Category	Geographic Scope & Timescales	Spatial and Temporal Data	Integration with other models
NREL ReEDS	• National-scale with 134 regions available. Can aggregate regions. • Typically, multi-decadal timescales.	• Model uses a single representation of load and renewable production profiles for solve years. • Profiles can be based on several weather years of load and production data to capture correlations. • Sites can be binned into resource classes and sub-categorized by interconnection costs. • Individual sites can also be represented.	• Tools available to pass ReEDS output to production cost models and resource adequacy models. • PCM: PLEXOS & SIIP, RA: Probabilistic RA Suite • No capability to directly pass data back from PCM and RA models into ReEDS.
EPRI US REGEN	• National-scale with flexible sub-regional detail down to state or NY zonal level. • Default 16 sub-regions. • Typically, multi-decadal with 5-year timesteps through 2050.		• Electric sector and end-use demand simulation. • Non-electric fuels and fuel production. • Models converge on energy price and quantities available. • Temperature changes due to climate change are represented in the end-use demand model. • Tools available to pass REGEN output to production cost models.
Optimal Capacity Expansion Planning Model v2	• National/multi-national and adaptive to other geographies. • Typically, multi-decadal timescales.		• Can be interfaced with other tools like production cost modeling and resource adequacy. • Other models are not directly integrated with this tool.
EnCompass v6.2	• Single or multiple ISO/RTO. • National scale for climate impact plans. • Typically, multi-decadal timescales.		• Can be run for production cost simulation, resource adequacy and DC optimal power flow runs. • Expansion not directly integrated with other results, but the same database can be used.
CGT-Plan (Expansion Planning Modeling System EPMS)	• Typically, single or multiple ISO/RTO • Typically, multi-decadal timescales.	• Model uses a single representation of load and renewable production profiles for solve years. • Profiles can be based on several weather years of load and production data to capture correlations. • Profiles can be regional or site specific.	• Iterative analysis between EPMS and CGT-Plan expansion output which uses expansion results in production cost models, then modifies expansion plan constraints and re-runs. • Plans to include resource adequacy assessment within the larger EPMS system.
RESOLVE v2.0 (beta)			• Can be run for capacity expansion or production cost modeling. • E3 co-develops Pathways (decarbonization model) and RECAP (resource adequacy model), but these are not directly integrated tools with RESOLVE.
Aurora v14.2			• Can be run for production cost simulation, resource adequacy and DC optimal power flow runs. • Expansion not directly integrated with other results, but the same database can be used.
PLEXOS v9.1			• Can be run for production cost simulation, DC optimal power flow and resource adequacy. • Can model gas, water, hydrogen and generic commodity markets. • Expansion not directly integrated with PCM and RA results, but the same database can be used.
Power System Optimizer 3.1 / ENELYTIX	• Typically, single or multiple ISO/RTO and multiple interconnections. • Typically, multi-decadal timescales.	• Model uses a single representation of load and renewable production profiles for solve years. • Profiles can be based on several weather years of load and production data to capture correlations. • Profiles can be regional or site specific • User controlled flexible stochastics.	• Can be run for production cost simulation, DC optimal power flow and resource adequacy. • Can model adjacent energy infrastructure and Power-to-X/X-to-X. (ex. Methane, Hydrogen, Water, Heat) . • Roundtrip analysis of expansion with production costing (PCM) and resource Adequacy (RA) simulations using the same database.

Category	Capacity Adequacy	Energy Adequacy and Chronological Dispatch
NREL ReEDS	• Constant seasonal PRM by region taken from NERC long-term reliability assessment. • Dispatchable resources use summer/winter capacities. • Hydropower uses seasonal ratings. • VRE and storage use ELCC solved every 2 years based on net load correlation for 2007-2013 weather year 8,760 dispatch.	• 17 time slices, four daily periods for each season and one afternoon summer peak. • Time slices use average profiles for load and VRE generation. • Between each pair of solve years using a single weather year 8,760 load and renewable profile to determine average and marginal curtailment of VRE and transmission and storage ability to reduce VRE curtailment.
EPRI US REGEN	• Default PRM is set to 7% above peak net load by sub-region. PRM must be met by dispatchable resources within the region. • Capacity credit by resource is based on correlation between resource generation and load from the 8760 weather year profile used and endogenous to the model.	• Typically, 120 representative hours are created for each 5-year period and energy adequacy is evaluated for each sub-region. • Dispatch is computed for representative hours and weighted by hours represented by the segment. • Energy storage uses a system state approach based on Worgin et al. (IEEE, 2016). • Alternatively, can use a 1 year 8760 hour static equilibrium approach which allows for fully endogenous storage investments when looking at years further out.
Optimal Capacity Expansion Planning Model v2	• Evaluates 8,760 hourly load profiles against VRE generation, storage charging/discharging and other generation assets. • 8,760 representation captures low wind and solar days.	• 8,760 chronological supply-demand balance considering ramping constraints of different technologies. • Investment decisions are made annually or every five years (can hybridize investment periods).

EnCompass v6.2	• PRM targets using three-point demand curve (min, target, max) for regions or sub-regions.
	• Capacity enforcement can be tailored to annual, month, season, etc.
	• Resources contribute to PRM based on firm capacity contribution (ELCC curves).
	• Demand resources assumed to target peak reduction.
		• Representative periods use average profiles and chronological dispatch within the periods.
		  ◦ Type 1 week uses 7 representative days each month.
		  ◦ Type 2 on-peak/off-peak uses 2 days per month.
		• Timesteps can also be aggregated within periods to provide detail in profiles where needed (e.g., high detail in morning and peak and less midday/overnight)
		• Ending conditions (e.g., storage charge) target beginning conditions for energy limited resources.
		• Demand and VRE profiles are adjusted to maintain peak, peak hour, min load and total energy.

CGT-Plan (Expansion Planning Modeling System EPMS)	• Uses PRM and capacity value inputs by region modeled.
	• Sharing capacity between regions is allowed with deliverability of shared capacity enforced under a 115% of peak load condition.
		• Periods are modeled non-chronologically using time-slices (or “blocks”).
		• Typically, 15-20 blocks per year are used to represent the three seasons and several periods of unique interest (e.g., regional peaks).
		  ◦ Least-cost dispatch is modeled for every block.
		• Storage and demand reduction is modeled using adjoining blocks by season.
		  ◦ Charging (discharging) in block *k* is discharged (charged) in block *k+1*.

RESOLVE v2.0 (beta)	• Typically uses PRM and capacity value inputs (net qualifying capacities/ELCC). • Has been used with alternative capacity adequacy approaches (e.g., HECO Energy Reserve Margin). • Sub-zonal transmission investment heuristic trigger helps determine if enough transmission is available at peaks to meet peak resource production.	• Typically uses a representative day approach for dispatch. ◦ Ex) 37 representative days with 24-hour resolution. • Energy only resources can be selected which ignores the need for transmission capacity to be available during peak periods (employed in CPUC IRP).
Aurora v14.2	• Uses PRM and capacity value inputs. • Price signals from inadequate capacity provide additional economic incentive to build resources. • Firm capacity input directly by user or determined dynamically as resources are added to the system (ELCC curve).	• Chronological dispatch or load duration curve methodologies available. • Dispatch can be sampled into chunks of hours by days of week or weeks of the year.
PLEXOS v9.1	• Uses PRM and capacity value inputs. • Can incorporate ELCC curves. Economic signals from scarcity, A/S, transmission congestion and natural gas scarcity provide additional incentives for build decisions.	• Three chronology options are available to use depending on system needs. ◦ Fitted, sampled and partial (derivative of load duration curves). • Recommended using fitted or sampled chronology for renewable, storage and demand response modeling.
Power System Optimizer 3.1 / ENELYTIX	• Uses PRM and capacity value inputs. • Also considers reliability and economic constraints (transmission congestion, fuel scarcity, etc.) as drivers for investment decisions. • Firm capacity input directly or determined dynamically as resources are added to the system (ELCC curves).	• Both load duration curves , 8,760 chronological, and representative periods methods are available. • Chronological 8,760 data can be used and aggregated into time slices or time step chunks. • Intertemporal constraints such as storage state of charge targets, fuel constraints, emissions, resource availability are maintained between aggregated time steps.

Category	Co-optimizations	Transmission Representation	Transmission Investment
NREL ReEDS	• Generation, transmission, storage and reserves for bulk power system.	• Pipe and bubble transport model between 134 zones. • Representative paths for new transmission based on land slopes and terrain types to identify lowest cost route. • Spur lines connecting VRE sites uses cost adders. Bulk transmission is greenfield single-circuit 500 kV lines. • AC vs DC lines differ on cost and losses.	• Investments in interzonal capacity expansion based on $/MW-mile costs. • HVDC lines can be modeled as multi-terminal for VSC DC converter stations to allow an HVDC macro grid.
EPRI US REGEN	• Generation, transmission, storage and reserves for bulk power system. • Fuel production/conversion, gas/CO2/H2 pipeline expansions and flows. • Also includes 8760 hour end-use demand module which is run in iteration with the energy production model to convergence.	• Pipe and bubble transport model. • Intra-zonal transmission upgrades represented with cost adders. • Different voltages or line types evaluated based on costs, losses, lifetime and length limits.	• Every 5-year timestep additional transmission between zones evaluated in cost minimization objective. • Costs are based on high voltage AC lines in a $/GW-mile metrics developed by EPRI.
Optimal Capacity Expansion Planning Model v2	• Generation, transmission, storage, and reserves for bulk power system • Adjacent energy infrastructure (e.g., hydrogen production, transport and storage).	• Pipe and bubble transport model. • Different voltages or line types evaluated based on costs, losses, lifetime and length limits.	• Transmission investments based on technology parameters on a cost per MW and cost per MW-km basis.
EnCompass v6.2	• Generation, transmission, storage and reserves, and environmental policies for bulk power system.	• Pipe and bubble transport model with bi-directional limits, losses, tariffs, and flowgates. • Nodal representation is possible with DC power flow which use load and generation shift factors.	• Transmission upgrades available for selection by the model along with resource expansion. • Capital costs and recovery requirements dictate project economics and selection.
CGT-Plan (Expansion Planning Modeling System EPMS)	• Generation, transmission, storage and DERs. • DERs are modeled using a single three-segment, three-bus feeder at each load bus. • Each feeder bus represents rooftop solar, microturbines, energy efficiency and DR which can be selected.	• Characterized as a DC power flow nodal model.	• Transmission investments are represented by expanding line limits, with impedance unchanged. • Investments are also made at the voltage level of the existing line using a cost per MW-mile as a function of voltage level. • New transmission links are modeled as existing zero-capacity circuits.
RESOLVE v2.0 (beta)	• Generation, transmission, storage and reserves for bulk power system. • Includes electrolyzer operations.	• Pipe and bubble transport model with bi-directional MW ratings. • Interface limits can be defined for single or multiple lines and vary over model hours/years.	• The model selects transmission upgrades based on a levelized $/MW-year cost based on capex and financing assumptions. • Sub-zonal transmission upgrade costs triggered by combinations of zonal resource investments to be selected by the model. • Based on heuristics for VRE levels and transmission needs developed by E3.
Aurora v14.2	• Generation, transmission, storage and reserves for bulk power system.	• Pipe and bubble transport model for capacity expansion. • Different voltages or line types evaluated based on costs, losses, lifetime and length limits.	• Transmission investments are represented using sensitivity cases, not selected by the model.
PLEXOS v9.1	• Generation, transmission, storage and reserves for bulk power system. • Adjacent energy infrastructure (e.g., hydrogen, natural gas, heat, water).	• Pipe and bubble transport model for regional zonal configurations. Different voltages or line types evaluated based on costs, losses, lifetime and length limits. • Offers roundtrip integration with Siemens PSS/E power flow software for production cost simulation.	• Investments can be assessed using sensitivity cases or by allowing the model to select transmission upgrades based on cost information and recovery requirements. • Individual transmission component (e.g., reconductoring) upgrades can be represented and selected if nodal representation is used.
Power System Optimizer 3.1 / ENELYTIX	• Generation, transmission, storage and reserves for bulk power system. • Adjacent energy infrastructure, fuel networks, fuel storage and fuel supply and conversions. (methane, hydrogen, heat, water) • Co-optimized expansion of generation, transmission, storage (including impact of duration (MWh vs MW), fuel systems (including impacts of reliability on capacity expansion)	• Pipe and bubble transport model, nodal or hybrid zonal/nodal with bi-directional limits, losses, tariffs and flowgates. • Nodal representation with DC power flow for both Generation and Transmission Expansion Options • Different voltages or line types evaluated based on costs, losses, lifetime and length limits.	• Transmission investments are available for selection by the model based on fixed and variable costs, system constraints, and greenfield vs brownfield. • Full parameterization of transmission investments on par with generation expansion. • Full security-constrained power flow identifies impacts on adjacent facilities and need for concurrent upgrades / installations. • Multiple facilities with different costs and constraints can be evaluated and constrained based on other investments • Individual transmission component (e.g., reconductoring) upgrades can be represented and selected.

Category	Model Availability and Base Datasets	Runtime and Performance	Documentation
NREL ReEDS	• Open access but requires a GAMS license and CPLEX license (or open-source solver). • Processed data available with model, raw base data is from public sources.	• A single run with default settings takes <12 hours on 16 GB RAM laptop. • Full-year chronological dispatch or individual site resolution for wind require high-memory or HPC clusters. • Runtimes are 2 days or more.	• Docs: https://www.nrel.gov/docs/fy21osti/78195.pdf • Access: https://www.nrel.gov/analysis/reeds/request-access.html
EPRI US REGEN	• Available through EPRI. • Development of open-source version is in progress.	• Typical model is for 2015-2050, using 120 time segments for each 5-yr timestep and default 16 sub-regions takes ~30 minutes with 128 GB, 6 thread HPC. • 1 year 8760 hour model takes ~2 hours with HPC.	Docs: https://us-regen-docs.epri.com/
Optimal Capacity Expansion Planning Model v2	• Commercial availability TBD.	• Ex) European energy system model with 70 zones, 8760 hours per year, 2022-2050, 5-yr investment decisions solves in 10-12 hours with HPC. • Reducing slices to every second hour, third day and 12th week (or other combination) allows 32 GB laptops to solve.	• Docs: Not publicly available • Reference provided: https://www.sciencedirect.com/science/article/abs/pii/S0360544221006277
EnCompass v6.2	• License by Anchor Power Solutions. Partnership with Horizons Energy provides National Database (NDB) for licensees. • Data available for 78 markets within NERC. Generation, zonal transmission, fuel prices, load and A/S forecast data. • Nodal datasets are available for Eastern Interconnect, WECC, and ERCOT.	• Horizons Energy 30-year NERC expansion uses typical on-peak/off-peak 2-days per month and hourly aggregation and runs in ~8 hours. • Annual production cost models take ~1.6 hours per year. • Single large RTO (e.g., MISO), 30-yr expansion ~1 hour expansion and 45 min per year for PCM. • Recommended min 4 cores, 32 GB of RAM with 4 simultaneous 8,760 runs.	• Docs: Not publicly available • Website: https://anchor-power.com/encompass-power-planning-software/
CGT-Plan (Expansion Planning Modeling System EPMS)	• Model is research-grade and users commission developer (Iowa State University) to run.	• Model runtime and performance is dependent on model size and model reduction software used. • Typically, runtimes are 1-6 hours using 300-400 bus models on an Intel-Xeon Linux server having 252 GB RAM and 32 CPUs at 2.70 GHz.	• Inquiries should be directed to James McCalley at jdm@iastate.edu.
RESOLVE v2.0 (beta)	• Users typically commission E3 to develop and run the model. Input datasets offered upon client request. • Open-source license available end of 2022. • No built-in data provided with the model.	• Typically, generation resources, balancing areas are aggregated, and time series sampled to improve runtime. • Runtimes range from minutes to several hours based on aggregations, scope, and timescale.	• CPUC Public Release Version: https://files.cpuc.ca.gov/energy/modeling/2021%20PSP%20RESOLVE%20Package.zip
Aurora v14.2	• Licensed by Energy Exemplar. • Data available from Energy Exemplar for resources, load, existing generation and transmission in the United States and Canada. • Capacity expansion futures from Energy Exemplar are also available.	• Model timestep chunks, day/week selection, and size drive the computing and runtime needs. • Some users implement non-standard hardware such as gaming laptops, desktops or larger virtual machines. • WECC zonal data with out-of-the-box configuration can run standard 25-year expansion in several hours.	• Docs: Not publicly available • Website: https://www.energyexemplar.com/aurora
PLEXOS v9.1	• Licensed by Energy Exemplar. • Data available for 50+ countries. Zonal Electric and Nodal Electric available for U.S., Canada and New Zealand. Fundamental natural gas models also available. • PLEXOS user published datasets, such as Pan-European snapshot or PLEXOS World.	• Provides PLEXOS Cloud platform for scalable cloud computing environment to fit model needs. • WECC zonal data with out-of-the-box configuration can run standard 25-year expansion in several hours.	• Docs: Not publicly available • Website: https://www.energyexemplar.com/plexos
Power System Optimizer 3.1	• Licensed either for PSO engine (standalone) or through ENELYTIX cloud-based platform. • Data available from ENELYTIX for existing generation, load and transmission (zonal or nodal). • Datasets cover North America, Europe and other select locations.	• Model runtime and performance dependent on size and resolution of the model. • RTO-scale multi-decade expansion models typically solve between tens of minutes to several hours. • ENELYTIX cloud-based service allows for scalable computing environment to fit user needs.	• Docs: Not publicly available • Website: https://www.enelytix.com/home/pso