National Energy with Weather System

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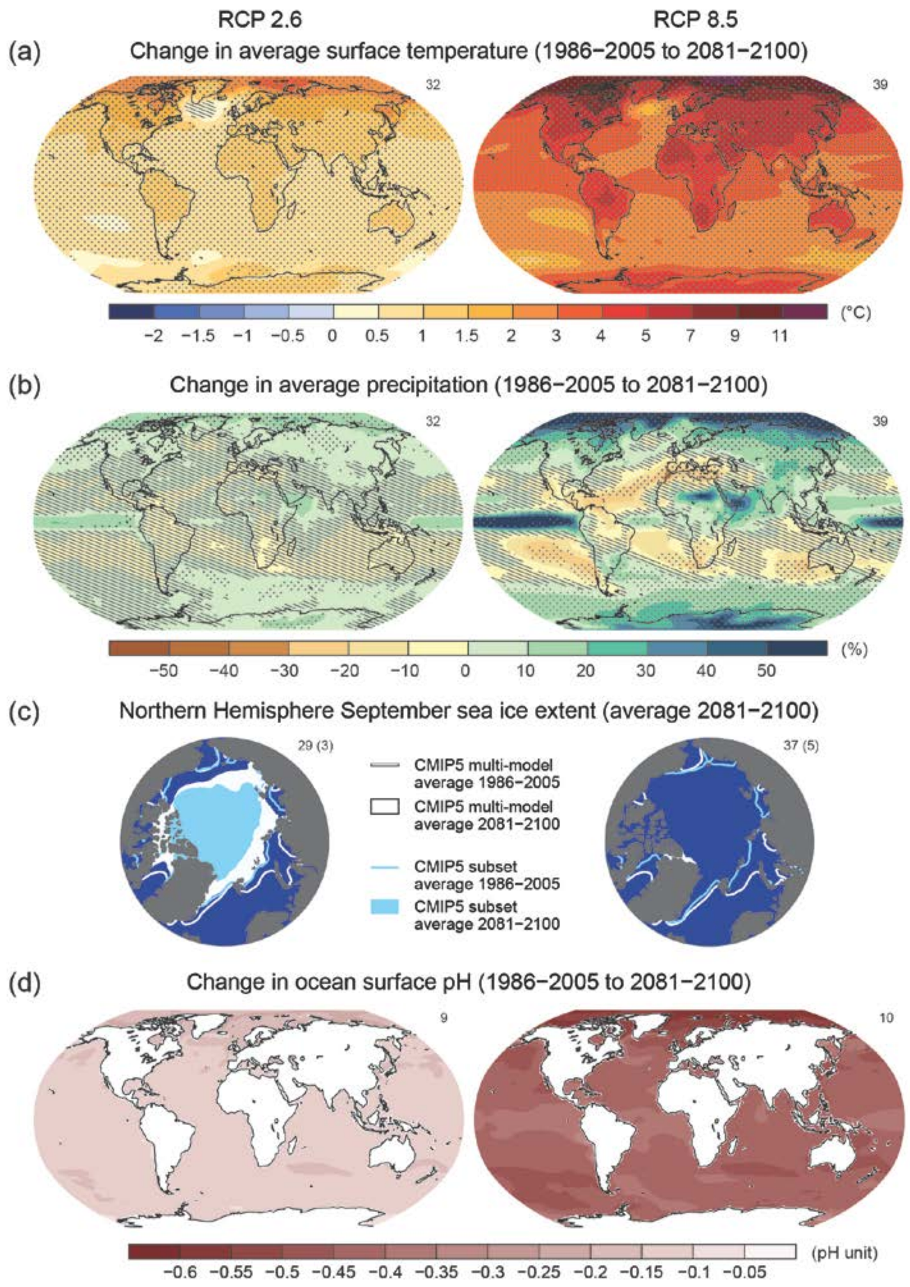
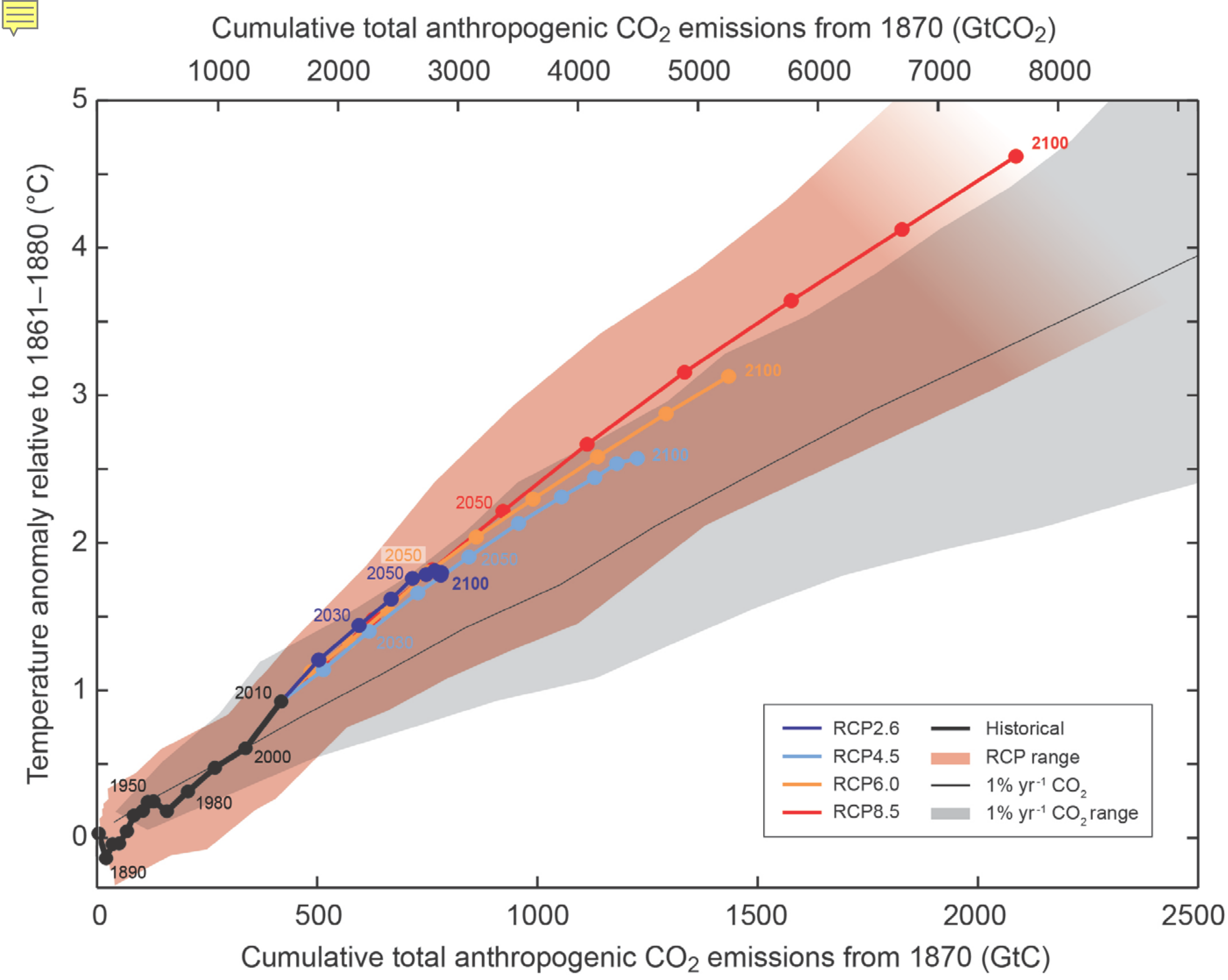
Math, programming, and all images in these slides (besides those from IPCC) are the work of Dr. Christopher Clack.

Key Points

- The NEWS model co-optimizes dispatch, transmission and capacity expansion, using high-resolution (13-km, hourly) weather data for three years.
- The NEWS model implicitly computes the security-constrained unit commitment and economic dispatch, and explicitly determines planning reserves, load-following reserves and calculates the hourly transmission power flow, the capacity expansion of generators and of transmission.
- Based on a range of estimated cost for various energy technologies, NEWS designs multiple cost-minimized energy systems.
- Demonstrates the benefit of an HVDC network to ship electricity to major load centers and to leverage the reduction in wind and solar powers' variability in large geographic areas.

Projections of Climate Change by 2100: IPCC WG1 AR5





IPCC AR5 WG1 Figure SPM.10 | Global mean surface temperature increase as a function of cumulative total global CO2 emissions from various lines of evidence. Multi-model results from a hierarchy of climate-carbon cycle models for each RCP until 2100 are shown with coloured lines and decadal means (dots). Model results over the historical period (1860 to 2010) are indicated in black. The coloured plume illustrates the multi-model spread over the four RCP scenarios and fades with the decreasing number of available models in RCP8.5. The multi-model mean and range simulated by CMIP5 models, forced by a CO2 increase of 1% per year (1% yr–1 CO2 simulations), is given by the thin black line and grey area. Temperature values are given relative to the 1861−1880 base period, emissions relative to 1870.

IPCC AR5 WG1 Table SPM.3 | Cumulative CO2 emissions for the 2012 to 2100 period compatible with the RCP atmospheric concentrations simulated by the CMIP5 Earth System Models.

Scenario	Cumulative CO_2 Emissions 2012 to 2100[a]			
	GtC		$GtCO_2$	
	Mean	Range	Mean	Range
RCP2.6	270	140 to 410	990	510 to 1505
RCP4.5	780	595 to 1005	2860	2180 to 3690
RCP6.0	1060	840 to 1250	3885	3080 to 4585
RCP8.5	1685	1415 to 1910	6180	5185 to 7005

Notes:

[a] 1 Gigatonne of carbon = 1 GtC = 10^{15} grams of carbon. This corresponds to 3.667 $GtCO_2$.

Limiting the warming caused by anthropogenic CO2 emissions alone with a probability of >33%, >50%, and >66% to <2°C since the period 1861–1880, will require cumulative CO2 emissions from all anthropogenic sources to stay between 0 and 5760 GtCO2, 0 and 4440 GtCO2, and 0 and 3670 GtCO2 since that period, respectively.

These upper amounts are reduced to about 3300 GtCO2, 3010 GtCO2, and 2900 GtCO2, respectively, when accounting for non-CO2 forcings as in RCP2.6.

NEWS: National Energy with Weather System

1. NEWS leverages high-resolution weather data.
2. NEWS meets the energy demand every hour of the year, for three years. Load data come from FERC (Form 714) data for the same years, projected to 2030 levels.
3. NEWS uses a range of estimated prices for each technology and set price for HVDC.
4. NEWS co-optimizes dispatch, transmission and capacity expansion to design cost-minimized energy systems.

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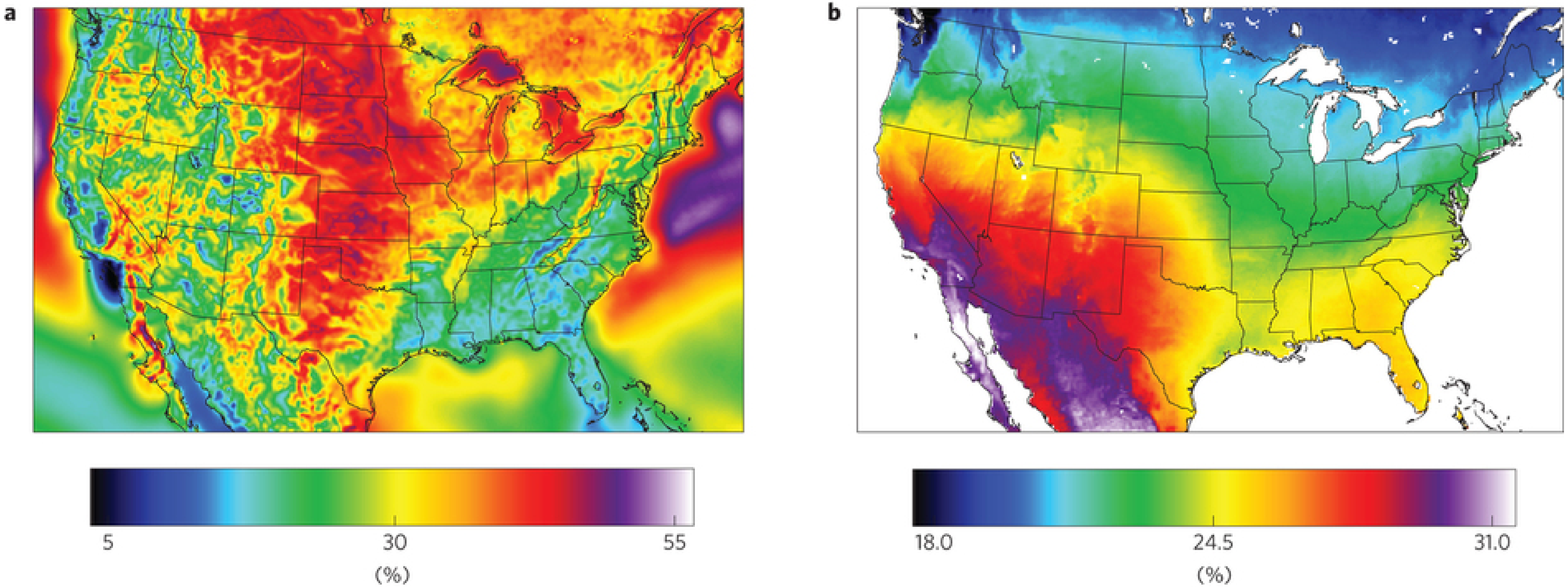
Weather Data: Resource Potential as Capacity Factor

Wind

Solar



Low

High

Low

High

Note: Different scales

Image credit - Nature Climate Change, MacDonald and Clack et al., Jan. 25, 2016, Figure 2.

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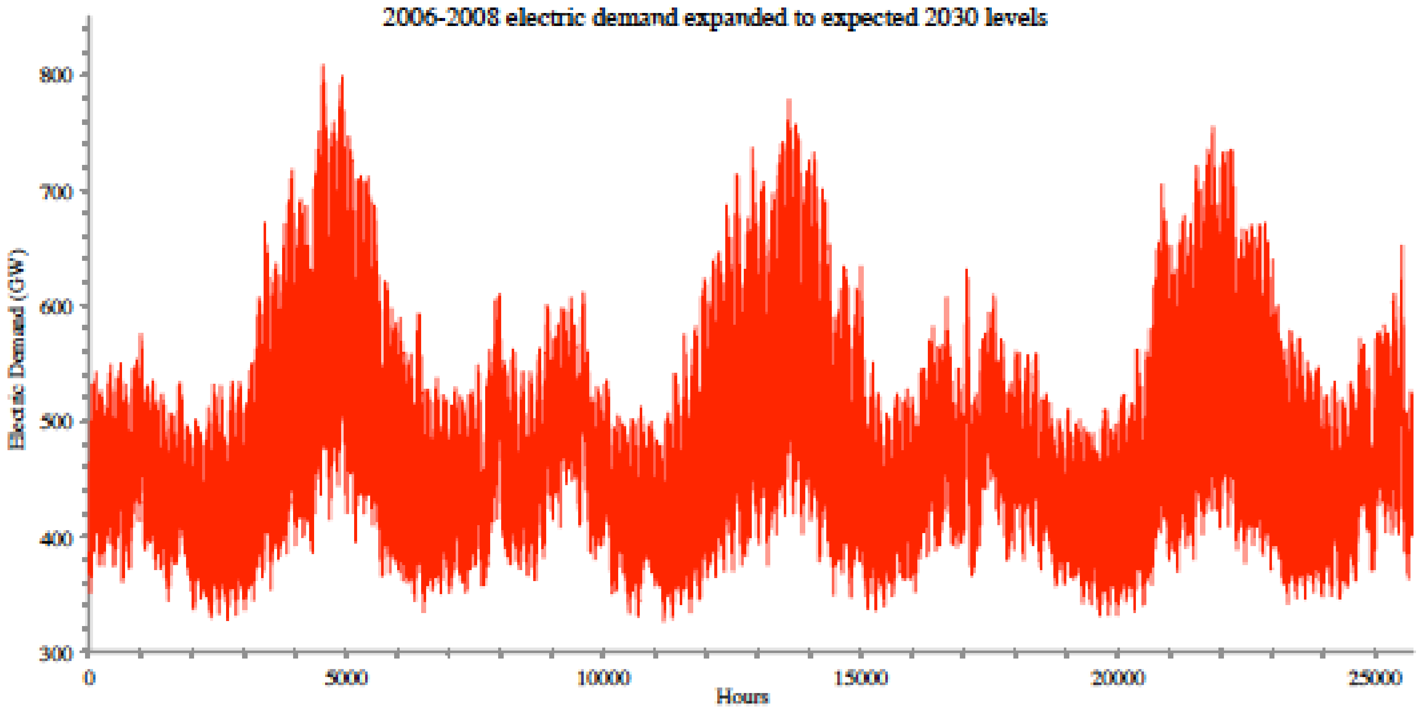
Energy Demand at 2030



The aggregated US 48 states hourly electric load for 2006–2008 expanded to 2030 levels. The higher peaks are the summers which are dominated by air conditioning demand.

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Ranges of Prices Used

Cost of capital and O&M of technologies (2013$ / W), natural gas fuel (2013$ / MMBtu), HVDC transmission line (2013$ / MW-mile), and HVDC stations (2013$ / MW).

	Onshore	Offshore	PV	CCGT	NG Fuel	HVDC lines	HVDC Stations
LRHG Scenario	$2.16	$3.41	$1.19	$1.24	$11.10	$701.36	$182,856.11
MRMG Scenario	$2.25	$5.53	$2.57	$1.24	$8.82	$701.36	$182,856.11
HRLG Scenario	$2.36	$7.64	$3.94	$1.24	$5.40	$701.36	$182,856.11

LRHG = Low-cost Renewables, High-cost Gas
MRMG = Mid-cost Renewables, Mid-cost Gas
HRLG = High-cost Renewables, Low-cost Gas

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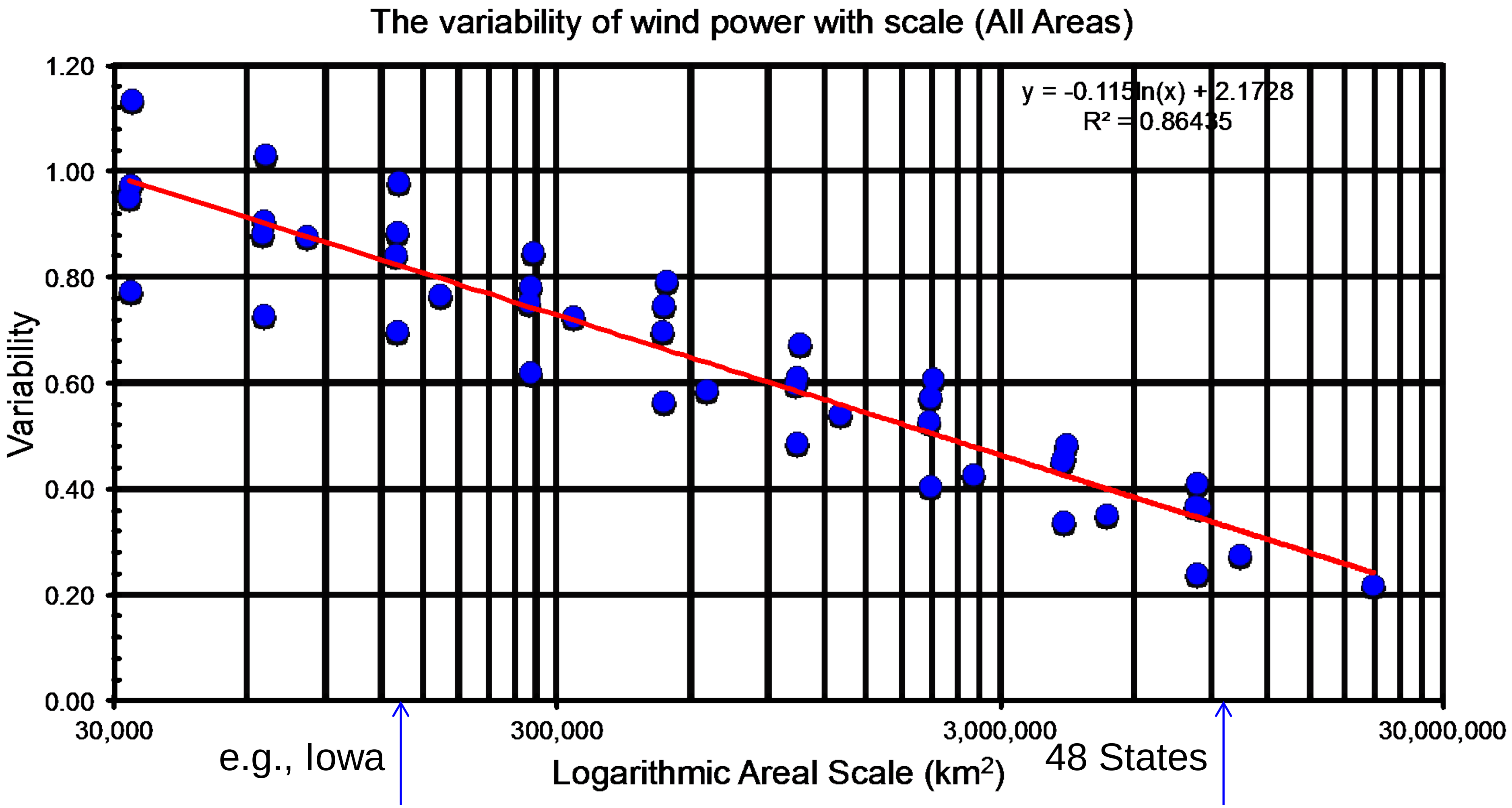
Basics of the Mathematical Optimization in the NEWS Model

ALL OTHER EQUATIONS CONSTRAIN THE MAGNITUDE OF ANY OF THE TERMS

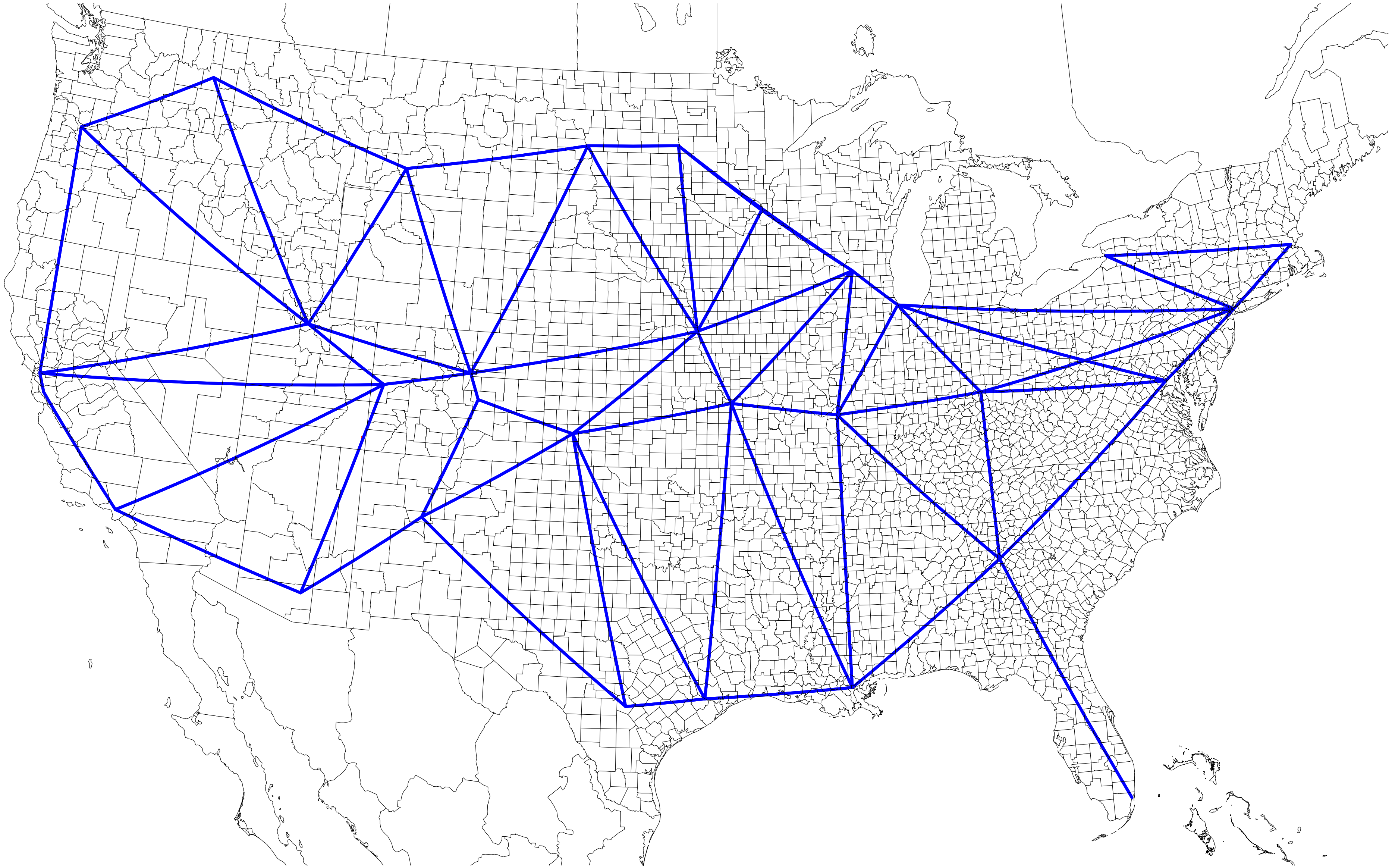
For details of the NEWS optimization see Clack *et al.*, IJEPES 2015.

Wind *is* variable



Variability here is defined as the average coefficient of variation over a geographic region when divided up into isolated regions

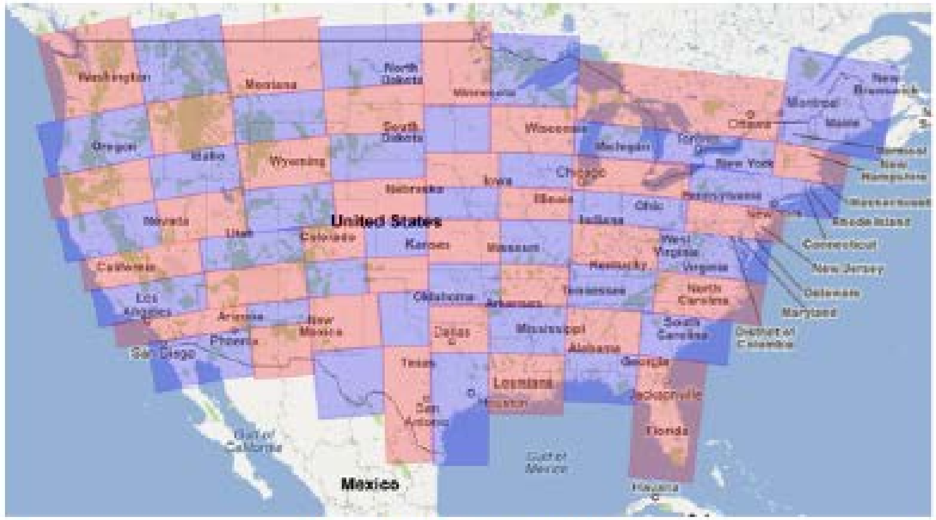
HVDC Transmission Network



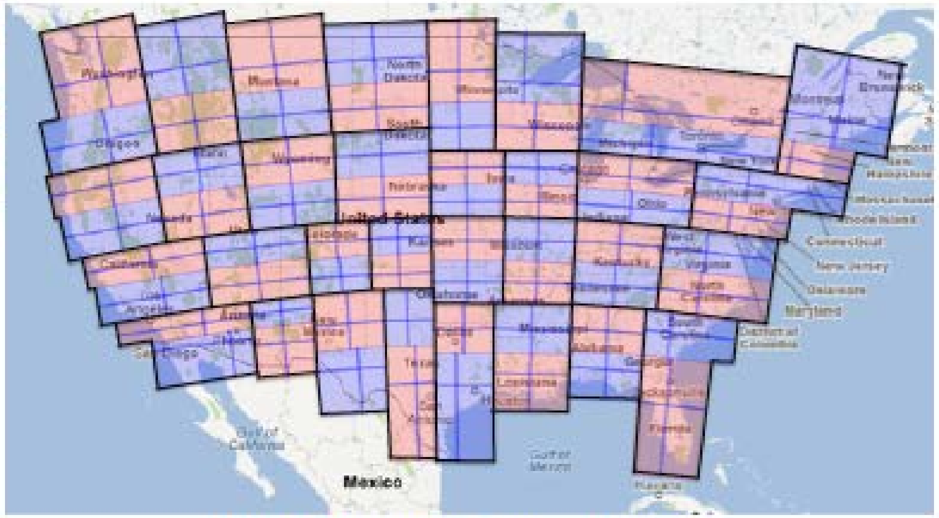
NEWS Divisions, Regional Market Areas, and Nodal Areas

(a) Single division

(b) Four divisions

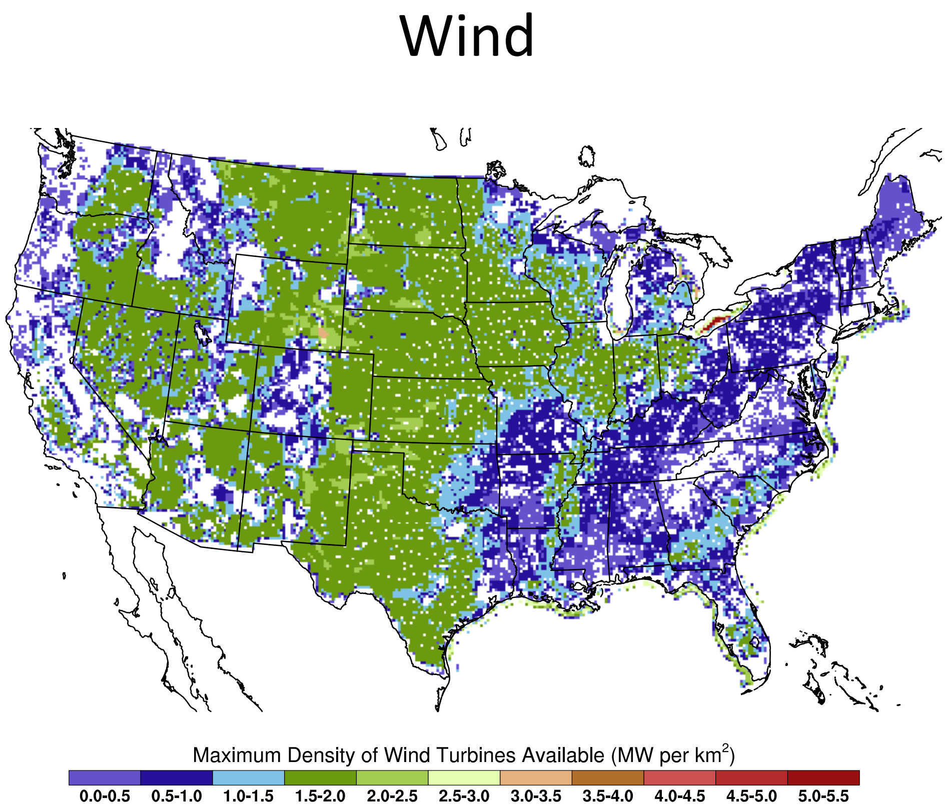


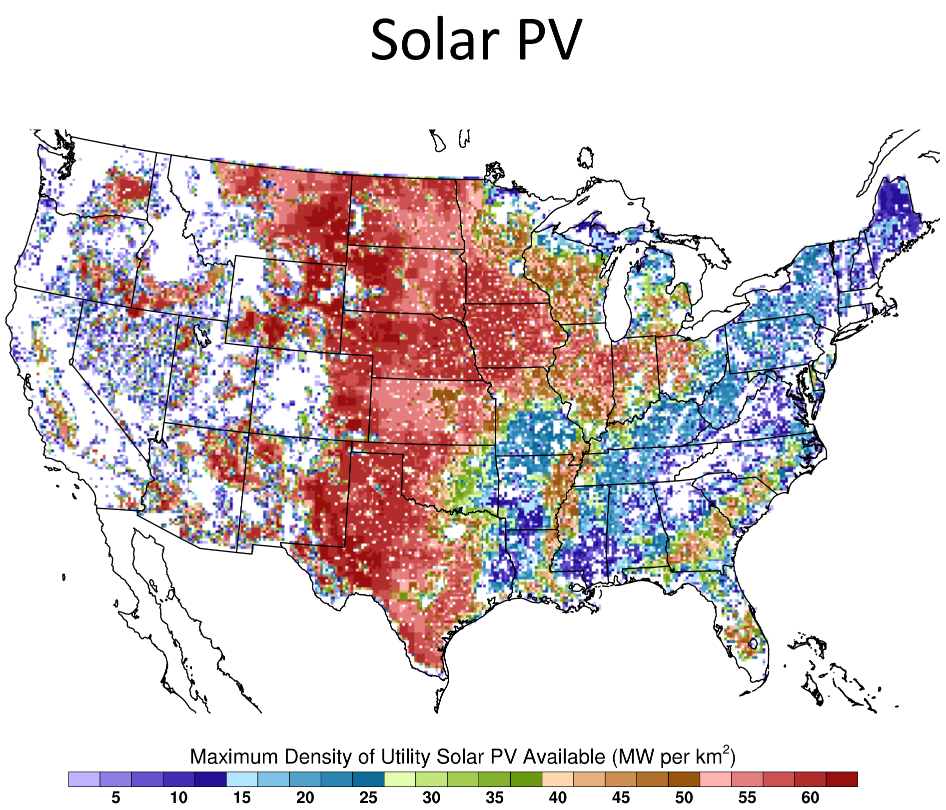
(c) Sixty four divisions



(d) The thirty two regional markets

Land Use Constraints for RE Deployment





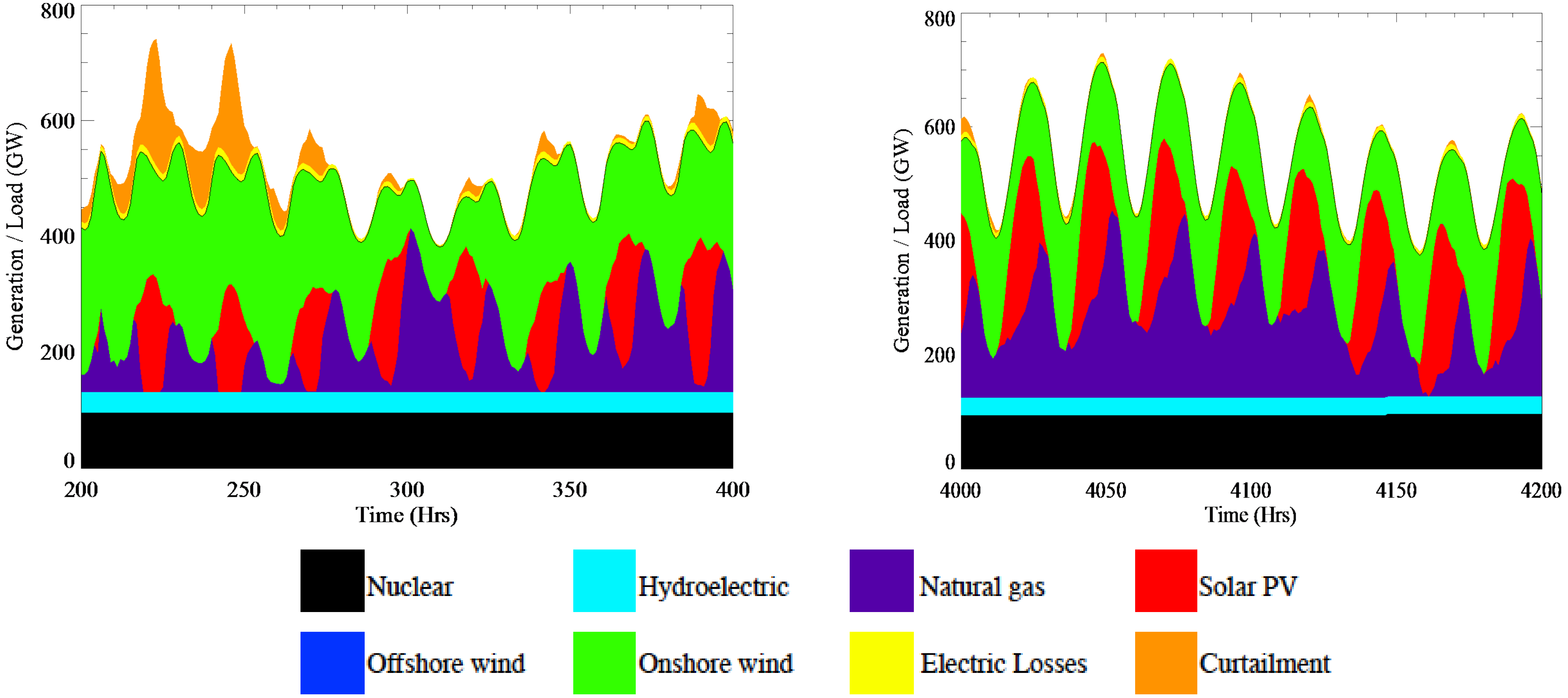
The type and amount of electricity generation installed in each RUC cell is constrained by:

- **Spacing between facilities**
- **Topography of the land**
- **Land Use (residential, commercial, protected lands, etc…)**

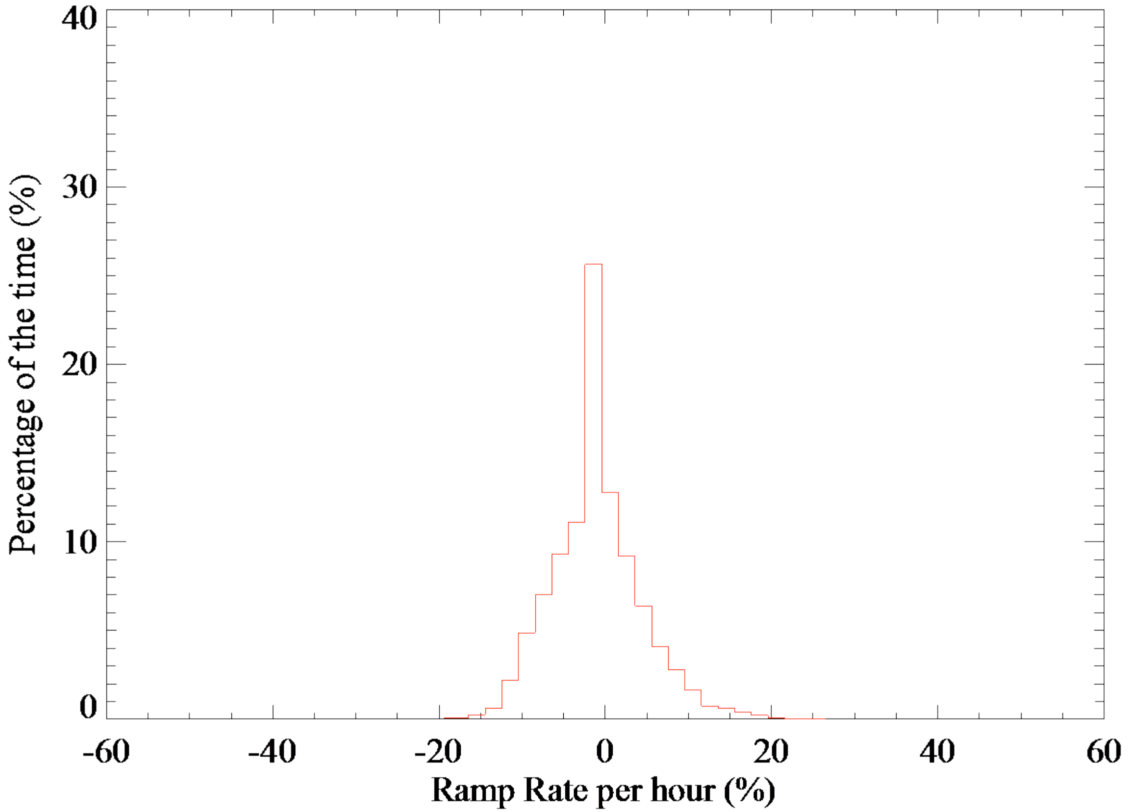
Dispatch Stacks

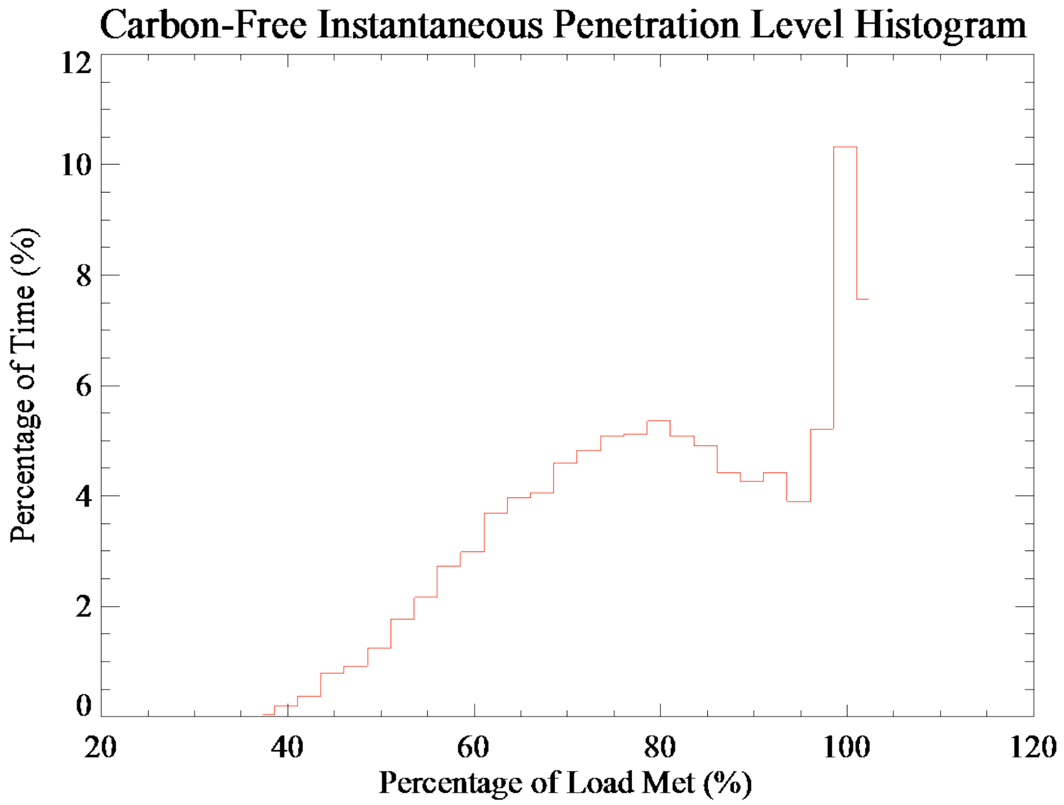
Week in Winter

Week in Summer

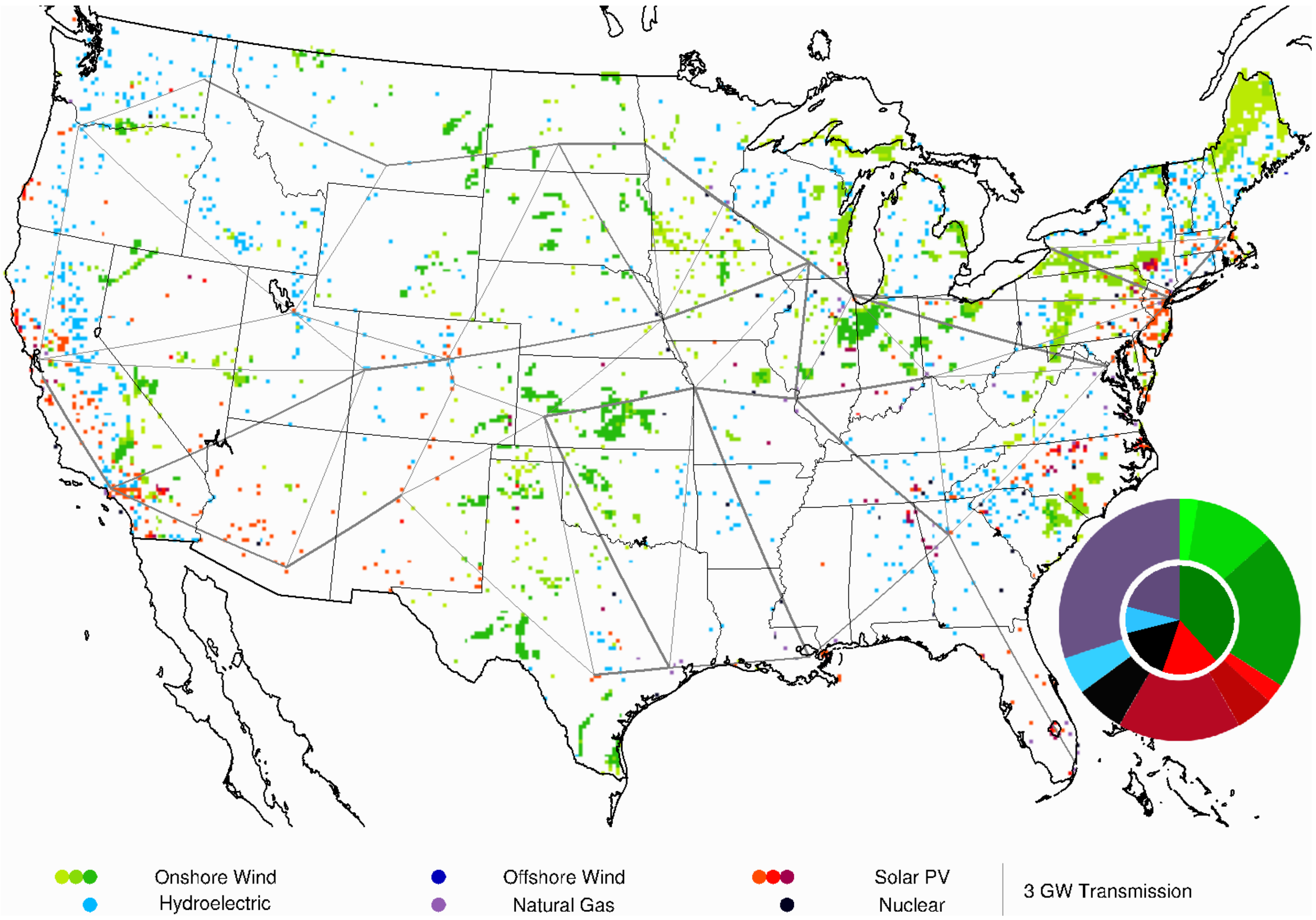


Statistics for Entire Year





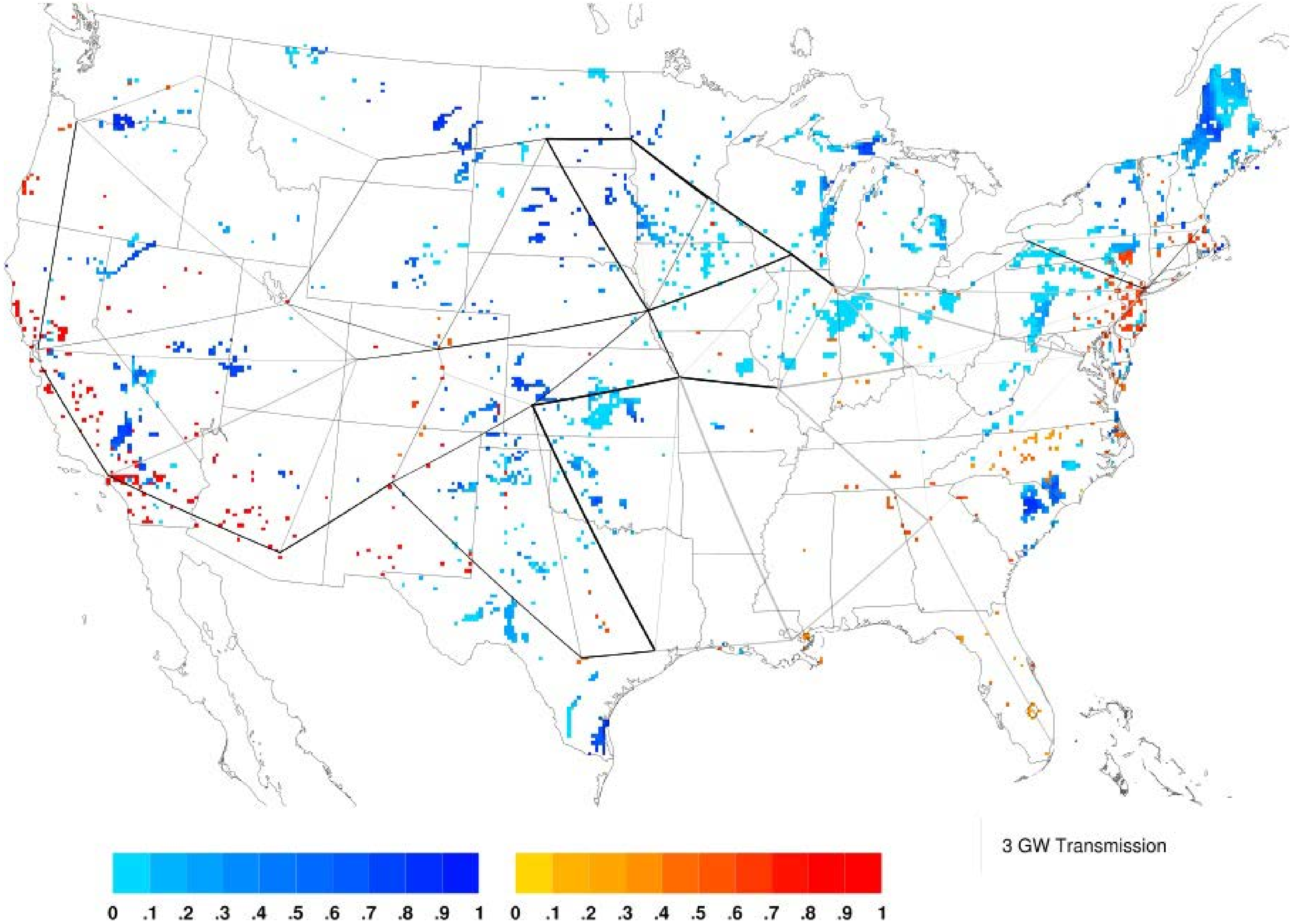
One Solution: Cost Optimized US Electric Power System ifor2030 (LRHG)



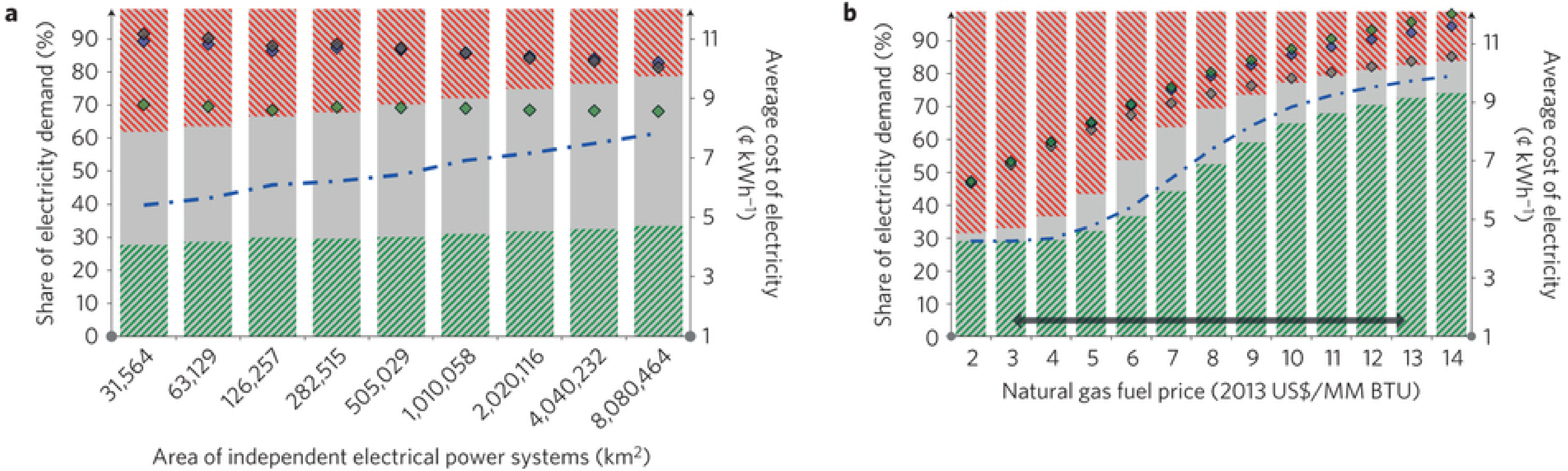
Wind	38%
Solar PV	17%
Nat'l Gas	21%
Nuclear	16%
Hydro	8%

Cost-optimized single electrical power system for the contiguous US, using data year 2007. The colors indicate that a model grid cell has a technology sited within it. Onshore wind and solar PV are split into three bins to designate the density of installations. For wind the bins are: less than 0.5 W/m^2; between 0.5 W/m^{2}and 1.5 W/m^2; above 1.5 W/m^2. For solar the bins are: less than 5 W/m^2; between 5 W/m^{2}and 10 W/m^2; above 10 W/m^2. The grey lines show the HVDC transmission network. The outer pie chart represents the installed capacity, whereas the inner pie chart shows the electricity demand met by each technology.

National Electric Power System (2007 / Low RE & High NG / 1 System) Hour 4000



Sensitivity of Electric System to Geographic Scale and Natural Gas Fuel Cost



Levelized Cost of Electricity for a National System

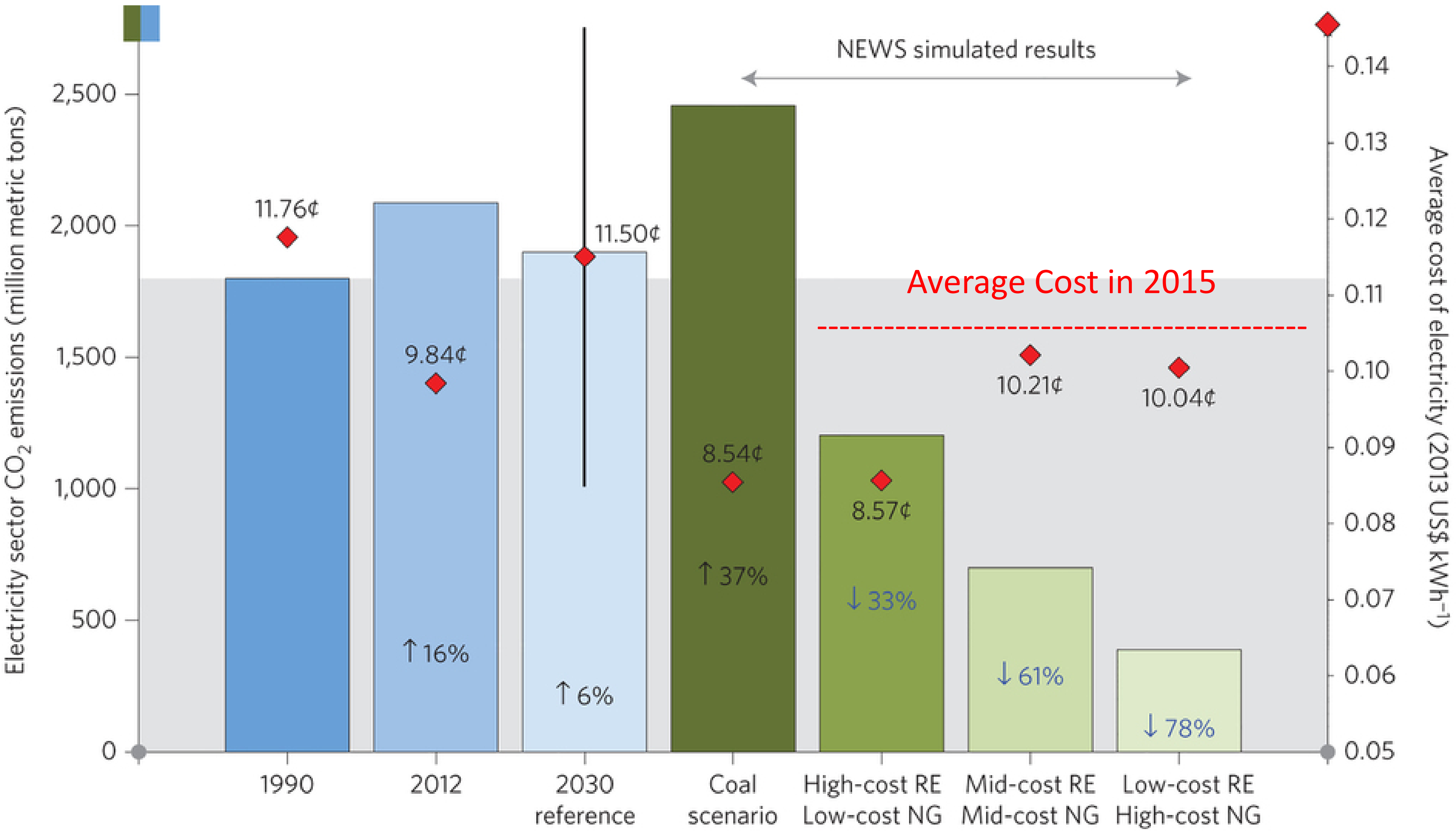


Image credit - Nature Climate Change – Figure 2 - http://rdcu.be/f2Dg

Key Points

- The NEWS model co-optimizes dispatch, transmission and capacity expansion, using high-resolution (13-km, hourly) weather data for three years.
- The NEWS model implicitly computes the security-constrained unit commitment and economic dispatch, and explicitly determines planning reserves, load-following reserves and calculates the hourly transmission power flow, the capacity expansion of generators and of transmission.
- Based on a range of estimated cost for various energy technologies, NEWS designs multiple cost-minimized energy systems.
- One of the cost-minimized systems designed by NEWS calls for U.S. electricity generation as follows:

  38% wind, 17% solar PV, 21% natural gas , 16% nuclear, and 8% hydropower without an increase in LOCE
- HVDC network to ship electricity to major load centers and to leverage the reduction in wind and solar powers' variability in large geographic areas.
- Contacts: christopher.clack@noaa.gov and Melinda.Marquis@noaa.gov
- http://www.esrl.noaa.gov/gsd/renewable/news-simulator.html

Back-up Slides

Assumptions in NEWS

- Electric load is met or exceeded by the generation at every hourly model time step in every nodal area.
- The natural gas plants can only be sited at geographic locations that have fossil fuel plants in 2012 (shown in Fig. 31), to ensure that the necessary infrastructure and permitting is in place.
- Utility-scale solar PV is considered, but rooftop solar PV is not. The transmission handling of the optimization model is high level and does not extend beyond the last busbar before the customers are reached in each of the 256 nodal areas, where the rooftop solar PV resides. Further, the optimized solutions tends to locate solar PV near nodal centers (cities) that can be substituted, in part, by rooftop solar PV if the cost becomes favorable.
- Indirect costs associated with approval of new generation facilities (legal, environmental, health, etc.) are not explicitly accounted for. However, the meta-analysis of the cost projections does include studies that do account for part of these costs.
- Negative externalities often associated with fossil fuel electricity generation are not assigned a cost in the present model, i.e. no carbon or other emissions tax is applied for the results presented and discussed in the present paper.
- Hydroelectric generation is dispatched based upon historical monthly average values for the three data years to account for the seasonal hydrological cycle.
- Nuclear generation is dispatched based on the lowest historical monthly average for the last decade to be conservative with respect to its production.
- Nuclear and hydroelectric generation is allowed to ramp by small amounts (2.5% and 5%, respectively) around the historical values for numerical stability

Assumptions (cont’d)

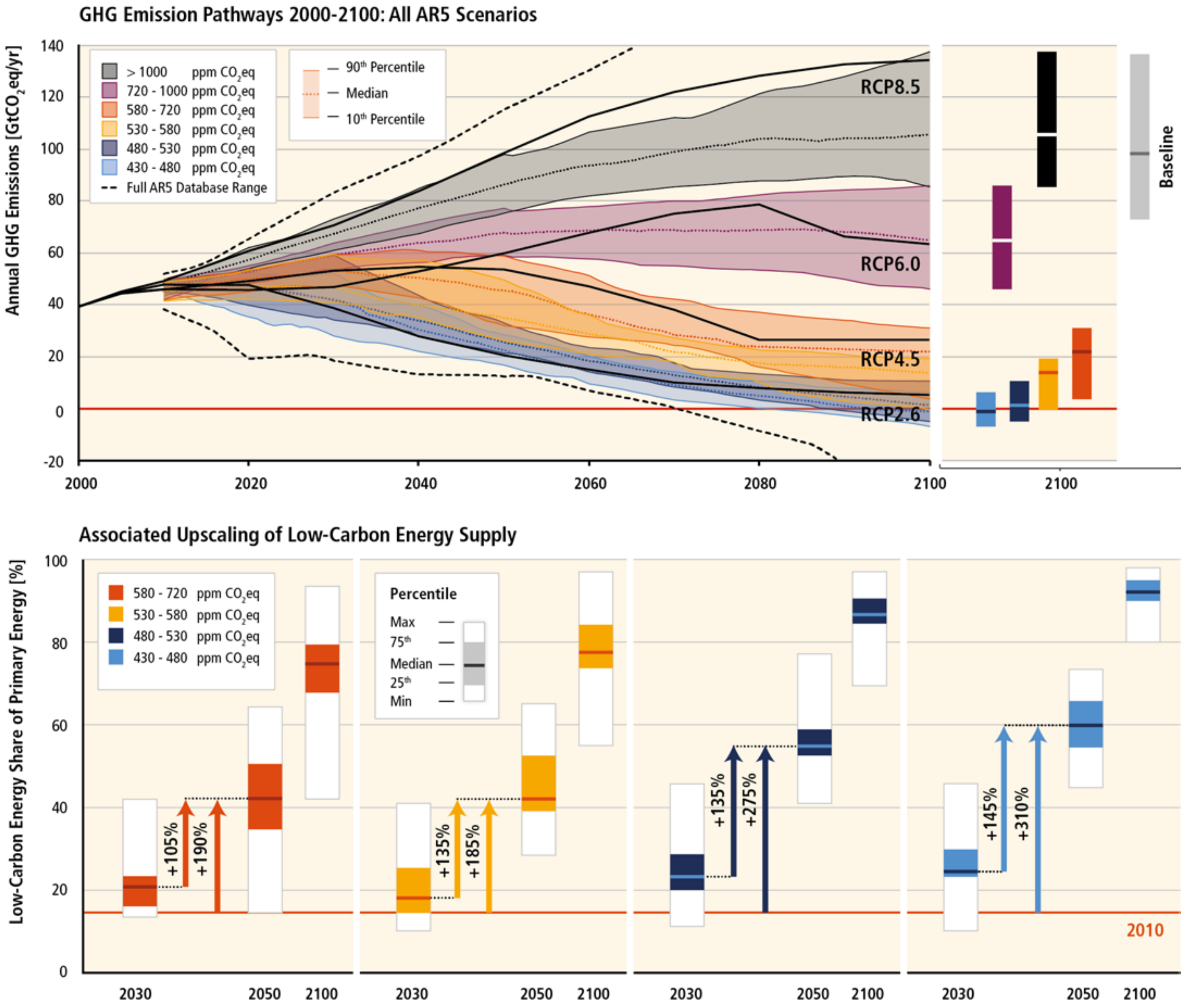
- The modeled system is optimized, having the benefit of load distribution and weather data a priori; hence the resulting optimization is free from transmission congestion. Market dynamics associated with capacity-dependent transmission and weather forecast uncertainty are not modeled.
- Within each nodal area, AC electrical losses are simply modeled based on geodesic distance between generator and node center. The local AC distribution network is not modeled explicitly, but is assumed to be capable of providing necessary transmission within each nodal area.
- An additional overlay HVDC transmission system is used to transmit power between the 32 regional market areas. This is done because a) it is the most cost-effective from a capacity (MW-mile) basis over long distances, b) the associated line losses are significantly lower than with AC transmission, and c) there are no steady-state stability or other AC phase problems across long distances.

Some of the main assumptions used to build the model are:

- Three cost scenarios are presented in the present paper. All generators available to the optimization are assumed to have a 30-year service life. The annual plant cost is amortized over its service life using a real discount rate of 6.6%. The 2025 projection of costs are considered “Low”, present-day costs are considered “High” and “Mid” is a simple average of these two costs. The natural gas turbine technology is assumed to be mature and plant cost is not varied between the three cost scenarios. The natural gas fuel cost is taken from the 2040 high resource, reference, and low resource scenarios from the EIAs 2013 Annual Energy Outlook. Costs are held constant throughout the optimization period and across geographic regions.

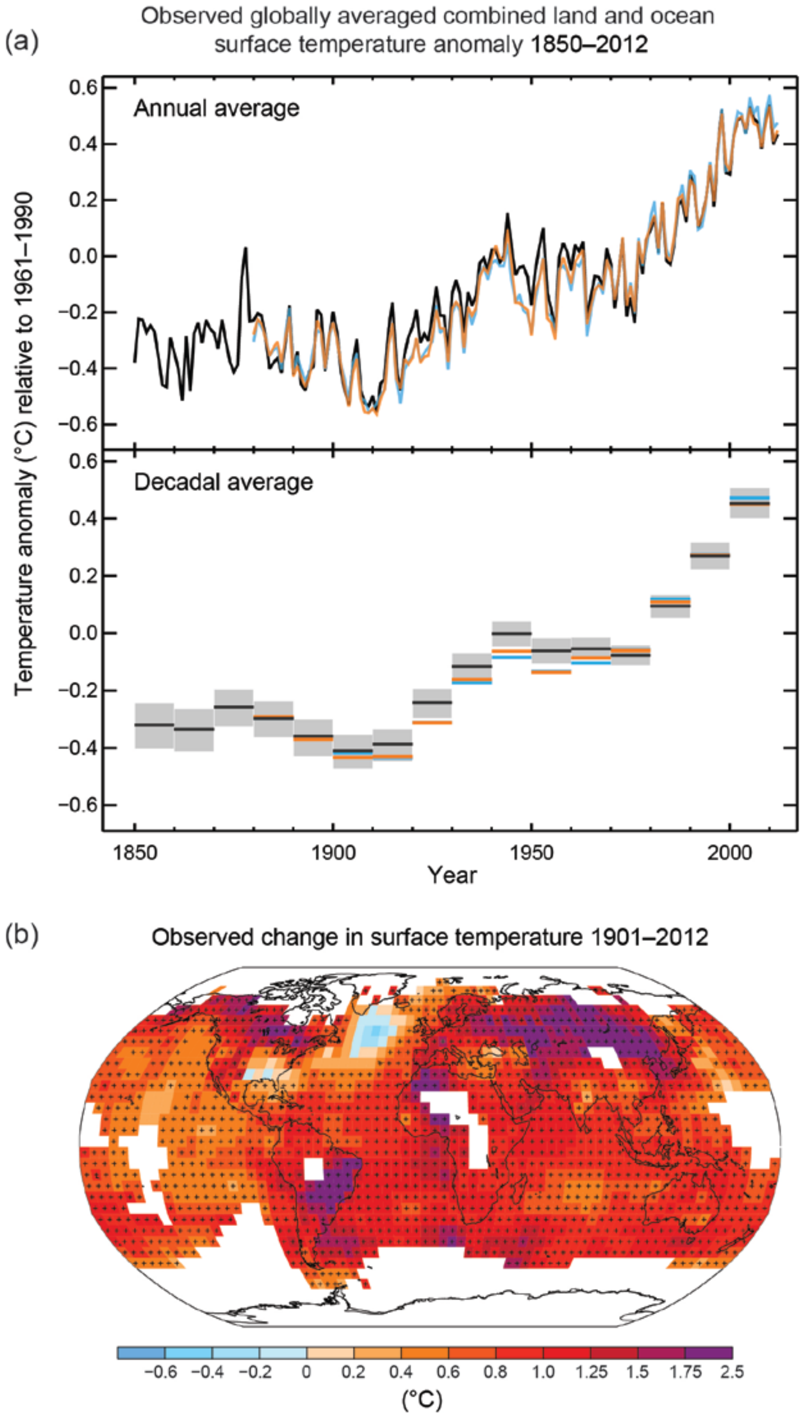
Assumptions (cont'd)

- The optimization routine provides the single best solution in terms of cost. Numerous solutions exist that are slightly sub-optimal, but possess very similar features in terms of siting, dispatch, etc.
- The load-following and planning reserve requirements are identical at all geographic locations.
- Natural gas plants have no ramping constraints in the present paper. However, gas sector ramp rates were analyzed for the resulting systems and were found to be between 60% / hour up-ramp and 60% / hour down-ramp which is well within current combined cycle gas turbine capability.
- There is no pre-determined dispatch order. The cheapest generation sources will be brought online as needed at each model time step.
- Nuclear, hydroelectric, wind and solar PV generators that existed by the end of 2012 are assumed to be in-place and operational in all optimization scenarios.
- Electricity storage is considered in the optimization model; however, current and projected storage costs resulted in it never being selected as an option; so it was removed to simplify the description of the model. Storage is selected if its price is considerably reduced, or other constraints are enforced (such as carbon mitigation targets etc.).
- Hourly electric load and meteorological data are sufficient to model the electric power system subhourly variability; since the electric grids are on such a large geographic scale.
- The projected load is simply the 2006–2008 load increased by 0.7% per annum. As such, there are no specific assumptions regarding electric vehicle charging or discharging.
- Social and political constraints on the development of generation plants and transmission are not considered; other than exclusion from existing protected areas (National Parks, urban areas, wildlife habitats, shipping lanes. etc.).
- Demand response, load shifting, or future electric load behavior alterations are not accounted for.



IPCC AR5 WG3 Figure SPM.4

Pathways of global GHG emissions ($GtCO_2eq$ / yr) in baseline and mitigation scenarios for different long-term concentration levels (upper panel) and associated upscaling requirements of low-carbon energy (% of primary energy) for 2030, 2050 and 2100 compared to 2010 levels in mitigation scenarios (lower panel) . The lower panel excludes scenarios with limited technology availability and exogenous carbon price trajectories. For definitions of CO2-equivalent emissions and CO2-equivalent concentrations see the WGIII AR5 Glossary.



IPCC AR5 WG1 Figure SPM.1 |

(a) Observed global mean combined land and ocean surface temperature anomalies, from 1850 to 2012 from three data sets.

Top panel: annual mean values.

Bottom panel: decadal mean values including the estimate of uncertainty for one dataset (black). Anomalies are relative to the mean of 1961−1990.

(b) Map of the observed surface temperature change from 1901 to 2012 derived from temperature trends determined by linear regression from one dataset (orange line in panel a).

$$\text{Minimize}\quad \psi = \sum_{\phi}\sum_{\kappa}\mathscr{C}^{v}_{\phi\kappa}\cdot x_{\phi\kappa} + \sum_{\mu}\mathscr{C}^{g}_{\mu}\cdot C^{g}_{\mu} + \sum_{\mu}\mathscr{C}^{s}_{\mu}\cdot C^{s}_{\mu}$$

$$+ \sum_{\hat{\alpha}}\sum_{\hat{\beta}}\mathscr{C}^{T}_{\hat{\alpha}\hat{\beta}}\cdot T_{\hat{\alpha}\hat{\beta}}\cdot\mathscr{D}_{\hat{\alpha}\hat{\beta}} + \sum_{\mu}\left[\left(\mathscr{C}^{f}_{\mu} + \mathscr{C}^{c}_{\mu}\cdot\mathscr{H}_{\mu}\cdot\mathscr{F}\right)\cdot\sum_{\tau}g_{\mu\tau}\right]$$

subject to:

$$\sum_{\phi}\sum_{\kappa}\left(b_{\phi\mu}\cdot x_{\phi\kappa}\cdot r_{\phi\kappa\tau}\right) + g_{\mu\tau} + t_{\mu\tau} + s^{i}_{\mu\tau}\cdot\left(1-\mathscr{L}^{fs}_{\mu}\right) - s^{o}_{\mu\tau} - c_{\mu\tau} = L_{\mu\tau},\quad \forall\, \mu,\tau;$$

$$t_{\mu\tau} = \sum_{\alpha}\mathscr{T}_{\alpha\beta\tau}\cdot\left(1-\mathscr{L}^{T}_{\alpha\beta}\cdot\mathscr{D}_{\alpha\beta}\right)\Big|_{\beta=\mu} - \sum_{\beta}\mathscr{T}_{\alpha\beta\tau}\Big|_{\alpha=\mu},\quad \forall\, \mu,\tau\ (\alpha\neq\beta);$$

$$T_{\hat{\alpha}\hat{\beta}} \geq \mathscr{T}_{\alpha\beta\tau}\big|_{\alpha,\beta=\hat{\alpha},\hat{\beta}} \geq 0,\quad \forall\, \hat{\alpha},\hat{\beta},\tau\ (\hat{\alpha}>\hat{\beta});$$

$$\hat{S}_{\mu\tau} = \left[s^{o}_{\mu\tau}\cdot\left(1-\mathscr{L}^{ts}_{\mu}\right) - s^{i}_{\mu\tau}\right] + \hat{S}_{\mu(\tau-1)}\cdot\left(1-\mathscr{L}^{rs}_{\mu}\right),\quad \forall\, \mu,\tau\geq 1;$$

$$C^{s}_{\mu} \geq \left(1+\mathscr{R}^{s}_{\mu}\right)\cdot\hat{S}_{\mu\tau} \geq 0,\quad \forall\, \mu,\tau;$$

$$0 \leq s^{o}_{\mu\tau} \leq \mathscr{S}^{\mathrm{D}}_{\mu}\cdot C^{s}_{\mu},\quad \forall\, \mu,\tau;$$

$$0 \leq s^{i}_{\mu\tau} \leq \mathscr{S}^{\mathrm{C}}_{\mu}\cdot C^{s}_{\mu},\quad \forall\, \mu,\tau;$$

$$C^{g}_{\mu} \geq \left(1+\mathscr{R}^{g}_{\mu}\right)\cdot g_{\mu\tau} \geq 0,\quad \forall\, \mu,\tau;$$

$$0 \leq g_{\mu\tau} \leq g_{\mu(\tau-1)} + \mathscr{G}^{u}_{\mu}\cdot C^{g}_{\mu},\quad \forall\, \mu,\tau\geq 1;$$

$$g_{\mu\tau} \geq g_{\mu(\tau-1)} - \mathscr{G}^{d}_{\mu}\cdot C^{g}_{\mu} \geq 0,\quad \forall\, \mu,\tau\geq 1;$$

$$0 \leq x_{\phi\kappa} \leq X_{\phi\kappa},\quad \forall\, \phi,\kappa;$$

$$\sum_{\phi}\sum_{\kappa}\sum_{\tau}\left(b_{\phi\mu}\cdot x_{\phi\kappa}\cdot r_{\phi\kappa\tau}\right) \geq \mathscr{P}_{\mu}\cdot\sum_{\tau}L_{\mu\tau},\quad \forall\, \mu;$$

$$\alpha,\hat{\alpha},\beta,\hat{\beta},\mu \in \mathscr{N},\ \phi\in\mathscr{B},\ \kappa\in\mathscr{V},\ \tau\in\mathscr{Q}.$$

Optimization Procedure

$$\text{Minimize} \quad \psi = \sum_{\phi}\sum_{\kappa} \mathcal{C}^{v}_{\phi\kappa} \cdot V_{\phi\kappa} + \sum_{\mu}\left(\mathcal{C}^{g}_{\mu} \cdot G_{\mu} + \mathcal{C}^{f}_{\mu} \cdot \sum_{\tau} D_{\mu\tau}\right) + \sum_{\hat{\alpha}}\sum_{\hat{\beta}} T_{\hat{\alpha}\hat{\beta}} \cdot \left(\mathcal{C}^{ts} + \mathcal{C}^{tl}_{\hat{\alpha}\hat{\beta}} \cdot \delta_{\hat{\alpha}\hat{\beta}}\right)$$

Natural gas generation (MWh)

Yearly cost of transmission stations ($/MW)

Yearly cost of variable generation ($/MW)

Yearly cost of conventional generation ($/MW)

Installed capacity of transmission (MW)

Installed capacity of variable generation (MW)

Installed capacity of conventional generation (MW)

Yearly cost of transmission lines ($/MW-mile)

Cost of conventional fuels ($/MWh)

Length of transmission lines (mile)

Optimization Procedure

Load constraint

VARIABLE GENERATION

CONVENTIONAL GENERATION

NET ELECTRIC DEMAND

Subject to:

$$\underbrace{\sum_{\phi}\left(b^{v}_{\phi\omega}\cdot\sum_{\kappa}V_{\phi\kappa}\cdot\mathcal{W}_{\phi\kappa\tau}\right)}_{\text{VARIABLE GENERATION}}+\underbrace{\sum_{\mu}b^{c}_{\mu\omega}\cdot\left(D_{\mu\tau}+N_{\mu\tau}+H_{\mu\tau}\right)}_{\text{CONVENTIONAL GENERATION}}=\underbrace{\mathcal{L}_{\omega\tau}-F_{\omega\tau}+E_{\omega\tau}}_{\text{NET ELECTRIC DEMAND}},\quad\forall\,\omega,\tau$$

Variable generator Filter

Installed capacity of variable generation (MW)

Weather Component (h)

Conventional generator filter

Natural gas generation (MWh)

Nuclear generation (MWh)

Hydroelectric generation (MWh)

Electric demand (MWh)

Transmission power flux (MWh)

Excess generation (MWh)

Optimization Procedure

Transmission power flux (MWh)

Transmission power flow (MWh)

Transmission power flow (MWh)

VERY IMPORTANT CONSTRAINT AND EXTREMELY COMPUTATIONALLY EXPENSIVE

HVDC transmission flux constraint

$$F_{\omega\tau} = \sum_{\alpha} T_{\alpha\beta\tau} \cdot (1 - \lambda_{\alpha\beta} \cdot \delta_{\alpha\beta})\Big|_{\beta=\omega} - \sum_{\beta} T_{\alpha\beta\tau}\Big|_{\alpha=\omega} \quad , \quad \forall\, \omega, \tau \ (\alpha \neq \beta)$$

Length of transmission lines (mile)

Electric loss factor (%/mile)

Optimization Procedure

Transmission Capacity Bound (MW)

Transmission capacity constraint

Transmission Capacity (MW)

Transmission power flow (MWh)

$$\mathcal{T}_{\hat{\alpha}\hat{\beta}} \geq T_{\hat{\alpha}\hat{\beta}} \geq T_{\alpha\beta\tau}|_{\alpha,\beta=\hat{\alpha},\hat{\beta}} \geq 0, \quad \forall\ \hat{\alpha}, \hat{\beta}, \tau\ (\hat{\alpha} > \hat{\beta})$$

Optimization Procedure

Planning reserve requirement constraint

Installed capacity of conventional generation (MW)

Conventional generator filter

Conventional generator filter

Planning reserve (%)

Natural gas generation (MWh)

$$\sum_{\mu} b^{c}_{\mu\omega} \cdot G_{\mu} \geq (1 + \mathcal{R}^{g}_{\mu}) \cdot \sum_{\mu} b^{c}_{\mu\omega} \cdot D_{\mu\tau} \geq 0, \quad \forall\, \omega, \tau$$

Optimization Procedure

$$\mathcal{B}^{n-}_{\omega} \cdot \sum_{\mu} \left(b^{c}_{\mu\omega} \cdot \mathcal{N}_{\mu\tau} \right) \leq \sum_{\mu} b^{c}_{\mu\omega} \cdot N_{\mu\tau} \leq \mathcal{B}^{n+}_{\omega} \cdot \sum_{\mu} \left(b^{c}_{\mu\omega} \cdot \mathcal{N}_{\mu\tau} \right)$$

$$\mathcal{B}^{h-}_{\omega} \cdot \sum_{\mu} \left(b^{c}_{\mu\omega} \cdot \mathcal{H}_{\mu\tau} \right) \leq \sum_{\mu} b^{c}_{\mu\omega} \cdot H_{\mu\tau} \leq \mathcal{B}^{h+}_{\omega} \cdot \sum_{\mu} \left(b^{c}_{\mu\omega} \cdot \mathcal{H}_{\mu\tau} \right)$$

Nuclear and hydroelectric dispatch constraints

$$\mathcal{B}^{v-}_{\phi\kappa} \leq V_{\phi\kappa} \leq \mathcal{B}^{v+}_{\phi\kappa}, \quad \forall\ \phi, \kappa$$

Wind and solar siting constraint

$$0 \leq G_{\mu} \leq \mathcal{B}^{g}_{\mu}, \quad \forall\ \mu$$

Natural gas siting constraint