively used to analyze the Spanish power system, in

1 MIT electricity modeling tools include GenX. Similar to EleMod, the model GenX is a capacity expansion planning and hourly dispatch modeling tool (Jenkins and Sepulveda, 2017). It is also deterministic and optimizes generation and storage expansion decisions and dispatch of energy resources on an hourly basis to meet electricity demand in a year, at the lowest cost possible. Unlike EleMod, GenX includes additional power system decisions layers such as transmission network expansion; distribution power flows, losses, and network reinforcement decisions; and interactions between electricity and heat markets. The model also includes demand-side resources and endogenous hydro reservoir plants, technology options that EleMod does not have currently. GenX allows choosing between modeling generation resources at an individual plant level or aggregate similar plants into clusters which reduces considerably the solution time (Palmintier and Webster, 2011; Sepulveda, *et al.*, 2018). Finally, GenX works with one future target year and it produces a snapshot of the optimal mix for the chosen target year, whereas EleMod has a recursive-dynamic structure with optimal solutions computed sequentially for every two-year period.

2 In the case the model is a Quadratic Program (QP) problem, the formulation maximizes the total social welfare, i.e., the difference of consumers' benefit and overall costs of producing electricity by power suppliers, subject to system operational, security and policy constraints This formulation is critical for the evaluation of demand response in the long-term and hence for the integration of EleMod with an economy-wide model.

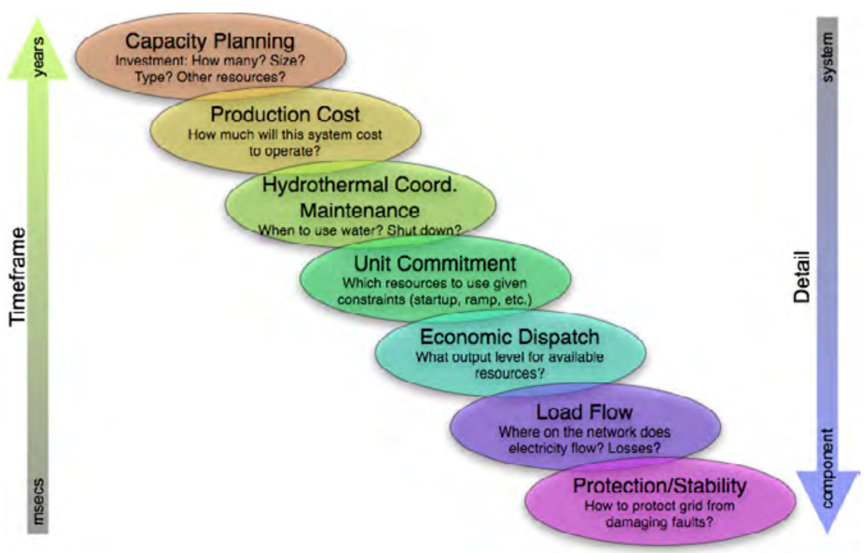

Figure 1. Hierarchical decision-making process in power systems (Palmintier, 2013).

particular, to understand generation cost recovery according to simulations of marginal wholesale electricity prices (Pérez-Arriaga and Meseguer, 1997; Meseguer *et al.*, 1995, Pérez-Arriaga, 1994).

Optimal solutions are computed sequentially for every two-year period, adding new capacity as needed to meet growing demand, replace retired units, or meet new policy constraints. It includes three-time ranges in the decision-making process: capacity expansion, operation planning and operation dispatch. Although the recursive-dynamic structure of EleMod makes it myopic about the future, the model considers past decisions as starting conditions to move in time, with a sequence of optimal solutions computed in every intra-period (two years in this case). EleMod includes a pre-defined number of thermal technologies and also different classes of wind and solar generation. Several constraints are incorporated to have a better representation of the dispatch and also the provision of reserves for adequacy and for short-term reserves. The model includes hourly chronological details for regional load demands and regional wind, solar, hydroelectricity profiles estimates. EleMod represents the U.S. by twelve geographic regions (**Figure 2**), namely Alaska (AK), California (CA), Florida (FL), New York (NY), Texas (TX), New England (NENGL), South East (SEAST), Lakes-Mid Atlantic (LMATL), South Central (SCENT), North Central (NCENT), Mountain (MOUNT), and Pacific (PACIF).

Generation options include twelve conventional technologies, on-shore wind, utility scale PVs, and hydro. It also includes a generic storage technology, which can be configured to be pumped hydro, and existing regional transmission interties are approximated based on their aggregated power capacities. For thermal generators, the model decides the investment in new annual capacity, daily connected power for operating reserves and hourly economic-dispatch. Fossil-fueled technologies are represented by several attributes such as economic lifetime, overnight capital costs and fixed operating and maintenance (O&M) costs, non-fuel variable O&M costs, start-up costs, and projection of fuel prices. Other characteristics include availability factors, forced outage rates, thermal efficiencies and minimum load requirements. For wind and solar, annual installed capacity and hourly production are the decision variables included in the formulation. Both resources can be curtailed depending on technical constraints and system's oversupply conditions, or the existence of priority dispatch rules. See Appendix for details about technology costs and operational parameters.

Renewable technologies are characterized by their economic attributes such as annualized capital cost, lifetime and also operational features like hourly-normalized generation profiles, average capacity credits, and regional resource availability per class (in the case of wind, this information is normally based on power density and speed, as well as, available regional land area and terrain conditions for instance ridge-crest versus flat-land). Although the model currently does not endogenously optimize existing hydro power dispatch, based on current hydroelectricity operations, we developed the ability to distribute monthly reservoir release over the course of an average day or across months to account for the possibility of flexing it to better match intermittent renewable supply and daily and seasonal peaking needs.

Figure 2. EleMod geographic regions

Finally, all the decision variables in EleMod are non-negative and continuous. Similar to the approach adopted in MARGEN, some variables - normally assumed discrete such as installed capacity, startup and shut down decisions - are being relaxed in order to keep the linear structure of the formulation. The stand-alone version of EleMod, as presented in this document, is used for analyzing the electric power sector in response to technology, economic and regulatory changes. However, for a consistent economy-wide assessment of energy and carbon policies that considers all sectors of the economy, the model has been integrated into a top-down bottom-up modeling framework that combines a multi-region multi-sector dynamic general equilibrium model of the U.S. economy with the electricity sector. For the integrated approach we used the MIT US Regional Energy Policy (USREP) (Rausch *et al.*, 2010, 2011; Rausch and Mowers, 2014; Rausch and Reilly, 2015; Yuan *et al.*, 2017, 2019a) and a comprehensive description along with case studies of the USREP-EleMod model can be found in Yuan *et al.* (2019b, 2020, 2021).

2. Model formulation

2.1 Objective function

EleMod, when formulated as a LP, minimizes the total annual costs of producing electricity in a region, considering annualized investment costs for conventional and wind technologies, fuel operational costs, start-up costs and additional costs related to connected power of conventional technologies power to maintain pre-determined levels of operating reserves into the system. In addition, the cost of non-served energy is included as a reliability criterion and an economic measure of the cost of electricity interruptions in the system. A carbon tax is built-in in the case of scenarios looking into the implementation of CO_2 prices into the electricity sector. The objective function is show in Eq.1.

$$\min TC = \sum_{r} TC_r \quad (1)$$

Where:

- TC: total power system costs - [$]
- TC_r: total power system costs per region r, $\forall r \in RE$ - [$]
- RE: number of regions
- T: number of years of the simulation's horizon
- N: number of thermal technologies
- C: number of wind classes
- H: number of hours
- D: number of days

Total power system costs TC_r are defined as the sum of investment costs, operational costs, connected thermal power costs, non-served energy costs, start-up thermal costs, and investment and operational costs of storage and hydro (Eq.2).

$$TC_r = I_r + O_r + CP_r + NSE_r + SUP_r + PHS_r + HYD_r \quad (2)$$

a. Investment costs

Total investments costs *Ir* is the sum of the annualized capital and fixed costs per type of generation resource and inside region *r* (Eq.3).

$$I_r = \sum_{t,n} vk_{t,n} * pcf_n + \sum_{t,c} vkw_{t,c} * pcfw + \sum_{t} vks_t * pcfs \quad (3)$$

Where,

- $vk_{t,n}$: (variable) new installed capacity per year t and thermal technology n, $\forall t \in T, \forall n \in N$ - [GW]
- pcf_n: (parameter) annualized investment per thermal technology n, $\forall n \in N$ - [$/GW.year]
- $vkw_{t,c}$: (variable) new installed capacity per year t and wind class c, $\forall t \in T, \forall c \in C$ - [GW]
- $pcfw$: (parameter) annualized investment of wind - [$/GW.year]
- vks_t: (variable) new solar installed capacity per year t, $\forall t \in T$ - [GW]

pcfs: (parameter) annualized investment of solar - [$/GW.year]

b. Operational costs

Total operational costs of thermal technologies O_r are defined by Eq.4.

$$O_r = \sum_{t,h,n} vg_{t,h,n} * (pfp_{t,n} * phr_n + pcvom_n) \quad (4)$$

Where,

$vg_{t,h,n}$: (variable) generated energy per year t, hour h and thermal technology n, $\forall t \in T, \forall h \in H, \forall n \in N$ - [GWh]

$pfp_{t,n}$: (parameter) fuel price used per thermal technology n and in year t, $\forall n \in N, \forall t \in T$ - [$/MMBtu]

phr_n: (parameter) heat rate per thermal technology n, $\forall n \in N$ - [MMBtu/GWh]

$pcvom_n$: (parameter) cost associated with non-fuel variable O&M per thermal technology n, $\forall n \in N$ - [$/GWh]

c. Connected thermal power cost parcel

Operational costs associated to daily connected power by thermal technologies CP_r is valued based on the non-fuel variable O&M cost according to Eq.5.

$$CP_r = \sum_{t,d,n} (vcp_{t,d,n} - vg_{t,d,h,n}) * pcvom_n \quad (5)$$

Where,

$vcp_{t,d,n}$: (variable) power connected per year t, day d and thermal technology n, $\forall t \in T, \forall d \in D, \forall n \in N$ - [GW]

$vg_{t,d,h,n}$: (variable) generated energy per year t, day d, hour h and thermal technology n, $\forall t \in T, d \in D, \forall h \in d \cap h \in H, \forall n \in N$ - [GWh]

$pcvom_n$: parameter cost associated with non-fuel variable O&M per thermal technology n, $\forall n \in N$ - [$/GWh]

d. Non-served energy costs

The cost of potentially having non-served energy in each region r NSE_r is based on a fictitious generator that does not have associated investment or connection costs, but it has a specific variable cost that is based on estimations of the cost of having non-served energy in the system (Eq.6).

$$NSE_r = \sum_{t,h} vnse_{t,h} * pcnse \quad (6)$$

Where,

$vnse_{t,h}$: (variable) non-served energy per year t and hour h, $\forall t \in T, \forall h \in H$ - [GWh]

pcnse: (parameter) penalization for non-served energy - [$/GWh]

e. Start-up thermal costs

The start-up costs SUP_r of each thermal technology n is related to the amount of power that needs to starts up from one day to the next one in region r according to Eq.7.

$$SUP_r = \sum_{t,d,n} vsup_{t,d,n} * pcsup_n \quad (7)$$

Where,

vsup$_{t,d,n}$: (variable) start-up power from day *(d-1)* to *d,* per year *t* and thermal technology *n,* $\forall t\in T, \forall d\in D, \forall n\in N$ - [GW/day]

pcsup$_n$: (parameter) cost associated with the start-up of thermal technology *n,* $\forall n\in N$ - [$/GW]

f. Investment and operational costs of storage technology

Investment and fixed O&M costs of storage technologies, as well as the variable cost associated with the operation of system is described in Eq.8. Although we parametrized the model to pumped-hydro storage PHS_r, it could also be formulated as a more generic utility-scale storage technology.

$$PHS_r = \sum_t vkphs_t * (pcfphs + pcfphsom) + \sum_{t,h} vtepphs_{t,h} * pcphsvom \tag{8}$$

Where,

vkphs$_t$: (variable) new pumped-hydro storage system installed capacity per year *t*, $\forall t\in T$ - [GW]

pcfphs: (parameter) annualized investment of pumped-hydro storage system - [$/GW.year]

pcfphsom: (parameter) annualized cost associated with fixed O&M for pumped-hydro storage system - [$/GW.year]

vtepphs$_{t,h}$: (variable) total energy involved in the process of charging/discharging the pumped-hydro storage system per year *t* and hour *h,* $\forall t\in T, \forall h\in H$ - [GWh]

pcphsvom: parameter cost associated with variable O&M for pumped-hydro storage system - [$/GWh]

2.2 Constraints

In this section, we will describe several operating and planning constraints considered in the main formulation of EleMod, as well as optional energy and climate policy constraints that can be added to the model depending on the scenarios being studied.

a. Energy balance

In each region, the balance of generation and demand must be met at every hour of the year. So, the sum of electricity production from thermal generators, non-served energy, imported energy from neighboring regions, discharged energy by storage technologies, and wind, solar and hydro production should equal energy demand plus the sum of the exported energy and energy charged into storage systems, as showed in Eq.9.

$$\begin{aligned}\left(\sum_n vg_n(t,h,r)\right) + vnse(t,h,r) + \left(\sum_{r_i,r_j} vflow_{r_i,r_j}(t,h)\right) \\ + vdisphs(t,h,r) + vghydro(t,h,r) \\ + \left(\sum_c vgwind_c(t,h,r)\right) + vgsolar(t,h,r) \\ = pdem(t,h,r) + \\ \left(\sum_{r_j,r_i} vflow_{r_j,r_i}(t,h)\right) + vchaphs(t,h,r)\end{aligned} \tag{9}$$

Where,

vg$_n$: (variable) generated energy per year *t*, hour *h*, thermal technology *n* and region *r,* $t\in T, \forall h\in H, \forall n\in N, \forall r\in R$ - [GWh] *vnse: (variable)* non-served energy per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

$vflow_{ri,rj}$: (variable) energy flow received by *ri* from *rj* per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh], where *i* and *j* represent the possible connection between regions

vdisphs: (variable) discharged energy by pumped-hydro storage system per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

vghydro: (variable) energy generated by hydro per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in$ - [GWh]

$vgwind_c$: (variable) generated energy by wind per year *t*, hour *h*, wind class *c* and region *r*, $\forall t \in T, \forall h \in H, \forall c \in C, \forall r \in R$ - [GWh]

vgsolar: (variable) generated energy by solar per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

pdem: (parameter) energy demand per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

$vflow_{rj,ri}$: (variable) energy flow received by *rj* from *ri* per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh], where *i* and *j* represent the possible connection between regions

vchaphs: (variable) charged energy into pumped-hydro storage system per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

b. Hydroelectric generation

We added to the model a restriction related to the maximum amount of hydro generation based on the regional hourly hydro profiles (Eq.10).

$$vghydro(t,h,r) \leq pprofhydro(t,h,r) \tag{10}$$

Where,

vghydro: (variable) energy generated by hydro per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

pprofhydro: (parameter) profile of energy generated by hydro per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

c. Hydro energy spillage

By considering the hydro generation profile in each region, it is also possible to calculate the amount of energy that is not been used or curtailed, according to Eq.11.

$$vspillhydro(t,h,r) = pprofhydro(t,h,r) - vghydro(t,h,r) \tag{11}$$

Where,

vspillhydro: (variable) spilled energy by hydro per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

pprofhydro: (parameter) profile of energy generated by hydro per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

vghydro: (variable) energy generated by hydro per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

d. Energy storage system

The amount of energy stored into the system, pumped-hydro storage in this case, for each hour of the simulation is given by Eq.13.

$$vstorphs(t,h>1,r)= \tag{13}$$

$$(1-pstorphsloss)*vstorphs(t,h-1,r)-$$

$$vdisphs(t,h,r)+pstorphsef*vchaphs(t,h,r)$$

Where,

vstorphs: (variable) energy storage in pumped-hydro storage system per year t, hour h and region r, $\forall t\in T,\forall h>1\cap h\in H,\forall r\in R$ - [GWh]

pstorphsloss: (parameter) loss factor associated with one-hour period of storage - [%]

vdisphs: (variable) discharged energy by pumped-hydro storage system per year t, hour h and region r, $\forall t\in T,h>1\cap h\in H,\forall r\in R$ - [GWh]

pstorphsef: (parameter) efficiency factor associated with charging energy into pumped-hydro storage system - [%]

vchaphs: (variable) charged energy by pumped-hydro storage system per year t, hour h and region r, $\forall t\in T,h>1\cap h\in H,\forall r\in R$ - [GWh]

e. Energy storage initial condition

In order to start the simulation, it is necessary to stablish the initial status of the energy storage system. Eq. 14 initializes the first hour of operation.

$$vstorphs(t,h=0,r)= \tag{14}$$

$$pstorphslevel*pcapstorphsh*vkpshacum(t,r)$$

Where,

vstorphs: (variable) energy storage in pumped-hydro storage system per year t, hour h and region r, $\forall t\in T,h=1\cap h\in H,\forall r\in R$ - [GWh]

pstorphslevel: (parameter) initial storage level associated with the first hour of each year t of simulation and per region r - [%]

pcapstorphsh: (parameter) number of hours associated with the capacity of pumped-hydro storage system - [h]

vkphsacum: (variable) total accumulated installed capacity of pumped-hydro storage system in year t and region r, $\forall t\geq 1\cap t\in T, \forall r\in R$ - [GW]

f. Energy storage capacity

The capacity of the energy storage system is represented by Eq.15.

$$vstorphs(t,h,r)\leq \tag{15}$$

$$pcapstorphsh*vkpshacum(t,r)$$

Where,

vstorphs: (variable) energy storage in pumped-hydro storage system per year t, hour h and region r, $\forall t\in T,\forall h\in H,\forall r\in$ - [GWh]

pcapstorphsh: (parameter) number of hours associated with the capacity of pumped-hydro storage system - [h]

vkphsacum: (variable) total accumulated installed capacity of pumped-hydro storage system in year t and region r, $\forall t \geq 1 \cap\ t \in T,\ \forall r \in R$ - [GW]

g. Minimum energy storage level

In order to maintain a minimum value of energy stored in the system after a discharge, the level of energy required is indicated in Eq.16.

$$vstorphs(t,h,r) \geq \tag{16}$$

$$vkpshacum(t,r)$$

Where,

vstorphs: (variable) energy storage in pumped-hydro storage system per year t, hour h and region r, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

vkphsacum: (variable) total accumulated installed capacity of pumped-hydro storage system in year t and region r, $\forall t \in T,\ \forall r \in R$ - [GW]

h. Maximum energy discharged and charged by the storage system

Considering the one-hour interval, the energy storage system is able to discharge energy limited by its installed capacity, according to Eq.17 and 18.

$$vdisphs(t,h,r) \leq vkpshacum(t,r) \tag{17–18}$$

$$vchaphs(t,h,r) \leq vkpshacum(t,r)$$

Where,

vdisphs: (variable) discharged energy by pumped-hydro storage system per year t, hour h and region r, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

vchaphs: (variable) charged energy by pumped-hydro storage system per year t, hour h and region r, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

vkphsacum: (variable) total accumulated installed capacity of pumped-hydro storage system in year t and region r, $\forall t \geq 1 \cap\ t \in T,\ \forall r \in R$ - [GW]

i. Storage system energy cycle

Eq.19 determines the energy cycle for the storage system. Considering one-day cycle, the amount of energy to be stored into the system must be discharged at the same day of the operational schedule, taking into account the efficiency involved in the charging process.

$$\sum_h vdisphs_h(t,d,r) \leq pstorphsef * \sum_h vchaphs_h(t,d,r) \tag{19}$$

Where,

vdisphs$_h$: (variable) discharged energy by pumped-hydro storage system per year t, day d, hour h and region r, $\forall t \in T, \forall d \in D, \forall h \in d \cap h \in H, \forall r \in R$ - [GWh]

pstorphsef: (parameter) efficiency factor associated with charging the energy into pumped-hydro storage system - [%]

vchaphs$_h$: (variable) charged energy by pumped-hydro storage system per year t, day d, hour h and region r, $\forall t \in T, \forall d \in D, \forall h \in d \cap h \in H, \forall r \in R$ - [GWh]

j. Storage technology total installed capacity

For each year of simulation, the total installed capacity associated with the storage technology is updated, following the recursive-dynamic approach mentioned earlier. Eq.20 determines total cumulative installed capacity of the storage system in year *t* and after.

$$vkpshacum(t,r) = \left(pexphs(t-1,r) * \frac{t}{plcyclephs}\right) + vkphs(t,r) \quad (20)$$

Where,

vkphsacum: (variable) total accumulated installed capacity of pumped-hydro storage system in year *t* and region *r*, $\forall t \geq 1 \cap t \in T, \forall r \in R$ - [GW]

pexphs: (parameter) existent pumped-hydro storage system capacity by year *t-1* and region *r*, $\forall t \geq 1 \cap t \in T, \forall r \in R$ - [GW]

plcyclephs: (parameter) pumped-hydro storage system life cycle - [years]

vkphs: (variable) new pumped-hydro storage system installed capacity per year *t* and region *r*, $\forall t \in T, \forall r \in R$ - [GW]

k. Energy storage resource potential

Eq.21 imposes a restriction on expanding new storage systems based on resource potential.

$$vkpsh(t,r) \leq ppotentialphs \quad (21)$$

Where,

vkphs: (variable) new pumped-hydro storage system installed capacity per year *t* and region *r*, $\forall t \in T, \forall r \in R$ - [GW]

ppotentialphs: (parameter) associated with resource potential of pumped-hydro storage system - [GW]

l. Energy related to the process of charging/discharging the storage system

The total energy involved in the process of charging and discharging the storage system is presented in Eq.22.

$$vtepphs(t,h,r) = vchaphs(t,h,r) + vdisphs(t,h,r) \quad (22)$$

Where,

vtepphs: (variable) total energy involved in the process of charging/discharging the pumped-hydro storage system per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

vchaphs: (variable) charged energy by pumped-hydro storage system per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

vdisphs: (variable) discharged energy by pumped-hydro storage system per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

m. Total installed capacity of wind

The cumulative installed capacity of wind up to a specific year *t* is calculated according to Eq.24.

$$vkwacum(t,c,r) = \left(pexw(t-1,c,r) * \frac{t}{plcyclew}\right) + vkw(t,c,r) \quad (24)$$

Where,

vkwacum: (variable) total cumulative installed capacity of wind per year *t*, wind class *c* and region *r*, $\forall t \geq 1 \cap t \in T, \forall c \in C, \forall r \in R$ - [GW] *pexw*: (parameter) existing wind capacity for year *t-1*, wind class *c* and region *r*, $\forall t \geq 1 \cap t \in T, \forall c \in C, \forall r \in R$ - [GW]

plcyclew: (parameter) wind project lifetime - [years]

vkw: (variable) new wind installed capacity per year *t*, wind class *c* and region *r*, $\forall t \in T, \forall c \in C, \forall r \in R$ - [GW]

n. Total installed capacity of solar

The cumulative installed capacity of solar up to a specific year *t* is calculated according to Eq.25.

$$vksacum(t,r) = \left(pexs(t-1,r) * \frac{t}{plcycles}\right) + vks(t,r) \tag{25}$$

Where,

vksacum: (variable) total accumulated installed capacity of solar per year *t* and region *r*, $\forall t \geq 1 \cap t \in T, \forall r \in R$ - [GW]

pexs: (parameter) existent solar capacity per year *t-1* and region *r*, $\forall t \geq 1 \cap t \in T, \forall r \in R$ - [GW]

plcycles: (parameter) solar project life cycle - [years]

vks: (variable) new solar installed capacity per year *t* and region *r*, $\forall t \in T, \forall r \in R$ - [GW]

o. Wind generation profile

The maximum production for wind is limited by its hourly profile, according to Eq.26.

$$vgwind(t,h,c,r) \leq vkwacum(t,c,r) * pprofw(t,h,c,r) \tag{26}$$

Where,

vgwind: (variable) generated energy by wind per year *t*, hour *h*, wind class *c* and region *r*, $\forall t \in T, \forall h \in H, \forall c \in C, \forall r \in R$ - [GWh]

vkwacum: (variable) total accumulated installed capacity of wind per year *t*, wind class *c* and region *r*, $\forall t \geq 1 \cap t \in T, \forall c \in C, \forall r \in R$ - [GW]

pprofw: (parameter) capacity factor associated with wind profile per year *t*, hour *h*, wind class *c* and region *r*, $\forall t \in T, \forall h \in H, \forall c \in C, \forall r \in R$ - [p.u]

p. Wind energy curtailment

The level of energy curtailment for this technology in given by Eq.27.

$$vwindcurt(t,h,c,r) = \tag{27}$$

$$(vkwacum(t,c,r) * pprofw(t,h,c,r)) - vgwind(t,h,c,r)$$

Where,

vwindcurt: (variable) wind energy curtailment per year *t*, hour *h*, wind class *c* and region *r*, $\forall t \in T, \forall h \in H, \forall c \in C, \forall r \in R$ - [GWh]

vkwacum: (variable) total accumulated installed capacity of wind per year *t*, wind class *c* and region *r*, $\forall t \geq 1 \cap t \in T, \forall c \in C, \forall r \in R$ - [GW]

pprofw: (parameter) capacity factor associated with wind profile per year *t*, hour *h*, wind class *c* and region *r*, $\forall t \in T, \forall h \in H, \forall c \in C, \forall r \in R$ - [p.u]

vgwind: (variable) generated energy by wind per year *t*, hour *h*, wind class *c* and region *r*, $\forall t \in T, \forall h \in H, \forall c \in C, \forall r \in R$ - [GWh]

q. Solar generation profile

The maximum production for solar is limited by its hourly profile, according to Eq.28.

$$vgsolar(t,h,r) \leq vksacum(t,r) * pprofs(t,h,r) \tag{28}$$

Where,

vgsolar: (variable) generated energy by solar per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

vksacum: (variable) total accumulated installed capacity of solar per year *t* and region *r*, $\forall t \geq 1 \cap t \in T, \forall r \in R$ - [GW]

pprofs: (parameter) capacity factor associated with solar profile per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [p.u]

r. Solar energy curtailment

The level of energy curtailment for solar in given by Eq.29.

$$vsolarcurt(t,h,r) = \tag{29}$$

$$(vksacum(t,r) * pprofs(t,h,r)) - vgsolar(t,h,r)$$

Where,

vsolarcurt: (variable) solar energy curtailment per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

vksacum: (variable) total accumulated installed capacity of solar per year *t* and region *r*, $\forall t \geq 1 \cap t \in T, \forall r \in R$ - [GW]

pprofs: (parameter) capacity factor associated with solar profile per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [p.u]

vgsolar: (variable) generated energy by solar per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

s. Wind energy resource potential

Considering wind resource potential of each region *r*, Eq.30 sets an upper limit on installed capacity per wind class.

$$vkwacum(t,c,r) \leq ppotentialw(r,c) \tag{30}$$

Where,

vkwacum: (variable) total cumulative installed capacity of wind in year *t*, wind class *c* and region *r*, $\forall t \geq 1 \cap t \in T, \forall c \in C, \forall r \in R$ - [GW]

ppotentialw: (parameter) associated with wind resource potential per region *r* and wind class *c*, $\forall c \in C, \forall r \in R$ - [GW]

t. Solar energy resource potential

Considering solar resource potential of each region *r*, Eq.31 sets an upper limit on installed capacity for solar.

$$vksacum(t,r) \leq ppotentials(r) \tag{31}$$

Where,

vksacum: (variable) total accumulated installed capacity of solar per year *t* and region *r*, $\forall t \geq 1 \cap t \in T, \forall r \in R$ - [GW] *ppotentials*: (parameter) associated with solar resource potential for region $r\ \forall r \in R$ - [GW]

u. Total connected thermal power

The daily available power of a conventional thermal power is restricted by the total cumulative installed capacity up to year *t* and de-rated by its average availability factor as shown in Eq.32.

$$vcp(t,d,r,n) \leq \left[\left(pex(t-1,r,n) * \frac{t}{plcyclet(n)}\right) + vk(t,r,n)\right] * (1 - pfor(r,n)) \quad (32)$$

Where,

vcp: (variable) thermal connected power per year *t*, day d, region *r* and technology *n*, $\forall t \geq 1 \cap t \in T, \forall d \in D, \forall r \in R, \forall n \in N$ - [GW]

pex: (parameter) existing thermal capacity until year *t-1*, region *r* and technology *n*, $\forall t \geq 1 \cap t \in T, \forall d \in D, \forall r \in R, \forall n \in N$ - [GW]

plcyclet: (parameter) thermal lifetime per technology *n* - [years]

vk: (variable) new thermal installed capacity per year *t*, region *r* and technology *n*, $\forall t \in T, \forall r \in R, \forall n \in N$ - [GW]

pfor: (parameter) forced outage rate per thermal technology *n* and region *r*, $\forall t \in T, \forall r \in R, \forall n \in N$ - [%]

v. Total thermal start-up and shut-down power

The amount of power that different technologies start up or shut down in a day is modeled using continuous decision variables. By means of using the connected power in one day *d* and the day before (*d-1*) is possible to define the power that needs to start up and the power that needs to shut down on a daily basis for conventional technologies located within a particular region (Eq.34). All variables in the expression are positive.

$$vcp(t,d,r,n) = vcp(t,d-1,r,n) + vsup(t,d,r,n) - vsdw(t,d,r,n) \quad (34)$$

Where,

vcp: (variable) total thermal connected per year *t*, day d (or day *d-1*), region *r* and technology *n*, $\forall t \geq 1 \cap t \in T, \forall d \in D, \forall r \in R, \forall n \in N$ - [GW]

vsup: (variable) total start-up thermal power per year *t*, day *d*, region *r* and technology *n*, $\forall t \geq 1 \cap t \in T, \forall d \in D, \forall r \in R, \forall n \in N$ - [GW]

vsdw: (variable) total shut-down thermal power per year *t*, day *d*, region *r* and technology *n*, $\forall t \geq 1 \cap t \in T, \forall d \in D, \forall r \in R, \forall n \in N$ - [GW]

w. Maximin thermal power generation

An upper bound for power production is included for the different thermal technologies. During one-hour interval, the energy produced by power plants is limited by the available connected power determined for the particular day (Eq.35)

$$vg(t,d,h,r,n) \leq vcp(t,d,r,n) \quad (35)$$

Where,

vg: (variable) generated energy per year *t*, day *d*, hour *h*, region *r* and thermal technology *n*, $\forall t \in T, \forall d \in D, \forall h \in d \cap h \in H, \forall r \in R, \forall n \in N$ - [GWh]

vcp: (variable) total thermal connected per year *t*, day d, region *r* and technology *n*, $\forall t \geq 1 \cap t \in T, \forall d \in D, \forall r \in R, \forall n \in N$ - [GW]

x. Minimum thermal power generation

A lower bound for energy production has been included in order to consider the minimum load requirement of certain thermal technologies. In EleMod this value is assumed to be proportional to the daily connected power by a predetermined percentage that is characteristic of each thermal technology, as showed in Eq.36.

$$vg(t,d,h,r,n) \geq vcp(t,d,r,n) * pminpt(n) \tag{36}$$

Where,

vg: (variable) generated energy per year *t*, day *d*, hour *h*, region *r* and thermal technology *n*, $\forall t \in T, \forall d \in D, \forall h \in d \cap h \in H, \forall r \in R, \forall n \in N$ - [GWh]

vcp: (variable) total thermal connected per year *t*, day d, region *r* and technology *n*, $\forall t \geq 1 \cap t \in T, \forall d \in D, \forall r \in R, \forall n \in N$ - [GW]

pminpt: (parameter) minimum thermal generation level per technology *n*, $\forall n \in N$ - [%]

y. Downward operating reserve

The downward reserve margin is aimed at reducing generating output on a very short notice, for instance in the case of sudden demand decrease or wind and solar production increase. This reserve is defined as the difference between the electric output of conventional technologies and the minimum connected power of all technologies, for every day of the year. Depending on their flexibility, conventional power plants will have different minimum load characteristics, while wind, solar, hydro and storage technologies are assumed to be fully flexible, i.e. they could be curtailed if needed by the system operator. The amount of reserve needed is assumed to be the sum of a percentage of electricity demand and a percentage of the maximum daily wind and solar production, intended to account for forecast errors associated to wind and solar production levels[3] (see Eq.37).

$$\begin{pmatrix} \sum_n (vg_n(t,d,h,r) - vcp_n(t,d,r) * pminpt(n)) + \\ \sum_c (vgwind_c(t,h,r)) + vgsolar(t,h,r) + \\ vdisphs(t,h,r) + vghydro(t,h,r) \end{pmatrix} \tag{37}$$

$$\geq$$

$$pferdem * pdem(t,h,r) +$$

$$pferw * \sum_c (vkwacum_c(t,r) * pprofwmax_c(t,d,r)) +$$

$$pfers * vksacum(t,r) * pprofsmax(t,d,r)$$

Where,

vg_n: (variable) generated energy per year *t*, day *d*, hour *h*, region *r* and thermal technology *n*, $\forall t \in T, \forall d \in D, \forall h \in d \cap h \in H, \forall r \in R, \forall n \in N$ - [GWh]

3 We assume 1% of the electricity demand. For simplicity, we use a mean absolute percentage error (MAPE) index for wind and solar of 20%. Although very dependent of the particular power system's characteristics, for a single wind power plant forecasts that are one to two hours ahead can achieve an error level of approximately 5-7% which increases to 20% for day-ahead forecasts (Milligan, Porter, and DeMeo 2009). For solar, this index was estimated to be in the range of 15% to 20% for different geographic locations within the U.S. western region, which very much depends of the spatial and temporal scales being considered (Zhang *et al.* 2015).

vcp_n: (variable) total thermal connected power per year t, day d, region r and technology n, $\forall t \geq 1 \cap\ t \in T, \forall d \in D, \forall r \in R, \forall n \in N$ - [GW]

$pminpt$: (parameter) minimum thermal generation level per technology n, $\forall n \in N$ - [%]

$vgwind_c$: (variable) generated energy by wind per year t, hour h, wind class c and region r, $\forall t \in T, \forall h \in H, \forall c \in C, \forall r \in R$ - [GWh]

$vgsolar$: (variable) generated energy by solar per year t, hour h and region r, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

$vdisphs$: (variable) discharged energy by pumped-hydro storage system per year t, hour h and region r, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

$vghydro$: (variable) energy generated by hydro per year t, hour h and region r, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

$pferw$: (parameter) factor associated with error in day-ahead wind forecast - [%]

$vkwacum_c$: (variable) total accumulated installed capacity of wind per year t, wind class c and region r, $\forall t \geq 1 \cap\ t \in T, \forall c \in C, \forall r \in R$ - [GW]

$pprofwmax_c$: (parameter) factor associated with the maximum wind production per year t, day d, wind class c and region r, $\forall t \geq 1 \cap\ t \in T, \forall d \in D, \forall c \in C, \forall r \in R$ - [p.u]

$pfers$: (parameter) factor associated with error in day-ahead solar forecast - [%]

$vksacum$: (variable) total accumulated installed capacity of solar per year t and region r, $\forall t \geq 1 \cap\ t \in T, \forall r \in R$ - [GW]

$pprofsmax$: (parameter) factor associated with the maximum solar production per year t, day d and region r, $\forall t \geq 1 \cap\ t \in T, \forall d \in D, \forall r \in R$ - [p.u]

$pferdem$: (parameter) factor associated with error in hour-ahead demand forecast - [%]

$pdem$: (parameter) energy demand per year t, hour h and region r, $\forall t \in T, \forall h \in H, \forall r \in R$ - [GWh]

z. Upward operating reserve

The upward reserve margin is aimed at providing a predetermined level of reserve to the power system in case of sudden increase in demand or decrease of supply, for example plant outage or unexpected low wind or solar production. It is is specified as the difference between connected power and the electric output of all thermal technologies being operated, for every day of the year. We assume that wind and solar technologies do not contribute to this kind of reserve, while hydro and storage are able to contribute. The amount of reserve needed is estimated to be a percentage of the electricity demand, plus the capacity of a medium (or large) size unit and a percentage of the maximum daily wind and solar production[4] (see Eq.38).

4 We assume 1% of the electricity demand and a unit size of 500MW. For simplicity, we use a mean absolute percentage error (MAPE) index for wind and solar of 20%. Although very dependent of the particular power system's characteristics, for a single wind power plant forecasts that are one to two hours ahead can achieve an error level of approximately 5-7% which increases to 20% for day-ahead forecasts (Milligan, Porter, and DeMeo 2009). For solar, this index was estimated to be in the range of 15% to 20% for different geographic locations within the U.S. western region, which very much depends of the spatial and temporal scales being considered (Zhang *et al.* 2013).

$$\left(\begin{array}{c}\sum_{n}(vcp_{n}(t,d,r)-vg_{n}(t,d,h,r))+\\ \big(vkpshacum(t,r)*(1-pphsfor-pphspla)-vdisphs(t,h,r)\big)+\\ (pcaphydro(t,r)*(1-phydrofor-phydropla)-vghydro(t,h,r))\end{array}\right) \tag{38}$$

$$\geq$$

$$punit(r)+pferdem*pdem(t,h,r)+$$

$$pferw*\sum_{c}(vkwacum_{c}(t,r)*pprofwmax_{c}(t,d,r))+$$

$$pfers*vksacum(t,r)*pprofsmax(t,d,r)+$$

Where,

vcp_n: (variable) total thermal connected power per year *t*, day d, region *r* and technology *n*, $\forall t\geq 1\cap\ t\in T, \forall d\in D, \forall r\in R, \forall n\in N$ - [GW]

vg_n: (variable) generated energy per year *t*, day *d*, hour *h*, region *r* and thermal technology *n*, $\forall t\in T, \forall d\in D, \forall h\in d\cap h\in H, \forall r\in R\ , \forall n\in N$ - [GWh]

vkphsacum: (variable) total accumulated installed capacity of pumped-hydro storage system in year *t* and region *r*, $\forall t\in T,\ \forall r\in R$ - [GW]

pphsfor: (parameter) forced outage rate for pumped-hydro storage system - [%]

pphspla: (parameter) planned outage rate for pumped-hydro storage system - [%]

vdisphs: (variable) discharged energy by pumped-hydro storage system per year *t*, hour *h* and region *r*, $\forall t\in T, \forall h\in H, \forall r\in R$ - [GWh]

pcaphydro: (parameter) installed capacity of hydro per year *t* and region *r*, $\forall t\in T, \forall r\in R$ - [GW]

phydrofor: (parameter) forced outage rate for hydro - [%]

phydropla: (parameter) planned outage rate for hydro - [%]

vghydro: (variable) energy generated by hydro per year *t*, hour *h* and region *r*, $\forall t\in T, \forall h\in H, \forall r\in R$ - [GWh]

punit: (parameter) size of a medium generation unit in each regions *r*, $\forall r\in R$ - [GW]

pferdem: (parameter) factor associated with error in hour-ahead demand forecast - [%]

pdem: (parameter) energy demand per year *t*, hour *h* and region *r*, $\forall t\in T, \forall h\in H, \forall r\in R$ - [GWh]

pferw: (parameter) factor associated with error in day-ahead wind forecast - [%]

$vkwacum_c$: (variable) total accumulated installed capacity of wind per year *t*, wind class *c* and region *r*, $\forall t\geq 1\cap\ t\in T, \forall c\in C, \forall r\in R$ - [GW]

$pprofwmax_c$: (parameter) factor associated with the maximum wind production per year *t*, day *d*, wind class *c* and region *r*, $\forall t\geq 1\cap\ t\in T, \forall d\in D, \forall c\in C, \forall r\in R$ - [p.u]

pfers: (parameter) factor associated with error in solar day-ahead - [%]

vksacum: (variable) total accumulated installed capacity of solar per year *t* and region *r*, $\forall t\geq 1\cap t\in T, \forall r\in R$ - [GW]

pprofsmax: (parameter) factor associated with the maximum solar production per year *t*, day *d* and region *r*, $\forall t\geq 1\cap\ t\in T, \forall d\in D, \forall r\in R$ - [p.u]

aa.Long-term reliability requirement on firm installed capacity

Capacity reserve requirement is aimed at guaranteeing the supply of demand in the long-term. The system will have an excess of capacity beyond peak demand in order to respond to unexpected increases in demand or unforeseen outages in supply. Total firm capacity by conventional and renewable technologies must exceed the peak load of a particular region and year, which in EleMod is assumed to be those one hundred hours of the year with the highest demand, plus a certain margin as described in Eq.39. In the case of conventional power technologies, the contribution to reserves is estimated considering their forced outage rates, while for renewables energy technologies (wind and solar) the contribution is valued considering their firm capacity (i.e., contribution to demand during peak hours given normally by their capacity credits).

$$\left(\begin{array}{c} \left[\left(pex(t-1,r,n) * \dfrac{t}{plcyclet(n)}\right) + vk(t,r,n)\right] * (1 - pfor(r,n)) + \\ \sum_{c} (vkwacum_c(t,r) * pfcapw_c(t,r)) + \\ vksacum(t,r) * pfcaps(t,r) + \\ vkpshacum(t,r) * (1 - pphsfor) + \\ pcaphydro(t,r) * (1 - phydrofor) \end{array}\right) \geq \left(1 + pores(r)\right) * \frac{\sum_{hmax} pdemmax_{hmax}(t,r)}{100} \qquad (39)$$

Where,

pex: (parameter) existing thermal capacity until year *t-1*, region *r* and technology *n*, $\forall t \geq 1 \cap t \in T, \forall d \in D, \forall r \in R, \forall n \in N$ - [GW]

plcyclet: (parameter) thermal lifetime per technology *n* - [years]

vk: (variable) new thermal installed capacity per year *t*, region *r* and technology *n*, $\forall t \in T, \forall r \in R, \forall n \in N$ - [GW]

pfor: (parameter) forced outage rate per thermal technology *n* and region *r*, $\forall t \in T, \forall r \in R, \forall n \in N$ - [%]

$vkwacum_c$: (variable) total accumulated installed capacity of wind per year *t*, wind class *c* and region *r*, $\forall t \geq 1 \cap\ t \in T, \forall c \in C, \forall r \in R$ - [GW]

$pfcapw_c$: (parameter) factor associated with the firm wind capacity per year *t*, wind class *c* and region *r*, $\forall t \geq 1 \cap\ t \in T, \forall c \in C, \forall r \in R$ - [p.u]

vksacum: (variable) total accumulated installed capacity of solar per year *t* and region *r*, $\forall t \geq 1 \cap t \in T, \forall r \in R$ - [GW]

pfcaps: (parameter) factor associated with the firm solar capacity per year *t* and region *r*, $\forall t \geq 1 \cap\ t \in T, \forall r \in R$ - [p.u]

vkphsacum: (variable) total accumulated installed capacity of pumped-hydro storage system in year *t* and region *r*, $\forall t \in T,\ \forall r \in R$ - [GW]

pphsfor: (parameter) forced outage rate for pumped-hydro storage system - [%]

pcaphydro: (parameter) installed capacity of hydro per year *t* and region *r*, $\forall t \in T, \forall r \in R$ - [GW]

phydrofor: (parameter) forced outage rate for hydro - [%]

pores: (parameter) factor associated with long-term reliability reserve in region *r*, $\forall r \in R$ - [%]

$pdemmax_{hmax}$: (parameter) peak demand per year *t*, hour *h* and region *r*, $\forall t \in T, \forall h \in H \cap h = \{100\ hours\ of\ maximum\ demand\}, \forall r \in R$ - [GW]

bb. Interregional power trade

The amount of power being trade from and to each region is restricted by the maximum intertie transfer capacity (Eq.40).

$$-plinecap_{ri,rj}\ (t,h) \leq vflow_{ri,rj}\ (t,h) \leq plinecap_{ri,rj}\ (t,h) \tag{40}$$

Where,

$vflow_{ri,rj}$: (variable) energy flow from r_i to r_j per year t, hour h and region r, $\forall\, t \in T, \forall\, h \in H, \forall\, r_i, r_j \in R$ - [GW]

$plinecap_{ri,rj}$: (parameter) inter-tie capacity from r_i to r_j per year t, hour h and region r, $\forall\, t \in T, \forall\, h \in H, \forall \forall\, r_i, r_j \in R$ - [GW]

cc. Regional or national CO_2 emissions cap (optional)

The formulation includes CO_2 emission limitations for those scenarios that need to analyze the impact of emissions cap in the electricity sector. It is defined as the annual sum of overall CO_2 emissions from conventional power plants (determined by their outputs, heat rates, and fuel emission factor), which has to be lower than a CO_2 emission level set exogenously for a region. It also possible to impose an emissions cap at national level if that option is desired (Eq.41).

$$\sum_{h,n} vg(t)_{h,r,n} * pemf_n * phr_n \leq\ pcapem(t,r) \tag{41}$$

Where,

$vg_{h,r,n}$: (variable) generated energy per year t, hour h, region r and thermal technology n, $\forall\, t \in T, \forall\, h \in H, \forall\, r \in R\ , \forall\, n \in N$ - [GWh]

$pemf_n$: (parameter) factor for CO_2 emission per thermal technology n, $\forall\, n\ \in N$ - [MMton/MMBtu]

phr_n: (parameter) heat rate per thermal technology n, $\forall\, n\ \in N$ - [MMBtu/GWh]

$pcapem$: (parameter) cap emissions of CO_2 per year t and region r $\forall\, t\ \in T, \forall\, r \in R$ - [MMton]

dd. Regional Renewable Portfolio Standards (RPS)

Depending on the technologies eligible, the model also incudes a restriction that imposes RPS targets for particular years and at a regional level. Eq.42 below presents the case of wind and solar as qualifying RPS technologies.

$$\left(\sum_{h,c} vgwind_{h,c}(t,r)\right) + \left(\sum_{h} vgsolar_h(t,r)\right) \geq \tag{42}$$

$$prps(t,r) * \left(\sum_{h} pdem_h(t,r)\right)$$

Where,

$vgwind_{h,\,c}$: (variable) generated energy by wind per year t, hour h, wind class c and region r, $\forall\, t \in T, \forall\, h \in H, \forall\, c \in C, \forall\, r \in R$ - [GWh]

$vgsolar_h$: (variable) generated energy by solar per year t, hour h and region r, $\forall\, t \in T, \forall\, h \in H, \forall\, r \in R$ - [GWh]

$prps$: (parameter) percentage of total annual energy demand supplied by renewable generation per year t and region r, $\forall\, t \in T, \forall\, r \in R$ - [%]

$pdem_h$: (parameter) energy demand per year t, hour h and region r, $\forall\, t \in T, \forall\, h \in H, \forall\, r \in R$ - [GWh]

3. Examples of model's applications

The model has been used for different applications: to assess the suitability of top-down modeling approaches to deal with intermittent renewables in the electricity sector (Tapia-Ahumada *et al.*, 2015); to understand the role of role for nuclear power under deep decarbonization scenarios in the U.S. (Tapia-Ahumada *et al.*, 2019); and to explore regional electricity systems in New England (Tries, 2018), Ghana (Gadzanku, 2019), and Brazil (Vitorino, 2021). The integrated USREP-EleMod framework has been applied to analyze the transition to low-carbon energy systems, in particular understand the impacts of tighter renewable portfolio standards (RPS) on the delivered cost of electricity and the marginal investment costs in carbon reduction scenarios in the U.S. (Yuan *et al.*, 2019b); explore economy-wide decarbonization pathways in California (Yuan *et al.*, 2020); and study the role of electricity trade between the U.S. Northeast region and Canada in meeting ambitious regional climate goals (Yuan *et al.*, 2021).

To visualize the capabilities of EleMod, we extracted from Tapia-Ahumada *et al.* (2019) some results for the U.S. and one of the simulated regions (New York). **Figure 3** shows results for the U.S. as a whole, for the total installed capacity by technology type from years 2020 until 2050 for the reference case used in the study - with prescribed annual demand path for electricity, technology performance characteristics and costs, and fuel prices mostly used by the EIA; RPS requirements that reflect existing and planned state initiatives; and electricity trade limited to existing transmission capacity based on NREL's data.

Figure 4 provides annual generation by technology for the New York (NY) region in the reference case. Different regions have dissimilar varying resource availabilities, and we can see that NY has important wind resources that, because of declining costs, are being exploited.

Figure 5 shows total installed capacity (GW) for NY region by technology type for the refence case. We see that, relative to generation in Figure 4, nuclear has a relatively small share of capacity because it tends to operate at 80 or 90%. Aggregated gas technologies show a higher share of capacity relative to generation, and we also note the important deployment of storage in the form of pumped hydro.

Prices in EleMod are resolved on an hourly basis to match supply and demand. For New York, **Figure 6** shows average annual wholesale electricity prices (with the annual average weighted by the amount of electricity sold at those prices) and annual CO_2 emissions for the reference case.

Finally, **Figure 7** and **Figure 8** show hourly generation disaggregated by technology type, curtailments of wind and solar resources, charging and discharging of pumped hydro storage systems, and demand load for New York during one week of April 2050. Both figures also display the hourly wholesale electricity prices in the reference scenario.

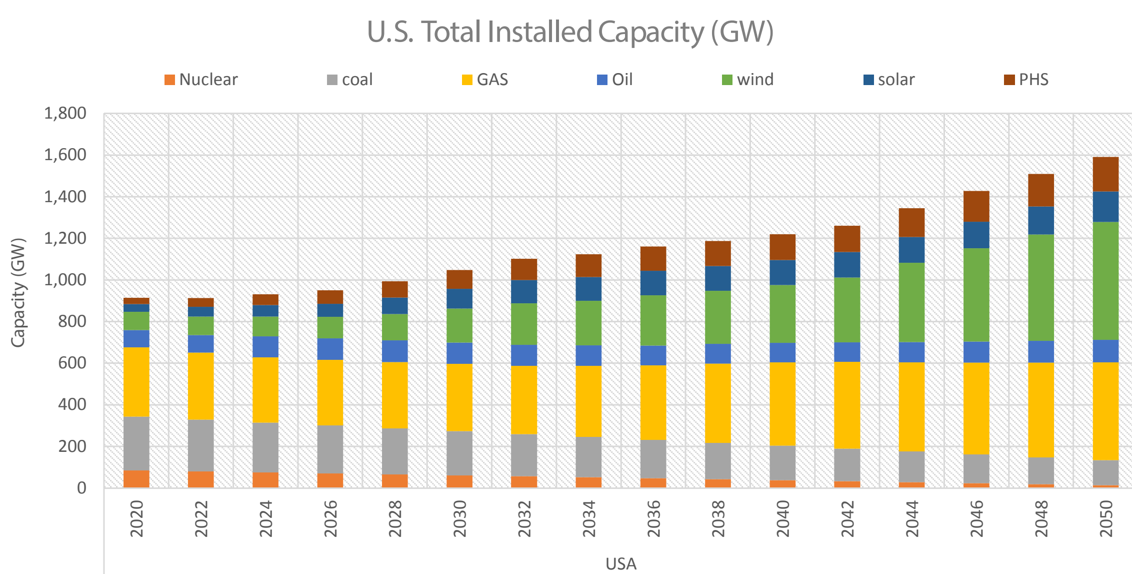

Figure 3. Electricity generation expansion (total installed capacity) for the United States (GW)

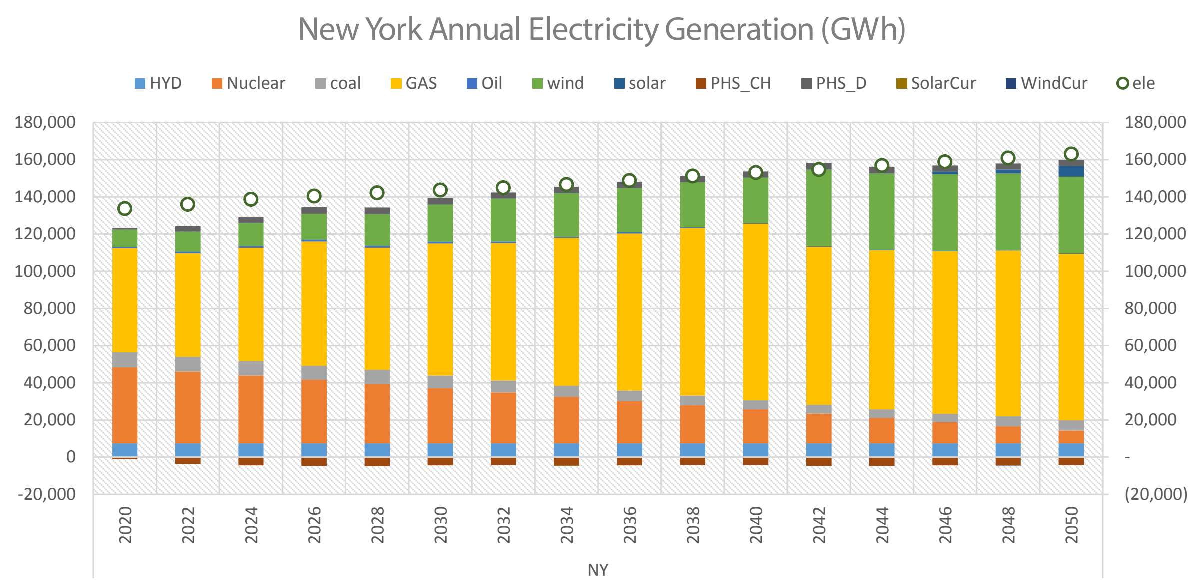

Figure 4. Electricity generation in New York region (GWh per year). Note: The white dots represent prescribed regional electricity demand

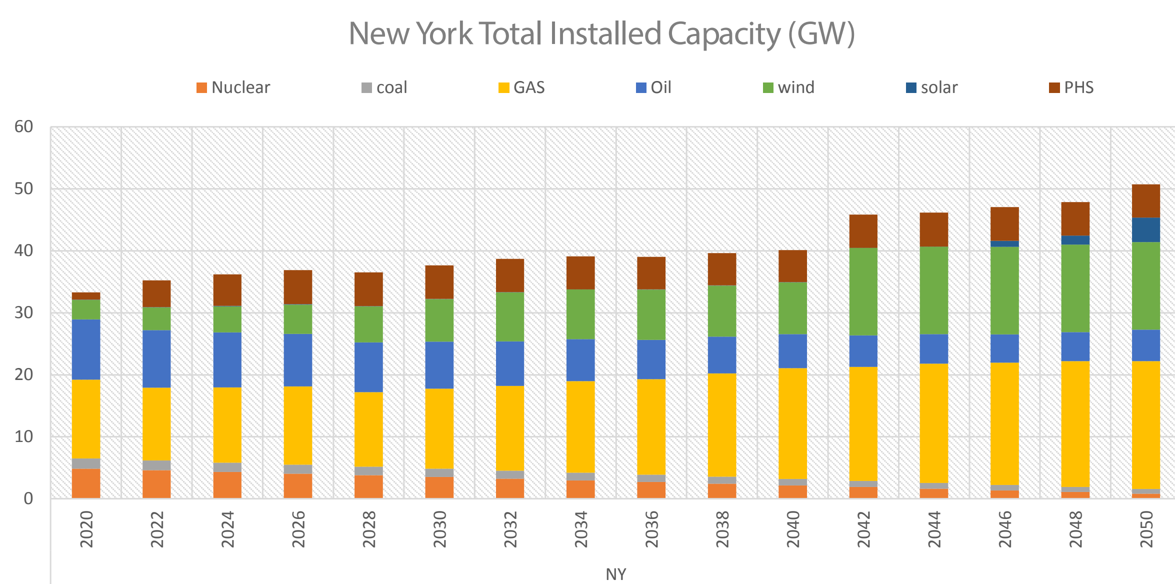

Figure 5. Cumulative installed generation capacity in New York region (GW)

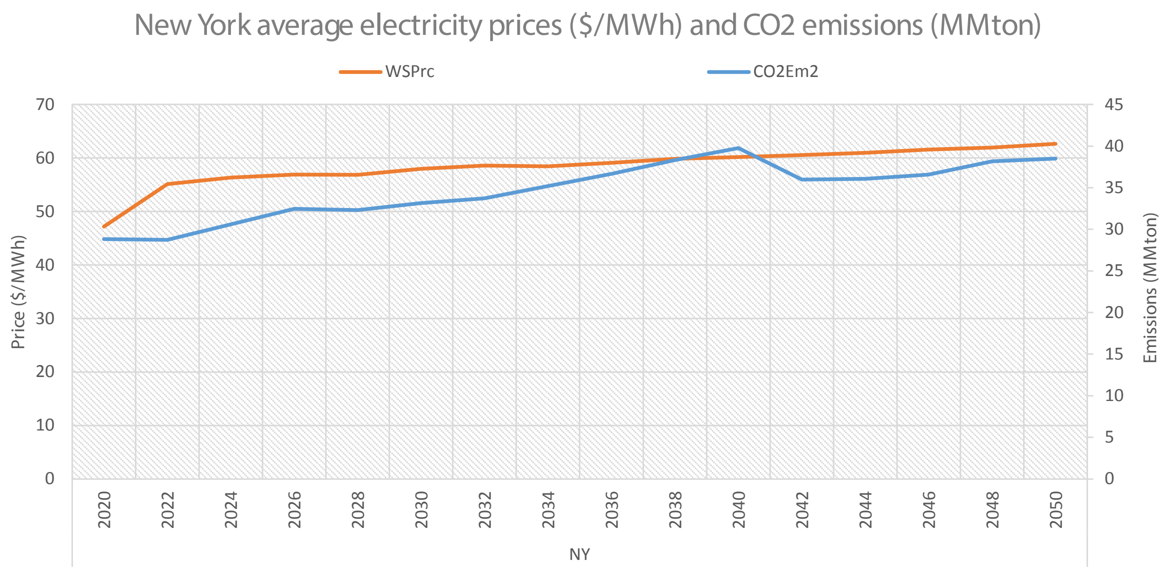

Figure 6. Annual average wholesale electricity prices ($/MWh) and CO_2 emissions (MMton) for New York region. Note: Price is the orange line, CO_2 emissions is the blue line

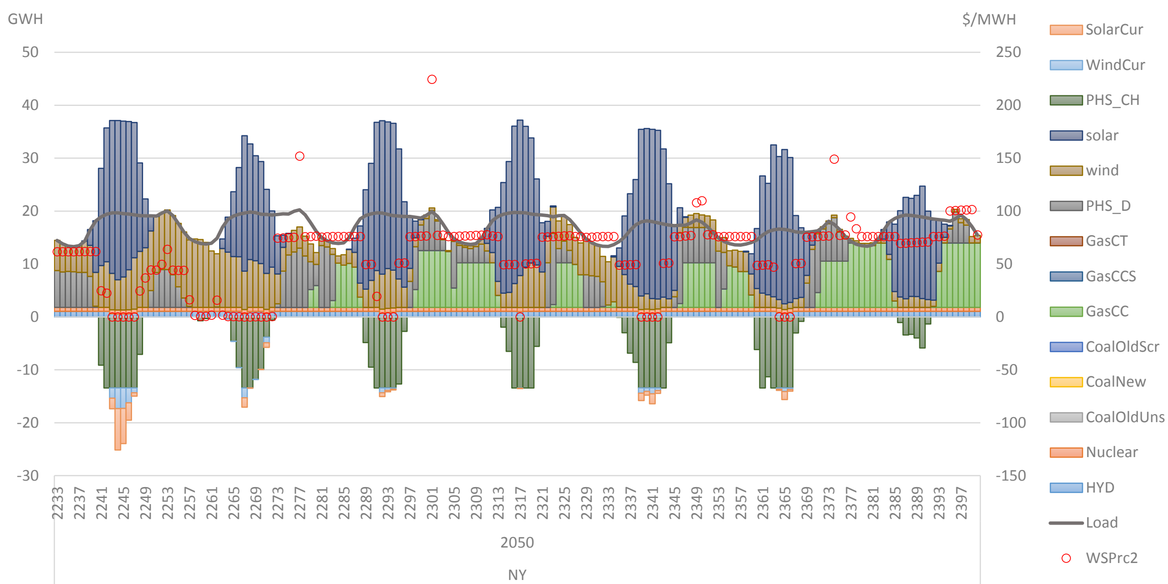

Figure 7. Simulated hourly operation for one week in April 2050 for NY region - Generation (GWh), Demand (GWh), and wholesale electricity prices ($/MWh)

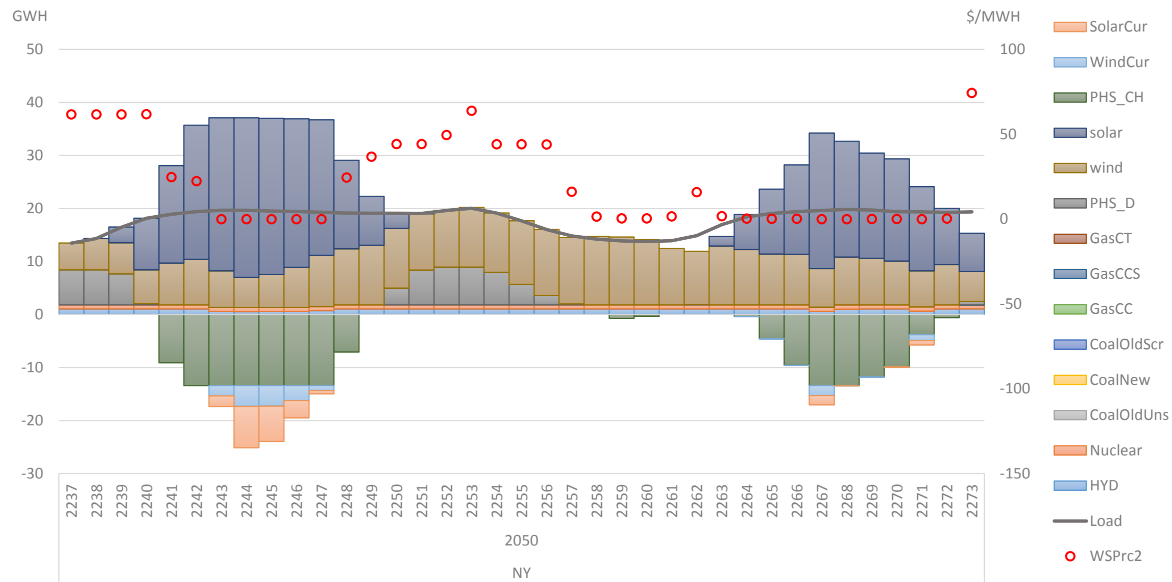

Figure 8. Closeup of simulated operation for 40 hours of a week in April 2050 for NY region - Generation (GWh), Demand (GWh), and wholesale electricity prices ($/MWh)

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Appendix A: Technology Costs and Operational Performance Parameters, Demand and Fuel Costs Projections

Table 1: Technology Costs (2018$). Sources: EIA AEO 2017, NREL ATB 2016, NREL reports

		Annualized Capital and Fixed Costs	Variable O&M	Lifetime
		[$/kW]	[$/kWh]	[yr]
Gas Combustion Turbine	GasCT	103.22	0.0128	30
Gas Combined Cycle	GasCC	177.44	0.0033	30
Gas Combined Cycle with Carbon Capture & Sequestration	GasCCS	270.20	1.2350	30
Oil/gas Steam Turbine	OGS	68.36	0.0059	50
Pulverized Coal Steam with SO_2 scrubber	CoalOldScr	196.07	0.0084	60
Pulverized Coal Steam without SO_2 scrubber	CoalOldUns	159.83	0.0125	60
Advanced Supercritical Coal Steam with SO_2 & NOx Controls	CoalNew	362.28	0.0042	60
Integrated Gasification Combined Cycle Coal	CoalIGCC	795.95	0.0072	60
IGCC with Carbon Capture & Sequestration	CoalCCS	624.83	1.2350	60
Pulverized Coal Steam with SO_2 scrubber & Biomass Cofiring	CofireOld	216.18	0.0125	60
Advanced Supercritical Coal Steam with Biomass Cofiring	CofireNew	377.80	0.0084	60
Nuclear Plant	Nuclear	791.07	0.0042	40
Wind	Wind	313.09	0.0177	20
Utility Solar	Solar	254.23	0.0135	30
Pumped Hydro Storage	PHS	115.96	0.0088	50

Table 2: Conventional Generation Technologies: Operational parameters and cost performance. Sources: Mostly based on EIA AEO and NREL reports

		Minimum Plant Loading	Availability Factor	Forced Outage Rate	Electric Heat Rate	CO_2 Emission Factor
		[%]	[p.u.]	[p.u.]	[MMBtu/kWh]	[Mton/MMBtu]
Gas Combustion Turbine	GasCT	0%	0.9215	0.0300	0.010033	0.0540
Gas Combined Cycle	GasCC	0%	0.9024	0.0400	0.006682	0.0540
Gas Combined Cycle with Carbon Capture & Sequestration	GasCCS	0%	0.9024	0.0400	0.007525	0.0081
Oil/gas Steam Turbine	OGS	40%	0.7927	0.1036	0.011500	0.0540
Pulverized Coal Steam with SO_2 scrubber	CoalOldScr	40%	0.8460	0.0600	0.010400	0.0930
Pulverized Coal Steam without SO_2 scrubber	CoalOldUns	40%	0.8460	0.0600	0.011380	0.0930
Advanced Supercritical Coal Steam with SO_2 & NOx Controls	CoalNew	40%	0.8460	0.0600	0.008784	0.0930
Integrated Gasification Combined Cycle Coal	CoalIGCC	50%	0.8096	0.0800	0.010062	0.0930
IGCC with Carbon Capture & Sequestration	CoalCCS	50%	0.8096	0.0800	0.010062	0.0140
Pulverized Coal Steam with SO_2 scrubber & Biomass Cofiring	CofireOld	40%	0.8463	0.0700	0.010740	0.0930
Advanced Supercritical Coal Steam with Biomass Cofiring	CofireNew	40%	0.8463	0.0700	0.009370	0.0930
Nuclear Plant	Nuclear	100%	0.9024	0.0400	0.010452	-

Table 3: Demand and Fuel Costs (2018$) Projections. Source: EIA AEO 2017

	DEMAND	DFO	RFO	GAS	COL	NUC
Year	**[TWh]**	**[$/MMBtu]**	**[$/MMBtu]**	**[$/MMBtu]**	**[$/MMBtu]**	**[$/MMBtu]**
2020	3820	21.93	16.38	5.58	2.87	0.77
2021	3848	22.34	16.98	5.66	2.87	0.79
2022	3886	22.66	17.46	5.71	2.89	0.82
2023	3927	23.07	17.94	5.77	2.91	0.85
2024	3963	23.45	18.25	5.84	2.93	0.86
2025	3992	24.06	19.01	5.90	2.94	0.91
2026	4015	24.47	19.57	5.98	2.95	0.94
2027	4042	24.69	19.75	6.03	2.95	0.96
2028	4065	24.70	19.91	6.13	2.96	0.99
2029	4089	25.02	20.16	6.21	2.98	1.00
2030	4105	25.52	20.55	6.26	2.99	1.01
2031	4121	25.97	20.98	6.35	3.00	1.04
2032	4139	26.54	21.43	6.37	3.01	1.06
2033	4162	26.45	21.34	6.36	3.04	1.10
2034	4191	26.86	21.65	6.34	3.06	1.12
2035	4222	27.05	21.76	6.41	3.09	1.16
2036	4252	27.70	22.19	6.48	3.12	1.19
2037	4284	27.85	22.23	6.56	3.15	1.22
2038	4320	27.97	22.37	6.56	3.17	1.26
2039	4353	28.41	22.74	6.62	3.19	1.30
2040	4374	28.68	22.95	6.61	3.21	1.33
2041	4394	28.73	23.06	6.58	3.22	1.37
2042	4421	28.75	22.88	6.67	3.24	1.41
2043	4451	28.81	22.72	6.76	3.24	1.44
2044	4481	28.95	22.59	6.83	3.25	1.49
2045	4510	29.08	22.40	6.92	3.26	1.53
2046	4539	29.31	22.58	7.00	3.27	1.58
2047	4567	29.68	22.82	7.08	3.27	1.62
2048	4597	29.86	23.02	7.14	3.29	1.67
2049	4628	29.92	23.09	7.25	3.30	1.72
2050	4661	30.28	23.40	7.30	3.31	1.77

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