Colorado Renewable Energy Legislation

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Presentation Overview

- Background
  - Introduce past legislation which has led to the current Colorado Renewable Energy Standard (RES)
  - Show how the overall requirements have changed, what the current requirements are and how Colorado is doing
  - Review two aspects of the Colorado Renewable Energy Standard
    - Verifying Compliance - Renewable Energy Credits (RECs)
    - Funding Incremental Cost -Renewable Energy Service Adjustment (RESA)
- Present further detail about the most recent legislation
  - House Bill 10-1001: Increase in Renewables
  - House Bill 10-1342: Solar Gardens
  - House Bill 10-1365: Clear Air, Clean Jobs

Colorado's Renewable Policies History

- Amendment 37 (2004)
  - Voter initiative, 10% by 2020
- Legislative Initiatives
  - HB 07-1281: Increases the RES, encourages additional utility funding for renewables, further encourages utility ownership
  - SB 07-100: Identifies zones in Colorado rich in energy resources; intended to spur transmission investments
  - SB09-051: Accommodates expanded utility programs for on-site solar installations
- Governor Ritter's Climate Action Plan (2007)
  - 20% reduction in CO_2 emissions for electric utilities by 2020 compared to a 2005 baseline

Colorado's Renewable Policies History

- Main Aspects of Amendment 37 & HB-1281
  - Set Milestones of Levels to be Achieved
    - 10% Renewable Energy by 2020
    - Later increased to 20% then to 30%
  - Limit Incremental Cost
    - Initially set not to exceed 1% of retail sales
    - Later increased to 2%
  - Incentivize Smaller Scale Distributed Renewables
    - Community Projects
    - On-site solar
    - Later on-Site solar is included with retail distributed generation
  - Net Metering

Current Renewable Requirements

- Colorado Renewable Energy Standards (RES)
  - Each Regulated Utility shall generate, or cause to be generated, electricity from eligible renewable energy resources in the following minimum amounts:

    (as a percentage of retail electric sales MWh)

    - 2007 : 3%
    - 2008 – 2010: ~~3%~~ 5%
    - 2011 – 2014: ~~6%~~ ~~10%~~ 12%
    - 2015 – 2019: ~~10%~~ ~~15%~~ 20%
    - 2020 & beyond: ~~10%~~ ~~20%~~ 30%

Current Renewable Requirements

- ~~Solar set aside: 4% of the above from solar energy, half of which from customer sited resources and set rebate $2 rebate payment~~

- Distributed Generation (DG)

  (as a percentage of retail electric sales MWh)

  (counts toward overall requirement)

  - 2011 – 2012: 1%
  - 2013 – 2014: 1.25%
  - 2015 – 2016: 1.75%
  - 2017 – 2019: 2%
  - 2020 & beyond: 3%

Current Renewable Requirements

- Colorado Renewable Energy Standards (RES)
  - Each Municipal Owned Utility and Rural Electric Association shall generate, or cause to be generated, electricity from eligible renewable energy resources in the following minimum amounts:

    (as a percentage of retail electric sales MWh)
    - 2008 – 2010: 1%
    - 2011 – 2014: 3%
    - 2015 – 2019: 8%
    - 2020 & beyond: 10%

Current Renewable Requirements

- What does this approximately translate to for generation in Colorado
  - 30 MW of Existing Hydro
  - 2,400 MW of Wind (1,800 MW existing)
  - 225 MW Central PV (18 MW existing)
  - 300 MW of Bio-mass or Concentrating Solar (20 MW)
  - 250 MW of Retail DG (50 MW existing)

(includes 1.25 REC in-state multiplier for non retail DG)

(35,000 GWh QRU & 24,000 GWh other)

(includes no ERP Resources)

Verifying Compliance

- Renewable Energy Credit (REC)
  - 1 MWh of Energy from a Renewable Resource = 1 REC
  - A REC is meant to represent the incremental benefits between a megawatt hour produced by conventional generation and a megawatt hour produced by a renewable resource, such benefits include:
    - Clean air and water
    - Economic benefits
    - Less Fuel Volatility and More Diversity
  - Issues that Complicate Matters
    - Different Life Expectancies (shelf-life)
    - Type of Generation Resource
    - Location of Resource
    - Different Emission Impacts

REC Retirement

- Public Service

Year	Balance	RECs Generated	RECs Retired for Compliance
2009	7,879,668	3,666,715	1,377,341
2010	10,169,042	3,872,890	1,430,210
2011	12,611,722	4,267,768	3,473,042
2012	13,406,448	4,738,897	3,570,104
2013	14,575,241	5,325,241	3,609,765
2014	16,209,717	6,254,548	3,632,046
2015	18,913,219	6,503,098	6,125,884
2020	N/A	N/A	9,893,182

Funding of Incremental Cost

- Renewable Energy Service Adjustment
  - Bill Rider set at 2% of Retail Sales
  - Funds collected are set aside in a RESA account
  - Costs spent for renewable resources are tracked and reported each month to the Commission
  - Incremental costs are calculated and charged against the RESA account
  - Non-incremental costs or the costs left over after deducting the incremental costs are charged to the Electric Commodity Adjustment (represent costs that would have otherwise been incurred if renewables were not acquired)

Funding of Incremental Cost

- Calculation of Incremental Costs (2% Limit)

RES Plan: Modeled System Cost of Utility Resources with Renewables	-	NO-RES Plan: Redispatch of the Model with Traditional Resources Replacing Renewables	=	(Modeled) Incremental Cost

Funding of Incremental Cost

- Renewable Energy Service Adjustment
  - System modeling used instead of a resource by resource comparison in order to capture intangeable benefits such as gas volatility, emission benefits and resource utilization
  - Existing wind and hydro projects result in “negative incremental costs”
  - Difficult to audit
  - Sunk costs are locked down in order to prevent wide swings from year to year as a result of gas and or carbon price changes which would lead to uncertainty when committing to resources

Other Means to Acquire Renewables

- Windsource: funding source to augment the RESA budget for additive acquisitions of renewable resources
  - Projected contributions of ~$5 million in 2010
- “Section 123” requires that the Commission give fullest possible consideration of new clean energy and energy efficient technologies (demonstration)
  - Commission’s interpretations of the statutes exempts “Section 123” resources form the retail rate cap to allow for consideration of “Section 123” resources whose net incremental costs could break the RESA budget

Recent Renewable Energy Legislation

- House Bill 10-1001: Increase in Renewables
  - Increases the State's Renewable Portfolio Standard (RPS) to 30% by 2020
- House Bill 10-1342: Solar Gardens
  - Requires some renewable energy be procured from Community Solar Gardens
- House Bill 10-1365: Clear Air, Clean Jobs
  - Mitigate or retire coal facilities to reduce NOx and other emissions

Increase in Renewable Energy

- HB 10-1001: Increase in the Renewable Energy Standard (RES) from 20% in 2020 to 30% and:
  - Requires 3% Distributed Generation (DG), instead of a previous 4% solar requirement
  - Encourages local job growth
  - Provides the Commission discretion to adjust the solar standard rebate offer
  - Requires that all renewable energy facilities greater than 1 MW register with a REC tracking database
  - Specifically allows the "borrowing forward" of future funds at the utilities weighted average cost of capital

Increase in Renewable Energy

- HB 10-1001: Distributed Generation
  - DG – Renewable Energy Resource that does not require any additional transmission or substation facilities other then what is needed for interconnection
  - 3% of total retail sales by 2020
    - o 50% Retail DG – interconnected on the customer's side of meter (does not receive 1.25 in-state multiplier)
    - o 50% Wholesale DG – a renewable resource less than 30 MW which does not qualify as Retail DG
  - Funds allocated according to the proportion of the revenue derived from each customer group

Increase in Renewable Energy

- HB 10-1001: Job Creation
  - Maintain documentation proving that:
    - Solar installations supervised by a certified member of the North American Board of Certified Energy Practitioner (NABCEP)
    - Electrical work completed by a licensed journeyman electrician
    - Maintain a 3:1 ratio of assisting workers to licensed/certified professionals
  - In the evaluation of resource acquisitions, economic factors such as employment benefits shall be considered

Increase in Renewable Energy

- HB 10-1001: Standard Offer Rebate
  - Its been difficult to incentivize different sizes of solar electric systems due to the economies of scale
  - PSCo REC Cost
    - o Levelized Capacity Cost $102.28 /kW-yr
    - o Levelized Avoided Cost of Carbon $99.41 /MWh
    - o Levelized REC Cost $184.05 /MWh (large systems)
    - o Levelized REC Cost $261.63 /MWh (medium systems)
    - o Levelized REC Cost $256.59 /MWh (small systems)

Increase in Renewable Energy

- HB 10-1001: REC Database
  - A REC database serves to validate compliance with State RPS's and facilitate trading of RECs
    - Upon generation of a MWh of renewable energy a certificate is created
    - Once created it the certificate can be transferred, retired or exported according to the needs of the owner
    - A REC Database administrator is an independent, policy neutral, body representing numerous stakeholders in a given geographic area

Increase in Renewable Energy

- HB 10-1001: REC Database
  - Data Recorded
    - o Facility Location
    - o Generating Technology
    - o Facility Owner
    - o Fuel Type
    - o Nameplate Capacity
    - o Year Operation Began
    - o Month/Year of Generation

Increase in Renewable Energy

- HB 10-1001: Borrowing Forward
  - Funds from ratepayers for renewable energy are often collected over time however development of renewable energy resources often requires large up front capital expenditures
  - Borrowing forward entails, using this future cash flow stream of ratepayer funds as collateral against a large upfront payment

Solar Gardens

- HB 10-1342: Help customers participate in solar generation even though solar may not be feasible at their personal location
  - Establish incentives for solar facilities under 2MW and owned by 10 or more customers
  - A subscription is limited to 120% of the owners annual consumption
  - Energy produced shall be credited to the subscribers bill
  - Allow shares to be portable and transferable

Net Metering

- Net Metering
  - Excess generation paid annually at average hourly incremental cost of electricity supply
  - Second meter required for systems >100 kW for recording RECs
  - Solar power generated at peak does not receive premium prices
  - Customer enjoys the benefit of reliability power from the grid but may not pay an appropriate share
  - HB 10-1001: Customers with DG resources will continue to contribute to the Renewable Energy Standard Adjustment rider

Clean Air, Clean Jobs

- HB 10-1365: Coal Retirement
  - 70-80% reduction in (NOx) and other emissions from 900 MW of existing coal generation
  - Primary consideration is to consider gas generation as a replacement for coal and also other low-emitting resources
  - Encourages the use of long-term gas contracts
  - Maintain the sound financial health of the utilities and allow utility ownership and recovery of construction work in progress

ERP Process – Inputs

Emission Rates of New Resources

Typical Emissions Rates	SO_2 (lb/MWh)	NO_X (lb/MWh)	PM (lb/MWh)	Hg (lb/milllion MWh)	CO_2 (lb/MWh)
Combined Cycle	0.004	0.105	0.0701	0	869
Combustion Turbine	0.006	0.159	0.104	0	1265
Coal (sub-critical)	0.73	0.94	0.146	5.21E-6	2211
Coal (super-crit.)	0.50	0.54	0.100	3.78E-06	1920

Renewable Energy

- Additional Topics
  - Renewable Resource Acquisition
  - Renewable Energy Integration
  - Feed In Tariffs

Renewable Energy Acquisition Process

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Paths to Acquiring Renewables

- Large Resources (> 30 MW)
  - Competitive bidding per an Electric Resource Plan (ERP) (IPPs and utility-builds)
  - Cost-comparable, utility-owned resources (exemptions from competitive bidding)
  - Most large non-renewables acquired under ERP

- Small Resources (<= 30 MW)
  - Competitive bidding or alternative acquisition plans pursuant to a RES Compliance Plan (primarily solar)
  - Project development through bilateral arrangements (exemptions from ERP; typically non-solar resources)
  - R&D (Xcel Energy's Innovative Clean Technology Program)

Evolving Commission Rules

- Resource Planning Rules (4 CCR 723-3-3600 to 3649)
  - Least-cost planning paradigm modified to account for increased emphasis on renewables, energy efficiency, and carbon emissions reductions
  - Resource plans culminate in “cost-effective” resource portfolios
  - Increased regulatory oversight

- RES Rules (4 CCR 723-3-3650 to 3665)
  - Greater flexibility for the utility
  - Encouraging investments above statutory minimums

Cost Prudency and Recovery

Electric Resource Plan

> 30 MW

Utility Files Plan for Approval

Commission Approves Plan

Utility Implements Plan

Utility Actions Consistent with Approval of Plan Enjoy a Presumption of Prudence

Utility Recovers Costs

RES Compliance Plan

<= 30 MW

(Mostly On-Site Solar)

Utility Files Plan for Approval

Commission Approves Plan

Utility Implements Plan

Utility Actions Consistent with Approval of Plan Enjoy a Presumption of Prudence

Utility Recovers Costs

Other Projects

<= 30 MW

(Other than On-Site Solar)

Utility Develops Project (with or without IPP)

Utility Files for Approval of Project

Commission Approves Project

Utility Recovers Costs

Electric Resource Planning

- Systematic review of future generation needs and the utility's ability to meet them
  - Load forecasts (numbers of customers, demand, sales)
  - Assessment of existing resources
- Acquisition process for acquiring new utility resources (generation and transmission)
- Preference for competitive bidding yet recognition of benefits of utility ownership
- Demand-side versus Supply-side
- Externalities– emissions and "non-energy benefits"
- Cost-effective: "reasonable cost and rate impact"

Elements of an ERP

- Comprehensive filings every 4 years
- Resource acquisition plans for 8 to 10 years into the future
- Planning horizon up to 40 years
- Resource need identified by comparing existing resources to expected loads
- Model RFPs, resource portfolio modeling inputs and assumptions, and policy objectives
- Phase I establishes an approved approach to acquiring new resources and the ground rules for making decisions
- Phase II establishes a final plan for acquiring a specific portfolio of resources given actual bids and utility proposals
- An independent evaluator assists the Commissioners in Phase II

RES Compliance Plans

- Update on status of compliance with the RES
  - Coordination with ERP for large resources (> 30 MW)
  - Renewable Energy Credits (RECs)
- Plans to acquire additional renewable resources
  - Coordination with ERP for large resources (> 30 MW)
  - Generally budgets and goals for on-site solar segments
  - Option for addressing other small resources (<= 30 MW)
  - RFPs, standard contracts, proposed levels of ownership
- Determination of rate impact
  - 2% cap on retail rate impact
  - Current projection of budget to fund net incremental costs of acquiring more renewable resources
  - Changes in the RES Cost Adjustment (RESA)

Contract Review

- Initial “A37 RES rules” provided option for 60-day contract review and approval of all renewable energy supply contracts
- With procurement of renewable and non-renewable resources within the ERP process
  - Bids and proposals addressed through Phase II
  - Presumption of prudence
  - If utility wants approval of specific contracts, standard timelines apply unless the utility is granted an expedited process

Plant	Approximate Size	Plan	PUC Approved PPA
Cedar Creek (W)	300 MW	2003 LCP	No
Twin Buttes (W)	70 MW	2003 LCP	No
FPL Peetz (W)	400 MW	2003 LCP	No
Colorado Green (W)	160 MW	1999 IRP	Yes
Ridge Crest (W)	30 MW	WindSource	Yes
Spring Canyon	60 MW	WindSource	Yes
SunE Alamosa (S)	8 MW	2007 RES	Yes
N Colorado (W)	175 MW	--	Yes
Sandhill (S)	19 MW	--	Yes

Cost Recovery Assurances

- Commission's rules include provisions that reduce the risks associated with the acquisition of renewables.
  - Rules allow for cost recovery through riders and adjustment clauses
    - o Automatic
    - o Deferred balance reconciliation (utility kept whole)
  - Cost recovery can be forward looking (rates based on projections of costs incurred at the time of revenue collection)
  - Cost recovery allowed even if the incremental costs of the renewables already acquired found later to exceed the retail rate impact due to changed circumstances

Xcel Energy Cost Recovery

- Since Xcel Energy owns few renewable resources in Colorado built after A37, costs are recovered through riders (adjustment clauses) rather than "base rates"
  - Electric Commodity Adjustment (ECA)
    - Wind and solar PPAs
  - Renewable Energy Standard Adjustment (RESA)
    - Credit to the ECA for the net incremental costs of wind and solar
    - On-site solar costs
  - Purchased Capacity Cost Adjustment (PCCA)
    - Non-renewable capacity costs (mostly gas PPAs)
  - Transmission Cost Adjustment (TCA)
- Base rate recovery will come into play as utility owned renewable resources are acquired and come into service

Utility Ownership

- A37 and HB 07-1281 include provisions that encourage utility ownership of renewables
- Utilities may earn “extra profit” on renewables investments if that resource provides “net economic benefits” to consumers
- Utilities may acquire utility-owned resources absent competitive bidding
  - Up to 25% of the renewable resources acquired as long as the utility owned resources comparable to market
  - Up to 50% of the renewables if “cost comparable” and they provide economic development, employment, energy security, and other benefits

Xcel (PSCo) Renewables Acquisitions

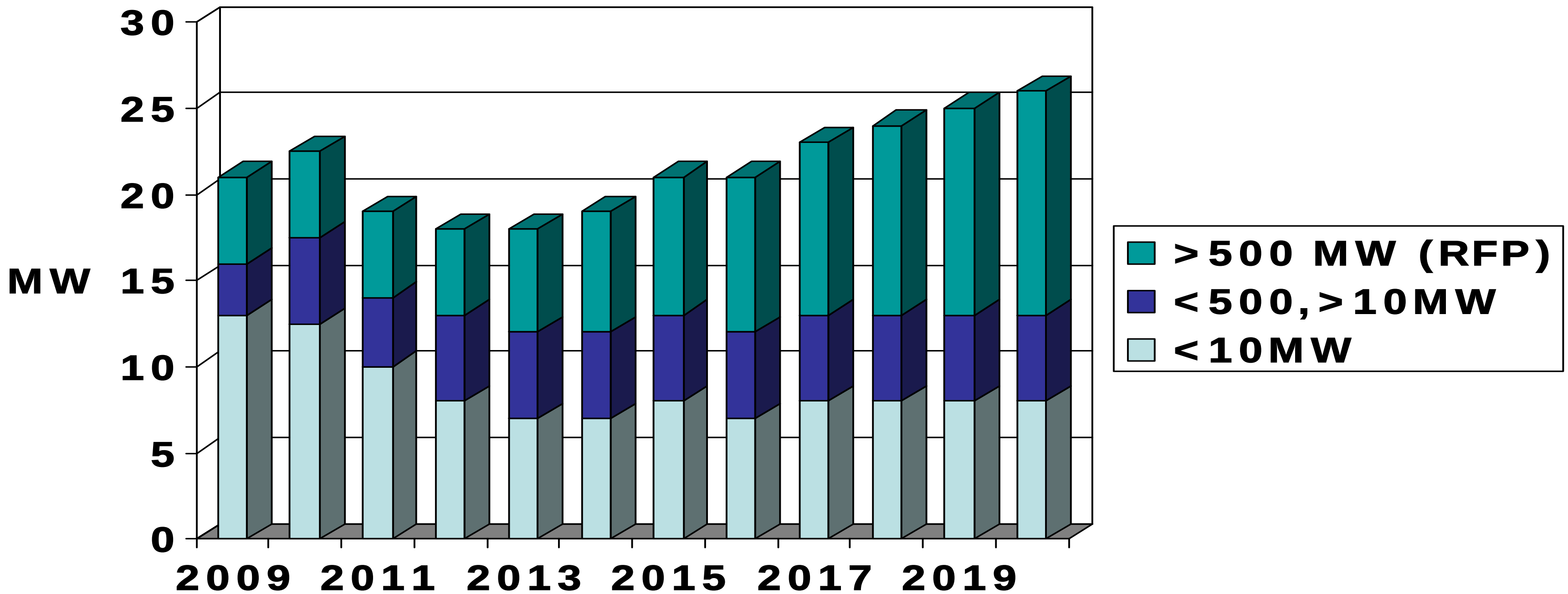
Electric Resource Plan (2011-2015)

- Photovoltaic and Highly Concentrating Photovoltaic (123 Resource) projects – 100 MW
- Concentrating Solar Thermal with 4 to 8 hours of Storage (123 Resource) – upto 250 MW
- Wind – 700 MW

- 900 MW of gas generation
- NPVRR cost for entire portfolio: $49.4 Billion

Xcel (PSCo) Renewables Acquisitions

RES On-Site Solar (declining incentives)



Discounted total cost through 2020: $320 Million

Xcel (PSCo) Renewables Acquisitions

Other Projects (2010 & 2011)

- Northern Colorado Wind – 175 MW
- Microgy Bio-gas – 2700 MMBTU per day
- Sandhill Utility Scale PV – 16 MW
- Cameo Coal/Concentrating Solar Hybrid

- Total Present Value Contract Cost $1 Billion

Black Hills Renewables Acquisitions

- Non-solar portion of the RES requirement met through wholesale power purchases from PSCo at no incremental cost
- Recent ERP focused on a capacity shortfall in 2012 and did not address any renewables
- Aspire to acquire 20 MW of wind in next ERP
- BP-Solar Photovoltaic SEPA – 1 MW (2009)
- Co-firing with Biomass and Using Biodiesel

Black Hills Renewables Acquisitions

On-Site Solar – continue current program

- <=10 kW
  - $4.50 per DC watt total incentive
- <=100kW, >10 kW
  - $2.00 per DC watt one time rebate
  - $115 per MWh of AC output
- >100kW
  - Single $200,000 one time rebate offer
  - Price per MWh of AC output is negotiated

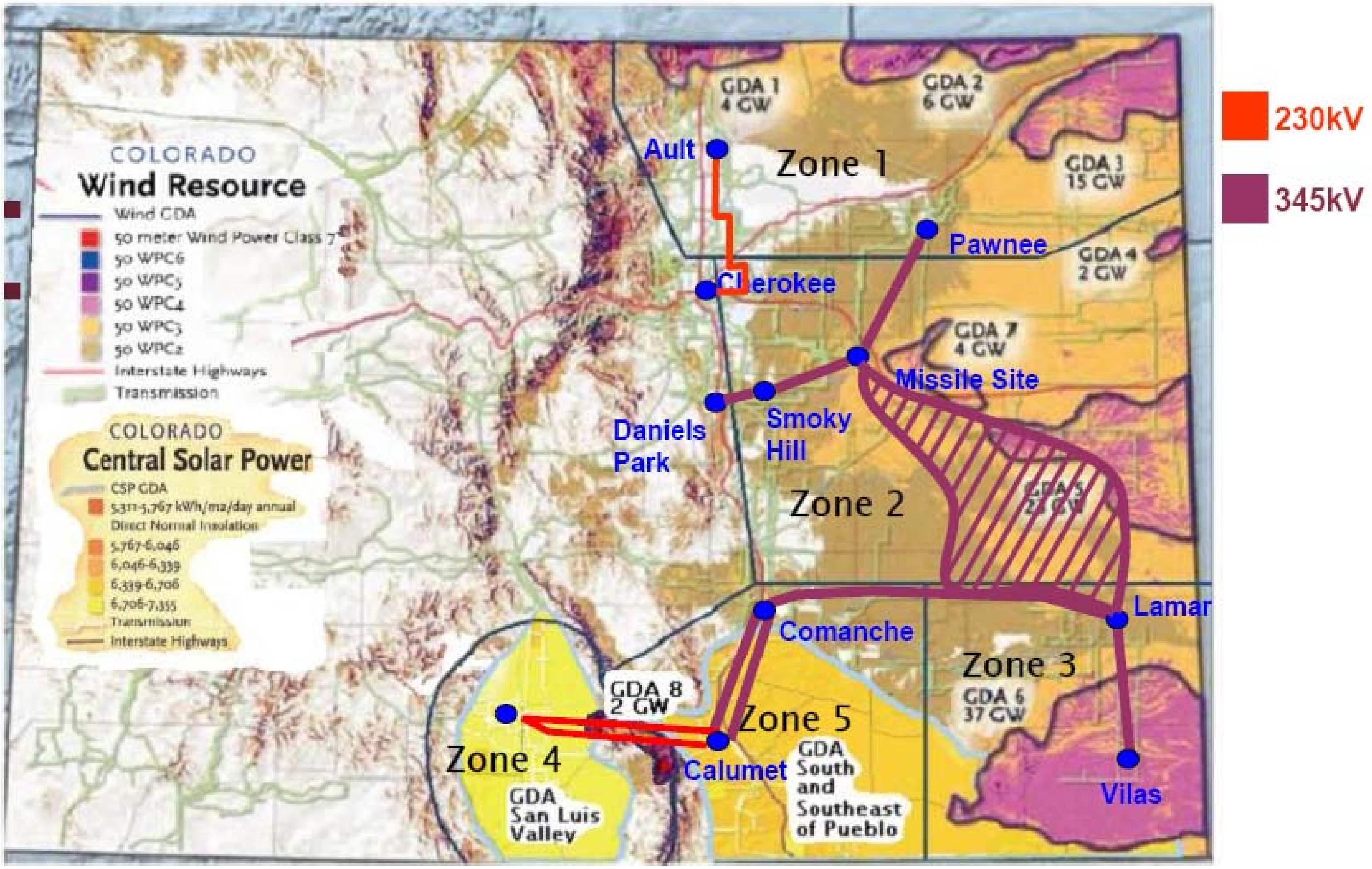
Other Colorado Utilities

- Tri-State Generation and Transmission
  - Cimarron I Photovoltaic Solar – 30 MW (New Mexico)
  - Kit Carson Wind 51 MW (2010)
  - Biomass projects in Colorado and Wyoming 445 kW
- Colorado Springs Utilities
  - Up to 50 MW of Wind Planned
  - US Air Force Academy Solar Array
  - Co-firing with wood bio-mass
- Platte River Power Authority
  - 10% renewable energy by 2018

Increase in Renewable Energy

- Small (<10 kW) and Medium Programs (<100 kW)
- Actual Installations as of 4/1/2009, starting in 2006
  - ~ 16.2 MW small (<10 kW), 1.5 MW medium
  - Average System Small: size 5.0 kW, cost $39,000
  - Average System Medium: size 57 kW, cost $ 440,000
- Large Onsite Solar and Renewable Energy Credit Acquisition (> 100 kW and < 2 MW)
  - Three Competitive RFP Completed, 12.8 MW Contracted – Typically 3rd Party Developer builds and finances system on Commerical and Industrial Customer Site, Sells Energy to Customer, RECs to Utility
- Central Solar > 1.0 MW Purchase Power Contracts
  - SunE Alamosa, 6.9 MW (AC) , operational 12/2007
  - SandHill Solar , 16.1 MW (AC), start date 12/10/2010

Xcel Colorado Transmission Plan



Proposed Transmission Projects

Project	Description	Generation injection	Cost	Energy Zone	Priority
Pawnee – Daniels Park– 345 kV line	Second circuit 345 kV line in Energy zone 1.	300-500 MW	$65,000,000	1	Medium -1
Ault to Cherokee 230 kV	New mile 230kV line in energy Zone 1.	300-600 MW	$64,000,000	1	Medium -2
Missile Site	345/230 kV switching station on Pawnee to Daniel Park line in energy zone 2.	200-500 MW	$13,500,000	2	High-2
Lamar to Comanche 345 kV line and Lamar	New 345kV lines to access energy zone 3.	800-1000 MW	$240,000,000	3	High -3
Lamar to Vilas 345 kV line	New 345kV line in Energy Zone 3 to access wind rich area.		$27,000,000	3	Low
San Luis – Calumet – Comanche Line	Double circuit 230 kV line(SLV to Calumet) and double 345 kv line(Calumet to Comanche).	600-1000 MW	$150,000,000	4 and 5	High -1
Total			**$559,500,000**		
	generation values are non simultaneous				

Current Status

- Xcel has met compliance through 2008
  - Current REC balances are: 6,185,382 RECs, 11,011 SO-RECs, and borrowing 4,400 SO-RECs from future years

- Black Hills has met compliance through 2008
  - Current REC balances are: 248,413 RECs, 45 S-RECs, and borrowing 1,779 SO-RECs from future years

- All REA's and Municipal Utilities have reported to the Commission to have met compliance in 2008

Renewable Energy Integration

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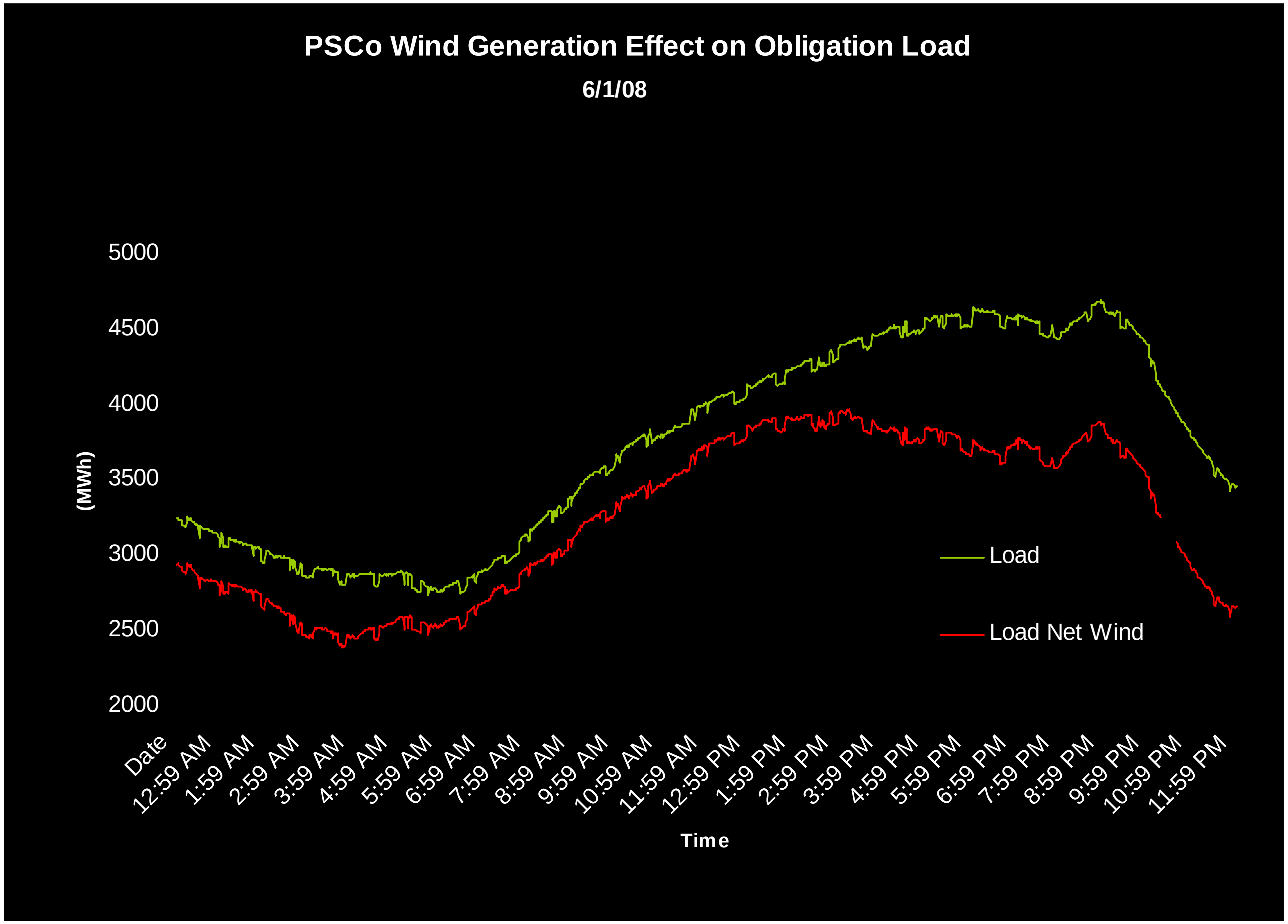
ERP Process – Renewable Energy

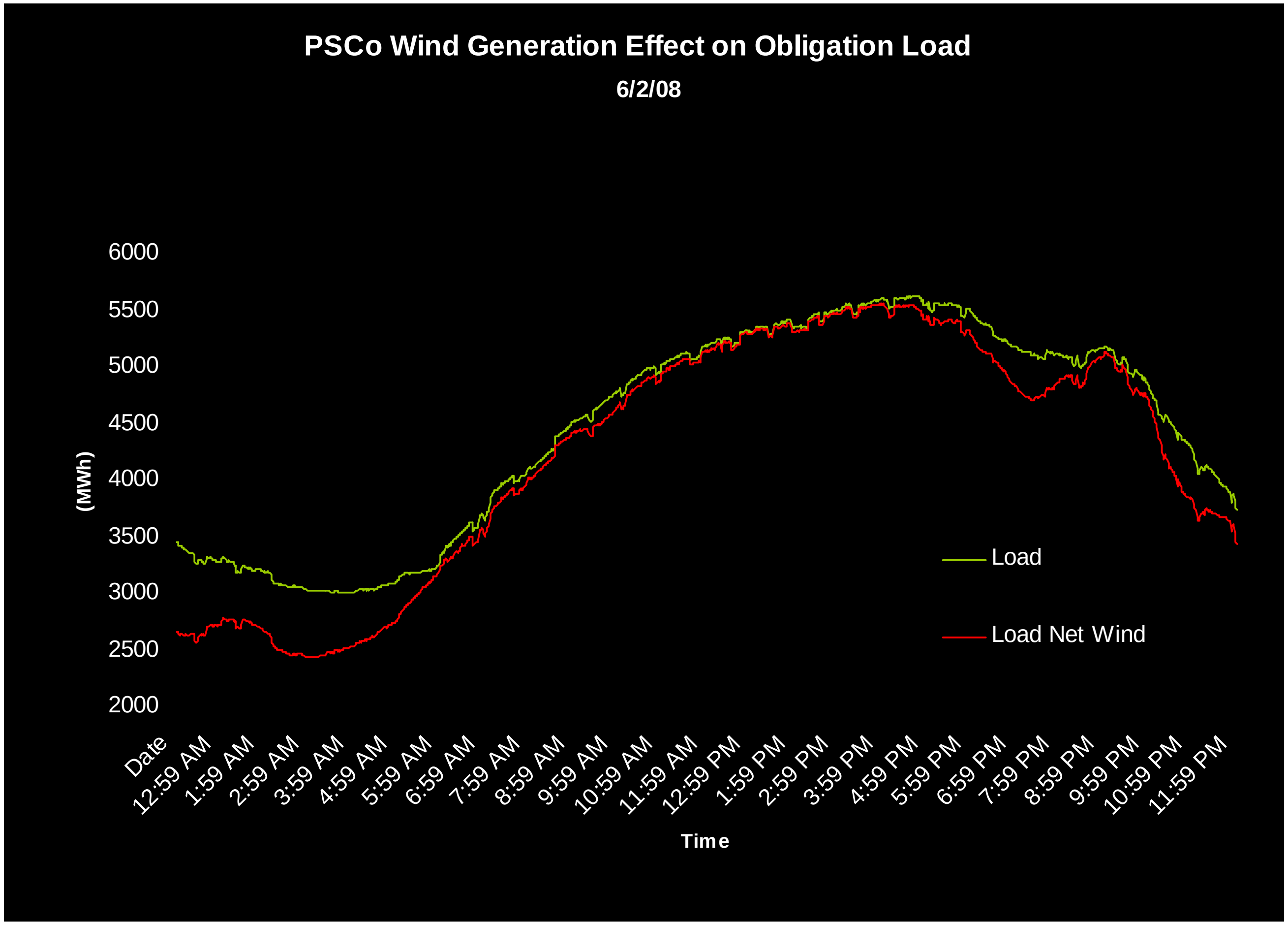
- Characteristics of Renewables
  - Capacity Factor
    - o Wind 30 to 40%
    - o Solar 30% (PV) 50% (trough)
  - Capacity Credit (Effective Load Carrying Capability)
    - o Wind 12.5%
    - o Solar 60% (fixed PV) 70% (single axis) 81% (troughs)
  - Integration Costs
    - o Wind at 20% 8.56/MWh ($10 gas price)
    - o Solar up to 400 MW $1.00 to $2.00 /MWh,

      >400 MW $5.00 to $6.00

ERP Process – Integration Costs



ERP Process – Integration Costs



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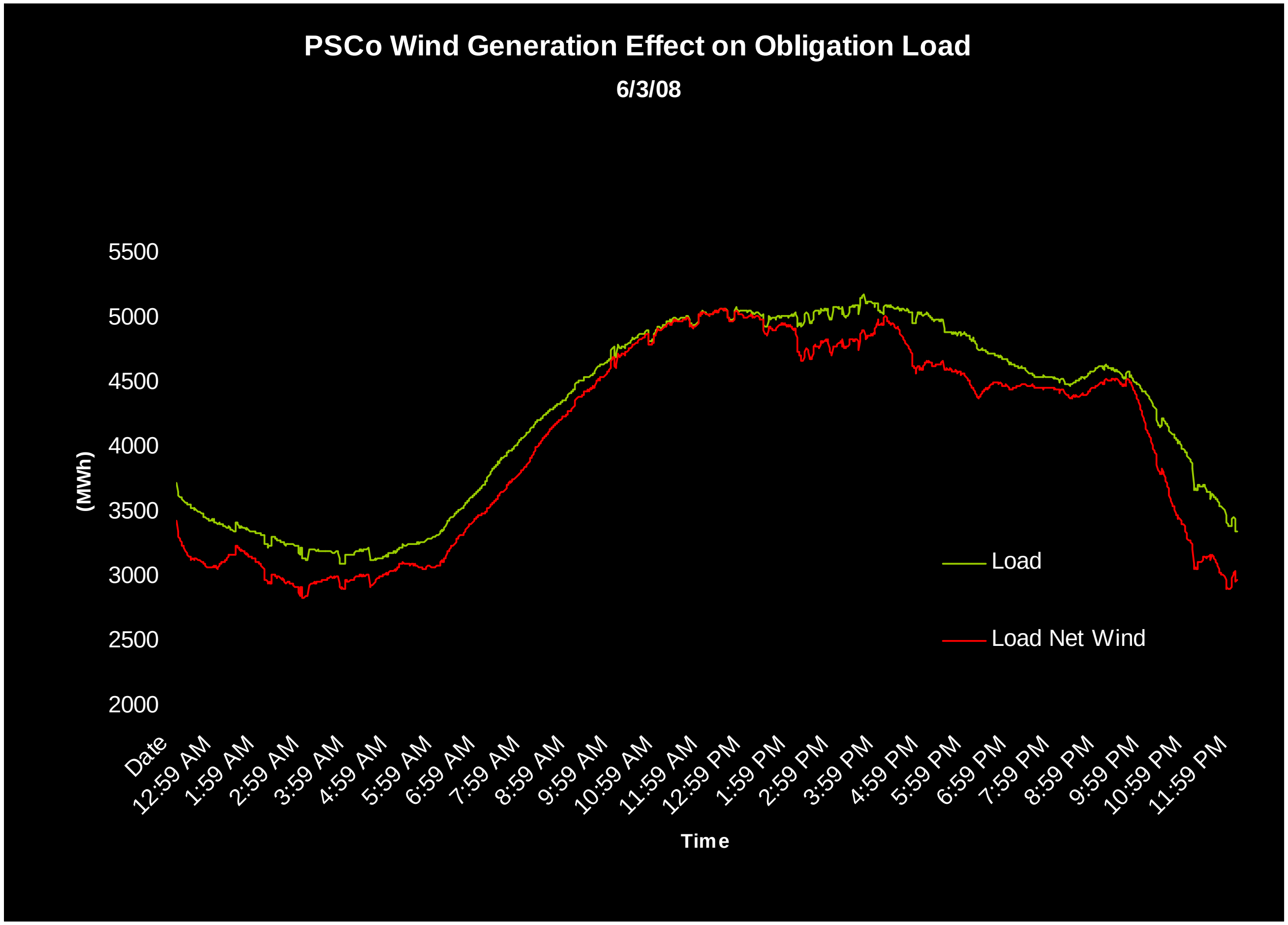

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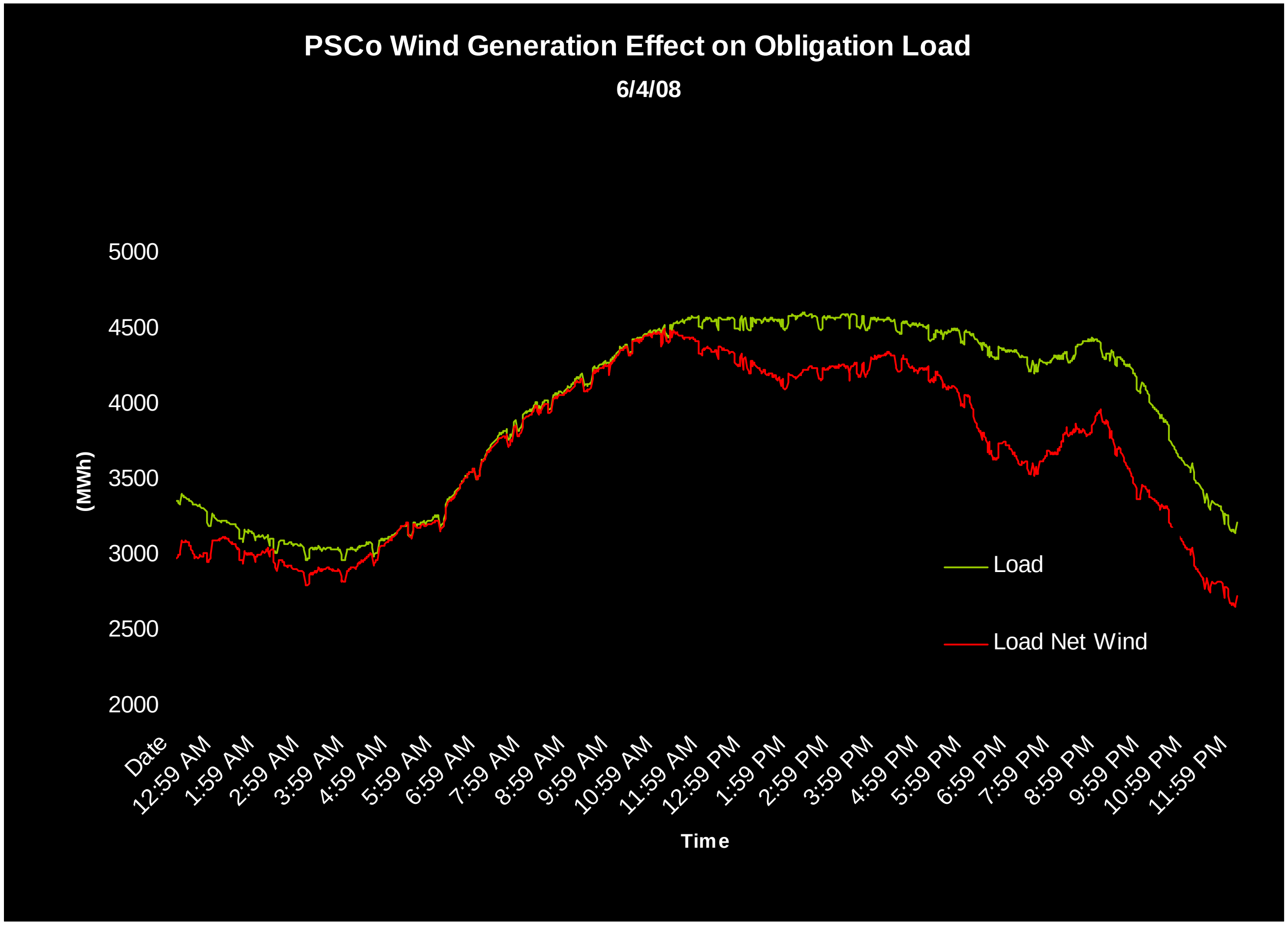

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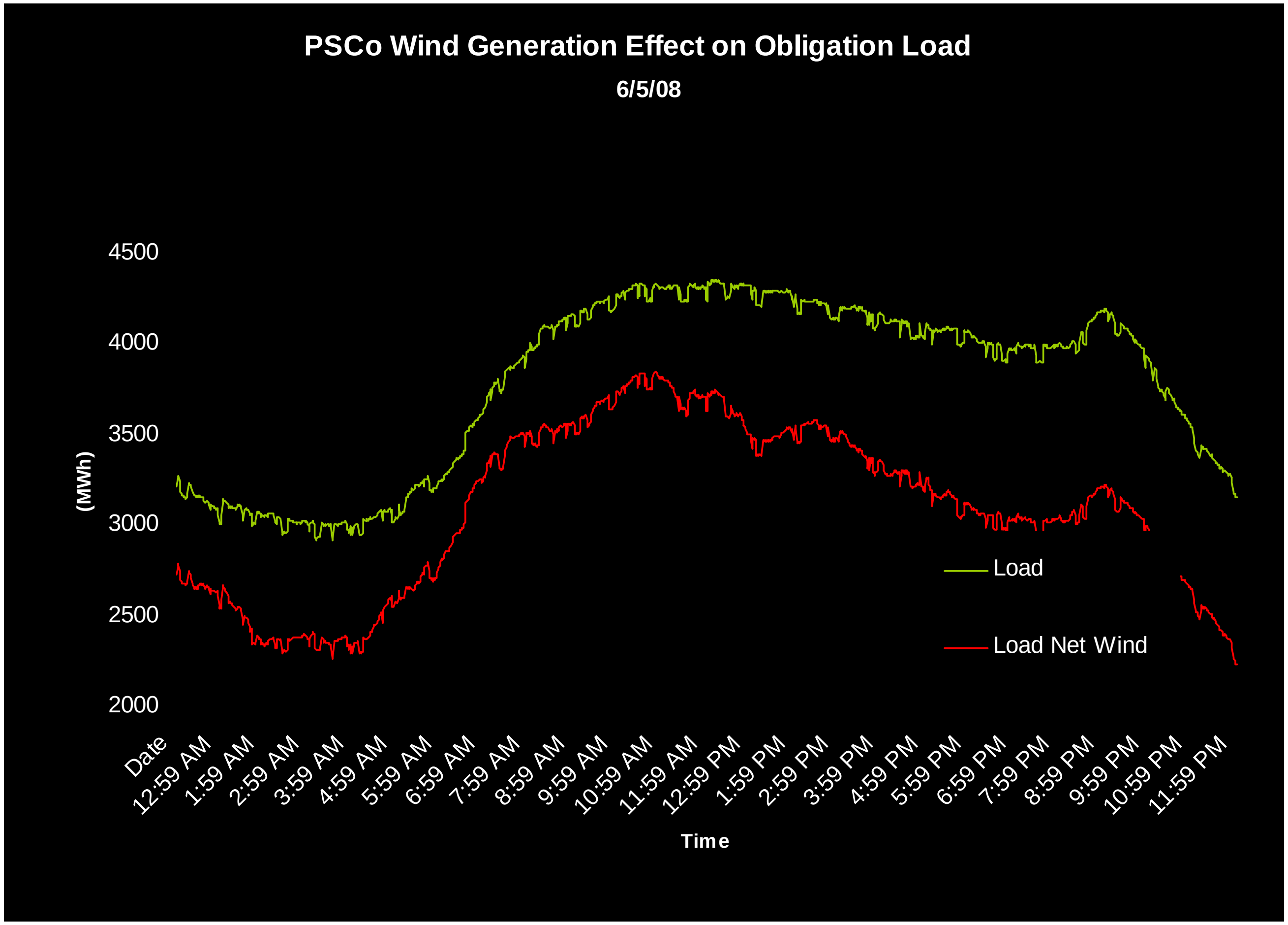

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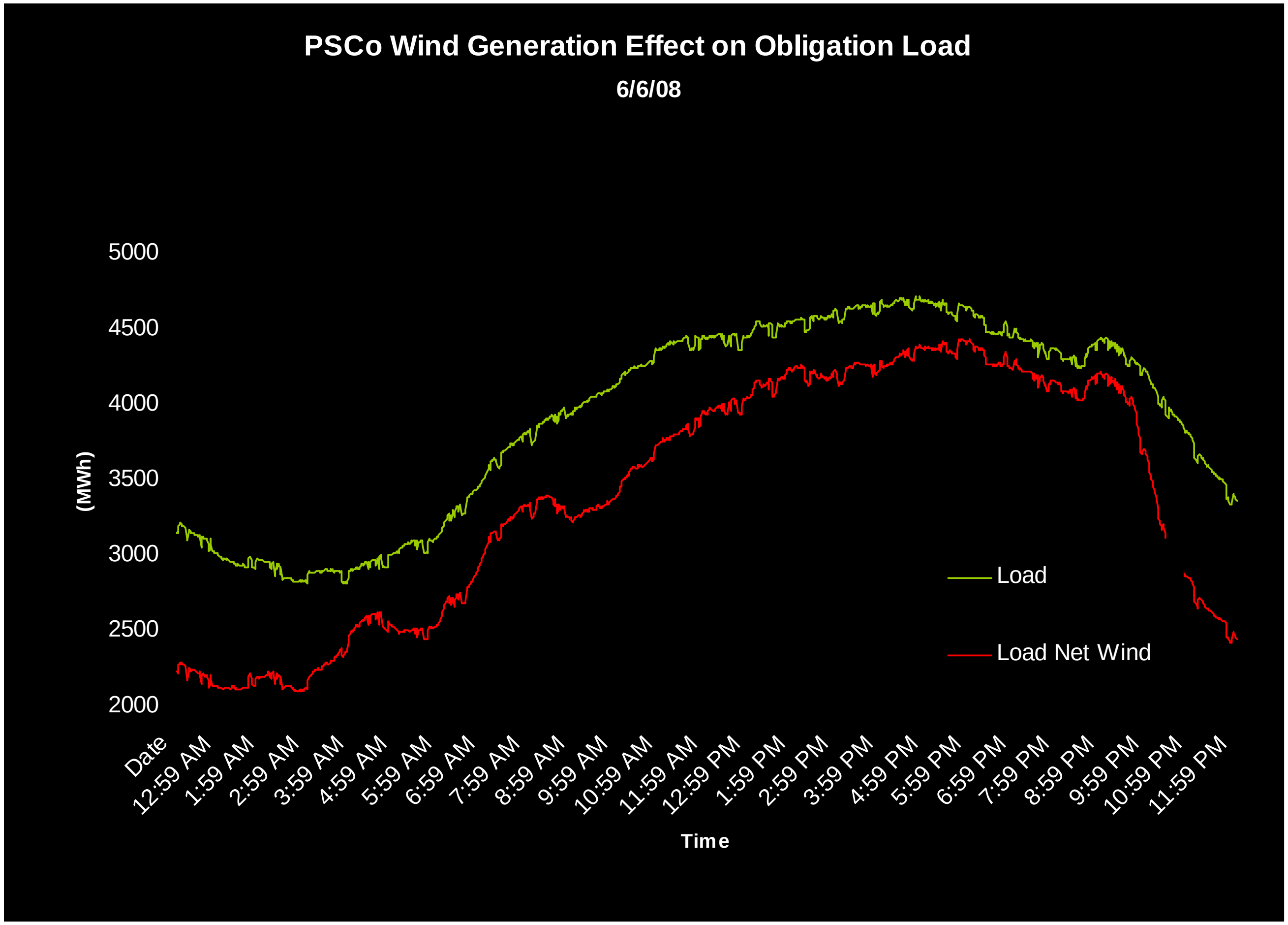

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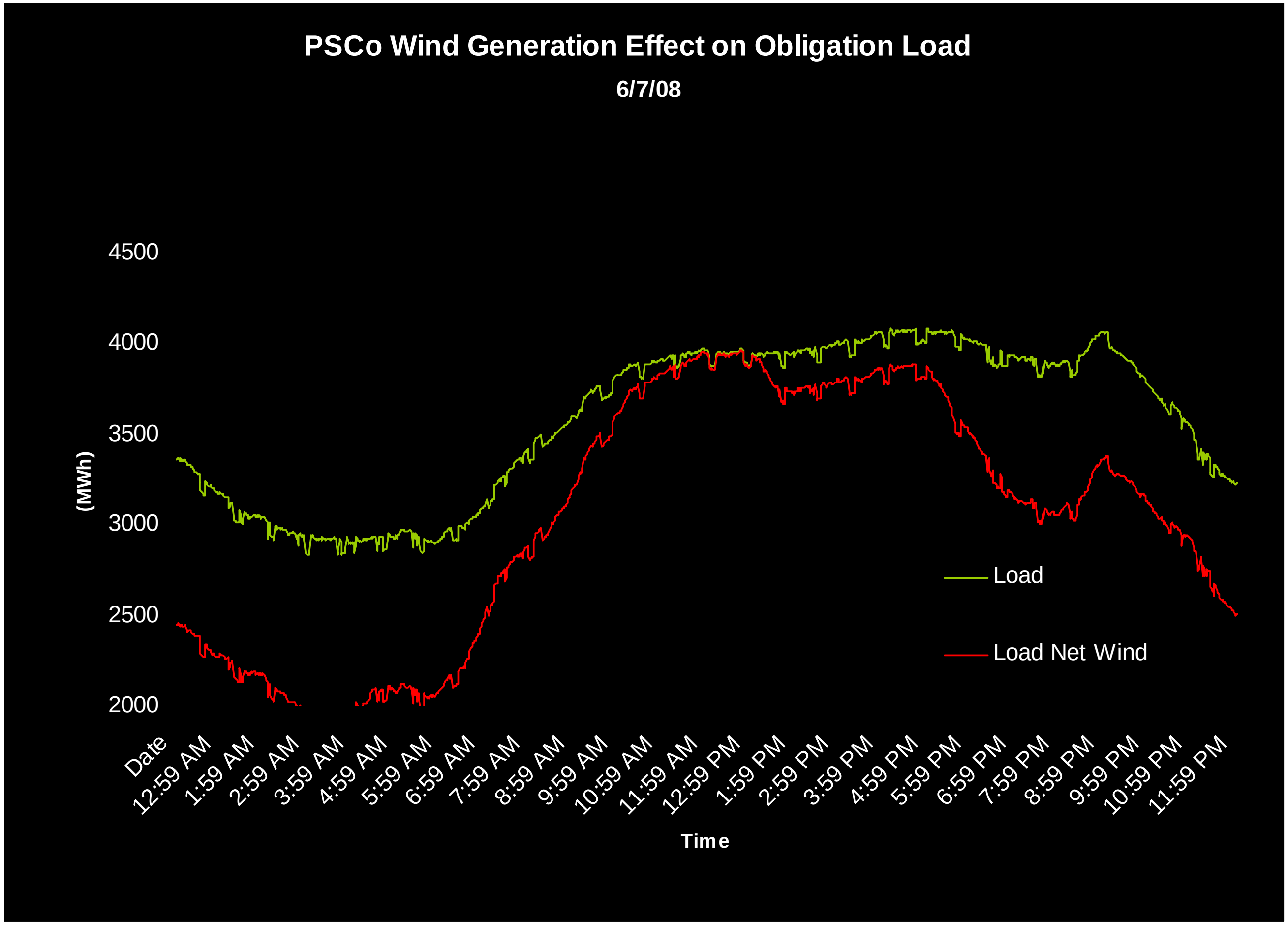

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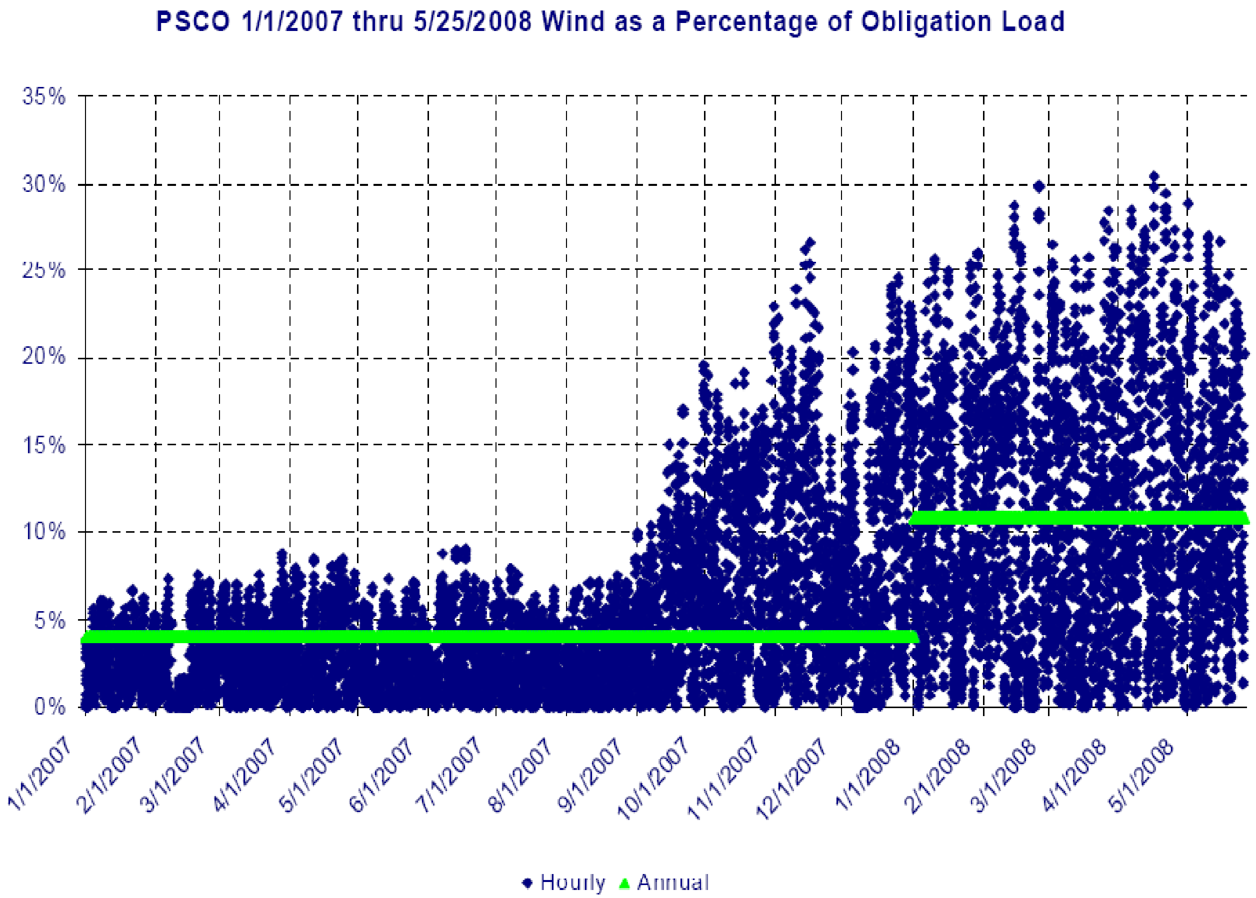
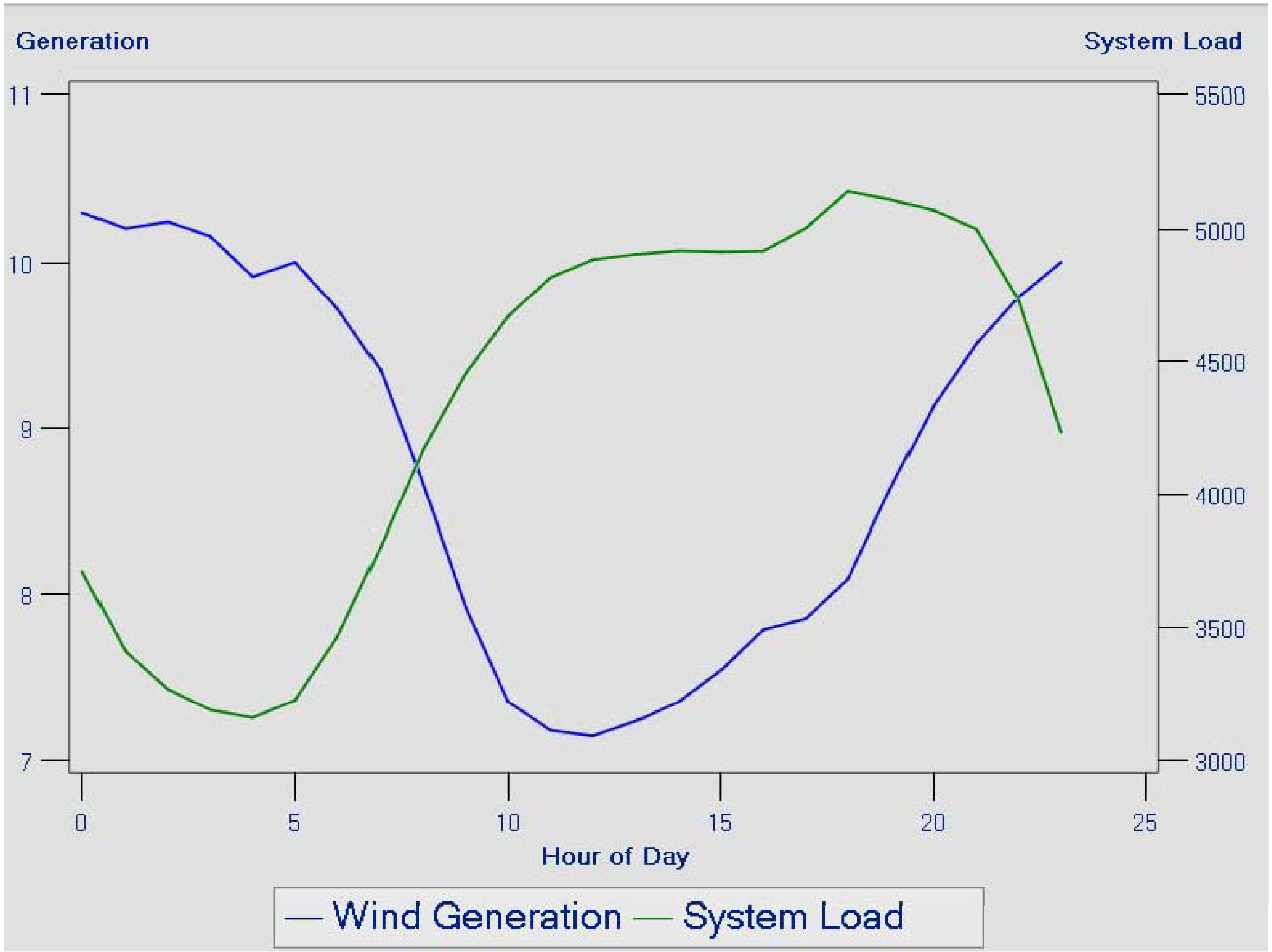


ERP Process – Integration Costs



ERP Process – Integration Costs

- Integration Issues
  - Large Ramp Up/Down situations
  - Greater Cumulative System (Load + Wind) Variability
  - Increased Starts/Stops (costs) on Gas-fired units
  - Gas pipeline balancing issues
  - Large penetration levels of wind requiring turn-down in baseload levels at nighttime and in shoulder months
  - Future unit minimum issues

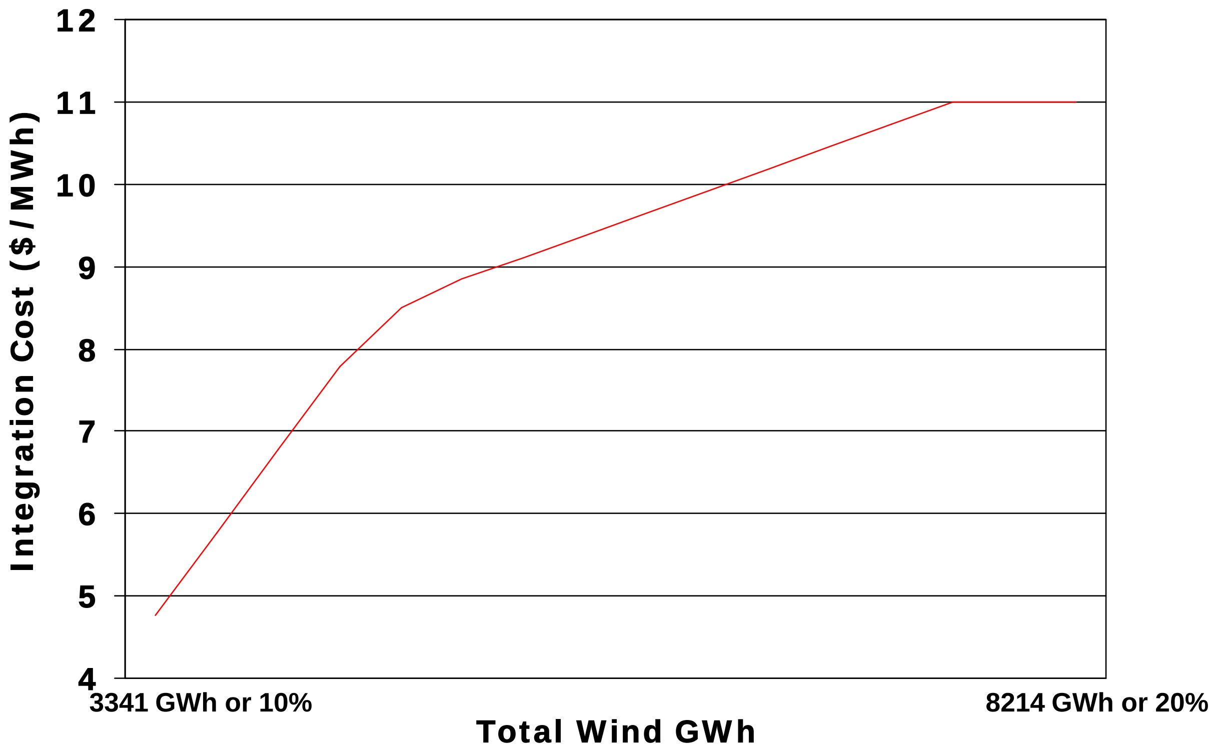
ERP Process – Integration Costs

Table 2.9-4 Integration Costs for Each Additional 100 MW Added

MW Wind Added	Total Wind on System MW	Average MWh per 100 MW Added GWh	Total Wind on System GWh	Integration Cost $/MWh	Total Integration Costs $	Amount to Apply to Each Increment of Additional Wind $/MWh
0	1000		3341	$ 4.77	$ 15,938,112	For Strat O&M
100	1100	305	3646	$ 5.77	$ 21,050,259	$ 16.79
200	1200	305	3950	$ 6.78	$ 26,773,779	$ 18.79
300	1300	305	4255	$ 7.78	$ 33,108,673	$ 20.80
400	1400	305	4560	$ 8.50	$ 38,756,151	$ 18.54
500	1500	305	4864	$ 8.85	$ 43,026,442	$ 14.02
600	1600	305	5169	$ 9.11	$ 47,112,305	$ 13.42
700	1700	305	5473	$ 9.38	$ 51,362,194	$ 13.95
800	1800	305	5778	$ 9.65	$ 55,776,108	$ 14.49
900	1900	305	6082	$ 9.92	$ 60,354,048	$ 15.03
1000	2000	305	6387	$ 10.19	$ 65,096,014	$ 15.57
1100	2100	305	6691	$ 10.46	$ 70,002,005	$ 16.11
1200	2200	305	6996	$ 10.73	$ 75,072,021	$ 16.65
1300	2300	305	7301	$ 11.00	$ 80,306,064	$ 17.19
1400	2400	305	7605	$ 11.00	$ 83,656,180	$ 11.00
1500	2500	305	7910	$ 11.00	$ 87,006,296	$ 11.00
1600	2600	305	8214	$ 11.00	$ 90,356,412	$ 11.00

ERP Process – Integration Costs

- Graph of Wind Integration Costs

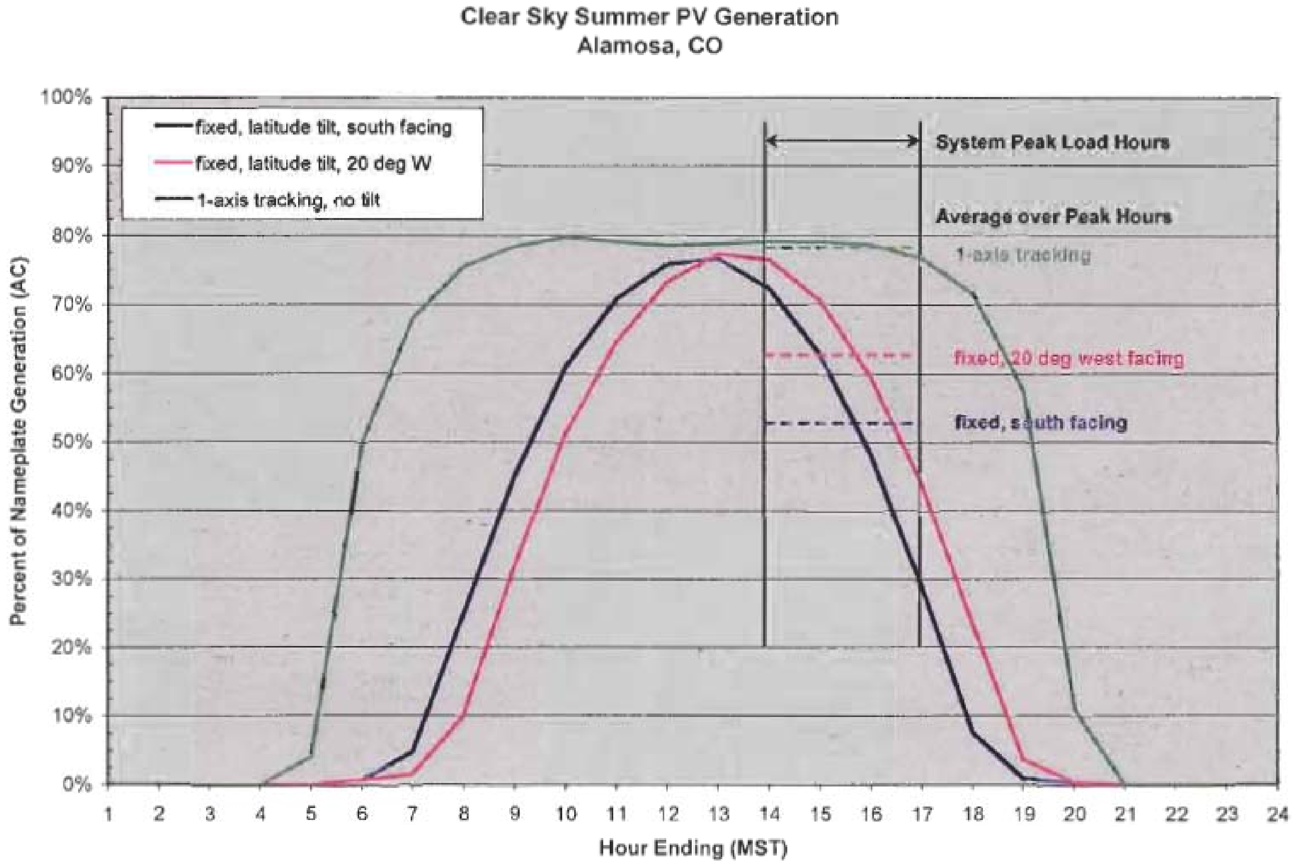


ERP Process – Integration Costs

- Ways to mitigate Integration Costs
  - Wind forcasting; PSCo Wind Predictor (WiP)
    - Currently 18% error
    - PSCo Estimates savings of $1,379,000 /yr (1% reduction in error)
    - Estimated cost $2.6 million for implementation and 0.75 million for hardware and software at windfarms
  - Geographic Diversity
  - Storage

ERP Process – Renewable Energy

Figure 3 Clear Sky, Summer PV Generation in Alamosa, CO



Wind Integration Costs

- Integration Issues
  - Large Ramp Up/Down situations
  - Greater Cumulative System (Load + Wind) Variability
  - Increased Starts/Stops (costs) on Gas-fired units
  - Gas pipeline balancing issues
  - Large penetration levels of wind requiring turn-down in baseload levels at nighttime and in shoulder months
  - Future unit minimum issues

Renewable Energy Feed In Tariffs

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May 17, 2010

Feed In Tariffs

- What is a Feed In Tariff:
  - A guaranteed long term contract (typically 15-20 years) at a specified rate for all electricity generated by a designated renewable resource,
    - o Typically set administratively based on the actual costs of generation with a modest rate of return included;
    - o Rates can be differentiated based on RE source, technology type, capacity size, the date the system becomes operational, and geographic locale.
    - o Rate adjustments can be made in the future based on inflation, technological innovation resulting in reduced system and installation costs, and successfully meeting generation capacity benchmarks.

Feed In Tariffs

- Advantages
  - Support mid-to-longer-term technologies
  - May be tailored to support different market conditions (developing less desirable sites, moving renewables into spot market, encouraging repowering)
  - Can “jump start” a market for eligible technologies
  - Offers investment security and market stability
  - Less Paperwork
- Disadvantages
  - Risk of over-funding, particularly if technology cost reductions and learning curve not built into tariffs
  - May not be provide stable market attractive to investors if frequently amended
  - Difficult to determine market price

Feed In Tariffs

- Required:
  - Purchase obligation
  - Guaranteed payment
  - Long-term contract

- Specify:
  - What technologies do you want to promote?
  - Who is eligible to receive a tariff?
  - How long should the contract last?

Feed In Tariffs

- Utility Obligations
  - Purchase obligation
  - Prioritization
  - Probably required to pay for grid upgrades depending on national interconnection standards

- Generator Obligations
  - Project Development
  - Forecasting
  - Facility Management

Feed In Tariffs

Germany

Tariff Structure

– Grid operators must pay fixed rates and may pass costs along to customers

– Rate of payment depends on year of commissioning

• rate is decreased annually at 1–5%, depending on technology

– Total length of time for tariff is 20 years

• excluding hydroelectric projects which have payment periods of 15 or 30 years depending on size

• payments are fixed for the 20–year period for all but wind power

– Smaller capacity projects receive higher tariffs

• Biomass

– Ranges from 8.4 eurocents/kWh (5 MW-20 MW) to 11.5 eurocents/kWh (for up to 150 kW)

– Plants greater than 20 MW: 3.9 eurocents/kWh

– Bonus for self-regenerating raw materials, CHP, or new technologies

Feed In Tariffs

Wind Power

– Higher payments initially, stepped down over time

– On-shore wind

• initial tariff paid for first 5 years: 8.7 eurocents/kWh in 2005

• Lower “regular” tariff paid in years 6-20: 5.5 eurocents/kWh

• initial fee can be extended beyond 5 years depending on the wind conditions of the site

• wind parks that can not achieve 60 percent of the reference yield in planning materials are not eligible for feed-in tariff

– Off-shore wind

• initial tariff paid for 12 years is 9.1 eurocents/kWh in 2005

• 6.2 eurocents/kWh beginning in year 13

• Initial tariff can be extended beyond 12 years for facilities further from the coast in deeper water

Feed In Tariffs

Geothermal

– Between 7.16 and 15 eurocents/kWh, depending on size

• Landfill gas, sewage gas, mine gas

– Between 6.65 – 8.65 eurocents/kWh

– Depending on capacity size and technology, e.g., higher rates paid when innovative

technologies are used

• Hydropower

– Small hydro up to 5 MW

• Facilities less than 150 kW receive 9.67 eurocents/kWh

• Facilities between 151 kW and 5 MW receive 6.65 eurocents/kWh

– Modernization of medium sized hydro 5 MW – 120 MW

• increase in capacity only with a maximum increase of 150 MW

• Rates range from 3.7– 7.67 eurocents/kWh depending on size of increased capacity

• Solar

– Integrated PV: 59 – 62.4 eurocents/kWh, depending on system size

– Surface mounted PV: 54 – 57.4 eurocents/kWh, depending on system size

Feed In Tariffs

Utility Ownership vs. IIP

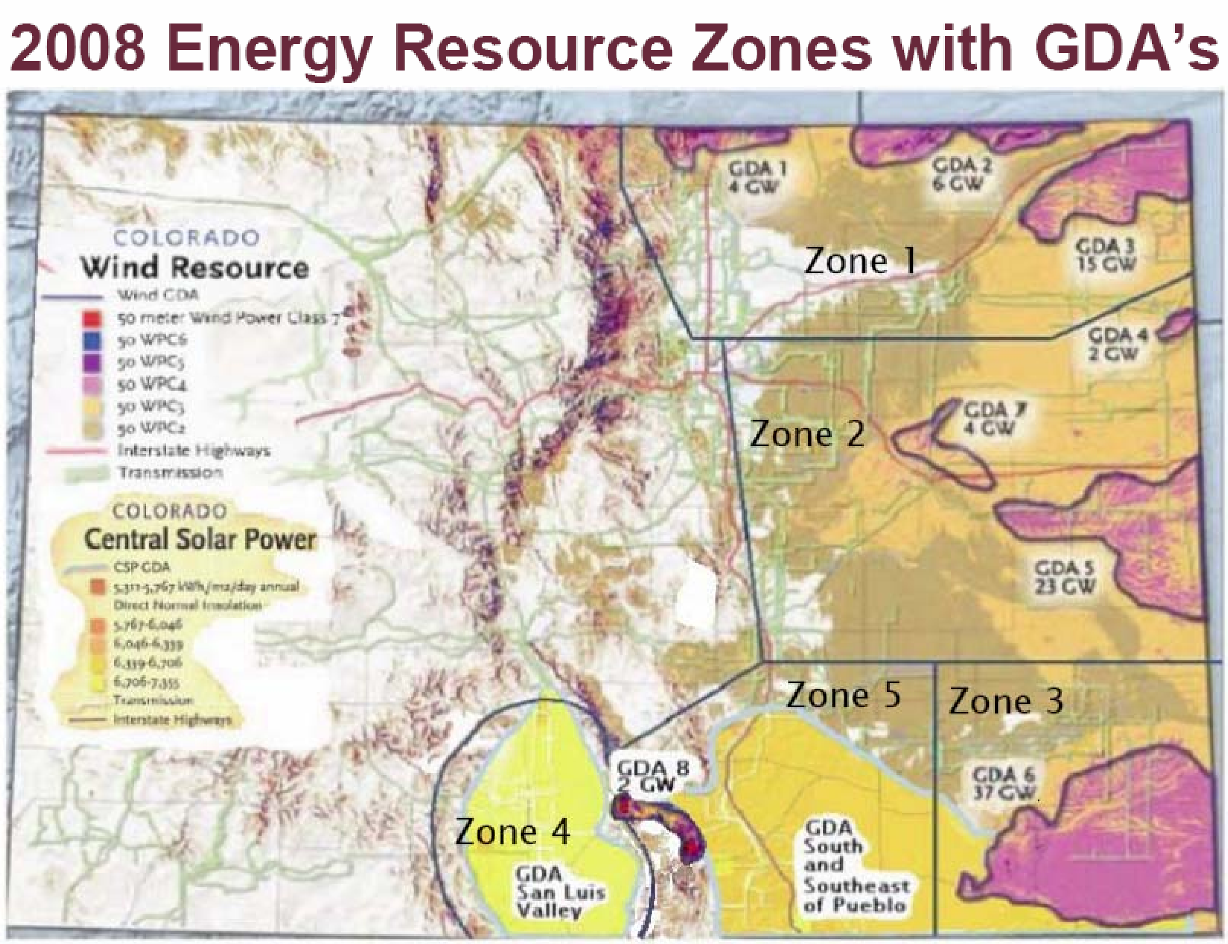
- Utility Ownership Benefits
  - Operational flexibility
  - Easier to make changes to reflect policy shifts
  - Utility has an obligation to serve
  - Ratepayers benefit from operating an asset beyond depreciated life
  - Assets are not considered as imputed debt
- Benefits of IPP Ownership
  - Capital cost risks borne by investors
  - Commitment to technology is limited to contract term
  - Competition between supplier leads to greater innovation and lower costs

Renewable Energy

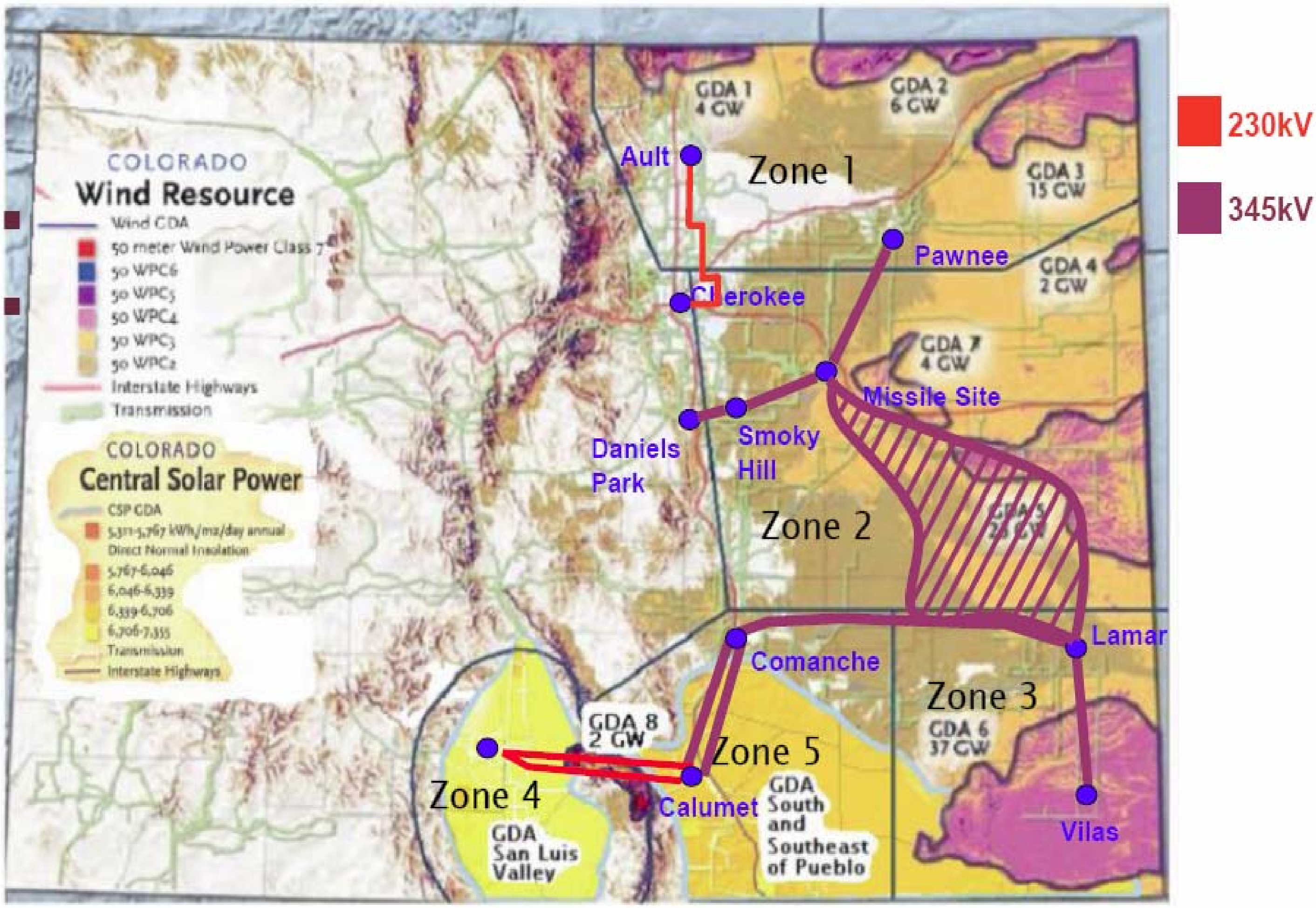
- Characteristics of Renewables
  - Capacity Factor
    - o Wind 30 to 40%
    - o Solar 20% (PV) 50% (trough)
  - Capacity Credit (Effective Load Carrying Capability)
    - o Wind 12.5%
    - o Solar 60% (fixed PV) 70% (single axis) 81% (troughs)
  - Integration Costs
    - o Wind at 20% 8.56/MWh ($10 gas price)
    - o Solar up to 400 MW $1.00 to $2.00 /MWh,

      >400 MW $5.00 to $6.00

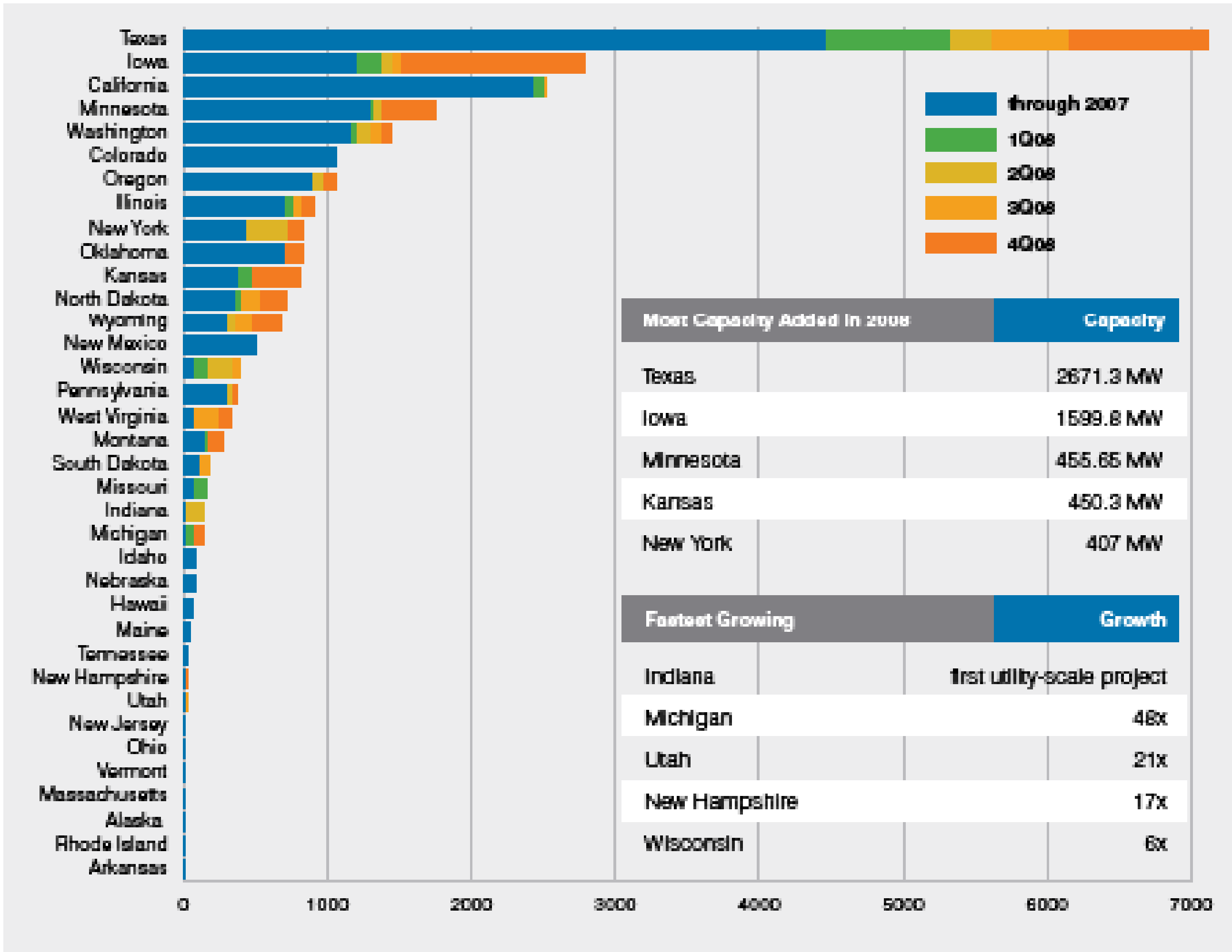
ERZ & GDA Map


2008 Energy Resource Zones with GDA's
COLORADO
Wind Resource
Wind GDA
50 meter Wind Power Class 7
50 WPC6
50 WPC5
50 WPC4
50 WPC3
50 WPC2
Interstate Highways
Transmission
COLORADO
Central Solar Power
CSP GDA
Transmission
Interstate Highways
GDA 1
4 GW
GDA 2
6 GW
GDA 3
15 GW
GDA 4
2 GW
GDA 7
4 GW
GDA 5
23 GW
GDA 6
37 GW
GDA 8
2 GW
Zone 1
Zone 2
Zone 3
Zone 4
Zone 5
GDA
San Luis
Valley
GDA
South
and
Southeast
of Pueblo

Renewable Energy Zones

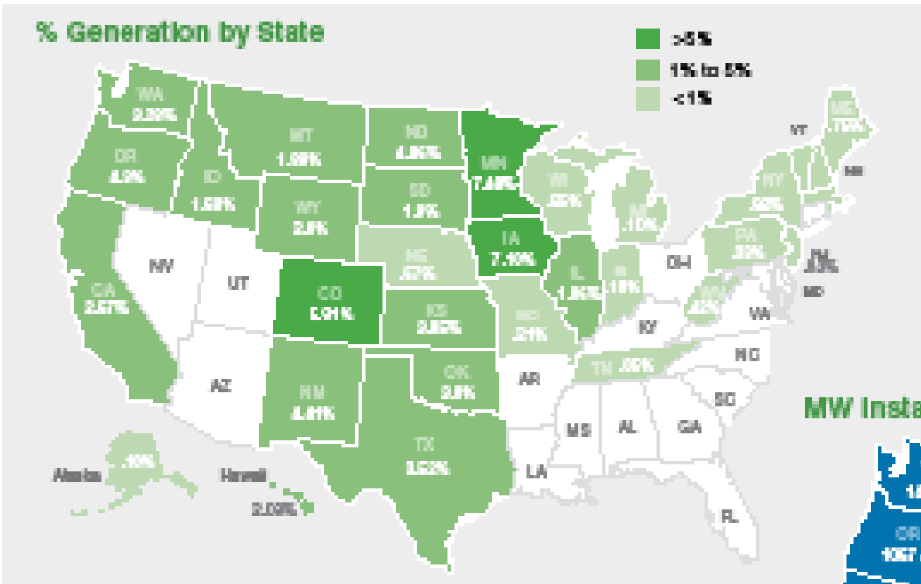


National Wind Energy



ANNUAL STATISTICS ON U.S. WIND ENERGY

National Wind Energy



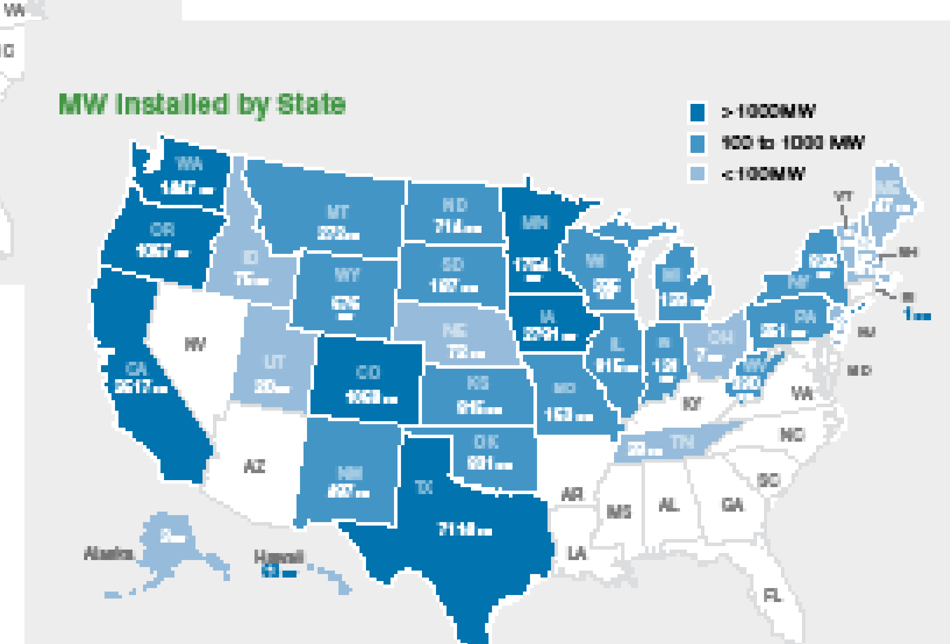
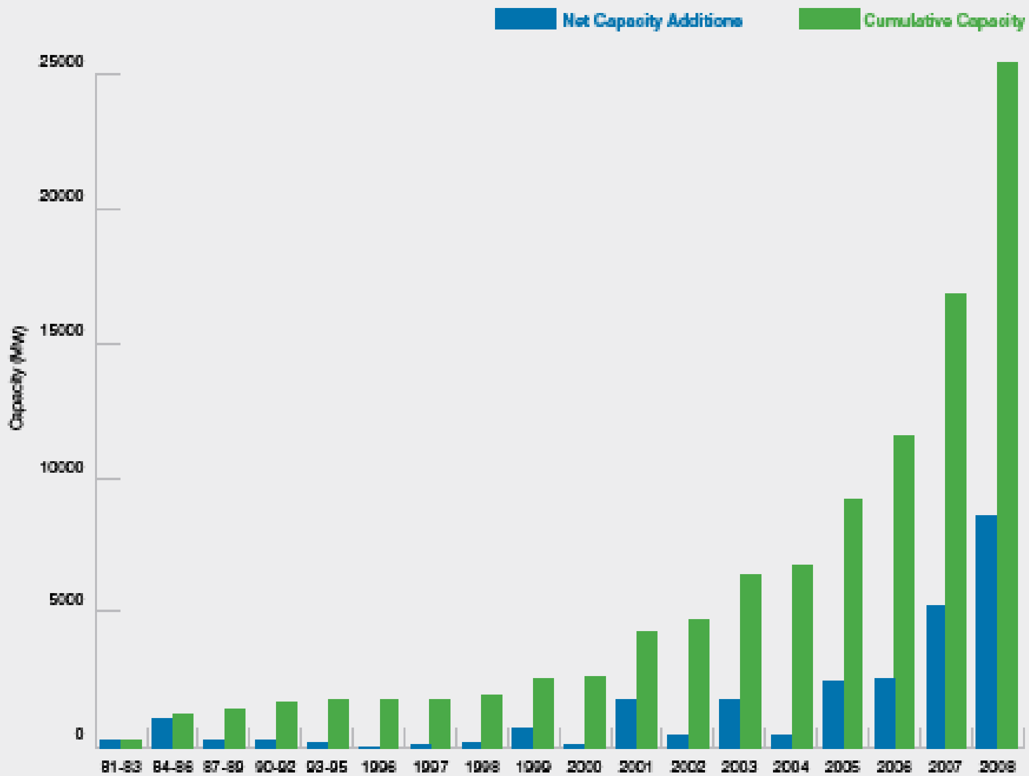


Figure 9: Actual

National Wind Energy

Year	Net Capacity Additions	Cumulative Capacity
1981-1983	240	240
1984-1986	982	1,222
1987-1989	181	1,403
1990-1992	181	1,584
1993-1995	119	1,703
1996	1	1,703
1997	8	1,711
1998	142	1,853
1999	659	2,512
2000	67	2,579
2001	1,694	4,273
2002	412	4,685
2003	1,672	6,357
2004	372	6,729
2005	2,420	9,149
2006	2,454	11,575
2007	5,249	16,823
2008	8,545	25,369



Wind capacity additions in 2008 were 8558 MW. 12.5 MW of wind power were decommissioned.

Wind - Modeling

- Interaction of different resource within a system

Wind

Size	100 MW
Capital Cost	2512 $/kW
Fixed O&M	1,500 $/kW
Variable O&M	17.19 $/MWh
Typical Capacity Factor	35%
Year Available	Incremental
Construction Time	Incremental

Central Solar

SunE Alamosa 6.9 MW AC

•Single axis tracking array

•Fixed-mount array

•Dual axis tracking array with photovoltaic concentrator technology

SandHill Solar

16.1 MW AC, ~ 5,900 SunPower T-20 units

Other Renewables

- CONCENTRATING SOLAR
  - Commission has approved acquisition of a minimum 200 mW CSP, RFP process underway, bids are in, some CSP bidders, under evaluation for resource needs and cost effectiveness.
- BIOFUELS
  - Current application for natural gas derived from biomass -- Controlled Anaerobic Digestion of animal waste (cattle) and used food oils/grease. Process expected to yield ~ 985,000 Dth annual natural gas.
    - Expect More to Come.
- GEOTHERMAL
  - Geothermal – Promise but little to no action on indentifying and developing resources. Colorado is home to numerous hot springs and has potential.
    - Expect to see some activities.

Increase in Renewable Energy

- On-site costs 4500 watt system (DC)
  - System Cost: $36,000 (typical $6 to $9/watt)
  - $2.00 rebate: -$ 9,000 (in statute)
  - $1.50 REC : -$ 6,750
  - Net System : $20,250
  - 30% ITC : -$ 6,075
  - System Cost : **$14,175**

Increase in Renewable Energy

- On-site costs 4500 watt system (DC)

Station Identification	
City:	Boulder
State:	Colorado
Latitude:	40.02° N
Longitude:	105.25° W
Elevation:	1634 m
PV System Specifications	
DC Rating:	4.5 kW
DC to AC Derate Factor:	0.770
AC Rating:	3.5 kW
Array Type:	Fixed Tilt
Array Tilt:	40.0°
Array Azimuth:	180.0°
Energy Specifications	
Cost of Electricity:	8.4 ¢/kWh

Results			
Month	Solar Radiation ($kWh/m^2/day$)	AC Energy (kWh)	Energy Value ($)
1	4.43	480	40.32
2	4.89	470	39.48
3	6.05	634	53.26
4	6.09	596	50.06
5	5.99	589	49.48
6	6.08	563	47.29
7	6.06	565	47.46
8	6.24	583	48.97
9	6.25	580	48.72
10	5.67	566	47.54
11	4.60	473	39.73
12	4.29	465	39.06
Year	5.56	6564	551.38

Solar*Rewards Large (primary voltage)		
Levelized REC Price ($/MWh)	$	184.05
Levelized Inc. Transmission ($/MWh)		-
Total Cost ($/MWh)	$	184.05
Avoided Energy/Carbon ($/MWh)	$	99.41
Transmission/Distribution Losses [1]		4.97%
Avoided Energy/Carbon ($/MWh)	$	104.61
Avoided Capacity Cost ($/kW-mo)	$	102.28
Accredited Capacity Factor [2]		69.00%
Annual Energy Capacity Factor		22.9%
Transmission/Distribution Losses		4.97%
Planning Reserve Margin		16.00%
Avoided Capacity ($/MWh)	$	44.53
REC Multiplier		1.00
$/REC	**$**	**34.91**

Solar*Rewards Medium (secondary voltage)

Levelized REC Price ($/MWh)	$	261.63
Levelized Inc. Transmission ($/MWh)		-
	$	261.63
Avoided Energy/Carbon ($/MWh)	$	99.41
Transmission/Distribution Losses		7.69%
Avoided Energy/Carbon ($/MWh)	$	107.69
Avoided Capacity Cost ($/kW-mo)	$	102.28
Accredited Capacity Factor		59.00%
Annual Energy Capacity Factor		21.6%
Transmission/Distribution Losses		7.14%
Planning Reserve Margin		16.00%
Avoided Capacity ($/MWh)	$	41.45
REC Multiplier		1.00
$/REC	**$**	**112.48**

Solar*Rewards Small (secondary voltage)

Levelized REC Price ($/MWh)	$	256.59
Levelized Inc. Transmission ($/MWh)		-
	$	256.59
Avoided Energy/Carbon ($/MWh)	$	99.41
Transmission/Distribution Losses		7.69%
Avoided Energy/Carbon ($/MWh)	$	107.69
Avoided Capacity Cost ($/kW-mo)	$	102.28
Accredited Capacity Factor		59.00%
Annual Energy Capacity Factor		21.6%
Transmission/Distribution Losses		7.14%
Planning Reserve Margin		16.00%
Avoided Capacity ($/MWh)	$	41.45
REC Multiplier		1.00
$/REC	**$**	**107.45**

Solar GDA's

SB-091

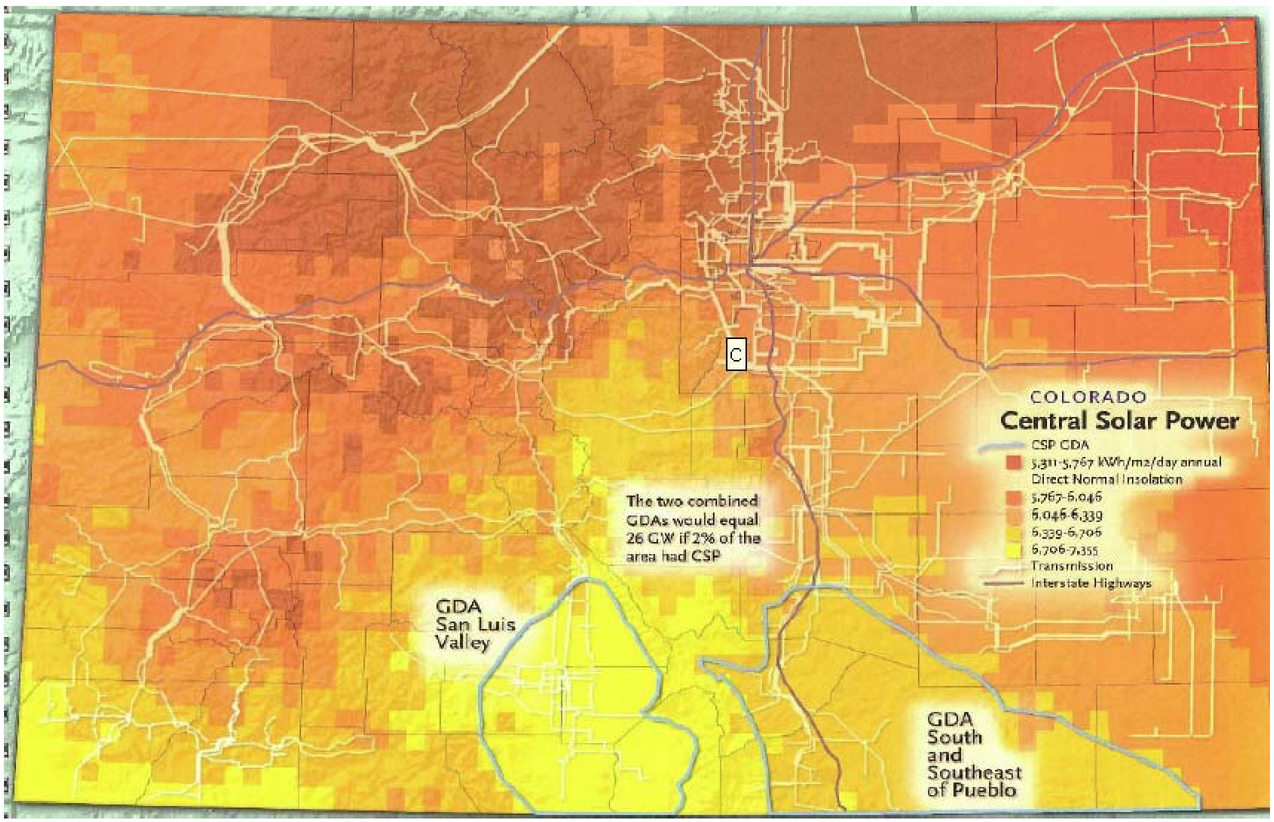


Figure 2.6-5 Cost/Capacity