UNIVERSITY OF HAWAIʻI AT MĀNOA

HAWAII ENERGY POLICY FORUM

Final Report On

Environmental Requirements on Energy Producers

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D R A F T

Hawai'i Energy Study Project

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Environmental Requirements on Energy Producers

Executive Summary

1. Notwithstanding current political uncertainties affecting the Kyoto Protocol process, greenhouse gas emissions and climate change are poised to become the dominant energy-environment problem facing Hawai'i and the developed world. While direct trade-offs between local environmental issues (e.g., energy facility siting) and global effects are difficult to make, even at today's depressed valuations in the global carbon market the economic (shadow) value of greenhouse gas reductions is already 5-10 times higher than other air emissions reductions in the Hawai'ian airshed.

2. It is unlikely that voluntary measures (such as the voluntary Renewables Portfolio Standard instituted in Hawai'i) will have significant impact on environmental emissions, especially greenhouse gas emissions which are invisible and not subject to easy public scrutiny. The Bush Administration's reliance on voluntary measures in its Climate Change Action Plan is not sound environmental policy – it is a recipe for continuation of business-as-usual trends. The claimed savings are based on trend-based emissions intensity reductions, but these will be quickly overwhelmed by economic growth once the economy resumes significant expansion. Pressure will mount for the U.S. to come under international emissions constraints under "Son of Kyoto."

3. There is certainly a place for voluntary action, however. This could most effectively pursued through corporate adoption of internal greenhouse gas emissions reduction targets, and the simultaneous institution of internal carbon trading mechanisms under which corporate units engage in inter-unit trading. BP, Shell and PEMEX (the Mexican oil and gas giant) have pursued this strategy with good effect. It sensitizes operational managers to the opportunities to improve efficiency and reduce emissions throughout corporate operations, provides hands-on experience in the future global business of the trading of environmental commodities, and reveals the marginal cost curve for attaining reductions. This valuation can then be entered in project evaluation in order to assess future contingent liabilities associated with long-lived energy producing and consuming capital stock.

4. In any case, the Renewables Portfolio Standard may not represent the best renewable energy policy option for the Hawai'i utility industry. RPS creates competitive pressures when there are actually multiple utilities operating in a state or service territory. In Hawai'i, only pseudo-competition with little or no internal trading of renewable energy certificates/credits would result. Hawai'i would be well advised to look into instituting a System Benefit Charge (a small levy on electricity consumption) that could fund competitively awarded subsidies for private sector development of grid-connected renewables á la the U.K. and California.

5. Hawaii's emphasis on tax credit incentives to promote renewables is also somewhat misplaced. These are well suited to stimulate uptake of small-scale and distributed clean energy sources like solar water heaters. However, they do not inspire market entry and competition for the larger scale grid-connected renewables (e.g. wind) that will be a necessary component of any longer-run energy-environment strategy.

6. Hawai’i cannot afford to put all its energy-environment eggs in the renewables basket. For reasons of geography and local opposition, renewables are unlikely to play a dominant role in the islands' utility system. The emphasis on renewably produced hydrogen fuels is similarly misplaced. Hydrogen will be the basis of the very long term sustainable energy future, but for the next 20-30 years the transition is more relevant and that will be significantly based on fuel cells (and micro-turbines) fed by hydrogen-rich gas streams derived from reformed hydrocarbons. The energy carriers of choice for stationary applications will be natural gas or coal-derived syngas.

7. Key transition energy supply options are thus LNG and coal gasification. Hawai’i would be well advised to study the experience of Puerto Rico (one LNG terminal in operation) and the Dominican Republic (one LNG terminal in operation and one under construction). Both are tourism-dependent island economies with utility system demands in the range of 1,500-2,000 MW - about the size of Hawaii's electrical demand. Shipboard-based LNG re-gasification is now being deployed commercially and could emerge as an attractive option for alleviating Hawaii's safety and siting concerns. The favorable economics of barge-based CNG distribution at distances up to hundreds of miles make this an attractive option for the neighboring islands. Greenhouse gas savings of natural gas in utility applications are typically 50-75 percent compared to conventional alternatives.

8. Coal gasification offers the promise of high-efficiency electricity generation and supply of syngas for distributed energy applications. Integrated Gasification Combined Cycle (IGCC) electricity generation technology can be readily adapted to the separation of hydrogen and CO_2 from the gas stream. Long-run viability under future greenhouse constraints will be dependent on finding an environmentally acceptable, low-cost means of CO_2 storage or disposal. Meanwhile, the Statoil demonstration project in Norway involving IGCC-based CO_2 separation and deep-sea burial has been blocked due opposition by the environmental community. Such experiments, if eventually allowed to proceed, would provide valuable learning for Hawai’i.

Hawai'i Energy Study Project

Environmental Requirements on Energy Producers

This paper briefly reviews constraints that may be placed on Hawaii's energy economy over the coming three decades, and outlines forward-looking coping strategies. It begins with a discussion of the principal environmental challenges facing the global and the Hawai'ian energy sector, then reviews some energy system fuel and technology options to address these challenges, and concludes with an analysis of policies and instruments to stimulate the coming energy transition.

Environment: A New Energy Paradigm

During the 1970s and early 1980s, the period of the oil price shocks, there were widespread fears that major fuels were running short and that a world energy crisis was impending. But the world's energy industry—particularly the private sector—proved its ability to discover reserves faster than they were used up. In the future, just conceivably, another oil price shock could happen given a bout of trouble in the Middle East, but a major supply shortage looks unlikely for the moment. The far bigger worry now is the energy-environment nexus.

Historically, energy 'revolutions' have hardly been sudden or revolutionary, requiring 40-60 years to achieve capital stock replacement and technology and fuel substitution. Nevertheless, local and global environmental mitigation, coupled with desires for economic growth and enhancement of energy security, are poised to accelerate the pace of the coming energy transition – all the more so as the underlying synergies are recognized and exploited. As a geographically fragmented, ecologically sensitive and highly energy import-dependent economy, Hawai'i faces heightened difficulties in meeting the energy-environment challenge.

Local vs. Global Environmental Externalities

Energy-related environmental problems (environmental "externalities") may be broadly classified as:

(a) Local – These are fundamentally plant-siting related and consist of impacts on surrounding land (e.g. ash disposal), water (e.g., groundwater contamination) and natural habitats (e.g., forest ecosystem disturbance), and localized air emissions (principally particulate emissions, although NOx and SOx have localized effects).

(b) Regional – These externalities typically impact an entire airshed or region, such as acid rain (a cocktail of SOx and NOx emissions).

(c) Global – Global warming and climate change is a nearly 'perfect' global externality, as the radiative forcing impacts of the major greenhouse gases – carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) – spread nearly instantaneously in the global atmosphere, result from emissions from a myriad of sources spread around the globe, and cannot be mitigated by the unilateral action of any one nation or state.

A key question to guide decision-making is the relative seriousness of these impacts, and the so-called "local vs. global" comparison has sparked a significant debate as to what phenomena are more damaging, and therefore deserve higher attention and mitigation expenditures. The answer is that there are no easy answers: Prioritizing local vs. global environmental problems boils down to attempting to analyze the synergies and trade-offs, maximizing the former and minimizing the latter.

In terms of air emissions, the following are the key observations:

- Many processes that address local air emissions (particularly end-of-pipe solutions like filters) have no or slightly negative effects on energy plant efficiency and hence global greenhouse gas (GHG) emissions.

- However, the converse is true: Almost all fuel and technology substitutions that reduce GHG emissions have a parallel and positive impact on local/regional air emissions.

The implication is that a cost-effective greenhouse gas emissions reduction strategy will simultaneously help address local air pollution problems.

The key potential trade-off is between reducing local and global air emissions on one hand and, on the other, creating conflicts between energy production facilities and the surrounding natural and human milieu. Evaluation of these trade-offs is beyond the scope of this paper, as for example examining the safety risks posed by an LNG terminal vs. oil tankers would consume years and volumes. Relative environmental seriousness of various fuel/technology combinations is therefore gauged in the next section through a look at values associated with various air pollutants.

Valuing Local/Regional Air Emissions Externalities

Valuing local/regional air emissions impacts is an inexact science based on decomposing a chain of emission, concentration, dose-response, impact and economic valuation data. However, 1997 studies performed for the three Hawai'ian electric utilities provide an estimate of unit damage values for Oahu, Maui and the Big Island (Hawai'i), as shown in Table 1:

Table 2.1 Mid-Range Estimated Damages from Air Pollutants Without Adjustment for Emission Fees

Pollutant	HECO	MECO	HELCO
Damages in Dollars Per Ton			
NO_x	$ 9.95	$ 5.28	$ 2.12
SO_2	$ 20.52	$ 10.25	$ 5.09
PM 10	$ 1,280.02	$ 706.21	$ 284.34
Damages in Cents Per KWh			
All	0.005-0.044	0.004-0.026	0.002-0.011

ERG 1997, 5-36 to 5-37

These damage valuations estimates may be compared with those derived in a 1999 study conducted by the The Gas Company, shown in Table 2:

Table 2.2 TGC's Proposed Greenhouse Gas and Air Emissions Externality Values Per Ton of Emissions

	Greenhouse Gases		Criteria Air Pollutants				
Estimate	CO_2	CH_4	NOx	SOx	PM_{10}	CO	VOC
Low	$ 10	$ 210	$ 3	$ 4	$ 162	N/A	N/A
Mid	$ 27	$ 567	$ 8,100	$ 1,913	$ 4,162	$ 1,080	$ 6,683
High	$ 77	$ 1,617	$ 18,147	$ 9,304	$ 59,668	$ 11,653	$ 8,659

TGC 1999, 5-13

There are wide variances between the utility company's and gas company's estimates. Particularly with respect to damage valuations for SOx and NOx, the utility central scenario appears to correspond most closely to TGC's "Low" scenario. However, when translated to the common denominator of impact on electricity costs (damages expressed in cents per kWh equivalent), the largest contributor will be found to be particulates (PM_{10}). A rule-of-thumb figure for the valuation of local/regional air externalities in Hawaii's clean and tradewind-swept airsheds is on the order of 0.10 cents per kWh or less.

Valuing Global Greenhouse Gas Emissions

Although perhaps an equally uncertain exercise as for local environmental phenomena, numerous studies that assign a dollar cost to global carbon emissions exist in the economic literature. Although there are still uncertainties [1/] and wide ranges [2/], the use of $25/tonne carbon (~$6.80/tonne CO_2) as a reasonable estimate for the shadow price of carbon emissions is consistent with the existing work by many experts:

- Anderson et al. (1990, 1993) estimated a $25/tC shadow price using a carbon accumulation-backstop technology model based on the Hotelling rule;
- Fankhauser (1995, 1996) estimates a global damage function for climate change, and derives a range of $6-45/tC shadow price, with a best estimate of $20/tC;
- Simulations of the global carbon offset market performed by the Norwegian research group, ECON, the Massachusettes Institute of Technology and U.S. DOE (Battelle) indicate a future market price for carbon of $10-30/tC under an unrestricted trading regime with all Annex I (OECD + Economy-in-Transition) parties participating, with a central figure of $25/tC (see Table 3).

Table 3: Global Carbon Market Simulations

Marginal Costs of Abatement ($/tonne carbon)

Scenario	MIT (2010, 1985$)	PNL (2010, 1992$)
Independent Compliance	$584- Japan $273- EU $186- USA $233- other OECD	$458- Japan $350- Canada $168- USA $117- Australia
Annex I Trading	$127	$105 (monopolistic) $73 (competitive)
Global Trading	$24	$26

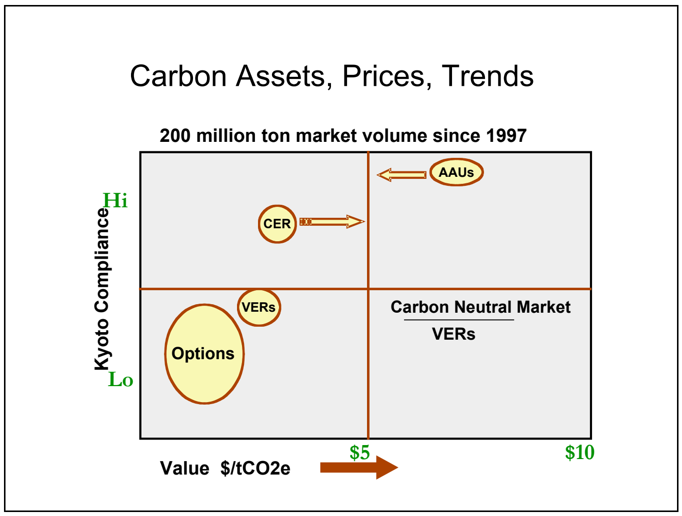
Most of recent valuation work has focused on the implications for the global carbon market of the recent agreements reached on the implementation of the Kyoto Protocol. The agreement on the carbon trading mechanisms, including International Emissions Trading (IET), Joint Implementation (JI) and the Clean Development Mechanism (CDM), has established an emerging market. However, the size and growth of that market is uncertain at this juncture given the significant allowance for carbon sinks (land-use and

1/ Perhaps the largest uncertainty factor is the discount rate used for future global damages from climate change.

2/ In its 1995 assessment, IPCC estimated a global damage function equivalent to $5-125 per tonne of carbon.

forestry-based activities) in net emissions accounting, the large excess of "hot air" (excess emissions credits stemming from the post-1991 economic transition) in Russia, the non-participation of the United States, and the possibility that the Kyoto Protocol will not enter into force. The net implication of these developments is that actual market prices are currently about 1/4th the previously expected levels, i.e. at levels of $5-10/tonne carbon (see Figure 1) instead of the previously forecast $25-30/tC. This is consistent with the quadratic nature of the of global carbon offset supply and demand functions, and the fact that the U.S. is estimated to account for almost half of the global demand for purchased carbon offsets.

Figure 1: Current Global Carbon Market Prices and Trends



However, the $25/tonne carbon figure emerging in international markets will not necessarily represent the marginal cost of GHG emissions abatement that will eventually be faced by OECD utility and industrial entities, including in Hawai'i. The above simulations of the global carbon markets, in which low-cost carbon offsets sourced in developing countries through the CDM clear the market at low prices, assume high market liquidity and unconstrained market access. In reality, for reasons of business strategy, risk, and carbon offset supply constraints, U.S. domestic entities will choose to purchase only a portion of their GHG reduction needs from international carbon markets, with the balance derived from within-the-company measures or more limited domestic trading. This more corresponds to the "Annex I" scenario in Table 3, or marginal costs of abatement in the range of $75-125/tonne carbon and up.

These GHG emissions abatement costs may be translated into the common yardstick of impact on electricity costs for purposes of comparison with local externality valuations. However, the cents/kWh impact of carbon emissions depends importantly on the fuel and conversion technology employed; this calculation is performed in Table 4 for a range of current and possible future Hawai'i energy chains. The carbon impacts associated with current Hawai'i coal utilization (atmospheric fluidized bed combustion) ranges from 0.6 to 2.3 cents/kWh over GHG emissions abatement costs of $25-100/tonne carbon, and for oil-fired steam plants the equivalent figures are 0.5 to 1.9 cents/kWh.

The conclusion is that over a wide range of plausible externality values in Hawai'i for local and global externalities, global greenhouse gas effects dominate in the industrial and utility sectors. This is consistent with findings over much of the industrialized world. Figure 1 depicts the results of a World Bank study that compares local vs. global externality values in six major industrializing cities in Asia and Eastern Europe. Only in the case of small and mobile point sources – which are the major contributors to degraded air quality in highly polluted cities – do local effects outweigh global ones. For that reason,

Table 4:

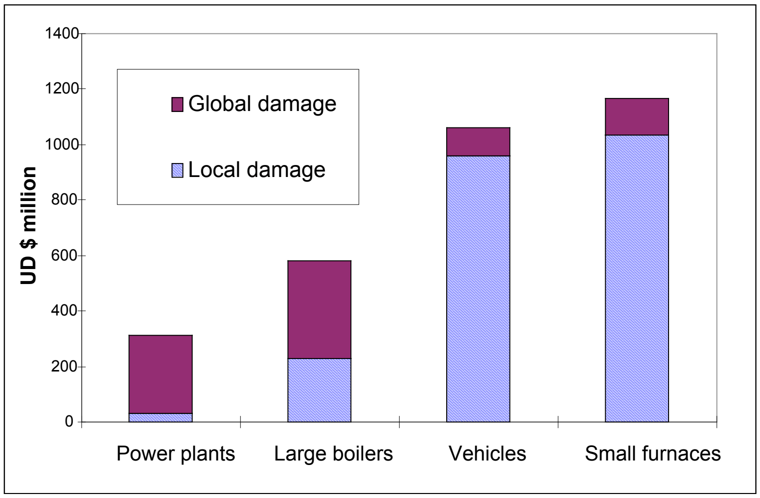
Electricity Pathways and Carbon Emissions Impacts

Fuel	Carbon Content (tons C / 10^9 BTU)	Relative Carbon Content (%)	Conversion Technology	Electricity Cycle Efficiency (%)	Cogeneration Cycle Efficiency (%)	Carbon Emissions/kWh (tons C per MWh)	CO2 Emissions/MWh) (tons CO2 per MWh)	Relative Carbon Emissions (%)		Carbon Cost/kWh at Assumed $/ton Carbon Value (cents/kWh) $15	$25	$50	$100	$150
Coal	25.71	100%	Pulverized Coal	35%		0.251	0.919	100%		0.376	0.627	1.253	2.506	3.760
			AFBC	38%		0.231	0.846	92%		0.346	0.577	1.154	2.308	3.463
			Supercritical	41%		0.214	0.785	85%		0.321	0.535	1.070	2.140	3.209
			IGCC (present)	42%		0.209	0.766	83%		0.313	0.522	1.044	2.089	3.133
			IGCC (next generation)	47%		0.187	0.684	74%		0.280	0.467	0.933	1.866	2.800
Coal SynGas			Molten Carbonate Fuel Cell	50%	75%	0.175	0.643	70%	47%	0.263	0.439	0.877	1.754	2.632
			Solid Oxide Fuel Cell	45%	70%	0.195	0.715	78%	50%	0.292	0.487	0.975	1.949	2.924
Fuel Oil	19.95	78%	Oil-Fired Steam	36%		0.189	0.693	75%		0.284	0.473	0.945	1.891	2.836
LNG	14.47	56%	Combined Cycle Turbine	54%		0.091	0.335	36%		0.137	0.229	0.457	0.914	1.371
			Phosphoric Acid Fuel Cell	40%		0.123	0.453	49%		0.185	0.309	0.617	1.234	1.851
			Molten Carbonate Fuel Cell	60%	85%	0.082	0.302	33%	23%	0.123	0.206	0.411	0.823	1.234
			Solid Oxide Fuel Cell	55%	80%	0.090	0.329	36%	25%	0.135	0.224	0.449	0.898	1.346

Source: EIA, EPA, HNEI/SENTECH

present lower costs of GHG abatement in large point sources compared to small/mobile sources, and the ease of monitoring large sources, the utility sector will be the first target of global greenhouse gas emissions reduction efforts. The next section examines the nature of the greenhouse gas problem.

Figure 1: Local vs. Global Energy Externality Values:
Case Study Results from Six Cities



The Climate Change Problem

Global climate change is perhaps the least quantitatively understood, but also potentially the most devastating result of modern energy use. Most scientific experts agree that climate change induced by human activity is occurring and that further change is inevitable. The *Third Assessment Report of the Intergovernmental Panel on Climate Change* (IPCC 2001) concludes that "most of the observed warming over the last 50 years is likely to have been due to the increase in greenhouse gas (GHG) concentrations." The question is not whether climate will change in response to human activities, but rather where (regional patterns), when (the rate of change) and by how much (magnitude).

Pre-industrial concentrations of CO_2 were 280 ppmv; today they are 371 ppmv. About 75 percent of the cumulative GHG emissions during the past 150 years have been emitted by industrialized countries.[3/] Between 1990 and 2100, global temperatures are projected to increase between 1.4 and 5.8 degrees Celsius. Even if greenhouse gas emissions were to stabilize at present levels, it is expected that average temperatures and sea level would continue rising for centuries.

Given the uncertainties surrounding the level and timing of climate change damages, there are multiple possible targets for an upper limit on greenhouse gas concentrations in the atmosphere. As shown in Table 5, associated with any given long-term stabilization target are multiple time paths of emissions rates. Each emissions path is in turn associated with a particular time horizon for action. For example, an aggressive target (450 ppmv atmospheric CO_2 concentration) implies an immediate reduction in global emissions. Less ambitious targets generally imply first reducing the growth rate in emissions, followed by a time in which allowable emissions reach a peak level and then follow a declining trajectory to the long-term sustainable level.

3/ The 150 year timeframe corresponds to the approximate atmospheric residence time of carbon dioxide.

Table 5: Time Horizons for Climate Change Action

Stabilization of atmospheric concentrations of CO_2 will require emissions reductions globally
(IPCC 2001)

Stabilization Level (ppm)	Date for Global emissions to peak	Date for global emissions to fall below current levels
450	2005-2015	2000-2040
550	2020-2030	2030-2100
650	2030-2045	2055-2145
750	2050-2060	2080-2180
1000	2065-2090	2135-2270

These dates are associated with CO_2 stabilization alone – stabilization of CO_2 equivalent concentrations need to occur even earlier because of the contribution of the non - CO_2 greenhouse gases

Despite the multiplicity of options, one thing is clear: In order to stabilize atmospheric concentrations of CO_2, emissions must be brought down below the level of natural absorption of greenhouse gas emissions in the earth's carbon cycle – this is equivalent to a 90 percent cut in the level of today's emissions. This is the level to which emissions would eventually need to be returned to meet the United Nations Framework Convention on Climate Change (UNFCCC) goal of "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."

The Kyoto Protocol

The Kyoto Protocol to the UNFCCC was adopted on December 11, 1997, and, if it enters into force, will result in binding carbon emission reduction limitations amongst thirty-nine developed countries and countries with economies-in-transition. Industrial countries must reduce their CO2 emissions an average 5.2 percent below their 1990 levels by the end of the first "commitment period" (2008-12). The Protocol will enter into force 90 days after ratification by 55 countries accounting for at least 55 percent of industrial country (Annex I) 1990 CO_2 emissions.

The Protocol has been criticized as containing unrealistically severe emission reduction requirements in the short-term, whereas analyses as shown above imply that smaller cuts can be accepted now so long as deeper cuts occur later. However, a key feature of the Protocol – the so-called "flexibility" provisions allowing industrialized countries to partially meet their obligations through ability to trade carbon reductions among countries ("international emissions trading"), and to jointly implement projects which can lead to carbon reduction on a project basis by reducing emissions or improving sinks ("joint implementation" or "JI") – is now widely supported on both sides of the Atlantic (see Table 6) and will likely be incorporated in any re-working or successor agreement to Kyoto. Joint Implementation involving developing country Parties (who have no emissions reduction obligations but can sell emission reductions below an established project baseline) can take place under the Clean Development Mechanism (CDM), with crediting being allowed after the year 2000.

Table 6:

Current or projected national policies

	Trading mechanism?	*Start-up*
EU	*Yes*	*2005*
UK	*Yes*	*2001*
France	*Yes*	*2003?*
Norway	*Yes*	*2005 or earlier*
Germany	*No*	▯
Denmark	*Yes*	*2001*
Sweden	*Yes*	*2005 or later*
Netherlands	*Ongoing work*	▯
Finland	*Ongoing work*	▯
Ireland	*Ongoing work*	▯
Australia	*Yes*	*US dependent*
USA	*Yes*	*?*
Canada	*Yes*	*US dependent*
Japan	*Ongoing work*	▯
New Zealand	*Yes*	*Not decided*
Russia	*No*	▯

As of December 2002, the European Union, Japan, Canada, Norway, New Zealand and most of the Central and Eastern European economies have ratified; they account for 43.9 percent of Annex I emissions. The U.S. (36.1 percent of Annex I emissions) and Australia (2.1 percent) will almost certainly not ratify. Of the remaining Parties yet to ratify, Russia is by far the most significant; with 17.4 percent of Annex I emissions their ratification would put the Protocol into force. Russia announced its intention to ratify at the Johannesburg Summit in October 2002, however internal debate on economic consequences is delaying a decision in the Duma until, many observers believe, Fall 2003. Russia stands to gain billions of dollars in hard currency through "hot air" sales; the main strategic choice is whether she would do better by banking the credits and selling them at a time when U.S. entry into the global emissions market will raise prices. Complicating Russia's decision is the heavy political pressure the U.S. is known to be exerting on Russia not to ratify, balanced against the close political and trading relationships Russia wishes to maintain with the EU who is pressuring Russia to ratify.

Thus there remains, at this writing, reasonable doubt as to whether the Kyoto Protocol will enter into force; if this does not occur by the end of this year then Europe will likely implement regional agreements on the road towards a new negotiating effort to adopt a "Son of Kyoto." For its part, the Bush Administration has proposed its own national Climate Change Action Plan. This is analyzed in Annex 1 and is found to not be a viable alternative to the Kyoto Protocol in terms of required environmental impact and effectiveness.

Regardless of the fate of the Kyoto Protocol, pressure will mount for the U.S. to take active measures to restrain its growing GHG emissions. In January, 2003, Sens. McCain and Lieberman tabled an alternative plan to require all U.S. power plants and industries to reduce their emissions of CO_2 and other GHGs. The McCain-Lieberman proposal would establish a nationwide cap, and all major energy, industrial and transportation sources would have to limit their emissions to 2000 levels by 2010 and 1990 levels by 2016. The bill would establish a trading system that would allow utilities and plants with excessive emissions to buy credits from more efficient or less emissions-intensive companies that have reduced emissions beyond their targets. A similar SO_2 emissions trading system has operated for years under the Clean Air Act, and the McCain-Lieberman proposal represents a domestic-level implementation of the international system proposed under the International Emissions Trading provision of the Kyoto Protocol. The proposal enjoys support of a number of large utility and industrial players who have federated under the aegis of the Pew Center on Global Climate Change. In addition to U.S. national moves, as shown in Table 7 a number of states have adopted regulations with similar aims.

Table 7:

Regional GHG Regulations in the U.S.

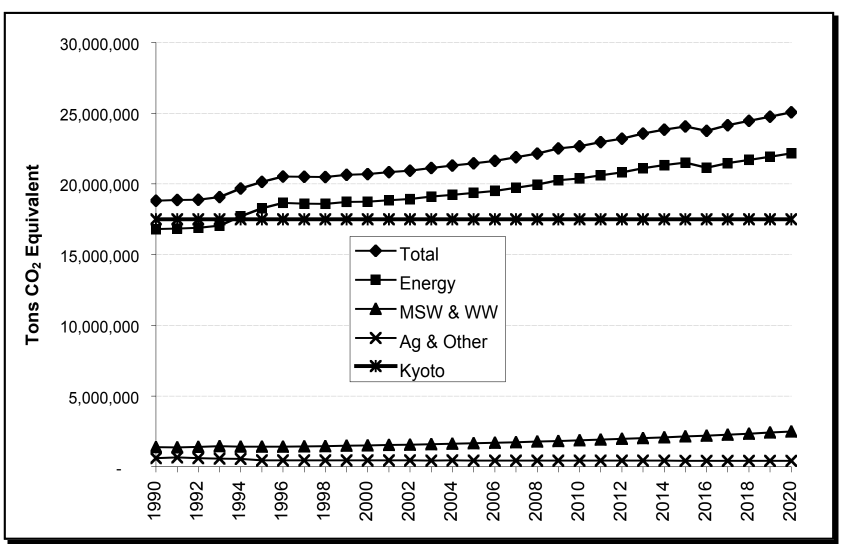
- **Oregon:** CO_2 emissions standard for new energy utilities. Price cap: $0.57/tCo2. Utilities can offset emissions using project based mechanisms.
- **Washington:** New plants must demonstrate the use of best available techniques for CO_2 emissions control.
- **Massachusetts:** CO_2 emissions cap for energy utilities effective in 2005. Utilities can offset excess emissions using project-based mechanisms.
- Near future: New York?

The conclusion is that while U.S. action on climate change will be delayed, planning for an indefinite suspension of the application of binding greenhouse emissions constraints is not a wise bet. Initial U.S. commitments, likely to be adopted over the next five years, will take the form of a national cap-and-trade system focusing on large industries and utilities, with possible extension to trading partners such as Canada and Australia.

Hawai'i Energy-Environment Pathways

The above noted environmental constraints – whether Kyoto-based or modeled on an alternative emissions limitation framework – imply a significant departure from business-as-usual for Hawaii's future energy development. This can be clearly seen from DBED projections for statewide greenhouse gas emissions, as summarized in Figure 2.

Figure 2: Hawai'i Present and Projected GHG Emissions



By 2010, the state's energy sector is projected to already be approximately 19 percent above its notional Kyoto target 1990 level, and under the trend-based scenario by 2020 this would rise to about 32 percent above the 1990 benchmark. In addition, given that Hawaii's energy use per capita ranked the lowest in the United States, and energy/GDP ratios that have been generally declining over the past decades, it may not be possible to significantly improve end-use energy efficiency and reduce energy demand through local actions.

Energy-environment pathways examined in this review boil down to three: (a) a renewables-intensive scenario, (b) an LNG-intensive scenario, and (c) a syngas-intensive scenario. While each representing a quite different option, it would be a mistake to consider them mutually exclusive and the optimal path will almost certainly be composed of a mix: Expanding renewable energy is virtually a must in any rational, hybrid strategy. Yet, as will be seen, there are limits to the potential penetration of renewables in the state's energy mix and Hawai'i cannot afford to put all its energy-environment eggs in the renewables basket.

Besides the environmental imperatives, there are other good reasons for Hawai'i to adopt a balanced and diversified, low-carbon energy strategy. One is the resulting reduction of vulnerability to external shocks through fuel and source diversity. Reducing vulnerability to external shocks through diversifying fuel types and sources is akin to portfolio diversification well known to investors. Planners need to not only evaluate the security of individual supply chains, but also the riskiness of their energy supply portfolio against the vagaries of energy markets. The contribution of new and renewable resources is also increasingly seen from an energy security perspective. Recent work extending modern portfolio theory to renewables shows that the reduction in risk through the introduction of some amount of renewables often outweighs the direct costs of even non-least cost renewable sources. Significantly, these same analyses indicate that the optimal proportion of renewables is higher than current levels of deployment in many jurisdictions.

The term "distributed energy" characterizes many of the anticipated future energy supply paths. Centralized energy infrastructure efficiently exploits economies of scale in construction and operation, and when adequately designed and maintained, has compiled an enviable record of technical reliability. However, large-scale centralized facilities are also perceived to be vulnerable to large-scale catastrophe and loss. In addition, technological change – initially in the form of combined cycle gas turbines but in the longer-term through efficient micro-turbines, fuel cells and sunlight-to-electricity converters as complements to large central facilities – is redefining the scale at which efficiency and economy can be captured. Many of the distributed energy technologies are inherently low-emission. In parallel, these distributed resources provide inherent security advantages through their modularity and geographic diversity. In this connection, it is interesting to recall that the Internet was initially developed as a fault-tolerant, distributed network to provide highly secure communications.

The Hydrogen Economy: Long Term Dreams vs. Short Term Realities

Many Hawai'i low-emission energy futures specifically envision a relatively rapid transition to a hydrogen-powered energy economy, and particularly a future in which hydrogen is primarily derived from renewable sources such as through solar-electric electrolysis. However, to a large extent this emphasis is misplaced. In many respects hydrogen is a near-perfect fuel but it has some troublesome properties:

- Potentially dangerous—explosive and invisible flame
- Very low fuel density—one-third of natural gas
- Very difficult to store and transport
- Not a natural fuel but a fuel carrier

- Expensive to manufacture by any means
- Ineffective fuel in traditional combustion technologies due to high NOx formation and low mass of fuel
- Lack of any large-scale hydrogen infrastructure
- Lack of greenhouse gas emissions is overstated on a full-cycle basis if origin of hydrogen is from fossil fuels (the bulk of hydrogen today is produced this way)

There is a small hydrogen economy today, about half of it based in the United States. The production of hydrogen is as an off-gas captured and utilized in the refinery and ammonia industries. Estimates of the cost of hydrogen production through renewable electricity-powered electrolysis range from $18-25/MMBTU equivalent (based on electricity at 6.9 cents/kWh) and up (Dr. Robert Williams, Princeton Environmental Institute estimates), even if the required volume of renewable generators could be installed, and this does not encompass the added costs of storage and transport. This compares to landed LNG costs in the Caribbean at long-term contract prices in the range of $5.00-6.00/MMBTU with re-gasification costs included; Hawai'i would face similar prices in arrangements with East Asian suppliers. Hydrogen production through centralized steam methane reforming is a more reasonable proposition: Based on LNG at $6.00/MMBTU an $85 million reformer plant could produce hydrogen at about $11.00/MMBTU (Cambridge Energy Research Associates estimates). The latter figure may become competitive in the future as the efficiency of fuel cells increases and their costs drop, thus closing the life-cycle cost differential with natural gas as the environmental premium rises.

While hydrogen will be the basis of the very long-term sustainable energy future, for the next 20-30 years the transition is more relevant and that will be significantly based on fuel cells (and micro-turbines) fed by hydrogen-rich gas streams derived from steam-reformed natural gas or oxygen-blown gasified coal. The energy carriers of choice for stationary applications will be natural gas or coal-derived syngas. Initially, reforming of the gas to hydrogen will take place in the front section of the fuel cell as in current phosphoric acid fuel cell technologies. Molten carbonate fuel cells now in commercial production can use hydrocarbon fuels directly without needing to first produce hydrogen in an external fuel processor.

Hawaii's hopes to capitalize on the introduction of the hydrogen economy by playing a large role in local fuel cell manufacture also seem misplaced. Current manufacturing scale-up plans among the major technology developers (e.g., Ballard, General Motors) are focusing on cost reduction through large-scale, capital-intensive factories producing fuel cell stacks in micro-thin layers under significantly automated processes. As the stacks will constitute a greater and greater proportion of the value in the fuel cell manufacturing chain as the industry shifts out of research and small-scale production, the potential comparative advantage of Hawai'i as a production site fades. An analogy can be made to Hawaii's situation with respect to refrigerators and air conditioners: There is a 'fridge in every home and an air-con unit in every office building, but no local manufacture. Rather, Hawai'i should concentrate on developing a capacity to efficiently install the balance of system and support infrastructure associated with fuel cells, and on developing the service and stack materials recycling capabilities that will be demanded by this new energy capital.

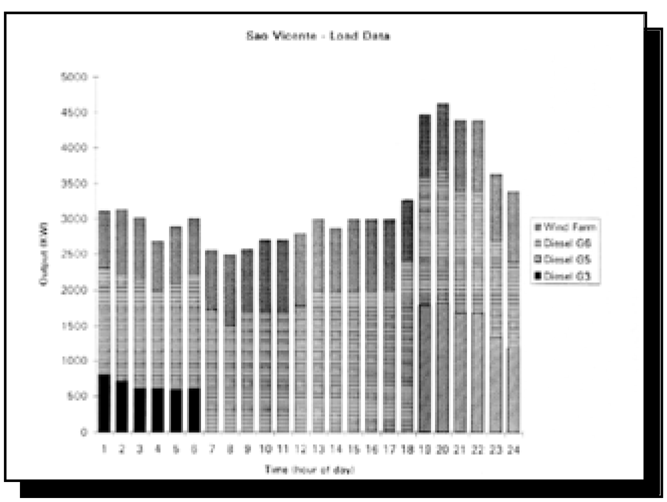
<u>Renewables Intensive Scenario</u>

It is often commented that Hawai'i is blessed by an abundance of renewable energy resources, particularly the sun, waves, ocean thermal gradients, biomass, geothermal and wind. This is patently true and Hawai'i should adopt appropriate market stimulation policies (reviewed in the final section of this paper) to exploit these opportunities. At the same time, it must be realized that Hawai'i faces a number of constraints to renewable energy resource development:

- Major resources (especially geothermal on the Big Island) are located away from the major load center of Oahu
- Large scale development of many resources such as geothermal, biomass (see Annex 2) and wind faces strong local opposition due to the ecological and cultural sensitivity of potentially affected sites
- A lack of major water impoundment schemes limits the ability of hydropower to store or complement the output of intermittent renewable resources such as wind and solar
- Similarly, the small and isolated nature of Oahu's main grid and of the neighbor island grids effectively eliminates the possibility of power banking and trading with grids having complementary seasonal and diurnal power demand and dispatch characteristics.
- The current installed generation capacity on Oahu is composed primarily of coal- and oil-fired steam units with high thermal and mechanical inertia and consequent poor load-following characteristics needed to integrate increasing amounts of intermittent renewables.

Assuming that large-scale baseload renewable options such as geothermal and biomass are constrained by a combination of land premia and transmission costs, the most viable near-term prospect for large scale development would appear to be wind power, and later, solar. However, engineering rules of thumb commonly dictate that no more than approximately 10-15 percent of total generation installed capacity can consist of intermittent sources so as to avoid dispatch failure and dynamic system instabilities. In order to accommodate increasing amounts of intermittent renewable sources such as wind, Oahu would need to increase the percentage of fast-responding conventional generation plant on the grid system. In this connection, it should be noted that gaseous fuels and Brayton cycle turbo-machinery (either simple-cycle peaking turbines or, more commonly, combined cycle gas turbines) are great friends of intermittent renewables due to their superior flexibility and load-following characteristics. Thus, the LNG option outlined below is particularly synergistic with renewables. The Oahu utility authorities would be well advised to initiate detailed dispatch simulations (using PSS/E or similar tools) so as to establish a plausible upper limit on the quantity of intermittent renewables that could be accepted under baseline least-cost generation expansion and dispatch plans, and under alternative, "renewables-friendly" generation resource scenarios.

Figure 3: Wind-Diesel Dispatch on San Vincente, Cape Verde



On the neighboring islands, the situation is perhaps more open to renewables development as a fraction of load, given that scale effects suggest that medium- and slow-speed diesel sets are a viable generation expansion option. Modern, multi-megawatt diesel sets are achieving impressive efficiencies while at the same time providing good part-load operational response. Real-world experiments such as in the wind-blessed island nation of Cape Verde (see title page picture) are demonstrating stable grid operations at 25-35 percent wind energy penetration, with the goal of the local utility being to achieve 45-50 percent penetration in the near future. Figure 3 depicts the high fraction of wind being dispatched in coordination with diesel on a representative day on one of the three main islands of Cape Verde.

<u>LNG-Intensive Scenario</u>

Liquified natural gas (LNG) represents an increasingly feasible and attractive option for Hawai'i's energy supply. LNG can be sourced on long-term contracts from an increasing number of supply points having sea communications with Hawai'i, including East Asia (Indonesia and Singapore) and South America (LNG export terminals for Bolivian and Peruvian gas in advanced stages of planning). The economics and minimum-scale requirements of LNG import and re-gasification terminals are also improving; plants supplying the equivalent gas consumption of a 2,000 MW combined cycle gas turbine are now considered fully viable.

Gas is virtually free of particulate and sulfur emissions; the main air emissions concern, NOx, can be controlled to acceptable levels through commercially available low-NOx burner or selective catalytic reaction (SCR) technologies at installed costs of approximately $50-75/kW. Greenhouse gas savings of natural gas in utility applications are typically 50-75 percent compared to conventional alternatives.

The experiences of Puerto Rico and the Dominican Republic are instructive. Both are tourism-dependent island economies with utility system demands in the range of 1,500-2,000 MW – about the size of Hawaii's electrical demand. In 1997, Puerto Rico accepted an offer for a privately financed, $670 million LNG project located on the south coast of the island comprised of: (a) an LNG import terminal consisting of a marine unloading terminal, two above-ground LNG storage tanks totaling one million barrels capacity, and vaporization systems; (b) a 507 MW cogenerating combined cycle power plant; and (c) a desalination plant capable of producing approximately 2,000,000 gallons per day of potable water. The LNG is sourced from Trinidad, and all the electric output is sold to the Puerto Rico Electricity Authority, whose system was formerly 98 percent imported oil-fired. The scheme has been operating since August, 2000, and plans are being advanced to extend the gas pipeline to existing thermal power plants to further back-out oil consumption.

The Dominican Republic has had a history of chronic electricity generation shortfalls as a consequence of poor utility sector management in an otherwise booming economic environment of high growth. While the distribution sector remains in dire financial condition, generation constraints have now been resolved principally through private sector-led investment in LNG and combined cycle (CCGT) technology. The D.R. began importing LNG from BP's facilities in Trinidad and Tobago in October, 2002. The initial plant constructed consists of a $550 million re-gasification plant and 500 MW CCGT station in Punta Caucedo. A second private project, a $340 million LNG import terminal, re-gasification facility, pipeline and 300 MW dual fuel-fired (natural gas and No. 2 oil) CCGT power plant located near Santo Domingo, will come on line later this year. A useful review of the Caribbean islands' gas market development is found in an OLADE (the Latin American Energy Development Organization, headquartered in Quito, Ecuador) report, "Incorporating Natural Gas into the Energy Matrix of the Caribbean" by Guillermo Torres.

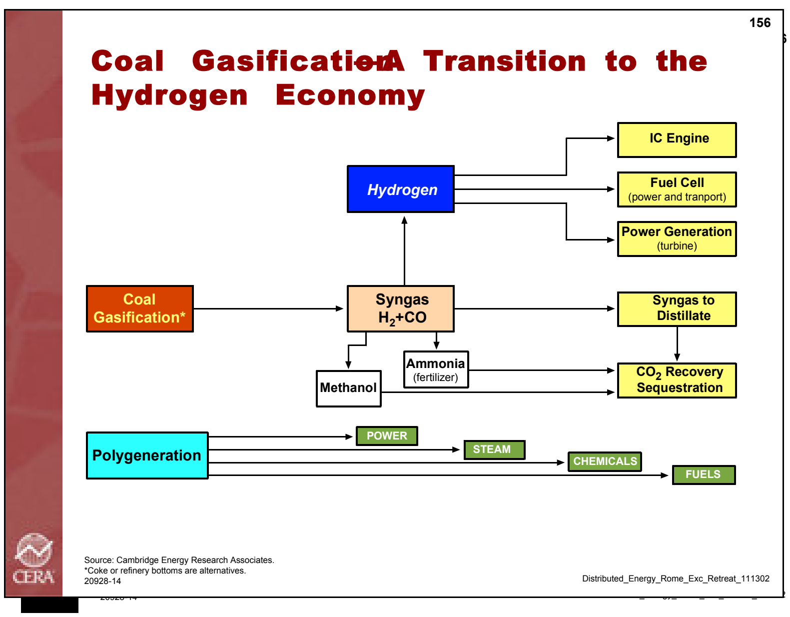
Safety and land-use/siting issues (an LNG terminal plan studied by the East-West Center some 10 years ago was estimated to require 190 acres) are principal constraints to the introduction of LNG to Hawai'i. However, shipboard-based LNG re-gasification is now being deployed commercially (see <u>Oil and Gas Journal</u>, December 2, 2002) and could emerge as an attractive option for alleviating the concerns of

Hawai'ians. The favorable economics of barge-based CNG distribution at distances up to hundreds of miles make LNG an attractive option for the neighboring islands.

Syngas-Intensive Scenario

A final and somewhat more speculative energy option for Hawai'i is the use of gasified coal to provide a bridge to a low-emission energy future, and to serve as the basis for a transition to a long-term hydrogen economy. Coal gasification offers the promise of high-efficiency electricity generation (current generation commercial demonstration plants are 41-43 percent efficient; next-generation plants are projected to attain 46-49 percent efficiency) and the supply of synthesis gas ("syngas") for distributed energy applications. Oxygen-blown integrated gasification combined cycle (IGCC) electricity generation technology can be readily adapted to the separation of hydrogen and CO_2 from the gas stream. Outside of power production environments, where high gasifier-power train integration and mass/energy balancing present tricky but not insurmountable operational challenges, coal gasification is a highly reliable, proven technology. China's ammonia (for fertilizer) industry depends on coal gasification, and nearly 20 large-scale gasification plants based on the Texaco oxygen-blown process are presently in commercial operation there. Figure 4 depicts possible energy migration paths based on coal gasification.

Figure 4:



Long-run viability of coal gasification power and fuel production schemes under future greenhouse constraints will be dependent on finding low-cost means of CO_2 storage or disposal. For continental regions, the main alternatives being studied are storage in depleted oil and gas wells, in coal-bed methane seams, or through injection in depleted aquifers. For Hawai'i, the same rapid coastal drop-offs that may someday provide favorable conditions for ocean thermal energy conversion may lend themselves to deep-sea burial of captured CO_2. Meanwhile, the planned Statoil demonstration project in Norway involving IGCC-based CO_2 separation and deep-sea burial was blocked by the Norwegian Ministry of Environment in August 2002 due to opposition from environmentalists who fear negative impacts on marine ecosystems, and due to legal concerns under the international marine treaty framework. Similarly, Hawaii's Coalition Against CO_2 Dumping has prevented two attempts to test the disposal of CO_2 off the coast of the islands. Analysts also suggest that the green movement remains opposed because it fears that sequestration of CO_2 will prop-up the global fossil fuel industry and distract attention from efforts to move towards a low-carbon economy, such as through renewable energy.

Policy Options for Environmental Mitigation

Given the environmental challenges outlined above and the consequent requirements for large-scale deployment of new technologies, it is quite apparent that Hawaii's energy-environment goals cannot be met under current trends and that specific new policies will have to be enacted in coordination with movements at the U.S. Federal and even international level. This section reviews and evaluates a set of relevant options and instruments.

Classification of Instruments

Reducing pollution damages beyond the level of "win-win" (the level obtained when only pure economic efficiency measures are taken into account) implies that somebody—whether polluters, consumers, or society at large—must bear the cost. For many externality problems the financial cost of abatement is small compared with the value of health and environmental damages avoided. For example, bag-house or electro-static precipitators in thermal power plants and large industrial boilers are highly cost-effective, since particulates typically impose the largest health damages and the abatement cost per ton is low. "Polluter pays" policies are also necessary to induce the development and marketing of less polluting technologies. However, without real incentives, technical change favoring cleaner fuels and technologies, renewables, and demand-side management, will not happen.

There are three clusters of policies available to reduce pollution damages: incentive-based policies, regulatory (or command and control) policies, and public awareness ("voluntary") policies. They are not mutually exclusive, and combinations of policies often work best. Some represent more politically acceptable approaches, although at varying costs and efficiency.

Instruments for Emissions Control

	Price	***Quantity***	***Technology***
Incentive-based			
Direct	• Emissions charges • Product charges	• Tradable emissions permits	• Technology taxes/subsidies
Indirect	• Fuel taxes • Performance bonds	• Tradable input or production permits	• Subsidies for R&D and fuel efficiency
Regulatory or "command-and-control"			
Direct		• Emission standards	• Mandated standards on control technologies
Indirect		• Land use zoning • Bans and quotas on products, fuels	• Efficiency standards for inputs or processes
Public Awareness		• Timely public *disclosure* of pollution levels; firm-level performance ratings; firm-level emissions; health and ecological impacts of pollution.	

Renewable Energy Support Mechanisms

There are numerous mechanisms in operation at state and national levels that have been pioneered in the United States and Europe. These are extensively reviewed in Annex 3 and highlighted below.

Tax Incentives

Tax credits/accelerated depreciation allowances encourage investment in new renewable energy equipment by assisting in the initial development of a market. As the market grows, equipment suppliers realize lower unit costs through economies of scale and lowered transactions costs. The tax incentive might be viewed negatively as a government intervention in the market economy, however, in cases where market barriers prevent the deployment of new and renewable energy technologies, i.e. where the market fails to provide an outcome that maximizes net benefit for society, a temporary intervention such as a tax incentive might be necessary to deal with the externalities effectively. Experience in, *inter alia*, the U.S. demonstrates that such subsidies are most effective if they are time-bound, consistently applied over time and linked to actual project performance. In general, tax credits are administratively low cost. They are well suited to stimulate uptake of small-scale and distributed clean energy sources like solar water heaters. However, they do not inspire market entry and competition for the larger scale grid-connected renewables (e.g. wind) that will be a necessary component of any longer-run energy-environment strategy. When tax credits have been applied for this purpose they have led to severe market distortions and poor performance, as with the 1980's California wind-machine tax shelters where owner/operators became essentially indifferent to actual power produced.

Production tax credits are a form of directly performance–linked tax incentive. They are particularly suitable for situations where outputs can be readily directly monitored, such as volume of renewably generated kWh sales to the grid. The current U.S. Federal renewable energy tax credit provides a tax benefit for wind and biomass energy producers equivalent to 1.7 cents/kWh through this mechanism.

Guaranteed utility buy-back schemes at premium prices over several years are a fiscal incentive implemented by OECD governments to promote renewable energy under the current climate of deregulation. The United Kingdom's *Non-Fossil Fuel Obligation* (NFFO) and Germany's *Electricity Feed Law* (EFL) for example, have been instrumental in increasing renewable electricity generation and capacity over a short time. The EFL pays renewable electricity-producing independent power producers (IPPs) up to 90 percent of the prices paid by end-users. The NFFO in the U.K. guarantees pre-determined prices for certain renewable electricity projects selected by the government. And in Japan, electricity from PV and wind sources is paid a buy-back rate set at the same level as consumer prices.

The NFFO is, in effect, a competitive bidding procedure for renewable electricity, requiring electricity distribution companies to contract for a certain amount of renewable energy. Under each NFFO round, IPPs submit bid prices for electricity generated from various renewable sources. The bidding is closed when the previously stated aim of approximate capacity is attained. The government, then, chooses successful projects for different technologies on the basis of costs within each technology, not between different technologies. IPPs are guaranteed the price bid for the number of years specified by the arrangement – usually for 8 or more years. Experience to date has shown the NFFO scheme to be very successful at attracting bids, and in accelerating the decrease in costs. Since the NFFO was initiated in 1989, bid prices have decreased in each technology – an indication that with competition, the cost of renewable electricity will come down, making renewable energy technologies more competitive.

Clean power portfolios are another market-based mechanism used to ensure renewables are not crowded-out during the transition to deregulation. One example of this is the Renewables Portfolio Standard (RPS), proposed for California, which later lost to another measure. Under an RPS, electricity generators or sellers are required to obtain a minimum percentage of their supply from renewable sources. This renewable obligation, in adopting jurisdictions equivalent to roughly 10 percent of the utility's total annual energy sales, would be represented by actual generating assets or by "renewable energy credits," which would be tradable. This way, the implementation of the RPS would rely entirely on market actors, thus, ensuring competition and efficiency. Government involvement would be limited to certification and monitoring compliance.

Surcharge-funded production incentive is the alternative mechanism chosen by California that collects funds through a "Systems Benefit Charge" and uses them to support renewables in the competitive market. The systems benefit charge is a non-by-passable, usage-based charge embedded in customer electricity bills (about 1 percent of the total bill), and since no customer is exempt from this charge, no utility will be put at a competitive disadvantage because of it. Utilities are then required to spend specified minimum dollar amounts collected through the mechanism on renewable energy, as well as energy efficiency, research, development and demonstration (RD&D) and other energy services. SBC funds may also be allocated through a competitive auction subsidy scheme (e.g., U.K. NFFO, the California Energy Commission renewable energy incentive program) that provides utility buy-back tariff support to renewable energy generators offering power at the least subsidy. Working up the supply curve for renewable energy, auction awards may be given until a given capacity target is reached in a given bid round, or until available funds for that round are exhausted.

Evaluation of Renewable Energy Policies

Global experience with the above instruments sends a strong message: "Policy matters." This is particularly true if policy goals are phrased not just in renewable megawatts installed or megawatt-hours produced, but rather in terms of cost-price progress and economic competitiveness leading to long-run sustainability. On this score the impact and effectiveness of different policies range significantly, as is suggested in Figure 5 comparing the wind energy development experience of four OECD countries.

In common with many nascent industries based on manufactured technologies, cost reduction and market acceleration in the renewable/low-emissions energy industry is fueled by three factors:

(a) Market scale, leading to capture of economies of scale, principally in manufacture;

(b) Competition, leading to technological progress and efficiency;

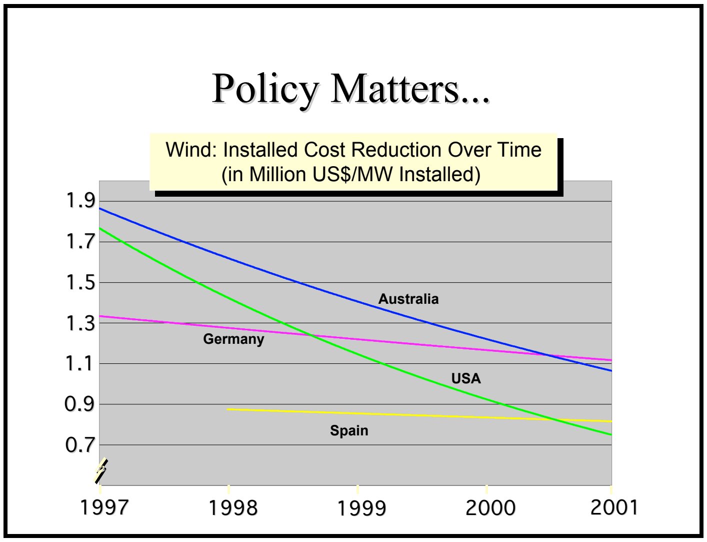
(c) Organizational learning, leading to reduced transactions costs and efficiency in deployment.

Generally speaking, capital cost rebates and tax-based investment incentives have not proven to be effective mobilizers of the combination of the above forces. Where tax-linked incentives are to be employed, production-based systems are preferred and can be efficiently administered.

Mandated purchase requirements imposed on utilities through electricity feed-laws have been effective in rapidly scaling up markets in jurisdictions such as Germany [4/] and Spain. The impact on competition has been less positive, however, and detailed analysis shows that the gains have been mostly captured by producers rather than the market/consumers and cost progress in domestic markets has not been as rapid as in the U.S. which has favored competition-enhancing instruments.

4/ Germany modified its original Electricity Feed Law (" Stromeinspeisungsgesetz") as from April 1, 2000, as a result of cost-effectiveness evaluations and the protests of the utility sector. The buy-back tariffs are now linked to utility marginal generation costs as opposed to retail consumer tariffs.

Figure 5:



While based on principles of flexibility and competition, the Renewables Portfolio Standard may not represent the best renewable energy policy option for the Hawai'i utility industry at the present time. RPS creates competitive pressures when there are actually multiple utilities operating in a state or service territory. In Hawai'i, only pseudo-competition with little or no internal trading of renewable energy certificates/credits will result. The benefits of cost-minimization through equalization of geographical and organizational marginal costs would similarly be dissipated. Hawai'i would be well advised to look into instituting a System Benefit Charge (a small levy on electricity consumption) that could fund competitively awarded tariff subsidies for private sector development of grid-connected renewables á la the U.K. and California.

Then too, Hawaii's enactment of its statewide RPS (Act 272 signed on June 25, 2001; see Annex 4) is classified as a voluntary system – this is the terminology used in analyses comparing various state RPS programs. Best practice RPS implementation provides specific penalties for non-compliance. This is typically a fine of ~200 percent of the expected market cost of a renewable energy credit (the renewable energy trading certificate or permit); in some systems the fine is levied as a increased obligation (a specific multiple of the shortfall) that carries over into the next compliance period. It is unlikely that voluntary measures will produce results adequate to meet long-term goals, especially concerning greenhouse gas emissions which are invisible and not subject to easy public scrutiny.

Emissions Levies/Carbon Taxes

Pigouvian taxes or levies paid on unit emissions have been described as an "economist's dream." While subject to the normal costs and inefficiencies of tax collection compliance, they produce efficient pollution control outcomes whose results can be shown to be equivalent to quota-based systems such as emissions trading. Emissions levies also offer the advantage of being able to fix a maximum unit cost of pollution control (although the quantity of reduction is unknown *ex ante*). However, in practice, carbon taxes have been demonstrated to be nearly politically intractable, as the failed BTU tax (an implied tax on carbon based on fuel calorific value) in the early Clinton-Gore Administration showed. It is unlikely that political support for a carbon tax could be garnered in Hawai'i. Carbon and other emissions taxes can be made much more palatable if they are administered in a revenue-neural fashion, with complementary cuts on taxes on income offsetting the additional pollution tax burden. This would have the welfare-enhancing effect of shifting taxation from "goods" (i.e., labor) to "bads" (polluting emissions). However, this too has proved to be politically elusive in practice, with only the Netherlands and some Scandanavian countries being able to move modestly in this direction.

Emissions Trading

Emissions trading schemes, such as the U.S. SO_2 market under the Clean Air Act, offer a significant advantage over technology supports including the renewable energy mechanisms described above: They are technology neutral. Given that a combination of low environmental impact technologies will be the most effective in meeting long-term energy-environment goals, emissions trading lets the market determine what the least-cost combination is.

Emissions trading mechanisms are of two broad types: Closed trading systems, and open trading systems. Closed systems, such as the EPA-administered national sulfur market, set an overall binding limit or cap for the unit of control (airshed) and then apportion rights to emit among the market participants who are subject to emissions constraints. The initial assignment of emissions rights may be by historical emissions benchmarks, by auction, or by some other activity-based allocation criteria. Carbon trading under closed systems is relatively simple to set up and administer. This is because carbon emissions do not have to be spacially tracked, and carbon emissions are directly proportional to the volume and intrinsic carbon content of combusted fossil fuels. Plant efficiencies or smokestack emissions therefore do not have to measured; the requirement is for regular (typically annual) reporting of the type and quantity of fuels consumed which in sophisticated markets can be by remote sensing/telemetry. Monitoring and enforcement is handled through post-audit and compliance checks similar to the accountancy industry, and this has spawned the appearance of a range of specialized environmental audit firms.

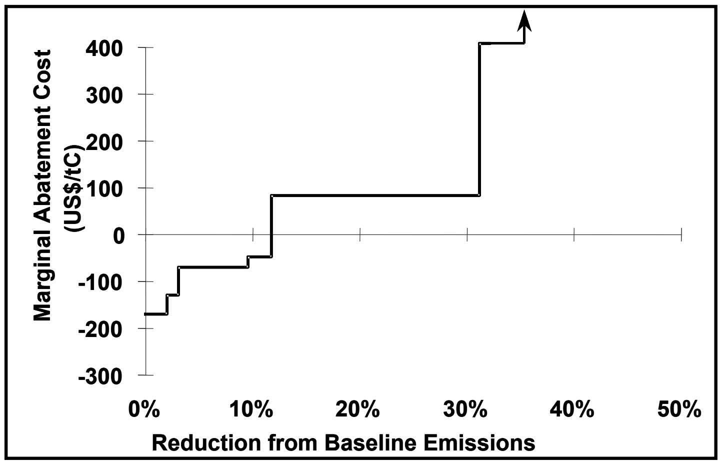
In open systems, the market player is not subject to an overall emissions limitation constraint. Rather, a level of baseline emissions for the emitter is established and technology and fuel substitutions result in reductions in emissions below a project-relevant baseline. Beyond this baselining requirement (and some implementations require that the baseline be dynamically adjustable and re-validated over time), the monitoring provisions are similar to closed systems but the unit of accounting and reporting is normally the project level as opposed to the enterprise or economy level.

The nascent global carbon market under the Kyoto Protocol represents a combination of closed and open system markets. OECD countries have binding emissions caps based on the 1990 emissions benchmark level but are free to trade "assigned amounts" with each other. OECD countries can also purchase carbon emissions reductions from developing countries (who do not have emissions caps under the Kyoto Protocol) by arranging for independent 3rd party *ex ante* validation that the contracted emissions reductions are "additional" to the levels in the baseline (i.e., not business as usual), and *ex post* verification that the expected emissions reductions actually occurred in practice. There are methodological difficulties associated with establishing robust baselines, and higher transactions costs associated with the operation of open vs. closed system markets. However, learning-by-doing and standardization are resulting in improved transaction efficiencies.

Intra-Company Emissions Trading

It is unlikely that Hawai'i would choose to implement a binding, closed emissions trading system in advance of U.S. national action, although as noted earlier Massachusetts is independently following this course of action. However, a more limited and voluntary form of trading can be set up at the energy utility or industrial enterprise level: Intra-company trading. This would be pursued through corporate adoption of internal greenhouse gas emissions reduction targets, and the simultaneous institution of internal carbon trading mechanisms under which corporate units engage in inter-unit trading. Leading energy corporations such as BP, Shell and PEMEX (the Mexican oil and gas giant) have implemented this strategy with good effect. It sensitizes operational managers to the opportunities to improve efficiency and reduce emissions throughout corporate operations, provides hands-on experience in the future global business of the trading of environmental commodities, and reveals the marginal cost curve for attaining reductions (see example in Figure 6).

Figure 6: Marginal Cost Curve for Emission Reductions



The information obtained is useful for corporate- and state-level planning and also indicates the frontiers of internal cost-effectiveness that can calibrate future moves to participate in domestic and international carbon markets. The internal valuation of the greenhouse externality can also be entered into project evaluation in order to assess future contingent liabilities associated with long-lived energy producing and consuming capital stock. Under the recommended new procedure, project economic evaluation would be effected by two methods. First, using the current standard method of externalizing carbon emissions using the default value of zero. Second, the economic analysis should alternatively be based on the inclusion of a recommended carbon shadow value, perhaps the market-clearing price of emissions reductions in the internal corporate trading market. In essence, the analysis would flag projects that are carbon-intensive and signal project managers try to identify low-carbon alternatives for all or part of the originally proposed investment.

Annex 1

Analysis of the Bush Administration Climate Change Action Plan

The key features of the Bush plan are:

- National goal -- The U.S. sets a national goal of an 18% reduction in the carbon intensity of the economy (the carbon/GDP ratio) over the next approximately 10 years. The implications of not reaching this goal are not clear.

- Voluntary action -- No corporation or economic actor will be under any particular target or emissions limitation constraint.

- National carbon offset registry -- U.S. corporations will be able to register their in-house carbon reduction activities, or their negotiated domestic trades where they finance others to achieve the same result. This is consistent with 'early action,' where first movers will be grand-fathered and rewarded through retroactive crediting should the U.S. ever decide to join up with the Kyoto Protocol or successor or impose domestic targets unilaterally.

- $4.6 billion over 5 years in tax credits for the development and deployment of low carbon technologies -- Favored technologies are various renewable energy technologies like wind, and fuel cells particularly in the transport sector.

- Further scientific study of the climate change problem -- Through federal funds for research and modeling.

The most important criticisms of Bush's announcement are as follows:

1. It continues to take a fundamentally skeptical view of climate change science, using the uncertainties as justification to delay short-term actions that will have relatively low costs. The most discussed example of this is the apparent abandonment of serious efforts to implement known, off-the-shelf and low cost vehicle fuel efficiency measures either with government support or through a ratcheting-up of the Corporate Average Fuel Economy standards.

Most other OECD societies have concluded that the debate should more be about designing rational strategies that are robust in the face of uncertainties, and they have accepted that they will have to incur some costs as a logical response to uncertainty. The Administration does not see this argument, and the Bush Administration believes that there can be no trade-offs with economic growth when scientific uncertainties continue to exist. The truth is that scientific uncertainties will be with us for a long time and are unlikely to reach the level of exactitude that the Administration is apparently demanding for at least 10-20 years. Meanwhile, the opportunity costs of inaction will mount.

2. It does not offer a compelling and logical counter-vision to the admittedly flawed Kyoto agreement. Many observers hoped that the Bush Administration would propose a new Kyoto architecture with, perhaps, a lesser emphasis on short-term cuts, and greater emphasis on stimulating technological acceleration that would lead to deeper commitments later on.

3. It relies exclusively on voluntary action. The 1992 UN Framework Convention on Climate Change also relied on voluntary action -- it didn't work. Voluntary action has its place in the climate change solution, but can never be a complete substitute for binding targets and mandatory measures.

4. It is business as usual. In fact, the national goal does not represent a commitment to reduce U.S. carbon emissions at all either in absolute terms or even with respect to existing 'baseline' trends. To see this, note the following identity:

$C = E/GDP * C/E * GDP$

Where:

C = Carbon emissions

E = Energy consumption

GDP = National income

The first term on the r.h.s. is the energy intensity of the economy, and has been declining at a rate of about 1% year for more than 25 years as a result of technological progress, capital stock turnover, and the on-going shift in the U.S. economy from energy-intensive manufacturing to light manufacturing and services.

The second term on the r.h.s. is the carbon intensity of the energy sector, and this has been declining in the U.S. at about 0.5%/year for a least 10-15 years, primarily due to the increasing penetration of natural gas at the expense of high-carbon coal.

The last term on the r.h.s. is just GDP, which on long-run trends grows at about 3%/year on average.

The Bush Administration target is that C/GDP will decline on average at 1.5% per year over the next decade. But note that C/GDP is simply the product of the first two terms on the r.h.s. The sum of the rate of change of these two terms is 1.0% + 0.5% = 1.5%. Thus the U.S. commitment represents no movement below the trend line.

Note also that continued GDP growth will overwhelm the 1.5% /year savings. So U.S. emissions will continue to rise, without any bend in the curve in the direction of stabilization of emissions levels, much less stabilization of the level of concentrations of greenhouse gases in the atmosphere.

5. It does not propose alternative mechanisms to draw in developing countries. Both the Clinton Administration and the Bush Administration have been concerned with the fact that developing countries have no emissions constraint commitments under the Kyoto Protocol, nor a so-called "commitment to commit." It is a scientific fact that the emissions reduction/limitation effect of Kyoto will be completely reversed if developing countries don't eventually also come under some form of emissions limitation constraint.

The Clinton Administration's approach to this dilemma was based primarily on (a) using the Clean Development Mechanism to draw in developing countries through a limited form of carbon trading that would also promote transfer of efficient technologies, and (b) entering into a dialogue with the likes of Argentina, Mexico and South Korea on a early commitment to reducing, initially, not their overall emissions, but a least improving and accelerating their carbon intensity measures.

Strong points of the Bush Administration plan:

- The national carbon offset registry and opening up of avenues for early crediting are welcome developments that should enjoy a lot of support among progressive Senate members and corporate leaders.

- The tax credits are generally well targeted and structured, and employ evolving best practice such as output-based credits for renewable power rather than investment tax credits.

- The U.S. will remain one of the most generous (perhaps the most generous) funders of important and needed climate change research, and the quality of U.S. science is very high.

Impacts of Biomass-based Ethanol Production and Use

Alcohol can be used as a liquid fuel in internal combustion engine either on its own or blended with petroleum-based fuels. Ethanol, as the most important alcohol fuel, can be produced by converting the starch content of biomass feedstocks (e.g. corn, sugarcane) into alcohol. The fermentation process is essentially the same as used to make alcoholic beverages, in which yeast and heat are used to break down complex sugars into simple sugars, creating alcohol. There is a relatively new process to produce ethanol that utilizes the cellulosic portion of biomass feedstocks like trees, grasses and agricultural wastes. Cellulose is another form of carbohydrate and can be broken down into more simple sugars. This process is relatively new and is not yet commercially available, but potentially can use a much wider variety of feedstocks.

Currently about 6 billion liters (3.85 liters = 1 gallon) of ethanol are produced this way each year in the U.S. The production is widely acknowledged to be supported by tax subsidies, and is pursued primarily for employment and political reasons. Worldwide, fermentation capacity for fuel ethanol has increased eightfold since 1977 to about 20 billion liters/year. Latin America, dominated by Brazil, is the world's largest production region.

Brazilian Experience

The Brazilian sugar cane industry produces between 3.4 and 3.7 billion gallons of ethanol for automobiles per year. The use of ethanol to fuel automobiles was initiated partially in response to the 1973 oil shock, and partly as an alternative to oil to promote self-sufficiency. In 1975, the government created the National Alcohol Program (ProAlcool) to regulate the ethanol market and encourage the production and use of fuel ethanol. The program guaranteed that all gasoline sold in the country would be blended with 22% anhydrous ethanol and that the pump prices would remain competitive with gasoline. Past sugarcane crop problems have slightly altered the percentage of ethanol in Brazilian gasoline, however, mandated levels usually remained at around 20%. While the manufacture of crop fertilizers and extraction and purification of ethanol can be highly energy intensive, in Brazil this is not the case because much of the work is done by hand.

Environmental pollution by the ProAlcool program has been a cause of serious concern, particularly in the early days. The environmental impact of alcohol production can be considerable because large amounts of stillage are produced and often escape into waterways. For each liter of ethanol produced the distilleries produce 10 to 14 liters of effluent with high biochemical oxygen demand (BOD) stillage. In the later stages of the program serious efforts were made to overcome these environmental problems, and today a number of alternative technological solutions are available or are being developed, e.g., decreasing effluent volume and turning stillage into fertilizer, animal feed, biogas etc. These have sharply reduced the level of pollution around Sao Paulo. The use of stillage as a fertilizer in sugarcane fields has increased productivity by 20-30 percent.

Despite many studies carried out on nearly all aspects of the program, there is still considerable disagreement with regard to the economics of ethanol production in Brazil. This is because the production cost of ethanol and its economic value to the consumer and to the country depend on many tangible and intangible factors making the costs very site-specific and variable even from day to day. For example, production costs depend on the location, design and management of the installation, and on whether the facility is an autonomous distillery in a cane plantation dedicated to alcohol production, or a distillery annexed to a plantation primarily engaged in production of sugar for export. The economic value of ethanol produced, on the other hand, depends primarily on the world prices of crude oil and sugar, and also on whether the ethanol is used in anhydrous form for blending with gasoline, or used in hydrous form in 100 percent alcohol-powered cars.

The costs of ethanol were declining at an annual rate of 4 percent between 1979 and 1988 due to major efforts to improve the productivity and economics of sugarcane agriculture and ethanol production. The costs of ethanol production could be further reduced if sugarcane residues, mainly bagasse, were to be fully utilized. A 1987 evaluation by the World Bank of the Brazilian program found that the loan project (the World Bank loaned Brazil $250 million in 1980 for ProAlcool) had a negative economic return, although it was viewed likely that in combination with high efficiency bagasse cogeneration integrated with the distilleries future investments could achieve break-even.

<u>Hawai'i Potential</u>

Fuel ethanol production in Hawai'i has been studied on at least three occasions over the past decade: A pre-feasibility study in 1994, a siting analysis in 1999, and an economic impact assessment in 2002/03. The recent work estimates that about 10% of the Hawai'ian consumption for land transport uses could be derived from a combination of sugar molasses alcohol (2/3^{rds}) and municipal solid waste (MSW) (1/3rd). The latter study does not attempt to estimate cost/benefit or production costs, but noted that MSW-based production would require technologies that are not yet commercial, as noted above. The best source of data on production costs and economics would therefore seem to be the 1994 study, in which production costs (in 1994 $) were estimated to range from $1.01 to 1.51 per gallon using molasses feedstock. This compares to an economic (i.e., net of taxes) cost of gasoline in bulk in U.S. mainland locations of about $0.80-1.00 per gallon (in 2003 $).

<u>Environmental Impacts</u>

Given the above Hawai'i production potential, it is assumed that local production would be blended at a ratio of 10% in gasoline to make E10. Using ethanol in low-level blends can have local air emissions benefits. Tests show that E10 produces less carbon monoxide (CO) and sulphur dioxide (SO_2) than reformulated gasoline (RFG). These blends have helped clean up carbon monoxide problems in cities like Denver and Phoenix. However E10 produces more volatile organic compounds (VOC), particulates (PM), and nitrogen oxide (NOx) emissions than RFG. Whether this results in a net air quality improvement for Hawai'i depends on the relative loadings and sensitivity of the local environment to the above pollutants. Another potential benefit of ethanol fuel is that the blending can substitute for MTBE, an oxygenate gasoline additive that has been associated with groundwater pollution and is targeted for phase-out status by the US EPA.

Savings in greenhouse gas (GHG) emissions from Hawai'ian fuel ethanol production would be expected to be modest, although a full life-cycle analysis would be required. This is because sugar/molasses production in Hawai'i is highly mechanized and fertilizer intensive, and these all require substantial energy inputs. A life-cycle analysis for Australian sugar ethanol, conducted by the CSIRO Division of Atmospheric Research, concluded as follows: "Specifically, total exbodied greenhouse gas emissions for passenger cars driven on conventional petrol have been calculated to be 0.21 kilograms CO_2 per kilometre travelled. For ethanol made from sugar cane, total emissions are 0.10-0.16 kilograms CO_2 per kilometre, depending on the assumptions made for the replacement of molasses as a stock feed. Even the most conservative assumptions give a greenhouse impact which is 25% less than for petrol." Thus using a 10% ethanol blend will reduce land-based transport CO_2 emissions by about 2.5-5.0%.

At a carbon emissions avoidance value of $100 per ton carbon, the CO_2 equivalent content of a gallon of gasoline is worth about $0.20. Given that the net GHG reduction benefit of fuel ethanol in Hawai'i would be similar to that estimated under Australian conditions -- on the order of 25-50% -- this translates to a equivalent value of about $0.05-0.10 per gallon of ethanol.

Policies to Stimulate the Market for Renewable Electricity

Internationally, two main strategic approaches have been developed to stimulate renewable energy:

- incentives, mainly financial, that stimulate investment in renewables; and, more recently;
- mandated market policies to create a market demand for renewable electricity.

Supporting activities such as research and development, demonstration, standards, 'commercialization' and outreach are also commonly used to help encourage investment. Increasingly, incentive mechanisms and elements of mandated markets are being used as mutually reinforcing tools, and tailored to suit specific country circumstances, abilities, and objectives.

Financial incentives

Initial efforts to stimulate renewable energy development often included capital cost subsidies to support research and development and technology demonstrations, followed by more targeted incentives as the scale of installations has increased and the technologies have come down in prices. The range of tools has included capital cost subsidies, tax incentives (accelerated depreciation, investment tax credits, reduced VAT or sales taxes); subsidized interest rates for investment financing, and cost-shared demonstration programs and technology research and development. Tariff-based incentives have been used to directly incentivize renewables and/or as part of competitive tenders for tariff support. More recently, Green Pricing mechanisms have emerged in response to consumer desires and increasingly to Kyoto-based opportunities to utilize the carbon avoidance of RE technologies; some of these include tradable certificate mechanisms to facilitate allocation in the marketplace.

Where financial incentives have been used, they have usually been funded from government revenues (or revenues forgone). Such incentives must be carefully designed if they are to be well-targeted, cost-effective and not distort investment decisions. Predicting the total costs of a financial incentive and how much RE capacity will result is difficult. In order to stimulate and maintain a stable RE industry, financial incentives need to be provided in a stable manner, or the industry may collapse or the stop-start impacts may prevent learning and price reductions. Perhaps most importantly, financial incentives need to be accompanied by a clear set of policies, available tariffs, and capacity development to facilitate sustainable mainstreaming of renewable technologies into the state's/region's portfolio.

Up-front capital cost subsidies are generally not considered to be effective: while perhaps necessary in early stages of technology development, and get over the initial high up-front costs of RE, it is not based on power production, so the incentive can be distorting (i.e. projects are built for the 'wrong' reasons; reduced incentive for cost reduction and long-term maintenance and operation.

Accelerated depreciation, while a potentially useful tool to signal government policy intentions and stimulate investment, can have a similar effect if used on an extreme basis (such as the installation credits used earlier in California). Like feed-laws, this approach can make it difficult to estimate how much capacity will result, and the costs are similarly hard to predict. On a more restrained basis it can be effective tool, and can be tied to other incentive programs to reduce the impact on treasury revenues.

Mandated Markets

Mandated markets may be adopted to address several barriers: first, the lack of any incentive to take electricity from renewable generators (particularly in a reformed and therefore competitive market); second, a natural preference for utilities to develop their own resources; and third (especially for large utilities) the buyers' negotiating power being much greater than that of the RE project sponsor.

Two broad categories of mandated markets attempt to reconcile these barriers, and include:

- ***Price-defined Targets*** to set a defined price at which renewable electricity must be purchased. In the U.S., an early example of this was the 1978 US Public Utility Policies Regulatory Act (PURPA) under which utilities had an obligation to connect and to pay the avoided cost. In Germany, Spain and France, **'Feed-In Laws'** have been used to set a specific price for favored technologies. If the price offered is attractive, such approaches can stimulate investment, but utilities may prove resistant and mainstreaming RE into utility operations may remain incomplete. The actual amount of RE power procured cannot be predicted accurately; too low an offer price will result in a low level of installation, and too high a level will result in over subscription and higher than anticipated costs. More importantly, this approach provides limited incentives to reduce costs, making continuation of the program an ongoing political and financial commitment.

Electricity Feed Laws

Focused on increasing installed capacity of RE, feed laws (such as in Germany and Spain) provide a premium price for electricity from RE sources (usually stated as a percentage of average prices). There is generally no cap on the amount of electricity qualifying, and there may or may not be a specification of the technology eligible to receive payment. One benefit of feed law approaches are that they are relatively easy to initiate and are continuous (if funding is available). Sponsors know the price they'll receive and thus have less market risk. This approach can also foster decentralized markets if that is an objective, but unless specified to include only large projects, may not achieve desired economies of scale.

The main drawback of feed laws is that there is an indeterminate effect on total supply, and consequently on total cost; if costs are higher than expected, the scheme may also be difficult to sustain politically. Further, feed laws do little to exert downward competitive pressure on prices over time. While cost caps may be imposed to manage overall program costs, this works against the higher level of installed capacity that is sought. As found in Germany, feed laws were found to create disproportionate impacts on utilities with different RE resources in their geographical region. A high producer surplus resulting from high feed law prices in German, Denmark, and Spain also resulted in high land-lease prices as land owners saw an opportunity; effectively reducing the share of the tariff support available to the project sponsors.

While feed-laws do tend to achieve rapid market development (which may offer learning curve benefits in terms of cumulative capacity) too rapid development may mean that learning effects (technological as well as procedural and institutional) aren't captured as part of a continuum of projects, and higher percentage of capacity is installed before cost reductions impact the market. A very rapid rate of growth in RE development may mean that the capacity value available in wind may be under-recognized if the rate of installation goes above the required rate of capacity requirements recognized in expansion planning. Thus, as an instrument of industrial policy to pursue technology expertise and market share, feed laws may suit country objectives, but are not the most cost-effective approach.

- ***Quantity-defined.*** These approaches set the quantity of renewable electricity to be purchased by the entity – either by placing an obligation on a set of utilities, or through a tender for capacity. Two broad categories include:

  - **Renewable Portfolio Standard (RPS).** In an RPS, electricity suppliers are required to show that a certain amount of their electricity (kWh or kW) was generated from RE sources. Least cost acquisition to meet required targets is typically left to market mechanisms, with utilities either producing their own power, procuring it directly, or by engaging in purchase 'Green Certificates' representing qualifying RE power produced by another supplier. Such a certificate approach can facilitate cost-effective transactions across utilities or regions with differing abilities and RE resource

  - **Systems benefit charge (SBC).** In an SBC, utilities, the regulator or government call for competitive bids from private developers to build capacity up to a pre-defined level, normally stated in terms of installed capacity. Developers providing the least-cost bid or bids receive funds to make up the difference between their bid cost and the market price of electricity. Costs are generally paid from a pool of funds generated from a surcharge on consumer tariffs.

An early example of SBC approaches is the UK's Non-Fossil Fuel Obligation (NFFO). The California Energy Commission has been using a version of this approach, and is now attempting to expand it to include a Renewable Portfolio Standard.

Renewable Energy Portfolio Standards

Patterned after the SO_2 credit trading program from the 1990 U.S. Clean Air Act, and RPS uses sales of Renewable Energy Credits as a mechanism by which revenues are transferred from traditional generators to the least cost RE generators to assure their entry into the system and maintain their viability. By closing the gap between RE generation costs and market prices – technologies become more competitive.

Typically has a set rate or target date by which targets must be met, and is underscored with penalties for non-compliance. Various program offer buy-out options for utilities unable to procure qualifying capacity, set higher than the expected marginal cost yet somewhat lower than the penalty – in this way funds are still generated for the supervising entity to procure the RE/clean power.

An advantage is that it doesn't require centralized distribution of funds and is compatible with transition to retail electricity markets and lends itself to green markets expected to develop. A potential downside of this is that the impact on consumers – and potential backlash – may not be known until later on.

Mandated Markets: In employing a mandated market share approach, policy can specify either the price that must be paid for renewable electricity or the quantity of renewable electricity that must be bought; ***it cannot do both***. In general, particularly when contrasting price-defined approaches (such as feed laws) and RPS approaches, this is true. Both feed laws (with a set price but an indeterminate subscription rate and costs) and RPS approaches (with set targets but indeterminate costs) can encounter higher than expected costs that could threaten their long-term political sustainability.

This either-or situation may be ameliorated to some degree by the NFFO/CEC type of approach. Unlike an RPS based on a percentage of RE targeted within the overall portfolio, the NFFO approach was quantity-specific only in individual tenders. The CEC mechanism is not quantity based except in the amount of funding available in the incentive pool for each auction. In both cases the programmatic intent was to reallocate funds from a pool of consumer surcharge funds. Neither approach specifies price, but both introduce competitive pressure to minimize price. The quantity requested in a tender can be specified incrementally and revised upwards if necessary and if funds are available. The amount paid per kWh can be capped to protect the program and fit the program within available resources. Both the penetration level attained and the price paid per unit may remain indeterminate, but can be estimated with reasonable accuracy and tested in the market. Total program expenditures can be defined - given a known level of resources, a known level of willingness by the utility to provide a tariff representing at least some of the value to the system (in terms of not only energy but also capacity, diversification value, and environmental benefits), and an expected level of price points offered by project sponsors in response to a tender, a competitive tariff support scheme can maximize the quantity available at any given set of financial resources. Thus, while the risk remains that the cost per unit and total RE generation purchased remains undefined until tenders are evaluated, the overall program approach can be open-ended. In terms of addressing the Hawai'ian context (where a *de facto* single utility approach makes an RPS less suitable), the NFFO/CEC approach appears most practical.

Example #1 – the U.K. Non-Fossil Fuel Obligation:

The NFFO was a guaranteed market enablement mechanism that introduced an obligation on the regional power companies in England and Wales to purchase a certain percentage of their electricity from non-fossil fuels. The policy arose as a consequence of utility privatization and the need to subsidize nuclear resources that couldn't be sold; renewable energy was not the initial target. The program provided for a premium payment for non-fossil power derived from a surcharge on utility bills across the consumer base, and its objective was to use a series of competitive tenders within defined technology categories (or 'bands') to get a steady convergence between price paid for RE under successive NFFO orders and the market price that was needed.

Projects awarded contracts to generate at its contracted capacity for up to 15 years (8 years in the first 2 tenders). In NFFO-2 – a 'strike-price' rather than bid price was used – i.e. all suppliers were paid the bid prices for the most expensive contracted project in each band. Thus, some suppliers got more than they bid; some suppliers intentionally underbid knowing they would get the strike price. Any generation in excess of agreed capacity was sold outside the NFFO agreement.

NFFO Benefits: The largest benefit from NFFO was a dramatics decrease in supply prices, especially for wind, where the average bid price fell by 31% between 3rd and 4th tenders, making it close to conventional costs. The decline was for a variety of reasons, including longer contracts allowing investment to be written off over longer period, technology improvements (in part due to rapid experience gains in Europe under feed laws), and a decline in the cost of finance. However, various sources attribute much of this cost reduction to development activity in Europe in response to feed law support, and critics say that the NFFO merely squeezed profitability in the U.K. The Irish AER (Alternative Energy Requirement) is outwardly similar to the British NFFO, with five tenders launched since 1994. One result of the AER is prices among the lowest in Europe, with projects over 3 MW get up to 4.812 eurocents per kWh and local/community projects (below 3 MW - 10% of contracts) get up to 5.97 eurocents.

NFFO Problems: Rapid development pace resulted in some poorly conceived projects; as a result, procedures for 3rd tranche changed to give contracts for 15 years rather than 8. The period tender approach created project clusters with relatively heavy activity interspersed with inactivity, creating a stop-start situation that was difficult for sponsors to manage effectively. Administrative costs were high, in part due to peaks of activity. Even with awards and purchase contracts, delays due to planning restrictions or local opposition hindered many projects.

A significant criticism of the NFFO approach is a high number of bid winners unable to come to closure - out of 3,271 MW of awarded contracts in the NFFO, only 821 MW have been installed – success rate of 25%. The lack of penalties for non-performance and lengthy development periods remitted resulted in speculative pressures as bidders anticipated future technology cost reductions that they would benefit from if they delayed.

NFFO Lessons:

- A large pool of developers can be unlocked if institutional *and* financial barriers are relieved.
- Flexibility of legislation to permit procedural changes to account for unforeseen consequences can be very useful.
- Gas prices were an ongoing obstacle, both in that by remaining low over a long period, they made it difficult to justify higher cost renewables in the long run, and by continuing to inhibit cost reduction that would follow from increased penetration of RE.

Example #2 - The California Approach:

The California Energy Commission (CEC) is currently operating a renewable energy incentive program based on competitive tenders for electricity production-based tariff support. As a function of deregulation of the California utilities in 1996, the California Legislature created enabling legislation that underlies the current program. Assembly Bill 1890 provided the initial guidance for de-regulation, while establishing policy over 4 years to maintain and protect existing in-state RE capacity through the restructuring process [5/]; it provided support for new RE capacity development, and created incentives to stimulate further penetration of emerging RE technologies. The bill required the CEC to submit a report to the Legislature outlining allocation and distribution recommendations. This report resulted in Senate Bill 90, which gave the State authority to administer funds totaling approximately $540 million collected from a small consumer surcharge collected through investor owned utilities. Other sources of funds included voluntary contributions from customers and municipalities.

Key features of the CEC program:

The CEC program includes distinct accounts for 4 categories - New Generation, Existing Generation, Emerging Technologies, and Consumer Applications.

New Renewables	50%
Existing Renewables	20%
Emerging Renewables	15% capital cost buy down, small scale
Customer Credit Fund	10%
Consumer Education	5%

Information here is based primarily on the New Generation support activities, which has spent a total of $241 million over three auctions ($161 million in Auction #1, $40 million for both the second and third auctions). The New Technologies Account has tendered $162 million in support in 3 auctions over 4 years and 3 auctions, based on following approach:

5/ California has nearly 6,600 MW of utility and independently owned RE resources across solid-fuel biomass, geothermal, wind, small hydro (size 30 MW or less), solar, landfill gas, digester gas, and municipal solid waste. Producing 26,000 GWh in 1994, or 12% of California consumption, continued operation of these resources was considered critical.

- Reverse auction - per kilowatt-hour incentive for power production incentive.
- Bids based on cents per-kilowatt hour request, cents bid (no finer than 1/100th of a cent in constant, nominal cents per kWh, paid monthly, over at most 5 year period).
- Bids ranked in order of lowest incentive required to highest until available funds are depleted or all bids have been accepted.
- Cap of 1.5 cents per kWh as an upper limit on bids.
- No project can receive more than 25% of total funds available.
- Minimum on-line date - projects on line before target date eligible for 10% bonus on top of original commitment (in no case can total incentive with bonus be more than 1.5 cents).
- 10% reduction basis for a range of incremental delays. By one year after target, award is reduced 50%; beyond that, to zero.
- New projects only; at least 80% of fair market value of project is from new equipment and output not sunder under previous contracts.
- Projects with fossil-fuel component not considered to be on-line as a RE generator until they meet requirement of no more than 25% of fossil in operations.
- Project must be located in California.

The CEC elected to let technologies compete within a common pool, and unlike the NFFO program, did not 'band' technologies to differentiate among different costs and operating characteristics.

Note that producers are generally also eligible for an approximately 1.7 cent Federal Production Credit for RE, bringing the potential for incentive to over 3 cents.

Estimated generation in bids is a key data input; it is hard to hard to define precisely, but important to determine level and allocation of incentive funding. Overestimation would tie up funds unnecessarily; underestimation would lead to insufficient funds in the program. Thus:

- Under-estimation of generation is discouraged by limiting incentive payments to no more than the generation proposed - i.e., extra generation will not receive incentive payment.
- Over-estimates are discouraged through reasonableness checks – if actual generation averages less than 85% of estimated generation over the first 3 years, cents/kWh reduced by 25% for remaining 2 years of payments.
- To avoid front-loading of payments, incentive payments in each of first three years limited to 25% of project's total award fund.

Well Defined Timeline:

#1 - Preparation and adoption of a project award package
While winners are notified, they are not assured of payment until a Project Award Package is completed. This document designates bid status as a winner, documents understanding of permitting and regulatory requirements, and listing and schedule of applicable milestones for construction and operation, and expected schedule for payments. CEC must be notified in advance of any post-bid changes relevant to the project, the bid, or amount of incentives, paid. (i.e., the ownership of the project could change, the size could increase, but additional generation wouldn't be paid for, etc.)

#2 - Project Applications Filed For	**6 months**
#3 - Project Approvals Obtained	**15 months**
#4 - Project Construction Started	**18 months**
#5 - Project Construction Progress Check	**24 months**
#6 - Project Completed and On Line	**36 months**

Forfeitable bid bonds are required (to ensure that bids are serious) as 10% of expected total incentive payments. These are not used to ensure construction or operation and are returned to sponsors after passing milestones 1 and 2 above.

Project late in coming on line forfeit payments beyond 5 years of expected on-line date - i.e. if it is a year late coming on line (but the CEC has permitted it to continue) it will be eligible then for only 4 years of payments. This protects the program against undue 'mortgages' of available funds, and incentivizes performance.

Cancellation of previous funding awards done only through irrevocable surrender of previous award, and cannot be conditional upon winning new award (in other words, if slow to perform on initial reward, can't reprogram with new funds and thus stall/keep commitment alive. Circumstances for canceling/reducing and award include:

- Material change in project
- Sponsor fails to satisfy terms, timing
- Commission loses contact
- False/leading info
- Project not making progress
- Funding not available

Observers have noted the need for flexibility to respond to changing landscape, which in California included both the need to support existing facilities that were 'orphaned' by industry restructuring, and by the overall power crisis in California – which also threatened existing projects while making it very difficult for CEC auction winners unable to reach closure on IPP contracts. Some stakeholders have suggested that there should be a limit on the amount of funding any single company (as opposed to project) can receive in auction. The drawback is that complexity of corporate structures makes this hard to determine; in addition, the CEC's view is that their aim of attracting the most cost-effective projects means that if a single company with multiple project is a successful bidder, then that is itself a measure of cost-effectiveness

Current Status: The CEC program is currently in flux with RPS legislation and the CEC program extension being passed at the same time. As SB 1078 (the RPS bill) is written, the CEC has authority only to set up a tracking and verification process, certify eligible renewables, and help the CPUC set the market price for energy to be used as a benchmark in utility solicitations for renewables. It currently appears that the utilities will actually conduct their own solicitations in response to their RPS targets under the aegis of the CPUC. The utility will not pay the bid price, but a 'market price' set by the Public Utilities Commission. Funding from the CEC program (i.e. the surcharge-supported fund) will then be used as "supplemental energy payments" to cover the difference between what new renewable projects bid into the utility solicitations and the benchmark set by the CPUC and CEC.

The challenge in this emerging system will be in determining the benchmark or market price that the utility must pay; the higher this is the more resistance there will be by the utilities; a lower benchmark will increase the costs incurred by the public use fund and at the extreme could exhaust this fund without reaching the RPS target. The provision in the RPS legislation that it should be evaluated on their 'least-cost best fit' remains ambiguous, as the real-world characteristics include level of production, firmness, impact on the transmission system, diversification and environmental values, etc.

Strategic Choices for Hawaii:

Program Choices: While perhaps a viable option for development of early technologies, direct subsidies are generally not an effective way of garnering cost reductions and learning already developed and internalized in the market and would be considered outmoded for today's renewable energy markets. Similarly, given the modest level of RE experience in Hawai'i, and the *de facto* single utility that significantly limits options for trading and cost minimization across multiple utilities, a quantity-defined approach also has limited prospects in the current Hawai'ian environment.

CEC approach and Hawai'i circumstances

In terms of developing and operating a renewable energy incentive program, the key differences between California and Hawai'i are the level of RE experience, the political environment, and the funding source for the current Hawai'i program. A key similarity that should be considered is the need for an incentive program to be linked to a clearly available IPP contract at specified conditions of price, capacity payment, and other supply requirements - the CEC reverse auction system has been successful, but nevertheless hindered by lack of contracts due to the poor financial condition of the sector. This experience with CEC incentive program has, in large part, stimulated political closure on an RPS. While an RPS is not currently a recommended approach for Hawai'i, this larger set of issues should be kept in mind for the long term and for the long-term sustainability of RE project and markets in Hawai'i.

Hawai'i Renewable Energy Portfolio Standard (RPS)

Act 272

Act 272 of 2001 was signed on June 25, 2001 and is available on line at the Capitol website, www.capitol.hawaii.gov, at www.capitol.hawaii.gov/session2001/bills/HB173_cd1_.htm

The law provides that:

"Each electric utility company that sells electricity for consumption in the State shall establish a renewables portfolio standard goal of:

(1) Seven per cent of its net electricity sales by December 31, 2003;

(2) Eight per cent of its net electricity sales by December 31, 2005; and

(3) Nine per cent of its net electricity sales by December 31, 2010."

[DBED Note: The requirement is for net energy generation. Existing renewables (about 7% statewide) can be counted in the total. This differs from some other states, which have requirements for "new" renewables.]

"An electric utility company and its electric utility affiliates may aggregate their renewable portfolios in order to achieve the renewable portfolio standard." [DBED Note: i.e. the Hawaiian Electric Company affiliates -- Hawaiian Electric, Maui Electric, and Hawaii Electric Light Company -- may add together their renewable energy numbers to meet the goal.]

"'Renewable energy' means electrical energy produced by wind, solar energy, hydropower, landfill gas, waste to energy, geothermal resources, ocean thermal energy conversion, wave energy, biomass including municipal solid waste, bio-fuels or fuels derived entirely from organic sources, hydrogen fuels derived entirely from renewable energy, or fuel cells where the fuel is derived entirely from renewable sources. 'Renewable energy' also means electrical energy savings brought about by the use of solar and heat pump water heating."

"Any electric utility company not meeting the renewable portfolio standard shall report to the public utilities commission within ninety days following the goal dates established in section 3 of this Act, and provide an explanation for not meeting the renewable portfolio standard. The public utilities commission shall have the option to either grant a waiver from the renewable portfolio standard or an extension for meeting the prescribed standard."

<u>[DBED Note: This legislation does not provide penalties for non-compliance; therefore, it is most appropriately characterized as a renewable energy "goal" rather than a requirement</u>.] [emphasis added]

"The public utilities commission may provide incentives to encourage electric utility companies to exceed their renewable portfolio standards or to meet their renewable portfolio standards ahead of time, or both."