Authors affiliations:

1. Institute for Sustainable Solutions, Portland State University, Portland, Oregon, USA
2. Northwest Power and Conservation Council, Portland, Oregon, USA
3. J.C. King & Associates, Portland, Oregon, USA
4. Center for Natural Resources and Environmental Management, Mae Fah Luang University, Chiang Rai, Thailand

Acknowledgements
This report was funded by the United States Agency for International Development through a contract with AECOM International Development, which implements the Environmental Cooperation–Asia (ECO-Asia) project.

We thank Paul Violette, Peter King, and Ornsaran (Pomme) Manuamorn from ECO-Asia for their help with several aspects of the report preparation. We thank the Mekong River Commission (MRC) for their cooperation, provision of data, and detailed comments on earlier drafts. We also thank external reviewers for their helpful comments and suggestions on an earlier draft.

Disclaimer
The authors’ views expressed in this publication do not necessarily reflect the views of USAID or the United States Government. Some sections of this report are reproduced from the authors’ prior published work.
Appendix A:  
Potential Alternatives for Power Production

Introduction

The scope of BDP2 was to assess the LMB countries’ own hydroelectric expansion plans (HEP) and not to validate their optimality or examine alternatives to those plans. However, the IWRM-based Basin Development Strategy recognizes the need to investigate power generation issues and a study is planned by the MRC of mainstream and tributary hydropower potential and alternative power options, including innovative hydropower schemes that do not affect connectivity in the LMB. In this connection, this appendix presents a preliminary review of alternatives to mainstream dams to serve the power needs of LMB countries. The alternatives presented in this appendix are potential opportunities for energy production within the LMB at various scales. The purpose of assessing these opportunities is to understand the stage and commercial readiness of different technologies, and their potential applicability or nonapplicability to the Mekong, in order to inform a discussion on which resources might be further researched and developed in lieu of mainstream hydropower if development of mainstream dams is deferred or curtailed. Investigations into these alternative energy developments are also needed if more comprehensive planning scenarios are to be developed for future assessment exercises in the LMB.

This appendix does not answer the question of how the LMB countries could meet their energy security goals or, for example, how Lao PDR could meet its 2020 poverty reduction goals without the budget injections from the mainstream dams. The purpose of this appendix is to present only a review of different technologies and offer preliminary comparisons of estimated costs of power generation for discussion purposes. Understanding their full applicability to the LMB, and, specifically, their relative scale of potential power generation to the mainstream and tributary hydropower projects, requires investigation of site specific data and is therefore a subject of further studies.

The appendix is divided into four sections. Section one describes hydropower and related power generation technologies. An extensive discussion of in-stream hydrokinetic generation is provided in this section. In section two, comparisons are drawn between benchmark fossil fuel resources, proposed mainstream hydropower projects, other hydropower and hydrokinetic resources, and other renewable resources. Section three provides observations regarding electricity resource planning and recommendations for research and development on promising resources. Section four provides additional information on non-water-based renewable generating options.

1. Hydropower and Related Generating Resources

Hydropower and related generating resources include large-scale impoundments, diversion projects, ocean wave generation, river current hydrokinetic generation, ocean thermal energy conversion (OTEC), salinity gradient generation, and tidal current hydrokinetic generation.
Conventional hydropower is classified by generating capacity, regulating capability (storage, run-of-river, or run-of-release), and water head. The classification of conventional hydropower chosen for this assessment is large-scale storage or run-of-river impoundments, run-of-river diversion or bypass projects, and addition of run-of-release power generation to existing nonpower impoundments and conduits.

**Large-Scale Storage and Run-of-River Hydropower Impoundments**

Large-scale impoundments with power generation typically consist of a dam with spillway and integral powerhouse, switchyard and transmission interconnection. Projects may also include upstream and downstream fish passage facilities, sediment flushing sluices and navigational locks. Impoundment projects provide firm capacity, energy and load following. Where topography permits, projects are often designed with working storage to provide seasonal regulation. Alternatively, projects may have little working storage and provide run-of-river output. As typical for river basin development, the upper Mekong (Yunnan) mainstream projects have substantial storage and regulation capability whereas the proposed lower mainstream projects would operate primarily as run-of-river facilities. Eleven of the twelve proposed lower Mekong mainstream projects are large-scale run-of-river impoundments. The twelfth project, Thakho, is a diversion type, discussed in the following section. The capacity, average energy production, total project cost and estimated levelized cost of electricity over the economic life of the lower mainstream impoundment projects are shown in Table A1. Here and in the sections that follow, common financing assumptions are used to provide comparable estimates of energy costs.

<table>
<thead>
<tr>
<th>Project</th>
<th>Capacity (MW)</th>
<th>Average Energy (GWh/yr)</th>
<th>Total Plant Cost ($/kW)</th>
<th>Levelized Energy Cost ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pak Beng</td>
<td>1230</td>
<td>5268</td>
<td>$1633</td>
<td>$45</td>
</tr>
<tr>
<td>Luang Prabang</td>
<td>1410</td>
<td>5437</td>
<td>$1679</td>
<td>$51</td>
</tr>
<tr>
<td>Xayaburi</td>
<td>1260</td>
<td>6035</td>
<td>$1554</td>
<td>$38</td>
</tr>
<tr>
<td>Pak Lay</td>
<td>1320</td>
<td>5421</td>
<td>$1546</td>
<td>$44</td>
</tr>
<tr>
<td>Sanakham</td>
<td>1200</td>
<td>5015</td>
<td>$1490</td>
<td>$42</td>
</tr>
<tr>
<td>Sangthong-Pakchom</td>
<td>1079</td>
<td>5318</td>
<td>$2068</td>
<td>$49</td>
</tr>
<tr>
<td>Ban Koum</td>
<td>1872</td>
<td>8434</td>
<td>$1998</td>
<td>$52</td>
</tr>
<tr>
<td>Latsua</td>
<td>686</td>
<td>2668</td>
<td>$2619</td>
<td>$60</td>
</tr>
<tr>
<td>Don Sahong</td>
<td>360</td>
<td>2375</td>
<td>$2026</td>
<td>$36</td>
</tr>
<tr>
<td>Stung Treng</td>
<td>980</td>
<td>4870</td>
<td>$4984</td>
<td>$117</td>
</tr>
</tbody>
</table>

6 Cost estimating assumptions: 2009 year US dollar values, 2015 service, 30-year economic life, 8 percent cost-of-capital and discount rate, no taxes, royalty payments, or financial incentives. Though the assumption of no taxes, royalty payments, or financial incentives is clearly not representative of real-world development, the purpose of these estimates is to provide a common basis of comparison among resources.

7 The project costs provided in MRC (2009) are described as “Project Investment (PV at Start).” This value is interpreted as Total Plant Cost (i.e., exclusive of financing costs and escalation and interest during construction) in constant 2009 dollars. In calculating levelized energy cost we assume that the investment costs include project development, infrastructure, and other owner’s costs; if not, the actual costs will be 15 to 20 percent higher than shown here.
Diversion Hydropower Projects

A diversion hydropower project diverts a portion of stream flow from an upstream location to a downstream, lower elevation powerhouse. Because the energy available to a conventional hydropower turbine is directly proportional to the water head (pressure) and volume, the relatively high head of diversion projects allows the generation of electricity with proportionally smaller water volume than lower heads typical of most dams with integral powerhouses. A portion of the natural flow sufficient to support the natural ecology and aesthetics is maintained in the bypassed channel. A diversion project typically consists of a small headwater pond created by a low diversion dam or weir, an intake structure, a penstock\(^8\) leading to a powerhouse at lower elevation and a tailrace to convey water from the discharge of the turbines back to the stream. The head is developed in the penstock as it drops from the intake elevation to the powerhouse elevation. Depending upon topography, diversion projects may include a lateral canal or low-pressure conduit to convey flow from the diversion to a point above the powerhouse to minimize the run of the more expensive high-pressure penstock. Because diversion structures are generally low and headwater ponds small, diversion hydroelectric projects avoid many of the environmental impacts of impoundment projects, providing that sufficient flow is maintained in the bypassed reach to support the native habitats.

Most diversion projects have little or no storage capability and operate on “run-of-river” flow. They provide firm capacity, energy, and some load-following capability. Run-of-river diversion projects range in capacity from tens of kilowatts to hundreds of megawatts. Larger projects justify longer transmission interconnections, and normally interconnected to a main grid. The transmission interconnections from larger headwater diversion projects can provide grid interconnection to intermediate off-grid loads. Small diversion projects can be dedicated to off-grid loads.

Most diversion projects are located in headwater drainages where stream gradients tend to be steep. This minimizes the length of the water conveyance structures but may limit the volume of water available for diversion. Waterfalls or cascades on lower reaches offer opportunities for close-coupled, high volume diversion projects. The proposed 50-megawatt Thakho Diversion project on the mainstream Mekong at Khone Phapheng Falls is of this type. Like headwater diversion projects, extensive alternation of the natural channel is not required. Because a natural drop often represents a natural barrier to the migration of aquatic fauna, environmental impacts can be minor. In-stream flows at major falls are often maintained for aesthetic purposes.

The cost of diversion projects is site-specific and varies greatly because of the range of sizes, diversity of project configurations, and the significant effect of factors such as terrain and length of transmission interconnection. Cost and energy production information was obtained for 35 recently developed or proposed North American projects ranging from 1.2 to 335 megawatts.

\(^{8}\) The pressurized pipe that conveys water to a hydropower turbine.
of this assessment ranges from $36 to $283/MWh. The energy-weighted cost is $96/MWh. The cost of comparable projects in the lower Mekong basin is likely to be lower because of lower labor costs. Using the same financial assumptions, the levelized lifecycle energy cost of the proposed 50 MW Thakho diversion is $35/MWh—the least cost of the proposed mainstream projects.

The regional potential for diversion project development is not known. The project database referred to in the BDP2 Hydropower Review (MRC 2009) may provide sufficient information for an initial estimate of undeveloped diversion project energy potential. This database, however, was not made available for this study.

**Retrofit of Hydropower Generation to Existing Water-Control Structures**

Opportunities exist to add power generation equipment to existing storage dams constructed for irrigation, flood control, or other nonhydropower purposes. Equipping these facilities to produce power is usually accomplished by modification of the existing discharge works, and addition of a powerhouse, tailrace, and switchyard and transmission interconnection. The incremental cost and environmental impact is therefore much less than that of a new dam and storage reservoir with power generation. The powerhouse generally operates in “run-of-release” mode, since power generation typically remains subordinate to original purpose of the facility. For example, releases from an irrigation facility may be limited during the wet season as water is stored for dry season releases.

Like other hydropower projects, the cost of power retrofits is site-specific and varies due to capacity, project configuration, length of transmission interconnection, and water release hydrograph. Cost and energy production information was obtained for nine recently developed or proposed North American projects ranging from 2.6 to 15 megawatts. The levelized energy cost of these projects, calculated using the common financing assumptions of this assessment ranges from $59 to $156/MWh.

Irrigation canal drops, irrigation wasteways, and municipal water supply system pressure reduction valves can also provide opportunities for addition of power generation capacity (conduit projects). Canal drop and wasteway projects generally involve diverting the full flow into a penstock that leads to a powerhouse at lower elevation. After passing through a turbine, the water is returned to the canal (or receiving stream in the case of a wasteway). Small hydropower turbines can be substituted for pressure reduction throttle valves in municipal water systems. Power production of conduit projects is run-of-release.

Like other hydropower projects, the cost of conduit power retrofits is site-specific and varies due to capacity, project configuration, length of transmission interconnection, and water release hydrograph. Cost and energy production information was obtained for five recently developed or proposed North American projects ranging from 750 kilowatts to 10 megawatts. The levelized energy cost of these projects, calculated using the common financing assumptions of this assessment ranges from $48 to $600/MWh. The high cost of several of these projects is partly attributable to the cost of long runs of large-diameter penstock runs over low gradient canal sections for the nonpower purpose of reducing water loss from unlined canal.
The energy-weighted cost of the 14 power retrofit projects discussed above is $90/MWh.

No inventory of nonpower dams or conduit hydropower development opportunities in the Lower Mekong Basin was located for this assessment. An assessment of the power potential of these facilities would commence with an inventory of existing nonpower projects, annual release hydrograph, reservoir operating rule curves, existing discharge works, and transportation and transmission infrastructure.

**River Current Hydrokinetic Generation**

Hydrokinetic energy conversion devices convert the kinetic energy of flowing water to electric power. Hydrokinetic devices for shallow channel applications show promise for small-scale power production from shallow streams, canals, tailraces, and outfalls. (Deepwater hydrokinetic technology suitable for capturing the energy of tidal and oceanic currents and the flow of deep (> 10 m) river channels are discussed later). Because of the kinetic energy density of flowing water, commonly encountered velocities are low and hydrokinetic devices have lower inherent conversion efficiency than conventional hydropower turbines. Hence, the capacity of river-current hydrokinetic installations will be small, ranging from tens of kilowatts to several megawatts. These facilities will be best suited to serving isolated and community-scale loads where they will compete with diesel generators, small hydropower diversions, community-scale wind, solar photovoltaic arrays, and small biofuel power plants. In-stream hydrokinetic plants will be able to produce power year-round in most locations. However, strongly seasonal streams will require backup diesel or biofuel capacity for use during the low-flow season.

In-stream hydrokinetic units can be deployed at sites lacking suitable topography for conventional hydropower. The physically compact and modular nature of hydrokinetic devices will facilitate transportation to remote areas and installation can be accomplished in many cases without the need for major civil works and heavy construction equipment. The compact and modular nature of the technology may facilitate rapid technical development and economies of production. Relatively conventional materials and technology are employed in the fabrication of hydrokinetic energy conversion units, facilitating the establishment of domestic manufacturing capability.

In-stream hydrokinetic devices do not block or alter natural channel geometry, or greatly affect flow velocity. Estimates of the impact of hydrokinetic flows for several sites in Alaska suggest reductions in flow velocity immediately downstream of hydrokinetic device arrays of 7 percent, or less (Previsic 2008). Thus, broad environmental impacts are expected to be far less than for conventional hydroelectric projects, except in cases where a large number of units have to be installed to maximize power output resulting in an increased environmental footprint. Moderate local impacts are also possible, including alteration of habitat, erosion and scouring, hydraulic shear stresses, turbulence, strike, entanglement, impingement, electromagnetic field effects, toxic materials, noise, and vibration. Because of the lack of large civil works, in-stream hydrokinetic facilities can be removed to reverse unanticipated environmental impacts.
A wide variety of design concepts for in-stream hydrokinetic devices have been proposed. Seventy-six of these are reviewed by Khan and others (2009). The fundamental design consideration is the energy capture mechanism; concepts include turbines, oscillating surfaces, piezoelectric, and induced vibration. Turbine-based concepts include axial, crosscurrent, and vertical axis rotors. Both drag (paddle) and lift (foil) turbine blades have been proposed. Other unsettled design parameters include support (gravity-founded or floating), submerged versus nonsubmerged generators, debris protection, fish screening, and the use of ducting to augment energy capture efficiency.

Turbine-based concepts are at the forefront of development. Lift blading is more efficient than paddles, though paddles may be less susceptible to weed and line entanglement. Floating arrangements position turbines near to the surface where flow velocities are the greatest, and automatically correct for changes in water level. Floating devices can be configured with nonsubmerged generators, and can be easily repositioned or moved to shore for maintenance. However, floating structures may interfere with navigation and may be more susceptible to damage or entanglement by floating debris.

Optimal turbine configuration is less settled. Vertical axis turbines offer advantages of design simplicity, easier generator coupling, nonsubmerged generator positioning, potential use of rectangular or curvilinear ducts with integrated flotation, lower noise, and less sensitivity to shear flow. Vertical axis turbines, though, are less efficient than axial flow machines, may produce torque ripple, and may not be self-starting. Axial-flow turbines are self-starting, produce little torque ripple, and benefit from an abundant knowledge base. Axial flow machines operate at a higher rotational speed, thereby reducing gearbox complexity. Higher turbine rotational speeds, however, may increase strike hazard and require screening. Axial flow turbines can be equipped with annular ducts that provide greater flow augmentation than the rectangular or curvilinear ducts used for vertical axis machines.

Johnson and Pride (2010) characterize river current turbines as an emerging technology, similar to wind 15 to 20 years ago. This would appear optimistic. Fifteen to 20 years ago, thousands of commercial wind turbines were operating and deployment of second-generation commercial technology was underway. River current turbines presently exist only as a scattering of prototypes and a plethora of conceptual designs. Though several firms have marketed small-scale in-stream turbines, no thoroughly tested commercial product appears to exist, and no commercial-scale installation has been deployed.

Achieving widespread commercial deployment of in-stream hydrokinetic technology will require refinement and commercial production of units optimized to representative sites, greater understanding and resolution of environmental issues, site surveys and evaluation, establishment of performance, permitting and manufacturing standards, and understanding and resolution of operating and maintenance issues. EPRI (2008) estimates the time from conceptualization to deployment of a full-scale river current hydrokinetic prototype to be about five years. A full year of operation, at minimum, is required for testing and evaluation. Another five years may be required for design and testing of a commercial machine. With consistent support, a new concept will require 10 to 11 years from conceptualization to reliable commercial product. This period could be shortened by several years for designs adapted from current prototypes. Once
developed, commercial deployment can be rapid, as fabrication and installation of an array can be accomplished within a year.

One set of cost estimates for a representative design was located for this review. The Electric Power Research Institute has conducted a system-level feasibility study of in-stream hydrokinetic installations at three Alaskan villages (Previsic 2008). The villages of Igiugig and Eagle are served by isolated microgrids using diesel generators. The third community, Whitestone, has been served by an isolated microgrid, but will be connecting to a main grid. The Igiugig and Whitestone cases are most representative of a humid warm climate site in that they are located on streams that flow year around, while Eagle is located on the Yukon River at a location fully clear of ice only five months a year. Two plant sizes were evaluated for Igiugig, a 3-unit 41kW array sized for load at maximum flow and a 9-unit 123kW array sized for load at minimum flow and provided with resistive load banks for dumping excess energy. Two cases were also considered for Whitestone, a 4-unit 79 kW array sized for local load and a 30-unit 594 kW array sized for selling excess energy when the main grid connection is established.

The assessment was based on a conceptual design consisting of a pontoon structure supporting four submerged generators, each powered by a fixed blade open rotor axial-flow turbine with debris and fish screens. A version using 1.5 m diameter rotors and would be rated at 14 kW. A second version using 2 m diameter rotors would be rated at 20 kW. These conceptual designs appear to be applicable to LMB sites.

The cost estimates were normalized to 2009 dollar values. An allowance for preconstruction project development, infrastructure, and other owner’s costs were added. Levelized revenue requirements and unit energy costs were calculated assuming a 15-year economic life. The financing assumptions described earlier yield levelized energy costs of $274 to $477/MWh. While competitive with diesel generator sets, these costs are far higher than other sources available to the main grid.

A favorable site will be adjacent to a microgrid to minimize voltage drop and electrical losses and have current velocity of at least 1, and preferably 1.5 m/s. Excessive velocities (exceeding 3.5 m/s) may be characterized by high sediment load and unstable channels leading to equipment wear and to anchoring and servicing difficulties. A good site will need sufficient midstream depth to accommodate the hydrokinetic energy conversion device and be of sufficient area to accommodate the needed number of units. Freedom from floating debris and relatively constant seasonal flow are other desirable attributes.

A complete site assessment will require a flow velocity frequency distribution and seasonal variation, channel geometry mapping, vertical and horizontal velocity profiles, and information regarding channel bed composition and debris and sediment loading. Annual load duration curves and seasonal variation for the local grid, an inventory of existing generation, options for meeting forecast load growth, and location and voltage of possible points of interconnection are needed. River usage and environmental information will be required; these needs can be refined as pilot projects are deployed representative sites and understanding of machine/environment interactions improves.
Little published information regarding current velocities in the LMB were located. Sokleang (undated) estimates average wet season Mekong mainstream current velocity between Pakse, Laos, and Kratie, Cambodia, to be 1.9 m/s, well above the 1 m/s considered feasible for hydrokinetic generation. Current velocities will vary along this reach, but this estimate suggests adequate velocity is available in some reaches, at least during the high runoff season. In contrast, water quality reports for a 22 km reach at the site of the proposed Xayaburi hydropower project cite current velocities of 0.25 to 0.5 m/s in November and 0.4 to 0.6 m/s in March (TEAM 2010). These velocities are well below those suitable for hydrokinetic generation. Flow estimates and documentation of channel geometry and environmental conditions may be available for other sites considered for conventional hydropower development. In addition, the Rivers System Research Group of the University of Washington appears to be developing flow estimates for the Mekong using hydrologic models and remote sensing (http://www.cev.washington.edu/story/VMB). Others working on site assessment methods include the Canadian Hydraulics Center, the University of Alaska, Anchorage, and the U.S. Department of Energy.

Additional mainstream hydrokinetic potential using deepwater technology may be present in the Mekong Delta.

**Ocean Wave Generation**

Increased interest in wave energy in recent years is resulting in accelerated development of wave energy conversion devices, assessment of environmental and socioeconomic effects and refinement of assessments of wave energy potential. A variety of wave energy conversion concepts are in various stages of development ranging from conceptualization to precommercial demonstration. However, the wave energy potential of the South China Sea is not promising. A recent assessment of global wave energy found that the annual average wave power potential of the Viet Nam coast is of low quality, ranging from five to 15 watts per meter (Mørk et al. 2010). For comparison, the wave power of coastlines considered promising for the commercial deployment of wave energy conversion devices ranges from 40 to 60 watts per meter, and greater. Moreover, the wave power of the South China Sea exhibits a very high degree of seasonal variation. The wave power potential of the Gulf of Thailand is less than five watts per meter.

**Salinity Gradient Generation**

Energy is released when fresh and saline water are mixed. The energy potential created by fresh water streams discharging to salt water bodies conceptually can be recovered and converted to electricity. Conceptual salinity gradient conversion technologies include osmotic hydro turbines, dilytic batteries, vapor pressure turbines, and polymeric salinity gradient engines. Osmotic hydro turbine technology is the furthest advanced. The Norwegian utility Statkraft has completed a 4-megawatt prototype osmotic hydro turbine power plant near Oslo with the intention of developing a commercial-scale plant by 2015 (http://www.powertechnology.com/projects/statkraft-osmotic/). A key to commercialization is reducing the cost of the osmotic membrane. Because of the volume of flow, the theoretical resource potential at
the estuary of the Mekong may be substantial. However, saline intrusion would constrain the ability to tap this resource.

**Ocean and Tidal Current Generation**

Hydrokinetic devices can be used to capture the energy of oceanic and tidal currents. The leading conversion technologies for these applications are bottom-founded, fully submerged open axial flow turbines, resembling stubby-bladed wind machines. Turbines are mounted on pedestals or in groups of several turbines on gravity-founded racks. The turbines are provided with reversible blades or yawing capability to capture both ebb and flood tidal currents. Tidal currents of sufficient magnitude for the practical production of electric power are typically located in well-defined locations and tidal current power plants are conceived as arrays of individual units at productive sites.9

The output of tidal current turbines is cyclically variable. In locations with semidiurnal tides such as the South China Sea, energy production will peak four times a day on the two flood and the two ebb tides. In contrast to other variable output renewable technologies such as wind and solar, the timing and magnitude of tidal cycles and the output of tidal energy conversion devices can be forecast years in advance.

Tidal hydrokinetic conversion technology is approaching the commercial pilot stage. Firms planning commercial installations include Verdant Power and Marine Current Turbines. Verdant Power’s “Free Flow” Kinetic Hydropower System is a fully submerged five-meter diameter, three-blade open turbine rated at 35 kW (http://verdantpower.com). Commercial machines will be mounted in groups of three on a gravity-founded “tri-frame.” Prototype testing commenced in 2002 and was followed in 2006–2008 by installation of six full-scale demonstration units in New York’s East River. In December 2010, Verdant applied to the U.S. Federal Energy Regulatory Commission (FERC) for a license to install a one-megawatt pilot project consisting of 30 turbines on ten frames at the East River site. Verdant commenced a second demonstration project in the St. Lawrence River in 2007, and plans to commence commercial build-out in 2011. The design low water depth of the commercial Free Flow unit is 10 meters, allowing the units to be installed in deeper stream channels.

The Marine Current Turbines “Sea-Gen” conversion technology consists of two 16-meter two-blade open turbines mounted on pivots at the ends of a horizontal beam (http://www.marineturbines.com). Each turbine is rated at 600kW at 2.4 m/s current for a total of 1.2 MW per unit. The beam is attached by a lifting mechanism to a monopile pedestal extending above the water surface. This allows the turbines to be raised above water level for maintenance. The Sea-Gen is intended for open marine applications and requires a minimum depth of 24 meters.

---

9 An earlier approach to capturing tidal energy is the construction of barrages across the mouth of bays or estuaries with extreme tides. The barrages are provided with inlet gates and reversible turbines to capture energy from the tidal ebb and flow. Several projects of this type are in operation, the largest being the Rance barrage in France. Though additional barrage proposals have surfaced over the years, interest has shifted to submerged hydrokinetic turbines because of the cost and environmental impact of barrage concepts and the limited number of sites with suitable topography and tidal range.
The only published cost and performance information available for marine-type hydrokinetic turbines are estimates released by Marine Current Turbines for proposed pilot projects in the British Isles. Estimated capital costs of $11,000/kW and a capacity factor of 50 percent yield an estimated energy cost of $325/MWh.

Ocean and tidal currents of sufficient velocity to have practical potential for electric energy production may occur at near-shore sites along the southern Viet Nam coast. The October through April Northeast monsoon drift runs along the Viet Nam peninsula, and may attain surface velocities of 1 to 1.5 m/s. This velocity is within the low end of the feasible range of hydrokinetic energy conversion devices. The June to August currents are weaker, attaining velocities of 0.5–1.0 m/s.

Potential for hydrokinetic generation using tidal hydrokinetic conversion systems may also be found in the delta reaches of the Mekong below Phnom Penh. Here, tidal currents influence river flow. Wet season ebb currents to 2 m/s are reported as far inland as Phnom Penh on the Song Tien Giang channel. Dry season ebb currents near the mouth are reported to be about 1 m/s (Prostar 2004). These currents are feasible for hydrokinetic generation, but because of the complex interaction between river flow and tidal effects, further documentation of the time variation and direction of currents are needed to ascertain the feasibility of hydrokinetic power production. Further investigation is also needed to determine if channel depths are sufficient for tidal hydrokinetic devices. MRC flood forecasting channel cross sections suggest that sites with adequate depth (10 meters, or greater) are present (Table A2). The Hydrographic Atlas of the Mekong River (Cambodia and Viet Nam) published by the MRC Data and Information Services (http://portal.mrcmekong.org/) and nautical charts of the lower Mekong may provide useful information for further assessment of resource potential.

**Table A2: Center channel depths reported for the southern Mekong**

<table>
<thead>
<tr>
<th>Site</th>
<th>Center Channel Depth (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phnom Penh (Port)</td>
<td>7–10</td>
</tr>
<tr>
<td>Phnom Penh (Bassac)</td>
<td>3–15</td>
</tr>
<tr>
<td>Koh Khel</td>
<td>2–6</td>
</tr>
<tr>
<td>Chau Doc</td>
<td>13–15</td>
</tr>
<tr>
<td>Neac Luong</td>
<td>17–20</td>
</tr>
<tr>
<td>Tan Chau</td>
<td>20–35</td>
</tr>
</tbody>
</table>

Source: MRC (http://ffw.mrcmekong.org/south.htm)

**2. Comparison of Electric Power Resource Alternatives**

Assessing the prospects for developing new power generating resources requires an understanding of the cost of competing resources. A basic principal of power system planning is to consider all resources having the potential to provide the needed power system services including demand side, energy storage, and generating resources. In this section, comparisons are drawn between benchmark fossil fuel resources, proposed mainstream hydropower projects, other hydropower and hydrokinetic resources, and other renewable resources.
Reference Fossil Fuel Generating Options

Coal, natural gas, and nuclear resources constitute the principal alternatives to large-scale hydropower for supplying bulk power to large-scale electric power grids. These are the resources against which other bulk power sources should be compared in terms of cost, environmental and social impacts, uncertainty, and risk. One or more of these alternatives are called for in the energy strategies of Cambodia, Thailand, and Viet Nam. While limited coal is produced for the cement industry, Lao PDR at this time does not have domestic fossil fuel resources to support coal or natural gas generation. Other than nuclear units, the development of which would appear to be infeasible at present for a country the size of Lao PDR, hydropower appears to be the principal source of additional domestic bulk power production.

Reciprocating engine-generator sets using distillate or residual fuel oil are the reference resource for community-scale power systems or small isolated power grids. This is the resource against which alternative local sources of electricity should be compared in terms of cost, environmental and social impacts, uncertainty, and risk.

The next two subsections establish normalized levelized cost of electricity estimates for natural gas combined-cycle plants and pulverized coal-fired power plants. These constitute the resource alternatives against which other new sources of bulk power should be evaluated. The third section establishes normalized levelized cost of energy estimates for diesel-fuelled reciprocating engine-generator units. This is the resource alternative against which other new sources of micro grid power should be compared.

Natural gas combined-cycle power generation. The natural gas combined-cycle power plant is the established technology for bulk electricity production from natural gas. Combined-cycle units provide energy, firm capacity, and load-following capability. High reliability and efficiency, low capital cost, relatively low CO₂ production, short lead-time, operating flexibility, and low air emissions have positioned gas-fired combined-cycle plants as the bulk power generation resource of choice in areas with pipeline access to gas. The emergence of the ability to economically produce natural gas from shale formations through horizontal drilling and fracturing techniques has greatly expanded natural gas reserves in North America, and is expected to do so globally. This has relaxed concerns regarding natural gas price risk, further cementing the leading position of gas combined-cycle bulk power technology, especially in regions with direct pipeline access to extensive gas reserves. Development of the extensive gas resources of the South China Sea, though currently contested in terms of national claims, is likely to lead to an expanding role for combined-cycle generating technology in the Lower Mekong region.

Viet Nam and Cambodia have access to South China Sea reserves of natural gas, and the cost of power from a new gas-fired power plant will remain an important consideration in evaluating the cost-competiveness of alternative bulk power generation resources. The levelized cost of electricity from a reference gas combined-cycle power plant is estimated to be about $47/MWh in the BDP2 Hydropower Sector Review (HSR) (MRC 2009). The normalized financing assumptions of this study with an 8 percent discount rate yield $43/MWh for the same underlying assumptions (Case 1 of Table A3). The capital cost used in the BDP2 HSR is consistent with the cost of the recently completed Nhon Trach 2 combined-cycle plant and the
heat rate is consistent with current combined-cycle technology. The assumed capacity factor (60 percent) of BDP2 HSR is lower than the expected capacity factor of Nhon Trach 2 (68 percent). Applying the expected capacity factor of Nhon Trach 2 yields an estimated levelized power cost of $41/MWh (Case 2 of Table A3). The base year natural gas price assumed in BDP2 HSR ($3.50/MMBtu) appears reasonable, but most analysts expect some escalation in natural gas prices in future years because of the clean-burning, low-carbon quality of the fuel. The International Energy Agency estimates a long-term average annual escalation of natural gas of 0.7 percent (IEA 2010). Applying a 0.7 percent annual gas price escalation yields $44/MWh (Case 3 of Table A3). One additional variable should be considered: the potential value of carbon dioxide (CO₂) allowances should international efforts at greenhouse gas control be established. Estimates of the future value/cost of CO₂ allowances abound, ranging from zero to in excess of $100/ton CO₂. The Northwest Power and Conservation Council, drawing upon the advice of experts in the field, adopted a range of estimates yielding a mean value of about $48/ton CO₂ by 2030 (NPWCC 2009). Applying this cost to the reference plant yields an electricity cost of $62/MWh (Case 4 of Table A3). Cases 3 and 4 will be used in subsequent comparisons.

Table A3: Reference natural gas fired combined-cycle plant

<table>
<thead>
<tr>
<th>Case</th>
<th>Total Plant Cost ($/kW)</th>
<th>Heat Rate (Btu/kWh)</th>
<th>Base Gas Price ($/MMBtu)</th>
<th>Annual Fuel Price Escalation</th>
<th>Capacity Factor</th>
<th>Levelized Energy Cost ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. BDP2 HSR assumptions, normalized financing</td>
<td>840⁰</td>
<td>7000</td>
<td>$3.50</td>
<td>Zero</td>
<td>60%</td>
<td>$43</td>
</tr>
<tr>
<td>2. Case 1 w/ 68% capacity factor</td>
<td>840</td>
<td>7000</td>
<td>$3.50</td>
<td>Zero</td>
<td>68%</td>
<td>$41</td>
</tr>
<tr>
<td>3. Case 2 w/ IEA gas price escalation</td>
<td>840</td>
<td>7000</td>
<td>$3.50</td>
<td>0.7%</td>
<td>68%</td>
<td>$44</td>
</tr>
<tr>
<td>4. Case 3 w/ CO₂ cost</td>
<td>840</td>
<td>7000</td>
<td>$3.50</td>
<td>0.7%</td>
<td>68%</td>
<td>$62</td>
</tr>
</tbody>
</table>

Coal-fired steam-electric power generation. The pulverized coal-fired power plant is the established technology for bulk electricity production from coal. These plants provide energy and firm capacity and limited load-following capability. Most new coal plants, including the Thai Binh 2 plant in Viet Nam for which construction was announced in March, use supercritical technology. Supercritical steam cycles operate at higher temperature and pressure conditions than sub-critical units. This results in higher thermal efficiency with corresponding reductions in fuel cost, carbon dioxide production, air emissions and water consumption.

⁰ MRC 2009 uses an EPC (engineering, procurement, and construction) cost of $700/kW. Total plant cost also includes owner’s costs for infrastructure, project development, and construction administration. Typical owner’s costs are about 20 percent of EPC costs, yielding the total plant costs shown. Total investment costs include financing fees and interest and escalation incurred during construction and are typically 10–15 percent greater than total plant cost.
Viet Nam has substantial reserves of anthracite-grade, low-sulfur coal, and the cost of power from a new coal-fired power plant will remain an important consideration in evaluating the cost-competitiveness of alternative bulk power generation resources. The levelized cost of electricity from a reference coal-fired power plant is estimated to be about $88/MWh in the BDP2 HSR (MRC 2009). The normalized financing assumptions of this study with an 8 percent discount rate yield $80/MWh for the same underlying assumptions (Case 1 of Table A4). The heat rate used in the BDP2 HSR (8000 Btu/kWh) is much lower than the heat rate assumed for supercritical units by the U.S. DOE (9000 Btu/kWh). Applying the latter heat rate yields an estimated power cost of $86/MWh (Case 2 of Table A4). The coal price assumed in BDP2 HSR is $5.51/MMBtu. This is extraordinarily high for domestic coal (nearly 60 percent higher on an energy content basis than the natural gas price appearing in the same table). The cost of coal production in Viet Nam is estimated to be $1.00 to $1.50/MMBtu (current prices to power generators are subsidized and about 35 percent lower). Applying the high end of the estimated Viet Nam coal production cost and the slight negative escalation rate estimated by the International Energy Agency (IEA 2010) yields $50/MWh (Case 3 of Table A4). Adding the potential value of carbon dioxide allowances yields a electricity cost of $90/MWh (Case 4 of Table A4). Cases 3 and 4 will be used in subsequent comparisons.

Table A4: Reference coal-fired supercritical steam-electric plant

<table>
<thead>
<tr>
<th>Case</th>
<th>Total Plant Cost ($/kW)</th>
<th>Heat Rate (Btu/kWh)</th>
<th>Base Coal Price ($/MMBtu)</th>
<th>Annual Fuel Price Escalation</th>
<th>Capacity Factor</th>
<th>Levelized Energy Cost ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. BDP2 HSR assumptions, normalized financing</td>
<td>2400</td>
<td>8000</td>
<td>$5.51</td>
<td>Zero</td>
<td>80%</td>
<td>$80</td>
</tr>
<tr>
<td>2. Case 1 w/USDOE supercritical heat rate</td>
<td>2400</td>
<td>9000</td>
<td>$5.51</td>
<td>Zero</td>
<td>80%</td>
<td>$86</td>
</tr>
<tr>
<td>3. Case 2 w/current Viet Nam coal cost &amp; IEA coal price escalation</td>
<td>2400</td>
<td>9000</td>
<td>$1.50</td>
<td>-0.1%</td>
<td>80%</td>
<td>$50</td>
</tr>
<tr>
<td>4. Case 3 w/CO₂ cost</td>
<td>2400</td>
<td>9000</td>
<td>$1.50</td>
<td>-0.1%</td>
<td>80%</td>
<td>$90</td>
</tr>
</tbody>
</table>

Diesel-fuelled, reciprocating engine generators. Diesel-fuelled, reciprocating engine generators are the conventional power supply for isolated loads and microgrids. Reciprocating engines provide energy, firm capacity, and load-following capability for these small systems.

---

11 MRC 2009 uses an EPC (engineering, procurement, and construction) cost of $2000/kW. Total plant cost also includes owner’s costs, including infrastructure, project development, and administration. Typical owner’s costs are about 20 percent of EPC costs, yielding total plant costs of $2400/kW. Total investment costs include financing fees, interest, and escalation incurred during construction and are typically 10–15 percent greater than total plant cost.
Though a mature technology, the thermal efficiency and air emissions of these units have improved in recent years. The cost of power from these units remains high, however, because of the cost of purchasing and transporting diesel fuel to the remote locations at which these units are typically located. Many alternative technologies available to isolated loads, such as solar photovoltaics and wind, cannot provide firm capacity. In microgrid applications, these energy displacement resources are valued on the basis of the variable cost of electricity from reciprocating engines. Other alternatives, such as small-scale biomass, geothermal hydropower, and hydrokinetic plants, may provide firm capacity and load following and are valued at the fully allocated cost of reciprocating units.

The levelized cost of electricity from a reference remote reciprocating engine is estimated to be about $290/MWh in the BDP2 Hydropower Sector Review (MRC 2009). The normalized financing assumptions of this study with an 8 percent discount rate yield $298/MWh for the same underlying assumptions (Case 1 of Table A5). The capital cost and heat rate of MRC (2009) appear reasonable. The high base year fuel cost is assumed to be attributable to the cost of transportation to remote locations. The capacity factor of 80 percent appearing in MRC 2009 is high for a unit supplying an isolated system; the more representative 70 percent value appearing in Table A5 is the reference value from MRC (2010b). Published fuel price information for remote Lower Mekong Basin locations is not consistent. The Hydropower Sector Review uses a base year distillate price of $27.58 and no real escalation, whereas BDP2 Technical Note 6 (MRC 2010b) uses a base year fuel price $16.63/MMBt and a 6 percent annual rate of escalation. March 9, 2011, diesel price at Singapore was $131/bbl, equivalent to $24.27/MMBtu, suggesting that the Hydropower Sector Review assumption is more realistic. However, the Hydropower Sector Review appears to assume no real escalation in diesel prices. Most analysts do expect continued real escalation of diesel prices and Case 2 of Table A5 incorporates the International Energy Agency estimate a long-term average annual escalation of crude of 0.5 percent (IEA 2010). This yields $315/MWh (Case 3 of Table A3). Finally, adding the potential value of carbon dioxide allowances raises levelized electricity cost to $349/MWh (Case 3 of Table A5).

As noted earlier, alternative electricity resources with firm capacity will compete against the full avoided cost of reciprocating engine-generators in an isolated grid application. Alternatives without firm capacity will compete on variable cost displacement. The fuel displacement values of the cases of Table A5 are shown in parentheses. Because of the high cost of fuel, variable costs are by far the largest component of the fully allocated cost.

**Load-Side Options**

Understanding of the potential for load-side services (energy efficiency improvements and peak demand shaving and shifting) is needed for fully informed decision-making regarding future electricity resource development. Assessment of load-side potential was not included within the scope of this work and is too complex for a quick assessment. Areas of potential may include transmission and distribution efficiency, motor efficiency, lighting, and reactive loads.
Table A5: Reference diesel-fired, reciprocating engine generator

<table>
<thead>
<tr>
<th>Case</th>
<th>Total Plant Cost ($/kW)</th>
<th>Heat Rate (Btu/kWh)</th>
<th>Base Distillate Price ($/MMBtu)</th>
<th>Annual Fuel Price Escalation</th>
<th>Capacity Factor</th>
<th>Levelized Energy Cost 12 ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. BDP2 HSR assumptions, normalized financing</td>
<td>480 13</td>
<td>10,000</td>
<td>$27.58</td>
<td>Zero</td>
<td>70%</td>
<td>$298</td>
</tr>
<tr>
<td>2. Case 1 w/ IEA crude price escalation</td>
<td>480</td>
<td>10,000</td>
<td>$27.58</td>
<td>0.5%</td>
<td>70%</td>
<td>$315 ($303)</td>
</tr>
<tr>
<td>3. Case 2 w/ CO₂ cost</td>
<td>480</td>
<td>10,000</td>
<td>$27.58</td>
<td>0.5%</td>
<td>70%</td>
<td>$349 ($337)</td>
</tr>
</tbody>
</table>

Comparisons of Resources

A summary comparison of electric power resource is provided in Table A6. Levelized energy cost comparisons of resources suitable for main grid service are provided in Figure A1. A similar comparison of resources suitable for microgrid and isolated load service is provided in Figure A2. These estimates were calculated using the levelized cost values using the energy production estimates and capital and O&M cost values developed as described in the text for the various electricity generation alternatives. MicroFin, an Excel workbook for calculating year-by-year and levelized lifecycle revenue requirements, was used for calculating these costs. MicroFin was developed and maintained at the Bonneville Power Administration and the Northwest Power and Conservation Council, and is publicly available on request from the Northwest Power and Conservation Council.

Figure A1 depicts the direct project costs of resources suitable for main grid service. On a normalized plant cost basis, the reference gas combined-cycle plant is 12 percent less expensive than the reference supercritical coal unit. Because of gas price uncertainty and uncertain long-term Vietnamese coal costs, this difference may not be significant. With consideration of CO₂ production, the comparative cost of the two thermal options tilts strongly in favor of the gas unit because of the much greater carbon content of coal and lower thermal efficiency of the steam unit. Considering the possible future cost of carbon dioxide production (or, alternatively, the value of the lower CO₂ production of the natural gas unit), the project cost of the combined-cycle plant is less than 70 percent of the cost of the reference coal unit.

On a normalized project cost basis, excluding possible CO₂ cost penalties, only four of the proposed hydroelectric projects (Thakho, Don Sahong, Xayaburi and Sanakham) have a lower

---

12 80 percent capacity factor.
13 MRC (2009) uses an EPC (engineering, procurement, and construction) cost of $2,000/kW. Total plant cost also includes owner’s costs, including infrastructure, project development, and administration. Typical owner’s costs are about 20 percent of EPC costs, yielding total plant costs of $2,400/kW. Total investment costs include financing fees and interest and escalation incurred during construction and are typically 10–15 percent greater than total plant cost.
expected project cost than a natural gas fired combined-cycle plant. Considering the possible future cost of CO$_2$ production, all but one of the hydro projects (Stung Treng) have lower project costs than the reference combined-cycle plant. The normalized cost of Stung Treng is significantly higher than the cost of the gas combined-cycle unit or the other mainstream hydro projects.

Near-term (commercial) alternatives to fossil thermal units or mainstream hydropower with large-scale (tens of thousands of GWh) energy production potential include utility-scale wind power, utility-scale solar photovoltaics, parabolic trough solar thermal, and possibly an aggregation of diversion hydropower projects. Of these, only diversion hydropower has the potential to be cost-competitive with conventional sources in the near-term, though wind costs may decline to the cost-competitive levels seen in the first decade of the century as turbine production catches demand and lower-cost wind turbines are increasingly available from China and India. Parabolic trough, solar-thermal plants are an emerging commercial technology, but require the strong, direct, normal, solar radiation characteristic of arid and high elevation sites for most efficient operation. Smaller-scale, potentially competitive contributors in the near-to midterm include conventional steam and biogas plants fueled by bioresidues and hydropower retrofits to nonpower, water control projects.

Reciprocating engines operating on biodiesel from jatropha or other sources may become commercially available for main grid service over the longer term. The engine-generator technology is commercially available, however many years may be required to develop a viable biodiesel industry. Moreover, transportation demand may result in biofuel prices that cannot be sustained by the electric sector. Finally, marine type hydrokinetic turbines may mature to a fully commercial technology within a decade, opening the potential for development of moderate amounts of generation in the Mekong Delta and along the southern Viet Nam and Cambodian coast. Capital costs must drop by a factor of five for the resource to become competitive. Not shown in Figure A1 is geothermal. While the technology is mature, the resource potential of the LMB appears to be very limited. Finally, demand growth might be tempered by aggressive energy efficiency measures. In many areas, energy efficiency measures are much more cost-effective than conventional fossil thermal technology and far more competitive than most resources considered here.

Resources available for isolated load service in the near- to midterm (2015–2020). Figure A2 depicts the direct project costs of resources suitable for service of isolated loads and microgrids. The contrast with Figure A1 is striking in that every alternative is more potentially cost-effective than the reciprocating engines currently used to service these loads. However, of the alternatives, only solar photovoltaics use a universally available resource; all others use energy resources that may or may not be available at a given location. Moreover, electricity from solar photovoltaics is nearly as expensive as electricity from diesel-fuelled reciprocating engine and photovoltaics provides no firm capacity. A companion firm supply, such as an engine generator or battery storage, is needed for firm service. All other alternatives shown (and community-scale wind, not shown) are commercially available and potentially economically attractive where available. Moreover all (except for wind) have the potential of providing firm capacity. All technologies shown in Figure A2 are commercially mature except for biodiesel and river current hydrokinetics. A decade may be required to commercialize the latter resources.
This section provides recommendations for consideration in future studies on alternative resources for power generation in the Mekong. As mentioned above, the BDP2 only evaluated impacts of the proposed countries’ water resources development plans, which include hydropower projects on the mainstream and tributaries; it did not seek to assess the power generation plans or examine alternatives to hydropower dams. However, the necessity to further investigate power generation options has been acknowledged by the MRC in its adopted IWRM-based Strategy. Initial recommendations are presented here which may be useful in MRC’s considerations to further research promising alternative power resources in the LMB.

Incorporate explicit consideration of risk and uncertainty into electric power planning. Scenario and sensitivity analysis are used for consideration of risk and uncertainty (MRC 2010a, Annex 4 Para 3.1.4). In view of the potential significance and uncertain nature of the environmental and socioeconomic consequences of mainstream hydropower development, consideration should be given to use of planning methodologies that explicitly incorporate uncertainty and risk. These include methods such as portfolio risk analysis, derived from the financial industry. These enable explicit consideration of uncertainties and portrayal of expected and severe outcomes.

Further assess the potential for low-cost diversion hydropower projects. Though the cost of individual projects will vary widely, diversion hydroelectric projects appear to have the potential of providing capacity and energy services at costs comparable to proposed mainstream impoundment projects. Moreover, the environmental and social impacts of diversion projects are likely to be less profound and better understood than those of major impoundments. Although the resource potential of diversions is likely to be much less than the potential from mainstream impoundments, diversion projects could serve local load growth until the environmental consequences of mainstream impoundments are better understood and the effectiveness of mitigating measures is improved.

Evaluation of replacement power cost. The estimated cost of energy from the proposed Mekong mainstream hydropower projects is about 20 percent less than the cost of power from alternative thermal generation options in Viet Nam and Thailand (MRC 2009). Given that the greatest portion of the value of these projects rests on power value, moderate changes in assumptions regarding the cost of alternative resources could significantly affect the net value of these projects. A review of the assumptions used to calculate the replacement cost of power (MRC 2009, Annex B; MRC 2010b) suggests several questionable assumptions, some of which might result in increased cost of replacement power and some that might result in decreased cost of replacement power.
<table>
<thead>
<tr>
<th>Resource</th>
<th>Application</th>
<th>Electrical Products</th>
<th>Commercial Status</th>
<th>Earliest Operation (New project)</th>
<th>Typical Project Size (MW)</th>
<th>Resource Potential</th>
<th>Key Issues</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas combined-cycle</td>
<td>Main grid bulk power supply</td>
<td>Energy, firm capacity, load-following</td>
<td>Mature</td>
<td>2015</td>
<td>Hundreds of MW</td>
<td>Extensive S. China Sea resources</td>
<td>Natural gas price uncertainty</td>
</tr>
<tr>
<td>Supercritical steam coal</td>
<td>Main grid bulk power supply</td>
<td>Bulk energy, firm capacity</td>
<td>Mature</td>
<td>2018</td>
<td>Hundreds of MW</td>
<td>Extensive Viet Nam reserves</td>
<td>Greenhouse gas control</td>
</tr>
<tr>
<td>Impoundment hydropower</td>
<td>Main grid bulk power supply</td>
<td>Energy, firm capacity, load-following</td>
<td>Mature</td>
<td>2018</td>
<td>Tens to thousands of MW</td>
<td></td>
<td>Stream blockage, reduction in flow velocity, flooding</td>
</tr>
<tr>
<td>Reciprocating engine-generators</td>
<td>Isolated grid or main grid load following</td>
<td>Energy, firm capacity, load-following</td>
<td>Mature</td>
<td>2013</td>
<td>Hundreds of kW to several MW</td>
<td>Not energy limited</td>
<td>Fuel cost</td>
</tr>
<tr>
<td>Diversion hydropower (run-of-river)</td>
<td>Bulk power supply or isolated grid</td>
<td>Energy, firm capacity, load following</td>
<td>Mature</td>
<td>2015</td>
<td>Tens of kW to hundreds of MW</td>
<td>Unknown potential</td>
<td>Maintenance of minimum in-stream flow</td>
</tr>
<tr>
<td>Retrofit hydropower (run-of-release)</td>
<td>Bulk power supply or isolated grid</td>
<td>Energy, firm capacity</td>
<td>Mature</td>
<td>2015</td>
<td>Tens of kW to tens of MW</td>
<td>Unknown potential</td>
<td>Limited site availability</td>
</tr>
<tr>
<td>River current hydrokinetic generation</td>
<td>Isolated grid</td>
<td>Energy, firm capacity</td>
<td>Early demonstration</td>
<td>2020</td>
<td>Tens of kW to several MW</td>
<td>Unknown potential</td>
<td>Technology commercialization</td>
</tr>
<tr>
<td>Ocean wave</td>
<td>Bulk power supply or isolated grid</td>
<td>Energy</td>
<td>Early demonstration</td>
<td>2020</td>
<td>Tens of kW to tens of MW</td>
<td>Inadequate energy density</td>
<td>Technology commercialization, competing sea space</td>
</tr>
<tr>
<td>Ocean and tidal current</td>
<td>Bulk power supply or isolated grid</td>
<td>Energy</td>
<td>Commercial pilot</td>
<td>2020</td>
<td>Hundreds of kW to tens of MW</td>
<td>Near shore and Mekong Delta potential</td>
<td>Technology commercialization</td>
</tr>
<tr>
<td>Salinity gradient</td>
<td></td>
<td></td>
<td>Conceptual</td>
<td></td>
<td></td>
<td></td>
<td>Technical immaturity, salinity intrusion</td>
</tr>
<tr>
<td>Bio-residues</td>
<td>Bulk power supply or isolated grid</td>
<td>Energy, firm capacity</td>
<td>Mature</td>
<td></td>
<td>Hundreds of kW to tens of MW</td>
<td>Cassava, palm oil, rice, sugarcane and timber residues</td>
<td></td>
</tr>
<tr>
<td>Energy crops</td>
<td>Bulk power supply or isolated grid</td>
<td>Energy, firm capacity, load-following</td>
<td>Demonstration</td>
<td></td>
<td>Hundreds of kW to tens of MW</td>
<td>Jatropha cropping potential</td>
<td>Cost and sustainability of jatropha cropping</td>
</tr>
<tr>
<td>Geothermal</td>
<td>Bulk power supply or isolated grid</td>
<td>Energy</td>
<td>Mature</td>
<td></td>
<td>Tens of kW to tens of MW</td>
<td>Limited potential</td>
<td>N. Thailand</td>
</tr>
<tr>
<td>Ocean Thermal Energy Conversion</td>
<td>Bulk power supply or isolated grid</td>
<td>Energy</td>
<td>Early demonstration</td>
<td></td>
<td>Tens of MW</td>
<td>No nearshore potential</td>
<td>Technical immaturity, lack of near-shore resource</td>
</tr>
<tr>
<td>Solar photovoltaics</td>
<td>Bulk power supply or isolated grid</td>
<td>Energy</td>
<td>Mature</td>
<td>2012</td>
<td></td>
<td>Good-quality global resource</td>
<td></td>
</tr>
<tr>
<td>Solar thermal</td>
<td>Bulk power supply or isolated grid</td>
<td>Energy, Early commercial</td>
<td></td>
<td></td>
<td></td>
<td>Fair quality direct normal resource</td>
<td></td>
</tr>
<tr>
<td>Windpower</td>
<td>Bulk power supply or isolated grid</td>
<td>Energy</td>
<td>Mature</td>
<td></td>
<td>Tens of kW to hundreds of MW</td>
<td>Good to excellent resource</td>
<td>Conflict w/forest management</td>
</tr>
</tbody>
</table>
Figure A1: Energy cost of resources for main grid service (2009 US$/MWh)

Source: Author’s estimates.
Alternative resource development for isolated loads and microgrids. To the extent that development opportunities are available, run-of-river diversion projects and addition of power generation to nonpower water control structures appear to offer the most economic alternatives for
supplementing or replacing diesel generation for microgrid and isolated load service. If not yet accomplished, a detailed survey of development opportunities should be undertaken. Solar photovoltaics, biodiesel, and river current hydrokinetic technologies, though considerably more expensive than hydropower options, also appear to be competitive with fossil diesel. These should be considered where hydropower development opportunities are unavailable. Solar photovoltaic technology is well established and requires little research or development beyond efforts to develop standard packages suitable for typical applications. Jatropha may be promising source of biodiesel fuel for existing and new reciprocating engine generators and the feasibility of establishing sustainable cultivation and processing should be investigated. River current hydrokinetic technology is at an early stage of development and the objective should be to develop robust standardized modular designs suitable for domestic fabrication and deployment. A suggested approach is as follows:

- Commence a hydrokinetic site assessment with the initial objective of identifying a set of representative sites at which demonstration projects can be undertaken.
- Fully characterize demonstration sites.
- Design, construct, and install units at these sites. Use a variety of machines incorporating design variations where the value and cost of these is not well understood.
- Operate and monitor demonstration units with the objective of developing a set of commercial production designs optimized for representative LMB sites.
- If results are favorable, expand site inventory characterization basin-wide.
- Commence general deployment of production designs at favorable sites.
- Maintain follow-up monitoring to ensure machines remain in-service and are properly maintained. Use operating experience to refine operating and maintenance protocols, equipment and plant design.

4. Other Renewable Generating Options

**Agricultural and Other Bio-Residues**

Conventional, steam-electric plants with or without CHP will be the chief technology for electricity generation using solid bio-residues in the near term. These units typically range from five to 50 megawatts in capacity; capacity frequently being determined by available fuel supply within economic transport distance. Modular, bio-gasification plants are under development and may be introduced within the next several years. Modular units would open the possibility of bringing the plant to the fuel, thereby expanding the potential fuel supply, reducing fuel transportation costs, and improving the economics of plant operation. Available fuels include residues from the harvesting and processing of cassava, palm oil, rice, sugarcane, and timber.

**Dedicated Energy Crops**

Dedicated energy crops are not usually considered economically feasible as a fuel for electricity production because the value of the energy product (usually ethanol or biodiesel) for transportation is greater than its value for electricity generation. Production of biodiesel in
areas of the Lower Mekong Basin suitable for growing jatropha may be an exception to this rule. Biodiesel obtained from jatropha seed can fuel the reciprocating engine generators that provide local electricity supply in many areas. Moreover, the husks and press cake residues of jatropha seed processing can be processed in anaerobic digesters to yield a biogas fuel suitable for gas-fired, reciprocating engine generators.

Jatropha (*Jatropha curcas*) is a drought-tolerant perennial shrub native to Central and South America. Though the plant is said to thrive on marginal soils, recent evidence suggests that economic oil yield requires abundant water and nitrogen and phosphorus fertilization (Achten et al. 2008). Jatropha produces inedible seed with high oil content. The oil can be used directly as a biodiesel blend or refined for use as neat biodiesel. Widely planted in tropical and subtropical countries as hedgerow, plantation cultivation of jatropha for oil and glycerin (a byproduct of refining) is increasing, especially in Brazil, the Philippines, India, and China.

The seed is obtained by manually collecting then hulling the mature fruit pods. The seed is sun or oven dried, then pressed to extract the oil. Solvent extraction methods are also available. Following removal of particulates by filtering or centrifugation, the oil can be used directly or blended with fossil diesel in older or low-speed engines. Further refining (transesterification) produces a biodiesel compliant with European and North American standards, plus glycerol, a marketable byproduct. The biodiesel can be used neat or blended with fossil diesel or methanol. The press cake can be used fertilizer or as feedstock for anaerobic digesters to produce additional fuel in the form of biogas.

Biodiesel can substitute for imported diesel fuel in the reciprocating engine generator sets used for community-scale or isolated grids as well as tractor, irrigation pump, and road vehicle engines. Crude jatropha oil is suitable for older vehicles and stationary engines, but newer diesels, including the high-efficiency generating units now available require jatropha biodiesel. Reciprocating engines are expected to remain an important component of community and isolated grid power systems, even as the penetration of renewable sources increases, to provide firm capacity, load-following capability, and dry season energy.

Limited and poorly documented information is available for jatropha biodiesel production costs. Jatropha oil was reported to cost approximately US$43/bbl at the time of the 2008 Air New Zealand flight test using refined jatropha oil as jet fuel. The Indian Planning Commission reports production costs of 26 rupees (approximately US$41/bbl at current exchange rates) per liter. At an estimated calorific value of about 5,500 MJ/bbl, this equates to US$7.90 to $8.20/MMbtu. In comparison, the cost of diesel fuel for replacement cost of power using diesel generators used by the MRC for the Basin Development Plan Power Benefits assessment (MRC 2010b) is US$16.63/MMBtu, forecast to escalate 6 percent annually. The comfortable spread between jatropha biodiesel prices and forecast diesel prices suggests that jatropha biodiesel has the potential of being a competitive domestic source of fuel for the reciprocating engines serving isolated electrical grids.

In addition to providing a competitive supply of renewable energy, jatropha biodiesel production could provide rural economic development and employment benefits, help restore degraded land, and enhance national energy security.
Jatropha has been heavily promoted in recent years and aggressive programs are underway in many countries, including Cambodia and Laos, to establish jatropha plantations for biodiesel production for export and domestic use. Some of these efforts have fallen short of official goals and important issues remain to be resolved. Domestic cultivars having reliable yield need to be developed. Systematic study of Jatropha agronomy is needed including optimal cropping schedules, spacing, irrigation, propagation, and fertilization. Finally, the naturally present toxins in jatropha fruit, the chemicals used in processing, and the air quality effects of jatropha biodiesel combustion warrant study.

Though small-scale pressing and refining equipment suitable for decentralized production is available, plantation agriculture tends to be more efficient than small-scale operations. Large-scale growing and processing operations, however, can present negative consequences including deforestation and accompanying ecological, hydrological, and erosion concerns; competition for land for food supply; and increased demand for irrigation and pesticides. Equity issues arise. Large-scale operations are often controlled by private concessions and national and local economic benefits are foregone. Plantation growers will seek out prime land to maximize production, pressuring small-scale farming and possibly raising food prices.

Other issues concern energy balance and global warming potential. Available studies suggest that the life-cycle energy balance of jatropha biodiesel is generally positive, providing that the byproducts (husks, seed cake, glycerol) are efficiently used. The global warming impact of jatropha biodiesel appears to be significantly less than fossil diesel, though it would include any forest clearing undertaken to establish jatropha cultivation.

Geothermal

The crustal heat of the earth can be used to produce electricity and useful thermal energy. Conventional geothermal development use requires the presence of fluids at sufficient temperature within a feasible drilling depth. Flashed steam technology can be used for intermediate to high temperature resources; binary fluid technology is used for low to intermediate temperature resources. Conventional geothermal technology is commercially mature, but suitable sites are limited. Engineered (or “enhanced”) geothermal technology requires only sufficient temperature and fracturable rock at feasible drilling depth. The fluid is supplied by injecting water from the surface following the creation of heat transfer surfaces by fracturing. Enhanced geothermal technology is in the early demonstration stage and, if successfully commercialized, is expected to greatly expand areas suitable for geothermal resource development.

Geothermal plants provide firm capacity and energy, but limited load-following capability. Binary technology with geothermal fluid reinjection (the typical configuration) has few environmental impacts. The principal risk is associated with the substantial capital investment needed to prove up a resource prior to financing plant construction.

One small (0.3 MW) geothermal unit is operating near the community of Fang in northern Thailand. Modest opportunities for additional geothermal development using binary-cycle geothermal technology appear to be available in this area. The Himalayan Geothermal Belt, lying
slightly north of the intersection of the Indian and Asiatic tectonic plates extends from Kashmir through Tibet, to Yunnan province of China, and possibly down into northern Myanmar and Thailand (Figure 1 of Eckstein et al. 2010). Seven intermediate temperature (150–200°C) geothermal systems have been identified within this area of northern Thailand. One near Fang is the location of the only reported operating geothermal power plant within the four LMB countries. This 0.3 MW binary unit with waste heat recovery has successfully operated on 117°C water since 1989. Though the presence of additional geothermal resource areas in Thailand is reported no further information was located regarding other geothermal resources in Thailand or other LMB countries. Binary geothermal technology has progressed rapidly in recent years and modular binary geothermal units ranging from 250 kW to about 15 MW in capacity are commercially available. The cost of recently developed, small (15 MW) binary plants in western North America is approximately $85/MWh (2009 US$, busbar, independent developer financing, no incentives).

Solar

Electric power can be produced from solar radiation using solar photovoltaic or solar thermal technologies. Photovoltaic plants convert sunlight to electricity using solid-state devices. Because no combustion or other chemical reactions are involved, power production is emission-free. No water is consumed other than for periodic cleaning. Power output is variable and battery storage or a backup power source is required for isolated loads demanding a constant supply. Grid-connected installations require firm capacity and balancing reserves. However, balancing reserve requirements may be reduced by distributing many small plants over a wide geographic area, dampening cloud-driven ramp rates. Most commercial photovoltaic devices are nonconcentrating, in that the sunlight is not concentrated using mirrors or lenses.

Solar thermal power generation (also referred to as concentrating solar power (CSP) uses lenses or mirrors to concentrate solar radiation on a heat exchanger to heat a working fluid. The working fluid is used directly or through a secondary working fluid to power a turbine generator. CSP technologies are categorized by the design of the concentrator and the type of thermal engine. The three basic types are parabolic trough, central receiver, and Sterling dish. Nonconcentrating devices utilize global radiation, i.e., direct solar radiation plus the diffuse sky and cloud radiation. Concentrating devices are limited to direct solar radiation and are more suitable for cloud-free locations.

Good-quality solar resources ranging from 5.5 to 6.0 kWh/m²/day annual average are found in southern Laos, northern Cambodia, and northern and central Thailand. Fair-quality resources (5.0–5.5 kWh/m²/day annual average) are found throughout the rest of the LMB. Direct normal resources in the region are fair, the best being 4.5 to 5.0 kWh/m²/day annual average in southern Laos, northern Cambodia, and east-central Thailand. Despite the quality of resource and coincidence with air conditioning loads, relatively little development of solar generation is reported. Figures are available only for Thailand, which reports 34 megawatts of distributed photovoltaic capacity. Substantial potential using nonconcentrating photovoltaic devices is available. This resource can be used in off-grid, community-scale grid, and utility-scale grid
applications. Grid applications normally require use of inverters and safety disconnect equipment, adding to the cost and reducing the output of these systems.

**Wind**

The most recent comprehensive assessment of the wind resources of the Lower Mekong Basin is the 2001 Wind Energy Resource Atlas of Southeast Asia prepared by TrueWind Solutions for the World Bank (TrueWind 2001). This assessment estimated wind resource potential for both large and small turbines (65 meter and 30 meter hub height). The assessment indicates that good to excellent potential (average annual wind speeds of 7.0 m/s or greater) for large-scale wind development is present in the mountains of central and southern Viet Nam, central Laos, and in the coastal area of southern and south-central Viet Nam. Scattered areas of good potential are also present in central and western Thailand. The extensive shallow seafloor off the southern coast of Viet Nam suggests the potential for offshore wind development using monopole turbine foundations as used in the North Sea. LMB winds are at their strongest in the December through February and June through August periods.

Areas in or near the LMB classed as good or better (average annual wind speeds of 5.0 m/s, or greater) for small turbines include the aforementioned areas plus east-central Thailand, scattered areas of Cambodia, south-central Laos, and central and southern Viet Nam.

**Ocean Thermal Energy Conversion**

Solar radiation incident on tropical oceans can create a surface-to-depth temperature differential of 20°C, or more. This is sufficient for generation of electricity from the potential energy of the temperature differential using Rankine cycle heat engines.

The leading ocean thermal energy conversion (OTEC) concept would use binary-cycle technology. Binary technology would use seawater from the heated surface layer to evaporate a low-boiling point working fluid such as ammonia. The vaporized working fluid would drive a turbine generator, then be condensed in a heat exchanger cooled by cold seawater pumped from depth. The condensate would then be repressurized with pumps for return to the evaporator. The pumps, heat exchangers, and turbine generators would be located on a floating or semisubmerged platform, or shore side in favorable locations. The low temperature differential limits recovery efficiency to less than 10 percent, necessitating the pumping of extremely large volumes of seawater. A 100 MW plant, for example, would require a 10-meter diameter, cold-water intake at least 1,000 m in length. Though the energy supply is “free,” the scale of the cold-water intake, seawater pumps, and heat exchangers will result in very high unit capital cost. Preliminary cost estimates of commercially mature facilities range from $7,000–17,000/kW, yielding electricity at $120–330 per MWh.

OTEC could provide significant amounts of renewable, baseload electricity with little environmental impact. Byproducts of plant operation could include desalinated water, chilled water for air conditioning, nutrient and cold water supply for aquaculture, and feedstock for extraction of dissolved minerals.
OTEC concepts were first proposed in the nineteenth century and significant research commenced in the late 1970s. Technical difficulties and persistently low fossil energy costs resulted in termination of most of this work during the 1980s. Rising oil prices, the resurgence of interest in low-carbon forms of energy, and efforts to achieve national energy security have revived interest in OTEC technology. At least two serious efforts are underway to develop the technology, including a 10-megawatt pilot plant for Tahiti and a five- to 10-megawatt pilot plant in Hawaii. Ten years or more are expected before operation of the first commercial plant. It is likely that the earliest commercial development of OTEC technology will be at tropical islands currently relying on imported oil for electricity and at arid sites benefitting from desalinated water byproduct.

Surface temperatures of the South China Sea are reported to average 29°C and temperatures of 3°C have been measured at 2,900 meters in the Sabah trough. However, the Gulf of Thailand and the westerly portion of the South China Sea lie over a continental shelf of less than 200 meters depth, whereas the cold water layer lies at 1,000 meters, or deeper. Of the LMB countries, only the central coast of Viet Nam approaches within 100 km of depths of 1,000 meters. This distance is likely to render OTEC an infeasible option for energy supply to the LMB countries for the foreseeable future.
Appendix B: Social Impacts and Recommendations for Future Assessments

1. Insights from Additional Resources

Social impact assessment in basin-scale planning purposes (as opposed to assessment of individual projects) is a complex issue, which is constrained by limited knowledge of impact processes and data availability. The challenge of social impact assessment is particularly relevant for the planning processes in the LMB. Despite MRC’s efforts to provide analytical inputs on the subject under the BDP and the SEA, key knowledge gaps remain with regards to the distribution of impacts from the key water resource developments, as currently planned by LMB governments, on different groups of Mekong stakeholders. In addition, the likely effectiveness of proposed mitigation and compensatory measures also presents a major source of risk and uncertainty in assessing the cumulative costs and benefits of the proposed projects. Within the time-scales of the planning periods under consideration, the social and socioeconomic landscapes can also be expected to change through exogenous factors (e.g., urbanization, education, health, poverty alleviation programs, etc.), such that the livelihoods situation in the LMB today within the potentially affected population will not be the same in 10 or 20 years time. Such a dynamic situation increases the analytical complexity in establishing a baseline situation against which social impacts of developments could be assessed.

Building on the social impact assessment aspects of the BDP and SEA, this appendix reviews some additional materials which further elucidate the current socioeconomic situation in the Mekong Basin and the social impacts of previous, large, infrastructure developments in the region. Given the wealth of literature that exists on the subject, this appendix chooses to focus on key insights from selected case studies which are especially useful in improving the LMB water resources planning processes, including those related to mainstream and tributary hydropower projects.

Insights from additional resources on current socioeconomic and livelihood conditions of the population in the LMB, and potential social and environmental impacts from new projects, are highlighted below:

a) Environmental Impact Assessment (EIA) studies (Sangha and Bunnarith 2006) have been inadequate, especially regarding the identification of and proposed mitigation for transboundary impacts.

b) While hydropower dams are expected to generate high revenues for the host country, livelihoods of affected people within the country may not be improved as much as expected from the development, as demonstrated by the past experience from several hydropower projects including the Pak Mun dam (PAP 2011), hydropower developments in the Sesan, Sekong, Srepok (3S) transboundary basin, and the Theun-Hinboun hydropower project (Norplan 2008).
c) Even when mitigation and compensation measures are in place, they may not be effective for the affected populations. Previous experience from the Pak Mun dam in Thailand and the Theun-Hinboun dam in Lao PDR illustrates the inadequacy of these measures. However, recent experience from the Nam Theun 2 project in Lao PDR suggests that putting in place a comprehensive and effective compensation and mitigation scheme is also possible when the government carefully negotiates a concession agreement with the developer.

i. Pak Mun Case Study, Thailand

A review of the Pak Mun dam experience revealed that the affected communities did not participate in the planning process for the project. As a result, environmental and social costs, which had to be borne by the communities, were not adequately taken into consideration. In addition, the displaced community members argued that both environmental and social costs—especially the intangible cost of loss of cultural heritage, traditional livelihood, and social breakdown—cannot be fully compensated and mitigated.

Table A2.1: Summary of Pak Mun Consultation Results

<table>
<thead>
<tr>
<th>Issues</th>
<th>Before dam construction</th>
<th>After dam construction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Food security</td>
<td>Easy to find food</td>
<td>More difficult because nearby ecosystem has been degraded</td>
</tr>
<tr>
<td>Debt</td>
<td>Little</td>
<td>More debt since communities are no longer self-reliant</td>
</tr>
<tr>
<td>Community integrity</td>
<td>High</td>
<td>Community breakdown</td>
</tr>
<tr>
<td>Culture and norms</td>
<td>United</td>
<td>Collapsed</td>
</tr>
<tr>
<td>Revenue from tourism</td>
<td>Higher</td>
<td>Lower</td>
</tr>
</tbody>
</table>

Source: Sub-committee for consultation with the people affected by the Pak Mun dam, 2010

ii. Theun Hinboun Case Study, Lao PDR

Darasouk (2009) researched the implementation of the Theun Hinboun Power Company (THPC) mitigation and compensation plan in Lao PDR. The company adopted a comprehensive 10-year mitigation and compensation plan following the construction of the Theun Hinboun hydropower dam, which inadvertently damaged the livelihood of local populations in the project area. Her research found that the plan “was significantly delayed by documentation requirements and late availability of fund.” As an example of a mitigation measure proposed for riparian communities affected by the project, “the dry season paddy land with irrigation system and other agriculture lands planned for are still pending (yet to be implemented). Therefore it can be concluded that these proposed packages are inadequate to restore livelihood and food security for recipient river communities in the first two years after relocation.”
In addition, Darasouk noted that “The four impacted communities studied still have no access to electricity and remain with poor access roads... The THPC compensation and mitigation program to deal with these impacts was totally inadequate. As examples, the drinking water supply in Khen village failed and cannot be used, three years of dry season rice practice for both Khen village and Kengkhot village were unsuccessful, and many households remain in debt to the savings and credit fund established by the project... The mitigation and compensation program initiated by THPC in 2001 to address the project’s social and environmental impacts has not lived up to expectations and is failing to restore people’s livelihoods” (Darasouk 2009).

Based on the above observations, Darasouk (2009) concluded that the THPC experience represents a clear case of failure of existing institutions to fulfill their promises and meet villagers’ needs. Darasouk analyzed key factors that contributed to the failure of these mitigation and compensation programs and summarized that:

- Project-affected people (PAP) were not properly identified, and upstream and downstream communities were excluded.
- Important environmental impacts emerged that had not been anticipated in the planning documents. For example, dynamic floods and erratic water flow changed after the project.
- Mitigation and compensation packages for the PAP were far from adequate, with no direct compensation or cash compensation available for physical and livelihood losses.
- New lands allocated to the displaced communities are very poor in terms of their agricultural potential.
- Substitute livelihood options for the communities failed or were unsustainable.
- Deforestation of previously unused mountainous and watershed areas for upland agriculture turned out to be severe, with the backfiring effect of reducing hydropower productivity.

iii. Nam Theun 2 Case Study, Lao PDR

The Nam Theun 2 hydropower project in Lao PDR is a recent project, which is recognized as having achieved a better outcome in compensation and mitigation for the PAP. Despite some unsuccessful mitigation programs to offset the social impact and loss of ecosystem services (such as the setting up of a Village Forest Association (VFA) at the Nakai Plateau), and some negative unforeseen impact on biomass decay releasing methane and CO₂, the Nam Theun 2 project has put in place several key mitigation and compensation measures with clear evidence of success. While some criticized that these programs and measures started much later after the dam operation when vast natural capital had already been depleted, key elements of these programs are effective and could provide a relevant example for future projects.

Specifically, the Nam Theun 2 Power Company (NTPC) under the concession agreement with Lao PDR Government has instituted an environmental management and monitoring system to carry out these programs:
1. Artificial habitats were created to replace habitat lost, such as eight “salt lick” locations for ungulates and 30 artificial wetlands.

2. A monitoring program was established in cooperation with the Watershed Management and Protection Authority (WMPA) with funding set aside by NTPC for long term monitoring for conservation purposes.

3. Under the Wildlife Management and Monitoring Program, some new animals were discovered, such as Muntjak and Chinese Swamp Cypress in the National Protected Area (NPA) and corridor zones. Fish inventory of both upstream and downstream river species is also included in this program.

4. Under the Biodiversity Conservation Program, a turtle conservation program was put in place where animals were collected and rehabilitated in their natural habitat.

5. An Invasive Species Program was put in place whereby some species were required to be removed or destroyed for health and safety reasons.

6. A Study Program for the Threatened Species was established. This program can be a valuable lesson for future development projects that could cause disturbance or interruption of ecosystem health and habitat, potentially resulting in a permanent or irreversible damage on unknown or undiscovered plant or animal species with unknown function in the food cycle.

7. The Environmental Education Program (EEP) was implemented on the Nakai Plateau to instill awareness and reduce exploitative danger to wildlife.

d) Environmental pollution can result from aquaculture development (Loc et al. 2009).

e) Seawater intrusion and sediment loss are likely to affect agricultural production in the Mekong (Nguyen Xuan Hien 2009).

The BDP notes that the Mekong Delta’s population of more than 17 million is directly impacted by changes in upstream flow and water quality conditions. These riverine populations are also the segment of basin population most vulnerable to the impacts of climate change, particularly potential sea level rise. Potential changes that will affect livelihoods of these populations, especially those in the delta, are not yet analyzed in detail as part of the BDP. The BDP does however provide a preliminary estimate of the number of vulnerable resource users in this category. In future water resource planning discussions in the Mekong, detailed assessments should be conducted on the impacts of these key changes on flow and sediment conditions which will affect the delta, especially with regards to agricultural lands and productivity, fisheries productivity, and lost fisheries-related activities and occupations.

f) Wealth distribution problems (disparity between rich and poor) may arise from mainstream development projects (Pongpaichit 2009).

g) Aquaculture may not replace lost captured fisheries in terms of affordability for local populations and nutrition (Hall and Manorom undated).

While the scenario analyses in the BDP2 report pointed to positive impacts for some key socioeconomic sectors, such as employment and agriculture, significant social impacts,
especially negative ones from lost capture fisheries, are anticipated at the local level. Lost capture fisheries is a key issue of concern for future social impact assessments in the Mekong due to its critical linkage to food security of local people along stretches of the river. For example, total fish consumption in Lao PDR is currently estimated to be 204,800 tons. Based on a population of five million people, the average annual per capita fish consumption would be 42.2 kg. Capture fisheries contribute the largest proportion of total fish consumption (85 percent or 182,700 tons), with the remainder coming from reservoir fish catch (16,700 tons) and aquaculture production (5,400 tons) (Hall and Manorom undated). It would take a vast expansion of reservoir fishing success to make up the difference if the country loses a minimum of 25 percent of its 182,700 tons of annual river fish consumption. In addition, increased aquaculture production in the delta may be geared more to export markets than to domestic supplies and there is no guarantee that fish sourced from remote aquaculture areas will be affordable to people who normally catch their own supply.

h) The importance of sediment deposition to agricultural productivity and riverbank gardens should be further analysed (Gajaseni 1995, 2005, 2006).

Based on field studies along the Mekong from Northern Lao (Bokaeo) down to Southern Lao (Champasak), and discussions by the Mae Fah Luang University (MFU) study team members with various groups and individuals at the Procedure for Notification, Prior Consultation, and Agreement (PNPCA)-related public consultation meetings in Thailand in 2011, essentially every rural family living along the Mekong practices riverbank gardening in the dry season (from January to May). Each riparian family in Thailand, for example, earns 50,000–70,000 baht from its annual riverbank agriculture. These riverbank gardens are only possible due to the nutrients provided by the Mekong’s natural river flows. Should these flows diminish markedly due to construction of mainstream or tributary dams or other diversion activities, these important food and income sources could disappear. For comparison, in Thailand’s Chao Phraya River nutrients from natural services of the river are equivalent to adding 62 kg per hectare of nitrogen and phosphorus fertilizers per year (Gajaseni 1995).

i) Stakeholders’ access to required project documents was limited during the PNPCA consultation process for Xayaburi, reflecting the need for project proponents to improve the quality of future public consultation processes.

From the discussion that took place during the public consultation organized as part of the PNPCA for Xayaburi by the Thai National Mekong Committee at Chiang Kong on January 22, 2011, the people along the Mekong River indicated that major project documents were not available for their review for an adequate period of time prior to the consultation. During the event, the people also perceived that there would be substantial social impacts, especially for food security and loss of traditional knowledge and local identity, if these ecosystem services provided by the river were altered by major development projects. The importance of adequate and informed consultation on these subjects was highlighted during the discussion.
j) Cultural service losses are irreplaceable and permanent. Indigenous knowledge learned over generations, even centuries, may evaporate if planning assessments do not properly factor in the value of this important ecosystem service of the Mekong.

People of the Mekong Basin recognize highly diverse ecosystem components of their region, often features that are unknown or unrecognized by academic ecologists. For example, local people can identify 1.1 systems that influence fish diversity in their fishing areas, each with a different structure, function, and dynamics. The Mekong fishermen use 71 different types of fishing gear that conform with the annual biophysical actualities and ecological dynamics of the Mekong River. These learned efforts allow them to maintain their sustainable family livelihoods. If the free-flowing Mekong River is turned into a series of interconnected reservoirs, many of these diverse (sub) ecosystems would be lost. Fishermen could no longer rely on their traditional fishing gear and their effective transferred indigenous knowledge to sustain their families’ livelihoods. Promotion of reservoir fisheries will be least beneficial to these affected communities because of the lack of knowledge to practice fishing effectively in such a vastly different biophysical environment under entirely different ecological conditions. Inter- and intrageneration networking and insight would be lost without proper management (Mekong-Lanna Natural Resources and Culture Conservation Network 2009).

k) A key adaptability issue to consider is how resilient and adaptive Mekong people are and, specifically, how likely it is that they can move from their traditional lowland floodplain areas into other areas of the basin.

Research and experience from within the region suggest that such a move would be tremendously disruptive and, for most of these individuals, highly unlikely (Gajaseni 2006). Their traditional livelihood practices of seasonal paddy rice cultivation passed down from generation to generation combined with fishing using highly diverse fishing gear reflecting accumulated indigenous knowledge would undergo a massive transformation. In their place, people would need to develop the capacity to engage successfully in upland rice cultivation techniques or slash and burn agriculture accompanied by hunting and gathering in nearby forests. Household economies that depend on paddy rice and riverbank garden vegetables for nutrition and on capture fisheries for protein will be forced to change into new and uncertain survival tactics, based on very little applicable indigenous knowledge. For nearly all of them, their new household economic situation is likely to be negative rather than positive when compared to their present conditions.


Based on the discussion above, key recommendations on the application of alternative methodologies and analytical approaches to enhance future social impacts assessments are offered for future basin-wide planning processes in the LMB.

**Stakeholder coverage**

- A full range of vulnerable resource user groups should be included in future social impact assessment strategies.
• Assessment of the differential impacts of planned projects on vulnerable groups (low income, disadvantaged, women, etc.) should be included in future.

**Social assessment and ecosystem services coverage**

• Sensitivity analysis should be improved to cover more variables of uncertainty. Variables should be specifically included for each geographical, political, and cultural boundary under analysis.

• There should be a study of baseline data on natural and man-made capital in the basin, employing different methods of sampling and collection, including one that addresses the linkage between ecosystem services and social impact. This information will be useful to inform the formulation of effective mitigation, replacement, and compensation programs. Evaluation and monitoring processes should be put in place for different stages of the project development to follow the impact of the project on social and ecosystem services to avoid risks and unexpected secondary impacts.

• Ecosystem health and integrity and linkages between the cultural services of the Mekong River, local livelihoods, social integrity, value and cultural identity should be addressed in social impact assessments. These issues should be dealt with at the start of the project.

• Cumulative and transboundary impacts are recommended to be included as an integral part of impact assessment, both for EIA and Social Impact Assessment (SIA) studies.

• Maintenance of “minimum environmental flow” should be negotiated and agreed upon by all stakeholders.

**Best practices**

International criteria and standards for evaluating the social impacts and effectiveness of mitigation measures should be adopted in the analysis of major projects in the Mekong, including mainstream and tributary dams. Best practice evaluations should cover all impacts that could result from the project and should estimate acceptable mitigation and compensation measures for key losses, such as fisheries and rice production.