Energy Supply Technical Work Group
Summary List of Recommended High Priority Mitigation Options

November 7, 2007: Yellow highlights indicate remaining questions and issues.

	Policy Option	GHG Reductions ($MMtCO_2e$)			Net Present Value 2008–2020 (Million $)	Cost-Effective-ness ($/t$CO_2$e)	Status of Option
		2012	2020	Total 2008 2020			
ES-1	Grid-based renewable energy incentives and/or barrier removal	0.9	3.1	17.2	$630	$37	updated text and preliminary quantification
ES-2	Distributed renewable energy incentives and/or barrier removal	0.13	0.31	2.3	$124	$54	Reviewed and affirmed at CAT meeting Oct 4th Updated quantification
ES-3	Efficiency improvements at existing renewable and power plants	Not Quantified					updated text, quantification removed
ES-4	Technology Research & Development, plus Technology-Focused Initiatives (originally 1.6, 2.8, and 3.4)	Not quantified					Reviewed and affirmed at CAT meeting Oct 4th
ES-5	CCSR (including pre and post-combustion) incentives, requirements and/or enabling policies plus R&D (originally 5.1, 5.2, and 3.1a and b)	Not quantified					Updated text for TWG review
ES-6	Transmission system capacity, access, efficiency, and Smart Grid (originally 6.1, 6.2, and 6.5)	Not quantified					Updated text for TWG review
ES-7	Combined Heat and Power (CHP) and Thermal Energy Recovery and Use (originally 2.5)	0.42	1.6	9.5	$82	$9	Reviewed and affirmed at CAT meeting Oct 4th

Note from TWG regarding future Natural Gas Prices and Supply:

Natural gas supply and price issues are not specifically addressed among the ES options, since direct opportunities for new GHG emission reduction initiatives appear somewhat limited. At the same time, it is important to recognize that if the availability of affordable natural gas supplies is limited, this could have negative consequence both for the state's economy as well as GHG emissions. Therefore, natural gas conservation, which is included in options both here (options that avoid electricity generation from natural gas fired facilities) and in the RCI TWG, may be critical. It is recommended that complementary efforts be undertaken in other venues to address these concerns.

The following options received significant interest from the TWG but were not considered high priority. Suggestions for follow up for some of the options are provided as well.

Catalog #	Mitigation Option Name	Comments
1.7	Climate change education initiatives	TWG suggests that the CAT should develop over-arching education policy
2.4	Green power purchases and marketing	Keep at moderate priority
2.7	Renewable energy development issues	Keep at moderate priority, limited ability for state actions
2.10	Use carbon offsets markets to promote additional renewable energy development	Include in other discussions on market based mechanisms (cap and trade, carbon tax)?
4.5b	Coal-to-gas production	Keep at moderate priority
4.7	LNG policies and infrastructure	Possibly consider needs for overall natural gas supply policies

ES-1. Grid-based[1] Renewable Energy Incentives and/or Barrier Removal

Based on ES Catalog Option 2.2

See also ES-2 and ES-7 for Distributed Energy and CHP applications and ES-6 for Transmission Requirements

Mitigation Option Description

This policy option addresses the barriers to and possible incentives for expanding grid-based renewable resources. Renewable resources, be they grid-scale or small-scale, can provide an important contribution to achieving the overall emission targets for Washington State. "Barriers" in this context should be thought of as institutional barriers to developing cost effective renewable resources or actions that will lead to grid-scale renewable resource being more economic. Such institutional barriers may include wind integration, transmission policies, interconnection policies, or regulatory cost recovery policies, or economic policy drivers. Financial incentives help address barriers such as higher upfront costs of these technologies.

Mitigation Option Design

The policy's objective is to *add the maximum amount of feasible renewable generation to the Washington State grid, taking into account the economic, environmental impacts and system reliability constraints.* This option should remove any barriers in existing regulations that limit achievement of the goal. In addition, the option should consider financial incentives to activities that exceed any legal requirements (for example I-937) for grid-based renewables. I-937 and SB 6001 are prescriptive policy measures to increase renewables and/or decrease GHGs. The policy changes discussed below would make increasing the supply of new renewables more attractive regardless of prescriptive policies.

Potential design elements are described below

Reduce Regulatory Uncertainty

Development Costs: Legislation/Executive order/Rulemaking process requiring the WUTC to develop policies and procedures to provide guidance to utilities on how different types of prudently incurred development costs will be recovered in rates before utilities make such expenditures.

[1] Grid-based means > 2 MW for these policy options, while Distributed Generation in ES-2 means up to 2 MW.

Transmission Cost Barriers: The state could provide no-interest loans or loan guarantees to utilities and non-utility generators for upfront transmission infrastructure charges related specifically to renewables.

Barriers to Non-Utility Generators: High interconnection costs, power dispatchability and regulatory barriers need also to be understood. Consider OR Public Utility Commission ruling under UM 1129 (need more specificity), so that the state can provide direct tax savings for energy efficient CHP and processes that reduce GHGs, where the benefits to the non-utility generators are in $/MWH. This will result in greater supply without burdening the utility customer with higher costs.

Incentives to directly support development of renewable resources This can be through some combination of tax supports to renewable developers, that may be bid into utility RFP's. The tax supports or other direct support could also be provided to utilities, that could be used for self-owned or non-utility renewable energy, which would help ensure energy and green attributes of such state-supported renewable resources stay in the state. What more is being called for? Volunteer group will provide additional input over the next week

Availability and Diversity of Resources: Legislative actions to expand list of available technologies and geographical limits. For example, new polices could expand the requirements for renewable resources and the definition of renewable for the purpose of GHG reduction to be more focused on non/low emitting resources. Targeted resources could include geothermal, solar, organic pulping by-products, tidal and ocean, and biomass. Energy comes to Washington from areas including Canada, Montana and California and renewable resources should be allowed from equally diverse and distant locations. This can be accomplished in one of two ways. One would be to update the geographic scope (eg, all of Western Electricity Coordinating Council), resource definitions and renewable targets in the RPS (I-937)—this would not represent a consensus recommendation by the TWG. A second way would be to add another layer to the existing legislation. What is being asked for? Volunteer group will provide additional input over the next week

Incentives and Other Strategies for Publicly Owned Utilities: Publicly-owned utilities do not operate for a profit, and therefore, incentives must be in the form of reduced taxes and/or zero-interest loans. At the state level, several taxes are assessed on a percent of retail sales, energy generated or materials purchased. These taxes could be reduced based on the percent of energy generation from renewable resources (e.g. if 15% of the retail load was served by renewable energy, then taxes would be reduced by an equal amount). In addition, sale taxes on materials purchased for eligible renewable energy projects could be waived. Finally, the state could develop a system of providing zero-interest loans for eligible renewable energy projects.

The state of Washington could provide public power utilities in the state with a renewable energy tax credit. For example, PUDs could receive a $0.003/kWh credit against the Public Utility Tax (PUT) for renewable energy delivered to retail customers, and a $0.001/kWh credit against the PUT for renewable energy credits ("Green Tags"). This could be a 10-year tax credit program per project.[2]

Incentives for Investor Owned Utilities: Utilities could be provided a rate of return kicker (or financial equivalent for purchases) for grid-based renewable resources and distributed generation.[3]

Utilities could be allowed to retain revenue from selling RECs generated/acquired in excess of those needed to comply with the RPS. This would provide positive incentives to comply with physical RPS targets early and in the long-term. Such an incentive could be coupled with a process to provide a cap on expenditures.

Policies that target non-or low-emission resources through financial incentives should include financial safeguards to ensure that the most cost competitive resources are developed and that end-use customers are protected from paying unreasonable costs.

Increase the capability and reduce the costs of integrating intermittent resources in the grid. The cost of wind integration services can be reduced through generally four types of actions: (1) developing more cooperation between regional utilities to spread the variability of wind more broadly; (2) developing markets that will reward entities who choose to market their surplus flexibility; (3) making more low-cost flexibility such as that provided by hydroelectric resources available; and (4) development and application of new flexibility technologies. Achieving these goals will require coordinated actions similar to those required to establish the Pacific Northwest Coordination Agreement of the Columbia River Treaty. Specifically, the Council's integration plan suggests that the:

- "four Northwest state regulatory commissions to review and amend as necessary regulatory policies to remove barriers to more efficient use of transmission for wind and other renewable resources, … and the
- Northwest Power and Conservation Council, working with BPA and other interested organizations, should establish a Northwest Wind Integration Forum to facilitate implementation of the actions called for in this Action Plan."

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[2] The current U.S. Tax Code provides tax incentives to private, for-profit utilities and developers to invest in renewable energy projects and new, efficient technologies. However, these tax incentives are not available to not-for-profit public power utilities because they have no federal income tax to offset. Congress passed the Renewable Energy Production Incentive (REPI) to provide public power with a comparable incentive. However, this program requires a congressional appropriation, which is severely under funded.

[3] For example, utilities could be allowed to earn at least 2% more on renewable resource rate base or equivalent expense, comparable to what was allowed at one time for conservation resources (One utility has recently applied to the UTC to capitalize a portion of their conservation expenditures. It is more common for utilities to expense their conservation costs). Applying this type of incentive for renewables was considered in the previous legislative session for SB6001, but was not included in the final version. Concerns regarding the incentive included (1) public utilities not having a similar incentive, (2) providing incentives for mandated renewable investments, and (3) whether the incentives could be applied to other non-renewable investments.

Jurisdictional authority may belong to FERC, the Bonneville Power Administration, and the North American Electric Reliability Council.

- **Goals:** *Add the maximum amount of feasible grid-based renewables, taking into account the economic, environmental impacts and system reliability*
- **Timing:**
- **Coverage of parties:**
- **Other:**

Implementation Mechanisms

Related Policies/Programs in Place

The Energy Independence Act (Initiative 937) passed by the state's voters in 2006 established renewable portfolio standards. Large utilities (25,000 customer and over) are required to obtain 15% of their electricity from new renewable resources, such as solar and wind, by 2020 (3% in 2012, 9% in 2016 and 15% in 2020). Additionally, utilities must undertake cost-effective energy conservation. The RPS affects 95% of the electric generation in the state.

See ES-2 below. See Senate Bill 6001 (April 2007), section 4d) and 4e),

Incentives for Non-Utility Generators—Combined Heat and Power incentives are discussed under ES-7

Type(s) of GHG Reductions

[Insert text here]

Estimated GHG Savings (in 2020) and Costs per $MtCO_2e$

------------- *Preliminary* -------------

#	Policy	Reductions ($MMTCO_2e$)*			NPV (2008-2020) ($ Million)	Cost Effective-ness ($/$tCO_2$)
		2012	2020	Cumulative Reductions (2008-2020)		
ES-1	Additional Grid-based Renewables	0.9	3.1	17.2	$630*	$37*

* - Costs for renewable energy are highly dependent on cost and policy assumptions that have large uncertainties as noted below. The analysis of these uncertainties indicates that the cost-effectiveness of this option could range from net benefits to almost $60/ metric ton CO2e, depending on the values assumed for capital costs of power plants and the potential extensions of the federal production tax credit.

- **Data Sources:**
  - Northwest Power Council 5th Power Plan (2005) and Biennial Monitoring Report (2007) – projections of costs and resource availability. http://www.nwcouncil.org/energy/powerplan/default.htm

- Integrated Resource Plans from Utilities http://www.nwcouncil.org/energy/Biennial/(P4-3)IRP%20Status.doc
- Union of Concerned Scientists. *The Washington Clean Energy Initiative: Effects of I-937 on Consumers, Jobs and the Economy.* http://www.ucsusa.org/clean_energy/clean_energy_policies/washington-clean-energy-i-937.html
- Renewable Energy Technology potential and costs from Western Governor's Association 2006 (WGA 2006) *Task Force Reports from the Clean and Diversified Energy Initiative,*[4] Energy Information Administration (EIA) Annual Energy Outlook (AEO),[5] National Renewable Energy Laboratory.[6]

- **Quantification Methods:** Analysis of the additional grid-based renewable generation involves the following steps: (1) estimate the maximum feasible renewable generation (2) identify the type of renewable generation that would most likely be used to meet the renewable energy requirements; (3) estimate the costs associated with each type of renewable technology; (4) estimate the type, cost and GHG emissions of the conventional generation that would be avoided by the increased energy efficiency and renewable energy; and (5) calculate the difference in costs and GHG emissions between the Additional Renewables scenario and the reference case (including I-937).

  Costs and emission reductions are calculated as incremental to the reference case, which includes energy efficiency savings and renewable generation expected from I-937.

Key Assumptions:

- **Maximum feasible renewable generation**: As a placeholder we have used 20% of total sales (after accounting for energy efficiency from I-937) in 2020
- **Renewable energy mix:** It is assumed that the additional renewable generation will be a combination of wind, solar thermal and biomass. For this preliminary analysis it is assumed that the renewable mix is made up of 88% wind, 2% solar thermal and 10% biomass (as fraction on new generation). These assumptions result in total capacity in 2020 (including I-937) of 6350 MW of wind (32% of estimated peak electricity demand), 300 MW solar thermal, and 360 MW of biomass.
- **Renewable energy costs:** The costs of the new renewable systems are based on those used in the EIA Annual Energy Outlook for 2007, except where better (e.g., updated or more local) data are available. The cost of renewable generation includes costs associated with connecting renewable technologies to the electric grid, and transmitting the

[4] http://www.westgov.org/wga/initiatives/cdeac/index.htm
[5] http://www.eia.doe.gov/oiaf/aeo/assumption/index.html
[6] http://www.nrel.gov/analysis/power_databook/

renewable generation to loads (see below). The cost of wind generation also includes costs associated with integrating wind onto the system, as detailed below.

- **Production Tax Credit:** For qualifying renewable energy technologies, a federal tax credit of $18/MWh (inflated) is assumed for the first ten years of operation for new facilities that commence operation by the end of 2010. Following the UCS analysis we adjusted this value as follows "However, because the PTC is a credit on tax liability rather than a dollar of taxable income, this value does not account for its full tax benefits. To capture the additional tax benefits of the PTC, we assumed that it has a 20-year levelized value of 2.2 cents/kWh."[7]
- **Transmission Expansion Costs**: Since many renewable resources are located away from existing transmission lines, additional transmission would likely be needed. Since the precise nature of those additional costs would require calculations beyond the scope of the current analysis, we propose using an average cost of $80/kW for all new resources, based on a recent scenario analysis by the WGA CDEAC.[8] *Washington-specific estimates would be helpful if available.*
- **Reference Technology Costs:** We use technology costs from the UCS 2006 report (see above) for wind and EIA's Annual Energy Outlook (AEO) for 2007 for biomass and solar.[9]

Technology Parameters							
	2012			2020			
Technology	Total Overnight Cost ($/kW)	Variable O&M (mills/ kWh)	Fixed O&M ($/kW)	Total Overnight Cost ($/kW)	Variable O&M (mills/ kWh)	Fixed O&M ($/kW)	Project Life (Years)
Biomass	2,155	3.0	50	2,066	3.0	50	30
Solar Thermal	2,959	0	52	2,784	0	43	25
Wind	1,419	0	31	1,179	0	26	20

All costs are expressed in year 2005 dollars and represent expectations as of late 2006.
Source: Wind: Union of Concerned Scientists. *The Washington Clean Energy Initiative: Effects of I-937 on Consumers, Jobs and the Economy.*[10] Solar: Ken Dragoon, RNP (based on information from Tacoma Power) and Biomass: *Puget Sound Energy2007 Integrated Resource Plan*[11]

7 http://www.ucsusa.org/clean_energy/clean_energy_policies/washington-clean-energy-i-937.html
8 CDEAC Transmission Report in the High Renewables case has an average incremental transmission cost of 80 $/kW compared to the reference case, i.e. 84,641 MW incremental capacity with additional transmission expansion costs of $6,786 million.
9 Electric Market Module, EIA Assumptions to the Annual Energy Outlook 2007.
10 http://www.ucsusa.org/clean_energy/clean_energy_policies/washington-clean-energy-i-937.html
11 http://pse.com/energyEnvironment/2007IRP/Appendices/I-ElectricAnalysis.pdf

- **Wind Integration costs**. The cost of integrating wind at various levels of wind penetration is estimated based on studies by utilities in the Northwest (Avista, Idaho Power, Puget Sound Energy and Pacificorp) as compiled for the *Northwest Wind Integration Action Plan* (March 2007)[12]. In general, wind integration costs rise with increasing penetration of wind in the grid, as shown below. However, these estimates are subject to uncertainty – see discussion below under "key uncertainties."

Wind Capacity Fraction of System Peak	Average Wind Integration Cost ($/MWh of Wind Generation)
0%	0.0
5%	$3
10%	$6
20%	$8
30%	$12.5

- **Avoided costs:** $43.5/MWh Based on analysis from NW Power and Conservation Council.
- **Avoided electricity emissions:** 0.5 metric ton CO_2/MWh, placeholder value (reflecting largely avoidance of natural gas) awaiting further consultation with NW Power and Conservation Council and TWG as analysis proceeds.
- **Impacts of Alternative Assumptions** In order to test the sensitivity of above uncertainties on the estimated costs and cost-effectiveness, we re-estimated the options with alternative assumptions for the key uncertainties.
  The following table summarizes the alternative assumptions that we tested, and the changes to the cost and cost-effectiveness results. Each alternative assumption was tested individually but the effects of combining the alternative assumptions can be roughly estimated by summing the changes.

			Change in Results, relative to Initial Assumptions	
	Initial Assumption	**Alternative Assumption**	**Costs ($ millions)**	**Cost Effectiveness ($/t$CO_2$)**
Capital Cost of Wind	$1,419/kW in 2012 $1,050/kW in 2020	$2,000/kW in 2012 $1,500/kW in 2020	**+$298**	**+$17**
Avoided Cost of Electricity	$43.46/MWh	$64.20/MWh	**-$422**	**-$25**
PTC sunset	2010	2020	**-$358**	**-$21**

[12] http://www.nwcouncil.org/energy/Wind/library/2007-1.pdf

The table indicates that if the capital cost of new wind plants are $2,000/kW, rather than the initial assumption of $1,557/kW – the estimated costs of the option will *increase* by $298 million (net present value) or $17/metric ton CO_2e , relative to the costs based on the initial assumptions (presented above). Therefore, with higher estimates for the capital cost of new wind, the total cost is approximately $1,017 million (net present value) and the cost-effectiveness is about $59/metric ton CO_2e.

Using and avoided electricity price of $64.20/MWh, the costs would *decline* by $422 million (net present value) or $25/metric ton CO_2e.

Using the assumption that the PTC will be extended to 2020, the initial costs would *decline* by $358 million (net present value) or $21/metric ton CO_2e.

Contribution to Other Goals

- **Contribution to Long-term GHG Emission Goals (2035/2050):**
- **Job Creation:**
- **Reduced Fuel Import Expenditures:**

Key Uncertainties

_Additional Benefits and Costs

[Insert text here]

Feasibility Issues

[Insert text here]

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

ES-2. Distributed Renewable Energy Incentives and/or Barrier Removal

Based on ES Catalog Option 2.3 and RCI Catalog Option 6.1

This option will be considered jointly with the RCI TWG group.

Mitigation Option Description

Distributed electricity generation sited at residences and commercial and industrial facilities, which is powered by renewable energy sources (typically solar, but also wind, small hydroelectric power sources, or biomass or biomass-derived fuels), displaces fossil-fueled generation and avoids electricity transmission and distribution losses, thus reducing greenhouse gas emissions. This policy can also encourage consumers to switch from using fossil fuels to using renewable fuels in applications such as water, process, and space heating. Potential technologies include: solar photovoltaic systems, solar water heating/space heating systems, wind power systems, particularly for rural areas, biomass-fired generation, space, or water heating systems.

There are numerous barriers to distributed renewable energy, including inadequate information, institutional barriers, community barriers, limited number of qualified contractors, high technology costs high transaction costs because of small projects, high financing costs because of lender unfamiliarity and perceived risk, "split incentives" between building owners and tenants, and utility-related policies like interconnection requirement, high standby rates, exit fees, etc. The lack of recognition for emissions reduction value provided also creates obstacles. Increasing the use of renewable energy applications in homes, businesses, and institutions in Washington can be achieved through a combination of regulatory changes and financial incentives.

The cost of distributed renewable generation is high relative to standard utility rates in the state and region; the economic and financial "barriers" to distributive generation investment by customers may be higher in Washington than elsewhere because of comparatively low electricity rates. This economic obstacle is difficult to overcome and may continue to represent a challenge unless utilities can be encouraged and empowered to capitalize and install distributed generation projects.

Mitigation Option Design

Potential elements of this option could include:

- The primary barrier to new small DG (<2 MW)[13] is the high initial cost which must be borne by the customer-generator. Tax credits, no-interest loans, rebates for specified technologies, and other mechanisms to make distributed renewable resources more economically viable are important to develop non-traditional resource alternatives.

- Washington already has uniform interconnection standards for small DG resources. The existing regulatory construct can discourage direct utility capital investment in DG; those barriers should be examined.[14] [15]
- Consider amending the net metering statute (RCW 80.60) to: (1) increase the size of qualifying [agricultural] systems from 100 kW to 200 kW (currently net metering is available generally up to 100 kW); (2) accelerate the timeline for increasing the cumulative generating capacity available to renewable net metered systems[16]; and (3) ensure a simplified process for customer-generators to utilize net metering.
- Efforts to simplify and standardize permitting for industrial and large commercial DG systems, as well as support for County and city land use prescreening efforts to facilitate siting.
- Training/certification programs for installers/contractors
- Consider requiring new connections representing a load greater than a certain threshold (x kW) to evaluate distributed generation options

- **Goals:** Overcome barriers posed by high up-front costs and other aspects of distributed renewable energy systems, in order to promote stronger market for Washington.
  - **Goals used in the preliminary analysis (subject to revision):**
    - rooftop solar photovoltaic (PV) systems: 20 MW by 2020. This value may be adjusted.
    - small wind: 30 MW by 2020. This value may be adjusted.
    - Solar Hot Water: have systems installed in 0.8% of new homes by 2015, based on Western Governors' Association estimate of an achievable goal of 500,000 systems installed by 2015 for entire region. The WA fraction accounts for electricity use, solar insulation [the amount of sunlight/solar radiation], and population growth.

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[14] Other "incentives" aimed at increasing market penetration of DG and certain energy efficiency technologies could be more effectively targeted at utilities, rather than individual consumers; utilities could be encouraged to create the market if they (IOUs) have the proper incentives to do so. Such incentives could be included under ES-1 or through DSM programs in RCI TWG.

[15] High interconnection costs and regulatory access barriers can be shifted from the customer-generator to the general population with appropriate legislation. [a specific recommendation to accomplish this action is needed]

[16] 80.60.020(1) says: "… On January 1, 2014, the cumulative generating capacity available to net metering systems will equal 0.5 percent of the utility's peak demand during 1996. Not less than one-half of the utility's 1996 peak demand available for net metering systems shall be reserved for the cumulative generating capacity attributable to net metering systems that generate renewable energy".

- Biomass and landfill gas: Goals for biomass options are outlined in the agriculture and forestry options (and will be reflected here); the TWG will consider whether to include additional goals (here or in ES-7). Currently 49 MW by 2020 has been estimated for biomass based on review of NW Council 5th Power plan resource assessment and 2.5 MW by 2020 for landfill gas, based on EPA's Landfill Methane Outreach Program,[17] assuming that 5% of the potential capacity could be achieved by this option.

- **Timing:**
- **Coverage of parties:**
- **Other:**

Implementation Mechanisms

- Expansion and/or extension of tax incentives provided under SB 5101 (2005).
- Conduct analysis to determine availability of DG supply.
- Consider establishing additional tax credit programs, patterned after successful programs in other states (e.g. Oregon's Business Energy Tax Credit (BETC), which is 35% of eligible project costs[18]
- Consider incentives that provide a payback period of 5 years[19]
- Increasing the current net-metering cap from 100 kW to 1 MW, and allow aggregation if appropriate in commercial and/or agricultural applications.
- Other potential financial incentives to implement distributed renewables programs include:
  - Siting Incentive Programs;
  - Low-cost bonding or loan guarantee programs;
  - Expanding incentives offered under the existing law to residential consumers to include commercial systems
  - Increase utility rates of return for investments in distributed renewables (under certain circumstances under I-937, a qualifying utility may count distributed generation at double the facility's electrical output)
  - Encouraging the creation of and support for biomass fuels markets.

[17] http://www.epa.gov/lmop/proj/index.htm#2

[18] Oregon Department of Energy – Conservation Division, *Business Energy Tax Credits*, www.oregon.gov/ENERGY/CONS/BUS/BETC.shtml (accessed September 25, 2007)

[19] Heron, Hollis of Flack + Kurtz, *POSITION PAPER – Washington State Photovoltaic Incentives*, August 28, 2007, Memo to Bert Gregory

- In Oregon, UM1129 took several steps toward supporting small-scale systems, including net metering changes and allowing combining of meters that are on the same property. Similar aspects could be considered in Washington.

Related Policies/Programs in Place

In 2005, the Legislature enacted the Renewable Energy System Cost Recovery (RCW 82.16.110) and Tax on Manufacturers or Wholesalers of Solar Energy Systems (RCW 82.04.294). The legislation provides incentives for the purchase of locally-made renewable energy products and provides a preferential rate under the business and occupation tax. Furthermore, tax exemptions under RCW 82.08.02567 and RCW 82.12.02567 incent the purchase and use of machinery and equipment used directly to generate electricity using fuel cells, wind, sun, or landfill gas. Similarly, RCW 82.08.835 and RCW 82.12.835 incent the purchase and use of solar hot water systems. Other renewable energy incentive programs include the federal income tax credit of 30% for one year (max $2,000).

Incentive payments are provided by electric utilities to customers generating renewable energy (i.e., solar, wind) on their property. For example, the Chelan County PUD Sustainable Natural Alternative Power Producers Program encourages customers to install power generators such as solar panels and wind turbines and connect them to the PUD distribution system; Avista Utilities provides a production credit of 14 cents per kWh for one year; Bonneville Environmental Foundation Green buys “tags” for five cents per kWh for up to five years (see additional information at end of this document).

A statewide biomass inventory and assessment was completed in 2005 by the U.S. Department of Energy (DOE) and Washington State University (WSU). The inventory identified nearly 17 million dry weight tons of annually renewable biomass resources across the state, with woody biomass as the dominant resource. Estimates indicate this organic resource is capable of supplying -- through combustion and anaerobic digestion -- about 50% of Washington annual residential electrical needs. In 2006, the Washington legislature authorized the “Waste to Fuels Technology” project, a partnership between the U.S. DOE and WSU, to evaluate the potential energy production from biomass feedstock, identify specific bio-fuels recovery technologies, and assess market development economics for organic resources.

Executive Order 05-01 mandates 10% reduction in State Agency energy purchases from 2003 levels by 9/1/2009, including through use of renewable energy

Initiative 937 allows qualifying utilities to count distributed generation at double the facility's electrical output if the utility meets one of two conditions:

1. The utility owns or has contracted for the distributed generation and the associated renewable energy credits; or
2. The utility has contracted to purchase the associated renewable energy credits.

Type(s) of GHG Reductions

CO2, N2O and CH4 from avoided electricity generation

Estimated GHG Savings (in 2020) and Costs per $MtCO_2e$

------------- *Preliminary* -------------

		Reductions	(MMtCO$_2$e)*			
	Policy	**2012**	**2020**	**Cumulative Reductions (2007–2020)**	**NPV (2007–2020) $ millions**	**Cost-Effective-ness $/tCO$_2$**
ES-2	Renewable DG	0.13	0.31	2.3	$124	$54
Results by Technology Type						
	Solar Hot Water	0.06	0.11	1.0	$3	$3
	Wind	0.02	0.05	0.3	$9	$29
	Solar PV	0.01	0.02	0.1	$86	$705
	Biomass, Landfill gas	0.04	0.13	0.9	$25	$29

Note: results may need to be adjusted to avoid potential double-counting with I-937.

- **Data Sources:** Western Governors Association's *Clean and Diversified Energy Initiative*; EIA *Annual Energy Outlook 2007* assumptions; Energy Trust of Oregon *A Comparative Analysis of Community Wind Power Development Options in Oregon*.
- **Quantification Methods:** Starting with the goals for each technology (see below), assumptions regarding the annual penetration of new distributed systems are generated. Estimates of cost and performance for different kinds of renewable systems and costs/emissions of avoided electricity are then used to estimate the overall net GHG emissions reduction and net cost of the policy.
- **Key Assumptions:**
  - **Technology costs:** from Western Governors' Association 2006 (WGA 2006) Task Force Reports from the Clean and Diversified Energy Initiative,[20] Energy Information Administration,[21]; and, Energy Trust of Oregon (Table ES-4).[22]

Table ES-4. Costs for distributed energy technologies.

Technology	Capital Cost ($/kW)	Capacity Factor	Project Life (Years)	Source/Notes
Solar PV	Residential: $4,904 (2012)	20%	20	WGA Clean and Diversified Energy Initiative

[20] http://www.westgov.org/wga/initiatives/cdeac/index.htm

[21] http://www.eia.doe.gov/oiaf/aeo/assumption/index.html

[22] *A Comparative Analysis of Community Wind Power Development Options in Oregon* http://www.oregon.gov/ENERGY/RENEW/Wind/docs/CommunityWindReportLBLforETO.pdf

	$3,265 (2020) Commercial $2,464 (2012) $1,870 (2020)			report on Solar, includes federal incentives
Solar Hot Water	$2,534 (2012) $2,200 (2020)	75%	20	EIA Annual Energy Outlook assumptions
Wind	$2,149 (2012) $1,194 (2020)	35%	20	Energy Trust of Oregon for 2020, 2010 rough estimate
Biomass	$2,500 (2012) $2,200 (2020	57%	20	Placeholder, need input from forestry TWG
Landfill	$2,000 (2012) $1,500 (2020	57%	20	Placeholder

- **Avoided costs:** $43.5/MWh Based on analysis from NW Power and Conservation Council.
- **Avoided electricity emissions:** 0.5 metric ton CO_2/MWh, placeholder value (reflecting largely avoidance of natural gas) awaiting further consultation with NW Power and Conservation Council and TWG as analysis proceeds.

See Appendix B: Further details on Quantification for Options

Contribution to Other Goals

- **Contribution to Long-term GHG Emission Goals (2035/2050):** Likely dependent on how key uncertainties noted below are resolved over time. Level of contribution to long term goals dependent on how broadly DG technologies are utilized, which are in turn highly dependent on per kW cost of systems.
- **Job Creation:** Washington is home to many companies, such as RES and Xantrex, that manufacture solar energy and other DG system components. Expansion of the market for DG systems should help grow this fledgling industry in Washington and create more jobs in places like Moses Lake, Arlington and Vancouver.
- **Reduced Fuel Import Expenditures:** Distributed renewable energy can contribute to reductions in natural gas imports.

Key Uncertainties

Growth in utilization of DG technologies will depend, in part, on new technologies, increased manufacturing efficiencies with existing technologies and increase in markets to drive economies of scale that will reduce system costs. The contribution of some technologies, such as geothermal and landfill gas, to energy production and GHG reductions will depend on resource supply.

Additional Benefits and Costs

- Distributed energy can increase energy supply reliability, although integrating intermittent technologies within the grid must be managed carefully (see Option ES-6).

- Reductions in overall electricity consumption and the shift from fossil fuel generation as a result of new renewables would lead to reductions in criteria air pollutants and, consequently, reduce health costs associated with those pollutants.
- Renewables can provide a fuel price hedge effect against fossil fuel price volatility, particularly natural gas.
- The operating costs of renewable generation, primarily maintenance, are generally spent locally and can provide a direct boost to local and state economies.

Feasibility Issues

Any distributed generation involving combustion may have an adverse impact on air quality, at least in the area close to the generator. Existing air quality rules may need to be changed to accommodate distributed generation and protect air quality.

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

ES-3. Efficiency Improvements, Capacity Additions and Fuel Switching at Existing Renewable and Fossil Power Plants

Based on ES Catalog Options 2.9 and 3.3

Mitigation Option Description

Efficiency improvements refer to increasing electric generation output at existing projects through incremental improvements at existing renewable projects (e.g. hydro, biomass, solar or wind) and at existing fossil plants (e.g., more efficient boilers and turbines, improved control systems, or combined cycle technology). Efficiency improvements at existing projects include incremental operational and equipment changes that result in more electric energy output using the same amount of fuel.

Capacity additions refer to adding electric generation capacity to any existing renewable projects. Fuel switching refers to switching to lower or zero emitting fuels at existing fossil plants. This may include the use of biomass or natural gas in place of coal or oil. (repowering is not fuel switching)

All of these (efficiency improvements, capacity additions and fuel switching) are effective ways of achieving lower GHG emissions and should be encouraged as part of state policy (*See additional information at end of this document*). Policies to encourage improvements at existing plants could include: new policies and principles, new laws and regulations, market-driven incentives, and financial incentives.

Mitigation Option Design

Potential elements of this option could include:

- Policies and Principles – establish policies and principles through the Governor that define and promote efficiency improvements at existing projects. Encourage optimal use of our existing resources and investments in new resources, consistent with appropriate new source review under the State's Clean Air Act.
- Laws and Regulations – develop implementing legislation or guidelines that provide the necessary market-driven incentive to accomplish overall goal.
- Market-driven incentives – provide incentives through future environmental attributes market (e.g. renewable energy credits, green power, and carbon offsets) that encourage and reward the efficient use of our energy resources.
- Financial incentives – provide incentives through reduced taxes and low-interest loans and other financial incentives.
- Explicit credit for GHG emission reduction could be a part of the prudence decision-making process, which could then result in more such improvements occurring.

- Incentives could be provided using investment and production tax credits, government loan guarantees, low interest loans and grants. Oregon's Business Energy Tax Credit system works well to encourage renewable energy generation and energy efficiency projects at commercial sites and industrial plants.
- To address potential efficiency improvements at plants under federal authority, the regional Governors and state delegations could, working with BPA, secure federal funding to first study and identify the potential efficiency improvements in the Bonneville hydro system and then obtain funding for implementation.

- **Goals:** *Implement the achievable, [cost-effective] efficiency potential at Washington's existing power plants. Reduce GHG emissions by substituting higher GHG fuels with lower GHG fuels [goal framing TBD].*
  - Thermal savings: Not yet estimated – note that capacity additions to thermal plants do not qualify for this option
  - Improve equipment and operational efficiency at existing hydro plants, to gain 500 aMW from existing plants by 2015 Value may be revised based on input from BPA
- **Timing:** To establish policies on or before January 1, 2009.
- **Coverage of parties:**
- **Other:**

Implementation Mechanisms

Additional Design Considerations [Should any of the following be moved to the Design section]

- Focus on efficiency improvements, capacity additions for renewable energy and fuel switching at existing renewable and fossil facilities. This could also include co-firing with biomass
- Need to clarify financial incentives. Favor utilizing incentives where appropriate.
- Under I-937, a qualifying utility may only count the incremental power from an upgrade made to its own hydroelectric projects against the renewable energy standard. It must also retain all renewable energy credits associated with that upgrade in order to count the incremental power against the standard. When a non-qualifying utility that serves retail electric load in the state upgrades a hydropower facility it owns, any power or renewable energy credits it may sell to a qualifying utility should count against the qualifying utility's renewable energy obligation.. TWG members disagree on whether changes should be made within I-937 to address this restriction or new policy/legislation should be developed to encourage efficiency improvements at hydro plants.
- Ensure full participation in the WREGIS trading system to establish market standards that prevent potential double-counting of renewable energy generation.
- Explore methods to recover capital expended on existing fossil-fueled resources that facilitate a transition to lower GHG-emitting resources.

- Changes to cost-benefit analysis of efficiency projects at existing projects to more directly reflect the benefits of the value of avoiding GHG emissions during any pre-approval or prudence review.
- A system that incorporates changes in the Washington's B&O tax to provide tax incentive credits similar to BETC could provide the tipping-force to move GHG reduction projects forward.
- Need to ensure financial incentives are equally available to both private and publicly-owned utilities.
- Consider whether avoided GHG emissions attributable to efficiency improvements, capacity additions and fuel switching at existing plants prior to any mandate or that exceed an operating permit limitation could be creditable as early actions within the context of a regional mechanism to achieve GHG reductions.

Related Policies/Programs in Place

- Senate Bill 6001 (April 2007), sections 4c) and 11.
- Implementation of the Energy Independence Act (RCW 19.285)

Type(s) of GHG Reductions

Estimated GHG Savings (in 2020) and Costs per $MtCO_2e$

------------- Preliminary -------------

		Reductions	($MMtCO_2e$)*			
	Policy	**2012**	**2020**	**Cumulative Reductions (2008–2020)**	**NPV (2008–2020) $ millions**	**Cost-Effective-ness $/tCO_2$**
ES-3	Efficiency Improvements at existing plants	0.04	1.4	6.5	Not yet estimated	Not yet estimated

Note: results need to be reviewed for potential double-counting with I-937 and adjustments for consumption (load)-based accounting.

- **Data Sources:** *Carbon Dioxide Footprint of the Northwest Power System*, NW Power Council, September 2007[23] (draft report still under public review, alternative source should be used)
- **Quantification Methods:**

[23] http://www.nwcouncil.org/library/2007/2007-15.pdf

    - For Hydro, used estimated GHG reductions from NW Council report. (draft report still under public review, alternative source should be used)

- **Key Assumptions:**

Contribution to Other Goals

- **Contribution to Long-term GHG Emission Goals (2035/2050):**
- **Job Creation:**
    - Implementation of efficiency improvements will produce high-quality technical and trade jobs.
- **Reduced Fuel Import Expenditures:**

Key Uncertainties

[Insert text here]

Additional Benefits and Costs

[Insert text here]

Feasibility Issues

- The estimated percent of efficiency improvements needs to be confirmed. An energy audit of existing projects to identify operational and equipment efficiency improvements and to identify new generation resources needs to be completed. Potential energy savings (aMW) and expected costs associated with those savings needs to collected and compiled before informed decisions can be made.

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

ES-4. Technology Research, Development & Demonstration and Technology-Focused Initiatives

Based on ES Catalog Options 1.6, 2.8, and 3.4

This option also relates to Options in other TWGs including Forestry and Agriculture.

Mitigation Option Description

Drive advances in technologies that would develop cleaner energy supplies and make existing fossil fuel energy sources less GHG emitting. Encourage deeper investments in implementation opportunities for these new technologies. Establish an emerging energy technology program to set the stage for wider-scale adoption of these emerging and break through clean energy and efficiency technologies. This may involve strengthening an existing program, such as the Washington Technology Center, or creating a new stand-alone entity.

Mitigation Option Design

- Establish an emerging energy technology program to help develop and deploy advanced technologies:
    - Provide opportunities and incentives to invest in, test, and deploy new technologies.
    - Promote research and development of cost-effective breakthrough technologies.
    - Support technology demonstration projects to help commercialize technologies that have already been developed but are not yet in widespread use.
- Criteria for the Program
    - Program investments must target efforts that reduce GHG, reduce energy imports and create clean energy jobs and economic development.
    - Increase collaboration between existing institutions for RD&D on technologies and support public and private partnerships. Create centers of technology excellence.
    - Implement a bi-annual strategic planning requirement (such as the Washington Technology Center conducted in 2001 to develop roadmap http://www.watechcenter.org/downloads/strategicplan_200308.pdf) to develop a rational and comprehensive approach to energy supply R&D needs in the State. Use this to prioritize research needs on a bi-annual basis.
    - Use an open bidding procedure (i.e., driven by bids received rather than by a focused strategy to develop a particular technology) within the sideboards provided by the bi-annual planning exercise.
    - Could consider opportunities for private sector companies to provide funding for this program

- The emerging energy technology program should be inclusive of legitimate technologies that among others, result in:
    - Efficiencies in power generation, fuel transport and co-firing
    - Efficiencies in power use
    - Advance energy storage systems
    - Carbon capture, storage and reuse
    - Alternative clean energy development

- Research Development and Demonstration Costs: The WUTC could be required to establish policies, guidelines, and procedures for reviewing, approving, and establishing accounting treatment for utility proposed RD&D projects. The process could clarify how costs of prudently managed, utility proposed RD&D projects may be recovered. HB 1032, which was considered but not passed in WA legislature last session, includes suggested criteria and considerations for recovering RD&D funding from customers.[24]

- **Goals:**
    - Build on existing state partnerships and initiatives. $10 million Emerging Energy Technology fund for advanced clean energy technologies. [*request has been made to WSU Energy program for estimate of annual budget, for comparison to the amount proposed here]*
    - Shared funding partnership with state, federal, and private sector partners to ensure the most effective deployment of these technologies.

- **Timing:**
    - TBD

- **Coverage of parties:**
    - State agencies, Washington Universities, private companies, utilities, Federal laboratories

- **Other:**

Implementation Mechanisms

- State program that partners with all levels of government, utilities, energy suppliers, and technology development companies.

Related Policies/Programs in Place

See Senate Bill 6001 (April 2007), various sections.

Northwest Energy Technology Collaborative

Washington Technology Center

Washington State University Energy Extension Service

Community Trade and Economic Development - Energy Policy Division

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[24] http://apps.leg.wa.gov/billinfo/summary.aspx?bill=1032&year=2007

Pacific Northwest National Laboratory

In 2006, the Washington legislature authorized the "Waste to Fuels Technology" project, a partnership between the U.S. DOE and WSU, to evaluate the potential energy production from biomass feedstock, identify specific bio-fuels recovery technologies, and assess market development economics for organic resources.

Type(s) of GHG Reductions

This option is an enabling strategy for achieving reductions estimated for other options, and is not quantified directly.

Estimated GHG Savings (in 2020) and Costs per $MtCO_2e$

- As indicated above, GHG savings are not quantified for this option

Contribution to Other Goals

- **Contribution to Long-term GHG Emission Goals (2035/2050):** Effective R&D is designed to substantially contribute to long-term GHG emissions goals by enabling GHG reductions identified in other options and creating new opportunities for GHG reductions.
- **Job Creation:** Jobs connected to the R&D program will directly contribute the State's Clean Energy Job Creation goals.
- **Reduced Fuel Import Expenditures:** R&D indirectly contributes to reducing fuel import expenditures by enabling other options.

Key Uncertainties

Additional Benefits and Costs

Feasibility Issues

- Review the achievements of other R&D programs to better understand the key components of successful R&D programs and seek to include these elements

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

ES-5. Carbon Capture, Storage, and Re-use Incentives, Requirements and/or Enabling Policies and Research & Development (including pre-combustion technologies)

Based on ES Catalog Options 5.1, 5.2, and 3.1b.

Mitigation Option Description

Carbon dioxide (CO_2) capture and storage or reuse (CCSR) is a process consisting of the separation of CO_2 from industrial and energy-related sources, transport to a storage location and long-term isolation from the atmosphere. The CO_2 from large point sources can be compressed and transported for storage in geological formations, in the ocean, in mineral carbonates, or for reuse in industrial processes. Captured carbon can be reused for enhanced recovery of oil and gas extraction or as a feedstock for industrial processes. Technological and financial barriers exist to implementation of CCSR.

For the electricity generation sector, current carbon capture technologies are immature, therefore, incentives need to be established that encourage the development of full scale pre-combustion and/or post-combustion carbon capture technologies. And, while separation, capture and transport of CO_2 are reasonably mature technologies only three industrial-scale storage projects are currently in operation. Further R&D funding to improve CCSR technologies and evaluation studies to identify geologically sound reservoirs technologies will be needed.

Mitigation Option Design

This option considers recommendations in the short terms and potential for the medium to long-term based on the outcomes of the analyses in the short term. The key element of this option is an Executive Order or legislation addressing various regulatory and/or legal barriers to the commercialization of CCSR projects (i.e., for coal, natural gas, and biomass). One possible near term goal might simply be a report, developed by one or more advisory groups, to either the Governor or the legislature identifying the barriers.[25]

CCSR raises new legal and regulatory risks associated with siting and permitting projects, CO_2 transportation, injection and storage.[26] These risks are not yet fully understood, nor are uniform

[25] California recently adopted Assembly Bill 1925 (2006), directing the California Energy Commission to recommend standards to accelerate the adoption of long-term management of industrial CO_2. A copy of the draft staff report may be found at http://www.energy.ca.gov/2007publications/CEC-500-2007-100/CEC-500-2007-100-SD.PDF. Similarly, New Mexico Governor Richardson's Executive Order 2006-69 required the New Mexico Energy, Minerals, and Natural Resources Department (EMNRD) to coordinate with a stakeholder group to explore and identify statutory and regulatory requirements needed to geologically sequester anthropogenic CO_2. The interim report may be found at: http://www.emnrd.state.nm.us/OCD/documents/InterimReportCO2Sequestration.pdf

[26] Robertson, K., Findsen, J., Messner, S., Science Applications International Corporation. June 23, 2006. "International Carbon Capture and Storage Projects Overcoming Legal Barriers", prepared for the National Energy Technology Laboratory (see http://www.netl.doe.gov/energy-analyses/pubs/CCSregulatorypaperFinalReport.pdf)

standards or government regimes in place to address and mitigate them. Among the key questions to be addressed in the development of a consistent regulatory framework for CCSR are: potentially applicable criminal and civil environmental penalties; property rights, including the passage of title to CO_2 (including to the government) during transportation, injection and storage; long-term CO_2 liability, insurance coverage for short-term CO_2 liability; the licensing of CO_2 transportation and storage operators, intellectual property rights related to CCSR, and monitoring of CO_2 storage facilities.

A. Regulatory Issues

Engrossed Substitute Senate Bill 6001 (ESSB 6001) includes a process for developing regulatory requirements for carbon capture and sequestration plans for new electricity generation. The Washington Department of Ecology has announced a formal ESSB 6001-related rulemaking[27] and the establishment of a work group as part of its process. The rulemaking seeks to first amend "Chapter 173-407 WAC - carbon dioxide mitigation program for fossil-fueled thermal electric generating facilities", to establish the level and effectuate ESSB 6001. The deadline for adopting the standard by rule is June 30, 2008. The rulemaking also seeks to amend "Chapter 173–218 WAC - underground injection control program" to establish criteria for evaluating carbon capture and sequestration plans to be undertaken within Washington. The Washington Energy Facility Site Evaluation Council is also expected to promulgate regulations complementing the rules eventually adopted by the Department of Ecology. The TWG believe these rulemakings are the beginning of an effort to develop a predictable state permitting process for CCSR projects.

B. Long-term Ownership and Liability Issues

- Determine which party(ies) will be liable over the long-term

The issue of who will assume the responsibility for long-term CO_2 storage in underground reservoirs was not addressed within ESSB 6001. The TWG believes this issue must be decided before storage technology can become widely deployed. We know that long-term ownership of CO_2 is an issue that must be resolved, with some suggesting that such ownership should be transferred to the state or federal government in order to provide an appropriate long-term incentive to site and store CO_2. Among the options it should explore is that adopted by Texas, which transfers the title (and any liability post-capture) to CO_2 captured by CCS to the Railroads Commission of Texas.[28]

Although the prospect of a catastrophic leakage event from a well-selected, designed and managed storage reservoir is low, liability for such an event must be resolved. In addition, liability for other potential issues -- such as incremental leakage to the atmosphere and shallow water sources, contamination of deep water aquifers and ecosystems from the displacement of mineral and other solutions by CO_2 injection, concerns with ground heave or subsidence, and

[27] See, http://www.ecy.wa.gov/laws-rules/activity/wac173407_218.html

[28] Texas H.B. 149 (2006).

damage to unclaimed hydrocarbon reserves -- must also be resolved. Additional experience with demonstrations of large-scale CCSR will likely provide important guidance about which of – and how -- these potential issues must be addressed to make CCS commercially feasible.

C. Pipeline Issues

- Assist to resolve pipeline siting issues

When a suitable reservoir is not located near the power plant, CO_2 will have to be transported via pipeline to its final storage site. Although there are presently 3,000 miles of CO_2 pipelines in the U.S. for Enhanced Oil Recovery purposes, additional and likely larger pipelines will be necessary. The siting of a CO_2 pipeline should be similar to siting a natural gas pipeline and will require federal and/or state eminent domain or rights-of-way in order to build. Unfortunately, state siting requirements were not addressed within ESSB 6001. Currently, natural gas pipeline companies are required to secure rights to use private land (rights-of-way) through negotiation and payment for that right, with eminent domain as a last resort. The negotiations and payments cover everything from gaining access to the land, to laying the pipeline, to restoring the land to its former state. Building a natural gas pipeline can take years, even with eminent domain.

D. Property Rights

- Establish greater certainty about property ownership rules for potential CO_2 storage sites in Washington

The ownership of underground pore space (i.e., potential reservoirs for CO_2 storage) varies from state to state. In states with past or current oil and gas exploration and production, underground property rights are well established.[29] Unfortunately, clarification of ownership rights was not accomplished within ESSB 6001. An assessment of the geologic storage capacity in Washington that includes an assessment of the legal accessibility to the sites should be undertaken. Greater certainty about property ownership rules for potential CO_2 storage sites in Washington is needed.

E. Public Acceptance and Communications Issues

- Educate the public about CCSR technologies

Public awareness of CCSR technologies is low. There is a need for public education about the potential benefits and impacts of CCSR technologies. The experience of successful large-scale storage demonstrations, together with a sound and reasonable regulatory framework, are needed to give the public confidence in the safety of storage. Otherwise, failure to gain public acceptance could jeopardize timely deployment of CCSR technologies.

[29] However, even in these states, agreement by all affected parties may be required. For example, in Illinois, there are 69 owners of the storage reservoir that the potential FutureGen plant would utilize, and all owners must agree before the reservoir can be accessed.

F. Incentives for CCSR

- Investigate potential incentives for CCSR in the medium term to long term (2015+), pending analysis in the short term points A. – E.

Incentives for CCSR are required to ensure innovation and full participation by all generating sources: Including, but not limited to investor-owned utilities, public power, and independent power producers. Potential ideas for incentives are listed below and provided in greater detail in Appendix A. These are results of TWG brainstorming and do not reflect TWG consensus.The following ideas have been suggested as potential incentives. TWG has divergent views on the inclusion of individual incentives.

- Enact State or jointly advocate for Federal tax incentives to encourage new IGCC and CCSR project development to serve Washington customers.
- Consider "pay as you go" cost recovery for use of IGCC and other CCSR technologies.
- Develop a transmission credit system that allows non-utility generators to recover development and operating costs for carbon capture technologies.
- Consider early action credits for avoided GHG emissions attributable to CCSR technologies placed into operation prior to any mandate

- **Goals:** The goal of this option is to gain clarity on points A. – F. above
- **Timing:** Develop increased understanding and decisions on issues A. – E. in the near term (2008-2015); pending some of these short-term outcomes seek development of early demonstration projects; leading to broader deployment in the medium-term, possibly including financial incentives, (2015-2029) and eventually long-term commercialization (2030+).
- **Coverage of parties:**
- **Other:**

Implementation Mechanisms

[Insert text here]

Related Policies/Programs in Place

See Senate Bill 6001 (April 2007), sections 4b, 7 and 5

Type(s) of GHG Reductions

[Insert text here]

Estimated GHG Savings (in 2020) and Costs per $MtCO_2e$

- **Data Sources:**
  - Pacificorp White Paper "Proposed IGCC/CCS Incentives for Washington" (May 2007)[30]
  - Recently released MIT report, "The Future of Coal" (2007) [31] which provides estimates of costs and emissions savings from various coal technologies with and without carbon capture and storage.
  - The IPCC Special Report on Carbon Dioxide Capture and Storage (2006)[32] which provides other estimates, including rough estimates of the costs of CO_2 transport and storage.
  - EPA report, "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," July 2006, which contains cost and performance estimates for various coal plant types and CO_2 capture, accounting also for high elevation issues with IGCC as might be encountered in Washington.
  - Advanced Coal Task force report and spreadsheets from Western Governor's Association 2006 (WGA 2006) *Clean and Diversified Energy Initiative*[33]
  - California Energy Commission draft Staff Report, "Geologic Carbon Sequestration Strategies for California: The Assembly Bill 1925 Report to the Legislature" (September 2007)[34]
  - New Mexico Energy, Minerals, Natural Resources Department Oil Conservation Division "Carbon Dioxide Sequestration: Interim Report on Identified Statutory and Regulatory Issues" (June 2007)[35]
  - Robertson, K., Findsen, J., Messner, S., Science Applications International Corporation. "International Carbon Capture and Storage Projects Overcoming Legal Barriers", prepared for the National Energy Technology Laboratory (June 23, 2006)[36]
- **Quantification Methods:**
- **Key Assumptions:**

Contribution to Other Goals

[30] http://www.pacificorp.com/File/File75668.pdf

[31] http://web.mit.edu/coal/

[32] http://www.ipcc.ch/activity/srccs/index.htm

[33] http://www.westgov.org/wga/initiatives/cdeac/index.htm

[34] http://www.energy.ca.gov/2007publications/CEC-500-2007-100/CEC-500-2007-100-SD.PDF

[35] http://www.emnrd.state.nm.us/OCD/documents/InterimReportCO2Sequestration.pdf

[36] http://www.netl.doe.gov/energy-analyses/pubs/CCSregulatorypaperFinalReport.pdf

- **Contribution to Long-term GHG Emission Goals (2035/2050):**
- **Job Creation:**
- **Reduced Fuel Import Expenditures:**

Key Uncertainties

[Insert text here]

Additional Benefits and Costs

[Insert text here]

Feasibility Issues

[Insert text here]

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

ES-6. Transmission System Capacity, Access, Efficiency, and Smart Grid

Based on ES Catalog Options 6.1, 6.2, and 6.5.

Mitigation Option Description

This option comprises three main elements: 1) increasing transmission system capacity for, and access to the grid by, clean energy technologies[37]; 2) improving efficiency and reducing line losses in the electric transmission and distribution system; and 3) providing support to "smart grid"[38] technologies that optimize the electricity grid (and unlock additional renewable resource alternatives) through devices that help manage electricity demand and supply;

Mitigation Option Design

1. **Provide financial incentives and remove barriers for implementing smart grid technologies that reduce GHG emissions.** Incentives may be necessary to counter any additional risk of bringing new smart grid solutions on line; incentives must be comparable for private and public utilities, as well as relevant non-utility actors. Utility regulators and managers should work together to identify smart energy technologies with ratepayer benefits such as improved reliability and efficiency, and environmental benefits in terms of reduced or avoided GHG emissions. Any barriers to adoption of these technologies, including potential regulatory challenges of retiring resources that have not been fully depreciated or that are still operating cost-effectively, need to be addressed. (Note that the RCI TWG proposes option RCI-5, which suggests pilot smart meter programs and the Transportation TWG proposed option T-10 – Actions to Accelerate and Integrate Plug-In Hybrid Electric; both of these options could complement ES-6.)

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[37] According to the Wind Integration Study conducted by the Northwest Power Planning and Conservation Council, transmission capacity currently available to Northwest is only sufficient to support anticipated wind project development through 2009. Additional transmission capacity will be needed to achieve the 6000 MW of wind envisioned in the Council's plan and to open up new areas for wind development, which could provide access to better wind resources, diversify wind production, and as a result, lower the costs of wind generation and integration. Although transmission is regulated at the federal level, state policies should encourage such investments. http://www.nwcouncil.org/energy/Wind/library/2007-1.pdf

[38] Smart Grid technologies can involve, for instance, devices that "turn off" non-essential power when demand, and subsequent electricity prices, are high. Also technologies are used to co-ordinate a range of small scale distributed generation (including electric vehicles) and/or intermittent power, such as wind. For a discussion of Smart Grid technologies, see "Poised for Profit in Clean Energy Report: Powering Up the Smart Grid" www.climatesolutions.org/pubs/pdfs/PoweringtheSmartGrid.pdf

2. Provide incentives and remove barriers to improving the efficiency of the T&D system and components and to reducing line losses. [39] Regulations, incentives, and/or support programs can be applied to achieve greater efficiency of transmission and distribution system components. Regulators and governing boards should encourage utilities to identify opportunities, beginning with pilot projects, to optimize transmission and distribution networks to minimize line losses through the replacement of or additions to existing facilities. Similarly, regulators and governing bodies should encourage utilities to consider distributed generation, combined heat and power, load management and end-use efficiency. If necessary, regulatory guidance could be provided by utility regulatory bodies.

3. **Develop and apply procedures** to ensure that utilities can fairly and transparently assess "non-wires options", such as distributed generation or demand management, that can avoid or otherwise free up transmission and distribution capacity. Place these "non-wires" technologies on a level playing field when considering upgrades in traditional pole and wire infrastructure. (see Related Policies/Programs in Place, below, for examples on current pilot programs)

4**. To help implement the above goals,**

- Examine the Oregon Public Utility Commission's UM1129 decision as a possible approach to achieving the above goals and consider how similar approach can be applied to public utilities. http://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=07-360
- Propose a multi-faceted study, perhaps predicated on local pilot projects, to evaluate the potential benefits to shareholders and ratepayers of deploying emerging technologies
- Employ smart grid technologies such as voltage reduction to optimize delivery networks for minimal line losses where appropriate.
- Work with public utility organizations, clean energy advocates and Bonneville Power Administration to overcome obstacles to local generation created by interconnection rules and losses of BPA power allocations.

5. This option could also include **reductions in use and leakage of SF_6** from distribution system transformers, plus efficient transformers and other materials and equipment. (*this element is covered by the RCI TWG, option RCI-11).*

- **Goals:** Increased understanding of the technologies and practices to improve the transmission system and the barriers to uptake of these improvements.

- o **Timing:**
- o **Coverage of parties**

[39] Utilities use a variety of components throughout the transmission and distribution system to reduce losses. Increasing the efficiency of these components can further reduce losses. Vermont State, for example, offers a rebate to encourage users to install energy efficient transformers.

- Electric Utilities
- Utility and Transportation Commission
- Bonneville Power Administration
- Northwest Power and Conservation Council
- Northwest Power Pool or other regional transmission authorities and regional control area operators.
- Coordinate with:
    - Northwest Energy Technology Collaborative
    - Northwest Center for Electric Power Technologies
    - Western Regional Climate Action Initiative
    - Energy Facility Site Evaluation Council

- **Other:**

Implementation Mechanisms

Related Policies/Programs in Place

BPA NonWires Solutions – is a highly advanced effort to replace costly transmission line upgrades with smart energy technologies.
http://www.transmission.bpa.gov/PlanProj/Non-Wires_Round_Table/

Pacific Northwest GridWise Testbed – intends to provide an institutional structure for developing and hosting smart grid demonstration projects.
http://gridwise.pnl.gov/

WA CTED is reviewing best practices for investing in smart-grid technologies

Type(s) of GHG Reductions

There are emissions reductions related to improved operations of electric power generation and improved access for renewables.
(Depending on whether it's included here: Emissions of SF_6 related to electric power transmission and distribution from WA GHG inventory, currently about 0.3 MMtCO2e.

Estimated GHG Savings (in 2020) and Costs per $MtCO_2e$

- **Data Sources:**
    - Poised for Profit in Clean Energy Report: Powering Up the Smart Grid, by Patrick Mazza
    - Northwest Wind Integration Action Plan, conducted by the Northwest Power and Conservation Council: http://www.nwcouncil.org/energy/Wind/library/2007-1.pdf

- Smart Meters: Commercial, Policy and Regulatory Drivers, by Gill Owen and Judith Ward, which reports on experience with smart meters in the UK, and reports one to several percent net savings in electricity consumption from implementation of smart meters, as well as peak reduction impacts. Dated March 2006, Published by Sustainability First, and available as http://www.sustainabilityfirst.org.uk/docs/smart%20meters%20pdf%20version.pdf

- **Quantification Methods:** This option has not been quantified since the majority of the actions that would lead to reductions are covered by other options in the Energy Supply TWG (ES-1 for grid-size renewables and ES-2 and ES-7for Non-wires options) and other TWGs (RCI-5, which suggests pilot smart meter programs, RCI-11 covers SF6 reductions from electricity transmission and distrtibution; the Transportation TWG option T-10 covers Actions to Accelerate and Integrate Plug-In Hybrid Electric).
- **Key Assumptions:**

Contribution to Other Goals

- **Contribution to Long-term GHG Emission Goals (2035/2050):**
- **Job Creation:** The Poised for Profit II Partnership found at least 225 companies in the Northwest representing 14% of the $15 billion global smart energy market. Additionally, the high regional concentration of software, semiconductor and wireless companies could find new opportunities and innovation in the energy sector.
- **Reduced Fuel Import Expenditures:**

Key Uncertainties

[Insert text here]

Additional Benefits and Costs

- Could eliminate $46-$117 billion in US peaking infrastructure investments over the next 20 years. (Poised for Profit in Clean Energy Report: Powering Up the Smart Grid, Climate Solutions, pg 8)
- Improves reliability of power grid
- Reduces losses from power lines
- Improves ability to utilize waste heat from power generation.
- Improves utilization of renewable generation

Feasibility Issues

- Issues associated with “access” and “planning” are subject to FERC jurisdiction and may not be appropriate to explore in the CAT venue.
- Reliance on new technologies which require extensive field testing.
- Can create shift from centralized power production to localized power production.

- Can have disruptive impacts on traditional utility business models that base revenue flows on gross throughput. Regulatory and ratemaking framework could create disincentives for adopting new technologies.

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

ES-7. Combined Heat and Power and Thermal Energy Recovery and Use

Based on ES Catalog Option 2.5.

Mitigation Option Description

Combined heat and power (CHP) and thermal energy recovery and distribution can reduce GHG emissions by increasing the overall efficiency of fuel use, by reducing energy losses (where facilities are located near heat and power demands). These emissions benefits can be particularly significant where CHP and thermal facilities utilize low GHG fuels and feedstocks (e.g. biomass resources such as organic pulping byproducts). There are opportunities to recover thermal energy from CHP, industrial or municipal waste heat or renewable energy sources.[40] District energy systems provide a key infrastructure for conveying this "recycled" energy from the sources to energy consumers.

Policies can be adopted to encourage cost-effective CHP and waste heat recovery ("recycling") by ensuring that the full cost (including related electric energy transmission and distribution infrastructure costs plus transmission losses) of the alternative technology generation (typically a combined cycle plant) is compared to the cost of generating electricity at a CHP site (with the cost of heat sales to the thermal energy consumer covering any additional capital and operating expenses of the CHP project).

Mitigation Option Design

Recommended policies to promote CHP and thermal energy use, and ensure equitable comparison with electricity-only technologies, include:

1. Incentives to encourage, new CHP facilities, as well to expand and/or repower existing facilities. No significant CHP system has been built in Washington in the last 15 years, in part due to the costs of CHP systems being higher than current avoided costs. In order to provide incentives to reduce GHG emissions through CHP, the state should specifically consider establishing CHP tax credits under existing B&O tax system or form other sources to provide investment incentives. These incentives should be equally accessible to public as well as private power suppliers. Oregon's Business Energy Tax Credit (BETC) program provides a useful

[40] A variety of industries, such as pulp and paper mills, saw mills, steel mills, and aluminum smelters, alternative fuel generation plants, cement plants and other facilities, produce waste heat at temperatures suitable for building heating. Additionally, municipal operations produce byproduct energy in the form of landfill gas (which can be combusted in CHP engines or turbines) or sewage effluent (which can be converted to usable heat with heat pumps).

example for the State to consider.[41] Other potential financial incentives to implement CHP programs include:

- o Siting Incentive Programs;
- o Low-cost bonding or loan guarantee programs;
- o Tax credits for investment in CHP;

2. Amended procedures for streamlined permitting of CHP and thermal energy recovery facilities, without compromising other environmental goals. (Seek input from air agencies on this and the following recommendation.)

3. Financial incentives to implement district energy thermal distribution infrastructure, waste heat recovery and renewable thermal energy systems through a variety of programs including:

- Property owner incentives to join waste heat based district heating systems;
- Low-cost bonding or loan guarantee programs;
- Tax credits for *investment* in thermal energy projects, and/or for *production* of recycled energy;
- Incentives for buildings to connect to district energy systems established to use or convert to renewable energy or recover waste energy; and
- Incentives to upgrade existing steam district energy systems to hot water district energy distribution to enhance system performance and improve efficiencies.
- Encouragement of public/private partnerships for thermal energy transmission and distribution infrastructure installation.

5. Pro-active information/education/outreach communications are needed to address the importance of removing barriers to optimizing existing and CHP generation and district energy development. We need to overcome real or perceived barriers about such important issues as avoided cost barriers, regulatory barriers, lack of integrated community energy planning, and lack of financial sector misunderstanding of these systems.

- o **Goals:** The goal will be expressed as an achievable fraction of technical or economic potential (see below). For preliminary analysis, the goal is to install 976 MW of new CHP capacity by 2020, 32% of the identified economic potential (when incentives and technological improvements are included).
- o **Timing:**

[41] For example, in Oregon there is a $20 million per project tax incentives program established under BETC system. Tax credits can be sold to third parties, enabling public utilities to take advantage of the program as well. Examples of incentives for CHP for avoided cost calculations include: Thermal efficiency - $7/MWh; GHG savings of 1092 pounds of CO2 - $ 8/MWh; T&D incremental cost savings plus 8% loss - $ 10/MWhn; Credit for not needing hydro backup compared with wind- $12/MWh; Renewable fuel credit - $ 10/MWh; System security distributed energy credit – $5/MWh; Avoided fuel (natural gas price risk adjustment) UM 1129 (Oregon State Ruling)

- **Coverage of parties:**
- **Other:**

Implementation Mechanisms

State wide IRP used to determine potential for CHP.

The following suggestions are from the RCI TWG: THIS SECTION NEEDS TWG REVIEW

- Training/certification of installers/contractors – Rationale requested
- Creation/support of markets for biomass fuels
- Leveraging of attractive financing arrangements, tax benefits such as the existing sales and use tax incentive for machinery and equipment used for cogeneration facilities (RCW 82.08.02565[42] and RCW 82.12.02565[43]) and other incentives to promote CHP technologies.

Interconnection issues:

- Removing high interconnection cost and regulatory access barriers similar to OR Public Utility Commission ruling under UM 1129. Need specific points within UM 1129

Permitting and siting

- Supporting county and city land use prescreening efforts to support siting.

Government lead-by-example:

- Addressing lack of funding for design of CHP and waste heat utilization systems associated with state facilities and university campuses.

Waste heat capture/recycling:

- A Washington State inventory of waste heat resources, evaluating the full renewable thermal energy potential in the State
- Incentives for new or existing waste heat generators to (re)locate adjacent or close by to heat users

Related Policies/Programs in Place

PURPA, 1978.
B & O Taxes.
Business Energy Tax Credits (BETC) in Oregon.

[42] http://apps.leg.wa.gov/RCW/default.aspx?cite=82.08.02565

[43] http://apps.leg.wa.gov/RCW/default.aspx?Cite=82.12.820

The Washington UTC has an interconnection standards process underway with provisions for comments

Senate Bill 6001 includes language to recognize the output of cogeneration, which could be modified for other policy design elements:
Section 5 (6) The department shall establish an output-based methodology to ensure that the calculation of emissions of greenhouse gases for a cogeneration facility recognizes the total usable energy output of the process, and includes all greenhouse gases emitted by the facility in the production of both electrical and thermal energy. In developing and implementing the greenhouse gases emissions performance standard, the department shall consider and act in a manner consistent with any rules adopted pursuant to the public utilities regulatory policy act of 1978 (16 U.S.C. Sec. 824a-3), as amended.

Senate Bill 6631 – Thermal Energy Companies – Exemption from Utilities and Transportation Commission Authority.

House Bill 114 – Regulation of District Heating Systems and Services

Chapter 35.97 RCW – Heating Systems

UM1129 Oregon Public Utilities Commission final order issues August 20th, 2007
http://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=07-360

Types(s) of GHG Reductions

By recovering waste heat and reusing it, the equivalent amount of new fossil-based energy will be displaced resulting in a more energy efficient energy production program and significantly less GHG production per MWh generated.

Estimated GHG Savings (in 2020) and Costs per $MtCO_2e$

------------- Preliminary -------------

		Reductions		($MMtCO_2e$)*		
	Policy	2012	2020	Cumulative Reductions (2008–2020)	NPV (2008–2020) $ millions	Cost-Effective-ness $/tCO_2$
ES-7	CHP	0.42	165	9.5	$82	$9

- **Data Sources:**

RCW 82.35, which expired in 1984, included tax credits for CHP facilities. Reports may be available on the approach for the credits and on their impacts on CHP uptake.

CHP market potential

- **Combined Heat and Power in the Pacific Northwest: Market Assessment** This 2004 report provides: 1) A comprehensive review of current CHP capacity in the Pacific Northwest including a database by each state; 2) A review of the economic and technical market potential for additional CHP; 3) A review of barriers and incentives to CHP; and 4) Recommended actions to increase CHP deployment. http://www.chpcenternw.org/NwChpDocs/Chp_Market-Assessment_In_PNW_EEA_08_2004.pdf

Washington State Estimated Economic Potential (using 10-year payback):

Two estimates of economic potential for CHP in Washington were provided by a recent report, based on two sets of assumptions on technology costs and performance, including assumptions on stand-by charges and financial incentives (see below). The assumptions for the Accelerated Case more closely reflect the policy design described above, so the quantification was based on economic potential of 2,847 MW in 2007.

731 MW (Business as Usual assumptions – current cost and performance specs, $3-4 /kW/month CHP Stand-by charges, no financial incentives)

2,847 MW (Accelerated Case assumptions – 2020 cost and performance specs, no stand-by charges, financial incentives equal to about 15% of capital costs)

Source: *Combined Heat and Power in the Pacific Northwest: Market Assessment* (Energy and Environmental Analysis Inc. 2004)

Northwest Power Council 5th Power Plan – estimates potential for CHP but need to consider the impacts of incentives and barrier removal on the CHP projections.

Technical Market Potential for CHP in the Pacific Northwest. This is an overview of CHP market potential by sectors.
http://www.chpcenternw.org/NwChpDocs/CHP_Market_Potential_in_PNW_Eng_Int_ORNL_rpt_07_2003.pdf

CHP

- **Quantification Methods :** Starting with an estimate for Washington's share of CHP potential in the Pacific Northwest, as provided in the *Market Assessment* report (Energy and Environmental Analysis Inc. 2004) referenced above, assumptions regarding the penetration of and fuel shares for new CHP systems, and estimates of future capacity of CHP developed under the policy, are generated. Estimates of CHP cost and performance for different kinds of systems are then used to estimate the overall net GHG emissions reduction and net cost of the policy.

- **Key Assumptions:** Key assumptions are the CHP potential in Washington, the analysis is based on a potential of 2,847 MW (per the *Market Assessment* source above)[44]; this potential grows with commercial and industrial loads; and the potential and can be realized at a rate of about 2-3% [2% per year through 2012, increasing linearly to reach 3% in 2020] of total potential per year.

Table Technology characteristics of new CHP equipment.

Size	Capital Cost ($/kW)		Fraction of New CHP capacity	
	2012	2020	2012	2020
<1 MW	$ 1,396	$ 1,073	14%	14%
1-4.9 MW	$ 1,046	$ 929	24%	24%
5-24.9 MW	$ 990	$ 879	19%	19%
25-39.9 MW	$ 890	$ 784	13%	13%
40-259.9 MW	$ 781	$ 734	15%	15%
>259.9 MW	$ 656	$ 589	16%	16%

Technology	Capital Cost ($/kW)		Fraction of New CHP capacity	
	2012	2020	2012	2020
Natural Gas	$ 964	$ 839	94%	94%
Biomass	$ 1,214	$ 1,089	6%	6%
Oil	$ 964	$ 839	0%	0%
Coal	$ 964	$ 839	0%	0%

Source: Energy and Environmental Analysis, Inc for Oak Right National Laboratory (2004) *Combined Heat and Power in the Pacific Northwest: Market Assessmen*t, based on average costs of the range of sizes of gas turbines; biomass assumed to be $250 higher; coal assumed to be equal to gas turbine

- **Avoided costs and emissions:** See ES-2

Waste Heat Recovery Market Potential

[44] An alternate estimate of CHP potential is 1092 MW from a 2004 analysis by the Western Resource Advocates, *A Balanced Energy Plan for the Interior West*. http://www.westernresourceadvocates.org/energy/clenergy.php

- Turbosteam looked at the waste heat potential of just 5 key waste heat potentials in a number of states including Washington. This report reviews the potential for generating electricity from waste heat processes and determined that 235 MW and 1553 GWh's annually could be achieved by 2020. This would result in an annual reduction of almost one million tCO2e. (Turbosteam Corporation 161 Industrial Blvd. Turners Falls, MA 01376)

  SEE WORKSHEET POSTED ON ENERGY SUPPLY TWG WEBSITE FOR AUGUST 30TH MEETING http://www.ecy.wa.gov/climatechange/cat_twg_energy.htm

- There does not appear to be a similar comprehensive analytical study of all the waste heat potential not used for electricity generation in Washington.

Other potential data sources

- Western Governor's Association 2006 (WGA 2006) *Task Force Reports from the Clean and Diversified Energy Initiative,*[45] Energy Information Administration,[46]; and, Energy Trust of Oregon.[47]

Contribution to Other Goals

- **Contribution to Long-term GHG Emission Goals (2035/2050):**
- **Job Creation:** Installation and maintenance of CHP systems will contribute to clean energy jobs in Washington
- **Reduced Fuel Import Expenditures:** Impact of CHP systems on fuel import expenditures in unknown, dependent on the source of avoided electricity..

Key Uncertainties

No significant CHP capacity has been built during the past 15 years due to a number of important economic and policy barriers that need to be overcome:

- Dispatchabilty control by utilities can be a concern for the plant owner. Mutually agreeable dispatch protocols should be negotiated between the plant owner and the host utility.
- Washington State could seek to influence and streamline grid interconnection standards and associated costs, where applicable. Standards are set be FERC and NERC rather than the State.

[45] http://www.westgov.org/wga/initiatives/cdeac/index.htm
[46] http://www.eia.doe.gov/oiaf/aeo/assumption/index.html

[47] *A Comparative Analysis of Community Wind Power Development Options in Oregon*
http://www.oregon.gov/ENERGY/RENEW/Wind/docs/CommunityWindReportLBLforETO.pdf

- High transaction costs associated with CHP projects, high financing costs because of lender unfamiliarity and perceived risk,
- "Split incentives" between building owners and tenants, and utility-related policies like interconnection requirement, high standby rates, exit fees, etc.
- Consistent, long term clear incentives supporting CHP and waste energy recovery.

Need for a pro-active public information campaign to educate and inform the public of the benefits of CHP to Washington and the NW economy.

Additional Benefits and Costs

[Insert text here]

Feasibility Issues

Local opposition to siting of facilities in areas where CHP would work - relatively high density areas with large thermal load needs

Air Quality impacts of CHP proposals will need to be evaluated. Local land use and zoning rules may need to be adjusted to encourage the use of CHP in providing both power and community heating/cooling energy to commercial operations and to planned residential communities.

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

ES-8. Advanced Fossil Fuel Generation and Pre-Combustion Sequestration Technologies

Based on ES Catalog Option 3.1a.

Based on TWG suggestions at the latest TWG meeting, this option is now being incorporated into ES-5.

APPENDIX A

ADDITIONAL INFORMATION FOR SPECIFIC OPTIONS PROVIDED BY TWG MEMBERS

ES-2. Distributed Renewable Energy Incentives and/or Barrier Removal

PSE offers two incentive programs that provide ongoing, annual benefits. Net Metering (Schedule 150) allows the energy produced by a customer's renewable-energy system to offset the customer's usage of PSE-provided electricity over the course of a year at the retail rate of ~9 cents per kWh. For months in which a customer's self-generated renewable energy exceeds the amount of PSE electricity consumed, that excess production is rolled over to offset PSE power usage in other months. Typically, high summer production of renewable energy can offset high winter usage of PSE-provided power. In addition to Net Metering, PSE elected to create a separate incentive program as authorized by State Senate Bill 5101 (2005) and Washington Administrative Code 458-20-273. PSE provides all of the consumer benefits allowed under the state law. The PSE program (called the Renewable Energy Advantage Program under Schedule 151) provides a payment for Production Metering. The purpose of this program is both to encourage small-scale renewable-energy generation and to induce in-state production of renewable-energy system components. The Production Metered payments to customers can range from 12 cents/kilowatt hour (kWh) to 54 cents/kWh if the parts of a particular renewable energy system were manufactured in Washington. The law set an annual cap of $2,000 in incentive payments per installation.

ES-3. Efficiency Improvements, Capacity Additions and Fuel Switching at Existing Renewable and Fossil Power Plants

- In Washington State, the overall energy load was approximately 9,500 aMW and the overall energy generation was 11,000 aMW. Approximately 70 percent of the energy generation was from non-emitting resources and 30 percent was from natural gas and coal. If existing projects were able to increase energy generation by approximately 10 percent through efficiency improvements, an additional 1,100 aMW would be available to replace the use of fossil fuels. This is equivalent to about 10,000,000 MWh – enough power to serve about 1,000,000 homes annually.
- In the Pacific Northwest, there are more than 20 projects currently being built and expected to be completed in the next two years. These projects total over 2,500 MW of capacity of which 1,300 MW is wind and other renewable generation. Many NW utilities (including all utilities operating in Washington) are in the process of developing integrated resource plans to evaluate their power needs for the next 10 to 20 years. Additional non-emitting or low-emitting generation resources from existing projects need to be encouraged.

- Although Washington State gets about 30 percent of its energy from GHG emitting resources, there are ways to reduce GHG emissions by switching high-emission fuels to other fuels sources or cleaner fuel types.

ES-5. Carbon Capture, Storage, and Re-use Incentives, Requirements and/or Enabling Policies and Research & Development (including pre-combustion technologies)

A broad regulatory framework is required that supports the identification, development and deployment of technologies that capture, sequester or reuse CO_2. For Washington State, and the USA, to achieve CO_2 goals a multi sector approach is required, but within the electricity supply sector three technologies are emerging as near term scalable technologies.

- **Pre and Post CO_2 Combustion Capture**
    - Technologies
- Do not try to pick a single winning technology. It is important to create a framework in which industry will invest in a broad range of low emitting technologies. It will take a sum total of all technologies to achieve long-term CO_2 reduction roles
- Proper incentives allow and encourage industries to take early risks inherent in new technologies. A broad range of incentives should be pursued which will apply to different technologies, and technologies at different stages of deployment.
- In the absence of long-term clarity, higher emitting generation will likely continue to be built, and may face extraordinary environmental costs later in life. Effort must be made to avoid stranding assets due to the financial implications on utility companies and the end customers.
- Current and new policies must be able to adapt to the latest changes, and continue to adapt as technology continues to be developed and implemented. Failure to do so is likely to stall, if not impede, the construction of billion of dollars of productive infrastructure in the US.
- Three technology branches appear to offer the best near-term solution to low-GHG emitting base load electricity:
    - Ultra supercritical [*coal-fired generation*] with carbon capture
    - IGCC [*integrated gasification combined-cycle plants using coal, sometimes with biomass co-firing*] with carbon capture
    - Nuclear [*power*] *[TWG members are not in agreement about including nuclear power here]*
- The net reduction of emissions to the atmosphere through CCSR depends on the fraction of CO_2 captured, the increased CO_2 production resulting from loss in overall efficiency of power plants or industrial processes due to the additional energy required for capture,

transport and storage, any leakage from transport and the fraction of CO_2 retained in storage over the long term. The most viable of these technologies today appears to be Integrated Gasification Combined Cycle (IGCC) combined with carbon capture and storage and reuse (CCSR) technology. There are also emerging CCSR technologies that show promise for capturing carbon emissions from traditional pulverized coal fired boilers. These emerging technologies include chilled ammonia scrubbing and oxy-fuel combustion. Carbon capture technologies have the potential to remove approximately 90 percent of a coal plant's CO_2 emissions.

- R&D for the CCSR technologies is also vital for their larger scale commercialization. R&D funding can also be made available to CCSR technologies through an open bidding procedure (i.e., driven by bids received rather than by a focused strategy to develop a particular technology.) Funding can also be given for demonstration projects to help commercialize technologies that have already been developed but are not yet in widespread use. Funding could be provided to increase collaboration between existing institutions for R&D on these technologies.
- The important role of advanced clean coal technology is recognized in the Western Public Utility Commissions' Joint Action Framework on Climate Change, signed on December 1, 2006 by the Washington, Oregon, California and New Mexico public utility commissions.[48] The Framework's Statement of Shared Principles includes five principles, the second of which is "Development and use of low carbon technologies in the energy sector." The third of six Action Items is: "Explore ways to remove barriers to development of advanced, low-carbon technologies for fossil fuel-powered generation capable of capturing and sequestering carbon dioxide emissions."

- **CO_2 Storage**
    - Technologies
    - Liability
- There are significant legal barriers to carbon sequestration related to environmental and other legal liability and property rights. Many of these fall into areas traditionally governed by state law and, hence, must be addressed if carbon sequestration is to become reality in the state.
- Avoided GHG emissions attributable to CCS equipment placed into operation prior to any mandate or that exceed an operating permit limitation should be creditable as early actions within the context of a regional mechanism to achieve GHG reductions
- Emphasize the need for Washington to support near term CCS demonstration projects (Similar to the arguments in the PacifiCorp white paper).

[48] Western Public Utility Commissions' Joint Action Framework on Climate Change (December 1, 2006), located at http://www.puc.state.or.us/puc/news/2006/2006026jointaction.

- Washington's large basalt formation may hold significant CO_2 sequestration capacity. Developing a carbon sequestration industry in Washington will bring long-lasting benefits. Industries created around reusing CO_2 should also have a high priority.
- There are significant technological challenges associated with post-combustion capture. Consequently, if this technology is going to emerge it will require much broader support

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Ideas for Potential Financial Incentives

The following ideas have been suggested during a TWG volunteer group brainstorming session as potential incentives. TWG has divergent views on the inclusion of individual incentives.

- Enact State or jointly advocate for Federal tax incentives to encourage new IGCC and CCSR project development to serve Washington customers. The most effective combination of tax incentives for development of CCSR technologies is a tax credit (i.e., modeled after the renewables Section 45 production tax credit) plus accelerated depreciation. Enact State or jointly advocate for comparable incentives for public power (i.e., interest free construction bonds and higher funding levels for the Renewable Energy Production Incentive or REPI payments). REPI generally underfunded – check with Kyle on typo

- Executive Order or legislation directing the Washington Utilities and Transportation Commission to implement changes to Washington's traditional least cost/least risk regulatory standard and the "used and useful" statute (i.e., mandating "pay as you go" cost recovery) in order to advance the use of IGCC and other CCSR technologies.

- Develop a transmission credit system that allows non-utility generators to recover development and operating costs for carbon capture technologies.

- Eventual cap and trade program design considerations:
  - Incentives to encourage early action recovery mechanisms?
  - Credits granted for plants that are permanently shut down?
  - Method to ensure credits are certified to ensure a robust and fair trading mechanism including the prevention of speculative trading that are in aggregate above any global, national or regional caps?
  - Credit to recognize avoided emissions due to energy conservation programs?

- Consider whether avoided GHG emissions attributable to CCSR technologies placed into operation prior to any mandate or that exceed an operating permit limitation should be creditable as early actions within the context of a state or regional mechanism to achieve GHG reductions.

APPENDIX B
QUANTIFICATON APPROACH

MEMORANDUM

To: Washington State Climate Advisory Team and its Technical Working Groups

From: Michael Lazarus, Jeff Ang-Olson, Alison Bailie, Katie Bickel, David von Hippel, Stephen Roe, Tom Peterson, Center for Climate Strategies

Re: Methods for quantification of draft greenhouse gas (GHG) mitigation policy options

Date: September 25, 2007

This memo summarizes key elements of the recommended methodology for quantifying the GHG impacts and costs for those TWG policy options that are considered amenable to quantification. Feedback from CAT and TWG members is encouraged. As noted in previous CAT meetings, impacts on clean energy jobs and fuel import expenditures will be quantified for the full suite of policy options, once assembled.[49]

- Common units and results reported:
  - **Net GHG reduction potential** in million metric tons carbon dioxide equivalent (MMTCO2e) using IPCC 100 yr global warming potential, reported for 2012, 2020, and cumulatively 2008-2020. Where significant additional GHG reductions or costs occur beyond the project period as a direct result of actions taken during the project period, these will be indicated as appropriate.
  - **Net present value** (NPV) **cost** (or cost savings) for the period 2008-2020 in 2006 constant dollars, using a 5% real discount rate.[50] Positive numbers represent options with net costs; negative numbers represent options with net cost savings.
  - **Cost per metric ton of CO2 equivalent** emissions reduced (or removed) in units of $/MTCO2e. This figure represents the NPV cost divided by the cumulative emission reductions, both over the 2008-2020 period.

- Consistent assumptions and methodologies: In order to ensure consistent results across options and TWGs, common factors and assumptions will be used for items such as:
  - **Electricity avoided costs and emissions**: Common values ($/MWh and tCO2/MWh) are being developed based on available studies, most notably those of the Northwest Power Planning Council. Once the full set of options is

[49] Input is currently being collected by CTED and CCS on analysis methodology.

[50] Capital investments with lifetimes longer than 2020 are represented in terms of levelized or amortized costs, in order to avoid "end effects".

identified, an integrated analysis will be undertaken, and these values may be revised based on the total reduction in requirements for business-as-usual electricity resources.
    - **Fuel costs and projected escalation.** Fuel costs estimates will be based on common sources, wherever possible. For example, fossil fuel price escalation will be indexed to USDOE projections as indicated in their most recent Annual Energy Outlook.
    - **Emission increasing activities.** Some options may involve some increased demand for energy or other potential emission sources (e.g. plug-in electric vehicles). Such direct emissions increases will be factored into the analysis.[51]

- Aggregation of impacts: Options may overlap in terms of coverage, both within and across sectors. In order to avoid double counting of GHG reduction potential and cost (e.g. more than one option avoiding the same emissions source), interactive effects will be estimated where possible, and emission reduction totals will reflect these overlaps. In other words, the total emissions reductions for the state will be lower than the sum of the results for individual options.

- Geographic scope and lifecycle analysis:
    - **GHG impacts of policy options are estimated regardless of the physical location of emissions reductions**. For instance, a major benefit of recycling is the reduction in material extraction and processing (e.g. aluminum production). While a policy option may increase recycling in Washington state, the reduction in emissions may occur where this material is produced. Where significant emissions impacts are likely to occur outside the state, this will be clearly indicated. These emissions reductions are counted towards the achievement of the state's emission goal, since they result from actions taken by the state.
    - Related to the previous point, **lifecycle analysis** is applied wherever emissions impacts upstream (e.g., production, extraction) or downstream (e.g. waste disposal) from a specific activity constitute a significant fraction of a policy option's emissions impacts *and* studies are sufficient to enable estimation. For example, lifecycle analysis is used to estimate the emissions benefits of biofuels relative to the fossil fuels they might substitute for.

- Transparency: Data sources, methods, key assumptions, and key uncertainties are clearly indicated.

[51] Some policy options could also result in emissions leakage, either positive or negative. Negative leakage would occur if a policy leads emitting activities to shift to areas outside its target area, or increases activity as a result of lowering the cost of service (e.g. the rebound effect). For example, if not considered carefully, policies to protect forest lands could shift forest clearing activities to other regions or states. Conversely, some policy options could result in positive leakage, through replication outside the target area, e.g. by lowering the price or increasing access to lower-emitting technologies. Where such effects might be significant, these should be noted qualitatively.

- Cost perspectives and inclusion: The general approach of direct (NPV) cost and cost-effectiveness analysis is used, as widely applied to GHG mitigation policy options.[52] Included are the direct, economic costs from the perspective of the state as whole (e.g. avoided costs of electricity rather than consumer electricity prices). This bottom-up approach is relatively transparent and is capable of reflecting the costs (and cost savings) associated with an individual policy option, in contrast to macroeconomic analysis, which aims to capture flows and interactions across all sectors of the economy. Potential macroeconomic impacts, costs or benefits that fall disproportionately on specific groups or actors, as well external costs and benefits, should be noted qualitatively, especially where studies or other information are available.

  Examples of costs included:
    - Capital costs levelized (amortized) where appropriate, e.g. for improved buildings, vehicles, equipment upgrades, new technologies, manure digesters and associated infrastructure, ethanol production facilities, mass transit investment and operating expenses (net of any saved infrastructure costs such as roads)
    - Operation, maintenance, and other labor costs (or incremental costs relative to standard practice),
    - Fuel and material costs, e.g. for natural gas, electricity, biomass resources, water, fertilizer, material use, electricity transmission and distribution
    - Other direct costs administrative and other costs (where readily estimated), such as the grid integration costs for renewable energy technologies, or the costs of administering an energy efficiency project, or of implementing smart growth programs (net of saved infrastructure costs)

  Examples of costs or benefits not included:
    - External costs such as the monetized environmental or social benefits/impacts (value of damage by air pollutants on structures, crops, etc.), quality-of-life improvements, or improved road safety, or other health impacts and benefits
    - Energy security benefits
    - Macroeconomic impacts related to the impact of reduced or increased consumer spending, shifting of cost and benefits among actors in the economy
    - Potential revenues from participation in a carbon market

[52] See e.g. Section 2.4 of the IPCC Fourth Assessment Report, Working Group III, for more discussion of various economic analysis approaches. http://www.mnp.nl/ipcc/pages_media/AR4-chapters.html

Estimate of Mitigation Option Costs and Benefits for Washington Energy Supply GHG Analysis

ES-1 Grid-based renewable energy incentives and/or barrier removal

Date Last Modified: *11/04/2007* *G. Powell*

Key Data and Assumptions	**2012**	**2020**	**Units**
Renewable requirements		20%	*fraction of state sales*

From Option Goals:
• Add the maximum amount of feasible grid-based renewables, taking into account the economic, environmental impacts and system reliability
• I-937 requires 15% by 2020

Mix of new renewables		
Wind	91%	88%
Solar Thermal	2%	2%
Biomass	7%	10%
Photovoltaic	0%	0%
Geothermal	0%	0%
	100%	100%

Switch to check impact of key assumptions

Use alternative scenario (y/n): n

Base scenario -- the following assumptions are currently in use

	2012	2020	
Wind capital costs	1419	1179	*$/kW*

See note 1

Wind Capacity Fraction of System Peak	Cost ($/MWh of Wind Generation)
0%	0.0
5%	$3
10%	$6
20%	$8
30%	$12.50

Source : calculations derived from Northwest Wind Integration Action Plan (March 2007)
http://www.nwcouncil.org/energy/Wind/library/2007-1.htm

End-date for PTC: 2010

Summary Results for ES-1	2012	2020	Units
Economic Analysis - Additional Renewables 20% of sales by 2020, all utilities			
Total Renewables Added			
based on generated rather than delivered energy	1,716	6,256	GWh
Avoided electricity emissions rate	0.500	0.500	tCO_2/MWh
Total Emissions Reductions	**0.9**	**3.1**	MMtCO2
Net Present Value (2006-2020)		**$630**	$million
Cumulative Emissions Reductions (2006-2020)		**17.2**	MMtCO2
Cost-Effectiveness		**$36.58**	$/$tCO_2$e

Other Data, Assumptions, Calculations	2012	2020	Units
Electricity Sales			
Reference case (accounts for conservation from I-937)	90,580	100,275	GWh
Renewable electricity requirements			
Targets, fraction of electricity sales -- all utilities included		20%	fraction of sales
Note: this requirement now applies to all utilities, including co-ops, for this option, assume gradual ramp up from 2007 levels			
Renewable generation in I-937 case	4,356	14,239	GWh
Renewable generation in I-937 reference case, as fraction of sales after	5%	14.2%	fraction of sales
Note: does not account for T&D losses in generation			
Feasible Renewables	7%	20%	fraction of sales
Feasible Renewables, delivered	5,947	20,055	GWh
Feasbile renewables, generated	6,417	21,571	GWh
Additional renewables for ES1 (excluding reference case renewables)	1,716	6,256	GWh

Calculations in Constant Base Year $

The following assumptions reflect the Scenario chosen above (top of page)

Production Tax Credit level	18.0	$/MWh
PTC Period	10	years
PTC End Year	2010	year

Source: o Union of Concerned Scientists. The Washington Clean

Average Wind integration Costs

Wind Capacity Fraction of System Peak	Cost ($/MWh of Wind Generation)
0%	0.0
5%	$3
10%	$6
20%	$8
30%	$12.50

Wind

Capital Cost	1,419	1,179	$/kW
Transmission	80	80	$/kW
Lifetime	20	20	Years
Capital Recovery Factor	11.07%	11.07%	
Levilized Cost	165.91	139.33	$/kW-yr
Fixed O&M	31.37	25.63	$/kW-yr
Fixed Costs	197.28	164.96	$/kW-yr
Capacity Factor	35%	35%	
LevCapCost	64.34	53.80	$/MWh
Variable O&M	0.00	0.00	$/MWh
Fixed+Variable Costs	64.34	53.80	$/MWh

Solar

Capital Cost	2,527	2,309	$/kW
Transmission	80	80	$/kW
Lifetime	25	25	Years
Capital Recovery Factor	9.90%	9.90%	
Levilized Cost	257.99	236.42	$/kW-yr
Fixed O&M	51.70	43.10	$/kW-yr
Fixed Costs	309.69	279.52	$/kW-yr
Capacity Factor	25%	25%	
LevCapCost	141.41	127.63	$/MWh
Variable O&M	0.00	0.00	$/MWh
Fixed+Variable Costs	141.41	127.63	$/MWh
Production Tax Credit level		18.0	$/MWh
PTC Period		10	years
PTC End Year		2010	year

Biomass

Capital Cost	2,155	2,066	$/kW
Transmission	80	80	$/kW
Lifetime	30	30	Years
Capital Recovery Factor	9.20%	9.20%	
Levilized Cost	205.64	197.39	$/kW-yr
Fixed O&M	50.18	50.18	$/kW-yr
Fixed Costs	255.82	247.57	$/kW-yr
Capacity Factor	75%	75%	
LevCapCost	38.94	37.68	$/MWh
Fuel Cost	2.84	2.84	$/MBtu
Heat Rate	8,911	8,911	Btu/kWh
Fuel Gen Cost	25.31	25.31	$/MWh
Variable O&M	2.96	2.96	$/MWh
Fixed+Variable Costs	67.20	65.95	$/MWh

Solar - Thermal

Capital Cost	2,959	2,784	$/kW
Transmission	80	80	$/kW
Lifetime	25	25	Years
Capital Recovery Factor	9.90%	9.20%	
Levilized Cost	300.78	263.50	$/kW-yr
Fixed O&M	51.70	43.10	$/kW-yr
Fixed Costs	352.48	306.60	$/kW-yr
Capacity Factor	25%	25%	
LevCapCost	160.95	140.00	$/MWh
Variable O&M	0.00	0.00	$/MWh
Fixed+Variable Costs	160.95	140.00	$/MWh

Solar - PV

Capital Cost	4,398	3,998	$/kW
Transmission	80	80	$/kW
Lifetime	20	20	Years
Capital Recovery Factor	9.90%	9.90%	
Levilized Cost	443.13	403.52	$/kW-yr
Fixed O&M	10.60	8.90	$/kW-yr
Fixed Costs	453.73	412.42	$/kW-yr
Capacity Factor	25%	25%	
LevCapCost	207.18	188.32	$/MWh
Variable O&M	0.00	0.00	$/MWh
Fixed+Variable Costs	207.18	188.32	$/MWh

Geothermal

Capital Cost	3,941	4,925	$/kW
Transmission	80	80	$/kW
Lifetime	30	30	Years
Capital Recovery Factor	9.20%	9.20%	
Levilized Cost	369.94	460.49	$/kW-yr
Fixed O&M	75.00	68.20	$/kW-yr
Fixed Costs	444.94	528.69	$/kW-yr
Capacity Factor	85%	85%	
LevCapCost	59.76	71.00	$/MWh
Variable O&M	0.00	0.00	$/MWh
Fixed+Variable Costs	59.76	71.00	$/MWh

Other Data, Assumptions, Calculations	2012	2020	Units
BAU total generation	115,788	126,177	GWh
Renewable Energy to meet I-937	1,993	14,239	GWh
BAU Renewable Energy	4,356	4,805	GWh
Total renewable energy (BAU + I-937 requirements)	4,356	14,239	GWh
BAU %	0.0%	0.0%	%
Wind Fraction	0.0%	0.0%	%
BAU Renewables Generation	4,356	14,239	GWh
electricity sales after efficiency measures	90,580	100,275	GWh
New Renewable requirement	6.6%	20.0%	%
Total Renewables (assuming ramp up starting in 2008)	5,947	20,055	GWh
Added Renewables Requirement	1,591	5,816	GWh
Incremental Additions	835	1,164	GWh
New RPS Fractions			Credit Mult
Wind	91.0%	88.0%	
Solar Thermal	2.0%	2.0%	
Biomass	7.0%	10.0%	
Photovoltaic	0.0%	0.0%	
Geothermal	0.0%	0.0%	
RPS Extra Credit for Solar/Geothermal/Biomass			
RPS Annual Additions (adjusted for RPS factors)			
Wind	760	1,024	GWh
Solar Thermal	17	23	GWh
Biomass	58	116	GWh
Photovoltaic	0	0	GWh
Geothermal	0	0	GWh
Total Additions	835	1,164	GWh
RPS Cumulative			
Wind	1,447	5,214	GWh
Solar Thermal	32	116	GWh
Biomass	111	485	GWh
Photovoltaic	0	0	GWh
Geothermal	0	0	GWh
Total Washington Peak Generation	18,444	20,071	MW
BAU Wind Generation	4,356	14,239	GWh
BAU Wind Capacity	1,421	4,644	MW
BAU Wind Capacity Fraction	7.7%	23.1%	%
BAU Integration Price	$5	$9	$/MWh
BAU Integration Cost	$20	$134	$million
Total Wind Generation	5,804	19,453	GWh
Total Wind Capacity	1,893	6,345	MW
Total Wind Capacity Fraction	10.3%	31.6%	%
Total Integration Price	$6	$13	$/MWh
Total Integration Cost	$35	$257	$million
Program Additional Wind Integration Costs	$15	$123	$million
New Capacity			
Wind	472	1,701	MW
Solar Thermal	15	53	MW
Biomass	17	74	MW
Photovoltaic	0	0	MW
Geothermal	0	0	MW

Additions Levelized Price			
Wind	$61	$54	$/MWh
Solar Thermal	$137	$128	$/MWh
Biomass	$67	$66	$/MWh
Photovoltaic	$201	$188	$/MWh
Geothermal	$64	$71	$/MWh
First Year Levelized Cost			
Wind	$46	$55	$million
Solar Thermal	$2	$3	$million
Biomass	$4	$8	$million
Photovoltaic	$0	$0	$million
Geothermal	$0	$0	$million
PTC Payment			
Wind	$0	$0	$/MWh
Solar Thermal	$0	$0	$/MWh
Biomass	$0	$0	$/MWh
Photovoltaic	$0	$0	$/MWh
Geothermal	$0	$0	$/MWh
PTC Levelization Adjustment			
Wind	$0	$0	$million
Solar Thermal	$0	$0	$million
Biomass	$0	$0	$million
Photovoltaic	$0	$0	$million
Geothermal	$0	$0	$million
Annual Program Costs			
Wind	$104	$425	$million
Solar Thermal	$4	$15	$million
Biomass	$4	$29	$million
Photovoltaic	$0	$0	$million
Geothermal	$0	$0	$million
Total	$112	$469	$million
Avg Program Cost	$71	$81	$/MWh
Avoided Generation Cost	$43	$43	$/MWh
Program Avoided Costs			
Wind	$63	$227	$million
Solar Thermal	$1	$5	$million
Biomass	$5	$21	$million
Photovoltaic	$0	$0	$million
Geothermal	$0	$0	$million
Net Program Costs			
Wind	$41	$199	$million
Solar Thermal	$3	$10	$million
Biomass	-$1	$8	$million
Photovoltaic	$0	$0	$million
Geothermal	$0	$0	$million
Total	$43	$217	$million
Biomass Consumption	992,188	4,324,680	MMBTU
	62,012	270,292	dry tons

NOTES AND DATA FROM SOURCES

Note 1:

Based on conversation with Ken Dragoon of Renewable Northwest Project and info from PSE and Avista.
Previous estimate for 2008 was $1557/kW; previous estimate for 2025 was $1050/kW
New estimate for 2008 is $2000/kW; the 2025 estimate is based on ratios from the previous estimate.

Estimate of Mitigation Option Costs and Benefits for Washington Energy Supply GHG Analysis

ES-2 Distributed renewable energy incentives and/or barrier removal

Date Last Modified: *11/05/2007* *G. Powell*

Key Data and Assumptions	2012	2020/all	Units
First Year Results Accrue		**2009**	
Option Design Elements:			
Target Year for Reaching Solar Hot Water (SHW) Implementation Level		**2015**	
Fraction of additional existing Washington Homes with Solar HW by Target Year		**0.8%**	
Using the Western Governor's Association estimate of 500,000 systems installed by 2015 for entire region. The WA fraction was estimated using same fraction as used for WGA estimates of Solar PV by state (accounting for electricity use, solar insolation, and population growth).			
Target Year for Reaching Distributed Wind Generation Implementation Level		**2020**	
Additional WA Distributed WindGeneration Achieved by Target Year		**30.0**	MW
*Placeholder for now (See **Note 7** for WA specific information)*			
Target Year for Reaching Solar PV Implementation Level		**2020**	
Additional WA Solar PV Achieved by Target Year		**20.0**	MW
*Placeholder for now (See **Note 9** for WA specific information)*			
Target Year for Reaching Biomass/Landfill Gas/Biogas Implementation Level		**2020**	
Additional WA Biomass/Landfill Gas/Biogas Achieved by Target Year		**50.0**	MW
Placeholder for now			
Avoided Electricity Cost		**$43**	$/MWh
Weighted average over total 2007-2020 electricity savings for this policy in each sector. See common assumptions ("Common Factors" worksheet in this workbook).			
Avoided Natural Gas Cost		**$11.4**	$/MMBtu
See common assumptions ("Common Factors" worksheet in this workbook)			
Avoided LPG Cost		**$8**	$/MMBtu
See common assumptions ("Common Factors" worksheet in this workbook)			

Results	2012	2020	Units
Savings due to Implementation of ES-2 Programs			
Electricity			
TOTAL Reduction in Electricity Sales (savings from SWH/CHP plus electricity output from CHP/Solar PV and landfill gas/biomass/biogas systems)	141	406	GWh (sales)
Reduction in Generation Requirements	152	436	GWh (generation)
Gross GHG Emission Savings	0	**0.22**	$MMtCO_2e$
Natural Gas			
Net Change in Gas Use (negative values denote increased use)	99	181	Billion BTU
Net GHG Emissions (negative values denote increased emissions)	0.01	0.01	$MMtCO_2e$
Landfill Gas			
Net Change in Gas Use (negative values denote increased use)	-21	-125	Billion BTU
Net GHG Emissions (negative values denote increased emissions)	0.0000	0.0000	$MMtCO_2e$
Biomass			
Net Change in Biomass Use (negative values denote increased use)	-475	-2,850	Billion BTU
Net GHG Emissions (negative values denote increased emissions)	0.000	0.000	$MMtCO_2e$
Biogas			
Net Change in Gas Use (negative values denote increased use)	0	0	Billion BTU
Net GHG Emissions (negative values denote increased emissions)	0.0000	0.0000	$MMtCO_2e$

Summary Results for ES-2 (DG)	2012	2020	Units
Total for Policy (Electricity, Natural gas, LPG, Oil, Landfill Gas, Biomass, Biogas)			
GHG Emission Savings	0.13	0.31	$MMtCO_2e$
Net Present Value (2007-2020)		$124	$million
Cumulative Emissions Reductions (2007-2020)		2.3	$MMtCO_2e$
Cost-Effectiveness		$54	$\$/tCO_2e$
Total for Solar Hot Water			
GHG Emission Savings	0.06	0.11	$MMtCO_2e$
Net Present Value (2007-2020)		$3	$million
Cumulative Emissions Reductions (2007-2020)		1.0	$MMtCO_2e$
Cost-Effectiveness		$3	$\$/tCO_2e$
Total for Distributed Wind Generation			
GHG Emission Savings	0.02	0.05	$MMtCO_2e$
Net Present Value (2007-2020)		$9	$million
Cumulative Emissions Reductions (2007-2020)		0.3	$MMtCO_2e$
Cost-Effectiveness		$29	$\$/tCO_2e$
Total for Solar PV			
GHG Emission Savings	0.01	0.02	$MMtCO_2e$
Net Present Value (2007-2020)		$86	$million
Cumulative Emissions Reductions (2007-2020)		0.1	$MMtCO_2e$
Cost-Effectiveness		$705	$\$/tCO_2e$
Total for Biomass/Landfill Gas/Biogas			
GHG Emission Savings	0.04	0.13	$MMtCO_2e$
Net Present Value (2007-2020)		$25	$million
Cumulative Emissions Reductions (2007-2020)		0.9	$MMtCO_2e$
Cost-Effectiveness		$29	$\$/tCO_2e$

Other Data, Assumptions, Calculations	2012	2020/all	Units
Residential Sector Water Heating			
Number of Total Housing Units in Washington (thousand)	2,956,453	3,210,585	
Estimates of Source: Population Division, U.S. Census Bureau Release Date: August 15, 2007			
Assumes 2005 ratio of new homes to increase in population holds through 2020.			
Fraction of Additional Housing Units Solar Water Heat through Program	0.4%	0.8%	
See assumptions above			
Fraction of Housing Units Using Non-Solar Water Heat In Absence of Program			
Fraction Using Electricity	42.0%	42.0%	
Fraction Using Natural Gas	58.0%	58.0%	
Fraction Using LPG	0.0%	0.0%	
Fraction Using Solar (alone or with back-up, before policy)	0.0%	0.0%	
Rough Estimates using NW region mix for new houses, From NW Alliance Water Heater Market Study, nwalliance.org/research/reports/06-158.pdf			
Use of Electricity and Other (non-solar) Energy Sources per (non-solar) Household in Absence of Program			
Electricity	4,000	3,810	kWh
Natural Gas	17.96	17.27	MMBtu
LPG	17.96	17.27	MMBtu
Value for 2010 assumes 4000 kWh per HH using electricity for water heat, which is a rough estimate pending receipt of state-specific data. Estimates for gas and lpg base on average EF of .93 for Electricity, .7 for Natural Gas/LPG. Value in 2020 assumes a 5% reduction in energy intensity			
Additional Households Using Solar HW Under Program (thousand)	12.7	24.1	
Fraction of household hot water needs provided by solar HW units	75.0%	75.0%	
Placeholder Assumption--Back-up fuels used for water heating in housing units with solar water heating are assumed to be distributed based on the pre-Policy fractions given above. (placeholder based on report for Environment Canada)			

Savings of Electricity and Other (non-solar) Energy Sources Due to Program			
Electricity	15.8	28.9	GWh
Natural Gas	0.099	0.181	TBtu
LPG	-	-	TBtu
Capital Cost of Solar Water Heater	**$2,534**	**$2,200**	
Assumption used in EIA's Annual Energy Outlook 2007. http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/residential.pdf			
Implied Cumulative Additional Annualized Capital Costs for Residential Solar Hot Waters Installed as a Result of Policy (thousand 2005 dollars)	**$ 2,182**	**$ 3,601**	
Factors for Annualizing Capital Costs (Residential Solar Hot Water Systems)			
Interest Rate (real)		7%	/yr
Economic Life of System		20	years
Implied Annualization Factor		9.44%	%/yr
Marginal Federal Tax Rate, Residential		28%	
Intermediate Results: Residential SWH Program			
Reduction in Electricity Sales from SWH Program: Residential	16	29	GWh (sales)
Reduction in Generation Requirements	17	31	GWh (generation)
GHG Emission Savings	**0.01**	**0.02**	$MMtCO_2e$
Economic Analysis (for Electricity Savings due to SWH Program)			
Net Present Value (2007-2020)		2	$million
Cumulative Emissions Reductions (2007-2020)		0.1	$MMtCO_2e$
Cost-Effectiveness		**$14.09**	$\$/tCO_2e$
Natural Gas			
Savings due to Implementation of SWH Program			
Reduction in Gas Use	99	181	Billion BTU
GHG Emission Savings	0.05	0.10	$MMtCO_2e$
Economic Analysis (for Gas Savings due to SWH Program)			
Net Present Value (2007-2020)		**$1.2**	$million
Cumulative Emissions Reductions (2007-2020)		0.84	$MMtCO_2e$
Cost-Effectiveness		**$1.46**	$\$/tCO_2e$
LPG			
Savings due to Implementation of SWH Program			
Reduction in Gas Use	0	0	Billion BTU
GHG Emission Savings	0.00	0.00	$MMtCO_2e$
Economic Analysis (for LPG Savings due to SWH Program)			
Net Present Value (2007-2020)		0	$million
Cumulative Emissions Reductions (2007-2020)		0.000	$MMtCO_2e$
Cost-Effectiveness		**#DIV/0!**	$\$/tCO_2e$

Distributed Wind Generation

Washington Potential for Distributed Wind		30	MW
*Placeholder for now (See **Note 7** for WA specific information)*			
Estimated Future Washington Potential for Distributed Wind	10	30	MW
Potential assumed to scale with forecast commercial plus industrial electricity sales.			
Fraction of Potential Installed Under Program (Cumulative)	100.0%	100.0%	
MW Wind Installed Under Program (annual installations)	3	3	MW
Average full-capacity-equivalent hours of operation for New CHP units:	3,066	3,066	
(Assumption based on capacity factors of :)	35.0%	35.0%	
Placeholder, from Energy Trust Oregon 2004 report by Wiser et al., based on 1.5MW system. See Note 4.			
Implied Cumulative Distriubuted wind Electricity Output (GWh)			
Wind	**31**	**92**	

Inputs to Cost Estimates for Distributed Wind Systems

Estimated Average Installed Capital Costs by System Type ($2005/kW)			
Wind	$ 2,388	$ 1,194	$/kW
Placeholder, from Energy Trust Oregon 2004 report by Wiser et al., based on 1.5MW system. See Note 4.			
Factors for Annualizing Capital Costs (all plant types)			
Interest Rate		8%	/yr
Economic Life of System		20	years
Implied Annualization Factor		10.19%	%/yr
Estimated Average Non-fuel Operating and Maintenance Costs by System Type ($/MWh)			
Wind	$ -	$ -	

Intermediate Results for Cost Estimates

Total Capital Costs for New Systems (thousand 2005 dollars)		
Wind	**$ 5,373**	**$ 2,985**
Annualized Capital Costs for All Systems (thousand 2005 dollars)		
Wind	**$ 2,341**	**$ 5,625**
Annual Non-Fuel Operating and Maintenance Costs for All Systems (thousand 2005 dollars)		
Wind	**$ -**	**$ -**
Total Non-Fuel Costs for All Systems (thousand 2005 dollars)		
Natural Gas	**$ 2,341**	**$ 5,625**

Intermediate Results: Distributed Wind

Electricity

TOTAL Reduction in Electricity Sales (electricity output from wind generation)	31	92	GWh (sales)
Reduction in Generation Requirements	33	99	GWh (generation)
Gross GHG Emission Savings	**0.02**	**0.05**	$MMtCO_2e$

Total for Distributed Wind Program

Net Present Value (2007-2020)	**$9**	$million
Cumulative Emissions Reductions (2006-2020)	0.3	$MMtCO_2e$
Cost-Effectiveness	**$28.90**	$\$/tCO_2e$

Solar Photovoltaics (PV)

Total Additional Capacity of PV Built under Program	6.7	20.0	MW
Annual Additional Capacity of PV Built under Program	1.7	1.7	MW
Fraction of Additional Capacity As			
Residential PV Systems	20%	20%	
Commercial PV Systems	80%	80%	
Average Capacity of Solar PV System Installed on Homes (kW)	**3.00**	**3.00**	
*Assumption, consistent with capacity assumption used in Source in **Note 2**.*			
Average Capacity of Solar PV System Installed on Commercial Buildings (kW)	**20.00**	**20.00**	
*Assumption, roughly consistent, per square foot of floor area, with capacity assumptions for new and existing residential buildings used in Source in **Note 2**. See also **Note 6** for calculation of average floor area of commercial builidngs.*			
Number of Homes Installing Solar PV Systems Annually	**111**	**111**	
Total Number of Homes with Solar PV Systems Installed under this Option, 2009 to 2020: 1,333			
*Note that a cummulative ~4,300 solar PV systems by 2020 is considerably less, on a per-capita basis, than the 1.2 million solar homes by 2020 used in an estimate of solar PV contributions to GHG emissions reduction in California (see **Note 2**).*			
Implied number of Commercial Solar PV Systems Added Annually	**67**	**67**	
Calculated based on target capacity and capacity-per-building assumption above.			
Total Annual Residential Solar PV Capacity Installed on Homes (MW)	**0.33**	**0.33**	MW
Total Annual Commercial Solar PV Capacity Installed (all Buildings) (MW)	**1.33**	**1.33**	MW
Estimated Annual Total Solar PV Installed Under Policy by Year (MW)	**1.67**	**1.67**	MW
Estimated Cumulative Total Solar PV Installed Under Policy by Year (MW)	**6.67**	**20.00**	MW
Average full-capacity-equivalent hours of operation for Solar PV Systems:	**1,752**	**1,752**	
Based on WGA report for Solar--See Note 4.			
(Assumption based on capacity factors of :)	20.0%	20.0%	
Implied New Solar PV Output, Cumulative Systems (GWh)	**11.68**	**35**	GWh

Inputs to Cost Estimates for Solar PV Systems (Data from Source in *Note 3*)

Capital Costs for PV Systems for Homes			
Total System - $/kW	**$ 4,904**	**$ 3,265**	
Total System - $	**$ 14,712**	**$ 9,795**	
*WGA report, See **Note 1,** assume additional decrease in cost after 2015 at half the rate of decrease from 2010 to 2015*			
Commercial System Capital costs/kW Relative to New Residential			
Total System - $/kW	**$ 2,464**	**$ 1,870**	
Total System - $	**$ 49,280**	**$ 37,400**	
*WGA report, includes Federal incentives, See **Note 1,** assume additional decrease in cost after 2015 at half the rate of decrease from 2010 to 2015*			
Solar PV Operating and Maintenance (O&M) Costs ($/MWh)	$ 10.00	$ 5.00	
WGA report,			
Federal Solar Tax Credits: Residential Sector--See ***Note 3***	0%	0%	
Federal Solar Tax Credits: Commercial and Industrial Sectors--See ***Note 3***	0%	0%	
already accounted for in capital costs			
Factors for Annualizing Capital Costs (Residential PV Systems)			
Interest Rate		7%	/yr
Economic Life of System		20	years
Implied Annualization Factor		9.44%	%/yr
Marginal Federal Tax Rate, Residential		28%	
Factors for Annualizing Capital Costs (Commercial PV Systems)			
Interest Rate		8%	/yr
Economic Life of System		20	years
Implied Annualization Factor		10.19%	%/yr
Reduce Captial Costs for Solar Tax Credits and Federal Mortgage Deductions?		**NO**	

Intermediate Results for Solar PV System Cost Estimates

Total Capital Costs for New Systems (thousand 2005 dollars) Before Tax Credits		
Systems for Residences	$ 1,635	$ 1,088
Systems for Commercial Installations	$ 3,285	$ 2,493
Annualized Capital Costs for All Systems (thousand 2005 dollars)		
Systems for Residences	$ 680	$ 1,647
Systems for Commercial Installations	$ 1,440	$ 3,699
Annual Operating and Maintenance Costs for All Systems (thousand 2005 $)	$ 93	$ 175

Intermediate Summary Results for Solar PV Generation Program

Total Electricity Output	11.7	35.0	GWh (sales)
Reduction in Generation Requirements	13	38	GWh (generation)
Gross GHG Emission Savings	0.01	0.02	$MMtCO_2e$
Total Cost (net of value of electricity output)	$ 8	$ 21	$million
Net Present Value (2007-2020)		$86	$million
Cumulative Emissions Reductions (2006-2020)		0.1	$MMtCO_2e$
Cost-Effectiveness		$704.62	$/tCO_2e$

Biomass/Landfill Gas/Biogas-fueled Systems

Total Additional Capacity of Biomass/LFG/Biogas Built under Program	16.7	50.0	MW
Annual Additional Capacity of Biomass/LFG/Biogas Built under Program	4.2	4.2	MW
Fraction of Additional Capacity as			
Landfill Gas	5%	5%	
Biomass	95%	95%	
Biogas	0%	0%	
The Agriculture, Forestry, and Waste TWG will account for biogas			
Implied Annual New Biomass/Landfill Gas/Biogas-fueled Capacity by Fuel (MW)			
Landfill Gas	**0.21**	**0.21**	
Biomass	**3.96**	**3.96**	
Biogas	**-**	**-**	
Implied Cumulative New Biomass/Landfill Gas/Biogas-fueled Capacity by Fuel (MW)			
Landfill Gas	**0.42**	**2.50**	
Biomass	**7.92**	**47.50**	
Biogas	**-**	**-**	
Average Full-capacity-equivalent Hours of Operation for Systems Above:	**5,000**	**5,000**	
Placeholder Assumptions			

Inputs to Cost Estimates for Biomass/Landfill Gas/Biogas-fueled Systems

Estimated Average Installed Capital Costs by System Type ($2005/kW)			
Landfill Gas	$ 2,000	$ 1,500	
Biomass	$ 2,500	$ 2,200	
Biogas	$ 2,500	$ 2,200	
Placeholder Assumptions			
Factors for Annualizing Capital Costs (all plant types)			
Interest Rate		8%	/yr
Economic Life of System		20	years
Implied Annualization Factor		10.19%	%/yr
Estimated Average Non-fuel Operating and Maintenance Costs by System Type ($/MWh)			
Landfill Gas	$ 20.00	$ 20.00	
Biomass	$ 20.00	$ 20.00	
Biogas	$ 20.00	$ 20.00	
Placeholder Assumptions			
Implied Cumulative New Biomass/Landfill Gas/Biogas-fueled Electricity Output by Fuel (GWh)			
Landfill Gas	**2.1**	**12.5**	
Biomass	**39.6**	**237.5**	
Biogas	**-**	**-**	
Average Net Heat Rate by Fuel (Btu Fuel Input/kWh Electricity Output)			
Landfill Gas	10,000	10,000	
Biomass	12,000	12,000	
Biogas	10,000	10,000	
Placeholder Assumptions			
Implied Fuel Input by Fuel (Billion Btu)			
Landfill Gas	**21**	**125**	
Biomass	**475**	**2,850**	
Biogas	**-**	**-**	

Intermediate Results for Biomass/Landfill Gas/Biogas-fueled Cost Estimates

Total Capital Costs for New Systems (thousand 2005 dollars)		
Landfill Gas	$ 417	$ 313
Biomass	$ 9,896	$ 8,708
Biogas	$ -	$ -
Annualized Capital Costs for All Systems (thousand 2005 dollars)		
Landfill Gas	$ 85	$ 454
Biomass	$ 2,016	$ 11,466
Biogas	$ -	$ -
Annual Non-Fuel Operating and Maintenance Costs for All Systems (thousand 2005 dollars)		
Landfill Gas	$ 42	$ 250
Biomass	$ 792	$ 4,750
Biogas	$ -	$ -
Total Non-Fuel Costs for All Systems (thousand 2005 dollars)		
Landfill Gas	$ 127	$ 704
Biomass	$ 2,807	$ 16,216
Biogas	$ -	$ -
Total Fuel Costs for All Systems (thousand 2005 dollars)		
Landfill Gas	$ -	$ -
Biomass	$ -	$ -
Biogas	$ -	$ -

Intermediate Summary Results for Biomass/LFG/Biogas Generation Program

Total Electricity Output	83.3	250.0	GWh (sales)
Reduction in Generation Requirements	90	269	GWh (generation)
Gross GHG Emission Savings	0.04	0.13	$MMtCO_2e$
Total Cost (net of value of electricity output)	$ 2	$ 6	$million
Net Present Value (2007-2020)		$25	$million
Cumulative Emissions Reductions (2006-2020)		0.9	$MMtCO_2e$
Cost-Effectiveness		$28.96	$\$/tCO_2e$

NOTES AND DATA FROM SOURCES

Note 1:

From Western Governor's Association, Clean and Diversified Energy Initiative

Solar Task Force report http://www.westgov.org/wga/initiatives/cdeac/index.htm

Table 1. Current and Projected Levelized Cost of Energy for PV Systems

	Residential Systems (no incentives)			Commercial Systems (w/ ITC and MACRS)		
Year	2005	2010	2015	2005	2010	2015
Interest Rate (real) (i) *	4.0%	4.0%	4.0%	5.0%	5.0%	5.0%
System Lifetime (n)	25	30	30	25	30	30
Capital Recovery Factor (CRF)	0.064	0.058	0.058	0.071	0.065	0.065
System Selling Price ($/Wdc)	7.30	5.17	3.89	6.00	4.41	3.60
AC-DC Conversion Efficiency (%)	91%	94%	97%	93%	95%	97%
AC Equiv. System Price ($/Wac)	8.02	5.50	4.01	6.45	4.64	3.71
Fed ITC Rate (at permanent 10% level)	-	-	-	10%	10%	10%
Value of Fed ITC	-	-	-	0.65	0.46	0.37
Sys Cost after Fed ITC	-	-	-	5.81	4.18	3.34
Fed Accelerated Depreciation (Net Present Value)**	-	-	-	34%	34%	34%
Value of Fed Acc Dep. (basis = .95*system cost)	-	-	-	2.08	1.50	1.20
Final Cost ($/Wac) (ICC)	8.02	5.50	4.01	3.72	2.68	2.14
Capacity Factor (CF)	21%	21%	21%	18.5%	18.5%	18.5%
O&M	0.02	0.01	0.005	0.02	0.01	0.005
Levelized Cost of Energy (LCOE) (cents/kWh)* **	**29.9**	**18.3**	**13.1**	**18.3**	**11.8**	**9.1**

* These are real interest rates (i.e., adjusted for inflation and tax benefits) not nominal interest rates.

** Based on MACRS rates from IRS Publication 946, Table A-2 (assuming investment is made in 1st quarter of the year).

*** The LCOE values were calculated using the standard formula for amortization of cost over time, assuming the system is financed through a loan matched to the lifetime of the system.

LEC = (ICCx1000xCRF)/(CFx8760)+O&M, where

ICC = Installed Capacity Cost ($/Wp),

CRF = Capital Recovery Factor = (i*(i+1)^n)/((i+1)^n-1),

CF = Capacity Factor,

O&M = Operation and Maintenance ($/kWh),

i = interest rate,

n = system lifetime (i.e, how many years to amortize cost of system over).

Note 2:

Source: Worksheet "Solar Homes Summary table.xls", with calculations in support of the California Million Solar Homes Initiative, authored by XENERGY, Inc., and provided by M. Lazarus. Selected annual data provided.

Note 3:

A description of the new Federal Solar Tax Credits for businesses and residences as contained in the Energy Policy Act of 2005 (EPAct 2005) (see, for example, http://www.seia.org/getpdf.php?iid=21) provides for 30% (of system cost) tax credits for solar PV investments by businesses in 2006 and 2007, reverting to 10% thereafter. For residences, the credit in 2006 and 2007 is 30% with a "cap" of $2000, reverting to zero after 2007.

See also, for Example,

http://www.sdenergy.org/uploads/PV-Federal%20Tax%20Credits%20Summary%206-01-04%20FINAL.pdf.

Note 4:
Information from a report prepared for the Energy Trust of Oregon, prepared by
Mark Bolinger, Ryan Wiser, Tom Wind, Dan Juhl, and Robert Grace (2004)
A Comparative Analysis of Community Wind Power Development Options in Oregon
http://www.oregon.gov/ENERGY/RENEW/Wind/docs/CommunityWindReportLBLforETO.pdf

Note 5:
Source: International Energy Agency (IEA), T<u>RENDS IN PHOTOVOLTAIC APPLICATIONS</u>
<u>Survey report of selected IEA countries between 1992 and 2004</u>. Report #IEA-PVPS T1-14:2005.
Page 18.
"Indicative costs" in 2004 in USD per kWp (assumedly DC output) for on-grid PV systems in the US:

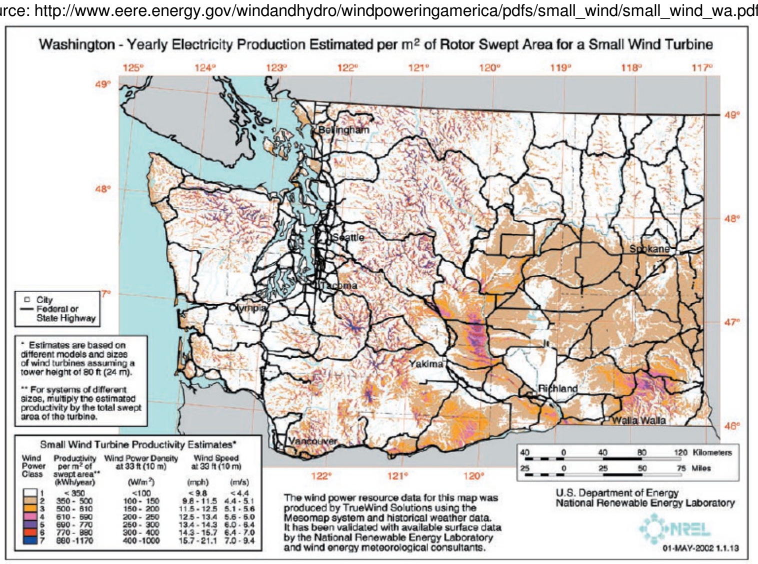
<10 kW	7000 to 10,000
>10 kW	6300 to 8500

In EIA Projections of Renewable Energy Costs, presented in "Forum on the Economic Impact Analysis of NJ's Proposed 20% RPS" by Chris Namovicz of the USDOE EIA (Energy Information Administration), dated February 22, 2005, and available as http://www.eia.doe.gov/oiaf/pdf/rec.pdf, a wind power average cost of
6000 dollars/kW is provided for a 25 kW Commercial system, or
8200 dollars/kW for a 2 kW Residential system, with
"Large potential for cost reduction".

Note 6:
An older (1997) US DOE document <u>OVERVIEW OF PHOTOVOLTAIC TECHNOLOGIES</u>
(available as http://www.eere.energy.gov/ba/pdfs/pv_overview.pdf) suggests that even early solar PV systems had O&M costs of under $ 0.005 per kWh, which in 2005 dollars would be: $ 0.0059 per kWh.

Note 7:
Small Wind Potential in WA:

Source: http://www.eere.energy.gov/windandhydro/windpoweringamerica/pdfs/small_wind/small_wind_wa.pdf



Source: http://www.awea.org/smallwind/documents/AWEA_SWT_Market_Study_6-05.pdf
Home and Farm Wind Energy Systems: Reaching the Next Level
AWEA Global Small Wind Industry Market Study Confirms Need for Level Playing Field: June 2005

30 MW of small wind capacity installed in US between 1990 - 2004.
Small wind companies project growth targets of 18-21% by 2010, 107 MW by 2010.

Source: Renewable Energy Atlas of the West: http://www.energyatlas.org/PDFs/LowRes/atlas_state_WA.pdf
Total WA wind potential: 62 million MWh/yr

Source: WA Governor's Report: Wind Supply Task Force http://www.westgov.org/wga/initiatives/cdeac/Wind-full.pdf
240 MW wind capactiy installed in WA as of 2004

Wind Potential in WA: 1,050 MW by 2015 under scenario 1

Scenario 1. Wind development that is either in progress or can be reasonably assumed to occur based on existing plans with minimal new transmission additions. Evidence from prior work on the ability of new transmission tariffs and related policy implementation was assumed to help stimulate wind additions. This represents a near-term goal.

Note 8:
Water Heater Fuel Sources

DOE, AEO 2007:

Residential Fuel Source for Water Heaters in the West:
Electricity: 15 million homes: 64%
Natural Gas: 7.9 million homes: 33%
LPG: 0.7 million homes: 3%

Source: http://nwalliance.org/research/reports/06-158.pdf
Northwest Energy Efficiency Alliance Proprietary
Water Heater Market Study
Retrofit water heaters: 57% electric and 43% natural gas
New construction water heaters: 48% electric and 52% natural gas

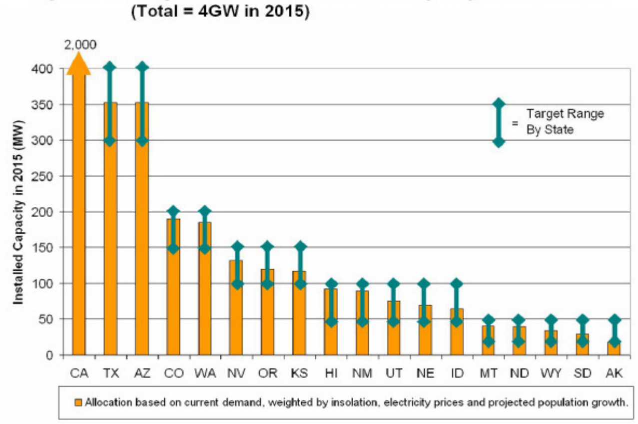
Note 9:
Distributed Solar PV

Source: http://www.westgov.org/wga/initiatives/cdeac/Solar-full.pdf
Western Governor's Report:

By 2015:
4,000 MW of distributed solar PV

WA potential:
Based on current demand, weighted by the amount of sunshine, electricity prices and projected population growth
WA installed capacity in 2015 184 MW +- 10 MW

Figure II-1. Weighted Allocation of Installed Capacity in WGA States (Total = 4GW in 2015)



Source: NREL

State	Electricity Demand (TWh)[1]	Initial Share	Solar Insolation (kWh/kW)[2]	Insolation Multiplier	Average Electricity Price 2003 (¢/kWh)[3]	Electricity Price Multiplier 2003	Population 2005 (million)[4]	Population 2015 (million)[4]	10 Year Population Growth Index	Population Growth Multiplier	Final Share[5]	Final Allocation (MW)
WA	79.7	17.3%	1139	0.72	5.9	0.94	6.205	6.951	1.12	1.03	11%	184

Source: PV Grid Connected Market Potential under a Cost Breakthrough Scenario: The Energy Foundation: Sept 2004
http://www.ef.org/documents/EF-Final-Final2.pdf

State	2025 Technical Ultimate Potential (MWp) Residential Total	Commercial Total	Total	% share of U.S Total	% share of Residential
Washington	13,337	11,297	24,633	2%	54%

Note 10
Solar Hot Water

Source: http://www.westgov.org/wga/initiatives/cdeac/Solar-full.pdf
Western Governor's Report:

By 2015:

500,000 solar hot water systems could be installed providing the equivalent of 2,000 MW generating capacity and 15 billion ft^3 of natural gas

As an example, Hawaiian Electric Company's Energy Solutions Solar Water Heating Program has grown to over 3,000 systems per year since its inception in 1996

European countries have also instituted a series of very successful incentive programs for solar water and space heating systems, enabling them to make significant progress and poising them for continued growth. Incentive programs are quite modest in countries with the most active solar water heating programs with rebates ranging from \$300 to \$1400 per system depending on size. Many of these countries have substantially less solar resource than that available in the Western US, yet they have more aggressive solar thermal programs. A subset of seven European Union countries[40] together installed approximately 250,000 solar thermal systems in 2003, or 875 MW_{th} equivalent.[41] Austria alone (population of 8.1 million) has an existing installed solar thermal generating capacity of 1,469 MW_{th}, equal to all of the installed solar thermal capacity in the entire US (population 294 million). Israel, with the population roughly equivalent to Arizona, is home to 5 percent of the world's solar water heating deployments. By contrast, the US solar thermal market for water heating has been stagnant for a number of years at around 8,000 systems.

WGA goal
500000 systems for entire WGA region

scale this goal to Washington based on the ratio used for PV in WGA report, see Note 9

WGA goals for Solar PV		
WGA region	4000	MW
WA	184	MW
WA's fraction	5%	
WA Solar Hot wa	23000	systems
	3,066,505	number of WA households in 2015
	0.8%	Fraction of homes in 2015

Note 11
Biomass/LFG/Biogas

Source: NW Council's Fifth Power Plan

			Capacity
Wood residue	1000-1700	aMW	1588 MW
Landfill gas	100-200	aMW	176 MW
Animal manure		50 aMW	59 MW
Pulping chemical recovery		280 aMW	329 MW
Biomass			1918 MW
Biogas			59 MW
Washington % of population			51.20%
Biomass in Washington (estimated based on population)			982 MW
Landfill gas in Washington (based on EPA LMOP numbers)			48 MW
Source: EPA's LMOP http://www.epa.gov/lmop/proj/index.htm#2			
Biomass/LFG/Biogass in Washington			1030 MW
Target implementation		5%	51.5 MW

Estimate of Mitigation Option Costs and Benefits for Washington Energy Supply GHG Analysis
ES-7 Combined Heat and Power (CHP) and thermal energy recovery and use

Date Last Modified: *11/01/2007* *G. Powell*

Key Data and Assumptions	2012	2020/all	Units

Total Remaining Estimated CHP Potential in WA as of 2004

2,847 MW (See ***Note 1***)

From the Combined Heat and Power in the Pacific Northwest: Market Assessment, dated August 2004, to the Oak Ridge National Laboratory (http://www.chpcenternw.org/NwChpDocs/Chp_Market-Assessment_In_PNW_EEA_08_2004.pdf)

	2012	2020/all	Units
First Year Results Accrue		**2009**	
Fuel Costs	**2012**	**2020/all**	**Units**
Natural Gas (Commercial and Industrial, Delivered)		**$6.8**	$/MMBtu
Based on 2006 projections			
Biomass		**$2.8**	$/MMBtu
Estimate based on national study of state-by-state biomass resource resource assessments (Biomass Feedstock Availability in the United States: 1999 State Level Analysis, M Walsh et al 1999, with 2000update). Price equivalent of $51/dry ton at 16 MMBtu/dry ton.			
Oil		**$9.5**	$/MMBtu
From Seattle Steam comments			
Coal		**$2.2**	$/MMBtu
Average coal heat content of 26.75 MMBTU/ton, based on 2001 USDOE/EIA data. USDOE/EIA figures for 2005 "other industrial users" are withheld for WA. www.eia.doe.gov/cneaf/coal/page/acr/table34.html			
Avoided Electricity Cost		**$43**	$/MWh
Estimate derved from NWPCC data from RTF analysis, same source as marginal CO2 emission rate for electricity reductions, this is the simple average (not levelized value) of the marginal dispatch costs for 2010, 2015, and 2020			
Avoided electricity emissions rate	**0.50**	**0.50**	tCO_2/MWh
Placeholder for now			

Summary Results	2012	2020	Units
Total for Policy (All Fuels)			
Total Net GHG Emission Savings	**0.42**	**1.6**	$MMtCO_2e$
Net Present Value (2007-2020)		**$82**	$million
Cumulative Emissions Reductions (2007-2020)		9.5	$MMtCO_2e$
Cost-Effectiveness		**$9**	$\$/tCO_2e$

Other Data, Assumptions, Calculations	2012	2020/all	Units
Fraction of Washington's Remaining Existing CHP Potential Tapped per Year	2.0%	3.0%	
Rough estimate to be refined in consultation with TWG. Fractions of remaining potential tapped in each year are assumed to be beyond "baseline plus existing policies" levels, and thus due to CAT policies.			
Annual Growth in CHP Potential	1.6%	1.6%	
Rough estimate based on consideration of growth in electricity use in the commercial and industrial sectors.			
Estimated CHP Potential by Year (MW)	3,182	3,612	*MW*
Potential shown above grows at the rate shown above.			
Estimated CHP Installed Under Policy by Year (MW)	64	108	*MW*
Average full-capacity-equivalent hours of operation for New CHP units:	4,000	4,000	
assumption			
Fraction of New CHP Capacity/Energy Fueled With:			
Natural Gas	94%	94%	
Biomass	6%	6%	
Oil	0%	0%	
Coal	0%	0%	
Assumptions - see Note 3			
Implied Annual New CHP Capacity by Fuel (MW)			
Natural Gas	60	102	
Biomass	4	7	
Oil	-	-	
Coal	-	-	
Implied Cumulative New CHP Capacity by Fuel (MW)			
Natural Gas	234	917	
Biomass	15	59	
Oil	-	-	
Coal	-	-	
Implied Cumulative New CHP Electricity Output by Fuel (GWh)			
Natural Gas	935	3,669	
Biomass	60	234	
Oil	-	-	
Coal	-	-	
Average Net Heat Rate by Fuel (Btu Fuel Input/kWh Electricity Output)			
Natural Gas	7,000	7,000	
Biomass	14,000	14,000	
Oil	13,000	13,000	
Coal	12,000	12,000	
Implied Fuel Input by Fuel (Billion Btu)			
Natural Gas	6,543	25,682	
Biomass	835	3,279	
Oil	-	-	
Coal	-	-	
Usable Cogenerated Heat Output as a Fraction of Fuel Energy Input			
Natural Gas	40%	40%	
Biomass	40%	40%	
Oil	40%	40%	
Coal	40%	40%	
Implied Usable Heat Output by Fuel (Billion Btu)			
Natural Gas	2,617	10,273	
Biomass	334	1,311	
Oil	-	-	
Coal	-	-	

Fraction of New CHP Capacity/Energy by Size:

<1 MW	14%	14%
1-4.9 MW	24%	24%
5-24.9 MW	19%	19%
25-39.9 MW	13%	13%
40-259.9 MW	15%	15%
>259.9 MW	16%	16%

Implied Annual New CHP Capacity by Size (MW)

<1 MW	9	15
1-4.9 MW	15	26
5-24.9 MW	12	21
25-39.9 MW	28	47
40-259.9 MW	9	15
>259.9 MW	15	26

Implied Cumulative New CHP Capacity by Size (MW)

<1 MW	35	137
1-4.9 MW	59	232
5-24.9 MW	47	185
25-39.9 MW	107	422
40-259.9 MW	35	137
>259.9 MW	59	232

Implied Cumulative New CHP Electricity Output by Size (GWh)

<1 MW	139	547
1-4.9 MW	237	930
5-24.9 MW	188	739
25-39.9 MW	430	1,688
40-259.9 MW	139	547
>259.9 MW	237	930

Average Net Heat Rate by Size (Btu Fuel Input/kWh Electricity Output)

<1 MW	11,234	10,343
1-4.9 MW	9,868	8,480
5-24.9 MW	9,213	7,935
25-39.9 MW	9,945	8,865
40-259.9 MW	9,220	8,595
>259.9 MW	7,937	7,300

Implied Fuel Input by Size (Billion Btu)

<1 MW	1,541	5,657
1-4.9 MW	2,271	7,882
5-24.9 MW	1,686	5,864
25-39.9 MW	4,183	14,961
40-259.9 MW	1,267	4,702
>259.9 MW	1,849	6,785

Usable Cogenerated Heat Output as a Fraction of Fuel Energy Input

<1 MW	40%	40%
1-4.9 MW	40%	40%
5-24.9 MW	40%	40%
25-39.9 MW	40%	40%
40-259.9 MW	40%	40%
>259.9 MW	40%	40%

Implied Usable Heat Output by Fuel (Billion Btu)

<1 MW	616	2,263
1-4.9 MW	908	3,153
5-24.9 MW	674	2,345
25-39.9 MW	1,673	5,984
40-259.9 MW	507	1,881
>259.9 MW	740	2,714

Other Data, Assumptions, Calculations	2012	2020/all	Units
Fraction of Usable Heat Output Replacing Space/Water/Process Heat Use	94%	94%	
(Assumption from Seattle Steam)			
Fraction of CHP Heat Output Displacing Thermal Energy Produced Using			
Natural Gas	90%	90%	
Biomass	0%	0%	
Coal	0%	0%	
Electricity	10%	10%	
Oil	0%	0%	
Based on input from TWG			
Net Efficiency of Displaced Boiler/Heater Thermal Energy Produced Using			
Natural Gas	75%	75%	
Biomass	75%	75%	
Coal	75%	75%	
Electricity	85%	85%	
Oil	75%	75%	
Assumptions			
Net Displaced Fuel Use (Billion Btu)			
Natural Gas	**3,329**	**13,067**	
Biomass	**-**	**-**	
Coal	**-**	**-**	
Electricity	**326**	**1,281**	
Oil	**-**	**-**	
Inputs to Cost Estimates for CHP Systems			
Factors for Annualizing Capital Costs (all plant types)			
Interest Rate		8%	/yr
Economic Life of System		20	years
Implied Annualization Factor		10.19%	%/yr
Estimated Average Installed Capital Costs by System Type ($2005/kW)			
Natural Gas	$ 964	$ 839	
Biomass	$ 1,214	$ 1,089	
Oil	$ 964	$ 839	
Coal	$ 964	$ 839	
Source: Combined Heat and Power in the Pacific Northwest: Market Assessment, based on average of 40MW and 260MW turbine systems; Biomass system assumed $250 higher than gas turbine; Coal system assumed equal to gas turbine			
Estimated Average Non-fuel Operating and Maintenance Costs by System Type ($/MWh)			
Natural Gas	$ 5.00	$ 6.00	
Biomass	$ 3.00	$ 4.00	
Coal	$ 12.00	$ 14.00	
Estimated Average Installed Capital Costs by Size ($2005/kW)			
<1 MW	$ 1,396	$ 1,073	
1-4.9 MW	$ 1,046	$ 929	
5-24.9 MW	$ 990	$ 879	
25-39.9 MW	$ 890	$ 784	
40-259.9 MW	$ 781	$ 734	
>259.9 MW	$ 656	$ 589	
Estimated Average Non-fuel Operating and Maintenance Costs by Size ($/MWh)			
<1 MW	$ 16.35	$ 11.60	
1-4.9 MW	$ 9.49	$ 8.44	
5-24.9 MW	$ 8.44	$ 8.44	
25-39.9 MW	$ 5.27	$ 4.22	
40-259.9 MW	$ 4.22	$ 4.22	
>259.9 MW	$ 4.22	$ 4.22	

Intermediate Results for Cost Estimates

Total Capital Costs for New Systems by Fuel (thousand 2005 dollars)

Natural Gas	$ 56,162	$ 85,479
Biomass	$ 4,539	$ 7,082
Oil	$ -	$ -
Coal	$ -	$ -

Annualized Capital Costs for All Systems by Fuel (thousand 2005 dollars)

Natural Gas	$ 22,713	$ 83,931
Biomass	$ 1,830	$ 6,848
Oil	$ -	$ -
Coal	$ -	$ -

Annual Non-Fuel Operating and Maintenance Costs for All Systems (thousand 2005 dollars)

Natural Gas	$ 4,673	$ 22,013
Biomass	$ 179	$ 937
Oil	$ -	$ -
Coal	$ -	$ -

Total Non-Fuel Costs for All Systems (thousand 2005 dollars)

Natural Gas	$ 27,387	$ 105,945
Biomass	$ 2,009	$ 7,785
Oil	$ -	$ -
Coal	$ -	$ -

Total Gross Fuel Costs for All Systems (thousand 2005 dollars)

Natural Gas	$ 44,489	$ 174,640
Biomass	$ 2,372	$ 9,311
Oil	$ -	$ -
Coal	$ -	$ -

Total Fuel Cost Savings from Displaced Heating Fuels for All Systems (thousand 2005 dollars)

Natural Gas	$ 22,636	$ 88,857
Biomass	$ -	$ -
Coal	$ -	$ -
Electricity	$ 718	$ 2,818
Oil	$ -	$ -

Total Capital Costs for New Systems by Fuel (thousand 2005 dollars)

<1 MW	$ 11,873	$ 16,302
1-4.9 MW	$ 15,489	$ 23,969
5-24.9 MW	$ 11,657	$ 18,028
25-39.9 MW	$ 23,900	$ 36,743
40-259.9 MW	$ 6,880	$ 11,149
>259.9 MW	$ 9,742	$ 15,214

Annualized Capital Costs for All Systems by Fuel (thousand 2005 dollars)

<1 MW	$ 4,866	$ 17,085
1-4.9 MW	$ 6,250	$ 23,295
5-24.9 MW	$ 4,704	$ 17,528
25-39.9 MW	$ 9,652	$ 35,854
40-259.9 MW	$ 2,758	$ 10,534
>259.9 MW	$ 3,926	$ 14,703

Annual Non-Fuel Operating and Maintenance Costs for All Systems (thousand 2005 dollars)

<1 MW	$ 2,278	$ 6,346
1-4.9 MW	$ 2,248	$ 7,842
5-24.9 MW	$ 1,588	$ 6,235
25-39.9 MW	$ 2,267	$ 7,119
40-259.9 MW	$ 588	$ 2,308
>259.9 MW	$ 999	$ 3,921

Total Non-Fuel Costs for All Systems (thousand 2005 dollars)

<1 MW	$ 7,143	$ 23,431
1-4.9 MW	$ 8,498	$ 31,137
5-24.9 MW	$ 6,292	$ 23,762
25-39.9 MW	$ 11,920	$ 42,974
40-259.9 MW	$ 3,346	$ 12,842
>259.9 MW	$ 4,925	$ 18,624

Total Gross Fuel Costs for All Systems (thousand 2005 dollars)

<1 MW	$ 6,568	$ 25,780
1-4.9 MW	$ 11,160	$ 43,807
5-24.9 MW	$ 8,872	$ 34,826
25-39.9 MW	$ 20,262	$ 79,538
40-259.9 MW	$ 6,568	$ 25,780
>259.9 MW	$ 11,160	$ 43,807

Total Fuel Cost Savings from Displaced Heating Fuels for All Systems (thousand 2005 dollars)

<1 MW	**$ 3,273**	**$ 12,848**
1-4.9 MW	**$ 5,562**	**$ 21,832**
5-24.9 MW	**$ 4,421**	**$ 17,356**
25-39.9 MW	**$ 10,098**	**$ 39,639**
40-259.9 MW	**$ 3,273**	**$ 12,848**
>259.9 MW	**$ 5,562**	**$ 21,832**

Results	2012	2020	Units
Electricity			
TOTAL Reduction in Electricity Sales (electricity output from CHP plus avoided electricity use in boilers/space heaters/water heaters)	1,090	4,279	GWh (sales)
Reduction in Generation Requirements	1,175	4,602	GWh (generation)
Gross GHG Emission Savings	**0.59**	**2.30**	$MMtCO_2e$
Natural Gas			
Net Change in Gas Use (negative values denote increased use)	-3,214	-12,615	Billion BTU
Net GHG Emissions (negative values denote increased emissions)	**-0.17**	**-0.67**	$MMtCO_2e$
Biomass			
Net Change in Biomass Use (negative values denote increased use)	-835	-3,279	Billion BTU
Net GHG Emissions (negative values denote increased emissions)	**0.00**	**-0.01**	$MMtCO_2e$
		-204912	dry tons
Coal			
Net Change in Coal Use (negative values denote increased use)	0	0	Billion BTU
Net GHG Emissions (negative values denote increased emissions)	**0.00**	**0.00**	$MMtCO_2e$
Oil			
Net Change in Oil Use (negative values denote increased use)	0	0	Billion BTU
Net GHG Emissions (negative values denote increased emissions)	**0.00**	**0.00**	$MMtCO_2e$

NOTES AND DATA FROM SOURCES

Note 1:

From *Combined Heat and Power in the Pacific Northwest: Market Assessment*
Task 1 - Final Report. Submitted to Oak Ridge National Laboratory
This report can be found at:
http://www.chpcenternw.org/NwChpDocs/Chp_Market-Assessment_In_PNW_EEA_08_2004.pdf
Accelerated Case assumptions – 2020 cost and performance specs, no stand-by charges,
financial incentives equal to about 15% of capital costs

Note 2:

Natural gas - cell AJ53 of SEDS workbook
Coal - cell AQ53 of SEDS workbook
Electricity - to be confirmed
Oil - pet. coke, pentanes plus, residential fuel, still gas, napthas, unfinished oils - cells AK53 to AP53 of SEDS workbook

Note 3:

From *Combined Heat and Power in the Pacific Northwest: Market Assessment*

Large industrial

From Table 4-1 (Washington only)
On-site CHP Technical Potential

Food	27
Lumber and Wood	33
Paper	122
Chemicals	25
Petroleum Refining	81
Primary Metals	28
Electronic Equipment	0
Transportation Equipment	45
Instrumentation	0
	361

From Table 4-1 (Washington only)
CHP Export Potential

Food	24
Lumber and Wood	28
Paper	229
Chemicals	11
Petroleum Refining	568
Primary Metals	9
Electronic Equipment	0
Transportation Equipment	0
Instrumentation	0
	869

CHP Technical Potential 1,230

Techical Potential

Existing facilities	
Large Industrial - On-site	360
Large Industrial - Export	870
Resource Recovery	27
Small Industrial	745
Commercial	2,885
New facilities	
Large Industrial - On-site	57
Small Industrial	304
Commercial	2,473
	7,721

Food	51	MW
Lumber and Wood	61	MW
Paper	351	MW
Total	463	MW

Biomass as percentage of total technical potential	6.0%	
Amount of CHP economic potential from biomass	171	MW

Source: NW Council's Fifth Power Plan

			Capacity	
Landfill gas	100-200	aMW	176	MW
Washington % of population			51.20%	
Landfill gas in Washington			90	MW

Assume landfill gas in included in "Technical Potential" in CHP in the Pacific Northwest: Market Assessment

Landfill gas as percentage of total technical potential	1.2%	
Amount of CHP economic potential from landfill gas	33	MW

Note 4:

Economic Potential - Accelerated Case

Upper limit of system size range		Potential (MW)	
500	kW	399	14.0%
1,000	kW	678	23.8%
5,000	kW	539	18.9%
20,000	kW	358	12.6%
50,000	kW	429	15.1%
260,000	kW	444	15.6%
		2,847	

From Table 5-1		Reciprocating Engine			
Size of System (kW -	100	300	1,000	3,000	5,000
CHP Potential (M	79.8	319.2	678	323	216
		Current Technology Specifications (2000)			
Electric_Heat_Ra	11,500	10,967	10,035	9,700	9,213
Electrical_Efficie	29.70%	31.10%	34.00%	35.20%	37.00%
Installed_Cost_--	$1,350	$1,160	$945	$935	$890
Installed_Cost_--	$1,424	$1,223	$997	$986	$939
O&M_Costs	$0.02	$0.01	$0.01	$0.01	$0.01
Fuel_Input	1.15	3.29	10.04	29.1	46.07
Total_Recoverab	0.56	1.52	3.7	9.84	16.66
Economic_Life_Y	10	10	15	15	15
Net_Power_Cost	$0.08	$0.07	$0.06	$0.06	$0.05
		Advanced Technology Specifications (2020)			
Electric_Heat_Ra	10,500	10,185	8,638	8,322	7,935
Electrical_Efficie	32.50%	33.50%	39.50%	41.00%	43.00%
Installed_Cost_--	$1,000	$930	$840	$830	$790

Installed_Cost_--	$1,055	$981	$886	$875	$833
O&M_Costs	$0.01	$0.01	$0.01	$0.01	$0.01
Fuel_Input	1.05	3.06	8.64	24.97	39.68
Total_Recoverab	0.49	1.35	2.9	8	13
Economic_Life_Y	10	10	15	15	15
Net_Power_Cost	$0.06	$0.06	$0.05	$0.05	$0.05

Note 5:

Biomass/LFG/Biogas